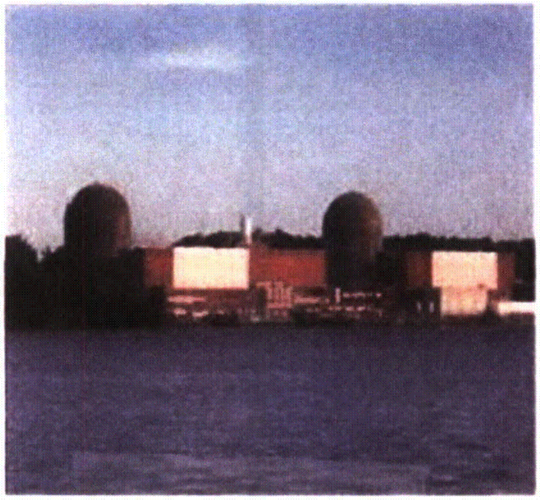
INDIAN POINT UNIT 2 AND UNIT 3



Coastal Zone Management Act Consistency Certification

In support of
Renewal of Indian Point Unit 2 and Unit 3 USNRC Operating Licenses

Submitted by:

Entergy Nuclear Indian Point 2, LLC
Entergy Nuclear Indian Point 3, LLC
Entergy Nuclear Operations, Inc.

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SUPPLEMENTAL INFORMATION ON NATIONAL AND STATE INTERESTS

VOL. III OF IV

SEPTEMBER 26, 2014

LIST OF SUPPLEMENTAL ATTACHMENTS:

S-1	Alice L. Buck, A History of the Atomic Energy Commission, U.S. Department of Energy, July, 1983
S-2	Report of the Subcommittee on Research and Development on the Five-Year Power Reactor Development Program Proposed by the Atomic Energy Commission, March, 1954
S-3-1, 3-2; 3-3 and 3-4	Deed dated October 30, 1954, recorded at Liber 5392, Page 29; Deed dated December 1, 1954, recorded at Liber 5398, Page 340; Deed dated January 1, 1955, recorded at Liber 5419, Page 283; Deed dated January 31, 1955, recorded at Liber 5538, Page 404
S-4	Excerpt from Major Activities in the Atomic Energy Programs, January—December 1961, United States Atomic Energy Commission, January, 1962, at Appendix 8, *License Applications Filed and Actions Taken: Summary of License Actions.*
S-5	Excerpt from Final Environmental Statement Relating to the Operation of Indian Point Nuclear Generating Plant No. 3, United States Nuclear Regulatory Commission, February, 1975. Attachment 21 to Consistency Certification, December, 2012; excerpts included as Attachment S-5 to this Supplemental Filing.
S-6	Message of the Governor in relation to the Use of Atomic Energy for Peaceful Purposes, State of New York Legislative Document No. 46 (1959)
S-7	Act inserting Article 19-D, Atomic Energy Law, and establishing the New York Office of Atomic Development, 1959 N.Y. Sess. Law 72 (McKinney)
S-8	Deed from New York State to Consolidated Edison Company dated October 17, 1959, recorded at Liber 5973, Page 283
S-9	An Atomic Development Plan for the State of New York, A Report to Governor Nelson A. Rockefeller, New York Office of Atomic Development, December 1, 1959.
S-10	Pub. Auth. Law § 1850-a, 1962 N.Y. Sess. Law. 428 (McKinney) (c. 210).
S-11	Civilian Nuclear Power . . . a Report to the President—1962, Atomic Energy Commission, November, 1962
S-12	Energy Resources: A Report to the Committee on Natural Resources, National Academy of Sciences, National Research Council, December, 1962.

S-13	National Power Survey, Federal Power Commission, October 31, 1964.
S-14	A Report by the Federal Communications Commission on the Northeast Power Failure of November 9-10, 1965, and its Effect on Communications, Federal Communications Commission, February 23, 1966.
S-15	Certificate dated January 1, 1966, recorded at Liber 6589, Page 308.
S-16	Deed from New York State to Consolidated Edison Company dated April 21, 1966, recorded at Liber 6614, Page 70.
S-17	Dr. Glenn T. Seaborg, *A New Look at Nuclear Power* Volume 8, Number 3: 8 Atomic Energy L.J. No. 3, 191 (1966).
S-18	Oliver Townsend, *Atomic Power Development in New York State*, 8 Atomic Energy L.J. No. 3, 207, 215 (1966).
S-19	Civilian Nuclear Power—The 1967 Supplement to the 1962 Report to the President, Atomic Energy Commission, February, 1967.
S-20	Neal L. Moylan, *The Role of Power in Economic Development,* 10 Atomic Energy L.J., No. 1, (1968)
S-21	United States v. Consolidated Edison of New York, Inc., 580 F.2d 1122 (2nd Cir. 1978).
S-22	Committee on Energy and National Resources, Executive Energy Documents, Publication No. 95-114 (Comm. Print July 1978).
S-23	Deed from Consolidated Edison Company to New York State dated August 31, 1971, recorded at Liber 7006, Page 298.
S-24	Letter from Federal Power Commission (T.A. Phillips, Chief, Bureau of Power) to Atomic Energy Commission, dated May 10, 1972.
S-25	A Review of Consolidated Edison Company 1972 Summer Power Supply Problems and Twenty-Year Expansion Plans, Bureau of Power Federal Power Commission, September, 1972.
S-26	Excerpt from Final Environmental Statement Relating to the Operation of Indian Point Nuclear Generating Plant No. 2, United States Atomic Energy Commission, September, 1972. Attachment 20 to Consistency Certification; excerpts included as Attachment S-26 to this Supplemental Filing.
S-27	Legislative History of the Coastal Zone Management Act of 1972, as Amended in 1974 and 1976 With a Section-By-Section Index, U.S. Government Printing

	Office, December 1976, at 211, reprinting Senate Report No. 92-753 (1972).
S-28	Joint Committee on Atomic Energy, Understanding the "National Energy Dilemma", 99-730 (Joint Comm. Print 1973).
S-29	The Nation's Energy Future, Atomic Energy Commission, December 1, 1973.
S-30	Letter from Federal Power Commission (T.A. Phillips, Chief, Bureau of Power) to Atomic Energy Commission dated December 13, 1973.
S-31	Pub. Auth. Law § 1001-a (1974), "Emergency Provisions for the Metropolitan Area of the City of New York," N.Y. Sess. Law 1974 c. 369, 1974 N.Y. Sess. Laws 505 (McKinney).
S-32	Deed from Consolidated Edison Company to Power Authority of the State of New York, dated December 30, 1974, recorded at Liber 7306, Page 736.
S-33	Annual Report, The Power Authority of the State of New York, March 25, 1976.
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S-37	National Power Survey, The Adequacy of Future Electric Power Supply: Problems and Policies, Federal Power Commission, March, 1976.
S-38	Factors Affecting The Electric Power Supply: 1980-85, Federal Power Commission December 1, 1976.
S-39	Federal Power Commission, Electric System Disturbance on the Consolidated Edison Company of New York, Inc., System, (July 13-14, 1977, supplemented August 4, 1977.)
S-40	Letter of Basil A. Patterson, August 13, 1982; NYCMP II-1, at 2
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S-42	New York State Energy Master Plan, New York State Energy Planning Board, March, 1982.
S-43	New York State Assembly, The Electric Industry in New York, Sheldon

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S-44	Excerpt from PSC Cases 94-#-0952, et al., "Competitive Opportunities Regarding Electric Utilities."
S-45	Deed from Power Authority of State of New York to Entergy dated November 21, 2000, recorded at Westchester County Registry, Control Number 403340618.
S-46	National Energy Policy Report by the National Energy Policy Development Group (May, 2001)
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S-48	A Roadmap to Deploy New Nuclear Power Plants in the United States by 2010, United States Department of Energy Office of Nuclear Energy, Science and Technology and its Nuclear Energy Research Advisory Committee Subcommittee of Generation IV Technology Planning (October 31, 2001)
S-49	The Future of Nuclear Power, An Interdisciplinary MIT Study, Massachusetts Institute of Technology, 2003.
S-50	White House National Economic Council, Advanced Energy Initiative, February, 2006.
S-51	Press Release, Governor Spitzer Unveils Cutting-Edge Global Warming Regulations, October 24, 2007.
S-52	Effects of Climate Change on Energy Production and Use in the United States, National Science and Technology Council, U.S. Climate Change Science Program, February 2008.
S-53	Press Release, "Governor Paterson Rings in New Era to Combat Climate Change," September 26, 2008.
S-54	Update of the MIT 2003 Future of Nuclear Power, An Interdisciplinary MIT Study, Massachusetts Institute of Technology, 2009.
S-55	U.S. Department of Energy, National Electric Transmission Congestion Study, December, 2009.
S-56	U.S. Department of Energy, Nuclear Energy Research and Development Roadmap, Report to Congress, April 2010.
S-57	President Obama, State of the Union Address, January 25, 2011.

S-58	Objective 1: Extend Life, Improve Performance, and Maintain Safety of the Current Fleet—Implementation Plan, U.S. Department of Energy, Office of Nuclear Energy, January, 2011.
S-59	Governor Cuomo 2012 State of the State Address.
S-60	Energy Security in the United States, Congressional Budget Office, May, 2012.
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S-62	Strategy for the Management and Disposal of Used Nuclear Fuel and High-Level Radioactive Waste, U.S. Department of Energy, January, 2013.
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S-64	Report to the President—Rebuilding America's Infrastructure: Cutting Timelines and Improving Outcomes for Federal Permitting and Review of Infrastructure Projects, The White House, May, 2013.
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S-69	The President, Memorandum of June 25, 2013—Power Sector Carbon Pollution Standards
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S-71	Hurricane Sandy Rebuilding Strategy, Hurricane Sandy Rebuilding Task Force, August, 2013.
S-72	Indian Point Contingency Plan, Final Generic Environmental Impact Statement (New York Public Service Commission, September, 2013)

S-73	Executive Order #13653, Preparing the United States for the Impacts of Climate Change
S-74	Excerpt from Climate Change Impacts in the United States, U.S. National Climate Assessment, U.S. Global Change Research Program, May, 2014
S-75	PlaNYC—New York City's Pathways to Deep Carbon Reductions, The City of New York, NYC Mayor's Office, December, 2013.
S-76	Annual Energy Outlook 2014, Energy Information Administration, May 7, 2014.
S-77	U.S. Environmental Protection Agency, Fact Sheet: Clean Power Plan State Roles (June 2, 2014)
S-78	2014 Reliability Needs Assessment, New York System Independent Operator, Final Report
S-79	U.S. Senators Lisa Murkowski and Tim Scott, Plenty at Stake: Indicators of American Energy Insecurity, An Energy 20/20 White Paper

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FEDERAL POWER COMMISSION

NATIONAL POWER SURVEY
THE ADEQUACY OF FUTURE ELECTRIC POWER SUPPLY: PROBLEMS AND POLICIES

THE REPORT AND RECOMMENDATIONS OF THE TECHNICAL ADVISORY COMMITTEE ON THE IMPACT OF INADEQUATE ELECTRIC POWER SUPPLY

United States. Federal Power Commission. Technical Advisory Committee on the Impact of Inadequate Electric Power Supply.

MARCH 1976

THE FEDERAL POWER COMMISSION

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FOREWORD

In July 1972, the Federal Power Commission established a new National Power Survey. Undertaken as a complement to the Commission's 1970 National Power Survey and earlier Surveys, the new effort is to be a continuing study of electric power requirements, resources, and related developments affecting the utility industry, the utility consumer, the air, water, and land environments, governmental authorities, and the general public throughout the contiguous United States.

In establishing the Survey, the Commission stated its intent that there be broad participation in the work by persons from the electric utility industry, from organizations representing consumer, labor, and environmental interests, and from governmental agencies, organized as advisory committees. The Commission noted, however, that the function of these committees would be limited to providing information and advice to the Commission, and that all determination of action to be taken and specific policy to be expressed within the scope of the Survey would be made solely by the Commission.

Subsequently, the Commission established an Executive Advisory Committee and six Technical Advisory Committees of the National Power Survey, as follows:

- Technical Advisory Committee on Power Supply
- Technical Advisory Committee on Fuels
- Technical Advisory Committee on Finance
- Technical Advisory Committee on Research and Development
- Technical Advisory Committee on Conservation of Energy
- Technical Advisory Committee on the Impact of Inadequate Electric Power Supply

Technical Advisory Committees were to study and report on the significant issues in their assigned areas of responsibility, and to make recommendations to the Commission as to policies and actions needed to deal with these issues.

The Federal Power Commission's staff representatives have participated in the deliberations of the Technical Advisory Committees and Task Forces. While consultation, suggestions, and technical data have been freely exchanged between the Advisory Committees and Task Forces and the staff, the final reports are the products of the Advisory Committees and Task Forces. The Commission's own report on the National Power Survey will be issued separately.

All the deliberations of the Technical Advisory Committees and Task Forces of the National Power Survey have taken place in meetings open to the public.

We gratefully acknowledge the participation of the members of the Technical Advisory Committees and Task Forces and the others who assisted in these studies.

THE FEDERAL POWER COMMISSION

SUMMARY

The health and efficient growth of the economy depend importantly upon the availability of sufficient electricity supplies. Because of the importance of adequate supplies of electrical energy to the nation's welfare the Federal Power Commission (FPC) added to the work of its National Power Survey the Technical Advisory Committee on the Impact of Inadequate Electric Power Supply, to provide it and the public with an overview of matters affecting governmental and utility industry policy decisions on the problems of supply adequacy.

How did the nation get itself into a situation in which it faces the prospect of inadequate electric power supplies? The answer is that we slid into it...slowly and imperceptibly through a long series of seemingly local unrelated governmental and utility actions (or inactions) in the late 1960s and early 1970s that ultimately proved to be related either directly to each other or indirectly through institutional mechanisms such as the capital market. Problems include those related to investment financing, delays in the expansion of capacity, uncertainty in load forecasting and the increasing risk of fuel shortages.

Actions needed to ensure the reliability of the nation's utility systems range broadly from modest improvements in system design, control and coordination to a

complete overhaul of the processes for regulating rates and a siting of new facilities. The Federal Power Commission can contribute directly and by example to a solution of the industry's financial problems by allowing adequate earnings on investments subject to its jurisdiction and by approving rate changes speedily. Second, the Commission can help to eliminate one of the most serious deficiencies in utilities' defenses against the risk of inadequate supplies of electric power: the lack of good "software" as opposed to "hardware." Load forecasting, the evaluation of reliability standards, rate design and the determination of reasonable and proper criteria for the rationing of service during prolonged shortages present difficult analytical and technical problems whose solution could help to resolve important policy conflicts. The Commission could seek to advance the state of the art in analyzing these problems by directly supporting research on methodological improvements. In addition, it could in cooperation with NARUC, begin to develop standards or methodological guidelines for individual utilities or state commissions to apply to their own particular cases. If necessary the FPC could consider the adoption of rules to permit discretionary application of its emergency powers according to the degree to which affected utilities had satisfactorily followed its guidelines regarding software.

State public utility commissions could be effective at promoting reliability and optimum supply by allowing electric utilities to earn at levels sufficient to attract required investment capital and by encouraging them to study and to adopt, where appropriate, peak-load pricing rate structures that more closely reflect the long-run marginal costs of service. (We note that when capacity is neither excess nor short, there is no difference between pricing at long-run and pricing at short-run marginal cost.) Other regulatory reforms either to improve cash flow such as allowing construction work in progress to be included in the rate base, or to rationalize the selection and approval of new power plant sites and facilities, would also help to ensure that capacity could be expanded to meet demand. In addition, state commissions could take the initiative in working with utilities to develop plans for emergency rationing of electric power within their jurisdictions. Even where commissions are willing to take the lead, state legislatures should be alert to ensure that the grant of such authority to their commissions is clear and unequivocal. Our brief review of state legislation on the subject suggests that a great many states may need to examine the statutory grants of authority to their respective utility commissions for the purpose of dealing with electric shortages. Action by state legislatures may also be required to rationalize the power plant siting process, to set guidelines for the internalization of environmental costs and to provide public utility commissions with the additional staff and other resources necessary to develop new policies on rates, emergency rationing and siting.

Utilities themselves can reduce the chances of having to meet excessive demands by actively exploring ways to apply long-run marginal cost estimates to ratemaking, especially in the form of peak-load pricing. Utilities should accelerate their efforts to test the potential benefits of peak-load pricing as a means of controlling load growth and improving system load factors. If a shortage of a capacity materializes--as a consequence, for example, of a reemergence of historic growth rates in the face of construction cutbacks--it will be important for utilities to have effective plans for rationing during shortages. Since utilities know their system operating characteristics best and can help to ensure that rationing priorities properly reflect those characteristics, they should work closely with their commissions in drawing up plans to meet shortages of various magnitudes and duration.

What is an adequate level of electricity supply? We believe that electricity supply is adequate if customers' desired loads in volumes of consumption at current prices are met with a degree of reliability they find acceptable. "Acceptable" means that they are willing to pay as much as it costs to maintain service reliability at the present level but would not--if given a choice--be willing to pay as much as it would cost to increase reliability by any further amount. Inadequacy can be defined as a situation where actual consumption (or load) is forced below the amount desired at current rates or where reliability is less than acceptable. But in a very real sense supply is adequate not just if customers' desired levels of service are met at current rates but also if current rates are no higher than long-run equilibrium rates. To put the matter differently, supply is inadequate whenever current rates would have to be higher than long-run equilibrium rates in order to bring demand and supply into balance, because in that event new and difficult adjustments would have to take place.

It is important to distinguish optimal electric supply from adequate electric supply. Supply is both adequate and optimal (in the long run), if it is adequate as defined above and rates are equal to the long-run marginal costs of providing additions to service. According to our definitions, therefore, supply could be adequate but not optimal. This would occur whenever demand and supply were in balance but were either too high or too low. On the other hand, supply could be inadequate but optimal. This situation would occur when three conditions prevailed. Rates were set below marginal costs so that demand was above optimum; nonprice rationing was used to hold consumption to the amounts that would have been consumed at optimal rates; and supply was sufficient to serve the optimum demand. Despite the restrictiveness of these conditions this case has some relevance to policy making since it may sometimes be better to ration an inadequate electric supply than to supply an uneconomically high demand.

Current industry planning practices usually involve designing increments to system capacity in such a way as to meet projected peak loads with a margin of reserve sufficient to keep the probability of outages at a very low level. We believe that more sophisticated approaches to planning reserve margins should be undertaken by utilities. In particular, it is now becoming possible to perform explicit evaluations of the cost and benefits of increments to system capacity or of any other reliability-improving investments. The relevant question is: at what level of reliability does the cost of an extra unit of capacity equal the extra saving and social cost derived from putting in the extra capacity?

Despite the best intentions and plans shortages may develop. A number of alternatives are available for rationing electricity supplies under shortage conditions. We believe that plans for refusing service to new customers have the greatest capacity for mischief and are therefore least desirable for dealing with the problem. They are likely to be both inequitable and wasteful of economic resources.

A far more acceptable way of dealing with electricity shortages would be to interrupt or to cut back service to existing customers according to some prearranged program. Many utilities already have plans to respond to excessive demand with such a series of steps. In principle the most economically efficient scheme for nonprice rationing would be the one that produced a pattern of electricity usage very close to that which would have prevailed if electric service had been priced as in a competitive market. Although many complications are likely to prevent full implementation of any scheme that could accurately substitute for competitive prices, a reasonable approximation to the competitive result might be obtained by basing rationing priorities on thorough studies of demand characteristics by customer group or type.

One way of ameliorating the effects of a shortage in the service area of a particular utility would be to allocate or spread the shortage across the service territories of a group of utilities who--as a group--might be less severely affected than the individual utility in question. This approach raises difficult questions concerning the authority and responsibility of the Federal Power Commission vis-a-vis state regulatory commissions and the individual utility companies.

The effects of shortages--whether of the sporadic or regular variety--can be grouped broadly into two categories: short run and long run. Both will be greater or lesser depending upon the kinds of plans and capabilities that users have developed for dealing with outages. But in the short run these plans and capabilities are fixed--determined by customers' evaluations of service reliability, the costs of alternative or backup systems, the importance of the uses to which users put electricity and so on. The long-run costs of power shortages are the costs that arise from implementing changes in customer preparations. They include the cost of such steps as installing and operating backup generating units or energy storage systems and converting to appliances or other devices using fuels instead of electricity (net of the cost of the electricity saved). They may also include less visible but more pervasive costs such as excessive conservation of electricity and consequent overreliance on other scarce resources, increased environmental pollution, a reduced rate of technological progress in some sectors of the economy and changes to less pleasant life styles. Many of these costs would translate into a reduced rate of economic growth. Finally, the long-run costs of shortages include the short-run costs of any outages that may be expected to occur after all adjustments and changes in customer preparations have taken place.

Existing studies of the costs and benefits of alternative reliability levels use a measure of potential short-run costs. This is entirely proper when dealing with the temporary shortage situations typical of past experiences. It is also acceptable to use a short-run measure for the <u>initial</u> stages of a prolonged period of supply inadequacy. Short-term measures would be excessive for the later stages, as businesses and individuals began to adjust to new conditions. A major unsolved problem is how to measure the long-run costs of shortages.

Even if we restrict attention to the short-run case, the problem of cost measurement is not simple. In practice, a number of restrictive assumptions must be made in order to simplify the task. Studies done to date indicate a short-run cost of electricity shortages of roughly fifty cents to perhaps as much as one dollar per kilowatt-hour. Much work remains to be done before these estimates (or others) can be accepted with any degree of confidence.

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I. PREFACE

The rash of cancellations and postponements of electric generating plant projects in the past two years has led to a concern that, at some time toward the end of this decade, the nation may be confronted with shortages of electric generating capacity. This is not the first time that such a prospect has been a source of concern.

The electric utility industry in the United States emerged from World War II with a precarious balance between demand and capacity. Immediately following the war there was considerable hesitation about adding additional capacity: predictions of a return to the long-term economic stagnation (no-growth) of the 1930s suggested that there would be little or no growth in electric power demand. When it became clear that the nation was entering a post-war economic boom in which electric energy demand would increase rapidly, the utility industry very quickly geared up to add the necessary generating capacity. At that time, construction lead times were relatively short and new baseload capacity could be added within three years. Consequently, by the early 1950s the utility industry was fully capable of meeting the loads imposed on it, including the rapid growth which accompanied the mobilization for the Korean War.

During the several economic recessions which followed the Korean War episode, the industry cut back its orders for generating capacity as it adjusted load forecasts downward. This process occurred during the 1954 recession, to be followed, when rapid economic recovery occurred, by an upward readjustment of load forecasts and a rapid increase in utility orders for generating capacity to a hitherto unprecedented level.[1] This cycle was repeated in the recession of 1958 and the recovery in 1959, and in subsequent business cycles during the decade of the 1960s and the early 1970s. In short, the utility industry has, in the past, experienced fluctuations in its expectations, which fluctuations have been reflected in its orders for generating equipment. Always, in the past the relatively short lead times for capacity construction saved the nation from power shortages.

The National Power Survey in 1964 projected a continuation of the long-term growth trend of electric energy demand. But it also signaled a new development in public policy, designed to reduce generating reserve margins. The Federal Power Commission, in its National Power Survey, urged strengthened interconnections and expansion of pooling among electric systems, and suggested that it would be possible to reduce reserve margins drastically without impairing reliability. The FPC set as its target reserve margins of about 15 percent and projected major savings to

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1 Sellers responded to the decline in orders in 1954 with a "White Sale" in 1955. Price reductions no doubt further stimulated the rebound in orders.

be achieved by 1980 as a result of reserve margin reductions to that level. One cannot say unequivocally that the FPC's goal was too optimistic with regard to the level to which reserve margins could be reduced without impairing reliability.[2] But it is possible that it was partly as a result of the utility industry's efforts to reduce reserve margins in response to the urging of the Federal Power Commission that some shortfalls in capacity began to appear by 1970. The problem in any event was compounded by the lower-than-expected reliability of some large new generating units and by environmental pressures, which gave rise to operating problems and construction delays.

The problem of capacity shortages in the future has been greatly intensified by the increase in construction lead times--from two and a half to three years in the 1950s and early 1960s to as much as ten years for nuclear capacity at the present time. Thus, the effects of any excessive downward adjustment in the planning of new generating capacity may not appear for as much as a decade ahead. In the intervening years, should the need for additional capacity be recognized, it will be far more difficult than in the past to accelerate the schedule for installing the required capacity. Consequently, if the conditions presently confronting

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2 The Northeast blackout of 1965 caused some utilities to reevaluate reserve margins and may have been a factor in the high ordering rates of 1966 and 1967.

the electric utility industry persist, the probability of a shortfall in electric generating capacity may increase significantly by the early 1980s.

But the prospect of an absolute shortage of generating capacity may not be the most serious shortfall problem confronting the industry and the country. The utility industry will probably somehow find the means to provide the capacity necessary to avoid major service interruptions. If a shortfall in capacity were in prospect, the industry would be likely to respond by ordering gas turbine capacity capable of being installed in the relatively short period of two to three years (assuming quite optimistically that manufacturing capacity were not a bottleneck). The urgent problem which would be posed under these circumstances is the possibility that such capacity would impose a very severe fuel supply problem on the country. Such capacity can neither be fueled by coal nor by uranium; it requires either gas or oil, the two fuels which confront the United States with the most severe supply deficiencies. Should the electric utilities, as a result of inadequate baseload capacity, be required to improvise short lead-time capacity to burn either natural gas or oil, the result is likely to be greatly intensified pressure on oil and gas markets with the utilities seeking to bid these fuels away from alternative uses, and heightened reliance on unreliable foreign suppliers.

Thus, the postponements and cancellations of coal- and nuclear-fired generating units which have occurred in the last two years may have their severest impact not upon the ability of the electric utility industry to meet peak demand, but rather upon its ability to sustain the level of energy consumption planned by its customers.

Finally, although we discuss the economic cost-benefit trade-offs of interrupting electric service, we are mindful of the great public interest in reliable electric service. In the past the public has assumed, and the electric utility industry planning objective has been, that virtually uninterrupted electric service would be provided. Perhaps the now-higher cost of providing such a historic degree of reliability will lead to a change in this objective on the part of both the consumers of electricity and utility planners. However, it is not yet clear that such a change has occurred or that it should. As electricity has increased in importance and as it continues in the future to replace scarcer gas and oil in many critical functions, the public's desire to maintain reliable electric service may become more intense.

We are led to the view that a reliable supply of electrical energy remains a crucial ingredient of national welfare.

II. INTRODUCTION

The health and efficient growth of the economy depend importantly upon the availability of sufficient supplies of electrical energy. In a modern economy, geared to a high level of electric service, any but the shortest interruption of that service is likely to impose losses far in excess of the value of sales lost, as business and factories are forced to curtail operations and individuals are variously inconvenienced--some seriously. Over the longer term electricity is a crucial input to economic growth; and although it is clear that the growth of power consumption need not bear precisely the same relationship to economic growth in the future that it has in the past, it is also apparent that an insufficient supply of electricity is likely to act as a drag upon the growth of real economic well-being by raising the volume of labor, machines and materials required to achieve any given increment in GNP.

To electricity's historic role has been added another special role: the continuing uncertain availability of imported oil and the limited supplies of domestic oil and gas mean greater-than-ever reliance on coal and uranium resources. Generated from relatively abundant domestic coal and from temporarily adequate if not vast uranium resources, electricity can contribute toward oil import independence and to the conservation of domestic oil and gas reserves, both of which may be important for national security and continued economic well-being.

Because of the importance of adequate supplies of electrical energy to the nation's welfare, the Federal Power Commission, on February 28, 1974,[3] added to the work of its National Power Survey this Technical Advisory Committee on the Impact of Inadequate Electric Power Supply, to provide it and the public with an overview of matters affecting governmental and utility industry policy decisions on the problems of supply adequacy.

A. The Committee's Assignment

The FPC is clearly obligated to play a role in the matter of electric power supply adequacy. Under provisions of the Federal Power Act it is given a mandate to promote an "abundant" electrical supply at minimum cost and with concern for natural resources.[4] While an "abundant" supply may be more than adequate in some sense of the word, it is surely nothing less.

This report is intended to provide an overview of matters affecting governmental and utility industry policy decisions on the problem of supply adequacy, including:

1. Possible actions for reducing the risk of--and ameliorating the effects of--inadequate supplies;

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[3] Federal Register, Vol. 39, No. 46, March 7, 1974, pp. 8962-8963.

[4] "For the purpose of assuring an abundant supply of electric energy throughout the United States with the greatest possible economy and with regard to the proper utilization and conservation of natural resources, the Commission is empowered and directed...." ("Federal Power Act" [49 Stat. 848; 16 U.S.C. 824a(a)].)

2. Conceptual problems in the definition and evaluation of the concept of "adequate" supplies; and

3. Approaches to estimating the effects of inadequate electric power supplies.

B. Organization of Report

This report is organized into several sections. Section III discusses how we arrived at our present situation and offers policy options for improving it. Section IV examines the principles and problems in the evaluation of supply adequacy and considers several methods of dealing with shortages. Section V looks at the probable effects of inadequate electric power supplies. In addition, there are two appendices. Appendix A discusses energy use in the United States economy. Appendix B is a roster of Committee members, many of whom participated actively in the drafting and redrafting of this document.

III. BACKGROUND AND POLICY OPTIONS

Is the United States moving inexorably toward a period of chronic electric power shortages or inadequacies during the late 1970s and early 1980s?

The gathering evidence, collected in this report and elsewhere, would suggest that the answer is a qualified "yes." The answer must be qualified because many of the technological, economic, financial, political and environmental factors which affect that answer are subject to control by the public and its elected and appointed representatives and hence subject to change.

A companion question to the opening one above might well be: Given the probability of electric power shortages and inadequacies, what will be the nature and magnitude of their predictably disruptive economic and social effects?

This report examines these and other related questions in their manifold implications. It traces some of the more important factors which have contributed to the current state of affairs with respect to the adequacy and reliability of the nation's electric power supply. It then suggests some of the technological, economic and regulatory policy options available to the Federal Power Commission, state regulatory commissions and the electric utilities which might help to obviate--and in some cases, eliminate--the prospects of electric power shortages and their consequences.

A. The Causes of Our Dilemma

How did the nation get itself into a situation in which it faces the prospect of inadequate electric power supplies? How indeed, given the historical fact that the United States has for long enjoyed a high standard of electric power reliability? The answer, of course, is that we slid into it...slowly, imperceptibly at first...through a long series of seemingly local, unrelated governmental and utility actions (or inactions) in the late 1960s and early 1970s that ultimately proved to be related either directly to each other or indirectly through the institutional mechanisms, such as the capital market, that serve the electric power industry.

The potential causes of insufficient supply can be broken into two major groups, according to whether they would contribute mainly to capacity shortages or mainly to energy shortages.[5] Under the first heading are causes having to do with investment financing difficulties, expansion delays, and load forecasting error; under the second are causes related to fuel availability or environmental restrictions upon operations.

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5 These categories are, of course, interrelated. Shortages of nuclear <u>capacity</u>, for example, can result in increased use of oil-burning combustion turbines, and hence contribute to <u>fuel</u> shortages.

1. Financing Problems

The cutbacks in utilities' expansion plans announced during the past year are partly a response to reduced load growth forecasts. But many industry officials indicate, and governmental observers agree, that they are also a reflection of increased costs of capital investment and financing on one hand and reduced earning power on the other. Inflation, tight money and eroding investor confidence have contributed to a general rise in the cost of capital financing. Environmental standards and construction cost escalation have boosted the cost of investing in new capacity. At the same time utility company earnings have tended to drop--in some cases drastically. The delay by some utility managers in seeking adequate rate relief, compounded by the lag in some regulatory commission responses to such requests, lower than expected sales,[6] and sharply rising costs of fuel and other inputs have been the principal sources of earnings deficiencies. They have seriously impaired the industry's ability to carry out construction programs and may have put pressure on some utilities to reduce these programs to levels dictated by their current ability to raise capital, rather than by their judgment concerning long-term growth expectations.

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6 Temporary decreases in sales serve to reduce current revenues without necessarily reducing current capital requirements.

The decline in electric utility earnings levels, interest-coverage ratios and credit ratings was most pronounced in 1973 and 1974. 1975 has been a year of moderate recovery, yet the willingness of investors to provide adequate funds for future capital investment is by no means assured, since the recovery has not yet produced earnings levels appropriate to the industry's relative risk and capital needs.

2. Expansion Delays

Although financial considerations probably represent the most tightly binding constraint upon capacity expansion today, delays in the process of planning, building and securing approval for new facilities have also hindered investment and contributed to cost increases. The list of underlying causes is all too well known: technical and design problems with nuclear plants, and with environmental control systems on all types of plants; active intervention by environmental and other citizens' groups at various phases of the approval process, both before and after construction; and the fragmentation and proliferation of agencies having authority over one element or another of the process. To cite these delays as a causative factor is not to deny the relevance of the considerations raised by environmentalists and others; but the costs of delay should be fully recognized, as when the threat of delay itself promotes an economically dubious course of action such as building combustion turbines in lieu of baseload nuclear capacity.

3. Uncertain Load Growth Rates

Rapid increases in energy prices, the downturn in economic activity, the sluggish growth of electricity demand following the Arab oil embargo, curtailments of natural gas service to industrial customers and embargoes on new gas hookups, and the talk of moving toward oil import independence in part through increased reliance upon nuclear and coal-fired electricity generation have created a good deal of uncertainty about the growth of future loads. Will the "pause" of 1974 be matched by a "spurt" at some later point in time? Will recent historical growth rates reemerge, but from a lower-than-anticipated base? Or will growth rates continue to be lower than in the past? Utilities are finding it necessary to adapt their methods of planning for system expansion to include the effects of considerably more uncertainty in load growth than heretofore. In particular, attempts are being made to improve the sophistication and accuracy of forecasts by application of econometric demand estimation techniques, a process as yet imperfect but potentially more satisfactory than the historic extrapolation techniques previously relied upon.

4. Fuel Availability

The factors contributing to the threat of fuel shortages for electric power generation are to some extent the same as those for the economy as a whole: the continuing risk of a renewed oil export embargo by the members of OPEC and the short-run (and possibly even long-run) inelasticity of supply of domestic fossil fuel resources.[7] But there are, in addition, a number of problems peculiar to the electric utility industry. Its low priority in the FPC's natural gas allocation program points to a sharp decline in the availability of that fuel for electricity generation. The effect of actual and imminent federal emmissions standards is to require the burning of low-sulfur fuels, which are scarcer than fuels generally, or to necessitate the installation of controversial SO_2 scrubbers. If scrubbers turn out to be unreliable, or if they are not installed in great numbers, shortages of low-sulfur fuels are likely to occur. Given the heavy reliance of utilities upon coal, they must be concerned about the availability not only of coal of the required quality but also of the means of transporting it in quantity from mine to generating plant. It is not clear that the nation's rail system will be geared up to meet projected coal transportation demand, especially if reliance upon low-sulfur western coal grows. The availability of nuclear fuel is also subject to some uncertainty. In particular, industry officials are expressing concern about the lack of investment plans and licensing procedures for new uranium enrichment and fuel reprocessing facilities for the 1980s and about the availability of raw uranium itself.[8] We have, then,

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7 The uncertainties surrounding federal leasing policy further complicate the long-run picture.

8 Some officials believe that the tails assay now set for uranium enrichment is uneconomically high, thus exacerbating the risk of a yellowcake shortage in the 1980s or 1990s.

a situation in which natural gas is becoming effectively unavailable to meet electric utility needs; the bulk of foreign oil supply is controlled by a cartel willing to halt production in pursuit of its members' foreign policy objectives; the use of increasing amounts of coal is discouraged by actual or proposed environmental restrictions and by the prospect of inadequate rail transportation capacity; and finally, the future availability of nuclear fuel is far less assured than was heretofore thought to be the case.

B. Reserve Margins and Reliability Standards

As a result of the preceding factors contributing to both capacity and energy shortages, the Committee believes we may be witnessing the emergence of a new interest among both utility executives and regulatory officials in reevaluating traditional United States reliability standards.

Historically the industry has striven to maintain high reliability standards. Some utilities, for example, try to ensure that demand (load) will not exceed generating capacity on more than once in 10 years. To achieve these standards, reserve margins have averaged 15 to 25 percent of annual peak load for most utilities. According to the statistics of the Edison Electric Institute, the average reserve margin for the nation ranged from a low of 16.6 percent to a high of 23.7 percent during the period 1964-1973. In 1974 the average reserve margin rose to 27.2 percent as a result of unexpectedly low growth in loads. Owing to the 1974-1975 recession, load growth (particularly in the industrial sector) continued to be slower than normal in 1975, with a resulting increase in the average reserve margin to 33.5 percent.[9] However, in view of recent deferrals--and even cancellations--of new installations, a downward trend in reserve margins is likely to emerge later in the 1970s.

Recent surveys of utility construction plans indicate the possibility of a serious inadequacy of reserves within the next decade. As little as 726,000 megawatts of capacity now appear to be planned for December 31, 1983, some 189,000 megawatts having been deferred or canceled.[10] This capacity would accommodate an annual growth rate of 5.2 percent from 1973 to 1983 if at the end of this period load factors and reserve margins were held at their relatively normal 1973 levels. But if the growth of demand turned out to be closer to the historic rate--say 7.2 percent--then the industry reserve margin would fall to zero by 1983, and the risk of power outages would be vastly greater than today.

Based upon a 1975 noncoincident peak demand of 358.2 thousand megawatts, a 1983 peak capability level of

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9 The seemingly higher reserve margins of 1974-1975 may be deceptive. The capacity of some companies may be overstated because of a failure to reevaluate capacity in the light of recent environmental restrictions, e.g., on the burning of high-sulfur coal.

10 National Economic Research Associates, Inc., survey of construction cutbacks, August 1974; updated by public announcements in trade press. Based upon the 1973 ratio, a 726,000 capacity figure for December 31, 1983 implies a capability at peak of 688,000 megawatts in 1983.

688,000 megawatts could sustain a growth rate of 6.0 percent while preserving 1973 load factors and a 1973 reserve margin of 20.8 percent. A growth rate of 8.5 percent would reduce reserves to zero by 1983. These relatively higher growth rates are due to the sluggish growth of peak loads in 1974 and 1975; and they yield a deceptively optimistic picture of the maximum growth ratio consistent with planned capacity additions and maintenance of historic reserve margins, since recovery from the current recession may well cause a temporary spurt in growth sufficient to offset much of the growth "lost" during the past two years.

Whether, after the pause of 1974-1975 and subsequent recovery, growth will resume its historic pace is uncertain. The downward effect of increasing electricity prices may be more than (or less than) offset by the upward effects of rising natural gas prices, natural gas curtailments, high oil prices, and uncertain supplies of foreign crude. Economic growth may or may not recover to the trend rate of the 1960s.

When establishing a target rate of system growth in the face of such uncertainty, utility planners must take into account the costs of under- and overestimating required capacity by any given amount. If load is underestimated by, say, 15 percent, then reserves will most likely be insufficient to prevent the risk of major interruptions of service. The only escape might be to install high-cost gas turbine generators on a last minute basis if the units and the fuel to be burned in them were available. Utility customers would then be stuck with these expensive sources of power for some time, and the nation with increased dependence on foreign oil.[11] If, on the other hand, load is overestimated by 15 percent, the only cost is that of carrying excess reserve capacity for a period of time. At a 6 percent rate of growth, excess capacity of 15 percent is reduced to 9 percent after one year and to less than 3 percent after two years. The costs of carrying such excess capacity are very likely to be smaller than the costs of underestimating load growth, especially when power plant construction costs are escalating rapidly or where new plants can replace old units having high operating costs. If so, then planners ought to pick a target expansion rate somewhere <u>above</u> the mean or expected rate of demand growth (assuming growth rates above or below the mean to be roughly equiprobable).

The possibility of a growth rate in the 6-percent-or-above range makes it impossible not to be concerned about the risks and costs of inadequate electricity generating capacity. We note, in addition, that reserve margin deterioration could become severe in certain regions before statistics based

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[11] That is, utilities could be forced into a situation of having to install a suboptimal generating mix, one excessively concentrated upon peaking-type units.

upon national averages provided any clear indication of the fact.[12]

C. Avoiding or Ameliorating Power Shortages: Policy Options

At the beginning of this background and policy section, the Committee indicated that it saw several policy options available to the FPC, state regulatory commissions and the electric utilities themselves which should help to avoid and ameliorate electric power shortages, and therefore, their disruptive social and economic consequences. These recommended options are summarized below; more detailed treatment of the problems and conceptual issues that underlie our recommendations appear elsewhere in this report.

1. The Federal Power Commission

Actions needed to ensure the reliability of the nation's utility systems range broadly from modest improvements in system design, control and coordination to a complete overhaul of the rules and procedures governing rate regulation and the siting of new facilities. Any consideration of the role of the Federal Power Commission in the matter of adequacy and reliability of power must recognize, however, that the Commission's legal authority to influence many of the factors bearing upon electricity supply is plainly circumscribed. Many

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[12] The foregoing discussion has concentrated upon shortages due to insufficient capacity expansion. The overall risk of shortages is greater owing to the possibility of fuel-related shortages or environmental restrictions upon the operation of certain types of plants; e.g., nondegradation rules for air pollution or nuclear plant deratings.

potentially desirable steps can be encouraged by the Commission through exhortation and example, but the authority and responsibility for many actions belong to individual companies (public and private), to the state utility regulatory commissions, to other federal agencies or ultimately to the state and federal legislatures. We have tried to keep this limitation in mind in developing the options discussed below.

First, the Commission can contribute directly and by example to the solution of the industry's financial problem by allowing adequate earnings on investments subject to its jurisdiction. Insufficient rates of return and delays of many years in giving final rate approval[13] not only reduce earnings directly but also set an example of regulatory lag that diminishes the credibility of the Commission's exhortations to others. The Commission can improve utilities' cash flow by modifying its rules governing construction work in progress and book depreciation ratio and by continuing to ensure the full normalization of tax benefits resulting from accelerated depreciation, investment tax credits, the immediate deductibility of overhead costs and similar items.

Second, the Commission can help to eliminate one of the most serious deficiencies in utilities' defenses against the risk of inadequate supplies of electric power: the lack of good "software" as opposed to "hardware." Load forecasting,

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[13] We recognize that the problem of FPC regulatory lag is mitigated by rules that allow new rates to go into effect five months after filing, subject to refund if not finally approved.

the evaluation of reliability standards, rate design and the determination of reasonable and proper criteria for the rationing of service during prolonged shortages present difficult analytical and technical problems whose solution could help to resolve important policy conflicts. The Commission could seek to advance the state of the art in the above processes by directly supporting research on methodological improvements. In addition, it could, in cooperation with NARUC, begin to develop standards or methodological guidelines for individual utilities or state commissions to apply to their own particular cases. Examples of the points to which guidelines might be directed are as follows:

a. Load forecasting techniques--more frequent and more skilled use of survey techniques and econometrics, more sophisticated treatment of uncertainty through sensitivity analyses and Monte Carlo simulations; this work should include analyses of price elasticity. The Federal Power Commission might consider preparing a survey manual of the latest methodology, including critiques thereof, for use by utilities and state regulators.[14]

b. Reliability evaluation--performance of full cost-benefit analyses of reserve margins using "expected energy unserved" as the basis of computing losses, rejection of rules

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[14] For an early example of such an attempt, see Federal Power Commission, The 1970 National Power Survey, Part IV (Washington, D.C.: U.S. Government Printing Office, 1969), The Methodology of Load Forecasting.

of thumb such as a "one-day-in-10-years" loss-of-load probability except as justified by cost-benefit analysis; an essential part of this work should be to develop better estimates of the short- and long-run costs of service interruptions. Such an evaluation would assist state commissions in appraising the adequacy of planned reserve margins and, hence, of construction budgets.

c. Rate design--development and application of techniques for computing long-run marginal costs[15] and for applying these costs to the design of rates reflecting peak-load pricing principles. The application of marginal-cost pricing principles to rate design should not be viewed as a routine mechanical process. Accomodation of regulatory constraints and of conditions in gas and oil as well as electricity markets will require careful analysis on a case-by-case basis. The Commission's guidelines should seek to promote such analysis and to focus it effectively upon the critical problem areas. As regards peak-load pricing, we recognize that any decision to proceed with full implementation for residential and small commercial customers should depend upon a determination that the benefits would exceed the metering and other costs. At this point in time there is

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[15] Pricing at long-run marginal cost is the exact equivalent of pricing at short-run marginal cost if capacity is expanded at the optimum rate; i.e., at a rate that maintains economic reserve margins.

insufficient evidence to indicate that such is or is not the case; we urge that the Commission closely monitor the progress of the studies underway in this area.

d. Rationing criteria--drafting of a model state statute in which the need for critical public services would be reflected in procedures for the allocation of electricity supplies during emergencies. Econometrics, surveys, and other analytical tools should be used to estimate customers' capacity to absorb cutbacks in both the short and long run.

Commission recommendations in the above-mentioned areas will be helpful only if based upon thorough study of the problems and if made in recognition of the fact that continued research is essential to the determination of the best long-term solutions. Neither the Commission nor the industry should be tied to rigid formulas; rather they should be free to develop or to exploit advances in analytical methods and to incorporate new knowledge into policy decisions. Flexibility is essential to effective management. The Commission should take care that its guidelines do not interfere unduly with it.

2. State Regulatory Authorities

State public utility commissions could be most effective at promoting reliability and optimum supply by allowing electric utilities to earn at levels sufficient to attract required investment capital[16] and by encouraging them to move toward the adoption of peak-load pricing rate structures that reflect the long-run marginal costs of service. Utilities cannot be expected to provide sufficient capacity if they can do so only at the cost of repeated dilution of stockholders' equity; they must have an opportunity to earn a fair rate of return on their investment in needed facilities.

These steps--adequate earnings and rational rate structures--would improve profitability and hence the ability of the industry to increase supply, while also discouraging uneconomic expansion of demand. Adequate earnings would make it possible to raise capital; peak-load pricing might contribute to a reduction in the growth of annual peaks, improving load factors and thus lowering system costs. At the very least it would place the cost of capacity maintenance and expansion more fully on the shoulders of those whose demands were responsible for such expansion than do current rate structures.

Other regulatory reforms either to improve cash flow, such as allowing construction work in progress to be included in the rate base, or to rationalize the selection and approval of new power plant sites and facilities with full opportunity for all affected parties to be heard, would of course help to

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[16] This goes beyond setting permissible rates of return at adequate levels. Those returns must be computed in a manner designed to provide utilities with an opportunity actually to earn them. In this connection see the recent decision of the New Mexico Public Service Commission, <u>In the Matter of a Rate Filing by Public Service Company of New Mexico</u>, Case No. 1196, April 22, 1975.

ensure that capacity could be expanded to meet demand. In addition, state commissions could--independently, or in cooperation with the FPC--establish methodological guidelines in the areas of load forecasting and reliability evaluation as noted above, and they could take the initiative in working with utilities to develop plans for emergency rationing of electric power within their jurisdictions. Indeed, unless the slowdown in facilities construction is halted, state commissions may find themselves with a need to redefine the "obligation to serve" concept in a manner reflecting the utilities' inability to conscript capital.

Even where the commissions are willing to take the lead in dealing with energy shortages, state legislatures should be alert to ensure that the grant of such authority to their commissions is clear and unequivocal. Indeed, our brief review of state legislation on the subject suggests that a great many states may need to examine the statutory grants of authority to their respective utility commissions for the purpose of dealing with electricity shortages.

Action by state legislatures may also be required (a) to streamline and to rationalize the power plant siting process, (b) to ensure that environmental protection activities are promoted wherever justified on the basis of their social costs and benefits and that the costs not only of pollution controls but also of unabated environmental effects are passed through to the users of electricity,[17] and (c) to provide public utility commissions with the additional staff and other resources necessary to develop new policies on rates, emergency rationing and siting.[18]

3. Electric Utilities

Utilities themselves are in the best position to deal with many of the problems noted above. In fact, many utilities both public and private are currently striving to advance their methods of load forecasting and reliability evaluation for system planning purposes by including more explicit analyses of the effects of prices, conservation, demographic developments and economic conditions. Other companies should follow this lead. Reliability evaluation, too, can be improved by developing ways to estimate the expected costs of outages given long-term load and resource availability projections. The cost of additional investment to reduce the likelihood and extent of outages should be at least as great as the outage costs thereby avoided.

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17 By taxing emissions, for example. Despite the political and practical difficulties that this might entail, it offers the best hope of a rational solution to pollution control problems.

18 Commissions, of course, have the burden of using such resources as are available to them in an optimal fashion, consistent with law, perhaps by liberating themselves from the tyranny of the rate case cycle, deploying a greater portion of their resources in generic hearings dealing with planning, rate structure reform and similar issues. A numbe of state commissions, notably those in California, Florida, and New York have instituted generic hearings on rate structure revision. More such hearings can be expected.

By actively studying and eventually applying long-run marginal cost estimates to ratemaking in the form of peak-load pricing, utilities may be able to reduce the chances of having to meet excessive demands. Utilities should accelerate their efforts to test the potential benefit of peak-load pricing as a means of controlling load growth and improving system load factors.[19]

Rational economic pricing by the industry is a desirable objective. Consequently, we are inclined to frown upon schemes whose primary purpose is to promote the underpricing of electricity--charging less than the real resource cost involved in its generation, transmission and distribution. Utilities should, in our view, eschew subsidies. They should neither seek them from government nor confer them upon customers without the most compelling of reasons.

If a shortage of capacity materializes--as a consequence, for example, of a reemergence of historic growth rates in the face of construction cutbacks--it will be important for utilities to have effective plans for rationing during shortages. Since utilities know their system operating characteristics best

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19 We note in this connection that, at the instigation of NARUC, the industry is undertaking (through Edison Electric Institute and the Electric Power Research Institute) a comprehensive review of its pricing practices, with emphasis on the feasibility and desirability of time-of-day and other peak-load pricing techniques. This study should shed a great deal of light on the effect of such techniques, as well as on the potential of direct load management devices.

and can help to ensure that rationing priorities properly reflect those characteristics, they should work closely with their commissions in drawing up plans to meet shortages of various magnitudes and duration. (Most large systems have sophisticated load-shedding procedures for emergencies of very short duration, but many lack suitable plans for more extended shortages.) Probabilistic loss-of-load simulation analyses may help to determine the kinds of "scenarios" that should be planned for. Price elasticity studies may help to identify which customer groups would have the greatest difficulty in reducing demand during prolonged shortages and may help to establish rationing priorities.

IV. PRINCIPLES AND PROBLEMS IN THE EVALUATION OF SUPPLY ADEQUACY

Leaders in the electric utility industry recognize that they can solve the problem of providing adequate power supplies only if they have developed suitable answers to the following important questions:

1. What is an adequate level of electricity supply?

2. What is the relationship between supply adequacy and costs?

3. How can the risks and costs of inadequate power supply be included in the system planning process?

4. What principles should guide governmental and utility industry actions in situations where supply is inadequate?

Sensible answers to these questions do not come easily and, no matter what the answers, are bound to generate a certain amount of controversy--owing to their novelty, complexity and economic importance. The discussion below is intended to serve as the basis for a thorough airing of the issues and concepts involved and not as the final word on the subject.

A. Adequacy and Inadequacy Defined

The standard economic definition of inadequate supply is very simple: demand exceeds supply at current prices (rates). It is deceptively simple. For present purposes the concept of demand must be considerably elaborated;

and as we indicate below, the implications of supply inadequacies for utility or governmental action may vary considerably depending upon the relationship of current rates to costs.

Demand in the economic sense differs from demand in the sense of customers or system load. Demand in the former case is the level of electric service planned or desired by customers at rates currently in effect.[20] If, therefore, the actual level of service provided is less than the desired or planned level, supply is inadequate. But electric service has at least three major dimensions: load (kilowatts of demand), volume of consumption (kilowatt-hours of energy) and reliability (expected service interruptions).[21] It may fail to be adequate in any one or all of these dimensions. Any useful definition of supply adequacy should reflect this fact. The following attempts to do so: Electricity supply is adequate if customers' desired loads and volumes of consumption at current prices are met with a degree of reliability they find

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[20] This is not to say that past rates, or expectations of future rates based upon past and present experience, do not influence demand. Clearly they do. The importance of current rates lies in the fact that those rates are (in principle) variable in the present. By raising or lowering <u>current</u> rates the <u>current</u> quantity demanded can be <u>immediately</u> raised or <u>lowered</u>. (Demand <u>will</u> respond to price changes if they are large enough.)

[21] Reliability is frequently measured in terms of the expected number of days on which the system cannot meet its load. But this measure ignores the extent, size and duration of outages. A better measure is the expected ratio of energy (kilowatt-hours) not delivered when demanded to total energy consumption. See Section IV-C below.

acceptable. "Acceptable" means that they are willing to pay as much as it costs to maintain service reliability at the present level but would not--if given a choice--be willing to pay as much as it would cost to increase reliability by any further amount.

On the other side of the coin, inadequacy may mean that desired consumption is met, but with less than acceptable reliability. In the extreme it may mean that total planned consumption (load or volume or both) cannot be fully met if the utility in question is to maintain a viable service. Inadequacy can be defined, then, as a situation where actual consumption is forced below the amount desired at current rates or reliability is less than acceptable.

Inadequacy, as we have defined it thus far, is a disequilibrium concept. If current rates are too low, some form of nonprice rationing or taxation is required to hold actual consumption below desired consumption. If rates were free to move as in a competitive market, such a situation would not occur. Rates would rise as high as necessary to choke off customers' desires to consume electricity. However, if rates had to rise drastically to achieve this result--and well they might if a marked shift in demand or supply conditions occurred--it is difficult to conceive of the resulting equilibrium as a situation where supply was "adequate" in any meaningful sense of that word.

At this point, the distinction between the short run and the long run is crucial. If underlying market conditions change markedly or rapidly, neither the industry nor its customers can adjust their patterns of behavior to conform immediately to the new state of affairs. Nor should they, since in most cases it would be uneconomic to do so. But after a suitable period of adjustment has passed, a new set of long-run equilibrium rates and quantities can emerge. In a very real sense, therefore, supply is adequate not just if customers' desired levels of service are met at current rates, but also if current rates are no higher than long-run equilibrium rates. To put the matter differently, supply is inadequate whenever current rates would have to be higher than long-run equilibrium rates in order to bring demand and supply into balance, because in that event new and perhaps costly adjustments would have to take place.

B. Rates, Costs and Supply Adequacy

It is important to distinguish "optimal" electric supply from "adequate" electric supply. Supply is both adequate and optimal (in the long run) if it is adequate as defined above and rates are equal to the long-run marginal costs of providing additions to service.[22] According to our

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[22] Market imperfections--other than regulatory constraints on aggregate revenues--may justify deviations from marginal cost pricing. Whether deviations from such pricing for this reason would be appropriate for electric utilities is unclear.

definition, supply could be adequate but not optimal. This would occur whenever demand and supply were in balance but were either too high (e.g., because of too low prices based on historical average cost pricing) or too low (e.g., because of too heavy reliance upon costly peaking units built as a result of improper planning or an unpredictable spurt in load growth). On the other hand, supply could be inadequate but optimal. This situation would occur when three conditions prevailed: rates were set below marginal costs so that demand was above optimum; nonprice rationing was used to hold consumption to the amounts that would have been consumed at optimal rates; and supply was sufficient[23] to serve the optimum demand. Despite the restrictiveness of these conditions, this case has some relevance to policy making, since it may sometimes be better to ration an inadequate electric supply than to supply an uneconomically high demand.

Rates set equal to the long-run marginal costs of service (LRMCs) offer considerable hope of inducing users of electricity to optimize their uses of electricity, but they can also raise problems with respect to earnings. If LRMCs are below average historical costs--as was the case throughout most of the 1950s and 1960s--then earnings will be inadequate to maintain company profitability and industry growth

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[23] In the absence of uncertainty and other market imperfections, taxation on subsidization, long-run equilibrium could not be suboptimal. Some form of subsidy would probably be required to ensure this condition on a continuing basis.

will suffer. If LRMCs are above average historical costs--as is currently the case--then earnings will exceed the levels required to raise capital for future growth and will probably conflict with regulatory restraints.

One way to satisfy earnings requirements while minimizing the distorting effects of not setting rates at LRMC is by application of the "inverse elasticity rule." This rule derives its name from the fact that "elasticity" is the form in which the responsiveness of demand to price is usually measured. The procedure is roughly as follows: Calculate rates on the basis of the LRMC for each class of customer. Estimate total revenues and compare them with required revenues. If there are excess revenues, reduce calculated rates to meet the revenue requirement, but concentrate the reductions on those portions of the rate schedules or on those types of customers for which the likelihood of inducing an <u>expansion</u> of demand (in the long run) is lowest. If there are insufficient revenues, raise the calculated rates to meet the revenue requirements, and concentrate the increases where the likelihood of causing a <u>reduction</u> in demand is lowest.

The procedure just outlined will work well if protracted disputes about which elements of demand are least price elastic can be resolved and as long as revenue requirements are set reasonably close to the level required to maintain profitability. If revenue requirements fail to reflect the increasing costs of providing additional service, or if regulatory lag is excessive, the resulting erosion of earnings may prevent utilities from raising sufficient capital for expanding capacity while encouraging demand growth by forcing excessive deviations from marginal cost pricing. Under such circumstances, the risk of inadequate electricity supplies necessarily looms larger.

C. System Planning and Supply Adequacy

Beyond allowing adequate earnings and encouraging rates that do not deviate too far from long-run marginal costs are a range of policy alternatives designed to accelerate additions to supply, to improve system performance, to limit consumption to economic levels and so on. To know whether it is really worthwhile to implement any of these alternatives, it is necessary to compare in some fashion the costs of inadequate supply with the costs that are incurred in reducing the likelihood or the undesirable effects of power shortages.

Current industry planning practices usually involve designing increments to system capacity in such a way as to meet projected peak loads with a margin of reserve sufficient to keep the probability of outages at a very low level. Some companies apply a rule of thumb directly to the reserve margin factor, say, 20 percent. Others set reserves equal to the capacity of the largest unit on the system. Still others calculate a loss-of-load probability or LOLP and design the system to achieve a given level of reliability, say, one day of outage in 10 years.[24] The target reliability level is usually a rule of thumb. Implicit in these rules of thumb is a judgment by each utility either that its customers as a group would be willing to pay the costs of achieving its targeted service reliability level, because the costs or inconvenience of lower levels would be even greater or --what is tantamount to the same thing--that public reaction to a lesser degree of reliability would redound unfavorably upon the company. Such reaction could range from customer protests or boycotts to increased public opposition to rate increases. Ultimately it could lead to more drastic governmental action.

We question whether this conventional approach to system capacity planning is adequate today. As indicated below, it is now becoming possible to perform explicit evaluations of the costs and benefits of increments to system capacity or of any other reliability improving investments. A few preliminary studies of this kind have been performed.[25]

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[24] LOLP is defined as the expected fraction of time in which there are outages of any size, though it is also commonly defined as the expected number of days per year on which a system outage of any duration occurs.

[25] See, for example, R. Bruce Shipley, et al., "Power Reliability vs. Worth," IEEE Transactions Paper, February 18, 1972; M. L. Telson, "The Economics of Reliability for Electric Generation Systems," Massachusetts Institute of Technology, May 1973; and Alvin Kaufman, "Reliability Criteria--A Cost-Benefit Analysis," Office of Research, New York State Public Service Commission, August 1975, OR75-9.

These studies do not provide conclusive evidence, but they do suggest the possibility that historical reserve margins may not have reflected a proper balance of costs and benefits. Second, even if target reliability levels have been correct in the past, they may be no longer.

As a first cut at the question of the proper reserve margin, we must recognize that when consumers of electric power cannot get power because of inadequate supply, a cost is incurred by the consumer. In some cases it is an implicit cost--inconvenience, bile, frustration. In other cases, production is curtailed; people and machines are idled; plant, equipment or inventories are damaged; and monetary losses follow. All these curtailment costs are external to the utility, and as a business enterprise the utility essentially does not, in a short-run profit-maximizing sense, have to care about them. In the long run it must do so, however; for the economic health of its service territory and the satisfaction of customers' demands for reliable service are essential to its viability and profitability. Moreover, the regulatory process will ensure that the utility internalizes some of these external costs, because the consumer cannot look to competitive enterprises willing to provide extra reliability for a higher cost. The utility and the regulators then have to make judgments about the social costs involved in different levels of reliability. What costs are imposed on society by generation-related outages occurring once every week as opposed to once every 10 years? Or by outages lasting six hours on the average, rather than one? The relevant question is: At what level of reliability does the cost of an extra unit of capacity equal the extra saving in social cost derived from putting in the extra capacity?

Determining the costs of adding to a reserve margin is not particularly hard. Determining the social costs avoided by changing the reserve margin is extremely difficult. The French have endeavored to do it by developing a plan for load shedding in the case of energy insufficiency (mainly low water, since the French system is heavily dependent upon hydropower and estimating the value of the loss of production at each level of supply insufficiency. The plan is then to add capacity to the point where the cost of an extra unit of capacity equals the reduction in probable loss to society which the extra unit of capacity provides.

This sort of calculation would require a change in the loss-of-load probability concept (LOLP) as it is generally applied. The problem with LOLP is that it makes no distinction between the probability of a small outage and that of a large one. Since the losses or inconveniences caused by an outage depend--among other things--upon its size, reliability should be measured in a way that includes both the probability of outages and their likely magnitude, extent and duration. One such measure is the expected fraction of energy demanded but not served due to outages--loss-of-energy probability or LOEP as it is sometimes called. The methods used to calculate LOLP can be extended quite easily to calculate LOEP. The latter can then be used to estimate the total kilowatt-hours expected, on the average, to be denied to customers when they want them. If a dollar value can be attached to those kilowatt-hours, then a utility can measure the cost savings to customers of raising reliability (lowering LOEP) and compare them with the costs it must incur to do so.

Another important area for investigation is the relationship between utilities' legal obligation to serve and economically determined reliability levels. In particular, some customers may demand more reliable service than would be economic, taking customers as a whole. In the event of an outage, many customers would merely defer activity until service was restored; some, however, would lose their entire scheduled output during the outage period, while still others would suffer losses over and above lost production. The importance of this last possibility would normally depend upon the kind of production process involved. For example, some metal-working processes require constant energy inputs to prevent "freezing" of the metal or cooling and spalling of the furnace linings.

Presumably, such customers would be willing to pay a premium for more reliable service than might be socially efficient for the bulk of a utility's customers. In order to provide such service the utility might install signal-actuated cut-off equipment to interrupt those customers who did not require the more reliable service. Alternatively, the utility might install suitable standby equipment, such as gas turbines, near those customers desiring a higher level of service.[26] The customer wanting additional reliability would be required to pay a premium sufficient to cover the extra cost of serving him.[27] This kind of customer is the reverse of the interruptible customer, who is willing to accept less than average reliability in exchange for a lower rate reflecting the capacity he saves for the utility.

One additional point concerning reserve margins deserves mention. Most reliability studies dealing with generating-capacity reserve margins have not taken into account the reliability of the transmission and distribution networks.[28] If, say, the distribution system is built to a lower order of reliability than other components, the higher level of generating reliability may represent a form of "gold-plating." On the other hand, some portions of a

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[26] To connect this capacity to the system as a whole would require rather complex and far from costless arrangements, so it is likely that the customer would do just as well to install it himself.

[27] Contributions in aid of construction have sometimes been used as a means of paying for higher than average service reliability.

[28] L. H. Roddis, Jr., Speech before the American Public Power Association, Power Supply Planning Committee, January 28, 1975.

transmission or distribution system may be built to a lower order of reliability for sound economic reasons. (Long feeder lines serving sparsely populated rural and suburban areas are often planned this way.) By contrast, the generating reserve margin must be great enough to maintain reliability standards for the highest priority elements of the transmission and distribution system. This margin will be greater than that required to maintain the average reliability level of the system taken as a whole.

D. Allocating Inadequate Supplies of Electricity

When supply is inadequate in a free and competitive market, rising prices are the means by which scarce supplies are allocated. This avenue of control generally is not open to electric utilities. Taxes or emergency penalties could be imposed through legislative action in lieu of rate increases, but the likelihood of enactment or enforcement to the degree required is quite low. If either were sufficient to choke off a major shortage, it would surely arouse great political opposition. Nonprice rationing--voluntary or involuntary, planned or de facto--is the most likely, indeed virtually the only remaining alternative.

The nature and extent of nonprice rationing likely to be required in a shortage depends significantly upon its expected duration. If reliability is more or less adequate and rates are close to long-run equilibrium levels, then shortages will tend to be mild and transitory. This was the situation generally faced by the industry up to the early 1970s. The principal concern was to develop system interties and load-shedding plans for shortages of relatively short duration, perhaps up to a few days' time. Both government and industry devoted considerable effort to this task.

The situation we face now, though, is something else again. The late 1970s and 1980s hold the distinct possibility of chronic shortages--lasting for weeks, months or even years--during which customers' desired consumption levels might have to be restrained in order to keep utility systems at even minimally viable levels of reliability. Under these conditions, the *de facto* rationing priorities in load-shedding plans could be replaced by rating systems that were more equitable and effective than those that were feasible under transitory shortage conditions. Below we review some possible courses of action.

1. Refusing New Customers

One rationing technique used by some gas utilities and sanitary districts is to refuse to connect new customers. This might apply across-the-board to all new electricity customers or only to those who wanted to install certain types of units like electric space heating systems. It might be limited further to one class of customers (e.g., industrial) or to a portion of one class (e.g., certain types of industries or customers with demand in excess of 50 megawatts). One advantage of such a scheme is that it would be easy to implement. Another is that it would affect a relatively small group of people or businesses compared to plans aimed at existing customers.

The very obvious disadvantage, of course, is that refusing to connect new customers would have a devastatingly inequitable effect upon the people refused, who--while fewer in number than existing customers--nevertheless amount to a very large number of people indeed. Moreover, the side effects of such plans would go far beyond the individuals who were denied electric service. For example, refusal to serve new industrial customers could well prevent entry by new businesses into markets that needed increased competition, and it would be likely to stifle economic growth in the areas affected.

In addition, while declining to connect new customers might be a more effective tool for dealing with energy shortages than rate structure adjustments, this approach is not an alternative for dealing with growth in demand that takes place among existing customers.[29] To the extent that this growth accounts for the excess of demand over supply, declining to serve new customers would be ineffective.

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[29] Average use per residential customer increased from 1,845 kilowatt-hours in 1950 to 8,079 kilowatt-hours in 1973, before declining to 7,907 kilowatt-hours in the recession-conservation year, 1974. This element of the industry's growth could have been restricted only by controls on appliance acquisition--a difficult policy to accept in a free society--or by rigid enforcement of user quotas, an equally unpalatable policy. Over the long term, it might be possible to affect usage per customer by mandatory changes in equipment design, but this would be of little immediate benefit at the onset of a shortage.

It is not uncommon for state regulatory commissioners to prohibit distributors of natural gas from taking on new customers during periods of natural gas shortage. Such actions have been widespread during the past two years. But there are other energy sources that were able to perform the tasks gas had been performing. In the case of electricity, there is no suitable across-the-board substitute, so that a refusal to connect is a decision to deny the customer the satisfaction of that need by any means.

All in all, plans for dealing with electricity shortages by refusing electric service to new customers appear to have great capacity for mischief and therefore, even if entirely legal,[30] would be undesirable for dealing with the problem. This judgment does not, of course, apply to contributions in aid of construction or other charges related to costs _specifically imposed_ on the system by new customers but not reflected in rates.[31]

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30 Some observers wonder whether refusals to serve new electricity customers would be constitutional or would conflict with antitrust laws.

31 These charges can properly be based on the assumption that the new customer is the marginal customer. But in the case of jointly used facilities, the appearance of the new customer is no more responsible for the need for new facilities than is the decision by the existing customer to continue to use those facilities. The cost of some facilities, e.g., line extensions, is of course directly ascribable to new customers; in those instances, charges of the type mentioned above become appropriate. In this connection, see Alfred E. Kahn, _The Economics of Regulation: Principles and Institutions_, Volume 1 (New York: John Wiley & Sons, Inc., 1970), p. 140.

2. Limiting the Service Provided to Existing Customers

One commonly accepted way of dealing with electricity shortages is to interrupt service to existing customers according to some prearranged program until the remaining demand for electricity no longer exceeds the supply. Many utilities already have such multi-step plans. For example, the first step may be to reduce voltage. The next may be to call major commercial and industrial customers and ask them to turn off equipment designated as nonessential. A third step may be to issue an appeal to the public to curtail usage. If all of the foregoing are inadequate, a utility may begin to interrupt service to customers for short periods of time on a rotating basis, avoiding--*if possible*--areas where there are hospitals and other public service facilities.[32] Programs of the sort described above are designed primarily for random outages of relatively short duration. They could be effective in the first stages of a prolonged shortage, but other measures are likely to be preferred in the later stages.

Programs for reducing service to all customers on a sustained basis might be designed in a variety of ways. They would almost certainly rely upon the use of quotas established

[32] It is often impossible in the short run and costly in the long run to separate critical facilities from their surrounding distribution areas. Of course, many facilities of this sort are equipped with emergency generating units--hospitals being a common example.

according to such criteria as end-use characteristics, customer type, size, location or time of day and might involve the use of coupons as well. The goal should be to ensure that customers share the burden of inadequate power supply equitably and at least cost. That burden will be distasteful, but by and large it should not be as oppressive as it would be if it were borne solely by prospective customers.

Nonprice rationing can be effective because it is direct and immediate, and it can be tailored to protect high-priority uses. But its political acceptability in periods of persistent rather than intermittent shortages is, to say the least, uncertain. Moreover, the risk of distorting economic incentives and consequently of imposing needless costs upon customers and investors may rise steadily under prolonged non-price rationing conditions.

3. Optimal Rationing

The most economically efficient scheme for nonprice rationing would in theory be one that produced a pattern of consumption closest to that which would prevail if electric service were priced as in a competitive market. Several complications make full implementation of such a scheme unlikely. It would be difficult, time-consuming and therefore costly to estimate the "competitive" allocation; it would be costly to administer and to enforce a scheme complex enough to produce a near-competitive allocation; and finally, considerations of equity might require an other-than-economic allocation.

A reasonable approximation to the competitive result might be obtained by application of an "elasticity rule" for allocating service by quota to customer groups. Those with the most price elastic demands (that is, the ones who would respond to any price increase with the largest percentage reductions in demand) would be required to make the largest cutbacks from their intended consumption levels. To state that proposition is also to state its weakness: The political appeal of a rationing program based on difficult-to-establish "elasticity" criteria is likely to be slight and could engender considerable controversy about who has the ability to pay.

4. Inter-Utility Sharing of Shortages

One way of ameliorating the effects of a shortage in one region would be to "allocate" or to "spread" the shortage among several less affected utilities. This approach raises difficult questions concerning the authority and responsibility of the Federal Power Commission vis-a-vis state regulatory commissions and the individual utility companies. The FPC has marched up to these questions without answering them, but it has given some strong indications that it believes it has the power to require sharing of shortages.

Section 202(c) of the Federal Power Act grants the Federal Power Commission broad authority to deal with emergencies, including:

> ...an emergency...by reason of a sudden increase in the demand for electric energy, or a shortage...of facilities for the generation or transmission of electric energy....

In particular, the Act empowers the Commission to require temporary connections of facilities and such generation, delivery, interchange or transmission as may be necessary to meet the emergency.

Although the FPC has invoked its Section 202(c) powers several times since World War II, it has only recently promulgated guidelines as to how those powers will be administered in the future. The guidelines are set out in Order No. 520, which was issued on November 29, 1974. Among other things, Order No. 520(a) establishes regulations for the filing of applications for "emergency orders" based on claimed inadequate supplies of fuel for generating stations or inadequate supplies of energy for system needs from any source, and (b) sets out ratemaking principles to be applied in connection with Commission-ordered transfers of capacity or energy from one system to another.

One of the issues raised by these new regulations is just how broad the Commission's Section 202(c) emergency powers are. The Commission very plainly takes a broad view of its authority. It states in its comments on Order No. 520 that the Section 202(c) power is separate and apart from its authority to engage in general economic regulation. For example, the Commission asserts that Section 202(c) gives it authority over the facilities of rural electric cooperatives, municipalities and federal facilities, such as those of TVA, even though it does not have jurisdiction over such facilities under other provisions of the Act.

It is worthwhile to examine the implications of Order No. 520 for the question asked at the outset of this subsection. Namely, to what extent is the Commission authorized to "spread" or "allocate" shortages of one utility to another? In terms of its articulated view of its power to "allocate" shortages, the FPC is proceeding tentatively. When an earlier version of what became Order No. 520 was proposed on August 26, 1974, the Commission contemplated that emergency energy transfers from other systems to an applicant's system would not result in the shedding of loads of ultimate consumers served by such systems. This observation was dropped, however, from the Commission's comments on the final version of the Order. Instead, the Commission noted the "desirability" that emergency power or energy transfers should not result in the dropping of loads of ultimate customers on the supplying system. But it added:

> However, data available to the Commission indicate that voluntary conservation and utility initiated measures can effect significant reductions in load and energy requirements and consideration of a reasonable and equitable level of such reductions by the supplying system will not be excluded from the Commission's review.

Moreover, the Commission was careful to point out that while its purpose in adopting Order No. 520 was to articulate the means for ordering systems to share capacity and energy up to the point of curtailing consumption loads, it did not undertake to establish the outer limits of its authority under Section 202(c) to allocate shortages. Instead, the Commission would await the developments of specific factual circumstances in particular cases before deciding the outer bounds of its Section 202(c) authority.[33]

It is possible, indeed likely, that hard questions will arise. For example, assume that the regulatory commission in State A grants Utility A rate relief sufficient to enable it to build required generating capacity and thus serve its customers with a reserve that is just adequate. The commission in the adjoining State B, on the other hand, grants inadequate rate relief with the result that Utility B cannot build the requisite capacity and soon suffers shortages. When Utility B applies under Order No. 520 for an FPC order requiring help from Utility A, the matter reserved by the FPC in Order No. 520 would be squarely presented.

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[33] The Commission has said in the past that it lacks authority to ration electric power among ultimate customers [38 Federal Register 33642 (1974), citing Order No. 445, 47 FPC 75-76 (1972)]. Yet, it would seem that the Commission would effectively be doing just that if, acting under Order No. 520, it were to compel utilities to share power shortages--that is, if it were to order Utility A to provide energy to Utility B even though to do so would cause a shortfall in Utility A's system. To be sure, Utility A might well be left to decide just which of its customers would suffer from the shortage caused by the FPC order that it send its electricity elsewhere, but the fact that the FPC does not select precisely who shall be hurt cannot reverse the fact that it is the FPC's order that makes the selection necessary.

If the Federal Power Commission were empowered to regulate the levels of retail rates in States A and B in the first instance, it could in theory prevent this difficult case. Indeed, some electric utilities, hard pressed by inadequate rate relief from their state commission, argue, largely on the basis of Section 202(c), that the Federal Power Commission already possesses the statutory authority to regulate retail electric rates. Although no one seems to doubt that Congress could constitutionally bestow such power upon the Commission, there is considerable doubt that it has already done so. Section 201(b) of the Federal Power Act expressly provides that Part II of the Act [which includes Section 202(c)] shall apply to the sale of electric energy "at wholesale and in interstate commerce" but shall not apply to "any other sale of electric energy...."[34]

Given the uncertainty surrounding FPC power over retail electric rates, it seems reasonable to urge that when electric power is transferred to states where capacity is inadequate, rates be charged that fully compensate customers in supplying states for their investment in sufficient reserve capacity.[35]

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[34] In Conway Corp. v. FPC, 510 F.2d 1264 (D.C. Cir. 1975), the Court of Appeals held that the Commission could "consider and investigate" the retail rates of an electric utility to determine whether the wholesale rates it charged municipalities and cooperatives with whom it competed at retail were just and reasonable.

[35] Federal Power Commission decision in Docket No. RM74-22.

E. Observations

There is no entirely satisfactory way of allocating persistent shortages of electrical energy. Schemes designed to discriminate against new customers would tend to affect living standards inequitably and to restrict economic growth. Plans designed to share the burden among all customers would have some of the same defects but would probably be more acceptable than those which would concentrate the burden on new customers. Such plans would be more attractive in the short than in the long term, since they make no distinction between essential and less essential uses, and do not address the long-term consequences (jobs versus comfort) of such an apparently equitable system. More economic rationing schemes would probably run afoul of notions of fairness and political acceptability and, even if implemented, would present formidable administrative difficulties. Plans to share the burdens among various utilities would depend, at bottom, on the presence of more than adequate capacity in at least some places, and on the ability of the FPC to conscript supplies from the "haves" for the benefit of the "have nots."

Additionally, the national defense aspects of any prolonged shortage must be considered. The Department of Defense has advised this Committee that:

> The continued availability of electric power at reasonable prices is, of course, essential and of concern to the Department of Defense (DOD)....In...1975 the DOD will use approximately 1.5 percent of the total amount of electricity sold in the

> United States....Without commercial electric power, DOD could not operate and maintain facilities or equipment.... Within the Department of Defense all essential communications equipment, weapons systems and related support facilities are provided with their own standby generating units so that as long as the fuel supply (usually petroleum) lasts, the DOD could operate. However, this generating capacity is quite small and much of the generating equipment is of high RPM and designed for relatively short periods of use.[36]

The preceding catalogue of electricity supply problems, of the difficulties affecting efforts to manage electricity shortages and of the national security implications of such shortages clearly underscores the need to ensure an adequate and reliable supply of electrical energy.

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36 "As the Department of Defense representative on this committee has noted, the military would expect to share the reduction of service to its community and residential type activities (troop housing, family housing, administrative buildings, etc.) on the same basis as nearby civilian communities. In industrial type installations engaged in defense essential activities, however, the DOD would be adversely affected by reduction of 20 percent or more and would therefore seek preferential treatment through the Defense Production Act of 1950 or a similar procedure to get relief for sudden reduction in power supply. For long term relief, the Defense Department might build its own generating facilities at industrial installations."

V. THE EFFECTS OF INADEQUATE SUPPLY

Power shortages are of two types: Unplanned, more or less sporadic curtailments of service, and regularly anticipated inabilities to meet needs.[37] The dividing line is, of course, a hazy one: as reserve margins shrink, service interruptions become a more frequent fact of life, and "sporadic" curtailments become a planned-for inability to serve.

The effects of shortages--whether of the sporadic or regular variety--can be grouped broadly into two categories: short run and long run. Both will be greater or lesser depending upon the kinds of plans and capabilities that users have developed for dealing with outages. But in the short run these plans and capabilities are <u>fixed</u>--determined by customers' evaluations of service reliability, the costs of alternative or backup systems, and the importance of the uses to which they put electricity. The long-run costs of power shortages are the costs that arise from implementing <u>changes</u> in customer preparations. They include the cost of such steps as installing and operating backup generating units or energy storage systems and converting to appliances or other devices using fuels instead of electricity (net of the cost of the electricity saved). They may also include less visible but more pervasive costs such as excessive conservation of electricity

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[37] Losses due to voltage reductions should be included in one or the other of these groups depending upon the circumstances.

and consequent overreliance on other scarce resources, increased environmental pollution, a reduced rate of technological progress in some sectors of the economy, and changes to less pleasant life styles. Many of these costs would translate into a reduced rate of economic growth. Finally, the long-run costs of shortages include the short-run costs of any outages that may be expected to occur after all adjustments and changes in customer preparations have taken place.

A. Two Recent Examples of Shortages

As a prelude to our general discussion of the effects of inadequate power supplies, we present two examples of recent shortages. We intend that they should serve as a means of getting a firmer grasp upon the physical and economic dimensions of shortages and of making the conceptual discussions that follow a little more concrete; although we hasten to add that the effects of shortages can vary widely from time to time and from place to place depending upon the conditions peculiar to the situation.

1. British Coal Strike--1972

Many observers expected the coal miners' strike in Great Britain that started on January 9, 1972 to run a smooth course and have little effect on the economy. Wage settlements had been averaging 15 percent, and the Conservative government of Prime Minister Edward Heath had chosen to fight wage inflation without interfering directly with negotiations in private industry. But the 280,000 striking miners demanded a 25 percent wage hike at a time when the government had embarked upon a strong policy of "voluntary" wage controls. The government underestimated the determination of the miners to hold out. It perhaps also overestimated the length of time that the country could ride out a strike without serious consequences and so maintained its determination to abide by its policies to curb inflation, despite the high costs of doing so. The strike lasted until the miners' demands were finally met--a period of seven weeks.

On February 11, 1972 the government declared a state of emergency. With 70 percent of the country's power dependent upon coal and only a five-week supply of coal in stock, the government ordered a drastic curtailment of power. Advertising and display lighting were prohibited. Domestic consumers were asked to heat only one room. Commercial establishments were banned from using electricity for heating and were required to reduce lighting levels. Voltage reductions and rotating power blackouts lasting up to four hours were imposed.

The power shortage had the severest impact in the manufacturing sector, particularly in the steel, auto, chemical and heavy engineering industries. Most of these industries were required to adopt a three-day workweek. Various union work-rule restrictions were temporarily suspended to permit maintenance activities to be scheduled during off-periods, and industry cooperation was enhanced as a result of discussions held with Electricity Council officials at early stages. Although productivity went up at first, the shortened workweek began to disrupt the flow of needed materials and supplies. Eventually firms had to lay off numbers of their employees. Some companies tried to squeeze a 36-hour workweek out of the three production days, but this required expensive overtime pay and proved economically infeasible. Other industries closed down completely. Large continuous process industries were allowed to operate full-time but were ordered to reduce their power loads by at least 35 percent.

The coal strike directly affected the supply of coal to the iron and steel sector, and in the later stages of the emergency a coal-induced shortage of iron and steel restricted industrial production more severely than the electricity shortage itself.

The transportation and communications industries were also seriously affected by the electricity shortage. Traffic signals did not function, and trains were canceled daily--causing massive traffic jams and confusion. Despite the difficulties of the shortage, the British adapted with little grumbling, although with decreasing willingness to reduce power consumption voluntarily.

Electricity industry officials estimate that, overall, energy savings amounted to 20 percent of consumption during the crisis period, with 4, 6 and 10 percent of the total coming from the residential, commercial and industrial classes, respectively. These savings represented 10, 23 and 29 percent, respectively, of class consumption.

Imports rose sharply, playing a key role in closing temporary gaps in the economy during the power shortage. Candles experienced the greatest relative increase in demand of any import commodity. At the same time exports plummeted. The balance of payments for February 1972 showed a 32 million pound deficit, and there were fears of a balance-of-payments crisis. These fears were short-lived, however. Business confidence perked up after the initial phases of the power shortage had passed and the demand for imports had backed off. The value of exports and imports for 1972 were 9,179 million and 9,866 million pounds, respectively. These compare with values of 9,746 million and 10,041 million for 1971.

The United Kingdom's Gross Domestic Produce (GDP) had been rising in real terms at an annual rate of 4.1 percent in the last quarter of 1971. The National Institute Economic Review estimates that GDP dropped 1.25 percent during the first quarter of 1972 and that industrial production fell by 2.75 percent.[38] Based upon an estimate that the manufacturing industry was at no more than two-thirds of its potential, The Economist calculated a loss of about 0.4 percent of the nation's annual output per week during the emergency.[39]

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[38] The National Institute Economic Review, Number 63, February 1973.

[39] The Economist, London, February 19, 1972.

Using this figure and assuming that GNP would have run at an annual rate of about $143 billion sans strike, the value of lost output amounts to approximately $85 million per day. Based upon an estimated cutback of 165 million kilowatt-hours per day in sales to the commercial and industrial sectors, this yields an average cost per kilowatt-hour lost of about fifty cents. This is close to estimates presented below for the United States.

<u>The Quarterly Economic Review of the United Kingdom</u> estimates unemployment at roughly 967,000 at the end of January 1972 (before the coal strike), which represented 4.3 percent of the labor force. In February, an additional 1.6 million were temporarily laid off due to the coal strike.

By March 1 the emergency was over. The British economy had gone through the power shortage seemingly without permanent damage. The growth of real GDP rebounded to a 5.4 percent annual rate in the second quarter. <u>The Quarterly Economic Review</u> estimates that total unemployment had fallen to 700,000 (3 percent) by the end of 1972 and that inflation had declined from an annual rate of 8 percent in February 1972 to 6 percent by June 1972. We conjecture that the daily costs of the shortage would have grown considerably had the emergency lasted longer. As it was, the economy moved back to full steam before any major collapse of business or industry could occur.

2. The Pacific Northwest - 1973

In 1973, the Pacific Northwest experienced an abnormal drought year, and by July of that year, the Bonneville Power Administration (BPA) was supplying only 25 percent of its normal interruptible power, or 250,000 kilowatts. Most of this cutback had been made in the spring because of low reservoir levels behind hydroelectric dams--a result of below-normal precipitation and low runoff from surrounding mountains. In August, the utilities announced voluntary curtailment plans. By September, the water levels indicated a potential of only 31 billion kilowatt-hours--one-third less than necessary, under normal conditions--to meet projected demands. The Pacific Northwest--heavily dependent on hydroelectric power--was faced with what threatened to be an acute electric energy deficiency, even before the rest of the nation felt the energy crunch. Utility officials were predicting that a demand reduction of 7.5 percent would be needed to avoid blackouts, and in the same month, the Washington legislature passed a bill giving the Governor authority to order curtailment of energy use by customers in the State. Later in September the Governor of Oregon imposed a mandatory ban on outdoor display and sign lighting. The region's utilities announced a voluntary conservation program whose goal was a 7.5 percent reduction in usage.

These efforts were reasonably successful. Overall, electricity use for November 1973 in the Pacific Northwest was almost unchanged from that for the same month a year earlier. In December it was 10 percent below the corresponding period of 1972. Industry officials meeting on October 10 estimated that voluntary curtailments amounted to 5.6 percent of expected consumption. (A subsequent analysis showed that savings averaged about 7 percent over the September-December period.) Later in October a lack of fuel began to threaten the availability of imported power and necessitated some cutbacks in thermal generation; but fortunately, November brought heavy rains, and the reservoir situation improved markedly. Although voluntary curtailment programs were maintained, the ban on outdoor display and sign lighting in Oregon was removed. Continued heavy rainfall eliminated the reservoir storage deficiency by mid-January 1974.[40]

The shortage affected the aluminum industry most seriously. The Pacific Northwest has the nation's largest concentration of aluminum smelters, all of which rely heavily on BPA hydroelectric power. BPA estimates that 1,070 workers were laid off by aluminum producers following curtailments of interruptible power; another 10,000 jobs were "affected" in fabricating plants; and "thousands" of additional jobs were "jeopardized" in manufacturing plants using fabricated

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[40] Pacific Northwest Utilities Conference Committee, The Pacific Northwest Electric Energy Shortage of 1973, April 1974.

aluminum.[41] It is not known how many jobs in these other plants were actually lost. Most observers think very few, since the electricity crunch was over before a major aluminum shortage could develop. Production of aluminum did decline by 20 percent during the curtailment period, and spot shortages did appear in various parts of the country. Some utilities were unable to obtain aluminum for transmission lines, for example. But the effect of lower aluminum production was somewhat softened by letting stocks (including government reserves) decline. Had stocks run out, conditions in aluminum markets would certainly have been worse.

By mid-August, 1973, Reynolds Aluminum was operating at only 60 percent capacity at their Troutdale plant and 75 percent capacity at their Longview plant. To help offset these production losses they reactivated two aluminum-producing potlines in Listerhill, Alabama, employing 75 workers. Unemployment at their plants in the Pacific Northwest reached 105, representing a total payroll of nearly $1 million a year. In April 1973, Kaiser Aluminum was forced to close one potline at Mead, Washington and delay a May 1 start-up of another. Aluminum Company of America was able to replace its interrupted power with electricity purchased from other sources. Martin-Marietta (operating aluminum plants in Oregon and

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41 "BPA Surplus Aids Aluminum Industry," Portland Oregonian, December 22, 1973. Aluminum company layoffs amounted to 9 percent of total industry employment.

Washington) had purchased 424 million kilowatt-hours of "provisional" (interruptible) power from BPA in 1972. In 1973, by arranging a 1.8 million barrel shipment of oil to Pacific Gas and Electric in California, it was able to obtain 550 million kilowatt-hours to offset its interrupted power.

When the Weyerhaeuser Company suffered power shortages, it applied for (and was awarded) an air pollution variance for its Everett mill--permitting operation of its boilers above capacity to produce enough steam to operate a small turbine generator. This variance was awarded by Puget Sound Air Pollution Control Agency with full recognition of the fact that its action would increase the smoke emanating from the mill's stacks.

Business, industry and residents reduced energy demand through various energy conservation measures including air-conditioning cutbacks, reduction of interior and exterior lighting, "lights-out-at-night" programs, removal of hot water handles from faucets in public washrooms and bans on decorative lighting. Some companies curtailed power and minimized layoffs by scheduling repair and maintenance work during the shortage period.

The reports contained in most news articles painted a fragmented, but generally gloomy, picture of the economic situation in the Pacific Northwest during the energy crisis. Were the effects of the shortages as far-reaching as it might appear from news accounts? Other observers offer the following comments:

> The energy crisis has had an insignificant impact on employment in the Pacific Northwest....[There was] no impact in the electric supply area except for the 1,000 plus layoffs due to BPA's interruptible contracts....[42]

> Oregon...experienced only a moderate number of layoffs due to the fuel crisis....[43]

The director of the Oregon Employment Division attributed the above-average unemployment figures for that period to seasonal variations, a national business turndown and unprecedented immigration.[44]

We conclude that the overall costs of the Pacific Northwest electricity shortage were rather small. Prior to the fall of 1973, electricity cutbacks had been restricted largely to interruptible service at aluminum plants. The heavy rainfall in the winter of 1973-1974 soon eliminated the possibility of a prolonged shortage affecting all customers. Many of the concurrent adverse economic conditions in the region were traceable to other causes--including, of course, the oil embargo and consequent shortage of petroleum products.

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[42] Internal correspondence from Lou Growney, Pacific Power & Light Company, April 3, 1974, quoting Dr. Edward W. Reed, Senior Vice President and Economist, U.S. National Bank of Oregon, Portland.

[43] <u>Ibid.</u>, quoting Ross Morgan, Director of Oregon Employment Division.

[44] <u>Ibid.</u>

B. Short-Run Effects

The most obvious short-run cost of service interruptions is, of course, the loss of output due to accidents, work stoppages, or slowdowns. It may extend beyond the businesses and industries directly affected through the network of inter-industry relationships to a broad array of firms throughout the economy. Capital losses constitute a second type of cost. They include spoilage, damage to plant and equipment, and personal injury. Such losses may be particularly important when outages occur without warning. Some types of manufacturing operations have equipment that is easily damaged if shut off suddenly, and some types of safety systems (e.g., ventilation) depend critically upon electric power. Finally, nonmonetary factors are not to be ignored. The time lost, the inconveniences suffered and the anxiety experienced by individuals during outages are very real and important costs.

The short-run costs of interruptions are, of course, dependent upon their extent and duration, but other more subtle factors may also play important roles. For example, as the frequency of outages grows it may become more costly to maintain backup systems or preparations in a state of readiness for the next interruption, and it will be harder to plan around each one. Most factories can easily make up the production time lost during an occasional widely spaced outage but would face a much larger problem if they experienced weekly or daily blackouts. Predictability can be important in many cases. If prior notice of an impending outage can be given out, users will have time to cut low-priority loads and to make emergency preparations.

The type of customer affected is another factor that can measurably influence short-run costs. Utility load-shedding plans give recognition to this fact when they prescribe continuation of service to essential or particularly vulnerable customers such as police or fire departments, communications facilities, hospitals, airports and cold-storage buildings. Equally important, however, are kinds of preparations customers have made and customer usage patterns at the time of interruptions. Residential customers, for example, are likely to be more seriously affected if service is interrupted at dinnertime, during a January cold wave or on a July afternoon when it is 95 degrees and humid than on a pleasant weekend morning in May. Commercial and industrial customers generally will be affected more seriously during working hours than during off-hours.

If customers have installed backup generating units or energy storage systems or have purchased appliances and heating, lighting or air-conditioning systems relying upon nonelectric energy sources, they may be affected very little in any direct way even by outages lasting a considerable period of time. Indirectly, however, they may feel the effects through declines in sales, higher costs--or reduced availability--of materials and supplies, increased employee absenteeism or tardiness and slower communications. Customers who are largely without alternatives to electricity must simply do without. The greatest short-run costs per kilowatt-hour lost will occur when imposed upon those in this group who are most dependent upon electricity by the nature of their technology, business characteristics, past investment choices or preferences. Examples include cryogenic gas producers, aluminum manufacturers and tenants of all-electric homes and office buildings.

C. Long-Run Effects

A customer has certain expectations about the reliability of service, formed primarily upon the basis of past experience. Because of the outstanding record of reliability posted over the years by the nation's utility systems, most customers have come to expect that very few outages will occur and that those that do will be of modest extent and duration. As a consequence they have, by and large, made few preparations for prolonged or frequent outages. If long-term service reliability were suddenly to deteriorate, the short-run costs of outages would be quite high owing to this lack of preparation. But if the new reliability situation persisted, customers would gradually raise their evaluations of the likelihood and duration of outages. In this new situation the expected costs of outages might be high enough for some customers to justify the costs of taking steps to ameliorate them. The long-run costs of outages are the net out-of-pocket costs to users and indirect costs to the economy at large of taking such ameliorative steps plus the expected remaining short-run costs of outages after the new preparations have gone into effect. Moreover, the long-run costs should be less than the originally expected short-run costs--otherwise it would not have been worthwhile to change plans.

We note two factors, however, that may inhibit the adoption of ameliorative steps. First, individual firms will generally not count the indirect cost savings they produce for other companies and individuals by improving their own situation. Second, customers who are particularly vulnerable to outages may try to convince utility companies to bear the cost of providing more reliable service than is desirable for most other customers in order to shift the costs of providing additional reliability onto other shoulders.

A decrease in reliability lowers the quality of service received; and if rates do not decline correspondingly, the customer, in effect, experiences a price increase, albeit one perhaps less immediately obvious to him. If, on the other hand, nonprice rationing schemes are used to limit demand so as to maintain reliability, the quality of service still declines because the customer is not able to consume as much as he wishes at whatever time he chooses. Again, he experiences an effective price increase. In many respects the long-run effects of inadequate electricity supplies are like those of a rate increase large enough to choke off the "excess" demand. The one area of notable difference is that rate increases would not--reliability held constant--generally induce customers to install backup emergency electricity-supply capacity.

Decreased reliability or nonprice rationing, if either occurs, will reflect the need to slow the growth of loads to a level consistent with utilities' ability to expand capacity. If nonprice rationing fails, decreased reliability will succeed in doing the job--most likely at greater cost. However, with the exception noted above concerning the incentive to install emergency backup generators, the long-run effects of shortages are likely to be generally similar in character[45] to the long-run effects of slowed electricity demand growth under appropriately higher rates. Our object is now to identify some of the important qualitative differences between a high-rate "electricity-restrained" economy and the economy that would have evolved otherwise. We see at least three:

1. Sectoral Output Patterns--Slowed electricity demand growth necessarily implies one or more of the following events:

a. Some, if not all, consumers of electricity use less electricity per unit of income (if households) or output (if firms) than they otherwise would.[46]

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[45] And probably greater in magnitude.

[46] Increased use of self-generated electricity is another possibility.

b. The output of some, if not all, firms that use relatively large amounts of electricity per unit of output grows more slowly than otherwise.

c. Total income and output grow more slowly than otherwise.

The first two of these three must give rise to shifts in sectoral output patterns.

In connection with the first, we may expect a slowing of the growth of industries whose outputs are complementary with electricity (mainly electrical equipment manufacturing) and a corresponding acceleration of the growth of industries whose outputs are substitutes for electricity (the fossil fuel-producing sectors)[47] and of industries whose outputs are complementary with fossil fuels (producers of fossil fuel-burning equipment).[48] The shift toward competing fuels would reduce the adverse environmental effects associated with electric power production and transmission, but would raise those associated with the production of fossil fuels for nongenerating purposes. It would probably lead to increased fuel imports.

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[47] Coal is a possible exception, owing to its extensive use in electricity generation and to environmental regulations that may restrict its use in nongenerating applications.

[48] An alternative possibility is that the manufacture of new, more efficient types of electrical equipment will accelerate while that of older, less efficient types declines. This situation would offset somewhat the tendency for nonelectrical equipment manufacturing to grow at the expense of electrical equipment manufacturing.

Readjustments of sectoral output patterns could be of such a magnitude that, during a period lasting perhaps several years, some industries would continue to invest in new capacity when it was unwarranted, while others would fail to invest rapidly enough to accommodate new conditions. The growth of labor supply in these industries could follow a similar pattern. As a result of these developments, we would anticipate some temporary unemployment and excess capacity in the decelerating sectors and some temporary shortages of productive inputs and outputs in the accelerating sectors. Shortages in the oil and gas markets might be severe, given the apparent low price elasticity of domestic supply of those fuels. In addition, some firms or households could experience considerable inconvenience or financial hardship until it became economically feasible to replace existing electrical equipment with types designed to reduce electricity consumption, or to use alternative energy sources.

2. Economic Growth, Employment and Wages--The role of electricity as an input to production is pervasive and complex, and its complexity increases in the long run as technology advances and opportunities for substituting one method of production for another arise. In practical situations, there is no easy way to estimate the effects of inadequate electricity upon economic growth. It would be convenient if there were a fixed ratio between output and electricity, but we know that it varies from time to time, from industry to industry,

from region to region and from country to country. Until we can explain these variations quantitatively in terms of underlying production relationships, it will be difficult to make accurate projections of electricity-output relationships. This is particularly true when future conditions are expected to differ radically from past conditions (e.g., scarce vs. abundant electricity), since it is then very risky to place reliance on historical trends or intuitive foresight.

The emergence of a chronic condition of inadequate power supply does not necessarily require that the growth of economic output be slower than in the absence of a shortage. That is by far the most likely outcome if electricity is priced fairly closely to the long-run marginal costs of service and any shortage reflects institutional (e.g., legal and procedural) barriers to expansion of capacity or acquisition of fuel as opposed to low profits. If, on the other hand, electricity rates are kept well below the long-run marginal costs of service--owing, say, to the continued use of historical average cost pricing in a period of high and increasing long-run marginal costs--then, paradoxically, the existence of a shortage may not impose a significant growth penalty.

How is this possible? Suppose that long-run marginal costs exceed average embedded costs. In the presence of regulatory lag, any expansion of capacity to meet growing demand will tend to erode earnings and increase the difficulty of raising capital. At the same time, low-user charges will encourage the expansion of demand.

Under such conditions, demand growth may outstrip a utility's ability to increase capacity. If nonprice rationing were successfully used to restrain consumption to a level close to that which would have prevailed under long-run marginal cost pricing _and_ if utilities were able to expand capacity fast enough to maintain economically reliable service at the more restrained pace of demand growth, then it is quite likely that economic growth would be (a) close to what it would have been under marginal cost pricing and (b) _higher_ than it would have been if utility industry capacity had been allowed to expand (e.g., with the help of government subsidies) to provide the levels of service demanded at the uneconomically low rates indicated by historical costs. In this paradoxical case, the existence of a shortage reflects a need to restrain overconsumption, and successful management of the shortage through nonprice rationing may be superior to subsidizing an expansion of capacity. A still better solution, given the administrative difficulties associated with nonprice rationing, would probably be to let rates rise to reflect long-run marginal costs.

As in the case of output growth, chronic shortages of electric power might not _inevitably_ lead to a decline in the growth of wages or employment. But if output growth slowed, it is almost certain that wage growth would also taper off. Theoretically, employment might still rise, if relatively labor-intensive production methods[49] began to be used in place of relatively machine-, and hence electricity-, intensive methods. But in fact, unemployment is no less a problem in most low-wage, labor-intensive economies than it is in high-wage, machine-intensive economies. Moreover, even if such a development reduced unemployment, it would not contribute to an increase in overall affluence.

3. Technological Progress--Perhaps the most unpredictable aspect of a marked shortage of electricity is its effect upon technological progress in the methods of production. Historically, electricity costs have formed a small share of total costs in most sectors of the economy and real electricity prices have tended to decline. The developers and designers of new types of equipment and processes have had to pay, in most cases, very little attention to the cost implications of electricity consumption parameters of new systems. The extent to which an increased incentive to economize upon the use of electricity would lead to an excessive diversion of resources from other R&D activities to conservation, and therefore to an unwarranted deceleration of the rate of development of other new technologies, is unknown.

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[49] That is, methods requiring more labor per unit of output but less of one or more nonlabor inputs.

D. Practical Measurement of the Costs of Shortages

Existing studies of the costs and benefits of alternative levels of reliability use measures of short-run outage costs to determine benefits. This is entirely proper when dealing with the temporary shortage situations typical of past experiences. It is also acceptable to use a short-run measure for the initial stages of a prolonged period of supply inadequacy. Such a measure would, however, be excessive for the later stages, as businesses and individuals began to compensate for the new conditions. A major unsolved problem is how to measure the long-run costs.

Even if we restrict attention to the short-run case, the problem of cost measurement is not simple. In practice, quite a number of restrictive assumptions are typically made in order to simplify the task. First, losses are assumed to be proportional to the energy not served, regardless of the size or timing of the outage. In actuality, we would expect very small kilowatt-hour losses to impose smaller costs per kilowatt-hour lost than very large kilowatt-hour losses. Similarly, outages occurring during business hours may impose a higher cost per kilowatt-hour than those occurring at other times. Second, capital and nonmonetary losses usually are ignored; attention is restricted to losses of income or output. We noted above that damage to plant, equipment, inventories--and people as well--may add costs over and above those due to lost productive time. We also observed that the personal inconveniences, annoyances, and anxieties suffered because of outages, even though seldom translated into monetary income losses, are important costs. It is arguable that capital and nonmonetary losses may be no less important than lost wages or income. Third, the distribution of outages across customer types is not treated explicitly. The cost per kilowatt-hour lost is taken to be an average for all customer groups, who are assumed to suffer energy losses in proportion to their consumption. Since direct monetary costs (and probably indirect costs[50] as well) vary according to the type of customer, and since the distribution of outages can be controlled to some extent, this simplification severely reduces the usefulness of the cost estimates for evaluating load-shedding or rationing priorities. Fourth, indirect effects are typically not counted. Implicit in this approach is the assumption that the electricity shortage is itself the only bottleneck; that is, no <u>additional</u> production or sales losses occur because of indirect effects. Such would be the case, for example, if all industries suffered equiproportional direct losses, which were also conveniently timed so as not to disrupt deliveries.

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50 Those caused by the chain effect of one industry's losses upon another's--either through lost sales or through shortages of needed inputs.

The end result of all these restrictive assumptions is usually a cost per kilowatt-hour given by the ratio of GNP (or value added in the region) to electricity sales.[51]

Such a figure is probably on the high side for the short-run costs of small interruptions of modest frequency and duration, and probably is too low for the short-run costs of longer or more massive shortages.[52] Still, it may well be an acceptable first approximation for most applications.

We summarize below the results of the few full cost-benefit studies done to date: Shipley, et al., using a value of $0.60 per kilowatt-hour for the loss per kilowatt-hour of shortage, find that "existing systems (or rather systems as they existed in 1967) are more reliable than can be justified" on the basis of their cost-benefit analysis. "The cost of interruptions would have to be about $5.50 per kilowatt-hour... for the system design of 1967 to be the economic optimum...."[53] Telson, using a figure of $1.17 per kilowatt-hour, finds that

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[51] Others use the ratio of wages to electricity sales presumably on the grounds that capital-related expenses (measured before deduction of losses for wages paid during idle production periods) will be recovered by extra production after the outage.

[52] Capital losses in the form of damage to plant and equipment can make the costs even of small interruptions considerably higher in some vulnerable industries.

[53] Shipley, op. cit., pp. 2-4.

"present reliability levels are too high [in the New York Power Pool]...." But later he conjectures:

> At present it seems that the one-day-in-ten-years criterion is used to plan overreliably, knowing that because of [construction] delays, actual operating reliability will be much lower.[54]

Kaufman, based upon an interruption-cost figure of $0.77 per kilowatt-hour in 1974, rising to $1.27 in 1985, finds for the New York Power Pool that the data indicate a maximization of net benefits somewhere near the one-day-in-one-year level (14.5 percent reserve).[55]

Exploratory work described in Appendix A goes some distance toward eliminating the third and fourth of the restrictive assumptions noted above. An inter-industry input-output model is used to calculate the minimum feasible loss of GNP due to restricted availability of electric service. The cutbacks that may be experienced by any one industry are limited by a set of constraints that impose minimum permissible values for deliveries to final consumers,[56] by maximum permissible values for compensating expansion of less severely affected industries, and by constraints upon employment and fossil fuel usage. These factors can then be altered to test their effect upon the outcome. Initial calculations suggest that a 12 percent reduction in electricity supply might

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[54] Telson, <u>op. cit</u>., pp. 235 and 250.

[55] Kaufman, <u>op. cit</u>., pp. 18-20.

[56] Households, government and net exports.

reduce GNP by 7 percent in the short run. Based upon 1974 figures, this implies an average cost of about $0.50 per kilowatt-hour. The crudeness of this estimate deserves emphasis. It is derived from a purely static model of the economy. Disruptions in the timing of productive activity or in the flows of deliveries are not recognized as having any significant effect; moreover, techniques of production are assumed to be rigidly fixed in the model. No substitution of abundant for scarce productive inputs is possible. Its time horizon is thus restricted to that pertaining to short-term effects. Finally, damage to plant, equipment and persons is not counted; nor are invisible psychological costs.

THE SHORT-RUN COSTS OF POWER SHORTAGES

by

Frank J. Allessio
Electric Power Research Institute

This Appendix summarizes an exploratory attempt by the TAC-IEPS to estimate the short-run economic costs of a one-year 12 percent reduction in the supply of electric power. No prior qualitative work in this area has come to the attention of the committee, save for the studies cited in Section V.D.

I. DESCRIPTION OF THE METHOD OF ANALYSIS

Our analysis of short-run costs relies upon 1963 U.S. inter-industry transactions data, 1963 energy flow data, and 1963 employment data.[1] We organized these data into 97 sectors and calculated 1963 coefficients for inter-industry transactions, energy use, and employment. We converted estimates of 1972 final demand, normalized to published control totals from the Survey of Current Business, to 1963 dollars with the use of price deflators obtained from the Bureau of Labor Statistics. The resulting final demand vector, together with the 1963 transactions, energy, and employment coefficients, yielded an estimate of actual 1972 gross outputs expressed in 1963 dollars, energy flows expressed in Btus, and employment expressed in number of jobs.

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[1] These were the most recent figures available at the time the work was done.

We used these values of final demand, gross output, energy use, and employment as "reference values" for a linear programming model. The model maximizes gross national product (GNP) subject to constraints that limit the size of deviations from the reference values. Five of the sectors in the model are energy-producing sectors. They are coal mining, crude petroleum and natural gas production, petroleum refining, gas utilities, and electric utilities.[2]

In matrix notation, the structure of the model is as follows:

$$\text{Maximize} \qquad v' \cdot X = G \qquad (1)$$

$$\text{subject to} \qquad x \leq X^{max} \qquad (2)$$

$$(I-A) \cdot X \geq Y^{min} \qquad (3)$$

$$m' \cdot X \geq M^{min} \qquad (4)$$

$$m' \cdot X \leq M^{max} \qquad (5)$$

$$e \cdot X \leq E^{max} \qquad (6)$$

where:

v' is the N-element row-vector of value-added coefficients

I is the NxN unit matrix

A is the NxN matrix of direct coefficients a_{ij}

m' is the N-element row-vector of employment coefficients p_j

e is the NExN matrix of energy coefficients e_{ij}

X is the N-element column-vector of gross industry outputs X_j

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2 Oil and other imports are deducted from exports to yield net exports, which may be positive or negative. Total final demand equals household consumption, government purchases, gross investment and net exports.

G is GNP

X^{max} is the N-element column-vector of maximum-permissible gross industry outputs

Y^{min} is the N-element column-vector of minimum-permissible final demands Y_i

M^{min} is minimum-permissible employment

M^{max} is maximum-permissible employment

E^{max} is the NE-element energy vector of maximum energy outputs

N is the number of industry sectors equal to 97

NE is the number of energy sectors equal to 5.

The constraints on the industry output and final demand vectors ensure that the program operates within reasonable limits when gross national product is maximized. The lower bounds for the final demand vector are based on historical trends. Specifically, we obtained the data for final demand (in constant dollars) for the years 1947, 1961, 1966, 1967, and 1972; we then fitted an ordinary least squares regression line (quantity vs. time) to the data.[3] We set the lower bounds in the model at one standard deviation below the calculated 1972 regression line value, or the actual 1972 value, whichever was smaller. We based our estimates of the upper bounds on industry output upon capacity utilization ratios developed by Wharton Econometric Forecasting

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[3] The years selected are those for which suitable data were available.

Associates.[4] In those industries for which no capacity utilization ratios were available, we set arbitrary upper limits equal to 20 percent above the actual 1972 value of industry output. Later, we examined the linear programming results to ensure that those industries which reached these arbitrarily imposed limits were capable of doing so. We set lower bounds on the industry output vector, since the lower bounds placed on the final demand vector ensure that the gross output does not go to zero in any industry.

We set bounds upon employment according to the size of the labor force and the historical pattern of unemployment. In particular, we used the 1972 unemployment rate of 5.1 percent to calculate the upper bound for 1973 employment, and we used the highest rate of unemployment after 1950 but prior to 1973 (i.e., 5.7 percent in 1963) to calculate the lower bound.

We relied upon capacity utilization ratios to calculate the upper bounds for the output of four of the five energy sectors. These constraints are in Btus. We set no upper bound on electric utilities' output measured in Btus, but we applied a capacity constraint to the gross output of this sector measured in dollars.

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[4] The numerator of the ratio is the Federal Reserve Board's Industrial Production Index, and the denominator is the level of industrial capacity calculated from the WEFA model.

II. DESCRIPTION OF THE RESULTS

To estimate the effects of a sudden shortage of electric power on the performance of these industries, we reduced the gross output of the electric utility industry to 88 percent of its actual 1972 level (as normalized to 1963). Table 1 reports the results for the 15 most energy-intensive industries. The Table distinguishes three classes of output losses: greater than or equal to 20 percent, less than 20 percent but greater than or equal to 10 percent, and less than 10 percent. We prefer to report our estimates in this fashion rather than as point estimates because we believe that the point estimates generated by the analysis are subject to considerable uncertainty. We are more comfortable in suggesting that the ordinal ranking of the percentage impacts as reported in Table 1 is roughly correct.

For the economy as a whole, the analysis indicates that a 12 percent reduction in the annual supply of electric power would cause annual GNP to fall 7 percent below the level that would have been achieved with an unconstrained power supply. This estimate is conditional upon the nexus of constraints imposed upon the model; it is merely illustrative and cannot be taken as a guide for policy making.

III. SOME CAVEATS

We recognize that the analytical techniques used in this exploratory work have severe limitations. Some of the problems are discussed below.

First, there are difficulties in applying capacity constraints to the energy sectors. In one case, the problem stems from the treatment of crude petroleum and natural gas as a single industry. The data unfortunately do not permit a finer breakdown of either gross output measured in dollars or intermediate output measured in Btus. The constraint on the coal industry is less problematic. But if the average heating value per ton of coal could be expected to vary significantly due to changes in the mix of coal-producing sources, then our constraint would be only roughly correct. The constraint on the energy content of electric utilities is a more difficult matter. One way to interpret this constraint is to view it as a constraint on generating capacity, yet it is clear that the total Btu output per year is not the adequate way to represent generating capacity. The capacity of the electric power industry to deliver more power is constrained only during the peak periods, and considerably more total energy could be delivered during the year provided that it were delivered off-peak. A more realistic approach might be to disaggregate electric energy inputs to the various sectors into peak-load and baseload components.

Second, the absence of relative price effects in our static input-output model means that possible interfuel and other input substitutions are not included in the results. In the short run, of course, the choice of inputs is largely determined by the composition of the capital stock of combustion equipment, so that input substitution, for example, of fuels for electricity is not likely to be significant. Nevertheless, other substitution effects--as yet unidentified--may be important even in the short run. Moreover, even when substitution is not possible it is not clear that the direct output loss due to electricity curtailments must be proportional to the magnitude of the curtailment, as implied by our model.

Third, the required adjustments or the mix of goods and services provided to households, government, and the export sector are assumed to take place freely, subject only to minimum-value constraints for each type of good or service. Our model does not admit the possibility that users would choose a different mix of final product or might even save rather than increase spending on the commodities least affected by the electricity shortage. In addition, the model assumes that electric utilities are clever enough to know exactly which industries must be curtailed and which should receive extra supplies to accommodate their increased final demands.

Fourth, our model--being static in character--implicitly assumes that any shortage-induced cutbacks in inter industry deliveries of goods and services will be timed

<u>conveniently</u>, that is, in such a way that each industry never loses production time beyond that required by the reduced availability of inputs. In the real world, delays in shipments due to electricity curtailments may result in <u>temporarily</u> binding shortages in the markets for nonelectric inputs to production that cannot be made up within the year and hence may lead first to additional output losses and then to unwanted inventory build-ups of the commodities that were temporarily in short supply.

APPENDIX A
Table 1

ESTIMATED SHORT-RUN IMPACT OF A REDUCTION IN THE AVAILABLE ELECTRICITY SUPPLY BY 12 PERCENT
FOR 15 MOST ENERGY-INTENSIVE INDUSTRIES

Estimated Short-Run Percentage Reduction in Gross Output

$\%\Delta GO \geq 20$	$10 \leq \%\Delta GO < 20$	$\%\Delta GO < 10$
Primary Nonferrous Metal Manufacturing: Primary aluminum Primary zinc Aluminum rolling & drawing	Primary Nonferrous Metal Manufacturing: Aluminum casting Nonferrous forgings	Petroleum Refining & Related Industries: Asphalt felts & coatings Petroleum refining
	Plastics & Synthetic Materials: Plastic materials & resins Synthetic rubber Cellulosic man-made fibers	Local, Suburban & Interurban Highway Passenger Transportation
	Stone & Clay Products: Cement Brick & structural clay tile Structural clay products	Chemicals & Selected Chemical Products: Industrial inorganic & organic chemicals Misc. chemical products
	Primary Iron & Steel Manufacturing: Blast furnace & basic steel products Iron & steel forgings	Paints & Allied Products
	Other Fabricated Metal Products: Misc. fabricated metal products Steel springs Metal foil & leaf	Paper & Allied Products: Paperboard mills Wallpaper, building paper & board mills Paper mills
	Metal Containers: Metal cans	Manufactured Ice
	Agricultural Metal Work	
	Electric Transmission/Distribution Equipment & Electric Industrial Apparatus: Carbon & graphite products	

APPENDIX B

COMMENTS

Statement by Dr. Samuel H. Schurr**
Director, National Energy Strategies Project
Resources for the Future

I have read the revised final copy of the report of the Technical Advisory Committee on the Impact of Inadequate Electric Power Supply, and, in general, feel that this is a worthwhile document. However, I have reached the reluctant conclusion that I must dissent from the report's espousal of peak load pricing and, in particular, its strong support of long-run incremental cost (LRIC) as the proper means of achieving peak load pricing. I don't believe that there is sufficient evidence at this point to support the view that the introduction of peak load pricing, especially for residential users, would be a cost-effective step, because of the failure to take into account the costs and technical constraints that might be connected with the introduction of such a pricing system. Also, it is not clear to me that the proper approach to peak load pricing, taking not just economic theory but also practical factors into consideration, would be by way of LRIC. I do not believe, either, that the problem of ratemaking under a peak load pricing approach is necessarily resolved by the use of the reverse elasticity rule which is suggested in the document.

** Mr. Edward V. Sherry, Manager - Energy Systems, Air Products & Chemicals, Inc., wishes to concur with the statement by Dr. Schurr.

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FACTORS AFFECTING

THE ELECTRIC POWER SUPPLY

1980 - 85

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EXECUTIVE SUMMARY AND RECOMMENDATIONS

The Bureau of Power

Federal Power Commission

December 1, 1976

INTRODUCTION

This Executive Summary, and the complete report upon which it is based, are the result of a comprehensive study by the Federal Power Commission's Bureau of Power on the adequacy of electric power supplies for the United States and the separate regions of the Nation during the 1980-85 period.

Commission Chairman Richard L. Dunham asked the Bureau in April 1976, to conduct the study and make a complete report the the Commission, stating at that time his concern over recent trends in the cost of generating plants, fuel availability, financing difficulties, and other problems concerning bulk power supply.

Electric power supply adequacy is a responsibility shared by the Nation's electric utilities, the States, and various Federal agencies, in particular the Federal Power Commission. Section 202(a) of the Federal Power Act contains the following national policy statement.

> "For the purpose of assuring an abundant supply of electric energy throughout the United States with the greatest possible economy and with regard to the proper utilization and conservation of natural resources, the Commission is empowered and directed to divide the country into regional districts for the voluntary interconnection and coordination of facilities for the generation, transmission, and sale of electric energy . . ."

The FPC, while directed to assure an adequate electric power supply, is not empowered to direct specific industry measures except for certain actions in emergencies. The FPC's contribution, therefore, consists largely of the identification of power supply problems and potential solutions which can stimulate appropriate actions by the utilities, state regulatory agencies, and the Congress. A continuing emphasis has been on encouraging greater cooperation among utilities in regional power supply planning and coordination.

An outstanding example of such cooperative action began immediately following the Northeast Power Failure in 1965. Within two months after that disturbance, the major utilities in New York, New England, and the HydroElectric Power Commission of Ontario formed the Northeast Power Coordinating Council (NPCC) to deal primarily with improving the adequacy and reliability of bulk power supply in that region. In 1966, the FPC's Industry Advisory Committee on Reliability of Bulk Power Supply singled out assuring bulk power supply reliability for the Nation."1/

1/ Federal Power Commission. Prevention of Power Failures, Vol. II, July 1967, p. 27.

Concurring with this view, the Commission recommended that ". . . strong regional organizations need to be established throughout the Nation for coordinating the planning, construction, operation, and maintenance of bulk power supply." 2/ By the end of 1966, utilities had established five coordinating councils to improve power supply reliability within their respective regions.

In June 1968, the National Electric Reliability Council (NERC) was formed to encourage improvement of coordination at both the regional and National levels. Today NERC is composed of nine Regional Reliability Councils covering all areas of the contiguous United States and parts of Canada. The council boundaries, their names, and acronyms are shown in Figure 1.

The stated purposes of NERC; are:

(1) To encourage and assist the development of interregional reliability arrangements among regional organizations.

(2) To exchange information on planning and operation matters relating to bulk power supply reliability.

(3) To periodically review regional and inter-regional activities on reliability.

(4) To provide independent reviews of inter-regional matters referred to it by a regional organization.

(5) And to provide information to FPC and other regulatory agencies.

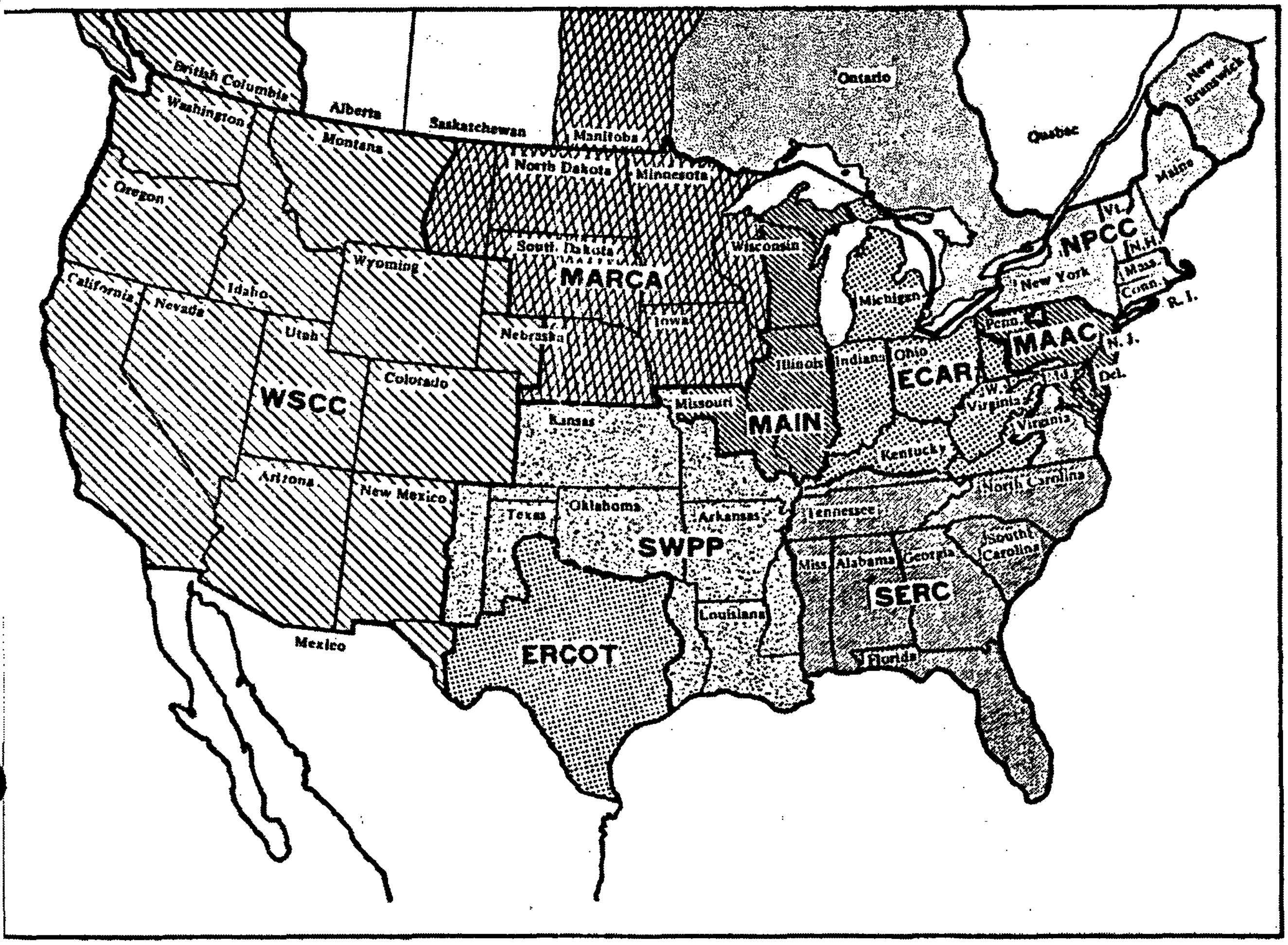
The fact that electric utilities, regardless of type of ownership, can participate in the Councils has brought the various segments of the industry much more closely together. This closeness is enhanced by both formal and informal participation of the FPC and other State and Federal regulatory agencies in Reliability Council proceedings.

Since the formation of NERC, a number of positive trends have developed. Joint ownership of power facilities is increasing, interconnections for many purposes have accelerated, and perhaps most important of all, it is now generally recognized that the requirements of the bulk power supply system must be dealt with on a regional rather than a State or local basis.

Information relating to the current status of the bulk power supply system together with detailed plans for its expansion over the following 10 years, with more conceptual plans for the next 10 years, is submitted annually to the FPC by the Regional Councils pursuant to FPC's Order 383 (issued in June 1969, with Amendments in Orders 383-1, 383-2, 383-3, and 383-4). This information has been useful to government agencies, the public, and the utilities themselves in illuminating the long term consequences and problems of electric power growth.

2/ Ibid, p. 88

REGIONAL ELECTRIC RELIABILITY COUNCILS



ECAR - East Central Area Reliability Coordination Agreement

MAIN - Mid-American Interpool Network

MAAC - Mid-Atlantic Area Council

MARCA - Mid-Continent Area Reliability Coordination Agreement

NPCC - Northeast Power Coordinating Council

SERC - Southeastern Electric Reliability Council

SWPP - Southwest Power Pool

ERCOT - Electric Reliability Council of Texas

WSCC - Western Systems Coordinating Council

FIGURE 1

NERC issues periodic reports reviewing the prospective adequacy and reliability of the North American bulk power systems. The two most recent of these reports 3/ expressed substantial concern over the adequacy of bulk power supply in the late 1970's and early 1980's.

The Federal Power Commission believes that the adequacy of electric power in the future is not assured and this concern is reflected by Chairman Dunham's instructions to the Bureau of Power to undertake this study and submit a report to the Commission on the prospective adequacy of power supply by electric utility systems through 1985. As outlined in those instructions, the report was to consider the following and other germane matters, among others:

(1) Trends in electric power demand and supply for electric systems, with special emphasis on the availability of bulk power supplies for power pool and wholesale service;

(2) Trends in the patterns and costs of generating and transmission capacity and of the availability and costs of fuel supplies, with identification of incremental costs and their impact on self-generation costs of systems and system average costs of bulk power suppliers;

(3) Capital requirements of generating and transmission facilities to meet the needs of electric systems and the access to and costs of financing for the various segments of the industry, investor-owned, state-owned, municipally-owned and cooperatively-owned, which might provide the facilities;

(4) Limitations arising from legal or administrative actions upon current or future generating and transmission facilities including, but not limited to, problems in siting, certification, environment and fuels availability.

(5) Effects of alternative wholesale rate policies, including average cost, incremental costs, and peak load pricing on the cost of wholesale service, energy conservation and the retail customer revenue requirements of wholesale suppliers.

(6) Recommendations to the Commission of actions which should be taken, if any, regarding the planning and development of bulk power supply.

A draft of the basic report entitled "Factors Affecting the Electric Power Supply 1980-85" was completed on July 31, 1976. Copies were provided

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3/ National Electric Reliability Council. "Sixth Annual Review of Overall Reliability and Adequacy of the North American Bulk Power System," July 1976. National Electric Reliability Council. "Fossil and Nuclear Fuel for Electric Utility Generation: Requirements and Constraints, 1976-1985," June 1976.

to all segments of the electric utility industry as well as other interested groups and individuals for comment. Numerous constructive responses were received and incorporated in the final report as appropriate.

The report concludes that additions to the bulk power supply system planned by the Nation's utilities will be adequate to meet demand through 1985 <u>if</u> a number of conditions are met. These include:

(1) Regional load growth not significantly higher than forecasted levels.

(2) Generation from existing nuclear plants not interrupted by external factors, and completion and placement in service on schedule of new nuclear plants under construction and set for completion by 1985.

(3) Completion of coal-fired generation additions on schedule, and availability of coal for these installations.

(4) Orderly conversion of plants from natural gas to oil or coal.

(5) Timely additions to bulk power transmission systems; and

(6) Timely utility rate schedule adjustments, so that an adequate supply of capital is available to finance additional facilities.

However, the report further concludes that it is highly unlikely that all of these conditions will in fact be met. Specific problems which could significantly limit total additions to bulk power supply include:

(1) Pricing actions by the Organization of Petroleum Exporting Countries.

(2) Modifications to nuclear plant design causing delays in completion and operation of such generating facilities.

(3) The possibility of further restrictive amendments to the Clean Air Act which may cause delays in completion of coal-fired plants, and add to their cost.

(4) Limitations on coal supply resulting from surface mining legislation.

(5) Increasing environmental opposition to both generation and transmission additions to the bulk power supply system.

Based on these considerations, the report finds that regional shortages of generating capacity and/or electric energy are distinct possibilities in the period from 1979 to 1985.

The staff of the Bureau of Power made several recommendations to the Commission based on the findings of the report. Among the report's recommendations to help alleviate possible power supply shortages are:

(1) A rulemaking to permit electric utilities to place in effect cost of service wholesale rate formats which would automatically adjust rates to reflect changes in all costs allocated to such wholesale service. This would shorten regulatory lag, avoid "pancaking" of rate increase requests, protect consumer interests, and allow better utilization of Commission time to other matters.

(2) A more complete utility conservation reporting program to specify measures which could be taken if regional capacity or power shortages develop in the future.

(3) Legislative recommendations to assist Commission efforts to create additional power pools, centralize electric power dispatch facilities to improve reliability, reduce reserve margin capacity, and optimize economical operation.

(4) Promote regional energy boards to facilitate siting and licensing approval, as well as resolution of other energy matters most effectively approached on a regional basis, and greater multi-State cooperation in planning.

(5) Promote additional interconnections in regions having inadequate or nonexistent ties, to increase efficiency and provide for emergency and economy energy transfers.

(6) Seek legislation to permit the Commission to order wheeling of electric power on its own motion, with authority to specify the economic and financial terms for the service provided.

(7) Support amendment to the TVA Act to remove limitations on interconnections with adjacent systems, to improve regional reliability; and

(8) Reconsider some boundaries of regional reliability councils, to improve collection of information relative to regional requirements.

In addition to its recommendations for action on the part of the Commission, regional groups, and utilities themselves, the report notes the importance of consmer conservation efforts in minimizing the need for new generation capacity, improving the adequacy of electric power supply, and holding down potential rate increases. A number of utilities have supported such consumer conservation initiatives as adding insulation in homes through utility funding for such projects, with repayment to the utility over a period of time. The report notes that continuation and expansion of these programs will require additional utility capital, and that investor confidence in utility rate of return is essential to raise this new capital.

The final report, dated December 1, 1976, is bound separately from this Executive Summary; copies are available from the Office of Public Information, Federal Power Commission, on request.

The contents of this Executive Summary are drawn mainly from the December 1976 report, but additional sources have been utilized as identified herein.

I. PEAK LOAD GROWTH AND GENERATION ADDITIONS

Historically, national peak load growth in the United States has averaged about 7 percent per year (equivalent to doubling every 10 years) with only brief, limited aberrations (See Figure 2). While this growth rate was relatively constant during the decade of the 1960's, the annual peak in most Regions shifted from winter to summer primarily due to increased air conditioning. Thus, the current and projected peak loads considered in this study are for the summer period.

As shown in Table 1, the OPEC oil embargo of 1973, the concurrent tripling of the price of oil (along with significant increases in the costs of other electric utility fuels), and the economic recession of the past several years have had a profound impact on electric peak load growth in the years 1974-1976.

Table 1

Year	Actual Summer Peak Load 1000 MW	Increase Over Preceding Year - %	Index of 1/ Industrial Production (1967=100)
1972	311.6	9.03	120
1973	336.2	7.89	128
1974	341.6	1.61	127
1975	347.7	1.79	118
1976	362.2	4.17	130 (Est.)

1/ U.S. Department of Commerce, Domestic and International Business Administration.

The future rate of growth of electric power demand is currently the subject of great controversy and uncertainty. The growth of the economy, the success of energy conservation efforts, and the substitution of electricity for primary fuels are only some of the more important factors which will have impact on the increased usage of electricity. While not unanimous, the consensus of projections indicates an average growth rate during 1976-1985 between the historic 7 percent on the high side to 4 percent on the low side. Figure 3 shows the projected national annual peaks for the 1976-1985 period developed using April 1976 Regional Council projections. However, the equivalent uniform annual increase shown of 6.84 percent is somewhat higher than the 6.3 percent given in Table 1-1 of the main Bureau of Power report. This resulted from the use of actual 1976 summer peak load (362.2 gigawatts) rather than the projected 1976 peak of 379.1 GW used in the report. Since the summer of 1976 was abnormally cool, future projections have not been changed. A curve of projected demand growth at a 4 percent rate is also shown on Figure 3.

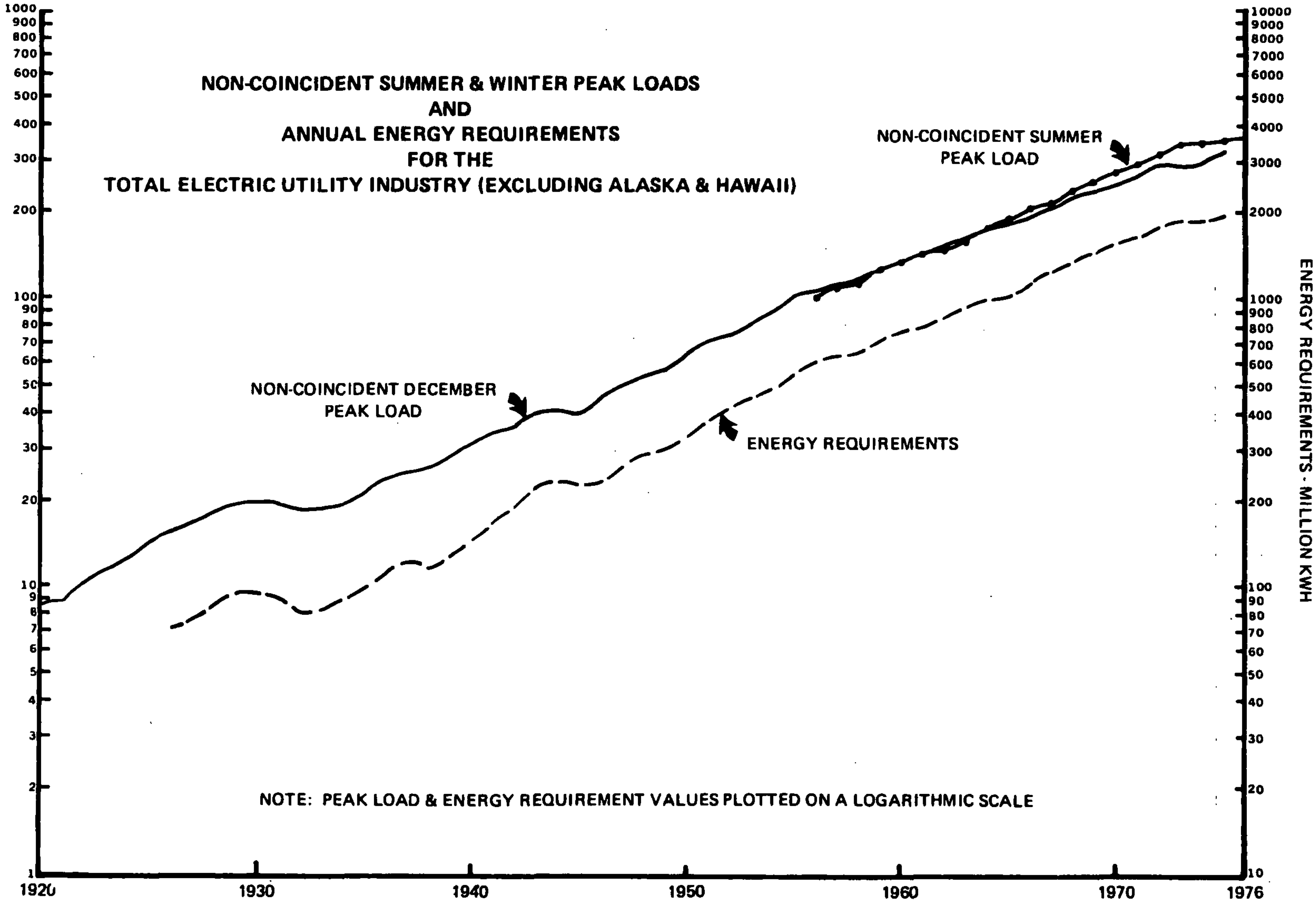

NON-COINCIDENT SUMMER & WINTER PEAK LOADS
AND
ANNUAL ENERGY REQUIREMENTS
FOR THE
TOTAL ELECTRIC UTILITY INDUSTRY (EXCLUDING ALASKA & HAWAII)
NON-COINCIDENT SUMMER PEAK LOAD
NON-COINCIDENT DECEMBER PEAK LOAD
ENERGY REQUIREMENTS
PEAK LOAD - MILLION KW
ENERGY REQUIREMENTS - MILLION KWH
NOTE: PEAK LOAD & ENERGY REQUIREMENT VALUES PLOTTED ON A LOGARITHMIC SCALE
1920
1930
1940
1950
1960
1970
1976

FIGURE 2

The sharp reduction in peak load growth since 1973 due in large extent to conservation pressures and the decline in industrial activity. While commercial and residential sales were increasing by 5.3 and 5.8 percent, respectively, during 1974-1975, industrial sales were decreasing by 3.7 percent. During 1976, however, industrial loads began to rebound. Table 1 shows that between 1973 and 1976 the Index of Industrial Production increased by 1.6 percent while peak load increased 7.7 percent. Since economic growth and electric power growth are closely related, the commitment by the new Administration to stimulation of the economy could result in peak load growth more closely approaching historic levels.

Inspection of the actual demand and capacity curves in the period 1973-1976 clearly shows the impact of reduced peak load growth on reserve margins during that period. The maximum reserve margin was 37.9 percent in 1975. In general, reserve margins in the range of 15 to 25 percent (depending on individual system characteristics) have been found to provide an acceptable degree of system reliability. If peak load growth in the 1974-1976 period had been at the historic rate of 7 percent per year, the percent reserve margin at the time of peak would have been as shown in Table 2.

Table 2

Year	Summer Peak Load With 7% Growth 1000 MW	Calculated Reserve Margin %
1973	336.2 Actual	21.1
1974	359.7	22.9
1975	384.9	22.0
1976	411.8	18.8

Due to the lead times required for base load capacity additions, almost all capacity added in 1974-1976 was already well under construction in late 1973. Table 2 shows that, had the unanticipated energy crisis and economic slowdown not occurred, reserve margins would have been in the order of 19-23 percent during this period, indicating that the electric utility industry planning was well conceived considering the information available when the decisions had to be made. Construction plans have been adjusted to bring reserve margins to normal levels, on a national basis by 1979, based on current assumptions by the Nation's utilities regarding future load growth.

The importance of considering the electric utility industry on a regional rather than a national basis is emphasized through inspection of Figures 4 through 22. A wide diversity of actual and projected load growth in the Regional Councils, ranging from a maximum rate of 8.29 percent in SPP to a minimum of 5.26 percent in NPCC is indicated in Figures 4 through 11 inclusive.

PEAK DEMAND & CAPACITY
SUMMERS, 1970 - 1985
TOTAL U.S.

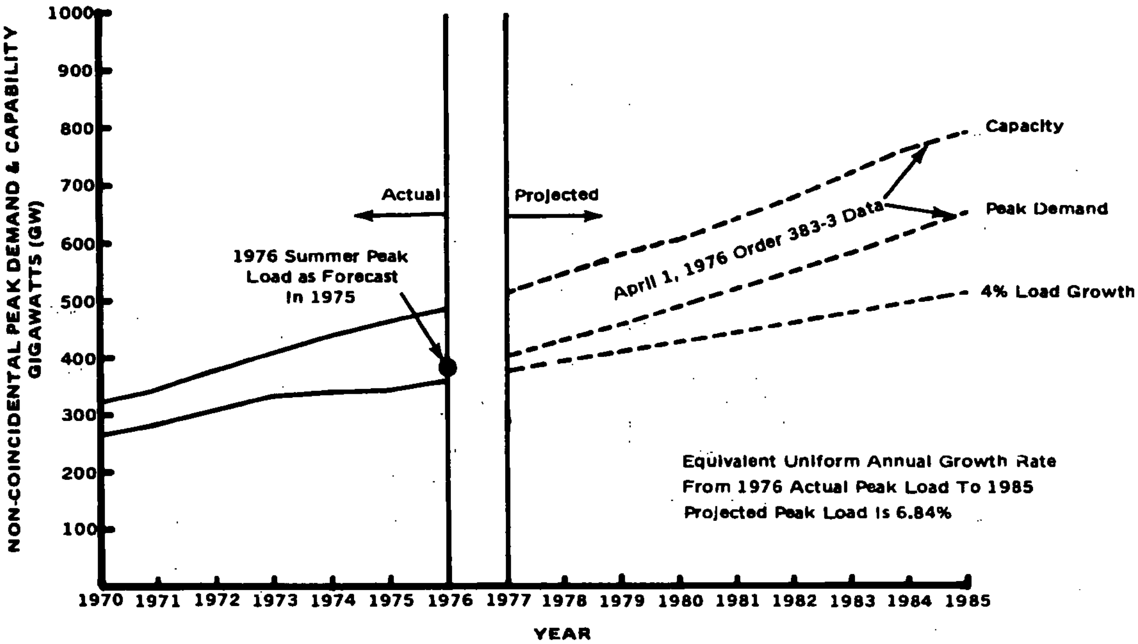


FIGURE 3

PEAK DEMAND & CAPACITY
SUMMERS, 1970 - 1985
EAST CENTRAL AREA RELIABILITY
COORDINATION AGREEMENT
(ECAR)

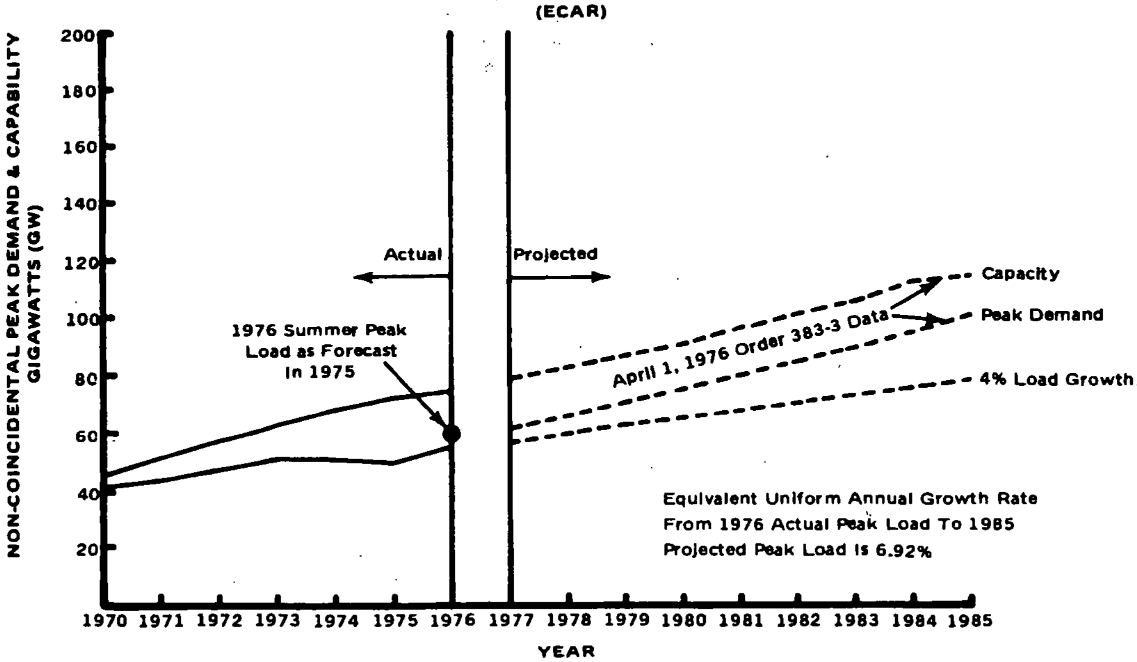


FIGURE 4

PEAK DEMAND & CAPACITY
SUMMERS, 1970 - 1985
ELECTRIC RELIABILITY COUNCIL of TEXAS
(ERCOT)

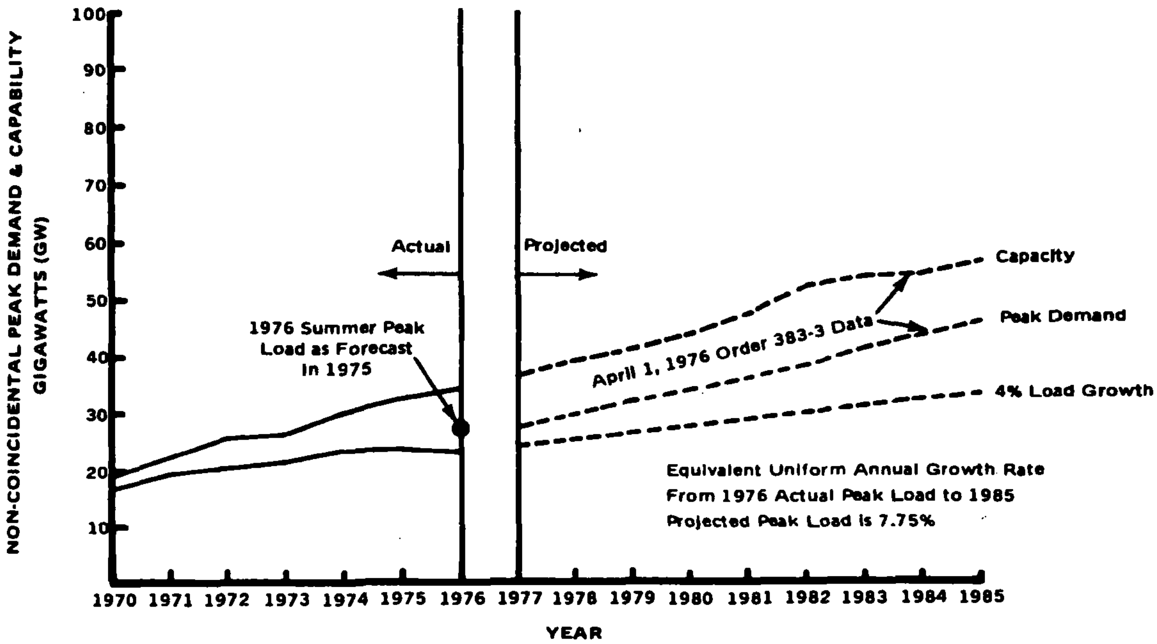
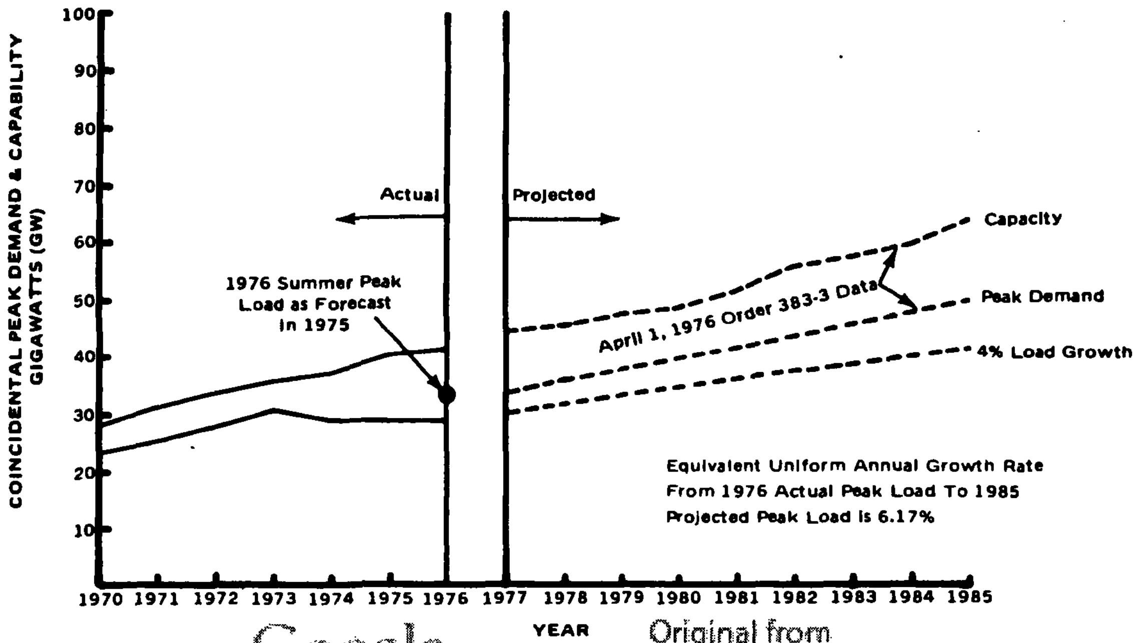


FIGURE 5

PEAK DEMAND & CAPACITY
SUMMERS, 1970 - 1985
MID ATLANTIC AREA COUNCIL
(MAAC)



FIGURE

PEAK DEMAND & CAPABILITY
SUMMERS, 1970 - 1985
MID-AMERICA INTERPOOL NETWORK
(MAIN)

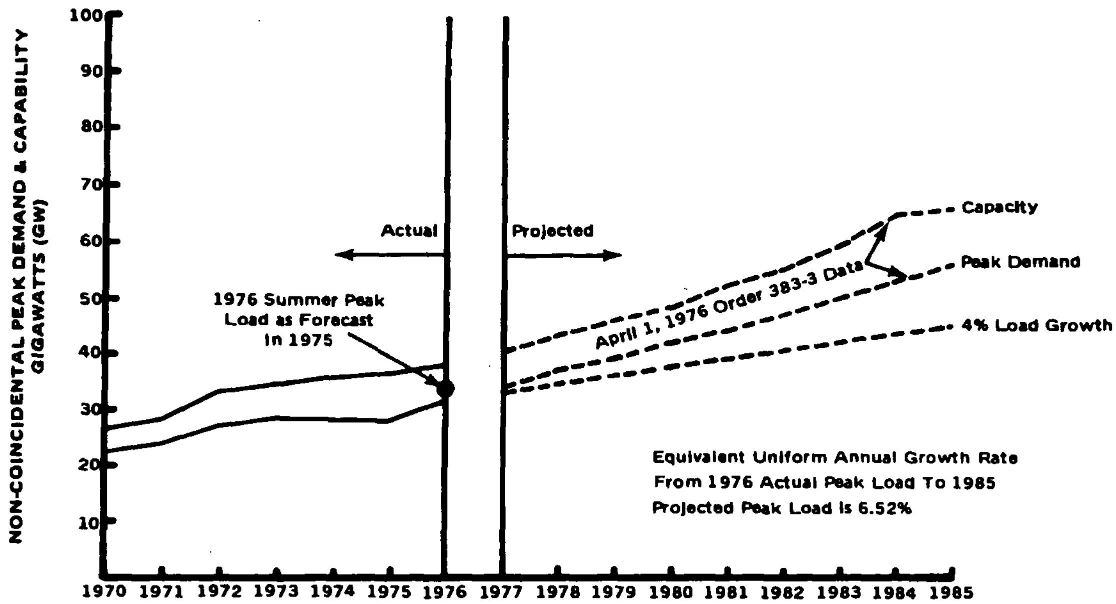


FIGURE 7

PEAK DEMAND & CAPACITY
SUMMERS, 1970 -1985
MID CONTINENT AREA RELIABILITY
COORDINATION AGREEMENT
(MARCA)

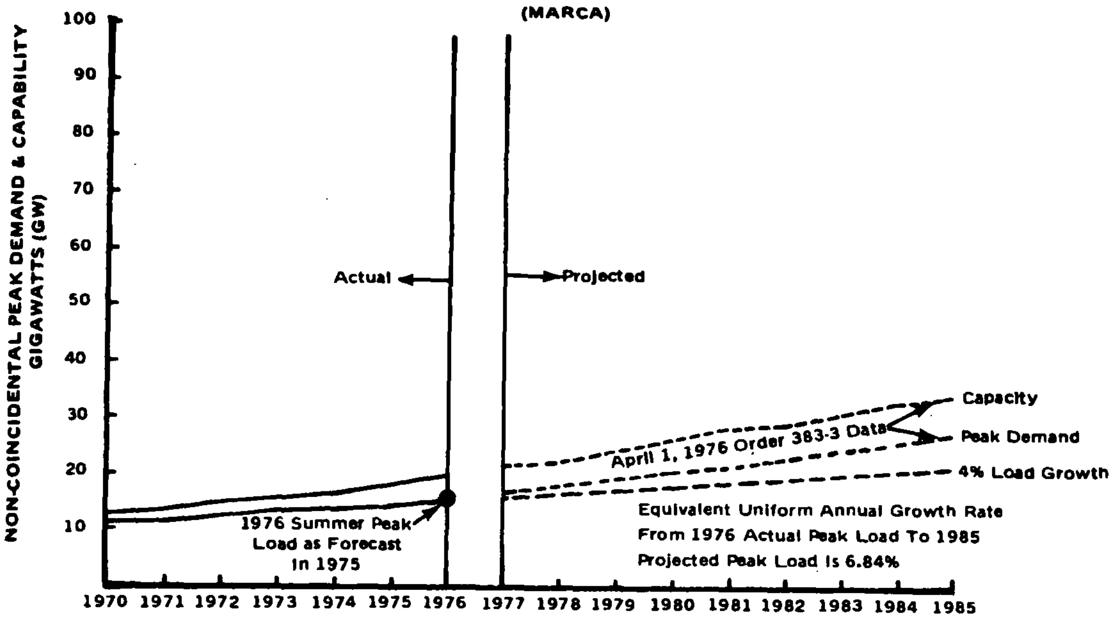


FIGURE 8

PEAK DEMAND & CAPACITY
SUMMERS, 1970 - 1985
POWER COORDINATING COUNCIL
(NPCC)

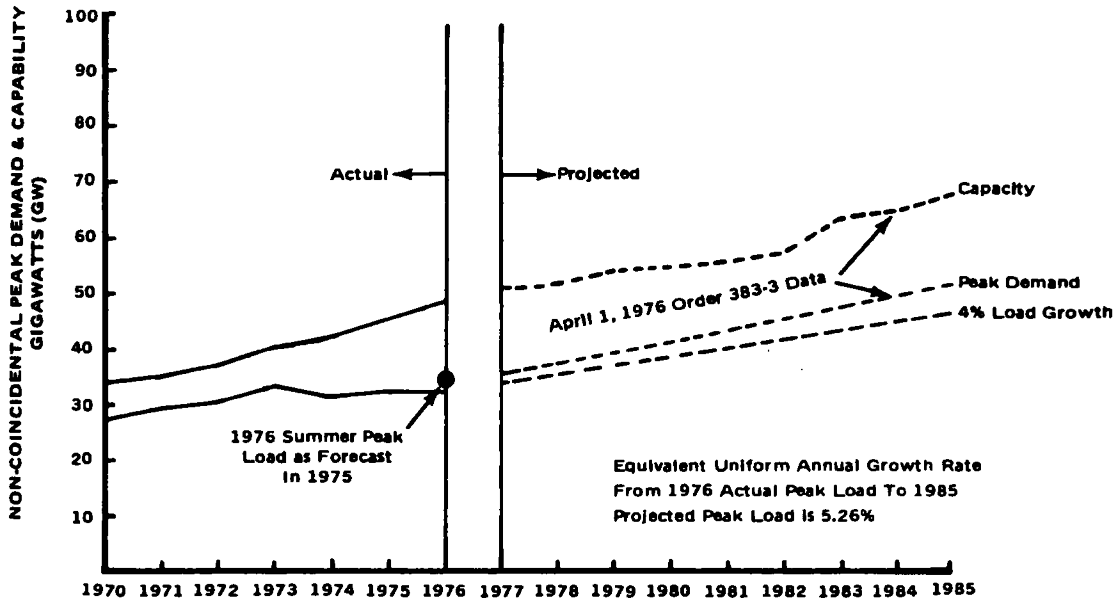


FIGURE 9

PEAK DEMAND & CAPACITY
SUMMERS, 1970 - 1985
SOUTHEASTERN ELECTRIC RELIABILITY COUNCIL
(SERC)

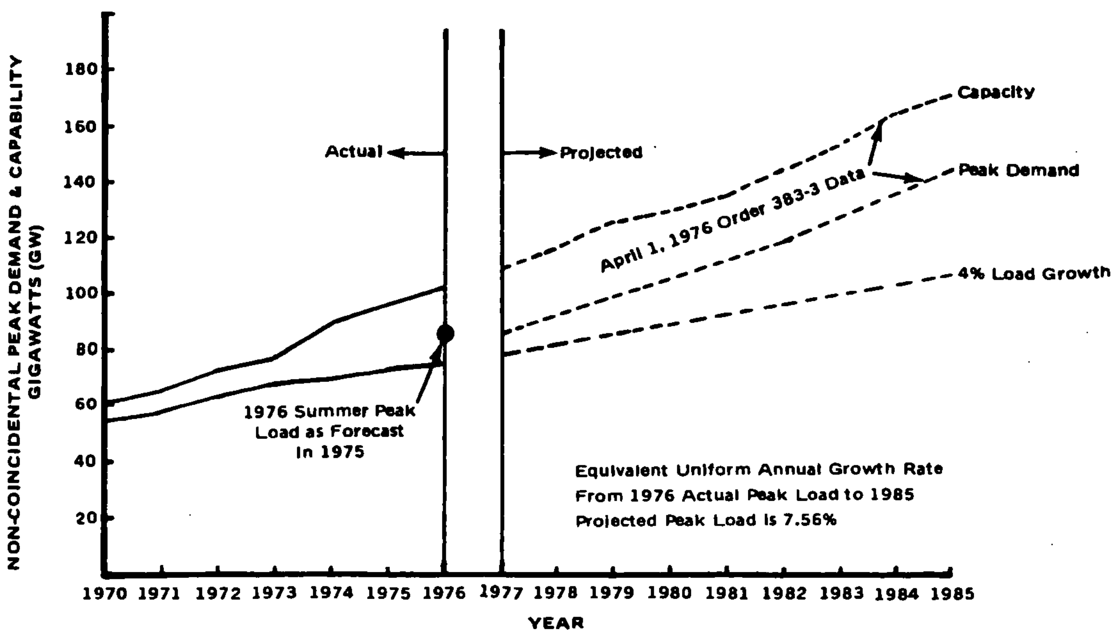


FIGURE 10

PEAK DEMAND & CAPACITY
SUMMERS, 1970 - 1985
SOUTHWEST POWER POOL
(SWPP)

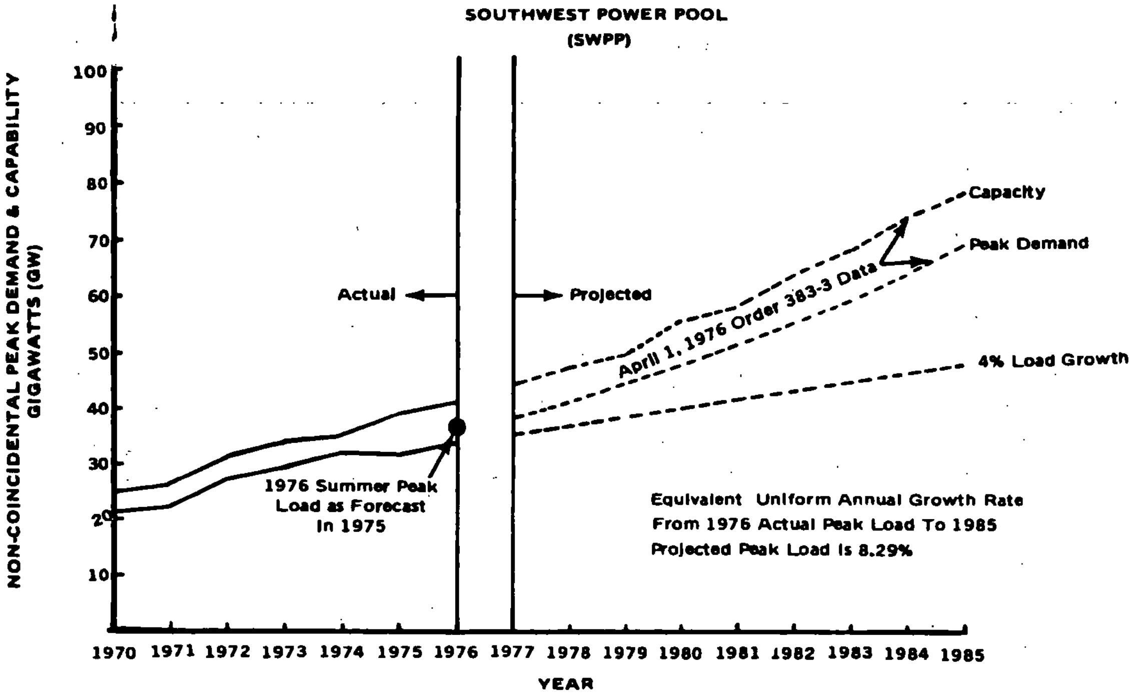


FIGURE 11

PEAK DEMAND & CAPACITY
1970 - 1985
WESTERN SYSTEMS COORDINATING COUNCIL
(WSCC)

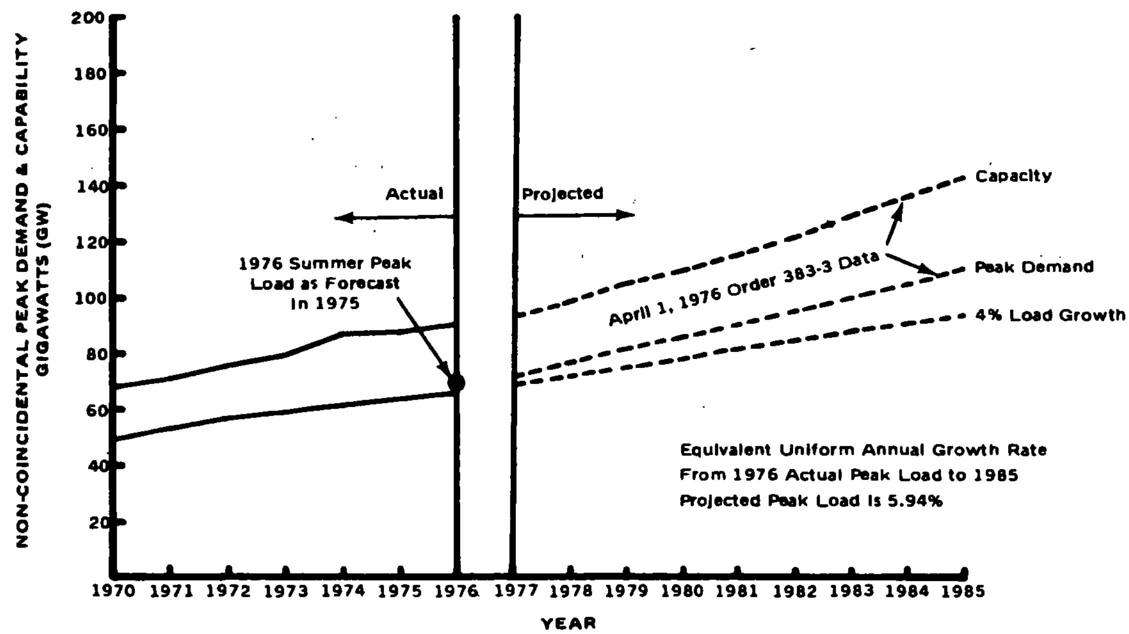


FIGURE 12

Such differences become even more apparent upon comparison of the national projected total percent reserve for the period 1976-1984 (Figure 13) with the projected reserves in the individual Regions (Figures 14-22). (The data from which these Figures were developed did not permit extending the period through 1985). Curve A on these Figures indicates the annual peak period generation reserve margin at the time of the projected summer peak load as anticipated in January 1976. Curve B shows the projected generation reserve margins based on an August 1976 appraisal of the situation. As shown, there has been substantial erosion of reserve margins in all Regions between January and August, indicating the slippage of scheduled capacity additions and some cancellations. With the increasing lead times on new capacity and the increasing complexity of the licensing process, together with "normal" construction delays, it is likely that additional slippage will occur, increasing the possibility of regional reserve deficiencies. While national reserve margins as shown by Curve B on Figure 12 never fall below 20 percent, regional reserve margins fall below 15 percent in MAIN and SERC in the early 1980's, and are below 10 percent in SPP in 1982.

About 44 percent, or 136 million kilowatts, of the new capacity planned by the nation's electric utilities during the 1976-1985 period is nuclear. **Figure 13-22** also show that even a limited nuclear moratorium (Curve C) would have a serious effect in all regions except ERCOT, NPCC, and WSCC, while a more extensive moratorium (Curve D) would have a disastrous effect both Nationally and in almost every region.

During 1976, nuclear power moratoria were presented to the voters in seven states. All were defeated, by majorities ranging from 58 to 71 percent. Those votes support a November 1976 Harris poll 4/, which reported that the American public despite some reservations favor building more nuclear power plants by nearly a 3 to 1 margin (61 to 22 percent). These developments indicate a greater degree of public understanding of the need for an adequate supply of electricity.

Due to the complex relationships no attempt has been made in Figures 13-22 to show the possible impact on National or regional reserve margins of various air and water quality standards. Since pollution control devices such as flue gas desulfurization and cooling towers may use 5 to 10 percent of the output of affected units, this factor could have a significant effect on future reserve margins.

4/ Louis Harris and Associates, Inc. "A Second Survey of Public and Leadership Attitudes Toward Nuclear Power Development in the United States," November 1976.

PERCENT GENERATION RESERVE AT TIME OF SUMMER PEAK LOAD

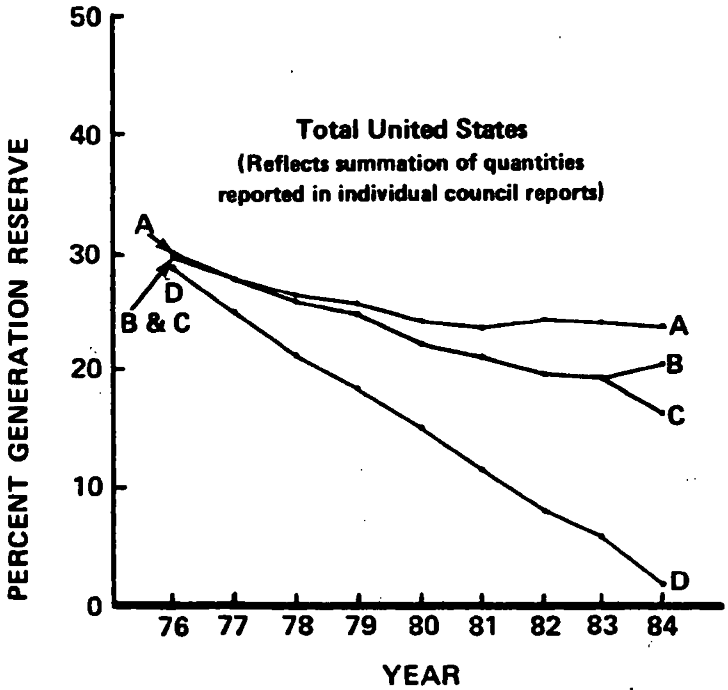


FIGURE 13

LEGEND

Curve A - Generation Reserve Margin as Forecast in 1976 Council Report to FPC

Curve B - Generation Reserve Margin as Modified Following Survey of Current Construction Status in August 1976

Curve C - Expected Generation Reserve Margin Should No Nuclear Construction Permits Be Issued After September 1, 1976

Curve D - Expected Generation Reserve Margin Should No Nuclear Construction or Operating Permits Be Issued After September 1, 1976

PERCENT GENERATION RESERVE
AT TIME OF SUMMER PEAK LOAD

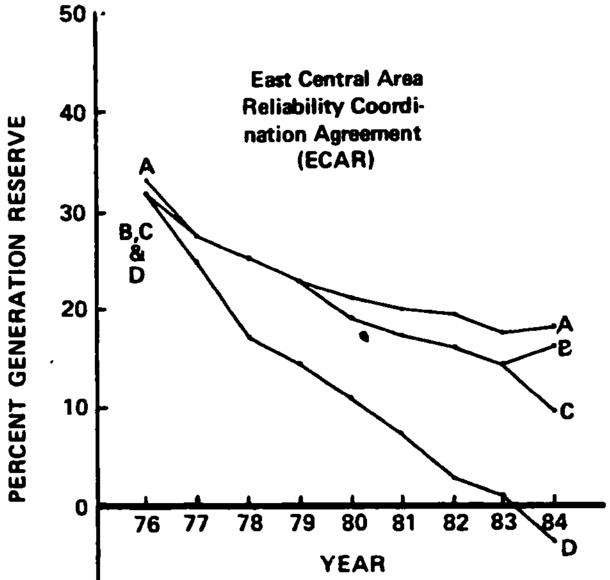


FIGURE 14

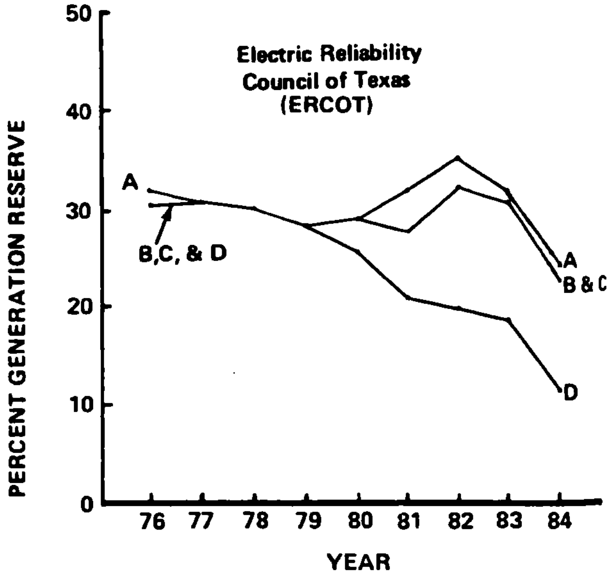


FIGURE 15

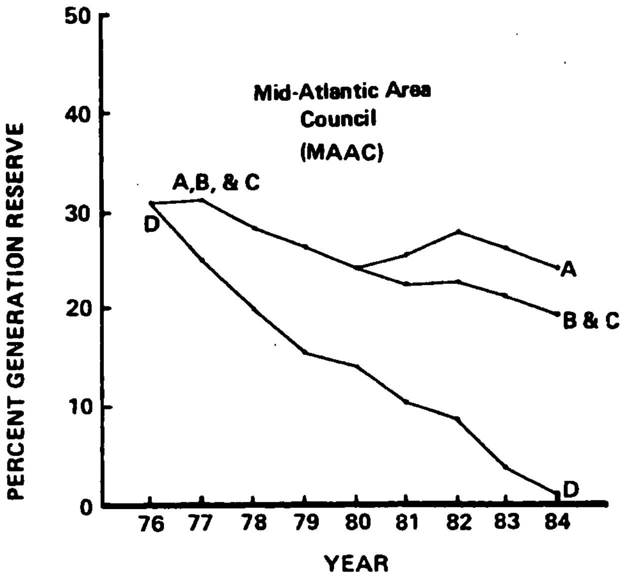


FIGURE 16

LEGEND

Curve A - Generation Reserve Margin as Forecast in 1976 Council Report to FPC

Curve B - Generation Reserve Margin as Modified Following Survey of Current Construction Status in August 1976

Curve C - Expected Generation Reserve Margin Should No Nuclear Construction Permits Be Issued After September 1, 1976

Curve D - Expected Generation Reserve Margin Should No Nuclear Construction Operating Permits Be Issued After September 1, 1976

PERCENT GENERATION RESERVE AT TIME OF SUMMER PEAK LOAD

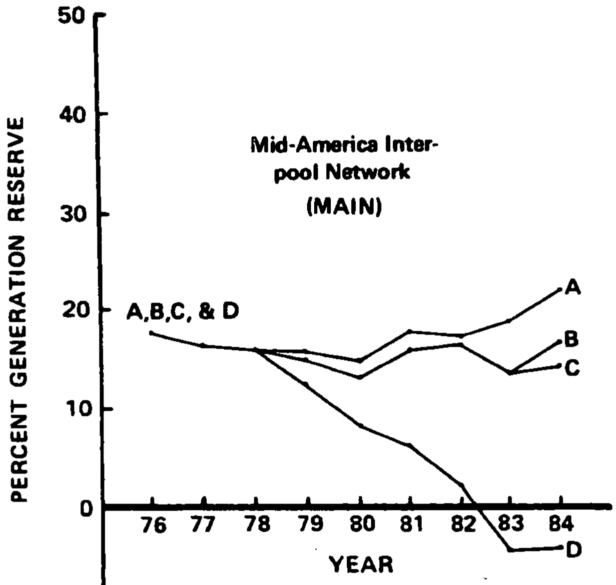


FIGURE 17

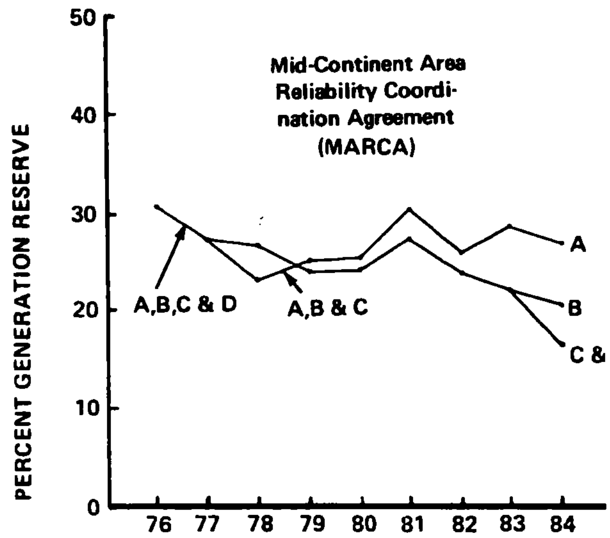


FIGURE 18

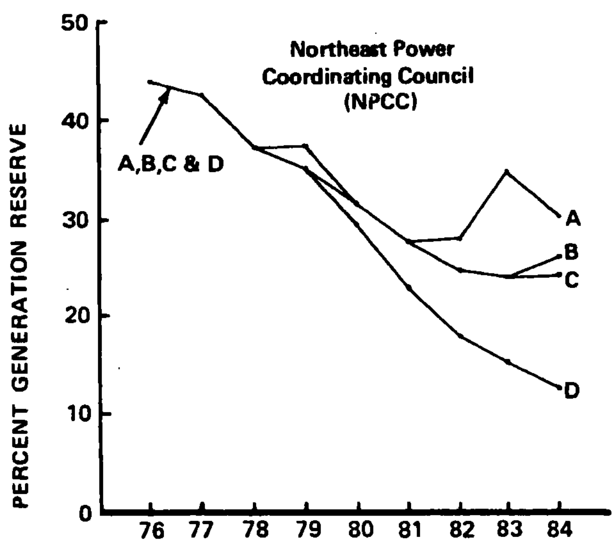


FIGURE 19

LEGEND

Curve A - Generation Reserve Margin as Forecast in 1976 Council Report to FPC

Curve B - Generation Reserve Margin as Modified Following Survey of Current Construction Status in August 1976

Curve C - Expected Generation Reserve Margin Should No Nuclear Construction Permits Be Issued After September 1, 1976

Curve D - Expected Generation Reserve Margin Should No Nuclear Construction or Operating Permits Be Issued After September 1, 1976

PERCENT GENERATION RESERVE AT TIME OF SUMMER PEAK LOAD

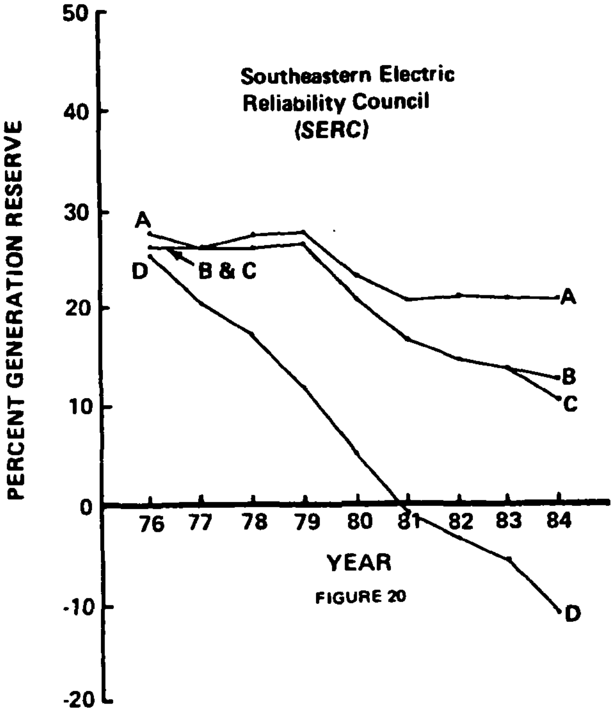


FIGURE 20

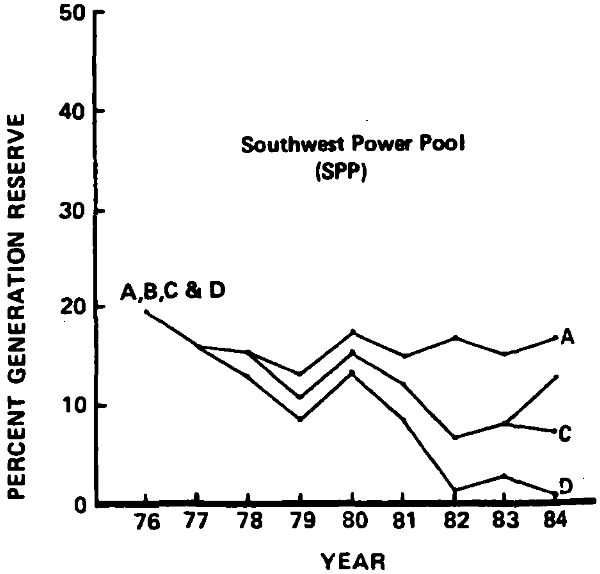


FIGURE 21

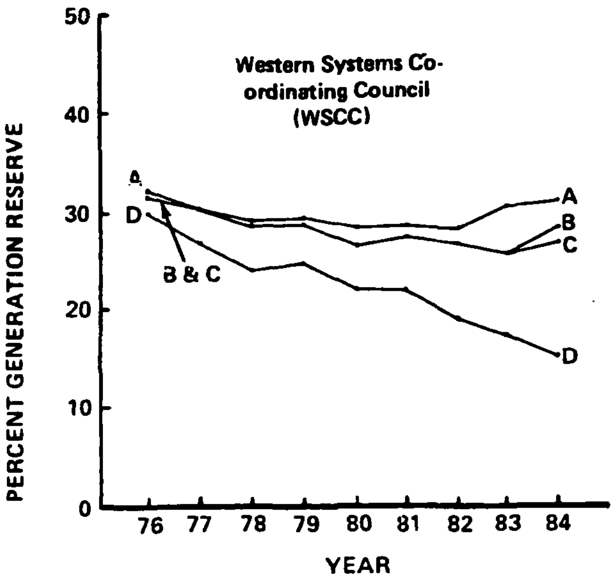


FIGURE 22

LEGEND

Curve A - Generation Reserve Margin as Forecast in 1976 Council Report to FPC

Curve B - Generation Reserve Margin as Modified Following Survey of Current Construction Status in August 1976

Curve C - Expected Generation Reserve Margin Should No Nuclear Construction Permits Be Issued After September 1, 1976

Curve D - [illegible]d Generation Reserve Margin Should No Nuclear Construction [illegible]ing Permits Be Issued After September 1, 1976

II. ENERGY

In the post-World War II period 1945 through 1973, electric energy production increased at an average annual rate of nearly 8 percent, as shown in Figure 23. The drastic increase in oil prices by the Organization of Petroleum Exporting Countries (OPEC) in the last quarter of 1973, combined with the growing economic recession, had a significant impact on national energy demands. In 1974, electric energy production increased only 0.38 percent over the previous year and in 1975 production grew only 2.57 percent. During the first eleven months of 1976, electric energy production increased 6.3 percent compared with the same period in 1975, as the nation partially recovered from the economic slump. Electric utility analysts, and energy forecasters, both within and outside government, are not confident, however, that the electric energy production growth rate will at any time during the next ten years, or ever, return to the historical growth rate. Federal Power Commission staff, having examined various projections, considers that in the period through 1985, a reasonable median projection of electric energy production would be as shown in Table 3.

TABLE 3

U. S. NET ELECTRIC ENERGY PRODUCTION
FOR SELECTED YEARS
1945 THROUGH 1985

Year	Billions of Kilowatt Hours
1945	222
1960	753
1970	1494
1973	1860
1975	1916
1980	2618
1985	3487

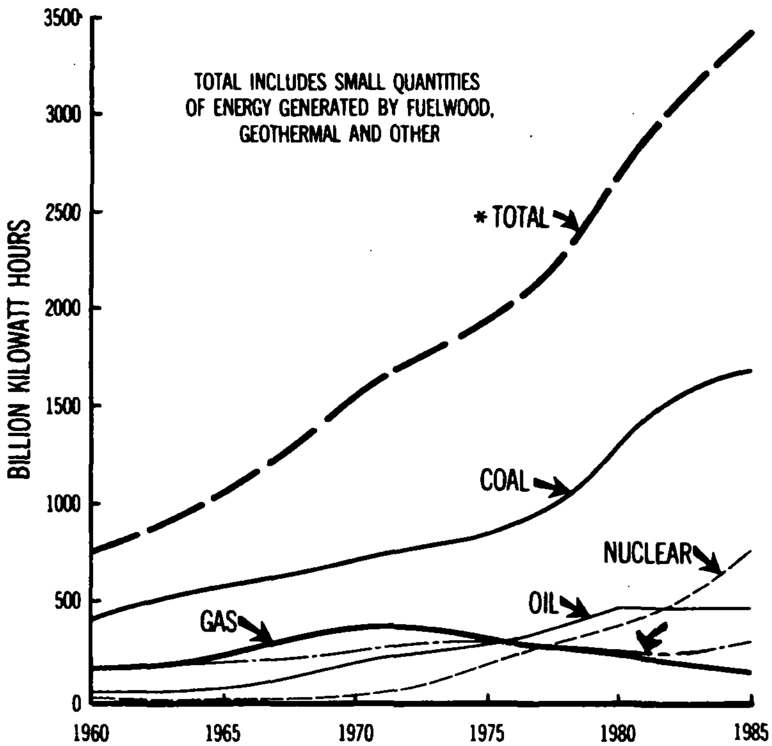
This median projection represents an average 6.5 percent annual rate of growth during the 1975-1980 period and an average rate of slightly more than 6 percent annually for the entire 10-year period through 1985. Actual growth is likely to remain within the bounds of 4 percent on the low side to 7 percent on the high side.

Generation Mix

In 1975 coal-fired generation accounted for 44 percent of total generation; nuclear generation accounted for nearly 9 percent; the remainder was almost equally divided among oil-fired, gas-fired, and hydroelectric generation.

Consumption of gas for electric power generation peaked in 1971/72. Its use by electric utilities is expected to decline at an average annual rate of 4 percent. In spite of the national policy to reduce oil demand and imports, electric utility use of oil will increase until the mid 1980's. The additional quantities of oil will be required to satisfy the needs of new oil-fired steam-electric units for which construction was begun prior to the oil embargo, for new combustion turbine and combined cycle units, to replace gas in plants which are being curtailed, and to fill energy gaps where and when they arise. Electric utility oil usage will stabilize during the 1980-85 period at a level of nearly 60 percent above that of 1975. A steady decline in oil usage should take place after 1985. With most of the hydroelectric potential already exploited, the bulk of the future growth in generation will, therefore, come from coal-fired and nuclear plants. The projected generation mix is shown in Table 4.

NET GENERATION
BILLION KILOWATT-HOURS



*NOTE: PROJECTIONS BASED ON ASSUMPTION OF A 6% PER YEAR ANNUAL GENERATION GROWTH RATE DURING THE PERIOD TO 1985

FIGURE 23

TABLE 4
ACTUAL AND PROJECTED
GENERATION MIX
IN BILLION KILOWATT HOURS

Type of Generation	1975 Net Kwh	1975 Percentage	1980 Net Kwh	1980 Percentage	1985 Net Kwh	1985 Percentage
Coal	852.7	44.5	1227	46.9	1690	48.5
Oil	288.6	15.1	465	17.8	465	13.3
Gas	299.6	15.6	255	9.7	205	5.9
Nuclear	171.4	8.9	380	14.5	807	23.6
Hydro	300.5	15.7	285	4-1/ 10.9	300	8.6
Other-Solar, Geothermal, etc.	3.4	0.2	6	0.2	20	0.1
Total	1916.2	100.0	2618	100.0	3487	100.0

4-1/ Median conditions; 1975 was an above-normal hydro year.

Fuel Mix

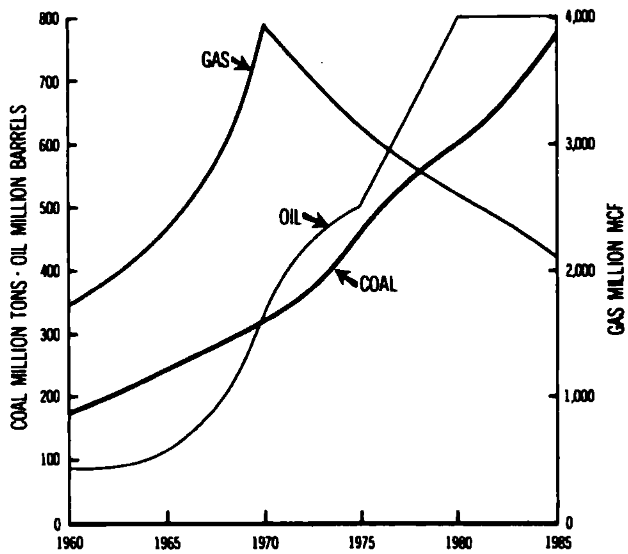
In 1975 electric utilities consumed about 28 percent of the Nation's total gross energy usage, including coal, oil, gas, and nuclear and hydroelectric power generation. The projected electric utility fossil and nuclear (U_3O_8) fuel usage corresponding to the generation mix, projected in Table 4 is shown in Table 5 and Figure 24.

TABLE 5

PROJECTED FOSSIL AND NUCLEAR (U_3O_8)
FUEL REQUIREMENTS
1980 AND 1985

Fuel	Units	1975 Actual	1980	1985
Coal	Million Tons	406	570	770
Oil	Million Barrels	507	800	800
Gas	Million Mcf	3113	2600	2100
U_3O_8	Thousand Tons:			
	No Recycle	12.7	30.7	61.5
	With Recyle	12.7	29.6	54.5

**FOSSIL FUEL CONSUMPTION
BY ELECTRIC UTILITIES**



NOTE: FUEL DEMAND PROJECTIONS ARE BASED ON THE GENERAL ASSUMPTION THAT ELECTRIC ENERGY DEMAND WILL GROW AT AN AVERAGE ANNUAL GROWTH RATE OF 6% PER YEAR DURING THE PERIOD TO 1985

FIGURE 24

By 1985, gross energy consumption by electric utilities is expected to reach the equivalent of 36 quadrillion Btu. The declining use of natural gas conforms with national policy. The increasing use of oil, however, does not and utilities will for the time being depend more heavily on foreign oil, adding to the dollar drain. The Nation is well endowed with coal resources and the projected increase in coal demand should not present any extraordinary mine supply problems. However, the ability of the transport industry to deliver the growing electric utility industry requirements without significant renovation and additions is in some doubt. Indigenous uranium resources appear to be adequate to satisfy the cumulative requirements of the industry through 1985, but absent an acceptable breeder technology the domestic resources will be strained severely in the nineties.

<u>Fuel Prices</u>

The strong demand for coal will pull the price of coal upward as the marginal cost of mining the less advantageous resources increase. Although overall gas usage for electric power generation will decline, the price of gas to electric utilities will continue to increase rapidly as the bulk of the gas is used by utilities in the southwest region where it is sold in unregulated intrastate markets. The already high price of oil probably will remain relatively stable and future prices will increase only to adjust for global inflation. The following graphic figure and table shows FPC staff estimates of future electric utility fossil fuel prices expressed in constant 1975 dollars:

TABLE 6

NATIONAL AVERAGE FOSSIL FUEL PRICES TO ELECTRIC UTILITIES (CENTS PER MILLION BTU)

	Actual Costs			Projected Costs In Constant 1975 Dollars		
	1973	1974	1975	1980	1982	1985
Coal	40.5	71.0	81.4	110	120	130
Oil	80.3	192.2	202.0	200	200	200
Gas	34.7	48.7	75.4	155	180	220

The Energy Research and Development Administration (ERDA) estimated the 1974 nuclear fuel cost at 2.15 mills/kwhr (1974 dollars), including a 0.49 mills/kwhr plutonium credit. The Nuclear Regulatory Commission (NRC) projects the 1982 cost at 5.14 mills/kwhr (1982 dollars), including a 0.68 mills/kwhr credit.

COST OF FOSSIL FUELS TO STEAM ELECTRIC PLANTS
CENTS PER MILLION BTU
(IN CONSTANT 1975 DOLLARS)
For Selected Years 1960-1985

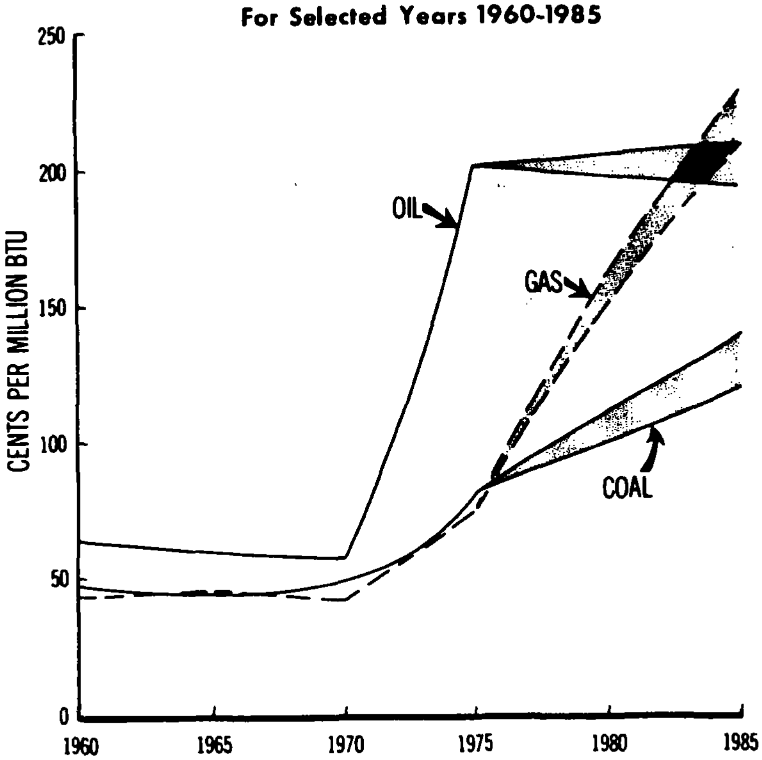


FIGURE 25

Other Energy Sources

In 1975 other energy sources, principally geothermal, wood fuel and small quantities of solid waste accounted for 0.2 percent of the total generation. Geothermal generation and the use of refuse-derived fuels commingled with coal are expected to increase while solar, wind, and tidal generation continue to remain essentially in the research and development stages. By 1985, these forms of generation will contribute only about 0.6 percent of the total. However, solar energy in its more direct form, i.e., not converted to electricity, has enormous potential and is likely to make significant contributions to overall energy demands in the period after 1980.

Conservation

Conservation actions to reduce electric energy and peak load requirements are essential to minimize the need for new capacity, improve the adequacy of the electric power supply and hold down rate increases. In many parts of the country an effective conservation measure is upgrading the insulation of existing residences. Analyses demonstrate that the cost of additional insulation can be recovered through reduced utility bills and a concept being explored in various forms calls for utilities to provide the capital for the insulation programs, with an amortization charge added to the customer's monthly bills. However, utilities would be forced to raise additional capital for such conservation programs and the feasibility and cost of obtaining the extra capital, and thus the effectiveness of the conservation program, is directly dependent upon the financial market's appraisal of the adequacy of the utilities' rate of return.

Active utility promotion of consumer conservation efforts has been, and will continue to be, among the most effective tools to hold demand growth to the lowest levels consistent with reasonable growth of the overall economy. Conservation, though, however effective it may be, is just one of the many actions which must be taken to assure reliability of future power supplies.

III. BULK POWER COORDINATION AND TRANSMISSION SYSTEM

The largest and most reliable bulk power supply system in the world exists today in the United States. This system is international in scope due to the many interconnections among U. S. and Canadian utilities and over 500 million kilowatts of electric generation is connected to this transmission system. It has proved to be adequate in most situations in the past; however, the future causes some concern.

Central dispatch of the generation facilities of individual utilities is used as a means to provide the most economical power system operation and control. The sophistication of centralized control ranges from manual calculation and voice communication to on-line computer systems automatically computing optimum system operating conditions and electronically controlling generation to match those conditions.

The benefits derived from central dispatch of individual utilities may be further enhanced by expansion to inter-utility centrally dispatched controlled areas. Table 7 lists these areas known to have fully integrated bulk power system central dispatch that have been consummated with formal agreements. Including the New York Power Pool which is scheduled to begin full central dispatch operation in 1977, 38% of the total net capability at the time of the 1976 summer peak in the Nation was under this form of control. This capability supplied 36.8% of the peak load.

Four of these central dispatch arrangements are among utilities owned by a holding company. It is obviously easier to obtain management agreement under those circumstances. It is encouraging to note that there are five agreements among utilities having individual ownerships with about twice the total capability of those central dispatch arrangements by holding companies.

It is undoubtedly true that plans for additional agreements among utilities have been deferred by the recent problems in the industry. However, they should be aggressively pursued to optimize system efficiency and hold down the cost of electricity.

TABLE 7

Net Capability and 1976 Summer Peak Loads
Inter-Utility Centrally Dispatched Areas
In the Contiguous United States

Centrally Dispatched Areas	Net Capability AT Time of Summer Peak Load	1976 Summer Peak Load
New England Power Exchange	20,032	13,079
Allegheny Power System	6,203	4,284
Michigan Coordinated Electric Systems	14,635	10,720
Michigan Municipal Cooperative Pool	236	195
American Electric Power	16,980	9,940
PJM Interconnection	41,358	29,264
Middle South Utilities	11,830	9,365
Southern Company	20,853	17,363
New York Power Pool 1/	29.240	19,544
Tennessee Valley Authority	23,633	17,656
Total-Central Dispatch	185,000	131,410
48 State Total	485,916	356,693
Centrally Dispatched As A Percent of 48 States	38	36.8

TABLE CORRECTED 2/11/77

1/ Plans to begin intersystem central dispatch in 1977.

A measure of the adequacy of the bulk power transmission system is its ability to transfer blocks of electric power and energy from one region to another. This ability is often referred to as the transfer capability. Interregional power transfer capability across Reliability Council borders varies significantly. Transfer capability in excess of 3000 megawatts exists at some ECAR interfaces, while no such capability exists at the present time from parts of Texas to other systems in Texas or to adjoining states. The recent addition of a direct current facility in western Nebraska provides 100 megawatts of power transfer capability from the eastern U.S. bulk power supply network to the western network.

A recent study by NERC indicates that in calendar 1980, 28,656,000 MWh of electricity, if available, could be transferred from coal fired generating stations through the bulk power supply network to displace gas and oil fired generation. This electric energy transfer could result in a saving of 3,820,000 mcf of gas and 45,871,000 barrels of oil. While these quantities are sizeable, there remains the question of whether more can be done.

Planning of the bulk power transmission system is handled by individual electric utilities or by various groupings of them. Minimal input, during the plan formulation stage, is now received from governmental bodies on the local, State, or Federal level. The FPC in its Order 383 series recognizes the nine Electric Reliability Councils and requests annual reports which indicate the existence of some coordinated regional planning.

Current environmental and siting constraints generally have the effect of delaying project in-service dates beyond those originally desired. Increased participation by State and Federal regulatory agencies in the planning process could have the effect of mitigating the delays. Electric utilities must communicate effectively the requirements and benefits of a proposed facility well in advance of the need. Various individuals or groups may have objections to the construction of a new facility; however, the overall public interest must ultimately be satisfied. At the same time, maximum effort is required to minimize any hardships caused by the construction of bulk power facilities.

The construction of electric power facilities by all utilities must satisfy an economic test. The proposed facility must generate benefits which in general exceed its cost. A major factor in this economic consideration is the time factor. Changing loads and load patterns result in different system needs at different times. Therefore, some facilities with long term benefits may not be economically justified at this time. It is evident that the bulk power transmission system is often constrained by economic considerations. An example of this occurred in the 1930-40 period when economics inhibited the immediate extension of electric service to many low consumption rural areas. The Rural Electrification Administration was established to meet that need.

Today there are some areas where additions to the bulk power transmission network will provide long term benefits; however, economic considerations delay their construction. More interconnections to Florida, New England, Texas, and the Pacific Southwest will be economically justifiable in the future; however, their construction in the present time period offers some benefits and may assist in the achievement of national policy. The economic considerations require study and will perhaps result in innovative solutions.

Finally, the control of bulk power transmission network needs more refinement. Better use must be made of existing facilities. "Wheeling" of electric power occurs when Utility B allows the transfer of power from Utility A to Utility C over its transmission facilities for the payment of an appropriate charge. The "wheeling" of electric energy has generally been accepted by the electric utility industry as necessary from the national public interest viewpoint, but the ability of FPC to order "wheeling" on its own motion could be useful in certain situations.

IV. DESIGN OF ELECTRIC RATES

Recent increases in fuel costs, construction costs, costs of obtaining new capital and the general rate of inflation have combined to necessitate large increases in electric rates throughout the country.

Figure 26 shows the price of electricity to ultimate customers from 1926 to 1976 in actual dollars and constant 1968 equivalent dollars. It also shows the Consumer Price Index (1968=100) for that period. These curves show that by any measure electricity is the best bargain in the consumer's market basket. Over the period, the Consumer Price Index has tripled, the cost of a kilowatt hour of electricity in current dollars is the same in 1976 as it was in 1926, and in 1968 equivalent dollars, today's price is only 1/3 of the 1926 figure. No other commodity has such a record.

PRICE OF ELECTRICITY TO ULTIMATE CONSUMERS

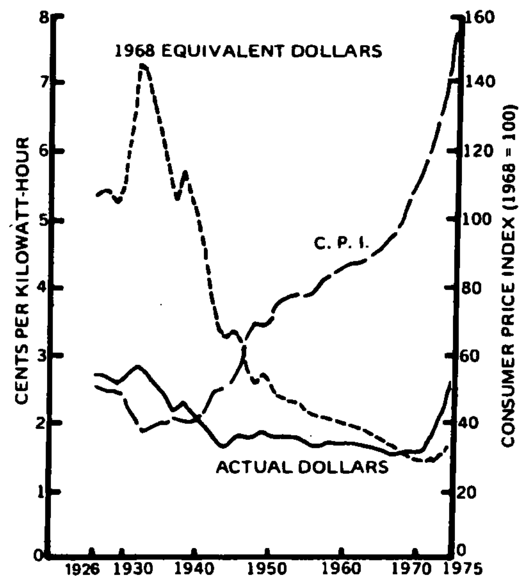


FIGURE 26

Unfortunately, after 43 years of almost uninterrupted decline, the current dollar cost of electricity began to increase in 1970 and since then the current cost of electricity has increased by 82% with 67% of the increase occurring since 1973. This was largely due to the oil price increase, with concurrent increases in natural gas and coal prices.

Also, the high inflation rates of the late 1960's and the early 1970's had a substantial impact which occurred at the same time that technological advances could no longer offset declining unit costs while the electric industry experienced additional costs as the result of stringent environmental requirements. Such a rapid increase in the cost of a basic commodity, regardless of its real value in terms of other commodities, has resulted in strong public resistance to the full recovery of these costs, however justified. Unfortunately, forecast upward trends in the price of fuels plus continuing inflation will result in continuing increases in the price of electricity at about the rate of increase in the wholesale price index. This increase will be ameliorated somewhat by efficiency improvements.

Due to the public distaste for increased rates there is a strong opinion that regulatory agencies are not acting in the public interest if they allow electricity prices to rise to meet increased costs. Quite the contrary is true as long as regulators fulfill their duty to assure that any increase is cost justified. Only by allowing justifiable rate increases can regulators insure that the industry remains healthy and permit it to raise needed capital at reasonable rates. Costs of capital are an element of cost just as much as fuel. In the worst case, inadequate rate relief can prevent a utility from providing the level of service the public needs and expects.

The increases in electric rates have generated interest in load management and changes in rate design to lessen load growth and the need for new construction. The interest in changes in rate design comes from various quarters and reflects various objectives. Conservationists and environmentalists would like to minimize growth and to make more efficient use of present systems, thus forestalling the installation of new pollution sources and the attendant environmental effects of increased fuel usage both in the production and consumption of such fuels. Consumer groups seek to minimize rates to the lower income consumer who has been particularly hard hit by all aspects of inflation, one of the most noticeable of which is the substantial increase in electric rates. Economists are looking to rate design for more optimum resource allocation. Regulatory bodies are concerned with equitably assigning increased costs to those customers responsible for such costs and the electric utilities are concerned with maintenance of adequate revenue and the effects of regulatory lag i.e., the time lag between the time cost increases are incurred and the time when such increases can be passed on to the ratepayer in the form of higher rates. The current discussions are centered around inverted rates, flattening or declining block rates, lifeline rates, marginal cost pricing, time-of-use pricing and the use of automatic adjustment clauses.

The electric rate increases experienced throughout the country for retail service have also been experienced in rates subject to the jurisdiction of the FPC, i.e., rates for the transmission of electric energy in interstate commerce and for the sale of electric energy at wholesale in interstate commerce. The latter includes rates for interconnection and coordination services between utilities with generation and for firm requirements service to distribution utilities without generation or other sources of supply. Firm requirements service to wholesale customers who in turn resell to the ultimate consumers, is similar to the firm requirements service provided to residential, commercial and industrial customers which are subject to the jurisdiction of the various state commissions, although some characteristics of service may differ. For example, the delivery voltage may be at transmission level for wholesale customers whereas retail customers are served at a distribution voltage.

Because of the similarity of services many of the rate design issues previously discussed may also be applicable to wholesale firm requirements service. The interconnection and coordination agreements on file with the Commission usually take the form of a mutually agreeable contract between parties providing for mutual services to make optimum use of existing generation and transmission facilities. To date, rate design issues have not become issues in rate filings involving such services although changes in policies with respect to rate design for firm service can be expected to have an impact on the rate design for interconnection and coordination services. More effective development of intercompany or interregional pooling or coordination, this could presumably be done through the interconnection and coordination services and rates. However, it must be noted that the Federal Power Act speaks in terms of voluntary interconnection and coordination of facilities and the Commission is not empowered to order wheeling through a system for other than emergency conditions. Such limitations may create obstacles in restructuring interconnection and coordination practices if voluntary action is inadequate.

On April 26, 1974, the Commission issued a Notice of Proposed Rulemaking proposing to amend the Regulations under the Federal Power Act by requiring the submission of rate design information by public utilities as part of their filings of rate schedules. In the notice the Commission referred to its policy to develop the role of rate design and the conservation and efficient utilization of energy resources. The proposed regulations would have required an explanation of each rate design in relation to conservation as well as cost considerations. In order to clarify the purpose and intent of the proposed rulemaking, the Commission issued a revised rulemaking notice on February 14, 1975. The Renotice makes clear the central role of costs in determining the reasonableness of rate designs and eliminates the suggestion or implication that the Commission intends to depart from the principle of costbased rates. On October 9, 1975, the Commission issued Order No. 537. This order amended the Regulations under the Federal Power Act and terminated the rulemaking Docket No. RM7420 with respect to the rate design information. Under the revised Regulations the Commission requires the submittal of a

"Statement P" supporting the rate design of any new rate submittal. Statement P includes a narrative statement describing and justifying the objectives of the design of the proffered rate. If the purpose of the rate design is to reflect costs, the narrative is to state how the objective is achieved and should be accompanied by a summary cost analysis that would justify the rate design. If the rate design is not intended to reflect costs, whether fully distributed, incremental or other, a statement is to be furnished justifying the departure from cost-based rates. Statement P also requires that where billing determinants, that is, quantities of demand, energy, delivery points, etc., are on a different basis than the cost allocation determinants supporting such charges, an explanation shall be submitted setting forth the economic or other considerations which warrant such departure. With rates being charged containing more than one demand or energy block a detailed explanation is to be submitted indicating the rationale for the blocking and the considerations upon which such blocking is based, together with adequate cost support for the specific blocking. Since the initiation of Order No. 537 the trend in wholesale rates has been to simplify rate design and to flatten rates by the elimination of blocking.

In issuing Order No. 537 the Commission made the following statement:

"The Federal Power Act establishes criteria for this Commission in the exercise of its rate regulatory authority. Rates must be just and reasonable, non-preferential and non-discriminatory. We believe that it would be appropriate for the Commission to consider the extent to which application of marginal cost pricing principles will result in rates which conform more closely with these criteria while at the same time achieving the objectives outlined above. The record before us in this proceeding, however, does not provide a sufficient basis to determine the feasibility of applying marginal cost pricing principles to the design of rates subject to our jurisdiction, particularly rates charged to distributor systems for firm power. 5/ Issuance of the subject filing requirements will not prejudice any party's rights, including those of our staff, to offer innovative rate design proposals through evidentiary presentations. Indeed, we believe that this matter should be examined by all electric systems with a view to determining whether alternate pricing mechanisms, particularly those based on marginal cost principles, for wholesale sales subject to the jurisdiction of this Commission would be economically sound as well as in accordance with statutory requirements. We note that at the present time a number of studies of rate design alternatives are in progress. We would welcome the introduction into evidence in

5/ Pricing on the basis of incremental costs, however, is quite common in rate schedules covering power pooling type transactions.

rate proceedings before this Commission materials that become available from these studies to assist us in reaching judgments that are in the public interest."

Although there has been widespread and growing interest in the application of marginal cost pricing principles, peak load pricing, long run incremental cost pricing, time of day pricing, daily and seasonal differentials and the like, there have been relatively few filings at the Commission involving such issues with the possible exception of seasonal differentials in wholesale pricing. The few cases filed involving time of day rates have generally been settled prior to hearing. To date no firm service rates have been filed based on marginal cost principles.

The effects of rate structure and price changes on patterns of electric use are generally referred to as price elasticity of electric comsumption. The magnitude of price elasticity and the proper form of rate to better reflect current economic realities are areas currently receiving substantial study and debate in many different forums. One such forum is the joint study by the Edison Electric Institute, and the Electric Power Research Institute, "Electric Utility Rate Design Study" being conducted at the request of the National Association of Regulatory Utility Commissioners. Also, the Federal Energy Administration is conducting some 16 demonstration projects through the cooperation of various state commissions. FEA is also currently preparing a report to Congress which will be a report on the various alternatives in electric rate design. Positive load management, either in response to pricing or through direct load management devices, has the potential for substantial desirable effects in the optimum utilization of our national resources and in the long run reducing overall costs of electricity to the ultimate consumer from what they would otherwise be. It should be recognized, however, that even in its most optimistic light such positive load management probably only has the limited potential to reduce the magnitude of anticipated future rate increases and will not eliminate the need for such increases in the future due to the fact that some continued load growth is anticipated.

The studies now under way on time of use pricing are directed to determining the proper cost of electric usage on the basis of time of usage whether seasonally or time of day. This recognizes that there may be substantial cost differentials existing on various systems for different periods of usage. Included as a sub-issue in the debates on time of use pricing is the use of marginal cost as the starting point of the rate design rather than the traditional fully distributed cost basis.

Lifeline rates define a minimum number of kilowatt hours required for residential subsistence and establish a low rate for such usage. Since the rationale for the lifeline rate is not based on the cost of providing such service, it departs from this Commission's ratemaking philosophy on costbased rates. However, this Commission only has jurisdiction over sales for resale and lifeline rates are, therefore, a matter that primarily involves the state commissions. This Commission has consistently opposed Federal legislation mandating lifeline rates.

An inverted rate is an increasing block rate with higher rates for higher use blocks. Under such rates, the average price increases as consumption increases. The opposite of an inverted rate is a declining block rate, that is rates which become lower with increased usage. The rationale for declining block rates is largely to track declining costs gained due to economies of scale. Declining block rates may also be necessary to track varying load factor/coincidence factor relationships which affect the collection of demand related costs in one-part rates not containing a demand charge. One of the reasons given for inverted rates is to promote conservation by providing a disincentive to load growth. The problem with such reasoning is that load may occur in other than high consumption blocks by the addition of new load consumption customers and by increasing consumption of customers whose usage is the lower usage blocks as opposed to higher consumption blocks.

Direct load management equipment may be utilized to control consumption at the customer level in lieu of customer control of the use patterns of consumption in response to price signals produced by time of use rates. The results of current studies on load research and the price elasticity of demand and energy are necessary to determine the potential, feasibility and cost/benefit ratios of proposed changes in rate design and load management.

In applying these concepts, the firm requirements service to wholesale customers would appear to be a significant problem since the wholesale customer's elasticity is no more than a composite of the elasticities of its ultimate customers. The wholesale customer is itself made up of residential, commercial and industrial customers and constitutes a mini-system similar to its wholesale supplier. The success of time of use pricing or use of load management equipment, therefore, can only be effective if the wholesale customer utilizes pricing policies or load management equipment similar to those utilized by the wholesale suppliers to their ultimate consumers. Advocates argue that implementation of marginal cost pricing at the wholesale level would encourage resale customers to pick cost minimizing mixes of power sources and not to influence the usage decision of the resale customers' ultimate consumers. This argument fails to recognize that there are great numbers of resale customers with no generation of their own and no effective ability or desire to engage in self generation. Such customers are content to remain distribution customers and not take on the added complexities of a generation and transmission utility which require standby contractual agreements, operating personnel for the generation facilities and planning, management and financial personnel required for the installation of new generation and transmission facilities. If time of use pricing is utilized for a wholesale customer, but not to the retail customers of the supplying utility (or vice versa), serious questions of discrimination can arise. A related issue was recently decided by the Supreme Court in FPC V. Conway Corp. Et. Al., Slip. Op. No. 75-342, decided June 7, 1976. In the Conway case the court held that the Commission may consider allegations as to price squeeze, i.e., discrimination between wholesale and retail rates for the purpose of forestalling wholesale customers from competing with the supplier at retail. In that case the court indicated that the Federal Power Act forbids the maintenance of any "unreasonable difference in rates" or service "with respect to any. . . sales" subject to the FPC's jurisdiction and that such prohibition extends to differences between wholesale and retail rates that are unreasonable and anticompetitive. The Conway case will have continuing ramifications on the setting of wholesale rates, including the area of rate design.

The substantial increases in costs in recent years have been accompanied by pleas from utilities to eliminate regulatory lag so that rates may be changed promptly and thus keep the utilities in a sound financial position. One vehicle to assist in reducing regulatory lag is the automatic adjustment clause. The most common automatic adjustment clause is the fuel adjustment clause. The Commission has stated in Opinion No. 633, issued on October 30, 1972, that fuel adjustment clauses are lawful and sound as a matter of regulatory policy. These sentiments were reaffirmed in Order No. 517, issued on November 13, 1974, in which the Regulations were changed to reflect improvements in the design of fuel adjustment clauses.

An example of another type of adjustment clause is that permitted by the New Jersey Board of Public Utilities (Board) in a telephone case in 1973. In that case the Board permitted adjustments for cost beyond the control of the utility in the following areas: (1) salaries and wages; (2) depreciation expense; and (3) tax adjustment clause for changes in the effective tax rate.

Also, the New Mexico Public Service Commission has recently permitted the use of an all inclusive automatic adjustment clause which provides the New Mexico Public Service Company with a 13.5 to 14.5 percent return on common equity. The utility's earnings are reviewed quarterly and if they exceed a 14.5 percent return on common equity the consumer rates are revised downward. If the return falls below 13.5 percent the rates are adjusted upward.

Two major criticisms of automatic adjustment clauses are the following: (1) that the clause may be automatically adjusting for certain increases in costs, whereas the other costs may be declining with no provision for adjustment for such costs; and (2) that such clauses are a disincentive to management to keep costs to a minimum. One of the possible answers to the first criticism might be to utilize a total cost of service adjustment clause. This would assure that all costs are being properly adjusted as opposed to selective costs. As to the second problem, it can be argued that the regulatory time saved in reduced amounts of rate cases might be utilized in auditing utility decisions to assure that effective, efficient management exists and the utility's decisions are in the public interest and designed to keep costs to the consumer at a minimum. Also, should doubt as to the efficiency of a utility exist, its allowable return could be maintained at the lower end of range.

V. CAPITAL REQUIREMENTS AND FINANCING ABILITY

In the six years 1970-75 investor-owned utilities invested $81 billion in new facilities. Since investor-owned utilities provide about 80% of total capacity and generation, the entire industry including municipal, cooperative, state and federal investment over this period was about $100 billion. The period was characterized by increasing escalation of costs, especially construction costs, and by rapid load growth early in the period, causing utility emphasis on facility construction. The year-by-year investments were as follows:

TABLE 8
Electric Utility Investment in New Facilities
$ Billions

	Investor-Owned (FPC Data)	Estimate for Total Industry
1970	9.9	12.4
1971	11.9	14.3
1972	13.3	16.7
1973	14.8	18.5
1974	16.5	20.6
1975	14.8	18.5
	81.2	101.0

From 1970 through 1974 the average annual growth in facility investment by privately-owned utilities was about 14%, but in 1975 investment fell back sharply, reflecting the financial crisis of 1974 and the drop-off in load growth. Consequently, the 1970-75 average growth in privately-owned utility investment was about 8% per year.

A median extrapolation of facility investments over the next decade might be for an average growth rate of about 10% per year, corresponding to a real growth in facilities of 4 or 5% per year and escalation of 5 or 6% per year. On this basis, the ten year investment requirements through 1985 of the privately-owned utilities would be about $240 billion and for the entire industry about $320 billion. Considering that actual load growth rates could range from 4 to 7% per year and inflation rates from 4 to 10% per year the range of industry capital investment requirements over the next decade could be as low as $220 billion or as high as $420 billion, approximately 75% of which would be accounted for by the privately-owned utilities.

Based on data from the Regional Reliability Councils and other sources the breakdown of expected capital requirements by ownership classes over the next decade is shown in Figure 27.

PROJECTED ELECTRIC UTILITY CAPITAL EXPENDITURES 1977 - 1985

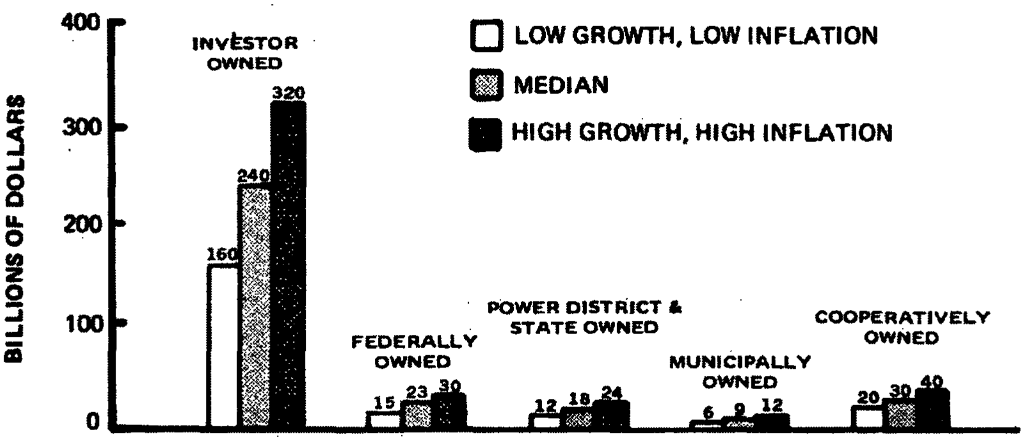


FIGURE 27

Investor-owned utilities have traditionally obtained about 65% of their capital requirements from external sources. Assuming that this proportion continues to hold over the next decade, the new-money financing requirements of investor-owned utilities would be in the range of 100 to 200 billion dollars with annual requirements in the mid 1980's in the range of 22 to 36 billion dollars a year. Traditionally, the sources of capital for investor-owned utilities have been approximately 35% common stock, 10% preferred stock and 55% long-term debt. The requirement to continually sell new stock as a part of the overall financing makes investor-owned financing strongly subject to the vagaries of the stock market. When new stock must be sold at prices considerably below book value, which was the case in 1974, the holdings of existing stock owners are diluted and in time a utility could find itself unable to sell stock and obtain the financing needed for new facilities.

Investors have long regarded electric utility stocks as 'quasi-bonds', demanding dividend yields comparable to those of high grade bonds. As interest rates have increased, reflecting inflation, the prices of utility stocks have declined to provide equivalent yields. Thus, the availability of investor-owned utility financing is tied closely to investor judgments of future dividend yields. These yields, in turn, are determined primarily by the rate of return on equity allowed by the various regulatory bodies.

Figure 28 shows how utility stocks have steadily declined in value relative to industrial stocks over the past decade.

Figure 29 shows the reduction in electric utility earnings in real dollars over the period, explaining the growing spread between industrial and utility stock prices. These trends demonstrate that over the past decade regulatory bodies have generally not provided returns that investors regarded as sufficient, in comparison to other opportunities, to maintain utility stock prices.

COMPARATIVE STOCK PRICE TRENDS

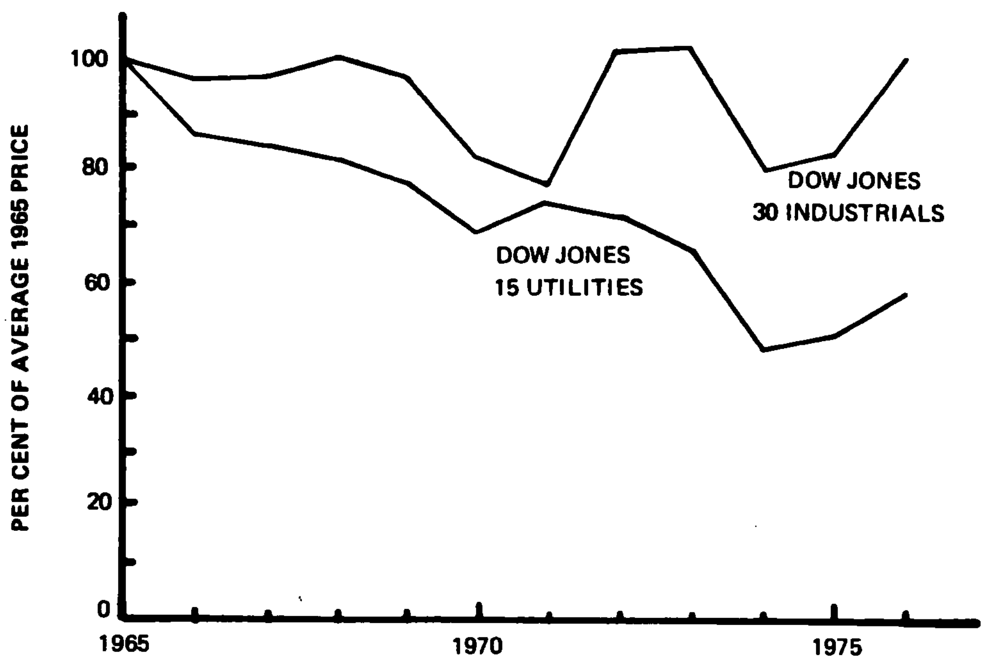


FIGURE 28

QUALITY OF EARNINGS

ALL FPC CLASS A & B INVESTOR – OWNED ELECTRIC UTILITIES

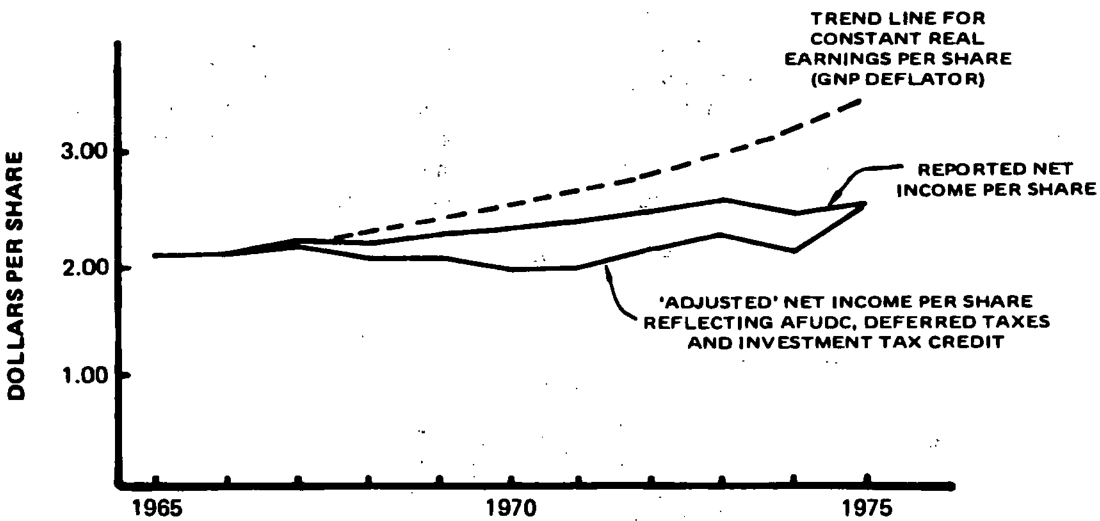


FIGURE 29

The easing of inflation and the recovery of the stock market in 1975 and 1976 have lessened the financial crisis for investorowned utilities generally. But as shown in Figure 29, utility stock prices are still at levels far below those obtaining in 1965. Fifty percent of utilities still have their securities selling at prices well below book value and find it difficult to acquire needed financing. Within the past several years, most regulatory bodies have increased electric rates substantially in an attempt to provide improved earnings and cash flow for industry viability and to support construction of facilities to meet future demands. Measures have included use of future test years, increased allowable rates of return on equity, addition of Construction Work In Progress to the rate base and automatic adjustments to maintain the allowable rate of return. However, it is not certain that the measures taken will completely assure adequate financing in the future. It is clear that the principal villain in the financing crisis for privately-owned utilities was inflation and that the most beneficial measure to alleviate their financing problems would be a progressive reduction in the inflation rate. However, a return to double digit inflation would almost certainly precipitate a new financial crisis for the investor-owned utilities, because of the lag inherent in the traditional regulatory process.

In contrast to the investor-owned utilities, the publicly-owned systems-- municipal, cooperative, state and Federal ---have not experienced significant difficulties in securing financing, although their financing costs have increased. Figure 30 compares the interest rates paid for long-term debt financing by municipal and Rural Electrification Administration borrowers, as compared to those paid by the investor-owned utilities. Basic reasons why the publicly-owned systems avoided the financial crises experienced by the investor-owned systems include government backing of loans, the fact that public systems do not require recourse to the volatile stock market and, in most cases, a greater freedom to adjust rates to keep pace with increased costs.

COMPARATIVE COSTS OF DEBT FINANCING

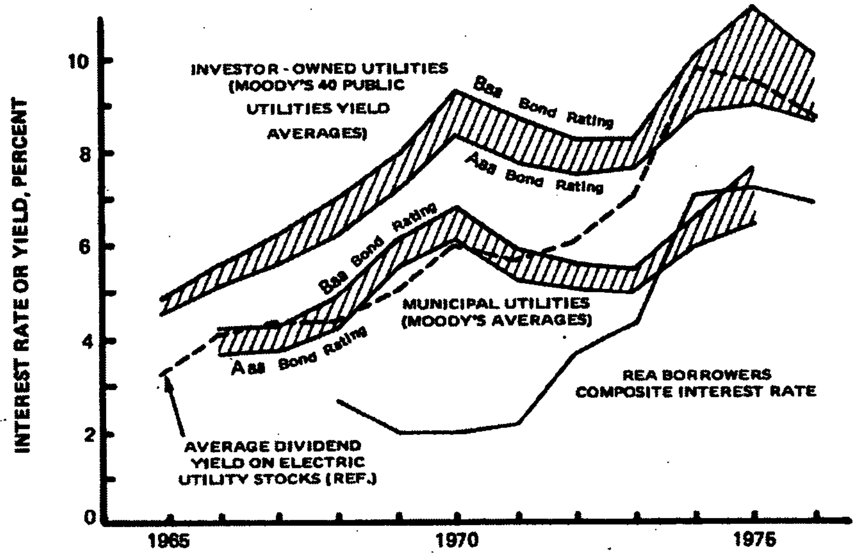


FIGURE 30

Data provided by the Regional Reliability Councils suggest that municipal systems are planning to remain large purchasers of wholesale power, since their identified generating capacity additions would not increase their share of self-generation. On this basis, the municipal utilities would be expected to make capital expenditures aggregating $7 to $13 billion over the next decade. If the traditional 60% is raised by borrowing, their financing requirements would be from approximately $4 to $8 billion over the period. Municipal electric system financing is achieved principally through the sale of revenue bonds, exempt from Federal taxation.

It is possible, however, that municipal utility financing requirements could be much larger than these estimates. There is considerable evidence that investor-owned systems are finding joint ownership arrangements increasingly acceptable, and even desirable, because of past and prospective financing problems. Should this develop into a strong trend, the magnitude of municipal utility financing over the next decade could easily double that projected from the announced plans, with a corresponding reduction in the amount of financing provided by the investor-owned systems. There is no indication that municipal systems would experience significant difficulty in securing even the larger amounts of financing. The recent Federal Tax Revision Act should make even more individual investor funds available to the municipal securities market, via the mutual funds.

The Rural Electric Cooperative Systems have been the fastest growing industry segment, reflecting the improving economic status of agricultural and rural areas. The 1976 Regional Reliability Council data indicates that cooperative systems are planning to substantially increase their share of self-generation over the next decade. However, more recent data from the Rural Electrification Administration based on loan applications indicate that self-generation will rise even more rapidly than shown by the Council data. The principal cause is a rapid trend toward jointly-owned generation projects, both with investor-owned systems and with publicly-owned systems. As in the case of the municipal systems, the ability of the cooperative systems to secure financing has been a major factor in this trend. On the basis of the REA data, cooperative system financing requirements over the decade are likely to be in the range of $20 to $40 billion.

Financing for the cooperative systems is not expected to present a problem since most of the loans are backed by Federal guarantees. However, the Congress could establish a ceiling for the loan amounts qualifying for Federal support.

VI. INSTITUTIONAL FACTORS CHANGING CHARACTERISTICS OF THE ELECTRIC UTILITY INDUSTRY

Pluralistic Nature of the Industry

Although privately-owned electric utilities have traditionally supplied the greatest share of the Nation's electricity, many communities and rural areas are served by municipally owned and cooperatively owned systems. The Federal government is also an important factor in electric power supply, generating large amounts of electricity, principally at Corps of Engineers and Bureau of Reclamation hydroelectric projects and through the Tennessee Valley Authority. There are also a number of state-owned generating systems. Typically, the Federal and State power is wholesaled to individual utility systems for distribution to retail customers. Thus, the United States electric power industry is pluralistic, consisting of a variety of ownership forms with operating patterns ranging from systems which purchase all their power and provide only distribution, to those which are vertically integrated from generation through retail deliveries, to those which provide only generation and/or transmission services. The systems vary from very small systems with peak loads of 10 megawatts or less to systems such as TVA with peak loads greater than 20,000 megawatts.

Although the number of municipal electric utility systems declined steadily in the early decades of this century, as a consequence of consolidating with investor-owned systems, there has been very little change in the composition of the industry in recent years, as shown by the tabulation, Table 9.

Traditionally, the municipal and cooperative systems have purchased large amounts of wholesale power from Federal, state and investor-owned systems rather than attempting to supply all their needs by self-generation. Generally, this has been economic, even for purchases from private systems, because of the better economics possible with large generating units. It is noteworthy that while municipal systems did not increase their shares of total capacity and generation over the decade, the cooperative systems did, almost doubling their shares. This trend reflects to some degree the ability of rural systems to establish joint generation and transmission projects, making self-generation economic. However, the rural electric cooperative systems and the municipally owned systems as a group are still strongly dependent on purchased power. Because Federal hydroelectric power is limited, the municipal and cooperative systems will become increasingly dependent on investor-owned systems unless they substantially expand their self-generation capabilities.

TABLE 9

Ownership Characteristics of the Electric Power Industry

1965

		Generating Capacity		Generation		Sales to Ultimate Customers	
	No.	MW	%	Billions of kWh	%	Billions of kWh	%
Investor-Owned	289	177,570	75.2	809	76.7	749	78.5
Municipals	2124	15,407	6.5	50	4.7	164	17.2
Power Districts and State		9,151	3.9	42	4.0		
REA Cooperatives	969	2,309	1.0	9	0.8	41	4.3
Federal	5	31,690	13.4	145	13.8	--	--
TOTAL	3387	236,127	100.0	1,055	100.0	954	100.0

1975

		Generating Capacity		Generation		Sales to Ultimate Customers	
	No.	MW	%	Billions of kWh	%	Billions of kWh	%
Investor-Owned	281	399,434	78.6	1,487	77.6	1,387	79.9
Municipals	2245	28,554	5.6	81	4.3	242	13.9
Power Districts and State		21,289	4.2	93	4.8		
REA Cooperatives	1050	9,137	1.8	34	1.8	108	6.2
Federal	5	50,058	9.8	221	11.5	--	--
TOTAL	3581	508,472	100.0	1,916	100.0	1,737	100.0

Economic self-generation for small systems is now generally possible only through sharing in the ownership of large generating plants, either with other publicly-owned systems or with investor-owned systems. An alternative means for a small publicly-owned system to satisfy its power requirements is through the availability of wheeling services, allowing wholesale power to be purchased from any of several sources, rather than just the adjacent investor-owned utility.

Traditionally, investor-owned utilities have regarded wholesale deliveries of electric power to municipally and cooperatively owned systems as generally desirable, providing a diversified load with an equitable return. However, the combination of dramatically increased costs for new generation, financing problems, and the resistance of municipal systems to wholesale rate increases needed to cover the cost increases of their suppliers has, in some cases, caused investor-owned systems to question the value of continuing to serve municipal and cooperatively owned systems. The prospect of being unable to purchase sufficient electricity for future customer needs is, of course, a serious problem to the publicly-owned systems affected. While participation in joint generation projects can be a solution, it is not without difficulties, requiring the raising of substantial amounts of capital and the establishment of appropriate arrangements to assure electricity supply at all times.

Roles of Various Organizations

State Commissions

In recent years there has been an evident upgrading of the capabilities of state bodies responsible for the regulation of electric utilities. Their staffs have been expanded and become more sophisticated in the many interactions of electric power with overall energy use, economic development, efficient use of resources and environmental impacts. State commissions, as in Wisconsin, New York and California have been leaders in innovative retail rate designs in attempting to achieve more accurate assignment of costs, in critical examinations of the economic merit of utility facility construction plans and their effect on future retail rates and in evaluations of primary energy supplies and other complex aspects of electric power. Thus, in general the state commissions are in a better position today to correctly evaluate electric power problems and initiate corrective actions.

Other State Bodies

However, there is also a trend toward increasing involve ment by other state agencies in the approval of utility construction plans. These include bodies such as environmental control boards, power plant sitting agencies, natural resources agencies and energy facility commissions. Examples are the

Maryland Power Plant Siting Program of the Department of Natural Resources, the California Energy Resources Conservation and Development Commission and the New York State Board on Electric Generation, Siting and the Environment. While the additional regulatory reviews may be fully justified they do at present add time and complexity to the establishment of new electric facilities. In addition they also tend to focus attention on electric power as though it were an issue totally contained within the state boundaries. In fact, modern electric power systems are regional in scope and the actions of one state affect others in the region.

This regional character of electric power supply is more recognized by states in some parts of the country than in others. New England is outstanding in its recognition of this fact and its governors have recently taken some actions which can lead to effective multi-state participation in regional power planning. On a more limited basis, the Southern Interstate Nuclear Board is an example of regional cooperation by states in energy matters.

Overall, however, it seems apparent that there is a considerable distance to go in achieving general recognition by the states that electric power is a regional matter and cannot be dealt with effectively on an individual basis by each state acting independently. The growing ramifications and concerns regarding electric power require cooperative multi-state consideration of the issues and development of acceptable regional plans which reasonably balance the benefits and costs for all the states.

Federal Activities

Federal regulation of the electric utilities is spread across many agencies. The FPC licenses hydroelectric projects and regulates wholesale electricity sales of jurisdictional utilities. The Nuclear Regulatory Commission licenses nuclear plants. The Environmental Protection Agency establishes national standards for air and water quality control and through a complex system of state permits and Federal reviews can prohibit the construction of new plants which it judges will not meet its standards. The Federal Energy Administration can prohibit the burning of natural gas or oil in new power plants. The Coastal Zone Management Act provides for the establishment of state plans which result in further circumscribing of utility facility options.

Regional Reliability Councils

In the late 1960's, following the massive Northeast power failure of November 1965, the electric utilities established nine regional reliability councils covering the contiguous United States. The councils provide for membership by all utility ownership categories and for participation in proceedings by the FPC and state regulatory bodies. The councils coordinate the plans of their members, but have no authority to impose requirements on any utility. Nevertheless, the councils have proved to be of great value in illuminating regional electric power issues, in evaluating proposed generation and transmission plans and in developing a comprehensive regional overview of electric power adequacy.

The councils vary widely in the effectiveness of their coordination. Some councils consist essentially of the members of formal power pools with centralized dispatch and specific capacity and energy commitments. These councils are tightly integrated and exhibit the best regional planning, provisions for contingencies and awareness of the interaction national, state and regional energy problems. Other councils, however, are very loosely tied together, including utility systems from vastly different geographic regions having dissimilar weather patterns and generation types. Such councils are less effective because they do not really cover a region with a reasonably definable community of interest or similar electric power supply problems. In some cases the councils have established sub-regions to help deal with these problems, but this has not resulted in the effective coordination seen in other regions.

As a generalization, it appears that the national electric power supply would benefit from additional formal pooling arrangements with their ability to minimize costly capacity requirements, to use the most efficient generating units at all times through centralized dispatch and to flexibly meet a variety of contingencies. It also appears that the boundaries of some of the councils could be redrawn to establish councils with stronger joint interests and similar problems and to assemble and report data by more meaningful groupings then at present.

VII CONCLUSIONS

1. Additions to the bulk power supply system planned by the Nation's electric utility industry appear to be adequate through 1985 if the following conditions are met:

   a. Load growth in the electric reliability councils regions does not significantly exceed forecasted levels.

   b. Generation from existing nuclear plants is not interrupted by external factors and all nuclear plants under construction and planned to be completed by 1985 enter commercial service substantially on schedule.

   c. Coal-fired plant additions are completed substantially on schedule and fuel is available to them as required.

   d. Conversion of plants from natural gas to oil or coal fuel occurs in an orderly, gradual fashion.

   e. Additions to the bulk power transmission systems are made in a timely manner.

   f. Utilities are allowed timely rate adjustments so that an adequate supply of capital is available at reasonable cost to finance additional facilities.

2. It is unlikely that all of the conditions enumerated above will in fact be met because of the following developments that are currently evolving:

   a. OPEC oil pricing actions.

   b. Increasing modifications to nuclear plant design effecting delays in completion and operation of nuclear generating facilities.

   c. Possible more restrictive amendments to the Clean Air Act that may cause delays in completion and increased costs of coal-fired plants.

   d. Limitations on coal supply due to strip mining restrictions.

   e. Increasing environmental opposition to generation and transmission additions to the bulk power supply system. Therefore, it appears that regional shortages of capacity and/or energy in the 1979-1985 period are distinct possibilities.

3. Despite efforts to maximize generation by coal and nuclear fuels, the electric utility use of oil will increase. Oil usage should stabilize during the 1980-85 period at a level of about 60% above that of 1975. A steady decline in oil usage should then begin. Impediments to the timely operation of additional coal-fired and nuclear plant will impact directly on the consumption of oil. Also, shift from these fuels to oil will significantly increase the Nation's electric power rates.

4. Electric energy requirements may increase by about 80 percent by 1985. Generation with coal is expected to double, oil generation is projected to increase by 60 percent, generation with natural gas is expected to decrease by 30 percent or more, while nuclear generation -- based on current plans -- will almost quadruple the 1975 level. By 1985, more than 20 percent of electric generation is expected to come from nuclear plants.

5. Although electric power costs in 1975 had increased by 1.3 cents per kWh since 1969, these costs were only 21 percent higher than 1969 levels on a real cost basis, and only one-third of the real costs of 50 years ago. Power costs are expected to continue to increase during the next decade. With continuing cost escalation, electric utility plant in service in dollars per kW of installed capacity may increase by 50 percent for the investor-owned sector by the early 1980's. Such increases, coupled with expected increases in utility fuel and operating costs, could mean a further 50 percent increase in electric power costs by 1982.

6. As mentioned, electric power costs could increase by 50 percent by 1982. Within the generally accepted range of generating reserve levels (say 15-25 percent), the exact level of reserve is expected to have a minor effect on power costs. For example, an increase in reserve levels from 20 percent to 25 percent in 1982 would increase retail power costs by about one percent. With the uncertainties extant in current electric utility load forecasts, such an increase may be a small premium to pay as insurance against either unforeseen load growth due to switches from scarce and/or expensive primary fuels to electricity, delays in the nuclear power program or in the expansion in the use of coal.

7. By 1982, the self-generation costs of municipal and cooperative power systems, and the wholesale power costs on a fully distributed cost basis of investor-owned utilities are expected to be quite competitive. This factor should encourage more joint ownership of generating facilities, along with joint planning and expanded interconnections and pooling operations. Statutes and regulations which restrict or constrain such activities should be identified and eliminated.

8. The overall availability of capital for construction of new electric utility facilities appears to be adequate. However, the lower financing costs experienced by publicly owned utilities, as compared to investor-owned utilities is likely to result in a steady increase in jointly-owned generation facilities.

VIII RECOMMENDATIONS TO THE COMMISSION

1. Initiate a rulemaking to consider utilization of a procedure that would, with appropriate periodic Commission review, permit an electric utility to put into effect a cost of service rate format for wholesale service that would automatically adjust rates to reflect changes in all costs allocated to such wholesale service. This would shorten the regulatory lag, and avoid "pancaking" of rate increases while still protecting the customers' interest, and the time saved and could be better utilized by the Commission to assure that utility operations and decisions are in the public interest and designed to keep costs to the consumer at a minimum.

2. Although the Commission has expressed its concern for energy conservation and management of electricity shortages through Orders 495 and 496 and 445, a more complete utility conservation reporting program should be initiated and other appropriate measures taken for the curtailment of electric power should it be necessary if regional capacity or energy shortages develop in the future.

3. Consider additional steps that can be taken, including legislative recommendations, to further the efforts of the Commission to create additional power pools and centralize electric power dispatch facilities to improve reliability, reduce reserve margin capacity, and optimize economical operation.

4. Take such steps as may be necessary, including legislation recommendations, to promote and effect the formation of Regional Energy Boards to coordinate and accelerate siting and licensing approval and the resolution of other electric energy supply matters which are best addressed on a regional basis. Also, encourage more active Federal/State participation in connection with the Regional Council activities and to encourage more timely multi-State participation in the regional power planning process.

5. Take additional steps that may be necessary and desirable to reinforce previous Commission efforts to bring about interconnections among regions having inadequate or nonexistent ties to improve reliability and provide for emergency and economy energy transfers.

6. Seek legislation to permit the Commission to order wheeling of electric power on its own motion, with authority to specify the economic and financial terms for the service provided.

7. Support amendment of the TVA Act to remove limitations on interconnections with adjacent systems for the purpose of improving reliability.

8. In cooperation with NERC reconsider the boundaries and reporting practices of Regional Councils with the expectation that some reorganization in regions may be appropriate. Such changes would permit the collection of more meaningful information relative to regional power supply requirements.

FEDERAL POWER COMMISSION

SUPPLEMENT TO STAFF REPORT
ON
JULY 13-14, 1977

ELECTRIC SYSTEM DISTURBANCE ON THE CONSOLIDATED EDISON COMPANY OF NEW YORK, INC., SYSTEM

 AUGUST 4, 1977

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CHAPTER I

HOW ELECTRIC POWER SYSTEMS ARE PLANNED AND OPERATED

The smooth and efficient functioning of modern day society is totally dependent on the constant availability of adequate supplies of electricity. For it to be available, a great deal of planning, investment, construction and other work must take place almost continuously in addition to the daily operation of the electric supply system. The major elements of this preparatory work are discussed below.

1. GENERATION

Generating facilities convert the potential energy of fuel, falling water, radioactive material or other sources, into energy in electrical form. Generators may be driven by steam turbines, combustion-gas turbines, water turbines, diesel engines, wind or tide. Whatever the type of fuel or type of generator, in the aggregate all the generators of a system comprise the system's "generating capacity". Generating capacity provides the force that drives electricity through the power system.

Generating capacity is needed to supply customer requirements for electricity. The rate of production and use of electricity is normally expressed in kilowatts or megawatts. It is common practice to integrate (sum up) the energy produced and used over a period of 15 minutes, 30 minutes or one hour and express the result, in kilowatt-hours or megawatt-hours, as the system "demand". The largest of these integrated demands is the system "peak load" for the period studied (a day, a week, a month, a year, a summer period, a winter period). For many systems, including Consolidated Edison Company, the greatest use of electricity occurs during the summer months. Whenever the annual peak demand occurs, generating capacity must be available to supply it. In other words, a sufficient number of generators must be in operation to supply energy at the greatest rate required by the customers.

The amount of generating capacity that a power supply system should have, in order to provide reliable service, has long been one of the central problems of system planning. Forecasts of demand are the starting point for capacity determination. Such estimates are not easy to make, with accuracy, for a number of reasons.

However, the topic of load forecasting is an entire field in itself and will not be treated here. 1/

Given the pattern of electricity requirements, planning engineers determine the corresponding generating capacity needs. Many factors must be carefully considered and their effects integrated.

One key factor - load - will vary geographically and in time, in each utility system service area. Like other elements of a power system, load is a multi-dimensional entity. For a given system, the load at any specified time is different in different areas of the system, and varies from hour to hour.

Electric power demands on a system result from the individual actions of all the customers. A light turned on, a refrigerator started or stopped, an electric arc furnace in operation, an air conditioning system operating, all these and many other devices combine to produce the system demand at any instant. Although the demands of the individual customers are not intentionally coordinated, the combined demands fall into well-defined patterns. The patterns vary from city to city, from region to region, but have some general characteristics in common. Daily loads are usually high in the afternoon and early evening, low during the late night and early morning hours. In some areas at some times of the year, there may be two high demand intervals during the day, with a low load interval between. The magnitude of the daily variation is different for each day, and it also changes with the season. Figure 1 shows the daily load variation, hour by hour, for Consolidated Edison Company of New York, for the week of August 1-7, 1976, to illustrate this fact. It shows very effectively the requirement that system capacity must meet a wide range of variation in customer demands. Figure 2 shows the hourly loads of Figure 1 rearranged in order of magnitude, as a "load duration" curve. From Figure 2 it can be seen that the minimum load during the week was 40 percent of the maximum load. The patterns of Figure 1 and Figure 2, and similar ones for other weeks, are important characteristics of the demand placed upon the system's generating units. They show that much of the capacity is not needed at times, but must be available for use at other times. The curves indicate the magnitude of "base load" capacity needed, and the amount of "peaking capacity" required for this particular period.

1/ A useful source document on electric load forecasting is "The Methodology of Load Forecasting", A Technical Advisory Committee Report to the Federal Power Commission, published in Part IV of the FPC's 1970 National Power Survey.

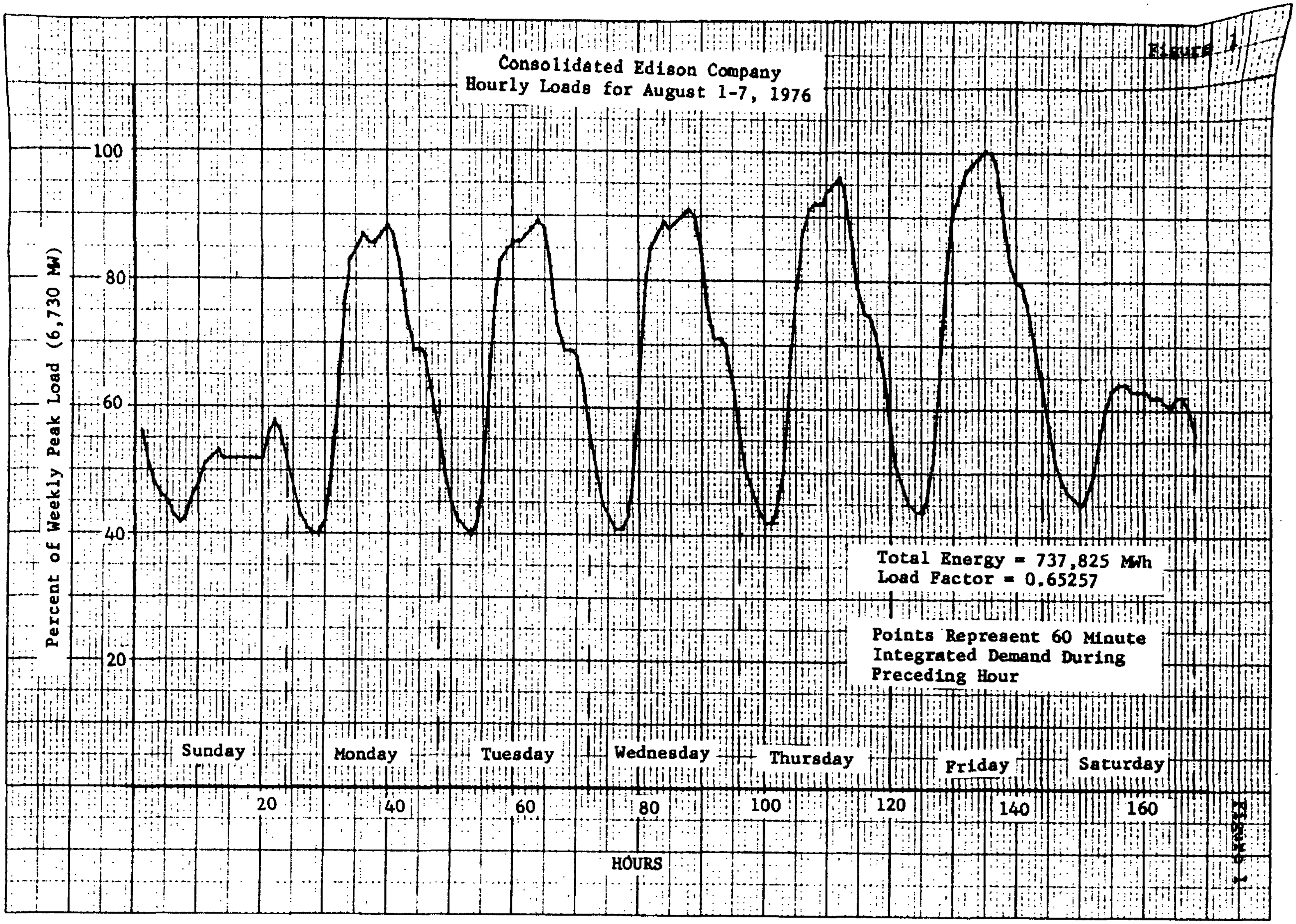
Figure 1
Consolidated Edison Company
Hourly Loads for August 1-7, 1976
Percent of Weekly Peak Load (6,730 MW)
100
80
60
40
20
Total Energy = 737,825 MWh
Load Factor = 0.65257
Points Represent 60 Minute
Integrated Demand During
Preceding Hour
Sunday
Monday
Tuesday
Wednesday
Thursday
Friday
Saturday
20
40
60
80
100
120
140
160
HOURS

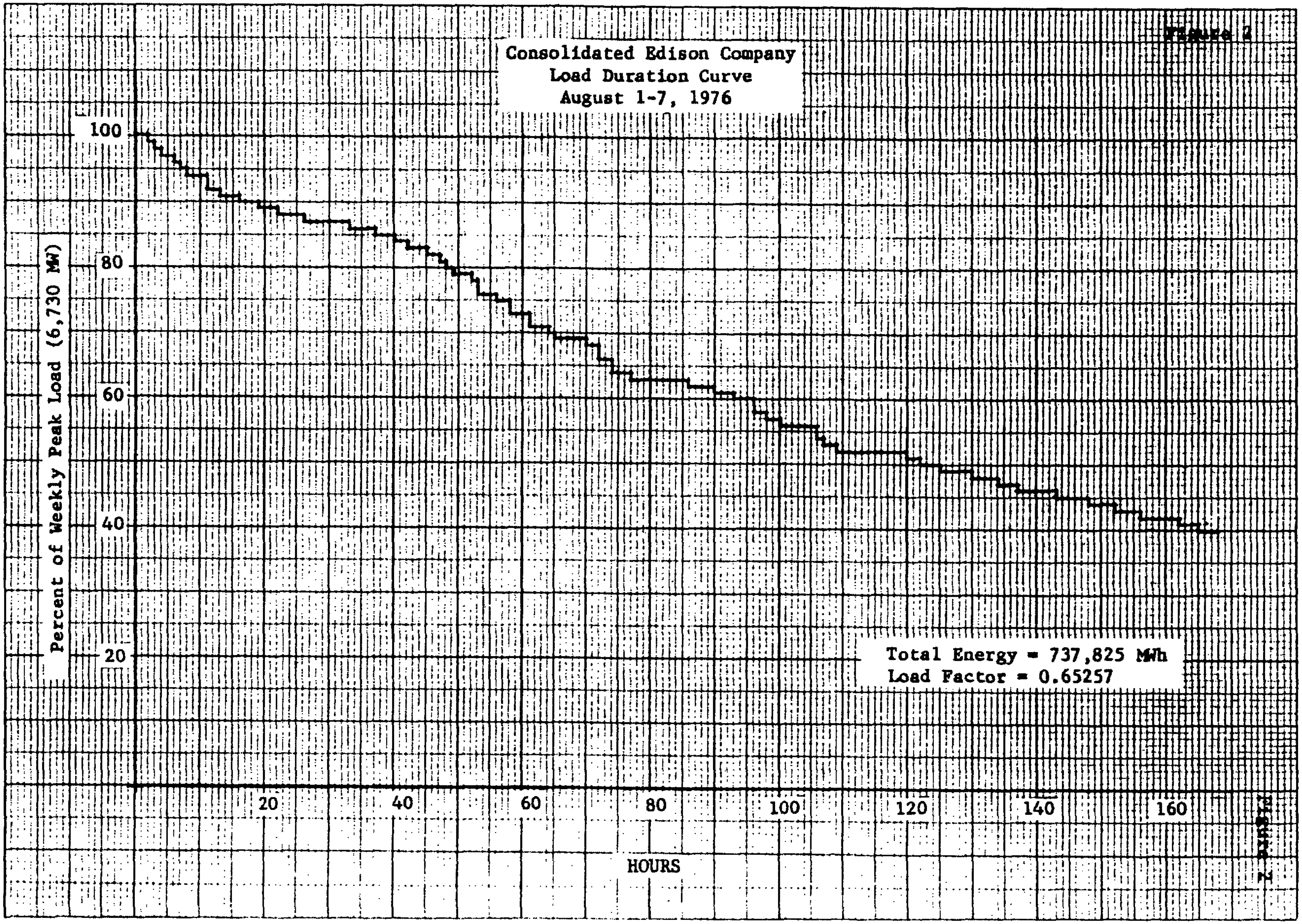
Figure 2
Consolidated Edison Company
Load Duration Curve
August 1-7, 1976
Percent of Weekly Peak Load (6,730 MW)
100
80
60
40
20
20
40
60
80
100
120
140
160
HOURS
Total Energy = 737,825 MWh
Load Factor = 0.65257
Figure 2

"Base load" generating capacity is that which is needed constantly throughout the year to meet minimum loads. If generators were perfect, and never failed, the generating capacity needed for "base load" would be just that which met the minimum demand. However, generating facilities do fail and do require repairs and maintenance and, thus, cannot run steadily for indefinite periods of time. From 5,000 to 7,000 hours of operation in a year is considered a reasonable running time for base load generators. As some are taken out of service for various reasons, others must be put "on line". One facet of prudent planning is a continuous effort to balance the need for a sufficiency of base load capacity against the need to avoid excessive investment in temporarily non-productive facilities.

Of course, "base load" is only one part of customer demands. As shown by Figures 1 and 2, demand increases over base load to some "peak demand" value. As load increases, additional generating capacity must be operative to supply the load. Part of this additional capacity can come from the unused portion of base load generating capacity. But when a base load unit is fully loaded, the system operator must decide how to meet further increases in load. As discussed elsewhere, some power may be purchased from neighboring systems but the system must be prepared to provide its share. To put on line a large base load unit is a complex, expensive and time-consuming process. If it is to run only for a short time (four to six hours as shown by the upper portions of the daily curves in Figure 1) the process would be uneconomical. Therefore, the system planner provides "cycling capacity" and "peaking capacity" for the system operator to use. "Cycling units" may run some 8 to 14 hours a day, to meet loads above the base load level. Peaking units are those designed for rapid inexpensive start-up and shutdown, and may run some 3 to 6 hours a day. In planning for generating capacity, consideration must be given to the "mix" of units in terms of base-load, cycling and peaking, if system operating costs are to be kept low.

In choosing the "mix",the planner has choices in each range. Base load units may be fired by coal or fueled by nuclear power. Currently, the use of natural gas as a utility fuel for projected units is no longer possible and the use of oil leads to expenses that may not be easily controllable under current conditions. Hydro energy can only be utilized where the terrain is suitable and water plentiful. Combustion-gas turbines have much shorter lead times than steam units but require oil or natural gas as a fuel and do not come in the 1,000 MW sizes of base load units. A further choice is the "combined-cycle plant" on which the exhaust heat of one or more combustion turbine units makes steam for one or more steam units. Table 1 summarizes the major factors that system planning engineers must evaluate in decisions regarding new capacity.

TABLE 1

Major Characteristics of Generating Units

(All Values in Table Are Approximate)

CHARACTERISTIC	STEAM UNITS: Fossil Fuel	STEAM UNITS: Nuclear Fuel	HYDROELECTRIC UNITS: Conventional	HYDROELECTRIC UNITS: Pumped Storage	Combustion Turbines	Combined Cycle Plant
Lead Time	8-10 yrs.	11-12 yrs.	8-10 yrs.	8-10 yrs.	3 yrs.	7 yrs.
Energy Source						
Coal	Yes	--	--	--	No	Possibly
Oil	Yes	--	--	--	Yes	Yes
Natural Gas	Yes	--	--	--	Yes	Yes
Nuclear	--	Yes	--	--	--	--
Water	--	--	Yes	Yes	--	--
Water for Cooling	Large Amount	Large Amount	--	--	Very Little	Some
Suitable for Base Load	Yes	Yes	Depends on Geography	No	No	No
Suitable for Cycling	Special Design	No	Depends on Geography	No	No	Yes
Suitable for Peaking	No	No	Depends on Geography	Yes	Yes	Yes
Largest Size	1,300 MW	1,300 MW	Depends on Geography (700 MW)	Depends on Geography (300 MW)	80 MW	Not Well Established (500 MW)
Cooling Towers Needed	Probably	Probably	No	No	No	Possibly
Construction Cost	High	Highest	Probably Less Than For Fossil Steam		Lowest	Intermediate
Reliability	Less Than Conventional Hydro	Less Than Fossil	Highest	Less Than Conventional Hydro	Lowest	Not Well Established
Startup Time in Normal Use	Long	Long	Rapid	Rapid	Rapid	Rapid for Part Load
Refueling Time	0	7 wks. per year, average	0	0	0	0
Complexity of Maintenance	High	High	Low	Low	Average	High
Operating Cost	Higher Than Nuclear, But Less Than Combustion Turbine	Low	Very Low	Very Low	High	High
Scrubbers Needed	Probably	No	No	No	No	No

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In addition to, and in the process of, determining the type of units needed, the planner must determine "how many" and "how big". The number and size of units, and their location, is a critical factor in system cost and reliability. There are a variety of methods for determining how much capacity is needed. Probability analysis, first applied in the 1930's,has come to occupy an important place in planning activities.

Capacity planning must project into the future a view of the characteristics shown in Table 1 (among other factors) and has to estimate how those characteristics may change. Capacity planning, looking to the operating problems, must determine the relative advantages of several small units, brought on-line one at a time to meet increasing daily load and then shut down as loads decrease, as compared with a few large units that would continue to operate, but at part load, as demands decrease. Investment costs and operating costs are involved in the determination, as well as the reliability aspects of a few larger units versus many smaller ones. Also to be considered are the effects on the units themselves of operation at part load versus frequent start-up and shutdown. The daily and seasonal load patterns, although primarily a concern of the system operator, must be factored into the planning of the system.

Generating capacity reliability is usually discussed in terms of sufficiency of capacity to meet total peak demand, the frequency and duration of situations in which capacity is less than demand and the ability to supply energy requirements over an extended period. In the past, it was the practice to provide capacity sufficient to supply the estimated peak demand plus an additional amount equal to some percentage of the peak demand or equal to the largest generating unit (or largest two units.) The total capacity then exceeded the projected greatest requirement by an amount that was supposed to allow for generator failures, for over- or under-estimating the load forecast, for extended maintenance work or for unknown factors. In an attempt to develop procedures more rational than rule-of-thumb methods, the power industry began to use probability analysis to compute the capacity needed. Consolidated Edison Company was one of the earliest systems to apply probability analysis to generating capacity studies.

Probability methods have now been developed to the point where many systems use them to factor into capacity planning relevant information as to load patterns, number and size of generating units, reliability of individual units, delays of unit construction. Probability analysis, in addition to furnishing quantitative results concerning system capacity levels to be expected, allows the planning engineer to determine as closely as possible the capacity needed to satisfy specified levels of reliability related to the frequency and duration of outages, the probability of outages, the probability of positive margin, the probability of energy deficiences anf the probabilities of various levels of capacity shortages. The operations engineer uses probability analysis to optimize operating reserve and its allocation between spinning and non-spinning components.

An example of the results of probability analysis is shown in Table 2, taken from a report of the New York Power Pool.

TABLE 2

New York Power Pool
Reliability - Reserve Relationships 1/

Member Reserve %	Pool Reserve %	Loss-of-Load Probability	5% Voltage Reduction	Customer Disconnections
		Days Per Year (Average		
12	16	6	65	.3 to 1.1
14	18	2	27	.07 to 0.3
16	20	0.8	8	.02 to 0.1
17	21	0.3	4	.007 to 0.04
18	22	0.13	2	.002 to 0.01
20	24	0.035	0.6	.003 to 0.0025
22	26	0.011	0.3	.00006 to 0.0006

1/ From 1976 New York Power Pool Report to New York Public Service Commission under Article VIII, Section 49-b of the New York Public Service Law.

However, and the reader must be cautioned strongly, the analyses represent only models of the system. The inputs into the studies are estimated loads, expected generation outputs, planned maintenance schedules, average experienced forced outage rates obtained under conditions that can never be exactly duplicated. The probability that all of the inputs will simultaneously exist at their assigned values is of a very low order indeed. This means that the analyses are valid as models only, and that the results are to be regarded only as indices of relative performance. In reality, this is what the planner desires: the relative benefits of one choice over another.

In developing the schedule of generating units to be constructed, the planner must consider them individually. It is not sufficient to talk in terms of total system capacity. The planning process requires addition (or retirement) of individual units. A unit must be selected of a certain size and type in order for the probabilistic method to function. On large 1,000 MW unit will have a different effect on reliability than two 500 MW units, and the effects of unit size will be related to system size. Studies of the relationship between maximum unit size and system size indicate that the largest unit should ordinarily be in the range of 4% to 10% of the system size. Consolidated Edison's largest unit, Ravenswood No. 3, with a net summer capability of 972 MW, is 9.8 percent of Consolidated Edison's total generating capability 2/ (summer rating). However in the New York Power Pool, which operates as a single control area, the unit is only 3.3% of the total NYPP generating capacity.

The reliability will again be different if the units are fired by coal or oil or gas, or if they are nuclear or hydroelectric. Each size and type of unit has a different reliability associated with it and requires different maintenance activities. Therefore, the availability patterns of units of different types differ. For instance, the power output reliability of four 200 MW hydro units is greater than that of four 200 MW coal-fired units. For instance, had the 2,000 MW of peaking capacity planned by Consolidated Edison for Cornwall (Storm King) been available, the loss of Ravenswood 3 should not have been so damaging to the system. But the energy reliability of the coal units may be greater than that of the hydro units, because coal may be readily available and water may be available only during certain seasons of the year. The Cornwall installation was planned to be peaking capacity, and therefore would not be expected to provide power continuously day after day. However, its projected function as peaking and emergency supply would have been valuable in the instance under consideration. The reliability of the total generating capacity supply is a composite of many factors: number and size of units; type of units; types and sources of fuel for fossil fuel units; availability of nuclear fuel; capacity available from interconnected systems; contractual obligations to supply capacity to interconnected systems; competence of operating and maintenance personnel; age of the system's generating units, their locations on the system, the "mix" of base load and peaking units.

2. TRANSMISSION

Transmission lines connect the loads to the system, connect generating plants together, provide pathways for energy to move from the generating plant to points near the user. Transmission refers to movement of electric power and energy in bulk. At points on the transmission system, power is taken out and sub-

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2/ As reported in the April 1, 1977 Response by NPCC to FPC Order 383-4.

divided for movement on the subtransmission and/or distribution system. Transmission lines have several functions:

1. Bring power from generating plant to areas where power is needed.

2. Connect power plants together for greater reliability of supply.

3. Connect substations together for greater reliability of supply.

4. Increase transfer capability and voltage control flexibility.

5. Improve system stability, to minimize the effects of "surges" of current, voltage and frequency, thereby preventing loss of synchronism between generators and consequent "black outs".

6. Connect systems together for sharing of reserve capacity, for emergency transfers of power, for sales of capacity.

7. Connect systems together to allow construction of jointly-owned generating units.

Transmission circuits may be constructed at various voltage levels from 69 kilovolts to 765 kilovolts. The advantage of the higher voltages is that transmission capacity increases nearly as the square of the voltage. Table 3 shows typical average overhead transmission line capacity for various voltage levels. Transmission may also be accomplished by means of underground cable, at voltages up to 500 kV.

TABLE 3

Typical Overhead Transmission Line Capacity
At Various Voltage Levels

Voltage, kV	MW Capacity 1/
115-138	100---120 2/
230	350
345	800-1,200 2/
500	2,700-2,900
765	5,700

1/ Will vary according to length of line, nature of the facilities and systems at each end, weather conditions and load pattern, among other things. Stability and overload probability may limit usable line capacity. Operating conditions frequently may restrict ability to transmit.

2/ Consolidated Edison's transmission is 138 kV and 345 kV and much of it is underground cable, which usually has less capacity than overhead lines at the same voltage.

Reliability evaluation is much more complex for transmission facilities than it is for generating capacity. The reason for this is structural and inheres in the nature of transmission. Generating units can be considered as point sources of power, whose capacities can be added to obtain a total capacity that can be matched against total system load. Transmission lines, however, cannot be treated in this fashion. Lines connect specific points, line capacities are not additive in general, and lines perform several functions. A generating plant has the sole function of providing capacity and energy to the system. Transmission lines perform many functions as indicated above.

A transmission line is added to a system for one or more of the reasons discussed. In some instances, it may be possible to accomplish the major function of the line by other means. Stability improvement, for instance, may be effected by means of fast valving 3/ or by an additional transmission line, in some

3/ An operating procedure which interrupts steam flow to a turbine momentarily in the event of a system disturbance. This type of operation requires appropriate design to be incorporated in the unit.

cases. Then, a decision must be made as to which option should be implemented. Economics will affect the decision but other factors will play a part: the effects on system operating practices, on reliability, on power transfer capacity, on stability, on future expansion of the system.

A transmission line (overhead or underground) must be designed with a number of factors in mind. The major functions must be performed, without undue effect on other necessary functions. It must be reliably designed for the terrain it will traverse -- possibly a mile or less to several hundred miles. Wind forces, icing conditions, river crossings, soil conditions, lightning storm intensity and frequency all play a part in the design decision for the tower design, conductors, tower spacing, and other details.

In New York City, much of the transmission is by underground cable. System planning and design are significantly different for cable networks than for overhead line networks. The physical parameters (resistance, inductance and capacitance) are significantly different and cable behavior, operation and maintenance methods differ greatly from those factors for overhead lines. For instance, an overhead line fault can be located relatively quickly, cleared and the line can go back in service. Cable faults take longer to locate and repair. Cables require pumps to maintain oil or gas pressure for cooling and insulating purposes. If the pumps fail, the pressures must be built up again carefully, and tested, before the cable can be re-energized.

Expected carrying capacity and voltage level affect choice of conductor sizes. Normal power flow as well as possible emergency or abnormal power flows must be considered in the choice of conductors and other components. The protective relaying system must be designed to function properly under various possible operating conditions, must retain stability of system operation and must provide protection against overloads. The reliability analysis of supply to lines moving power out of substations to the loads must take account of all the lines feeding the substation, their originating points, voltage levels, lengths, terrain traversed, and the weather expected. The configuration of connections among lines, switching equipment and transformers within the substation must also be factored into the study. Reliability analysis of transmission is both a system and a point-by-point affair that must look at every station supplying load to customers and take into account every connection between stations. System planning usually provides alternative and supplementary paths for flow of power from generating plants to substations, between substations and between utilities.

In the planning of transmission facilities, detailed attention must be paid to the physical constraints and environment. Much attention is paid by utilities to routing of transmission lines and much effort is expended in preparation of testimony when legal proceedings are initiated against proposed rights-of-way.

For the transmission lines, the environment and the physical conditions can be very much different in different parts of a utility's service area. These differences must be reflected in the physical characteristics of the line or cable which in turn may affect the electrical characteristics.

Besides the reliability of each transmission line as a single component of a system, it is necessary to consider the interactions among lines and generating plants. To give an extreme example, a single television set turned on or off will affect the current flows, voltage levels and frequency of all transmission lines and generating units associated with the system to which the TV set is connected. Of course, the effect of a single TV set is well below the sensing threshold of any devices now in use, and its effect is too small to be noticeable. But the point is that every device that draws power from a system affects the entire system in some degree. The summation of all load changes from instant to instant is reflected in redistribution of power flows over an entire system and in redistribution of power generated by all plants. Mismatches between generation and load cause frequency and voltage fluctuations as the system adjusts. Power production at plants can be controlled, by automatic or manual means, to match changes in load. Power flow over individual transmission lines cannot readily be controlled without the installation of special equipment. Of course each item of equipment introduces some probability of unreliable operation, requires maintenance, and increases the investment cost.

The establishment of an electric power interconnection must be evaluated from an economic point of view. This economic criterion will require that an interconnecting transmission facility serve several purposes. As the number of interconnections increase, there will normally be relative increases in the electric power transfer capability. However, it must be understood that increases in interconnecting facilities will make it necessary to strengthen the internal transmission systems of the interconnecting utilities.

More than 21 transmission lines interconnect systems in New York State and systems in Pennsylvania, New Jersey, Connecticut, Vermont and Massachusetts. By means of these interconnections and those with the Canadian power system (over 16 lines connect New York State with the Canadian power system) more than 5,000 MW can be moved into New York State under the appropriate conditions.

Electric energy flow in an alternating current network is a function of the electrical parameters of the involved electrical facilities and the operating situation at any time. The relative location of load to generation and the impedance of the connecting electric network are the significant factors. In some cases, special equipment installations such as phase shifting transformers, transformers whose voltage ratings can be changed under load, and current limiting reactors are required to assure proper performance of the electrical facilities.

The construction of power system interconnections in the New York City area has been limited by technical, economic and geographic considerations. The island geography of much of the New York City area and the presence of the Atlantic Ocean as a boundary limit the possible bulk power supply interconnections to the area. Interconnections from New Jersey to New York City proper must cross over or under water. Underwater cable crossings are very expensive and their relatively low impedance presents technical problems. The insulated nature of an underwater crossing limits circuit capability to a value less than that of overhead lines of the same voltage. If the capability is exceeded cable damage and subsequent failure can be expected. Repair of cable circuits is a lengthy and costly operation. Overhead lines can be loaded much more heavily than cables since the excess heat caused by the higher current flow is dissipated directly to the atmosphere, and repairs are less costly.

On July 13, 1977, the New York City area was interconnected with the Public Service Electric and Gas Company through one 230 kV overhead line from Linden Power Plant in New Jersey to Goethals Substation located on Staten Island. A 345 kV underwater cable from Farragut Substation in Brooklyn to Hudson Power Station in New Jersey was not in service due to failure of a phase shifting transformer at the Farragut Substation. This interconnection cannot be utilized unless the phase shifting transformer is operable. This transformer, originally scheduled for initial service in May 1972, was damaged during installation and was returned to the manufacturer for repair. Initial service occurred in December 1972. Other troubles were experienced with this transformer during the intervening period until September 1976, when the transformer failed in service. A new transformer has been ordered.

Two 138 kV transmission lines from Consolidated Edison's Jamaica Substation in Queens to the Valley Stream Substation of Long Island Lighting Company (LILCO) serve to interconnect these two utilities. LILCO has one 138 kV cable interconnection under Long Island Sound to Norwalk Harbor in Connecticut, but the power import capability of this facility is very limited.

Other than the previously described interconnections and local generating resources, all other electricity supply to New York City must come from transmission lines that originate north of the City. Consolidated Edison owns most of the bulk power transmission facilities in Westchester County. The Hudson River provides a formidable barrier to transmission line crossings. Therefore, the nearest crossings of the Hudson other than the Farragut cable are located in the vicinity of Indian Point Power

Station. Two 345 kV lines from Buchanan Substation near Indian Point extend to Ramapo Substation, which in turn is connected to Public Service Electric and Gas Company by a 500 kV line and a 345 kV line. Electricity imported through these interconnections must flow north to Buchanan Substation, if it is to be utilized by Consolidated Edison.

Current operating studies indicate that the Southeastern New York Area (SENY) can import over 1,200 MW from New Jersey. However the one in-service interconnection from New York City proper to New Jersey had no back-up, hence, the 600-700 MW power transfer capability of the Linden-Goethals circuit (included in the 1,200 MW total), could not be considered reliable. Therefore, the loss of the five in-system Consolidated Edison 345 kV transmission lines to the north severely limited the New York City area power import capability.

3. DISTRIBUTION

Distribution facilities are the portion of the electric system closest to the customer, and in the final analysis are individual to the customer. A generating unit provides power to the entire system, for use by all customers. Transmission facilities move power between areas or to a specific area. The distribution system moves power from a point on the transmission system to specific users of electricity. For this reason, a lower level of reliability can be tolerated in distribution facilities than in other parts of the system, since failures affect only a small number of customers, whereas failures in generation and transmission affect large numbers of customers. Construction of distribution facilities generally is timed to coincide as nearly as possible with growth of load. Long-range planning is usually not required for construction of distribution facilities to the same extent that it is required for large generating units and transmission lines. Distribution circuits and equipment are individually much less costly than generating units and transmission facilities, they have shorter lead times for construction, and can generally be repaired or replaced much more rapidly. On the other hand, the number of distribution circuits and facilities is much greater than the number of generating plants and transmission facilities, and offers more widespread (geographically) occasions for failures and undesirable performance.

The design of the distribution system can have a significant effect upon the ability of a system to maintain service in an emergency. System design that permits rapid dropping (and restoration) of relatively small groups of customers, under control of the load dispatcher, can help in cases where load exceeds generating capability. If customer load can only be interrupted in relatively large blocks, "blackouts" will occur over wide areas and restoration of service will be slower. Underground facilities, while they may improve the scenic environment, may require much longer time, and more effort, to repair when faults occur. In congested central city areas, such as much of Manhattan Island and other parts of New York, distribution facilities are required to go underground. Maintenance, repairs and upgrading (to meet increased loads) therefore become more costly and difficult.

Distribution circuits are most easily and least expensively laid out when geography is the only determinant. That is, loads near to each other will be served by the same circuit. Considerations of public safety on the other hand, if the sole determinant, would dictate that completely separate circuits be provided for hsopitals, water pumping stations, fire and police systems, traffic lights and other municipal purposes. Distribution systems planners must always keep costs in mind when extending or rebuilding a system. As areas change in population density, type of housing, type of commercial establishment and industry, the distribution system is also required to change. And, as the loads served by the distribution system shift from one area to another, changing in magnitude and pattern, the transmission facilities may also require modification.

4. THE RELATIVE IMPORTANCE OF GENERATION, TRANSMISSION AND DISTRIBUTION TO THE SYSTEM AND THE CUSTOMERS

The reliability of service experienced by the customers of an electric supply system is the composite result of the reliability of generation, transmission and distribution and includes the effects of maintenance and operation. There is no simple way to express quantitatively the reliability of service to a specified customer or group of customers. The reliability must take into account the reliability of capacity supply, of transmission supply to the bus from which the customer's distribution is fed, and of the distribution facilities up to the customer's service entrance. An indication of the complexity of the study required is the following list of information needed to determine the quality of service at a specified load bus. 4/ 5/

4/ Transmission Planning Using a Reliability Criterion, Part I -- A Reliability Criterion. Billinton, Bhavaraju, IEEE Transactions on Power Apparatus & Systems, January 1970, Vol. PAS-89, No. 1, pp. 28-34.

5/ A Method for Calculating Transmission System Reliability. Mallard, Thomas, IEEE Transactions on Power Apparatus & Systems, March 1968, Vol. OAS-87, No. 3, pp. 824-834.

1. Several load flow studies at different load levels, taking into account possible system component outages.

2. Allowable voltage limits at all busses.

3. Reactive power limits at generating busses.

4. Maximum current carrying capability of all lines and transformers.

5. Distribution of system load at various busses and the load duration curves.

6. The output of each generating plant at each of the load levels studied.

7. The failure and repair rates of the generating units, lines and transformers in the system.

8. Diagrams showing direct transmission paths to the specified bus and giving forced outage and scheduled outage data for all components in each path (lines, cables, transformers, circuit breakers, etc.)

9. Analysis of possible overload conditions.

10. Stability analysis for different fault conditions.

In view of the inter-relationships among generating capacity, transmission facilities and distribution facilities, the assignment of relative importance to these system components may not be appropriate. Surely, perfection in the transmission part of the system is useless if the generating capacity is totally inadequate, and thoroughly adequate generating capacity is of no value if the transmission or distribution facilities continually fail. Similarly, if distribution equipment all over the system never operates properly, the most perfect generating and transmission facilities are useless. An electric power supply system must operate as a whole, as an entire system, in order to fulfill its mission.

5. THE COSTS INVOLVED IN IMPROVING RELIABILITY; THE BENEFITS OBTAINED

The costs involved in obtaining improved performance of a system will be in some measure related to the degree of improvement desired. The costs will also be a function of the area in which improvement is sought. As one example, improved materials can improve power plant reliability: materials with greater resistance to wear, abrasion, corrosion, temperature and temperature changes would make more reliable such items as boilers, coal handling and pulverizing equipment, fans, burners, gas turbine and steam turbine blading. Steam plant condensers could be made more reliable and would require less maintenance if better means of reducing or preventing corrosion could be developed. Means of reducing the effect of polluted atmospheres on transmission line insulators and components would improve transmission reliability. More attention to design and layout of plant components and of transmission facilities might reduce the effect of equipment outages on reliability of supply. Research into the theory of system operation and control might lead to better methods of operating power systems, better in terms of reliability and possibly lower in terms of cost.

Since generating units serve the entire system, improvements in this area would affect the reliability at all levels. It would therefore appear that investment in generating plant reliability improvement could be justified to a higher level of cost than investment in transmission or distribution reliability improvement. Similarly, it would appear justifiable to invest more funds in the improvement of transmission reliability than in the improvement of distribution system reliability. At all events, it must be recognized that the incremental benefits obtained from reliability expenditures decrease as the level of reliability increases.

It is also necessary to recognize the practical factors that prevent immediate adoption of an improvement by the entire electric power industry. For instance, if new materials were to be discovered January 1, 1977 for use in coal pulverizers, that would significantly increase the reliability of these devices, complete change-over to such materials by February 1, 1977 would be a practical impossibility. It would in fact, require years and, in many cases, would never be practical.

New procedures, materials and devices must be carefully examined and tested before being adopted, and the economic balances among investment cost, operating cost, efficiency and reliability require considered evaluation.

6. FREQUENCY AND VOLTAGE

Frequency in discussions of electric power supply refers to the frequency of alternations of the current and voltage in the usual alternating-current (ac) system. In the United States, alternating current systems operate on a frequency of 60 cycles per second. Direct current systems have some characteristics that are desirable, but voltage cannot be transformed as easily as can be done for ac systems.

The frequency of the current and voltage produced by a generator depends on the rotational speed of the unit and the number of "poles" of the "field" winding. Large generators are designed with 2 or 4 poles, for operation at 3,600 or 1,800 revolutions per minute. When a generator rotates at a speed different from its design speed, the frequency of the current it delivers will differ from 60 cycles per second. The difference between the output of a generator and the load assigned to it by conditions will cause fluctuations in current, voltage and power on the system. As a generator slows down or speeds up, the timing of its currents with respect to the timing of the currents produced by other generators will change; this situation is known as a "phase angle shift". Within small limits, generator phase angles can and do change. But large sudden changes in a phase angle, which may be caused by a sudden load, short-circuit, failure of a generator or other reason, cause large oscillations in currents, voltages and power on a system. These conditions may cause automatic devices (relays and circuit breakers) to operate and disconnect some lines or generating units. These disconnections are designed to protect equipment from harm due to excess current and voltage. However, the effect on the system may be to intensify the disturbance to voltage, power and frequency, and cause additional disconnections.

This is an instance of the need for careful attention to design of system protective schemes, which generally require judgmental balancing of actions whose effects may be in opposition. Systems now use automatic devices (relays and circuit breakers) to disconnect some loads when frequency begins to drop excessively. 6/ The purpose is to prevent local overloads on generators, that would slow them down and further deteriorate the situation. Manual "load shedding" may also be implemented when necessary, the objective being to maintain load and generation in balance at all times in any area whose tie lines to other areas have opened. Frequency is controlled solely by the speed of the system generators, which in turn is a function of system loads and power input from fuel (or hydro power). In normal operation, additional load on a generator causes it to slow down slightly, the speed decrease activates fuel supply devices to increase the fuel fed in, and the machine speed (and frequency) return to normal. A decrease in load works in the opposite direction.

The voltage output of a generator depends upon the frequency and upon the operation of auxiliary devices that provide direct current to the "field winding". The voltages at different locations in the transmission system are a function of the voltages of the generators, transformers, transmission line characteristics and system loads. When a "short circuit" occurs, the voltage at the point of fault may go to zero, and large currents will flow, fed by the various generators on the system. The protective devices

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6/ Another section of this report contains a discussion of NPCC "load shedding" practices.

of the system operate to disconnect the faulty element (line, transformer or other device), so as to prevent the high currents from damaging anything. Although voltage at the generating plants is maintained at a fairly constant level by automatic devices, voltages at transmission substations will fluctuate somewhat as loads fluctuate. Voltage at the customer's level will fluctuate even more. A number of states have established allowable ranges of voltage variation at the customer level; 8 volts (from 114 volts to 122 volts) appears to be an average allowable range.

The opening and closing of circuit breakers, lightning strokes, sudden large changes in load, or other occurrences, may cause "transient" voltage waves in a system. The magnitude of the voltage depends on the circuit conditions and the initiating cause. Normally the transient condition causes no harm and dies out rapidly. The peak of the voltage wave, however, if excessively high, could puncture insulation or "flash over" an air gap, cause heavy currents to flow and trigger the operation of automatic safety devices as discussed above. The resultant effect on the system is a function of conditions immediately prior to the disturbance: Load magnitudes and distribution, generators on line and the loads they were carrying, transmission circuits in service and their loads. Cable circuits because of their large capacitance may offer more potential for problems due to transient voltages in normal switching. When cable circuits are re-energized after being disconnected by the opening of circuit breakers, care must be exercised to assure that the insulating oil or gas pressure is normal. If, as in the case of Consolidated Edison, power failures have caused pumps to stop, the entire pumping sequence must be initiated and all pressure throughout the entire length of a cable must be restored before it can be re-energized. Pressure must also be restored (and monitored) at cable "potheads" (terminations and connections to other devices) before re-energization.

7. INTERCONNECTION

Interconnection among electric power systems has grown since the inception of central station utilities. Interconnection of two systems provides benefits to each, but also imposes responsibilities.

An interconnection between two utilities may be in the form of joint connection to a single bus, a transmission line, or several connections of either or both types. When two systems are joined by a single line, power flow over the line can be controlled to a specified value. When the systems are joined at more than one point, the total power flow can be controlled but generally not the flow over any one line (unless expensive equipment is installed).

The reasons for interconnection are many, as discussed above under Transmission. The effect of an interconnection between two equally reliable systems is to improve the overall joint reliability and reduce the overall operating cost. Of course, before an interconnection is constructed, the utilities involved must agree as to the terms and conditions of construction and operation. Utilities which depend on privately invested funds, and customer revenues, for financing system expansion, must review very carefully the economics of any planned item of construction. Interconnections among several systems generally strengthen each member of the group in some way. Currently the electric systems of 39 states east of the Rockies (including a portion of Texas) are interconnected to a significant degree. And, these systems become more strongly interconnected each year, as new lines are built.

An interconnection between two utilities requires that each assume specified responsibilities. These may be no more than an agreement to maintain the interconnecting facilities in good condition, or to exchange small amounts of power or energy, or they may extend to sharing of reserves, extensive agreements to coordinate planning, and operation of both systems from a single control center.

Consolidated Edison is a member of the New York Power Pool, which consists of the major New York State electric utilities. These systems have a number of interconnections among them, and with utilities in other states and in Canada, and have agreed to assume many joint responsibilities for supplying adequate electric power in New York State. The Pool is further discussed in other sections of this report.

CHAPTER II

THE NEW YORK POWER POOL

The initial New York Power Pool (NYPP) Agreement was signed on July 21, 1966. The NYPP, as then established, replaced separate pooling arrangements between groups of upstate and downstate companies that had been in effect for some time. A later agreement dated March 31, 1971, was entered into by the seven orgiinal investor-owned utilities, with the addition of the Power Authority of the State of New York. The membership now includes:

Central Hudson Gas & Electric Corporation
Consolidated Edison Company of New York, Inc.
Long Island Lighting Company
New York State Electric & Gas Corporation
Niagara Mohawk Power Corporation
Orange and Rockland Utilities, Inc.
Rochester Gas and Electric Corporation
Power Authority of the State of New York

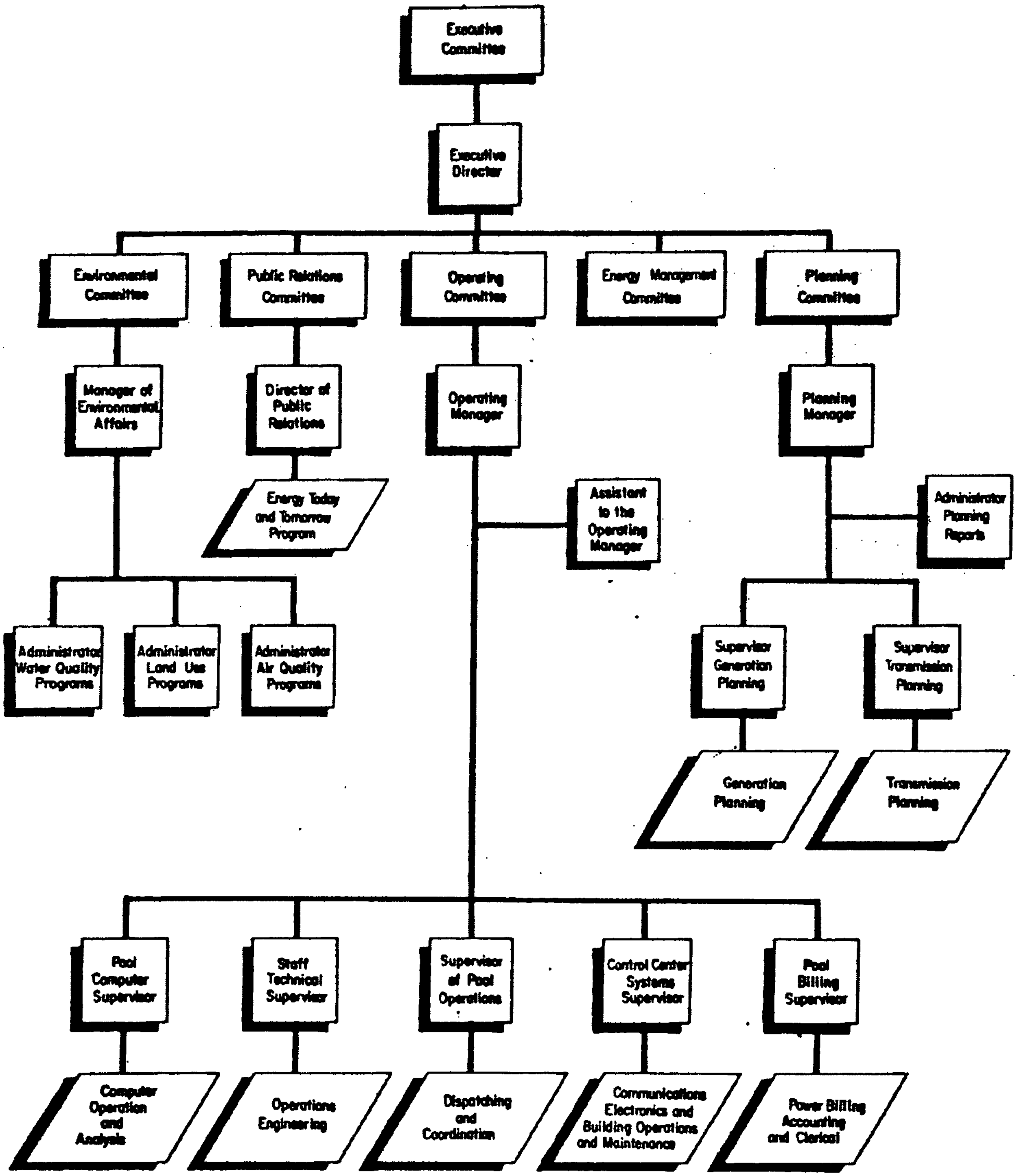
The reasons for the later agreement were principally to strengthen the organization and to establish, staff, and operate a Power Pool Control Center facility located near Albany, New York. The agreement was further modified and the present Agreement which became effective April 27, 1975, is on file with the Federal Power Commission as a rate schedule of each investor-owned company.

The purpose of the New York Power Pool, as stated in the NYPP Agreement, is to obtain the substantial mutual benefits for all members by "coordinated operation of their electric systems, including increased reliability of service and reduced capital costs made possible by coordinated system planning and reduced operating costs made possible by the interchange of electric energy for economy purposes." The Agreement establishes the Power Pool Control Center "for the principal purposes of (1) coordinating the operations of the member companies of the Power Pool insofar as they may affect the reliability of the bulk power supply on the interconnected systems in New York State; (2) dispatching energy requirements on an economy basis; and (3) monitoring the internal and external operations of the Power Pool to insure unimpaired overall security of bulk power supply at all times."

The Executive Committee reviews and directs the activities of the five other committees 7/ of the Pool as well as determines

7/ See Chart, NYPP Organization and Functions.

New York Power Pool
Organization and Functions



policy on all matters within the Agreement and the carrying out of the Agreement's provisions.

The five committees direct the staff of the Pool, and their functions are briefly described below:

1. The Operating Committee establishes rules and practices required to coordinate the operation of the bulk power supply system of the Pool's members so as to insure reliability of service and economic operation with due regard for environmental factors.

2. The Planning Committee has the responsibility to coordinate and develop plans for the installation of additional generating capacity and interconnecting transmission lines within the Pool. The Committee is also responsible for the coordination of planning between the Pool and adjoing pools and regional reliability coordinating councils to the extent appropriate.

3. The three remaining committees, dealing with Energy Management, Environment, and Public Relations support the primary functions of operating and planning the New York Power Pool.

In 1976 the Consolidated Edison Company contributed approximately 39 percent of the Pool's annual peak hourly demand which occurs in the summer. Their system energy requirements were about 32 percent of those of the entire pool. Also, Consolidated Edison's peak hourly demands are 61 percent larger than Niagara Mohawk Power Corporation, the next largest system. However, Consolidated Edison supplies the smallest geographic franchise area of all the members of the NYPP.

TABLE 4

Consolidated Edison Company of New York
Size Relationship To
The New York Power Pool

Year 1976	NYPP	CON ED	Percent of NYPP
Peak Hourly Demand in Megawatts	19,262	7,579	39
Energy Requirements in Millions of Kilowatt-hours	112,000	35,818	32
Owned Generation in Megawatts	29,699	9,880	33

Since the 1965 Northeast Blackout, there have been no power interruptions resulting in a complete system collapse until the recent blackout on Consolidated Edison's system. However, there have been a number of power interruptions and load reductions reported to the Federal Power Commission since 1965.

Pursuant to Order No. 331-1 in Docket R-361, utilities are required to report interruptions of bulk electric power supply caused by the outage of any generating unit or electric facility operating at a nominal voltage of 69 kV or higher and resulting in a load loss for fifteen minutes or longer of at least 100 megawatts, or for smaller systems, one-half or more of the annual peak load. Also, load reductions due to appeals to the public for curtailment of usage, load reductions due to system voltage reductions, and any unusual hazard to the bulk power supply system are required to be reported. Reports are made by telephone or telegraph during extended interruptions, followed by a written report. These interruptions are summarized quarterly in Bureau of Power Staff Reports.

The following Tables, 5 and 6, list the power interruptions and load reductions respectively reported to the Federal Power Commission under Order No. 331-1 for the systems of the New York Power Pool.

TABLE 5 - 1965-77 REPORTED SYSTEM DISTURBANCES, NEW YORK POWER POOL

DATE	UTILITY OR SYSTEM	LOCATION OF DISTURBANCE	REPORTED INITIATING EVENT	MW LOST	CUSTOMERS AFFECTED	DURATION HRS.	MINS.
11-9-65	Present New York Power Pool (NYPP) members, nearly all New England systems and Hydro-Electric Power Commission, Ontario Connecticut Light & Power Co., Hartford Electric Light Co., United Illuminating Co. Western Massachusetts Electric Co. (CONVEX) Vermont Electric Power Co., Inc. New England Power Co., Inc. Public Service Co. of New Hampshire Boston Edison Co. Central Vermont Public Service Co.	Northeast U. S.	Undesired relay operation	43,600	30,000,000	Varied from 1 hr. to 13½ hrs.	
8-15-67	Orange & Rockland Util. Co.	Rockland, New York-New Jersey	69 kV line tap burned off.	48.0	24,139	1	17
9-29-68	Orange & Rockland Util., Inc.	N.Y.- N.J. Boundary	Generator relayed out-bearing vibration.	151.0	136,484	2	24
11-8-68	N.Y. State Electric & Gas Corp., Niagara Mohawk Power Corp.	Lockport, N.Y.	Gunshot 115 kV insulator-Relay failed.	36.0	10,700	-	33
4-15-70	Orange & Rockland Utilities, Inc.	Southern New York	Transformer tripped for unknown reasons.	29	13,492	-	1/

See footnotes on page 5

TABLE 5 (CONT'D)

DATE	UTILITY OR SYSTEM	LOCATION OF DISTURBANCE	REPORTED INITIATING EVENT	MW LOST	CUSTOMERS AFFECTED	DURATION HRS.	DURATION MINS.
7-12-71	Consolidated Edison Company	Parts of Mahattan & Bronx, N.Y.	Three 138 kV circuits tripped at the Sherman Creek station interrupting service to two low voltage distribution networks.	270	135,000		[2]
8-18-71	N.Y. State from Syracuse east and New England	Trouble occurred near Syracuse, New York	Fault on a 345 kV line caused flashover to nearby tree. A parallel circuit was out of service for maintenance.	1,480[3]	740,000	1	00
3-29-72	Orange & Rockland Utilities, Inc.	Nyack, New York	Failure of 69 kV Breaker Bushing tripped two lines supplying Western area of System.	108	66,646	0	27
4-11-72	Orange & Rockland Utilities, Inc.	Southern New York State Area	Construction crane contact 2-69 kV lines.	[6]	75,700		11
4-19-72	New York State Electric & Gas	Northeast New York State	Defective oscillator in micro-wave multiplexing equipment at Richview substation in Ontario caused 6-230 kV lines to trip.	132	12,000	N.R.	
5-24-72	Orange & Rockland Utilities, Inc.	New York, Pennsylvania, New Jersey	Tree contact with line conductors caused the Branchburg-Ramapo 500 kV line to trip and subsequently the Lovett-Hillburn 138 kV circuit.	240	49,298 N.Y. 4,116 Pa. 40,356 N.J.		38
7-17-72	Consolidated Edison Co.	New York City	Failure of six 27 kV network feeder cables.	100	100,000	13	19

See footnotes on page 5

TABLE 5 - 1965-77 REPORTED SYSTEM DISTURBANCES, NEW YORK POWER POOL

DATE	UTILITY OR SYSTEM	LOCATION OF DISTURBANCE	REPORTED INITIATING EVENT	MW LOST	CUSTOMERS AFFECTED	DURATION HRS.	DURATION MINS.
11-9-65	Present New York Power Pool (NYPP) members, nearly all New England systems and Hydro-Electric Power Commission, Ontario Connecticut Light & Power Co., Hartford Electric Light Co., United Illuminating Co. Western Massachusetts Electric Co. (CONVEX) Vermont Electric Power Co., Inc. New England Power Co., Inc. Public Service Co. of New Hampshire Boston Edison Co. Central Vermont Public Service Co.	Northeast U. S.	Undesired relay operation	43,600	30,000,000	Varied from 1 hr. to 13½ hrs.	
8-15-67	Orange & Rockland Util. Co.	Rockland, New York-New Jersey	69 kV line tap burned off.	48.0	24,139	1	17
9-29-68	Orange & Rockland Util., Inc.	N.Y.- N.J. Boundary	Generator relayed out-bearing vibration.	151.0	136,484	2	24
11-8-68	N.Y. State Electric & Gas Corp., Niagara Mohawk Power Corp.	Lockport, N.Y.	Gunshot 115 kV insulator-Relay failed.	36.0	10,700	-	33
4-15-70	Orange & Rockland Utilities, Inc.	Southern New York	Transformer tripped for unknown reasons.	29	13,492	-	1/

See footnotes on page 5

TABLE 5 (CONT'D)

DATE	UTILITY OR SYSTEM	LOCATION OF DISTURBANCE	REPORTED INITIATING EVENT	MW LOST	CUSTOMERS AFFECTED	DURATION HRS.	MINS.
7-12-71	Consolidated Edison Company	Parts of Mahattan & Bronx, N.Y.	Three 138 kV circuits tripped at the Sherman Creek station interrupting service to two low voltage distribution networks.	270	135,000		2/
8-18-71	N.Y. State from Syracuse east and New England	Trouble occurred near Syracuse, New York	Fault on a 345 kV line caused flashover to nearby tree. A parallel circuit was out of service for maintenance.	1,480 3/	740,000	1	00
3-29-72	Orange & Rockland Utilities, Inc.	Nyack, New York	Failure of 69 kV Breaker Bushing tripped two lines supplying Western area of System.	108	66,646	0	27
4-11-72	Orange & Rockland Utilities, Inc.	Southern New York State Area	Construction crane contact 2-69 kV lines.	6/	75,700		11
4-19-72	New York State Electric & Gas	Northeast New York State	Defective oscilator in micro-wave multiplexing equipment at Richview substation in Ontario caused 6-230 kV lines to trip.	132	12,000	N.R.	
5-24-72	Orange & Rockland Utilities, Inc.	New York, Pennsylvania, New Jersey	Tree contact with line conductors caused the Branchburg-Ramapo 500 kV line to trip and subsequently the Lovett-Hillburn 138 kV circuit.	240	49,298 N.Y. 4,116 Pa. 40,356 N.J.		38
7-17-72	Consolidated Edison Co.	New York City	Failure of six 27 kV network feeder cables.	100	100,000	13	19

See footnotes on page 5

TABLE 5 (CONT'D)

DATE	UTILITY OR SYSTEM	LOCATION OF DISTURBANCE	REPORTED INITIATING EVENT	MW LOST	CUSTOMERS AFFECTED	DURATION HRS.	DURATION MINS.
7-24-72	Consolidated Edison Co.	New York City	Failure of seven 27 kV network feeders.	150	185,000	19	17
2-20-73	Consolidated Edison Co.	Portions of the Brooklyn and Staten Island Boroughs of New York City	Failure of circuit breakers and other control equipment to properly isolate a 345 kV circuit breaker with an internal short circuit.	350	356,000	5/	
3-1-73	Niagara Mohawk Power Corporation	Town of Tonawanda, New York	Explosion at the Food Machinery Corporation resulted in damage to towers and conductors of 2-115 kV 60-hz circuits and 4-69 kV 25-hz circuits.	140	9/	10	
8-29-73	Consolidated Edison Co.	Queens Borough of New York City	Failure of five 27 kV network feeders.	115	50,000	14	50
2-26-74	Orange and Rockland Utilities, Inc.	Northern Rockland County, New Jersey	69 kV circuit breaker fault.	6/	5,500	3	56
8-5-74	Consolidated Edison Company of New York, Inc.	Bronx, New York	Reclosure failure of a circuit breaker at Fordham substation.	244	244,000	2	
9-18-75	Orange and Rockland Utilities, Inc.	Orange and Sullivan Counties, New York; portions of Pike County, Pa. and Sussex County, New Jersey	A fire which originated in a ceiling light fixture at the Orange and Rockland Electric Energy Control Center destroyed all of the Company's supervisory control center	6/	37,500	3	20

See footnotes on page 5

TABLE 5 (CONT'D)

DATE	UTILITY OR SYSTEM	LOCATION OF DISTURBANCE	REPORTED INITIATING EVENT	MW LOST	CUSTOMERS AFFECTED	DURATION HRS.	DURATION MINS.
			facilities at the Middletown, New York operations centers. Because of the fire's intensity, a portion of the Shoemaker Substation, also at the site, had to be de-energized.				
7-18-75	Orange & Rockland Utilities, Inc.	New York Orange and Sullivan Counties, and Pike County, Pennsylvania	Fault on 69/34.5-kV transformer caused differential protective relays to operate at Company's Shoemaker substation.	30	37,400		40
10-31-76	Orange & Rockland Utilities	Port Jervis, New Jersey area	Flashover of 34 kV disconnect switch caused 69 kV Shoemaker Substation bus differential relay operation which opened all lines (69 kV and 34 kV) emanating therefrom.	57	30,487	7/	
12-2-75	Orange & Rockland Utilities, Inc. (Western and part of Central Division)	Orange and Sullivan Counties, Counties, New York	During the return to service of a 39.3 MW Shoemaker substation gas turbine unit, 69 kV bus differential relays tripped all 69 kV circuit breakers.	35	27,400		15
1-26-76	Municipal Lighting Department of Plattsburgh, New York	Plattsburgh, New York	A 230-kV lighting arrester explosion at Macena Substation resulted in the loss of all of the City's load. The City's system experienced low voltage for 40 minutes, prior to the outage.	50	7,000	5	15

See footnotes on page 5

TABLE 5 (CONT'D)

DATE	UTILITY OR SYSTEM	LOCATION OF DISTURBANCE	REPORTED INITIATING EVENT	MW LOST	CUSTOMERS AFFECTED	DURATION HRS.	DURATION MINS.
3-3-76	New York State Electric & Gas Corp.	Hornell, Buffalo, and Syracuse, New York	Severe icing conditions disrupted the operation of six 115-kV, one 69-kV, and twenty-four 34.5-kV transmission lines and forced one 115-kV and twenty 34.5-kV substations out of service.	90	67,000	6/	6/
3-3-76	Niagara Mohawk Power Corporation	Buffalo, Syracuse, Lake Shore, Geneseo, Rochester, west Lancaster and Auburn, New York	Severe ice storm forced several 115-kV transmission lines out of service. Storm also disrupted several low voltage distribution circuits.	310	106,000	8/	8/
7-13-77	Consolidated Edison Company of New York	New York City & West Chester County	Severe thunderstorm.	6,000	2,725,000	4 to 25	-28
7-13-77	New York State Electric and Gas Company (NYSEG)	Brewster District New York	Severe thunderstorm.	70	35,000	1 to 1	-13 -31

1/ Varied from 5 minutes to 2 hours and 15 minutes
2/ Varied from 3 hours and 7 minutes to 3 hours 29 minutes
3/ Includes approximately 350 MW shed by Con. Ed. via 8% voltage reduction.
4/ Outages ranged from 41 minutes to 14 plus hours.
5/ All Staten Island service was restored within 55 minutes.
All Brooklyn service was restored within 2 hours and 32 minutes
6/ Not reported
7/ 29,237 - 46 minutes
1,250 - 1 hour and 38 minutes
8/ Most service were returned after 5 hours and 30 minutes, other services after 11 hours and 30 minutes.
9/ Eight industrial 60-Hz customers (130 MW) and several 25 Hz customers (10 MW).

TABLE 6 - 1970-77 REPORT SYSTEM LOAD REDUCTIONS
NEW YORK POWER POOL

DATE	UTILITY OR SYSTEM	LOCATION OF INCIDENT	CAUSE	CURTAILMENT 12/ MEASURE INSTITUTED	EST. LOAD REDUCED MW	DURATION HRS.	DURATION MIN.
7-20-70	Consolidated Edison Company			3% VR		4	
7-28-70	Consolidated Edison Company 1/			3%-5% VR		8	
7-28-70	New York State Power Pool			3%-5% VR		5	30
7-29-70	Consolidated Edison Company 1/			3%-5% VR		7	
7-29-70	New York State Power Pool			3%-5% VR		6	30
7-30-70	Consolidated Edison Company 1/			3%-5% VR		7	
7-30-70	New York State Power Pool			3%-5% VR		6	30
7-31-70	Consolidated Edison Company 1/			3% VR		6	30
7-31-70	New York State Power Pool			3%-5% VR		6	
8-3-70	New York State Power Pool			3%-5% VR		6	30
8-13-70	Consolidated Edison Company 1/			3%-5% VR		7	
8-13-70	New York State Power Pool			3%-5% VR		4	

See footnotes on page 10.

TABLE 6 (CONT'D)

DATE	UTILITY OR SYSTEM	LOCATION OF INCIDENT	CAUSE	CURTAILMENT 12/ MEASURE INSTITUTED	EST. LOAD REDUCED MW	DURATION HRS.	DURATION MIN.
8-14-70	Consolidated Edison Company 1/			3%-5% VR		7	
8-14-70	New York State Power Pool			3%-5% VR		7	
8-17-70	Consolidated Edison Company			3%-5%-8% VR		7	30
8-17-70	Long Island Lighting Company			3% VR		3	
8-20-70	Consolidated Edison Company			3% VR		2	
9-4-70	Consolidated Edison Company			3%-5% VR		6	
9-4-70	Long Island Lighting Company			3% VR		3	30
9-22-70	Consolidated Edison Company			3%-5%-8%		6	30
9-22-70	New York State Power Pool			3%-5%-8% VR		9	
9-23-70	Consolidated Edison Company 1/			3%-5%-8% VR		12	
9-23-70	New York State Power Pool			5%-8% VR		11	30

See footnotes on page 10.

TABLE 6 (CONT'D)

DATE	UTILITY OR SYSTEM	LOCATION OF INCIDENT	CAUSE	CURTAILMENT MEASURE INSTITUTED 12/	EST. LOAD REDUCED MW	DURATION HRS.	MIN.
9-24-70	Consolidated Edison Company			5% VR		10	
9-24-70	New York State Power Pool			5% VR		8	30
9-25-70	Consolidated Edison Company			3%-5% VR		4	
9-25-70	New York State Power Pool			3%-5% VR		6	
1-18-71	New York Power Pool			5% VR		3 to 6	30 to 30
1-21-71	New York Power Pool			5% VR		2 to 4	15
1-27-71	New York Power Pool			5% VR		2 to 4	30
1-28-71	New York Power Pool			5% VR		8 to 10	30
2-1-71	New York Power Pool			3%-5% VR		15	
2-2-71	New York Power Pool			5% VR		12	15
2-3-71	New York Power Pool			3%-5% VR		10	
2-5-71	Consolidated Edison Company 3/			3%-5% VR		5	30

See footnotes on page 10

TABLE 6 (CONT'D)

DATE	UTILITY OR SYSTEM	LOCATION OF INCIDENT	CAUSE	CURTAILMENT MEASURE INSTITUTED [12]	EST. LOAD REDUCED MW	DURATION HRS.	MIN.
5-19-71	Consolidated Edison Company	Brooklyn, Manhattan and parts of Queens, New York	Voltage reduction instituted to prevent overloading of circuits following a circuit breaker failure.	3% VR		[4]	
6-7-71	Consolidated Edison Company	New York, N.Y.	Combination of heavy loads and large amounts of unavailable capacity.	3% VR			50
6-7-71	Long Island Lighting Company	Long Island, N.Y.	Heavy loads due to high temperature.	3% VR			48
6-30-71	Consolidated Edison Company	New York, N.Y.	Combination of heavy loads and large amounts of unavailable capacity.[6]	3% VR		3	35
6-30-71	Rochester Gas & Elec. Corporation	Rochester, N.Y. & surrounding area	Combination of heavy loads and large amounts of unavailable capacity[7]	5% VR		7	30
7-1-71	Consolidated Edison Company	Section of Brooklyn, Manhattan & Bronx	To prevent possible overloading of incoming tie lines.	3% VR		1	30
7-7-71	Consolidated Edison Company	New York City, N.Y.	Forced outage of Ravenswood Unit No. 3.	5%-3% VR		2	17
8-18-71	Consolidated Edison Company	New York, N.Y.	Widespread system disturbance due to transmission line fault caused system separation and generation deficiency.	8%		N.R.[5]	

See footnotes on page 10.

TABLE 6 (CONT'D)

DATE	UTILITY OR SYSTEM	LOCATION OF INCIDENT	CAUSE	CURTAILMENT[12] MEASURE INSTITUTED	EST. LOAD REDUCED MW	DURATION HRS.	MIN.
9-9-71	Consolidated Edison Company	New York, N.Y.	Heavy Summer Loads	3% VR		1	27
5-24-72	Consolidated Edison Company of New York, Inc.	New York, N.Y.	Voltage reduction instituted as a precautionary measure due to the interruption of the Ramapo-Millwood 345 kV line.	3% VR	71		45
7-12-72	Consolidated Edison Company	New York City	Critically loaded substation feeders. Bulk power supply not affected.	5% VR	N.R.[5]	4	
7-12-72	Consolidated Edison Company	New York City	Insufficient capacity.	3% VR		4	
7-20-72	Consolidated Edison Company	New York City	Insufficient capacity.	5% VR	N.R.[5]	3	
8-24-72	Consolidated Edison Company	New York City	Insufficient capacity.	5% VR	140	2	30
8-25-72	New York Power Pool	New York State	Insufficient capacity.	5% VR[1]	N.R.[5]	5	
11-30-72	Consolidated Edison Company	New York, N.Y.	Loss of the Pennsylvania New Jersey-Maryland Keystone No. 1 unit forced reduction of PJM's scheduled deliveries to the New York Power Pool.	8/	N.R.[5]	6	

See footnotes on page 10

TABLE 6 (CONT'D)

DATE	UTILITY OR SYSTEM	LOCATION OF INCIDENT	CAUSE	CURTAILMENT[12/] MEASURE INSTITUTED	EST. LOAD REDUCED MW	DURATION HRS.	MIN.
6-11-73	Consolidated Edison Company	New York City	Equipment outages coupled with high temperature.	1/ 9/	N.R.[5/]	8	41
6-11-73	New York Power Pool	New York State	Curtailments were implemented to assist Con Ed in meeting anticipated demand.	5% VR	N.R.[5/]	7	35
6-12-73	Consolidated Edison Company	New York, N.Y.	Insufficient capacity to maintain load.	5% VR[1/]	N.R.[5/]	4	
6-12-73	New York Power Pool	New York State	Assistance to Con Ed.	5	N.R.[5/]	7	
7-9-73	New York Power Pool	New York State	Insufficient reserve capacity.	5% VR, RP, RCI	N.R.[5/]	11	
8-10-73	Long Island Lighting Company	Central Long Island, N.Y.	Insufficient reserve capacity.	3% VR	N.R.[5/]	6	
8-27-73	Consolidated Edison Company	New York City and Westchester County, New York	Insufficient reserve capacity.	RP, RCI	N.R.[5/]	6	
8-28-73	Consolidated Edison Company	New York, N.Y.	Insufficient reserve capacity.	5% VR, RP	N.R.[5/]	5	30
8-28-73	New York Power Pool	New York State	Insufficient reserve capacity.	5% VR	N.R.[5]	8	
8-29-73	New York Power Pool	New York State	Insufficient reserve capacity.	5% VR	N.R.[5/]	8	
12-24-73	New York Power Pool	New York State	Energy conservation.	3% VR	N.R.[5/]	11/	

See footnotes on page 10

TABLE 6 (CONT'D)

DATE	UTILITY OR SYSTEM	LOCATION OF INCIDENT	CAUSE	CURTAILMENT[12] MEASURE INSTITUTED	EST. LOAD REDUCED MW	DURATION HRS.	MIN.
8-29-73	Consolidated Edison Company	New York, N.Y.	Insufficient reserve capacity.	RP	N.R.[5]	8	
8-30-73	New York Power Pool	New York State	Insufficient reserve capacity.	5% VR, RP, RCI	N.R.[5]	8	
8-31-73	New York Power Pool	New York State	Insufficient reserve capacity.	5% VR	N.R.[5]	8	
9-4-73	New York Power Pool	Eastern New York State	Insufficient reserve capacity.	5% VR	N.R.[5]	6	
9-5-73	New York Power Pool	New York State	Insufficient reserve capacity.	5% VR,RP, RCI	N.R.[5]	10	
1-14-74	Consolidated Edison Company	New York City and portions of Westchester County, New York	Low fuel oil inventory.	5% VR	N.R.[5]	24[11]	
1-16-74	New York Power Pool	New York State	Low fuel oil supplies.	3% VR, RP, RCI[10]	N.R.[5]	[11]	
2-1-74	Consolidated Edison Company	New York City and portions of Westchester County, New York	Voltage reduction of 1/14/74 decreased due to increased fuel oil supply.	3% VR	N.R.[5]	[11]	

See footnotes on page 10

TABLE 6 (CONT'D)

DATE	UTILITY OR SYSTEM	LOCATION OF INCIDENT	CAUSE	CURTAILMENT[12] MEASURE INSTITUTED	EST. LOAD REDUCED MW	DURATION HRS.	MIN.
3-29-74	New York Power Pool	New York State	State-wide 3% voltage reduction in effect since 12-26-73 by order of the N.Y. State Public Service Commission was discontinued because of increased fuel-oil supplies.				
5-17-74	Consolidated Edison Company	New York, N.Y,	High loads and low capacity reserves.	3% VR	N.R.[5]	2	
6-10-74	Consolidated Edison Company	New York City	Tripping of Indian Point No. 2 Nuclear Unit triggered necessity for full system voltage reduction.	5% VR	N.R.[5]	6	
6-10-74	New York Power Pool	Northern New Jersey and New York State	Partial system voltage reduction implemented in an effort to assist PJM companies.	5% VR	663	6	
7-9-74	Long Island Lighting Company	Long Island, New York	To assist NEPEX companies.	5% VR	N.R.[5]	N.R.[5]	
9-13-74	Consolidated Edison Company of New York	Manhattan, New York	Equipment malfunction involving Waterside Nos. 1 and 2 generating units.	5% VR	N.R.[5]	N.R.[5]	

See footnotes on page 10

TABLE 6 (CONT'D)

DATE	UTILITY OR SYSTEM	LOCATION OF INCIDENT	CAUSE	CURTAILMENT [12] MEASURE INSTITUTED	EST. LOAD REDUCED MW	DURATION HRS.	MIN.
11-8-75	Niagara Mohawk Power Corporation (NMPC) New York State Electric & Gas Corporation (NYSEG)	Portions of St. Lawrence and Franklin Counties in Northeast New York State	Fault on NMPC's Adirondack to Porter 230-kV line. Islanded system segment experienced frequency oscillations from 58.8 to 64.5 hertz.	Under Frequency relay operation	(NMPC) (NYSEG)	17 6	20 5
1-3-77	Consolidated Edison Company	Washington Heights and Riverdale, N.Y.	An auxiliary relay associated with load-shedding protective relaying shorted, resulting in automatic voltage.	8% VR	N.R.[5]		15
1-17-77	Niagara Mohawk Corporation	State of New York also Ontario, Canada	Reduction measure initiated to provided frequency support to the American Electric Power Corporation (AEP).	5% VR	120	9	50

See footnotes on page 10

TABLE 6 (CONT'D)

DATE	UTILITY OR SYSTEM	LOCATION OF INCIDENT	CAUSE	CURTAILMENT[12] MEASURE INSTITUTED	EST. LOAD REDUCED MW	DURATION HRS.	MIN.
1-17-77	New York Power Pool (NYPP) involving: Consolidated Edison Company of New York; Niagara Mohawk Power Corporation; Long Island Lighting Company; New York State Electric and Gas Corporation; Central Hudson Gas & Electric Corporation; Rochester Gas and Electric Corporation; Orange and Rockland Utilities, Inc.; and Power Authority of the State of New York.	States of New York, Pennsylvania, New Jersey, Maryland Delaware, and the District of Columbia	NYPP implemented voltage reduction to provide frequency regulation support to western interconnected systems.	5% VR, RP	580	9	50

1/ Utility or pool requested customers to reduce electricity use.
2/ Service interruption of non-critical loads.
3/ Voltage reduction instituted as a precautionary measure.
4/ Varied from 35 minutes to 55 minutes.
5/ Not Reported.
6/ Outage of Astoria Unit No. 3 due to boiler tube which occurred approximately 2 hours before the peak period contributed to the capacity shortage.
7/ Limited tie line capacity and loss of the 425 MW Ginna nuclear unit earlier in the day due to boiler feed pump trouble contributed to the overall capacity shortage. Ginna was returned to full load later the same day.
8/ Mutually shed load.
9/ 10:12 a.m. (3%); 10:20 a.m. (5%); and 1:13 p.m. (8%).
10/ In effect since December 26, 1973; under Opinion No. 73-46 issued December 21, 1973, by the State of New York's Public Service Commission.
11/ Until further notice.
12/ VR - Voltage Reduction Percentage
RP - Request of public to curtail non-essential usage
RCI - Request of commercial and industrial customers to curtail non-essential usages
INT - Contractually interruptible loads curtailed

The New York Power Pool Agreement establishes the coordination procedures for members within the Pool. The structure of the Pool with respect to committees was noted above. The obligations required of the member systems, including the Consolidated Edison Company under the NYPP Agreement are summarized in part as follows:

1. System Planning

Each party shall furnish the Planning Committee system load and capability forecasts, statistical data, and any other information which may reasonably be required in the course of the studies undertaken by the Committee.

2. Installed Capability Reserve

Each party is required to maintain 18 percent system capability over their maximum peak hour load for a capability period (summer or winter). Actual capability reserve could result in a capability deficiency or surplus capability with the deficient parties being charged and payments made to surplus parties.

3. Operating Capability

Each party agrees to provide the required minimum operating reserve as established by the Operating Committee. The operating reserve must be acquired from owned resources or through purchases. More specific information on operating reserve requirements is given elsewhere in this report.

The Agreement sets conditions for economy energy purchases among the parties as well. In April, 1977, the NYPP instituted centralized economic dispatch for all the member systems.

Examples of other activities or studies requiring intrapool coordination and performed in 1976 by the NYPP, as reported by the Northeast Power Coordinating Council under FPC Order No. 383-4, are listed below:

1. 1980-82 Study of the NYPP System Voltage and Voltage Control

   This study evaluates the capability of the proposed 1980-82 system to adequately control voltage on the 115 kV through 765 kV systems and recommends additional means of control, if required.

2. 1980, 1985, 1990 NYPP Transmission Studies

   These studies assess the performance of the NYPP internal transmission systems as posed by the member companies. In addition, numerous alternative reinforcements were considered in the three years.

3. <u>1982, 1987, 1993 NYPP Transmission Studies</u>

These three transmission studies are follow-on studies from the above 1980, 1985, and 1990 series above, wherein the proposed system performances were assessed. The alternative reinforcements found best in the above 1980, 1985, and 1990 studies were reviewed in these studies.

Another major activity of the Pool is the preparation of the NYPP annual submission to the New York Public Service Commission on April 1 of a report detailing the electric power requirements, long-range generation and transmission expansion plans, as well as projected research and development activities of the Pool members. This reporting requirement is pursuant to Article VIII, Section 149-b of the Public Service Law of New York.

Interpool coordination on matters of exchanging information on transmission and generation overhaul and maintenance schedules, near-term capacity situations, and other operating matters is handled within the Northeast Power Coordinating Council's (NPCC) Task Force on Interpool Coordination. Members of this Task Force are not only representatives from the New England Power Pool (NEPOOL), Ontario, and New Brunswick (all within NPCC) but also from the Michigan Electric Coordinated Systems (MECS) and the Pennsylvania-New Jersey-Maryland Interconnection (PJM). The NPCC Task Force on Interpool Coordination also reviews system disturbances and provides liaison with the North American Power Systems Interconnection Committee (NAPSIC). NAPSIC is the voluntary operating organization in which virtually all interconnected power systems in the U.S. and parts of Canada have membership.

NYPP is interconnected directly with the systems of NEPOOL, PJM, and Ontario. The interconnection agreements between members of NYPP, of neighboring pools or systems, are on file with the Federal Power Commission.

Figure 3 provides the grographic location and type of interstate transmission tie-lines of the NYPP systems.

The latest interconnection agreement between the seven investor-owned utilities within NYPP and eight members of PJM 8/

8/ Public Service Electric & Gas Co.
Philadelphia Electric Co.
Pennsylvania Power & Light Co.
Baltimore Gas & Electric Co.
Potomac Electric Power Co.
Pennsylvania Electric Co.
Metropolitan Edison Co.
Jersey Central Power & Light Co.

Figure 3

STATE OF NEW YORK
JULY 1977

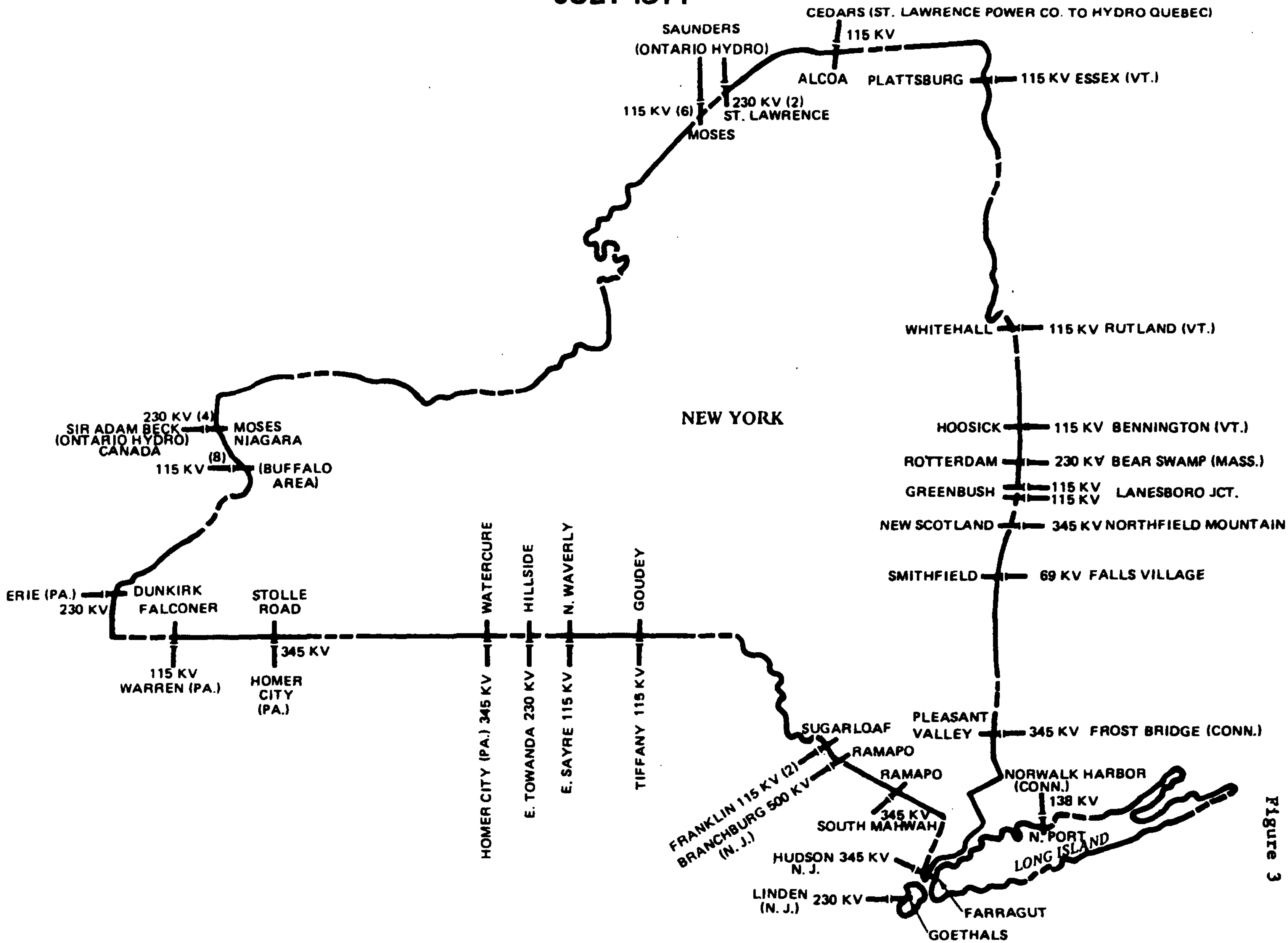


Figure 3

became effective August 1, 1974. The Agreement provides for continued parallel operation of the two areas and calls for both areas to "cooperate in the exchange of information with regard to pertinent matters affecting the planned development and reliable operation of their respective systems, shall cooperate in the determination of the benefits of interconnection and of their installed capacity requirements, and, to the extent possible, shall coordinate generating capacity and major transmission additions required" by the two areas.

Either NYPP or the PJM parties "in the event of breakdown of equipment, unusual load demands, or unusual or abnormal conditions in the other Group's system resulting in the need for capacity or energy in excess of that available from sources within or available to that Group, shall, if called upon, supply Emergency Operating Capacity, Emergency Energy or Non-Replacement Energy to the other Group."

The Agreement provides for an NYPP-PJM Operating Committee staffed by respective area personnel to carry out the terms of the Agreement.

NYPP INSTALLED CAPACITY

Table 7 provides the list of all the NYPP system's generating unit capacity (Manufacturer's Nameplate Rating) and summer capability ratings.

TABLE 7
PRESENT GENERATING CAPACITY OF THE NEW YORK POWER POOL SYSTEMS

New York Power Pool (NYPP)

SYSTEM NAME

Central Hudson Gas & Electric Corporation
Consolidated Edison Company of New York, Inc.
Jamestown Municipal Electric System
Long Island Lighting Company
New York State Electric & Gas Corporation
Niagara Mohawk Power Corporation
Orange & Rockland Utilities, Inc.
Power Authority of the State of New York
Rochester Gas & Electric Corporation
Village of Freeport*
City of Plattsburgh*
Long Sault, Inc.*

TYPE OF UNIT

ST - Steam Turbine - Non nuclear
SB - Steam Power - Nuclear
SP - Steam Power - Nuclear
SH - Steam HTGR - Nuclear
IC - Internal combustion
CT - Combustion - Turbine
HY - Conventional - Hydro
PS - Pumped Storage - Hydro

TYPE OF FUEL

C - Coal
G - Natural Gas
E - Synthetic Gas
K - Middle Distillate Oil
S - Heavy Oil
N - Nuclear

*Non-members of Northeast Power Coordinating Council nor signatories to the New York Power Pool Agreement.

TABLE 7 (CONT'D)

Consolidated Edison Co. of N.Y.

Station Name and Unit No.	Unit Type	Fuel Type	Generator Nameplate Rating (MW)	Summer Capability (MW)
Arthur Kill 2	ST	S	376.2	335
Arthur Kill 3	ST	S	535.5	491
Astoria 1	ST/CT	S/G	216	176
Astoria 2	ST/CT	S/K	376.5	317
Astoria 3	ST/CT	S/K	552.7	534
Astoria 4	ST/CT	S/K	563.7	535
Astoria 5	ST/CT	S/S	406.7	375
Bowline 1	ST	S	621 1/	401
Bowline 2	ST	S	621 1/	400
East River 5	ST	S	156.25	130
East River 6	ST	S	156.25	130
East River 7	ST	S	200	166
Hudson Ave. 2	ST/CT	S/K	68.6	52
Hudson Ave. 3	ST/CT	S/K	66.3	48
Hudson Ave. 4	CT	K	16.3	14
Hudson Ave. 5	ST/CT	S/K	226.3	88
Hudson Ave. 6	ST	S	110	77
Hudson Ave. 7	ST	S	160	112
Hudson Ave. 8	ST	S	160	113
Hudson Ave. 10	ST	S	60	42
Roseton 1	ST	S	621 2/	240
Roseton 2	ST	S	621 2/	240
Ravenswood 1	ST/CT	S/G	416	420
Ravenswood 2	ST/CT	S/K	556	525
Ravenswood 3	ST/CT	S/K	1,183.7	1,098
Waterside 8	ST	S	62.5	36.4
Waterside 9	ST	S	62.5	36.4

1/ Jointly owned Con Edison 400, Orange & Rockland 200.

2/ Jointly owned with Niagara Mohawk and Central Hudson.

Consolidated Edison Co. of N.Y.

Station Name and Unit No.	Unit Type	Fuel Type	Generator Nameplate Rating (MW)	Summer Capability (MW)
Waterside 7	ST	G	81.25	47.3
Waterside 4	ST	S	50	29.1
Waterside 5	ST	S	66.25	38.6
Waterside 6	ST	S	74.75	43.6
Waterside 11	ST	S	35	20.4
Waterside 13	ST	S	35	20.4
Waterside 14	ST	S	60	35
Waterside 15	ST	S	60	35
59th St. 7	ST	S	35	23.3
59th St. 8	ST	S	35	23.3
59th St. 13	ST	S	57.5	38.2
59th St. 14	ST	S	22	14.6
59th St. 15	ST	S	35	23.3
74th St. 3	ST	S	30	21
74th St. 9	ST	S	75	52.7
74th St. 10	ST	S	69	48.5
74th St. 11	ST	S	35	24.6
Indian Pt. 1	SP/CT	NS/K	291.6	19 2/
Indian Pt. 2	SP/CT	N/K	1,038	885
Arthur Kill	CT	S	16.3	16
Astoria 6	CT	S	19.8	16
Astoria 7	CT	S	19.8	16
Astoria 8	CT	S	19.8	11
Astoria 9	CT	S	19.8	16
Astoria 10	CT	S	25.0	19
Astoria 11	CT	S	25	17
Astoria 12	CT	S	25	20
Astoria 13	CT	S	25	17
Gowanus 1	CT	S	172	134
Gowanus 2	CT	S	172	134
Gowanus 3	CT	S	172	134
Gowanus 4	CT	S	172	134
Hudson Ave. 1	CT	K	17.1	17
Indian Pt. 3	CT	K	19.8	16
Kent G. T. 2	CT	K	14	9

2/ Station rerated to zero megawatts pending core cooling equipment.

TABLE 7 (CONT'D)

Consolidated Edison Co. of N.Y.

Station Name and Unit No.	Unit Type	Fuel Type	Generator Nameplate Rating (MW)	Summer Capability (MW)
Narrows 1	CT	K	196.6	157.5
Narrows 2	CT	K	196.6	157.5
Ravenwood 8	CT	K	22.4	19
Ravenwood 9	CT	K	22.4	19
Ravenwood 10	CT	K	22.4	19
Ravenwood 11	CT	K	22.4	19
Ravenwood 4	CT	K	16.3	16
Ravenwood 5	CT	K	16.3	16
Ravenwood 6	CT	K	15.8	17
Ravenwood 7	CT	K	15.8	17
Waterside 1	CT	K	14	11
59th St. 1	CT	K	17.1	17
59th St. 2	CT	K	17.1	17
74th St. 1	CT	K	18.6	17
74th St. 2	CT	K	18.6	17
			TOTAL	9,880

TABLE 7 (CONT'D)

Long Island Lighting Co.

Station Name and Unit No.	Unit Type	Fuel Type	Generator Nameplate Rating (MW)	Summer Capability (MW)
Northport 1	ST	S	387	386
Northport 2	ST	S	387	386
Northport 3	ST	S	387	386
Northport G. T.	S	S	16	16
Port Jeff 1	ST	S	46	49
Port Jeff 2	ST	S	46	49
Port Jeff 3	ST	S	187.5	196
Port Jeff 4	ST	S	187.5	196
Port Jeff G. T.	CT	S	16	16
Glenwood 1	CT	S	16	16
Glenwood 2	ST/CT	S	130.4	134
Glenwood 3	ST/CT	S	130.4	134
Glenwood 4	ST	S	113.6	114
Glenwood 5	ST	S	113.6	113
Barrett 1	ST/CT	S	205.5	204.7
Barrett 2	ST/CT	S	205.5	206.7
Barrett 3	CT	S	18	15.7
Barrett 4	C T	S	18	15.7
Barrett 5	CT	S	18	15.7
Barrett 6	CT	S	18	1.5
Barrett 7	CT	S	18	1.5
Barrett 8	CT	S	18	1.5
Barrett 9	CT	S	42	40.5
Barrett 10	CT	S	42	40.5
Barrett 11	CT	S	42	40.5
Barrett 12	CT	S	42	40.5
Barrett A. P. G.	CT	S	18.6	18
F. Rockway 4	ST	S	113.6	114
Shoreham 1	CT	S	53	51
W. Babylon 1	CT	S	18.6	17.3
W. Babylon 2	CT	S	18.6	17.3
W. Babylon 3	CT	S	18.6	17.3
W. Babylon 4	CT	S	53	48
Southold 1	CT	S	14	14
S. Hampton 1	CT	S	11.5	11

TABLE 7 (CONT'D)

Long Island Lighting Co.

Station Name and Unit No.	Unit Type	Fuel Type	Generator Nameplate Rating (MW)	Summer Capability (MW)
Montauk 2	IC	S	2	2
Montauk 3	IC	S	2	2
Montauk 4	IC	S	2	2
E. Hampton 1	CT	S	21.5	20
E. Hampton 2	IC	S	2	2
E. Hampton 3	IC	S	2	2
E. Hampton 4	IC	S	2	2
Holbrook 1	CT	S	56.7	52.8
Holbrook 2	CT	S	56.7	52.8
Holbrook 3	CT	S	56.7	52.8
Holbrook 4	CT	S	56.7	52.8
Holbrook 5	CT	S	56.7	52.8
Holbrook 6	CT	S	56.7	52.8
Holbrook 7	CT	S	56.7	52.8
Holbrook 8	CT	S	56.7	52.8
Holbrook 9	CT	S	56.7	52.8
Holbrook 10	CT	S	56.7	52.8
			TOTAL	3,727

TABLE 7 (CONT'D)

Power Authority of the State of N.Y.

Station Name and Unit No.	Unit Type	Fuel Type	Generator Nameplate Rating (MW)	Summer Capability (MW)
Moses Niagara 1	HY	Q	150	166
Moses Niagara 2	HY	Q	150	166
Moses Niagara 3	HY	Q	150	160
Moses Niagara 4	HY	Q	150	166
Moses Niagara 5	HY	Q	150	166
Moses Niagara 6	HY	Q	150	166
Moses Niagara 7	HY	Q	150	166
Moses Niagara 8	HY	Q	150	166
Moses Niagara 9	HY	Q	150	166
Moses Niagara 10	HY	Q	150	166
Moses Niagara 11	HY	Q	150	166
Moses Niagara 12	HY	Q	150	166
Moses Niagara 13	HY	Q	150	166
Lewiston	PS	-	240	240
Moses Power Dam 1	HY	Q	57	50
Moses Power Dam 2	HY	Q	57	50
Moses Power Dam 3	HY	Q	57	50
Moses Power Dam 4	HY	Q	57	50
Moses Power Dam 5	HY	Q	57	50
Moses Power Dam 6	HY	Q	57	50
Moses Power Dam 7	HY	Q	57	50
Moses Power Dam 8	HY	Q	57	50
Moses Power Dam 9	HY	Q	57	50
Moses Power Dam 10	HY	Q	57	50
Moses Power Dam 11	HY	Q	57	50
Moses Power Dam 12	HY	Q	57	50
Moses Power Dam 13	HY	Q	57	50
Moses Power Dam 14	HY	Q	57	50
Moses Power Dam 15	HY	Q	57	50

TABLE 7 (CONT'D)

Power Authority of the State of N. Y.

Station Name and Unit No.	Unit Type	Fuel Type	Generator Nameplate Rating (MW)	Summer Capability (MW)
Moses Power Dam 16	HY	Q	57	50
Blenheim-Gilboa 1	PS	-	250	250
Blenheim-Gilboa 2	PS	-	250	250
Blenheim-Gilboa 3	PS	-	250	250
Blenheim-Gilboa 4	PS	-	250	250
Fitzpatrick	SB	N	883	770
Indian Pt. 3	SP	N	1,125	873
			TOTAL	5,843

TABLE 7 (CONT'D)

New York Electric & Gas Corp.

Station Name and Unit No.	Unit Type	Fuel Type	Generator Nameplate Rating (MW)	Summer Capability (MW)
Goudey 7	ST	C	43.75	44
Goudey 8	ST	C	75	82
Greenidge 1	ST	C	20	24
Greenidge 2	ST	C	20	23
Greenidge 3	ST	C	58.8	55
Greenidge 4	ST	C	112.5	103
Hickling 1	ST	C	34.5	33
Hickling 2	ST	C	49	50
Jennison 1	ST	C	33	35
Jennison 2	ST	C	34.5	38
Milliken 1	ST	C	135	143
Milliken 2	ST	C	135	147
Homer City 1	ST	C	660	300 1/
Homer City 2	ST	C	660	300 1/
Miscellaneous Hydro	HY	-	-	40
Miscellaneous Diesel	IC	-	-	13
			TOTAL	1,430

1/ Joint ownership with Pennsylvania Electric Company.

TABLE 7 (CONT'D)

Orange & Rockland Utilities, Inc.

Station Name and Unit No.	Unit Type	Fuel Type	Generator Nameplate Rating (MW)	Summer Capability (MW)
Lovett 1	ST	S	23	19
Lovett 2	ST	S	23	20
Lovett 3	ST	S	69	63
Lovett 4	ST	S	197	197
Lovett 5	ST	S	202	202
Bowline 1	ST	S	621 1/	201
Bowline 2	ST	S	621 1/	200
Shoemaker 1	CT	K	40	37
Hillburn 1	CT	K	37	37
Hydro 1	HY	Q		44
			TOTAL	1,020

1/ Joint ownership - Orange & Rockland, 200 megawatts; Con Edison - 400 megawatts.

TABLE 7 (CONT'D)

Niagara Mohawk Power Corp.

Station Name and Unit No.	Unit Type	Fuel Type	Generator Nameplate Rating (MW)	Summer Capability (MW)
Oswego 1	ST	S	92	90
Oswego 2	ST	S	92	90
Oswego 3	ST	S	92	95
Oswego 4	ST	S	100	100
Oswego 5	ST	S	850	650
Huntley 63	ST	C	100	91
Huntley 64	ST	C	100	100
Huntley 65	ST	C	100	100
Huntley 66	ST	C	100	100
Huntley 67	ST	C	218	220
Huntley 68	ST	C	218	220
Dunkirk 1	ST	C	96	100
Dunkirk 2	ST	C	96	100
Dunkirk 3	ST	C	218	220
Dunkirk 4	ST	C	218	220
Albany 1	ST	S	100	100
Albany 2	ST	S	100	100
Albany 3	ST	S	100	100
Albany 4	ST	S	100	100
Colton 1	HY	Q	10	9.5
Colton 2	HY	Q	10	9.5
Colton 3	HY	Q	10	9.5
Trenton 1	HY	Q	1	1.2
Trenton 2	HY	Q	1	1.2
Trenton 3	HY	Q	1	1.2
Trenton 4	HY	Q	1	1.2
Trenton 5	HY	Q	6.8	8
Trenton 6	HY	Q	6.4	7.5
Trenton 7	HY	Q	6.4	7.5
School St. 1	HY	Q	7.2	7
School St. 2	HY	Q	7.2	7
School St. 3	HY	Q	7.2	7
School St. 4	HY	Q	7.2	7

TABLE 7 (CONT'D)

Orange & Rockland Utilities, Inc.

Station Name and Unit No.	Unit Type	Fuel Type	Generator Nameplate Rating (MW)	Summer Capability (MW)
Lovett 1	ST	S	23	19
Lovett 2	ST	S	23	20
Lovett 3	ST	S	69	63
Lovett 4	ST	S	197	197
Lovett 5	ST	S	202	202
Bowline 1	ST	S	621 1/	201
Bowline 2	ST	S	621 1/	200
Shoemaker 1	CT	K	40	37
Hillburn 1	CT	K	37	37
Hydro 1	HY	Q		44
			TOTAL	1,020

1/ Joint ownership - Orange & Rockland, 200 megawatts; Con Edison - 400 megawatts.

TABLE 7 (CONT'D)

Niagara Mohawk Power Corp.

Station Name and Unit No.	Unit Type	Fuel Type	Generator Nameplate Rating (MW)	Summer Capability (MW)
Oswego 1	ST	S	92	90
Oswego 2	ST	S	92	90
Oswego 3	ST	S	92	95
Oswego 4	ST	S	100	100
Oswego 5	ST	S	850	650
Huntley 63	ST	C	100	91
Huntley 64	ST	C	100	100
Huntley 65	ST	C	100	100
Huntley 66	ST	C	100	100
Huntley 67	ST	C	218	220
Huntley 68	ST	C	218	220
Dunkirk 1	ST	C	96	100
Dunkirk 2	ST	C	96	100
Dunkirk 3	ST	C	218	220
Dunkirk 4	ST	C	218	220
Albany 1	ST	S	100	100
Albany 2	ST	S	100	100
Albany 3	ST	S	100	100
Albany 4	ST	S	100	100
Colton 1	HY	Q	10	9.5
Colton 2	HY	Q	10	9.5
Colton 3	HY	Q	10	9.5
Trenton 1	HY	Q	1	1.2
Trenton 2	HY	Q	1	1.2
Trenton 3	HY	Q	1	1.2
Trenton 4	HY	Q	1	1.2
Trenton 5	HY	Q	6.8	8
Trenton 6	HY	Q	6.4	7.5
Trenton 7	HY	Q	6.4	7.5
School St. 1	HY	Q	7.2	7
School St. 2	HY	Q	7.2	7
School St. 3	HY	Q	7.2	7
School St. 4	HY	Q	7.2	7

TABLE 7 (CONT'D)

Central Hudson Gas & Electric Corp.

Station Name and Unit No.	Unit Type	Fuel Type	Generator Nameplate Rating (MW)	Summer Capability (MW)
Roseton 1	ST	S	621 1/	120
Roseton 2	ST	S	621 1/	120
Dansk 1	ST	S	72	39
Dansk 2	ST	S	62	66
Dansk 3	ST	S	121	118
Dansk 4	ST	S	229	229
Dansk 5	IC	K	2	2.5
Dansk 6	IC	K	3	2.5
Coxsackie	CT	K	19	19
South Cairo	CT	K	19	19
Neversink	HY	Q	27	27
Sturgeon 1	HY	Q	5	4.9
Sturgeon 2	HY	Q	5	4.9
Sturgeon 3	HY	Q	4	4.8
Dashville 1	HY	Q	1	1.5
Dashville 2	HY	Q	1	1.5
			TOTAL	780

1/ Joint ownership.
Central Hudson - 120 megawatts
Con Edison - 240 megawatts
Niagara Mohawk - 240 megawatts

TABLE 7 (CONT'D)

System	Station Name and Unit No.	Unit Type	Fuel Type	Generator Nameplate Rating (MW)	Summer Capability (MW)
City of Jamestown	S. A. Carlson 2	ST	C	5	5
	S. A. Carlson 3	ST	C	15	15
	S. A. Carlson 4	ST	C	13	13
	S. A. Carlson 5	ST	C	23	20
	S. A. Carlson 6	ST	C	27	25
				TOTAL	78
City of Freeport	Sunrise Highway 9	IC	S	2.1	1.7
	Sunrise Highway 10	IC	S	3	2.5
	Sunrise Highway 11	IC	S	3.4	2.8
	Sunrise Highway 12	IC	S	6	5
	Buffalo Ave. 1	IC	S	9.5	10
	Buffalo Ave. 2	IC	S	9.5	10
	Buffalo Ave. 3	CT	S	21	18
				TOTAL	50
City of Plattsburg	Diesel Rgh. 1	IC	S	-	3
				TOTAL	3

Lake Champlain
SANDBAR
CLINTON
ESSEX
SANFORD LAKE
HAMILTON
HERKIMER
WARREN
BLISSVILLE
GRANVILLE
WASHINGTON
SALEM
FULTON
SARATOGA
BENNINGTON
TO BEAR SWAMP
MADISON
OTSEGO
SCHENECTADY
SCHOHARIE
ALBANY
RENSSELAER
TO NORTHFIELD MTN
STEPHENTOWN
TO NEW ENGLAND
EAST NORWICH
COLLIERS
BLENHEIM
GILBOA
AXTELL RD
BLOOMVILLE
COLUMBIA
GREENE
AFTON
FRASER
DELAWARE
ANDES
ARKVILLE
BELLEAYRE
SHANDAKEN
BROOME
STILESVILLE
HANCOCK
HAZEL
GRAHAMSVILLE
ULSTER
DUTCHESS
SULLIVAN
FERNDALE
TO NEW ENGLAND
TO FROST BRIDGE
COCHECTON
ROCK HILL
PAWLING
Putnam Lake
PUTNAM
CROTON FALLS
WESTCHESTER
ORANGE
TO FRANKLIN
PENNSYLVANIA
NEW JERSEY
TO BRANCHBURG
White Plains
LONG ISLAND SOUND
SUFFOLK
NEW YORK CITY
For more detail of the NEW YORK CITY AREA see inset above.
ATLANTIC OCEAN
NEW YORK CITY

NYPP

NEW YORK POWER POOL

CENTRAL HUDSON GAS & ELECTRIC CORPORATION
CONSOLIDATED EDISON CO. OF NEW YORK, INC.
LONG ISLAND LIGHTING COMPANY
NEW YORK STATE ELECTRIC & GAS CORPORATION
NIAGARA MOHAWK POWER CORPORATION
ORANGE AND ROCKLAND UTILITIES, INC.
POWER AUTHORITY OF THE STATE OF NEW YORK
ROCHESTER GAS AND ELECTRIC CORPORATION

Coordinated by NYPP Planning Staff
Consistent with the April 1977 Filing of the Article VIII, Section 149 b Report.

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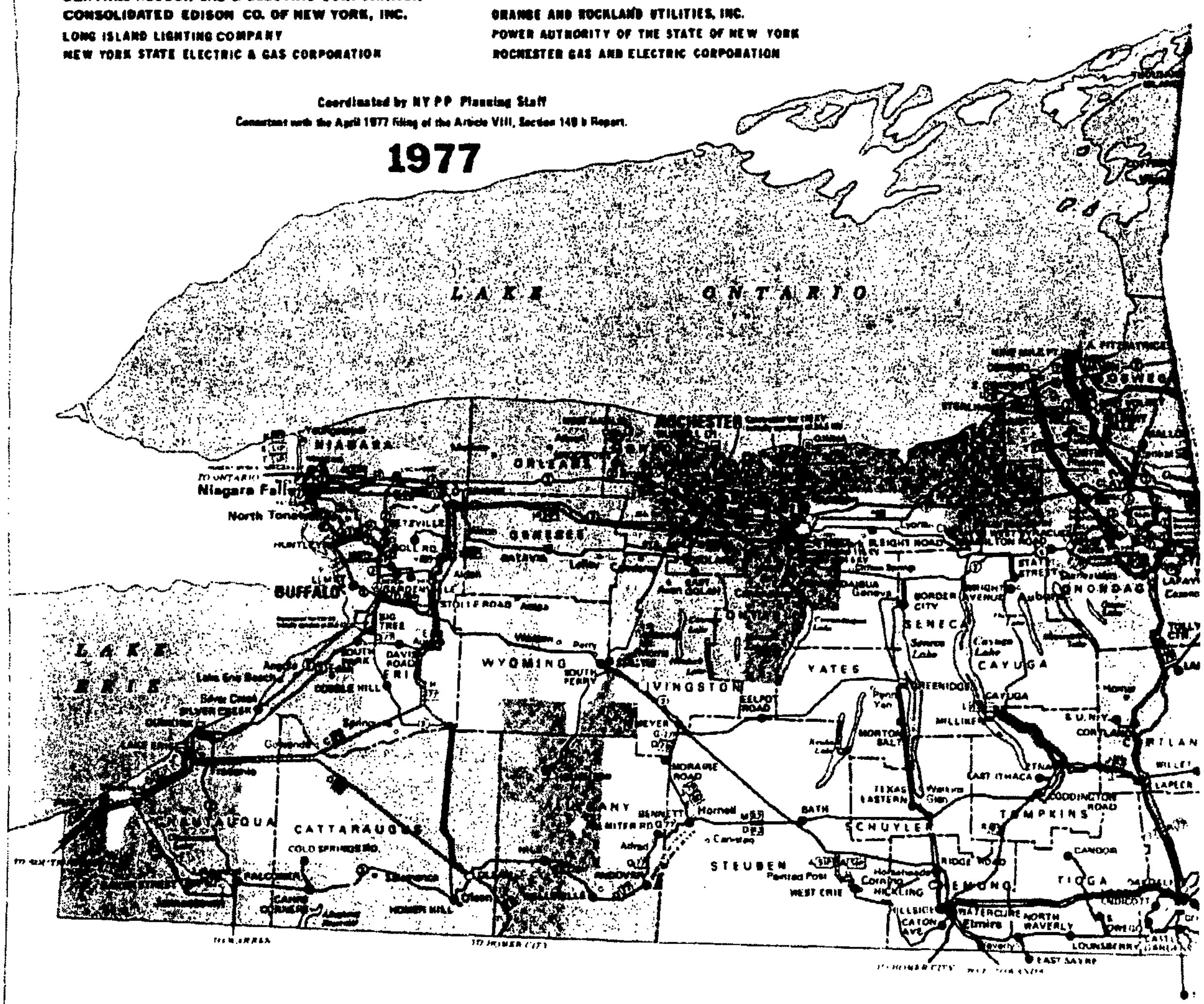

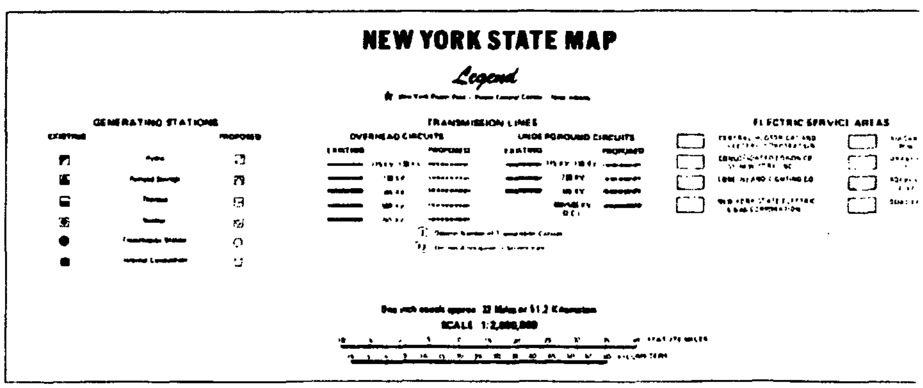

Lake Champlain
CLINTON
ESSEX
HAMILTON
HERKIMER
WARREN
FULTON
SARATOGA
BLISSVILLE
GRANVILLE
SALEM
BENNINGTON
TO BEAR SWAMP
SCHENECTADY
RENSSELAER
SCHOHARIE
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TO NEW ENGLAND
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For more detail of the NEW YORK CITY AREA see inset above.
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NYPP

NEW YORK POWER POOL

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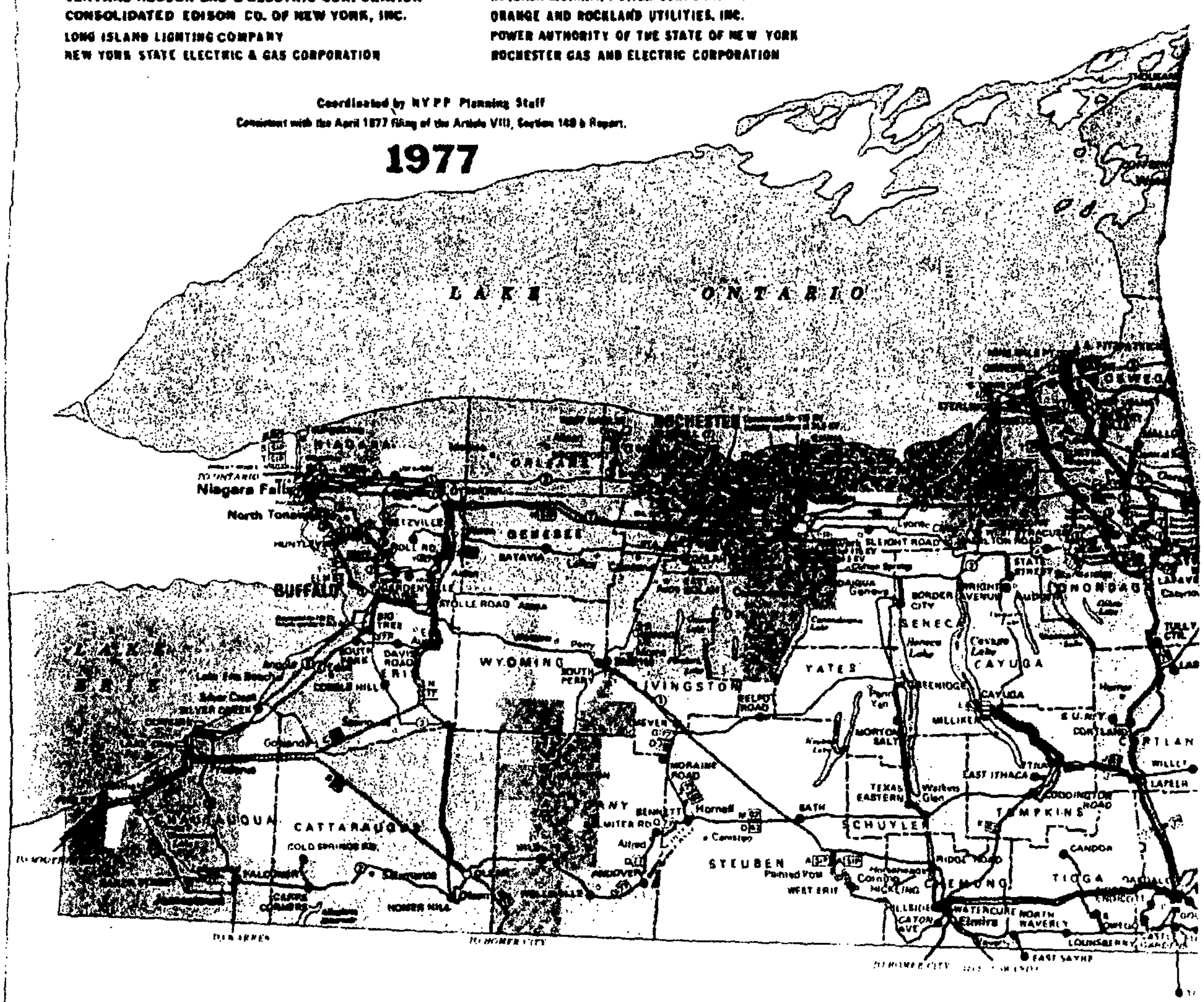

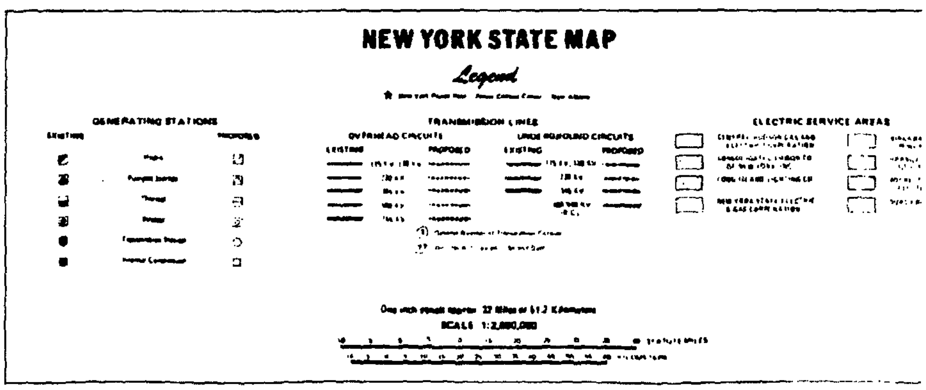

CHAPTER III

THE NORTHEAST POWER COORDINATING COUNCIL

On November 9, 1965, the Northeast Blackout interrupted electric service to some 30 million people over an 80,000 square mile area for periods of a few minutes to 13 hours. The event emphasized for the electric utilities of the Northeast the critical importance of reliability in the design and operation of electric power systems.

The widespread interruption triggered the most intensive investigation and analysis in the history of the electric power industry. After causes of the interruption and the sequence of events were determined, a Task Force was formed to verify the events through established engineering simulation programs. The Task Group then considered possible future contingencies in their simulations which resulted in changed plans, installation of special protective equipment, broadened operations control, and development of planning and operating criteria for the participating Northeast systems--all directed at minimizing the extent of any resultant interruption.

At the same time, executives from the Northeast electric systems began to reexamine the whole philosophy of interconnections and the procedures for coordinating planning and operations then in effect. Their conclusion was that, although interconnected systems in the Northeast provide a high degree of reliability to the consumer, it could be improved by greater coordination in the planning of future power systems and in their daily operation.

On January 19, 1966, very shortly after the Northeast Blackout, executives representing electric systems in New York, New England, and Ontario signed a Memorandum of Agreement establishing the Northeast Power Coordinating Council (NPCC), the first organization of its kind in North America.

The following year, the Federal Power Commission's Industry Advisory Committee on Reliability of Bulk Power Supply singled out regional coordination as "the most effective and economical means for assuring bulk power supply reliability for the Nation. 9/ Concurring with this view, the Commission recommended that ". . . strong regional organizations need to be established throughout the Nation for coordinating the planning, construction, operation,

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9/ FPC Prevention of Power Failures, Vol. II, July 1967.

and maintenance of bulk power supply." By the end of 1967, utilities had voluntarily established five coordinating councils to improve power supply reliability within their respective regions. Presently, there are nine Regional Electric Reliability Councils which cover virtually all interconnected systems in the continental United States and bordering provinces of Canada. 10/

The Northeast Power Coordinating Council presently consists of 21 member 11/ systems which supply about 98 percent of the electric requirements in New England, New York, and the Canadian provinces of Ontario and New Brunswick.

The purpose of NPCC as stated in their Memorandum of Agreement ". . . will be to promote maximum reliability and efficiency of electric service in the interconnected systems of the signatory parties by extending the coordination of their planning and operating procedures." Full membership is limited to electric utility systems, whether investor-owned companies or governmental agencies, which by virture of generating or transmission capacity or concentration of load can have a substantial effect on the service reliability of the interconnected systems.

The work of the Council is done by an executive committee, three standing committees on system design, operating procedures and public information, and nine task forces, which carry on studies of all important aspects of bulk power supply reliability. In addition, the Council has a technical staff of full-time employees.

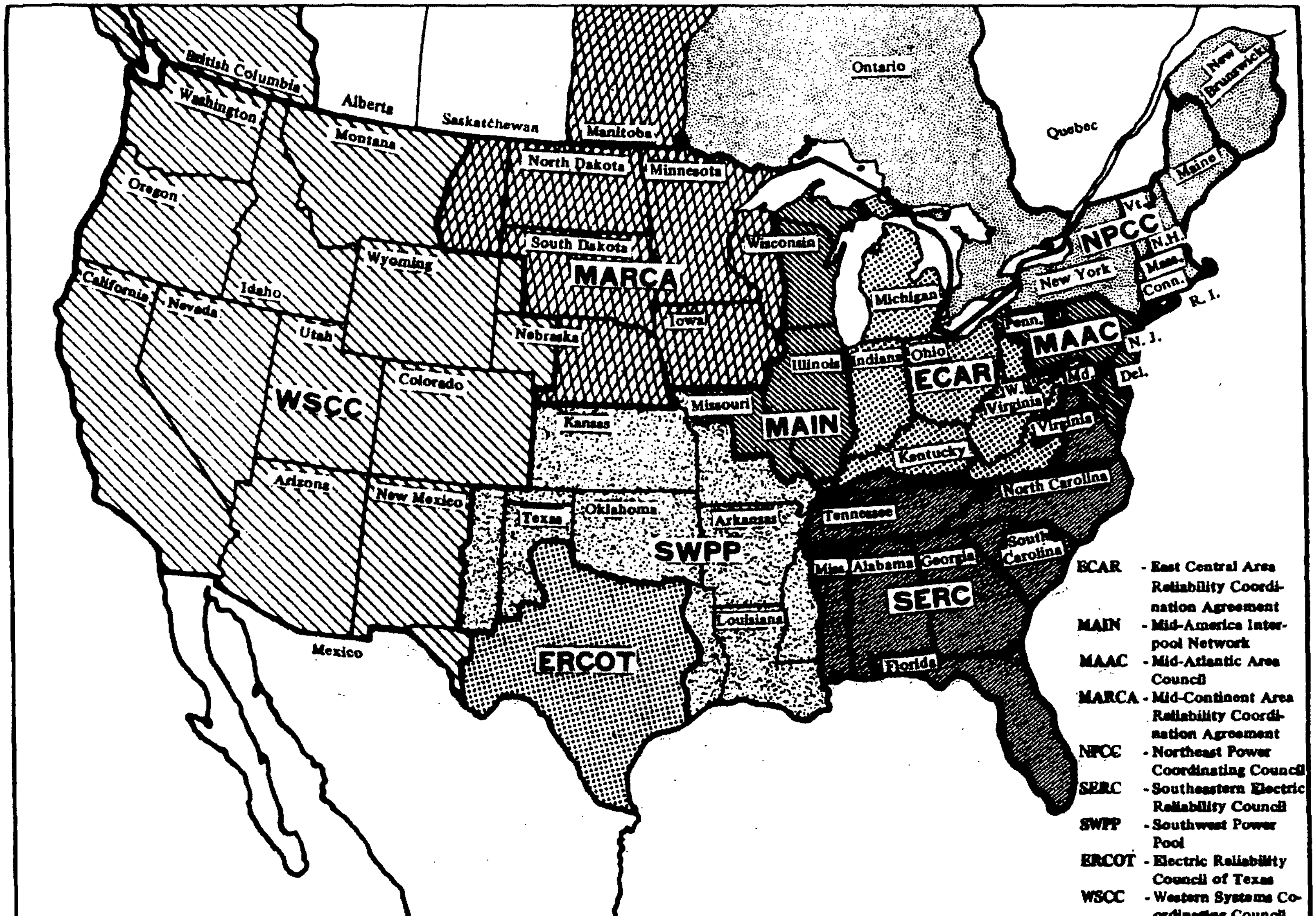
Four distinct planning and operating entities exist within the NPCC region, two in the United States and two in Canada. NPCC member systems located in New England are also members of the New England Power Pool (NEPOOL), and systems in New York State are members of the New York Power Pool (NYPP)--both of which operate under formal agreements on file with the Federal Power Commission. New Brunswick Electric Power Commission and Ontario Hydro are single entities serving their respective Provinces in Canada.

NPCC's "Memorandum of Agreement" discussed earlier and their "Statement of Principles Regarding the Council's Role in Planning" approved July 8, 1970, form the basis for the overall work of the Committees, Task Forces, Working Groups, and Technical Staff. 12/ The "Statement of Principles" lists the following:

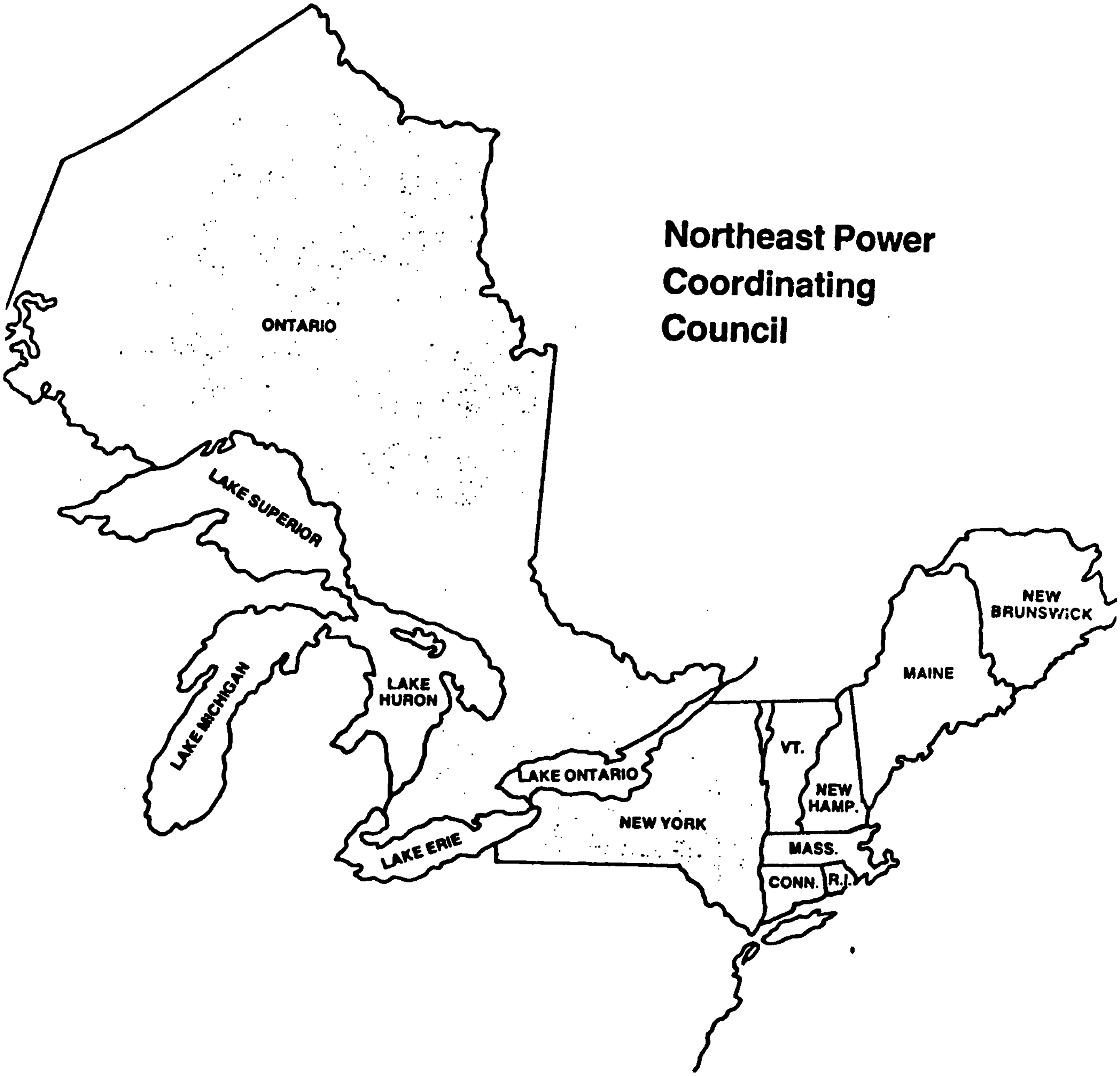
10/ See Map of Regional Electric Reliability Councils.

11/ See Map on Page and List of Members on Page

12/ See NPCC Organization Chart.



REGIONAL ELECTRIC RELIABILITY COUNCILS

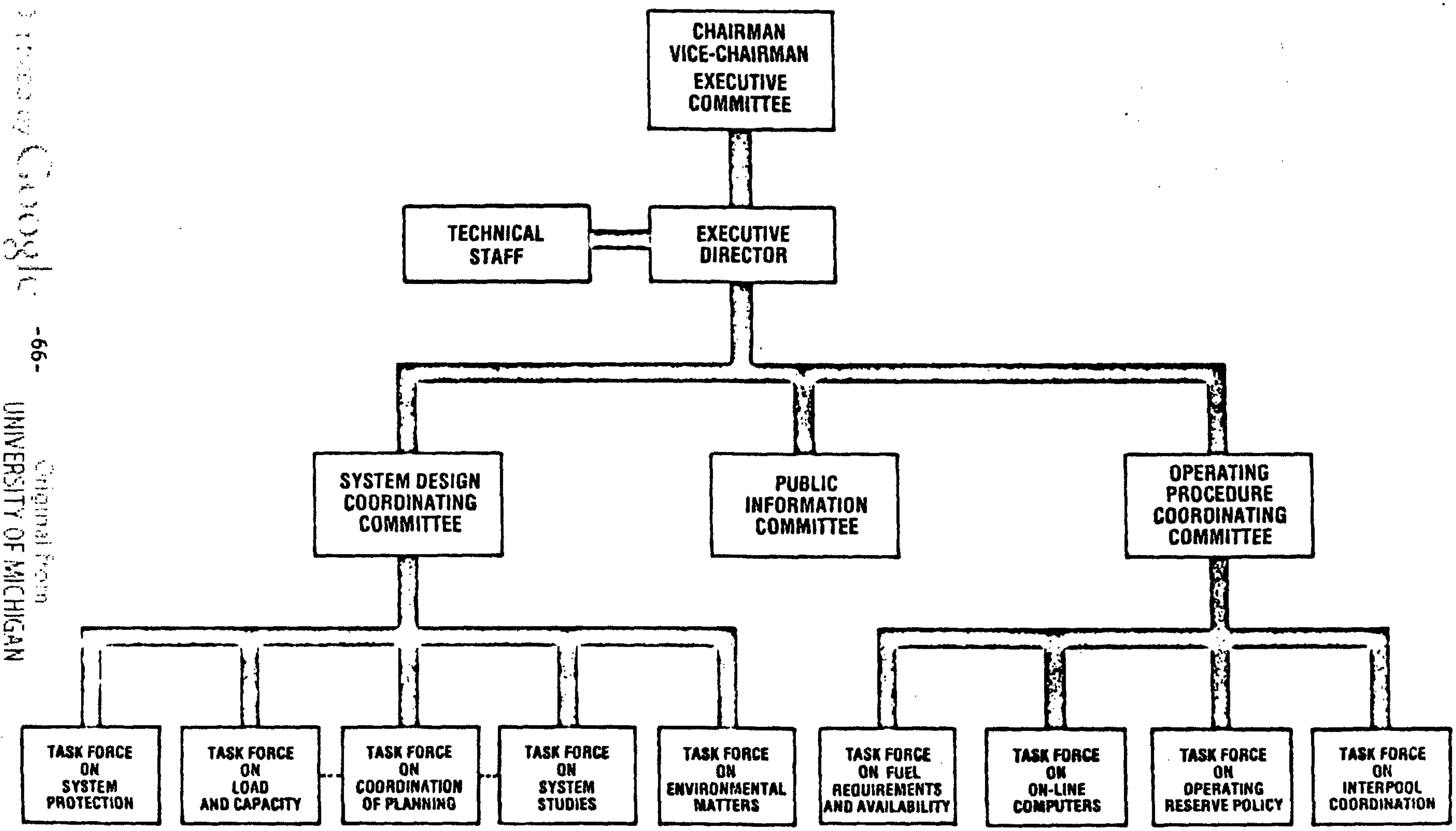


Northeast Power Coordinating Council

Northeast Power Coordinating Council
Membership List

Member Systems	Executive Offices
Boston Edison Co.	Boston, Mass.
Burlington Electric Department	Burlington, Vermont
Central Hudson Gas & Electric Corp.	Poughkeepsie, N. Y.
Central Maine Power Co.	Augusta, Maine
Central Vermont Public Service Corp.	Rutland, Vermont
Consolidated Edison Co. of New York	New York, N. Y.
Eastern Utilities Associates	Boston, Mass.
Northeast Utilities	Hartford, Conn.
Ontario Hydro	Toronto, Ontario, Canada
Orange and Rockland Utilities, Inc.	Spring Valley, N. Y.
Power Authority of the State of New York	New York, N. Y.
Public Service Co. of New Hampshire	Manchester, N. H.
Rochester Gas and Electric Corp.	Rochester, N. Y.
The United Illuminating Co.	New Haven, Conn.
Green Mountain Power Corp.	Burlington, Vt.
Long Island Lighting Co.	Mineola, N. Y.
The New Brunswick Electric Power Commission	Fredericton, N.B., Canada
New England Electric System	Westboro, Mass.
New England Gas and Electric Assoc.	Cambridge, Mass.
New York State Electric & Gas Corp.	Binghamton, N. Y.
Niagara Mohawk Power Corp.	Syracuse, N. Y.

Northeast Power Coordinating Council Organization



1. The System Members of NPCC shall report periodically their 10-year plans (including alternatives) for transmission and generation.

2. NPCC shall evaluate the plans from the standpoint of suitability for and the reliability of the Northeast Interconnected Systems and report its assessment and recommendations to the membership.

One important function of the Council is to provide the annual response to the Federal Power Commission's Order No. 383-4, Appendix A-1, Docket R-362. There are presently 10 items in Appendix A-1 all relating to future load projections, capacity additions, transmission line additions, statement on adequacy of plans, load flow and stability studies, communication and control facilities, and coordinated regional practices. The NPCC Task Forces, as well as the two U.S. entities within NPCC, provide the information for the "NPCC - Data on Coordinated Regional Bulk Power Supply Programs". These reports, submitted annually on April 1, are maintained as public information references by the Federal Power Commission.

The NPCC standing committees direct the efforts of the task forces. Some current activities of the task forces with duties directly related to regional reliability are as follows:

A. System Protection

1. Reviews underfrequency performance of nuclear pressurized water reactors.

2. Development of an NPCC philosophy for automatic reclosing of transmission lines.

3. Reviews status of the NPCC automatic load shedding program.

B. Load and Capacity

1. Issues the load and capacity report as part of response to FPC Order No. 383-4.

2. Supplies Load and capacity data to the national Electric Reliability Council.

C. Coordination of Planning

1. Reviews general pool-to-pool transmission interconnection studies

2. Reviews New England Power Pool and New York Power Pool analyses of generation reliability and reserve requirements.

D. System Studies

Examines the reliability of the future systems on two bases: security of the interconnected power system and the manner in which they are expected to recover from various types of disturbances; and the effect of reliability of the availability of generation and transmission.

E. Fuel Requirements and Availability

Submits NPCC expected fuel requirements on a monthly basis for two years into the future and thereafter on an annual basis for 10 years.

F. Operating Reserve Policy

Develops revisions to Operating Policy. The policy is presently reported to FPC under Order No. 383-4, Appendix A-1, Item 9-h.

G. Interpool Coordination 13/

1. Exchanges on a monthly basis transmission and generation overhaul and maintenance schedules and reviews the near-term capacity situation.

2. Reviews system disturbances.

3. Provides liaison with the North American Power Systems Interconnection Committee (NAPSIC).

All members of the New York Power Pool (NYPP) are members of NPCC. The New York Power Pool is one of the four areas of NPCC which provide a focus for electric system planning and operation. All members of the NYPP are bound by the multi-party pool agreement filed with the Federal Power Commission. The agreement not only provides the means whereby the member systems can coordinate system planning and operations (a similar function of the NPCC) but establishes rates and charges for equitable sharing in the benefits of such coordinated actions. The agreement also establishes the New York Power Pool Control Center which coordinates the operations of NYPP, dispatches energy requirements on an economic basis, and monitors security of the systems. The Control

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13/ Represents NEPOOL, NYPP, Ontario Hydro, New Brunswick operating areas. Michigan Pool and Pennsylvania-New Jersey-Maryland Interconnection participate as observers.

Center can then sell or purchase electric power and energy from not only the other three area dispatch centers (NEPOOL, Ontario, New Brunswick) within NPCC but other adjacent system dispatch centers.

A function of NPCC can be more appropriately viewed as providing the mechanism for coordinated planning and operations between the four areas in NPCC.

NPCC reviews the generation and transmission expansion plans for all four areas within NPCC. The test for each area plan, including the New York Power Pool, is whether it meets the established NPCC "Basic Criteria for the Design and Operation of Interconnected Power Systems".

NPCC performs a number of studies encompassing two or more of the four areas. For example, their April 1, 1977, response to FPC Order No. 383-4 reports for the year 1976 that a New York-New England interconnection study, which presents a logical expansion plan to increase power transfer capabilities between the two areas on a step-by-step basis with estimated costs, was completed. Also, a New York-Ontario interconnection study was completed to examine power transfer capabilities between the two areas for the projected 1980 and 1985 systems so as to determine the generating capability which might be available in each area for transfer to the other.

All of the present nine Regional Reliability Councils, including NPCC, belong to the National Electric Reliability Council (NERC) which was formed in June 1968 to encourage improvement of coordination at both the regional and national levels. Its stated purposes are to:

1. Encourage and assist the development of interregional reliability arrangements among regional organizations for their members;

2. Exchange information on planning and operation matters relating to the reliability of bulk power supply;

3. Review, periodically, regional and interregional activities on reliability;

4. Provide independent reviews of interregional matters referred to it by a regional organization; and

5. Provide information to the FPC and other Federal agencies.

NPCC is represented on all major NERC standing committees. In addition, NPCC regularly acts as a vehicle for providing information requested by NERC and for disseminating NERC reports to the member systems.

NPCC reported in their April 1, 1977, response to FPC Order No. 383-4 participation in the following NERC reviews:

1. A Study of Interregional Energy Transfers for the Year 1980

2. Fossil and Nuclear Fuel for Electric Utility Generation: Requirements and Constraints - 1976 through 1985

3. Sixth Annual Review of Overall Reliability and Adequacy of the North American Bulk Power Systems

Besides NPCC's membership in NERC, NPCC maintains two Interarea Coordination Agreements between the Executive Boards constituted under the Mid-Atlantic Coordination Agreement (MAAC) and the East Central Area Reliability Coordination Agreement (ECAR)--both being other reliability councils. Each of these agreements establishes an inter-area review committee to:

1. Exchange information on respective activities and decisions, including system future plans and forecasts;

2. Examine the effects of activities and decisions in one area on the reliability of bulk power supply in the other area and report findings to the respective parties.

NPCC has entered into joint inter-area studies with both ECAR and MAAC. Under the direction of a Joint Inter-Area Review Committee, the MAAC-ECAR-NPCC (MEN) Study Committee directs two working groups:

1. The MEN Future Systems Working Group studies interregional transmission electric power transfer capabilities.

2. The MEN Operating Studies Working Group performs power transfer capability and limited reliability assessments during the time of summer and winter peaks for each year. For example, the "1977 Summer Operating Study" was completed in May 1977 and includes:

a. Appraisal of Normal Operating Conditions;

b. Summary of 1977 Summer Emergency Transfer Capabilities; and

c. Appraisal of Network Stability.

The Northeast Power Coordinating Council participates by way of its members in the North American Power Systems Interconnection Committee (NAPSIC). In 1962, representatives of interconnected systems throughout the United States and parts of Canada met and laid the groundwork for a voluntary international organization to coordinate the operation of a developing coast-to-coast interconnected network. This led to the formation of NAPSIC. As of today, there are ten NAPSIC operating areas within three major interconnected systems in the U.S. and Canada: the Eastern, Western, and Texas Interconnected Systems. NPCC comprises about 18 percent of the total peak load demand in the Eastern Interconnected System (EIS) while EIS represents about 75 percent of the total peak demand for the entire U.S. and eastern Canadian interconnected systems.

The principal goals NAPSIC set for itself were to coordinate frequency, operating criteria related to time error, and tie-line bias settings. NAPSIC publishes an Operating Manual which includes twenty-two Operating Guides. The Guides also address emergency operating procedures. Although the Guides establish general criteria to enunciate generally accepted principles and codify minimum operating criteria for coordinated operation, they are not explicit enough to be used as detailed specifications for system operation.

NAPSIC's contribution to reliable system performance is enhanced by its close liaison with planning entities, regional reliability councils, and the National Electric Reliability Council.

FPC's HISTORICAL ROLE IN PROMOTING RELIABILITY

The Commission seeks to influence the planning, coordination and operation of the Nation's bulk power supply system in part through a series of reports which the councils and utilities are required to file at various times, and in part through attendance at meetings of the regional councils.

Order No. 383 issued on June 25, 1969 and subsequent amendatory orders (current Order No. 383-4), issued December 13, 1976) provide for extensive reports on existing generating, transmission, environmental, communications and safety equipment as well as planned future equipment, operation and loads in each of the nine regional councils. Reports are submitted to the appropriate state commissions. Much of the data contained in these reports are summarized by the Bureau of Power in a series of Staff reports. The Order No. 383-4 report requirements are in the process of being revised extensively in order to provide more uniform reporting among the individual regional councils.

Order No. 445 issued January 11, 1972 states the policies the Commission will observe under the voluntary action concepts of Section 202(a) of the Federal Power Act, in minimizing the consequences of bulk power supply interruptions or shortages. The general intent is to provide guidance to those who operate electric utilities as well as to those customers who are faced with power supply interruptions or shortages. Each jurisdictional utility and utility holding membership in a regional council was asked to make the following information public and, at the same time, to submit the information to the Commission: load shedding programs, emergency power and shutdown facilities, facilities available for startup, availability of continuous power for communications and control facilities as well as provision for scheduling maintenance outages and maintaining relays that affect the overall reliability of the interconnected network. Most utilities have complied with Order No. 445 by submitting initial reports, but few are providing revised reports when substantial changes in equipment or operating procedures occur.

The Commission also requires reports during certain emergencies that occur on electric utility systems. Pursuant to Order No. 331-1 issued on May 21, 1970 utilities are required to report interruptions of bulk electric power supply caused by the outage of any generating unit or electric facility operating at a nominal voltage of 69 kV or higher and resulting in a load loss for fifteen minutes or longer of at least 100 megawatts, or when the load loss is more than one-half of the annual peak load. Reports are made by telephone or telegraph during extended interruptions, followed by a written report. These interruptions are summarized quarterly in Bureau of Power Staff reports and released through the Commission's Office of Public Information.

Pursuant to Order 438 issued on March 15, 1974 utilities are required to report on Form 237A (coal) or Form 237B (oil) weekly during fuel emergencies. Because each utility has unique fuel requirements, the individual utility determines when a fuel emergency exists. When many utilities experience a fuel emergency simultaneously, the Commission issues emergency orders for limited term data collection so as to obtain all necessary data in the most convenient format. For instance, after the imposition of the Arab oil embargo in October, 1973 the Commission issued Order 497 (series) initially on December 7, 1973 implementing Form 23 (series), the Monthly Electric Utility Generation and Fuel Planning Report Form. Shortly after the United Mine Workers struck in 1974, the Commission issued Order No. 515 on November 7, 1974 which implemented weekly reporting of coal deliveries, consumption and stockpiles at major coal burning utilities.

Commission personnel attend NERC Executive Board meetings as official observers. They attend annual meetings, executive board meetings of the regional councils, as well as some regional council committee meetings. Order No. 383-4 specifically provides for state commission personnel to attend regional council executive board and committee meetings also. In eight of the nine regional council areas, the Commission has assisted in the formation of State-Federal Coordination Committees (consisting of personnel from the staffs of state commissions and Federal agencies). Commissioners are welcome at these meetings. The Coordination Committee meetings are open to regional council personnel or utility representatives only by direct invitation. The Coordination Committee in the NPCC area has been inactive during recent months due to the inability of several state commission staffs to obtain funding for attendance at such meetings.

GLOSSARY

1. Breaker Closing Switching Surge

When any device is connected to or disconnected from an operating electric system, "transient" electric voltages and currents are established. The "transients" disappear rapidly under normal conditions, but their magnitudes, for a few hundredths of a second, may be much higher than normal. Electric circuit characteristics are such that the transients travel along transmission lines very rapidly, building up "wave fronts" of voltage and current. Under some conditions, the magnitudes of the transients may be large enough to damage equipment or cause the operation of devices designed to protect equipment from damage.

A circuit breaker in "closing" (connecting a device or a line to the system) or in "opening" (disconnecting a device or a line) initiates a transient (surge) of the type described above.

2. Bus (or Busbar)

An electrical "bus" is an electrical connection between several transmission lines or facilities (transformers, circuit breakers, generators).

The physical form of a bus may be a large bar of copper or aluminum, a long large diameter (6 inches) tube, or rectangular arrangement of either, or a length of wire suspended from insulators. For a 3-phase circuit, a group of 3 such elements constitutes the "3-phase bus". All elements of such a bus are identical. In theory a bus is generally considered to be a single point, regardless of how many lines, etc. are connected to it, with no electrical characteristics except the perfect ability to conduct electricity. In practice, a bus must have physical dimensions and electrical characteristics (resistance, inductance, capacitance). For most purposes the magnitude of these characteristics is negligible.

3. Circuit Breaker

A circuit breaker is a device designed to connect and disconnect some device from an electric circuit. A circuit breaker is so designed that even when the current flowing through it is much greater than normal, little or no damage will be done when the flow of current is interrupted by the "opening" of the "breaker". A circuit breaker is "closed" (a connection is made between a device and the system, or between two transmission lines) when it is desired to "energize" a device or circuit. The "closing" of the "breaker" may be done manually, it may be done by an electric or spring-loaded device under electrical control of an operator, or it may be done automatically by means of a relay. A "relay" is a device which senses conditions on a circuit (voltage, current, power, frequency or other characteristic) and initiates an automatic action by means of an electric impulse.

Circuit breakers may be "opened" (disconnected) manually or electrically by an operator, or electrically and automatically by a relay. Relays are usually arranged to sense overloads, low frequency or low voltage, "short circuits" or other undesired situations, and initiate "opening" of a "breaker" accordingly so as to disconnect lines or equipment.

4. Conductor

A conductor is a wire (or group of wires combined to act as a single wire) which allows electricity to pass through it readily. But a metal structure (transmission line steel tower, for instance) can also act as a "conductor" when it becomes part of an electric circuit. Thus, if one of the "phase wires" of a transmission line is brought into contact with the steel of the tower, the tower will "conduct" electricity to the ground.

5. Double Circuit Line

An overhead transmission circuit (line) is a set of three conductors which together constitute a system of transferring electric power from one place to another. Each of the conductors is suspended from towers (or poles or other structures) located at intervals along the "right-of-way". The right-of-way may be along a railroad, the side of a highway or street or a path cut across open country. If the towers support one set of three conductors, the line is referred to as a "single-circuit line". If the towers support two sets of three conductors each, the line is referred to as a "double-circuit line".

6. Major Transmission Line

"Major" is a relative term. For a system whose transmission circuits operate at 69,000 volts (69 kV) and 120,000 volts (120 kV), a "major" line would be one of those operating at 120 kV, designed to transmit a large amount of power. For the Con Edison system, the 500 kV lines to other systems are considered "major" interconnections; the 345 kV lines are considered "major" interconnections, the 138 kV lines would not be considered "major", if the power transmitted by them is small compared with that transmitted by the 345 kV lines.

7. Megavolt-Ampere (MVA)

One megavolt-ampere is one million volt-amperes. One volt-ampere is the product of the volts and amperes associated with a circuit, their magnitudes being such that their product is unity. Thus, 10 volts and 0.1 ampere is 1 volt-ampere; 2 volts and 1/2 ampere is 1 volt-ampere.

The MVA associated with an alternating current circuit is a measure of the power that would be flowing in that circuit if the voltage and current were "in phase". That is, if the voltage and current reach their peaks at the same time during each of the 60 alternations per second, the two are said to be "in phase" and the MVA is the actual power. If the current and voltage reach their peaks at different instants, they are said to be "out of phase" (by so many degrees). The actual power when current and voltage are "out of phase" is equal to the product of MVA and the "power factor". The "power factor" is the cosine of the "angle" between current and voltage, where "angle" is the time difference between the peaks, expressed in angular measure.

8. Oscillation

Oscillation refers to the cyclic movement of a quantity about some normal or average value. For instance, the normal voltage of an alternating current circuit may be 120 kV. Voltage oscillations are said to occur, if the voltage increases above and decreases below 120 kV at some uniform or non-uniform rate. In an electric circuit disturbance, the frequency of alternation of the voltage above and below 120 kV usually is not constant, the voltage may reach 125 kV or 130 kV, drop to 100 kV or 110 kV and "oscillate" in that manner, at the same or with different magnitudes of voltage for seconds or minutes. Current may also oscillate about its normal value, and then power will also oscillate.

9. Phase-Angle Regulator

A group of transformers connected in a certain way and especially designed for use in shifting the phase of one circuit with respect to another. Alternating current circuits are those in which current and voltage vary from zero to maximum, and reverse their direction of flow, at a regular rate (60 times per second, or "60 Hertz", for U.S. electric power systems). The characteristics of electrical transmission lines (resistance, inductance, capacitance) cause the peak of the variation (current and voltage) to recur regularly at different times in different circuits. This difference in times of occurrence of the peak of the "wave" of current (and voltage) in different circuits is referred to as a "phase shift". For reasons related to the electrical characteristics of system networks, the "phase shift" in normal operation may be large between circuits connected to different networks or to different parts of the same network. "Phase" as used in this discussion refers to the time of occurrence of corresponding magnitudes of current (or voltage) on different circuits.

As a result of "phase shift" (or "phase angle" difference) between two circuits, large undesired currents may flow when these circuits are connected to form a loop. The phase angle regulating transformer, by means of its special windings and connections, adjusts the phase of one circuit with respect to another so that the "phase angle" difference is small and the undesired currents are reduced to a tolerable level. In so doing it controls the power flow between the points to which it is connected.

10. Phase-To-Ground Fault

"Phase" in the sense used here refers to a physical part of a circuit: one of the circuit wires or a device attached to one of the wires. A "three-phase" circuit is one which uses three circuit wires to transmit power. These wires may be identified as "A", "B", "C". "Ground" in the sense used here refers to the earth or to some structure connected to or supported by the earth (a building, a transmission line tower, an automobile).

"Fault" in the power system sense refers to an unintended electrical connection, which allows undesired currents to flow.

Thus, a "phase C-to-ground fault" means an unintended (accidental) connection (touching) of the circuit wire identified as "Phase C" and "ground". An accidental connection of this type is often called a "short circuit"; it causes undesired currents to flow which, depending on the circumstances, may cause damage.

11. Stability

A system is said to be "stable" when a disturbance causes only a brief departure from its operating state followed by operation at a new "normal" state.

"Instability" describes a circuit condition in which a disturbance causes a prolonged departure from normal operating values of currents, voltages, power and phase angles and failure to return to a new "normal" state,such that parts of the circuit must be disconnected. On an electric power system, a disturbance may be failure of a generator, accidental "opening" of a line (disconnection of the line from part of the circuit), "short-circuit" of some line or device (accidental connection to some part of the circuit) or other accident, or a sudden increase or decrease of load in large magnitude. Any of these disturbances may cause system frequency, voltages, currents and power flows to change. If the system frequency returns to normal within a few seconds, and if voltages, currents and power flows become steady at their new values, the system is said to be "stable". The system is said to be "unstable" if any disturbance is accentuated by the system itself, and causes additional, greater changes in frequency, voltage, currents, etc., to the extent that automatic devices (or manual devices) operate to disconnect facilities to prevent damage.

12. Substation

A substation is a location at which electric power in bulk is received from one or several sources, and is sent out to one or several locations. The voltage of the incoming power may be transformed (changed) to a higher or lower voltage before the power is sent out.

At a power plant, the voltage of the power produced by the generator is relatively low (some 18,000 volts to 33,000 volts) and it is "stepped up" at the power plant substation for transmission at 120,000 volts, 345,000 volts or other voltage level.

At a switching substation, the incoming power may or may not be moved through a transformer (voltage level changer) and will generally be connected to a bus (see definition) so that it can be distributed over several outgoing transmission lines.

At a distribution substation, power received in bulk at a high voltage is transformed to a lower voltage and sent out in smaller amounts over several lower-voltage lines.

A substation may contain, among other items, structures for supporting transmission lines, circuit breakers, switches for connecting circuit breakers to lines, relays and associated devices for automatically operating circuit breakers, and metering equipment for measuring and recording voltage, current, power and other electrical quantities.

S-40

STATE OF NEW YORK
DEPARTMENT OF STATE
ALBANY NY, 12231

Basil A. Paterson
Secretary of State

Mr. William Matuszeski
Assistant Administrator
Office of Coastal Zone Management
United States Department of Commerce
3300 Whitehaven Street, N.W.
Page Building 1
Washington, D.C. 20235

August 13, 1982

Dear Mr. Matuszeski:

I am pleased to submit New York State's Coastal Management Program and Final Environmental Impact Statement.

As Secretary of State, I have been designated, pursuant to the Waterfront Revitalization and Coastal Resources Act of 1981, and Chapter 464 of the 1975 Laws of New York State, to prepare and implement a coastal management program. This document is the culmination of years of local, state and federal government efforts, as well as those of groups representing civic, environmental, development, and other interests.

The public and government officials have had numerous opportunities to shape this program. Public meetings, held in 1978, were followed by public hearings in early 1979 conducted by this agency. Legislative hearings were held in late 1979. There were over 1,000 meetings to assist in the preparation of this document. As a result of the comments received, the State's program uses a networking approach enforced primarily through the existing New York State Environmental Quality Review Act.

In accordance with .the provisions of Section 102(*2)* (c) of the National Environmental Policy Act of 1969, 1,500 copies of the Draft Environmental Impact Statement on the proposed New York State Coastal Management Program were circulated for review and comment to Federal, State, regional and local government agencies as well as to numerous private interest groups. In response to the many comments received, numerous changes have been made to the program.

In accordance with the requirements of the Coastal Zone Management Act regulations (Section 923.48), a letter from the Governor will follow after the minimum ten-day review following the notice of availability of the Final Environmental Impact Statement. This review period is a requirement of the New York State Environmental Quality Review Act regulations (6NYCRR Section 617.9).

Upon completion of the Federal review process, we anticipate New York State will have an approved Coastal Management Program in September, 1982.

Sincerely,

Basil A. Paterson

Basil A. Paterson

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Chapters 701 to 1006 (End)

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ment of environmental conservation out of any moneys in the state treasury in the general fund to the credit of the state purposes fund and not otherwise appropriated, to defray the expenses of the department including personal services, operation and maintenance, in carrying out the provisions of article thirty-four of the environmental conservation law as added by this act[1]. Such moneys shall be payable from the state treasury on the audit and warrant of the comptroller on vouchers certified or approved in the manner prescribed by law.

[1] ECL § 34-0101 et seq.

§ 6. This act shall take effect immediately.

WATERFRONT REVITALIZATION AND COASTAL RESOURCES

Memorandum relating to this chapter, see Executive Memoranda, post

CHAPTER 842

Approved July 27, 1981, effective as provided in section 2

Passed on message of necessity. See Const. Art. IX, § 2(b)(2), and McKinney's Legislative Law § 44

AN ACT to amend the executive law, in relation to waterfront revitalization and the coastal resources

The People of the State of New York, represented in Senate and Assembly, do enact as follows:

Section 1. Subdivision one of section nineteen hundred eleven[1], subdivision two and the opening paragraph of subdivision five of section nine hundred fifteen and the opening paragraph of section nine hundred sixteen of the executive law, as added by a chapter of the laws of nineteen hundred eighty-one amending the executive law relating to waterfront revitalization and the coastal resources, as proposed in legislative bill number S. 1244 - A. 1646[2], are amended to read as follows:

1. "Coastal area" shall mean (a) the state's coastal waters, and (b) the adjacent shorelands, including landlocked waters and subterranean waters, to the extent such coastal waters and adjacent lands are strongly influenced by each other including, but not limited to, islands, wetlands, beaches, dunes, barrier islands, cliffs, bluffs, inter-tidal estuaries and erosion prone areas. The coastal area extends to the limit of the state's jurisdiction on the water side and inland only to encompass those shorelands, the uses of which have a direct and significant impact on the coastal waters. The coastal area boundaries are as shown on the coastal area map on file in the office of the secretary of state as required in section [nine hundred fifteen] nine hundred fourteen of this article.

[1] Probably should be section nine hundred eleven.
[2] 1981 McKinney Session Laws, Ch. 840.

2. The secretary may provide technical and financial assistance as provided in sections [nine hundred sixteen and] nine hundred seventeen and nine hundred eighteen to any local government for the preparation of a waterfront revitalization program for the purposes of this article.

The secretary shall approve any local government waterfront revitalization program as eligible for the benefits set forth in section [nine hundred seventeen] nine hundred sixteen of this article if he finds that such program will be consistent with coastal policies and will achieve the waterfront revitalization purposes of this article. In making such determination, the secretary shall find that the program incorporates each of the following to an extent commensurate with the particular circumstances of that local government:

In recognition of the state policy set forth in this article to encourage the revitalization of waterfront areas in a manner consistent with local objectives, the following benefits shall apply where a local government waterfront revitalization program has been approved pursuant to section [nine hundred sixteen] nine hundred fifteen of this article.

§ 2. This act shall take effect on the same date as such chapter of the laws of nineteen hundred eighty-one takes effect.[1]

[1] 1981 McKinney Session Laws, Ch. 840.

ALTERNATE ENERGY PRODUCTION, PARTICULARLY BY SMALL HYDRO FACILITIES

Memorandum relating to this chapter, see Executive Memoranda, post

CHAPTER 843

Approved and effective July 27, 1981

AN ACT to amend the energy law and the public service law, in relation to co-generation, and small hydro and alternate energy production facilities

The People of the State of New York, represented in Senate and Assembly, do enact as follows:

Section 1. Section 21-106 of the energy law, as added by chapter five hundred fifty-three of the laws of nineteen hundred eighty, is amended to read as follows:

§ 21-106. Co-generation, small hydro and alternate energy production [facility development] facilities. 1. For the purposes of this article:

a. The term "co-generation facility" shall include any facility with an electric generating capacity of up to eighty megawatts, together with any related facilities located at the same project site, which is fueled by coal, gas, wood, alcohol, solid wastes, refuse-derived fuel, water or

UPDATE

NEW YORK STATE

Energy Master Plan

& Long-range Electric & Gas Report

FINAL REPORT
MARCH, 1982

N.Y. STATE ENERGY OFFICE Hugh L. Carey, Governor. James L. Larocca, Commissioner

Final report, March, 1982

UPDATE

NEW YORK STATE

Energy Master Plan

& Long-range Electric & Gas Report

FINAL REPORT
MARCH, 1982

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New York State

Energy Master Plan

and long-range electric and gas report

EXECUTIVE SUMMARY

James L. Larocca
Commissioner
State Energy Office

Hugh L. Carey
Governor

NEW YORK STATE ENERGY MASTER PLAN AND LONG-RANGE ELECTRIC AND GAS REPORT

EXECUTIVE SUMMARY

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I. INTRODUCTION

It is the policy of the State to conduct energy planning in an integrated and comprehensive manner through development of a long-range State Energy Master Plan, which shall provide the framework for energy-related decisions made throughout the State (Energy Law, Sections 3-101 and 5-110).

Consistent with this State policy, the State Energy Office is required to prepare and biennially review and update as necessary a State Energy Master Plan and Long-Range Electric and Gas Report. The Plan, which must be approved by the Energy Planning Board, contains a forecast of State energy consumption, a forecast of electricity and gas demands, a strategy to meet the State's energy needs, a statement of specific energy policies, and recommendations for administrative and legislative action to implement State energy policy.

This document presents a summary of the first update to the State Energy Master Plan, which was approved by the Energy Planning Board on March 25, 1982.*

The principal goal identified in the first Plan of reducing the State's dependence upon petroleum, particularly foreign petroleum, through increased conservation in all consuming sectors and maximum diversification of the State's fuel mix, and in a cost-effective and environmentally sound manner, remains the central theme of the updated Plan.

Significant progress has been made by the State over the past few years toward achieving this goal, although, as noted below, the State remains highly dependent on expensive and insecure supplies of petroleum. Over the period 1978 to 1980, New York's energy profile has undergone profound changes:

- total energy requirements have declined almost 9 percent;
- petroleum dependence has dropped from 65 percent to 57 percent;
- dependence on OPEC oil has dropped from 36 percent of total energy to 29 percent;
- energy consumption per unit of gross state product has declined over 6%;
- natural gas has increased from 14 percent of the State's energy consumption to 19 percent; and
- the contribution of renewable resources to the State's primary fuel mix has increased by 15 percent.

Despite these positive developments, the State remains significantly dependent upon expensive petroleum, especially imported petroleum, to meet its energy requirements. Indeed, total expenditures by New Yorker's for energy reached $23.4 billion in 1980, a 46 percent increase over 1978.

The updated State Energy Master Plan provides a blueprint for reshaping the State's energy future. It sets forth four basic strategies to reduce New York's reliance on expensive imported oil:

- Increased penetration of conservation technologies and strategies into every aspect of energy use;
- Increased use of renewable energy resources, particularly those indigenous to the State;
- Improved use of natural gas; and
- Accelerated use of plentiful domestic fuels such as coal for electricity generation.

With full implementation of the Master Plan, which will require the active involvement of all responsible State agencies and substantial efforts by the private sector and energy consumers, New York can diversify its fuel mix and reduce its dependence on OPEC oil from 54 percent of petroleum use to a mere 14 percent.

By 1996, oil consumption in New York State could be reduced by approximately 97 million barrels per year, primarily due to the effect of increased conservation, increased use of renewable resources and coal conversions. Coal utilization would increase from 9 percent of total State primary energy consumption to 19 percent and utilization of renewable resources would increase from 8 percent to 13 percent of total primary energy consumption. Petroleum use for electricity generation would decline from 31 percent to 6 percent. The cumulative savings resulting from full implementation of the SEMP recommendations are projected to be approximately $10 billion over the planning period.

Full implementation of SEMP recommendations would also have a significant and favorable impact on the State's economy, resulting in the creation and support of an estimated 25,000 jobs and $467 million in earnings annually over the planning period. Finally, the SEMP recommendations would, if implemented, have a limited incremental effect on the environment.

II. NEW YORK STATE ENERGY PROFILE

New York State's energy profile is significantly different from that of the nation as a whole, in terms of the types and sources of fuel used and the patterns of energy consumption.

- The State is far more dependent upon petroleum and especially imported petroleum than the nation as a whole, as illustrated in Figures 1 and 2. New York relies upon petroleum for 57 percent of total energy consumption, compared to 41 percent for the nation. Moreover, the State's reliance upon foreign oil, particularly OPEC oil, to meet its petroleum needs is far greater than that of the nation. Therefore, the risk of a major petroleum supply disruption is a major concern.
- Figure 3 shows that New York's pattern of energy use differs markedly from that of the nation, with far greater consumption in the residential (including a large multi-family housing component) and commercial sectors and considerably less energy consumption in the industrial sector.
- As seen in Figure 4, New York's consumption of energy in the generation of electricity also differs significantly from the national profile:

  —much more petroleum is consumed in New York (31 percent vs. 12 percent);

  —much less coal is consumed (16 percent vs. 49 percent);

  —more hydro power is consumed (22 percent vs. 13 percent); and

  —somewhat more nuclear power is consumed in New York (16 percent vs. 11 percent).

  Therefore, strategies to help contain rising costs in this sector, such as the oil to coal conversion program, are vital.
- Figure 5 indicates that New York's overall per capita energy consumption is well below that of the nation, demonstrating that New Yorkers are not prolific consumers of energy despite the State's harsh climate. In 1980, New York's per capita consumption had dropped to 74 percent that of the nation, compared to 81 percent in 1965. It should be noted that the relatively low level of per capita consumption reflects, in large measure, substantially lower than average per capita consumption in the industrial and transportation sectors.

*On March 20, 1980, the Energy Planning Board approved the first State Energy Master Plan and Long-Range Electric and Gas Report (SEMP), thus completing the State's initial effort at comprehensive and integrated State energy planning.

- Reflecting the State's patterns of energy use, total expenditures by New Yorkers for energy reached $23.4 billion in 1980, a 46 percent increase over 1978 energy expenditures. Expenditures on petroleum products grew from $9.7 billion in 1978 to $15.2 billion during 1980, as illustrated in Figure 6. Energy has over the past decade become a major factor in the cost of doing business, in the household budget and in State and local government operating expenditures.

New York's energy profile highlights the need for New York State to adopt and implement policies designed to promote increased conservation in all consuming sectors and to diversify the State's primary fuel mix in a cost-effective and environmentally sound manner.

FIGURE 1 ***Primary consumption by fuel, 1980***
NEW YORK STATE AND UNITED STATES

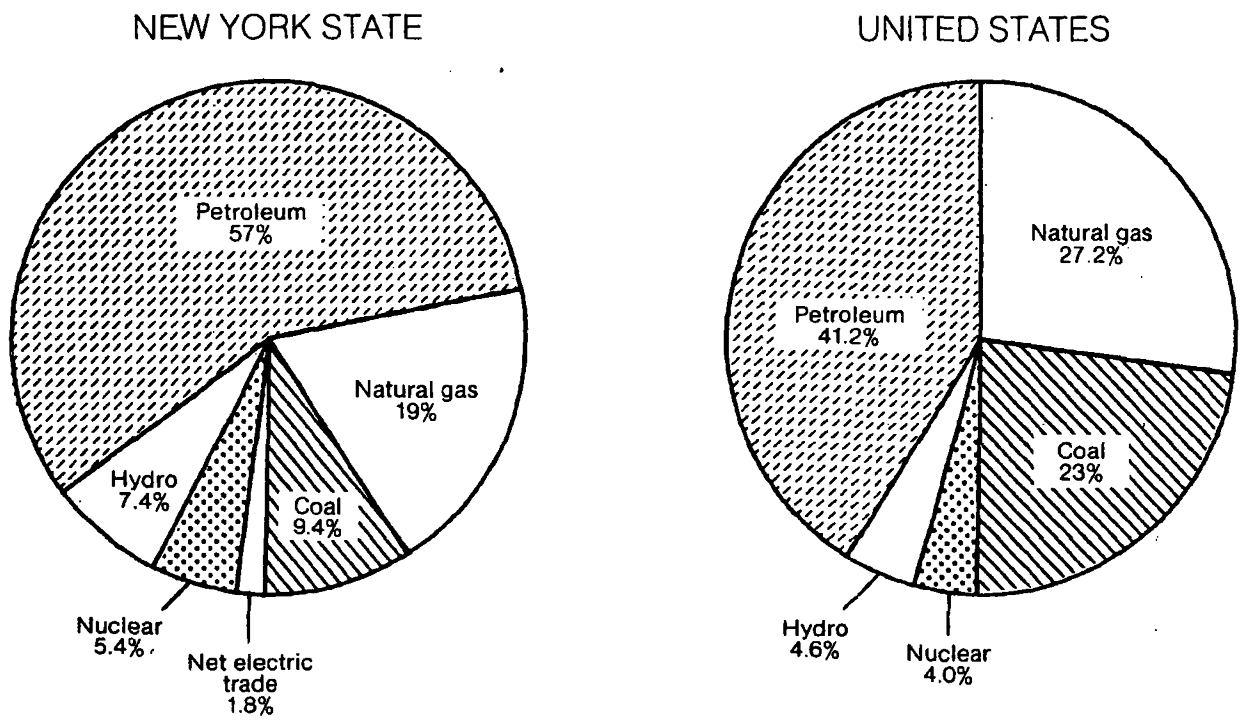
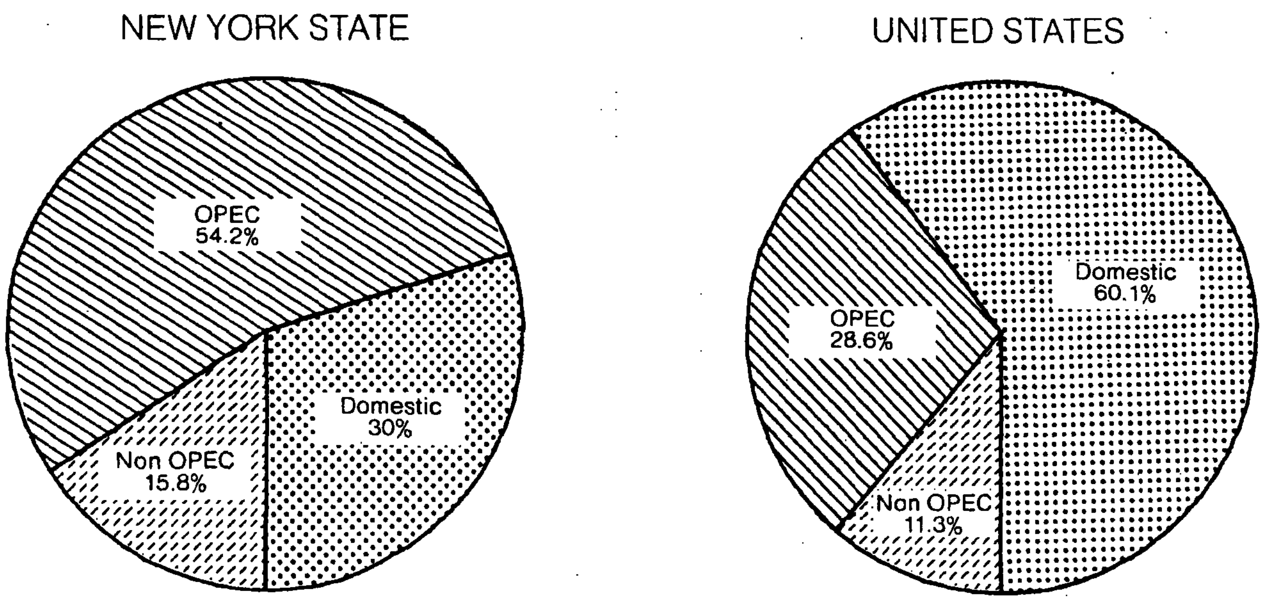


FIGURE 2 ***Sources of petroleum consumed***
NEW YORK STATE AND UNITED STATES, 1980



NOTE: The OPEC dependencies include indirect receipts via the Caribbean refineries.

FIGURE 3 ***Primary energy consumption by sector, 1980***

NEW YORK STATE AND UNITED STATES

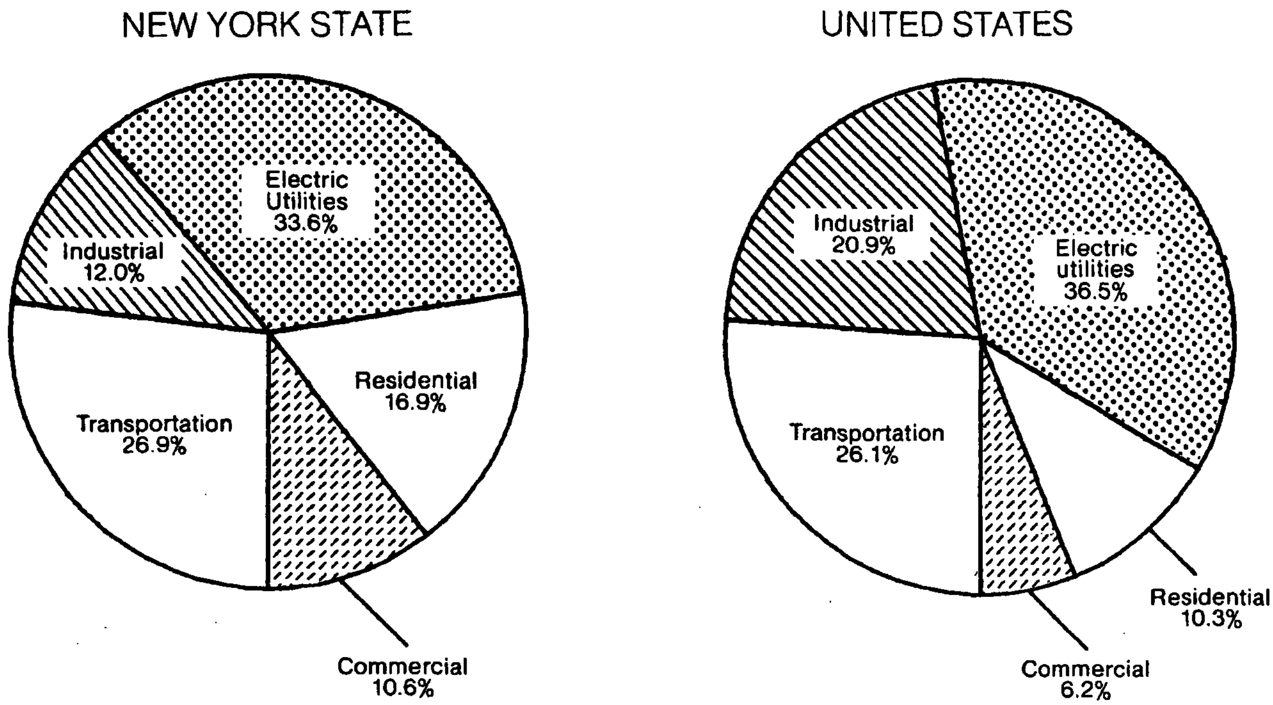


FIGURE 4 ***Primary consumption by the electric utilities, 1980***

NEW YORK STATE AND UNITED STATES

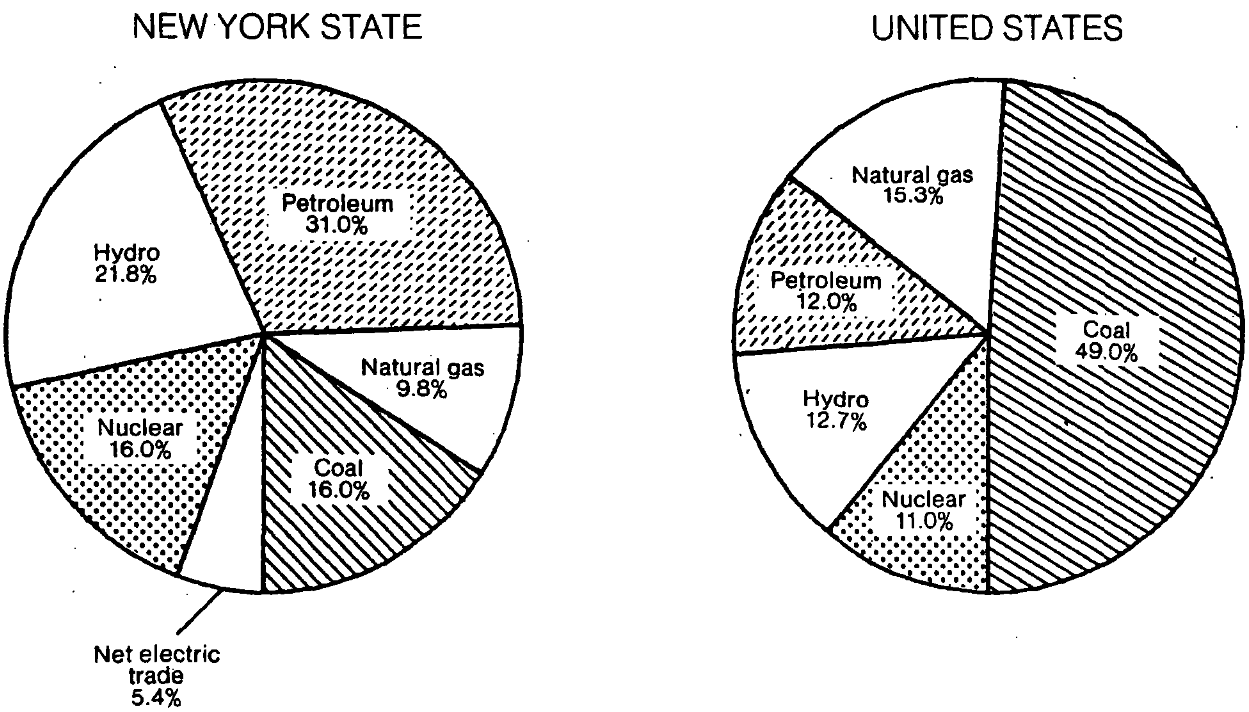


FIGURE 5

Primary energy consumption per capita

NEW YORK STATE AND UNITED STATES

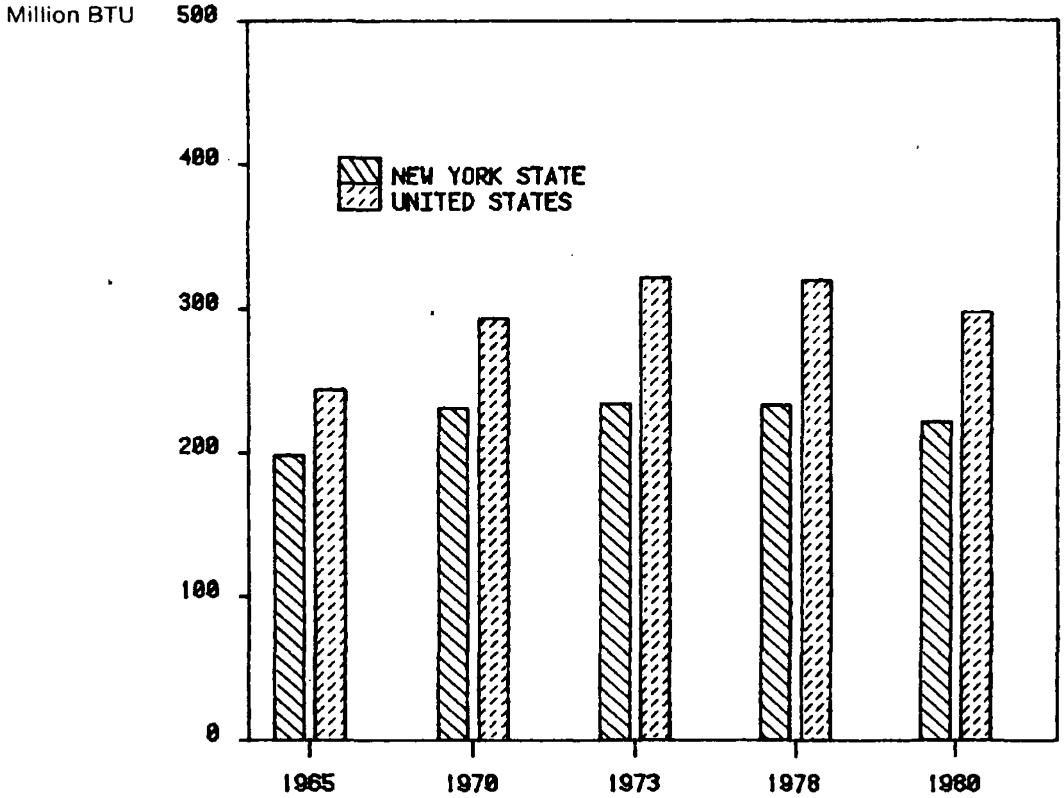
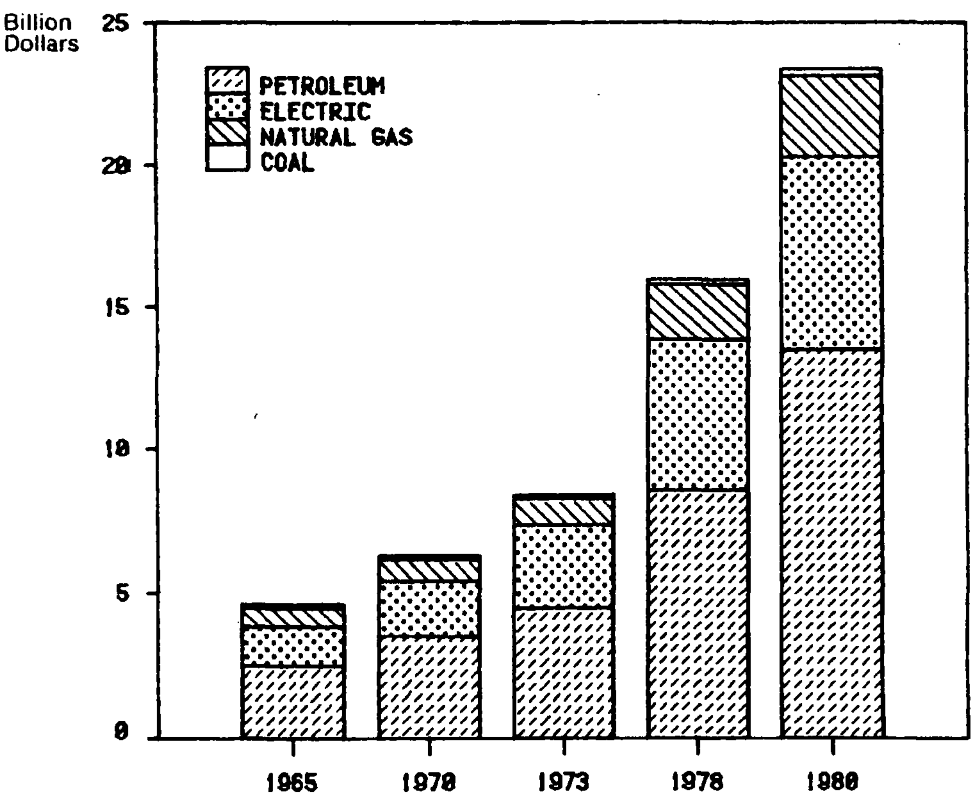


FIGURE 6

Net energy costs by fuel type, 1965-1980

NEW YORK STATE, CURRENT DOLLARS



III. NEW YORK STATE ENERGY POLICIES

[redacted]m. These energy policies, listed below, are the major themes of the updated State Energy Master Plan, from which recommendations for legislative and administrative action flow. Together, these policies provide the basis for a secure, cost-effective and environmentally sound energy future, supportive of continued economic growth.

New York State Energy Policies

1. The State's consumption of petroleum products must be reduced. The economic cost and vulnerability to disruption resulting from the State's continued disproportionate reliance on oil strongly support actions to shift to less costly and/or more secure energy sources.
2. Conservation and renewable resources must make a greater contribution to energy supply and will require substantial additional government support to do so, at least in the near term. In many applications, conservation and renewables appear to be the least costly, most economically productive and environmentally benign means to satisfy a significant portion of the State's current and anticipated energy requirements. Government action must enhance the respective contributions to be made by conservation and renewables in meeting those requirements.
3. The State of New York and its agencies should encourage the efficient use of natural gas and stimulate efforts to secure additional supplies of natural gas from sources that are economic, and compatible with environmental, public health, and safety standards in order to reduce New York's dependence on oil. Natural gas is and will likely remain an economic and environmentally compatible alternative to oil. This policy will help insure that supply and demand remain balanced throughout the planning period.
4. The increased use of coal must be promoted where economically feasible and consistent with applicable environmental standards. Compared to continued use of oil, particularly in the utility sector, use of coal will result in economic advantages, given current and forecast cost differentials of supply over the forecast period. Increased utilization of eastern coal is likely to stabilize regional energy costs and will stimulate regional economic development.
5. Regional cooperation, coordination, and action must be promoted to enhance the region's energy supply prospects. Interconnection of New York's electric and natural gas supply systems with Canada should be pursued as a vehicle for reducing costs and oil dependence to the extent economic and feasible. Interconnection may also lessen the adverse impacts on the State's environment from construction and operation of energy supply facilities.
6. New nuclear power plants beyond those now licensed or under construction should not be included in the State's electricity supply plan at this time. There is first a need to develop a fully adequate national nuclear waste disposal program, and a need to clarify substantial uncertainties associated with economic, saf[redacted] issues re[redacted]he electricity [redacted]availability of the state's current inventory of licensed nuclear plants.
7. All consuming sectors must be given increased choice among competing energy forms, including conventional fuels, conservation, and renewable resources. Increased choice will benefit consumers by increasing price competition among energy forms, and will benefit the State by stimulating innovation and efficiency improvements.
8. Government must act to remove any existing legislative and administrative barriers inhibiting the development of energy sources, competition among fuel forms and energy conservation, except where such action would clearly compromise public health, safety or environmental quality. Justification for any such institutional barriers must be reexamined in light of compelling State energy needs.
9. The State's electric and gas utilities, as well as PASNY, should encourage and stimulate conservation and efficient use of energy by their customers. Electric and gas utilities should become more active purveyors of conservation and renewable resource technologies.
10. No person should be without adequate heat or should be forced to forego conservation improvements by reason of inability to pay. A commitment to protect public health and safety requires no less.
11. The energy research, development and demonstration programs being pursued in New York must be expanded and must emphasize those technologies that will, over the mid- to long-term, mitigate energy cost increases and energy supply interruption. Formal and informal coordination of the numerous energy RD&D programs throughout the State is essential to assure that these activities support and complement State energy policy.
12. In view of the extensive reliance on oil in the transportation sector, the State should continue to take action to maximize the efficient use of energy in this sector. Moreover, the relatively energy efficient mass transit and railroad systems throughout the State must be maintained to prevent shifts of mass transit and railroad riders to less efficient automobiles.
13. Comprehensive energy emergency preparedness activities, directed at mitigating the adverse economic and social impact of an interruption in petroleum supplies, must be continued and increased in order to protect public health and safety.

IV. DEMAND FORECASTS

The updated SEMP presents a forecast of State energy consumption by fuel type, sector and end-use; a forecast of State electricity and gas demands; and a forecast of electricity peak demand and consumption by utility over the next fifteen years. The forecasts are consistent with and provide for the energy requirements of a growth economy and take account of the changed relationship between energy demand growth and economic health. Energy demand is not seen to increase in direct lock-step with growth of the economy as it has in the past. Rather, increased efficiency and effective conservation in the energy system are seen as slowing the increase in demand for energy while permitting the economic growth which results from greater efficiency.

The forecasts reflect significant conservation resulting from rising energy prices, mandated efficiency standards and State conservation programs now underway. They consider, in a systematic manner, the interrelationships of economic activity, fuel prices, national and State energy policies, fuel substitution, conservation and renewables, as well as the availability of conventional fuels.

Major highlights of the energy forecasts adopted by the Energy Planning Board include:

- Total end-use energy consumption will decline at a rate of 0.1 percent per year over the next 15 years;
- Gasoline use in the transportation sector will decline at a rate of 0.8 percent per year over the next 15 years;
- Statewide electricity consumption (sales) will increase at an average rate of 1.7 percent per year over the next 15 years;
- Total statewide electricity peak demand will increase at an average rate of 1.5 percent per year over the next 15 years;
- Electricity prices will increase in real terms at an average annual rate of 0.4 percent per year over the forecast period, consistent with the SEMP recommended electric supply plan;
- Total statewide natural gas demand will decrease at an average rate of 0.6 percent per year over the next 15 years; and
- Natural gas prices will increase in real terms at an annual average rate of 5.2 percent per year over the forecast period, reflecting the impact of decontrol of new natural gas supplies (post April 1977) as scheduled in 1985.

Figure 7 presents the forecast of end-use energy consumption by fuel type adopted by the Energy Planning Board.

FIGURE 7
New York State End-Use Energy Consumption by Fuel Type, 1980-1996

Fuel Type	Trillion BTU 1980	Trillion BTU 1996	Average Annual Percent Change 1980-1966
Electricity	367.1	478.6	1.7
Natural Gas	592.6	541.6	−0.6
Petroleum Products	1,783.2	1,639.7	−0.5
Res., Com., and Ind.	737.9	628.6	−1.0
Transportation	1,045.3	1,011.1	−0.2
Coal	69.2	90.0	1.9
Wood	30.9	47.0	2.7
Solar	0.1	3.1	23.9
Total End Use Energy Requirements	2,842.8	2,800.0	−0.1

V. MASTER PLAN ELEMENTS

The updated Energy Master Plan provides supply strategies for energy conservation, renewable resources, and each conventional fuel type. In addition, the updated Plan addresses the impacts of energy costs on low-income citizens; contingency planning; transportation; and research and development issues. The updated Plan also contains proposals for legislative and administrative action, which are derived from the broad energy policy expressed in the Energy Law and the more specific policies approved by the Energy Planning Board.

Full implementation of the recommendations in the updated Plan would significantly reduce the State's dependence on imported petroleum: substantially diversify the State's fuel mix; significantly increase the efficient use of energy, and the use of renewable resources in the State; moderate the expected increases in energy costs; contribute to the State's economy; and provide for a more secure and environmentally sensitive energy future.

A. Conservation

Energy conservation and increased efficiency represent New York State's least expensive, environmentally safest and most economically beneficial supply option available. Conservation activities create jobs, reduce the burden of energy costs and retain energy dollars within the State's economy rather than exporting the dollars out of the State.

New York has in place a broad range of energy conservation programs which have already helped to reduce the State's oil consumption. Together, governmental programs and rising energy prices have resulted in greater conservation of energy than was envisioned only a few years ago. Total end-use energy consumption in New York declined by almost 9 percent between 1978 and 1980.

Even with the conservation gains achieved to date, the potential for cost-effective conservation remains great. To a large extent, continued conservation actions will occur through the normal workings of the marketplace, spurred by rising energy prices. However, certain barriers still exist which limit realization of much of the potential for cost-effective conservation. The principal impediments include lack of objective and accurate information, high front-end costs, and certain institutional barriers.

The SEMP conservation program has three major objectives:

—expand the use of energy audits and the availability of conservation information and technical assistance;

—provide financing assistance and tax incentives for the implementation of high front-end capital cost conservation improvements; and

—mandate conservation actions where market forces are inadequate to trigger voluntary actions.

To accomplish these objectives the Energy Planning Board has recommended the following actions.

- Expand the State Energy Office energy audit and technical assistance programs and provide State funding for such efforts to the extent that Federal funding is no longer available.
- Expand the energy audit provisions of the Home Insulation and Energy Conservation Act to cover small commercial buildings.
- Establish a $10 million energy grants program for public K-12 schools. This program would be administered by the State Energy Office, with the assistance of the State Education Department, to address the larger inventory of conservation projects awaiting implementation in our public schools.
- Establish an energy grant program for State-supported public housing.
- Provide increased capital reimbursements for conservation measures in public and non-profit facilities which receive operating cost reimbursements from the State.
- Establish a self-sustaining $20 million fund, to be administered by the State Energy Office, to provide low interest loans at below market interest to hospitals, colleges, schools, and public care institutions which are privately owned (non-profit), and to local governments for energy conserving and renewable resource capital improvements.

- Establish a self-sustaining loan fund to be administered by the Division of Housing and Community Renewal to provide loans at below market interest rates for conservation improvements in Mitchell-Lama housing.
- Authorize the Power Authority of the State of New York to make conservation improvement loans for customers served by municipal or cooperative utility companies.
- Amend the State Tax Law to provide an additional business investment tax credit for investments by industry and commercial firms in acquiring and constructing energy conserving property and equipment.
- Require the owners of multi-family dwellings which receive governmental assistance, are subject to rent regulation, or are being converted to cooperatives or condominiums, to conduct energy audits and implement conservation measures.

Figure 8 presents estimates of the impact of conservation resulting from adoption of these recommended actions.

FIGURE 8
CONSERVATION PLAN IMPACT* (TBTU's)

	1986	1991	1996
Residential	2.5	8.6	9.0
Commercial	4.2	9.1	12.9
Industrial	8.6	17.2	25.8
TOTAL	15.3	34.9	47.6

*Numbers shown represent reduction in end-use energy requirements beyond those contained in the energy demand forecast.

B. Renewable Resources

A renewable resource is an energy form which can be continuously replaced by natural ecological or physical cycles and sound management practices. The term includes a variety of energy forms indigenous to New York: solar, wind, hydroelectric power, and biomass in all its forms (wood, agriculture wastes, municipal wastes). While not a renewable resource technology, cogeneration is addressed in this section because it too is a non-conventional means of producing electricity, and because it faces many of the same problems as renewable resources.

Increased development of renewable resources and cogeneration provide important energy and environmental advantages. Renewable energy supplies, by definition, are less susceptible to depletion than conventional energy forms, are relatively immune to sudden price increases or artificial interruptions in supply, and add diversity to New York's energy supply system. Renewable energy forms are also generally benign in terms of environmental impacts. Further, the increased development of renewable resources will create new job opportunities in the State instead of exporting our wealth to pay for conventional fuel imports.

Rising prices for conventional energy supplies and recent State and Federal actions have helped create a favorable climate for renewable resources and cogeneration. Certain financial, technical assistance, technological and regulatory problems must still, however, be addressed by the State and Federal government to realize the full potential for renewable energy technologies. The following recommendations address these issues.

- Amend the State Tax Law to provide an additional business investment tax credit for renewable resource investments.
- Establish a self-sustaining $20 million fund, to be administered by the New York State Energy Office, to provide low interest loans to hospitals, colleges, schools, and public care institutions which are privately owned (non-profit), and to local governments for renewable resource and energy conserving capital improvements.
- Establish a 25 percent Federal tax credit for builders of new private solar residences where solar design provides 40 percent of the heating requirements.
- Amend the Federal Internal Revenue Code to allow investments by business and industry in renewable resource equipment to be depreciated over a five year period.
- Amend the Federal Internal Revenue Code to provide a tax credit for residential passive solar systems.
- Amend the New York State Alternate Energy Production Act of 1980 to include all oil-fired cogeneration facilities.
- The Public Service Commission should ensure that natural gas supplies, which are available after priority attachments, are provided to those facilities which will use natural gas in the most efficient manner.
- Extend the applicability of the Federal Energy Regulatory Commission "short form" license application regulations and the licensing exemption provisions of the Energy Security Act of 1980, to include small hydro facilities up to 15 MW at all existing dams.

Figures 9 and 10 present the direct energy and electricity production impacts associated with implementation of these recommended actions.

FIGURE 9
RENEWABLE RESOURCE PLAN IMPACT*
Direct Energy
(TBTUs)

	1986	1991	1996
Passive Solar	0.3	0.8	1.5
Active Solar	0.1	0.3	0.5
Wood	1.5	4.3	7.1
BioGas	3.5	3.1	5.7
Resource Recovery	1.1	5.2	4.2

*Numbers shown represent reduction in end-use energy requirements beyond those contained in the energy demand forecast.

FIGURE 10
RENEWABLE RESOURCE PLAN IMPACT*
Electricity Generation
(MW)

	1986	1991	1996
Small Hydro	0	27	325
Cogeneration	208	412	600
Resource Recovery	50	63	82
Wind	12	82	307

*Numbers shown represent additions over the capacity projected in the Electricity Supply Plan.

C. Natural Gas

Natural gas will continue as an important element of new York's fuel mix over the next fifteen years. There are sound economic, environmental and energy security advantages associated with natural gas in New York State as an alternative to imported petroleum. Although the price of natural gas is expected to increase substantially in real terms due to the scheduled decontrol of most natural gas in 1985, average prices are projected to remain slightly lower than distillate oil prices in most New York demand sectors at the end of the planning period.

Because natural gas is a clean burning source of conventional energy, environmental considerations also favor its consumption over other fossil fuels, especially in urban areas of New York State where air quality is a concern. Natural gas is also a preferred fuel since approximately 93 percent of New York's current gas supply originates from domestic sources as compared to only 30 percent of the State's petroleum supplies.

Figure 11 shows the anticipated sources of natural gas supplies for New York State distribution companies over the next fifteen year period.

FIGURE 11
NEW YORK STATE GAS SUPPLY BY SOURCE
(BCF)

	1981	1986	1991	1996
New Gas (Post 78)	188.4	314.2	403.4	449.3
Old Gas (Pre 78)	356.5	197.4	92.7	44.7
Canadian/Mexican	12.8	58.4	59.2	16.8
LNG/SNG	11.5	13.5	13.5	13.4
Alaskan	0	0	5.0	5.0
Other*	95.2	94.2	99.2	155.4

*Primarily natural gas from tight sands, shale and deep (greater than 15,000 square feet) formations.

Considerable uncertainty surrounds specific projects associated with these supply sources. Consequently, New York State gas distribution companies should actively pursue the acquisition of additional natural gas supplies, such as the proposed Boundary Gas-Tennessee Project to import Canadian natural gas, and increase indigenous New York State natural gas supplies which are likely to be competitive with oil.

To insure that economic sources of natural gas supply are available for future use by New York consumers, the Energy Planning Board has approved the following policies:

- New York State should oppose any federal legislative or regulatory efforts to accelerate the deregulation of natural gas wellhead prices contained in the Federal Natural Gas Policy Act of 1978.
- Natural gas supplies should be acquired by New York State gas distribution companies:
  - —whenever they can be delivered to New York markets at a price that will be equal to or less than the delivered price of imported oil; or
  - —whenever it is demonstrated that acquisitions are in the public interest.
- Natural gas should be priced to consumers in a manner that will:
  - —encourage New York consumers to rely on natural gas instead of oil in markets where use of gas is an economic alternative to imported oil;
  - —encourage efficient use of gas by all consumers; and
  - —advance the policies and objectives of the State Energy Master Plan.

D. Electricity

The electricity supply plan approved by the Energy Planning Board reflects several major strategies directed at shifting the electric system fuel mix from overdependence on expensive imported oil, providing an adequate and reliable supply of electricity to sustain continued economic growth, and moderating consumer costs. The specific strategies include:

- completion of all baseload electric powerplants currently licensed and/or under construction;
- the phased conversion of twenty-one existing oil-fired powerplants to coal;
- increased use of small hydro, solid waste, cogeneration and wind technologies to produce electricity;
- increased levels of electric energy imports from Canada; and
- greater use of pumped storage hydroelectricity.

Figure 12 depicts the updated SEMP electricity plan.

Implementation of the proposed electricity supply plan will reduce oil consumption in the electricity sector by nearly 37 percent, from approximately 63.5 million barrels per year in 1979 to approximately 40.3 million barrels per year in 1996. Coal consumption will triple from about 8.5 million tons per year in 1979 to about 25.9 million tons per year in 1996. Total hydro electricity generation will increase from 23.6 billion kwh to 26.9 billion kwh in 1996. The contribution of cogeneration, resource recovery and wind facilities would increase from approximately 0.3 billion kilowatt hours in 1980 to 4.6 billion kilowatt hours in 1996. Canadian electricity imports would increase from about 9.2 billion kwh in 1980 to about 14.5 billion kwh in 1996. These changes in electricity production are expected to reduce consumer costs by $10 billion through 1996.

FIGURE 12
ELECTRICITY SUPPLY PLAN
(1981-1996)

New Facilities	Capacity (MW)	Fuel	Date
Under Construction			
Shoreham	813	Nuclear	1983
Somerset	625	Coal	1984
Nine Mile Point 2	1,080	Nuclear	1986
Licensed			
Arthur Kill	700	Coal/RDF	1987
Jamesport	800	Coal	1991
Lake Erie	850	Coal	1989
Planned			
Pumped Storage Hydro	1,000	PS Hydro	1987
Oil to Coal Conversion	(MW After Conversion)		
Ravenswood 3	923		1983
Lovett 4 & 5	387		1982-83
Arthur Kill 3	491		1983
Arthur Kill 2	333		1984
Albany 1-4	396		1984
Danskammer 3	137		1986
Danskammer 4	231		1986
E.F. Barrett 1 & 2	348		1987
Port Jefferson 3 & 4	348		1987

Alternative Generation (Cumulative Additions Since 1979)	1981	1986	1991	1996
Small Hydro	11.1	266.5	490.8	725.0
Cogeneration	26.7	230.5	322.5	373.5
Solid Waste	32.0	169.5	353.5	395.5
Wind	0.2	4.5	13.5	58.5

Canadian Imports	1981-1983	1984-1987	1988-1996
Energy (Billions of KWH per year)	10.5	12.5	14.5

E. Coal

Coal is an abundant and economic domestic energy source. Coal use is expected to increase dramatically within New York State over the next fifteen years, as shown in Figure 13.

FIGURE 13

FUTURE COAL CONSUMPTION IN NEW YORK STATE (10^6 tons)

	1986	1991	1996
Electric Utilities	15.8	23.3	25.9
Industrial	2.7	3.1	3.7
Coke Plants	3.2	3.3	3.4
Retail Dealers	0.1	0.2	0.2
New Technologies	0.0	1.8	4.6

The largest coal use increase is expected to occur in the production of electricity. The Energy Planning Board has endorsed the construction of three new coal or coal/RDF power plants and the phased conversion to coal of nearly 5700 megawatts of existing oil-fired capacity. The first phase, consisting of 3594 MW, includes facilities where there are substantial assurances that the conversions will be economic, are technically feasible, and can satisfy all appropriate environmental standards. Phase II conversions, consisting of 2044 MW, include those facilities (Ravenswood 1 and 2, and Northport 1-4) where there is less assurance of successful conversion.

While there has been considerable activity in the past several years, limited real progress has been made in accelerating the use of coal in the State. The slow pace has resulted from many factors, including uncertainty concerning Federal, State and municipal environmental requirements; uncertainty concerning the potential economic benefits and risks; and financing problems.

To address these concerns and help insure increased coal use, the Energy Planning Board has approved the following actions and recommendations:

- The utility coal conversion program should be implemented in a phased manner.
- The recommendations of the Governor's Clean Air Task Force should be adopted by Congress as changes to the Federal Clean Air Act. The principal recommendations are:
  - —provide voluntary coal conversion with the same statutory exemptions from certain requirements of the act as are available to PIFUA mandated conversions; while voluntary and ordered conversions are treated alike in regulations implementing the Clean Air Act, some have argued that this is inconsistent with the language of the act;
  - —provide the State with resource management flexibility to trade emissions from different sources through use of the so-called "bubble" concept. This concept could both reduce air pollution and permit coal conversions to proceed without violating environmental standards because emissions from coal conversions could be offset by an equal or greater decrease in emissions from other sources;
  - —provide a more flexible method for Federal management of the State Implementation Plan process; and
  - —eliminate Prevention of Significant Deterioration (PSD) for Class II and III areas, and require Best Available Control Technology for new or significantly modified sources.
- The Congress should modify the Federal Internal Revenue Code to provide an additional 20 percent investment tax credit for industries converting from oil and gas to coal through 1990.
- An accelerated depreciation schedule for recovering the costs of new industrial coal using equipment should be adopted by the Federal government.

F. Petroleum

The updated Master Plan emphasizes the need for the Federal and State governments to pursue policies aimed at reducing dependence on petroleum, particularly foreign petroleum. New York has made progress in the past two years in reducing its consumption of oil; however, the State remains vulnerable to petroleum supply disruptions and price increases to a significant degree.

Although New York State can and is doing much to reduce demand for petroleum, it can do little on its own to improve its oil supply situation. The Energy Planning Board has, therefore, called for the following federal actions to improve the security of petroleum supplies within New York State.

- Continue and expand Federal synthetic fuels activities.
- Encourage a shift to Western Hemisphere supply sources for oil imports.
- Provide uniform tax incentives for construction of petroleum storage facilities to replace aging facilities and increase storage capacity.

G. Transportation

Nearly one-half of all petroleum products consumed in New York State are consumed in the transportation sector, a sector consisting of mass transit systems (subways and buses); commuter railroads; long-distance intercity railroads and buses; automobiles; trucks; airplanes; ships and barges. It is therefore important for the State to seek to maximize the efficient use of energy in this sector in order to achieve the principal Master Plan goal of further reducing our reliance on imported petroleum.

The updated Plan concludes that, unlike other sectors which rely heavily on petrolem and for which a number of State actions are proposed to reduce its use significantly, the State, acting alone, is quite limited in its ability to substantially reduce consumption in the transportation sector. Indeed, the Plan notes that the most pressing concern for the State may be maintaining the relatively high efficiency of the existing transportation system.

To promote energy efficiency and further reduce petroleum use in the transportation sector, the Energy Planning Board has approved the following recommendations:

- Place a surcharge on all speeding citations for violation of the 55 MPH speed limit.
- Continue studies of the possibility of the use of tandem truck trailers on certain highways.
- Amend the transportation law to reform the economic regulation of the State's motor carrier industry in accordance with the 1981 Governor's Program Bill #164.
- Promote the use of wind deflectors and other fuel saving devices on trucks.
- Establish an expedited maintenance and rehabilitation program for the New York Barge Canal.
- Expand Park and Ride activities.
- Enact legislation to stimulate vanpooling and ridesharing through tax incentives.

- Teach energy efficiency driving techniques.
- The Federal government should ensure adequate funding for the operation, maintenance and upgrading of mass transit systems.
- The Federal government should ensure the continued improvement of rail service.
- The Federal government should continue to provide support for highway maintenance and rehabilitation for States like New York where the cost of repairing an aging system is beyond current financial capability of State and local governments.

H. Rising Energy Costs and Low Income Households

Increases in residential energy costs affect New York and other northeastern states more than the rest of the U.S., due to the region's colder climate and older housing stock. Moreover, the burden of these rising energy costs falls most heavily on low income households, which not only have less money to spend but also are more likely than other New York households to live in old, energy-inefficient, oil heated dwellings, particularly multi-family dwellings. The elderly living on relatively fixed incomes are particularly hard hit, since they are likely to need additional heat or lighting because of poor health and declining perceptual abilities.

Many government actions to help alleviate energy burdens on low-income and elderly households have been taken during the past few years. These actions have been helpful. New York State, however, must continue to support increased funding for Federal energy assistance programs and more flexibility in the use of available funds. The Federal government should:

- Provide continued funding for the Federal Home Energy Assistance Program (HEAP) at a level not lower than the present $1.87 billion.
- Continue the Federal Weatherization Program, but encourage weatherization of urban buildings, coordination with other programs, and greater program flexibility.

I. Contingency Planning

Experience since the 1973-74 Arab oil embargo, including the 1977 natural gas emergency and the 1979 gasoline supply emergency, demonstrates New York State's vulnerability to sudden disruptions of energy supplies. Reliability of supplies, particularly imported petroleum, will continue to be a major concern throughout the planning period.

The State's need to maintain a standby emergency preparedness program, already strong in light of the State's exceptional vulnerability to supply disruptions, has become even stronger because of the Federal government's recent withdrawal from an active emergency preparedness role. If an oil supply emergency occurs, the burden of responding to it will fall almost entirely upon the State. In order to meet this responsibility, New York State must provide funding for the following:

- A continuous petroleum supply and price monitoring program and up-to-date standby electronic data processing capability.
- A periodic review and update of the State Energy Emergency Plan, addressing all forms of energy emergencies.
- Standby transportation fuel emergency measures, such as minimum purchase and odd/even.
- A standby State fuel set-aside program.

State actions, while necessary, will not be completely sufficient, however, to handle a serious supply disruption without Federal assistance. The State Energy Master Plan proposes the following Federal actions necessary for effective response to a serious supply disruption:

- Continuation of Federal Energy Data Collection Programs.
- Continuation of the Emergency Energy Conservation Act (EECA) Program with Adequate Funding.
- Acceleration of the filling of the Strategic Petroleum Reserve using public monies to fund such acquisitions should be continued; additionally, DOE should undertake an evaluation of alternatives to building new underground storage facilities, including acquiring interim storage capability such as leasing temporary facilities or construction of above ground steel tanks, and the establishment of a system of Regional Petroleum Reserves, required by statute, should be implemented.
- Authorization of a Federal standby petroleum product and allocation program to replace the Emergency Petroleum Allocation Act.

J. Research and Development

Meeting New York's energy needs requires developing all options open to the State. Conservation, coal, renewable, and indigenous energy sources and nuclear resources are attractive because they are economic and available. All resources must be explored and, if found promising, developed and demonstrated to ensure meeting the State's need in an economical, safe and environmentally sound fashion. The State's current energy research and development program has taken a comprehensive approach through the cooperative efforts of the PSC, ESEERCO, NYGAS, ERDA, the utilities, industry, universities, local government agencies within the State, national organizations and the Federal government.

All major organizations in energy R&D must continue to communicate and cooperate with one another to ensure that the always limited RD&D resources are most effectively utilized. Funds must be used as advantageously as possible to promote the well-being of New York residents as well as the national interest.

VI. CONCLUSION

The updated State Energy Master Plan provides a blueprint for reshaping New York's energy future. The recommendations in the Master Plan would, if fully implemented, significantly reduce the State's dependence on imprted petroleum; substantially diversify the State's fuel mix; and increase the efficiency of energy use, and the use of renewable resources and coal in the State. Figure 14 illustrates the impact of full implementation of these recommendations on New York's future fuel mix.

Furthermore, the Plan projects cumulative economic savings in the State of at least $10 billion by 1996 as a result of implementation of the broad range of proposed actions. The substantial savings to consumers associated with the Plan will flow through to the State's economy and create significant additional income for other purposes. Full implementation of the Plan's recommendations will result in the creation and support of 25,000 jobs and $467 million in earnings annually by the year 1996. Finally, the Plan's recommendations would, if implemented, have a limited incremental effect on the State's environment.

[redacted]

FIGURE 14 ***Total primary energy consumption***
NEW YORK STATE, 1980 and 1996