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THE NEW YORK POWER SYSTEM

GENERATION AND TRANSMISSION PLANS

1971 – 1980

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THE NEW YORK POWER SYSTEM GENERATION AND TRANSMISSION PLANS 1971-1980

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A Report Prepared By The
System Planning Section, Power Division
of the
New York State Department
of
Public Service

44 Holland Avenue
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December, 1971

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Earlier in 1971 the System Planning Section, Power Division, of the Public Service Commission issued the first of a series of staff reports, entitled "Electric System Planning in New York State". The second in the series, an analysis of the New York Power Pool's 1971-1980 generation and transmission plan, is presented here. The third report, expected to be completed in mid-1972, will analyze the long-range, 20-year system plan.

The instant report does not present a 10-year plan developed by the Commission's staff; system planning is primarily the responsibility of the utilities themselves, and it is their plan which is here discussed. Nor does this report examine all aspects of power pool planning and operation. Rather, it is confined to the latest generation transmission plan, one that is already being revised to prepare for next year's 10 year plan. The staff has evaluated the report in terms of adequacy, reliability and efficiency, identifying basic problems and recommending appropriate action.

Ten year plans are adjusted almost continuously by the Pool in response to changing conditions. Full revisions are made about once a year Through its frequent contacts with the New York Power Pool Planning Committee, the System Planning Section will closely follow all such changes. The Section plans to issue an annual report covering each yearly revision of the 10 year plan.

Special appreciation goes to Dr. Eugene W. Zeltmann, Assistant to the Director, Power Division, for his technical and editorial advice.

This report was submitted to the Commission and has been released for publication as a staff report. It has not been approved by the Commission.

H. L. COLBETH
Director, Power Division

TABLE OF CONTENTS

	Page
Introduction	1
Summary of Recommendations	3
A Look into the Future	6
Load and Capacity	6
A Closer Examination of Each Utility	12
Central Hudson Gas & Electric Corporation	12
Consolidated Edison Company of New York, Inc.	13
Long Island Lighting Company	18
New York State Electric & Gas Corporation	19
Niagara Mohawk Power Corporation	20
Orange and Rockland Utilities, Inc.	20
Rochester Gas and Electric Corporation	21
Projected Capacity	21
Generation Mix	21
Optimum Mix	25
Reliability	26
Generation Economic Considerations	27
Today's Cost of Generation	27
Economic Selection of Generation Type	29
Estimated Generation Costs Without Nuclear Expansion	36
Delay Associated Costs	41
Fuel Supply	45

TABLE OF CONTENTS (CONTINUED)

Page

Projected Bulk Power Transmission 46

The Existing Transmission System 47

System Additions 50

Transfer Limits 51

Use of Existing System 51

Future 765 kV 52

Conclusion 53

Appendix I

Appendix II

Appendix III

Appendix IV

THE NEW YORK POWER SYSTEM

GENERATION AND TRANSMISSION PLANS

INTRODUCTION

The New York Power Pool (NYPP), formally inaugurated on July 21, 1966[1/] with the signing of the New York Power Pool Agreement, includes the following parties:

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.
Power Authority of the State of New York
Rochester Gas and Electric Corporation

The aim of the NYPP members is "to coordinate the development and operation of their respective electric production and transmission facilities in order to obtain optimum reliability of service and efficiency upon the interconnected systems of the parties hereto." The Commission, on December 1, 1970 in Case 25937, instituted a proceeding on its own motion to investigate the plans and procedures of electric corporations for load shedding in times of emergency. At the request and then approval of the Commission, the members of the NYPP filed an amendment which established a policy for "Operation in a Major Emergency." This

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1/ A new agreement signed March 31, 1971 formalizes the membership of the Power Authority.

established "a procedure to be used, internally within the Pool, when widespread outage is imminent to the entire Pool or a portion thereof, as a result of a shortage of generation or transmission capacity to meet load."[1/]

A portion of this coordination and development is the creation of expansion plans for the future. The System Planning Section of the Public Service Commission's Power Division intends by means of this report to evaluate the New York Power Pool's expansion plans for the 1971-1980 period.

These plans are and must remain flexible, based as they are on assumptions of conditions which are subject to change. Rigid adherence to a fixed plan in the face of changing conditions would not operate in the interest of the utilities or the consumer; it would not result in an optimum long-range plan. Therefore, this staff analysis is directed to the concepts embodied in these plans as well as to the specific projects recommended.

Electric utility planning is a fluid, continuous process. Soon after publication of any report such as this one, figures will have changed and estimates will have been revised. For the purpose of this evaluation the staff has used information supplied by the individual utilities showing their latest plans as of the April to July, 1971 period. These late reports were complemented by the Northeast Power Coordinating Council's report to the Federal Power Commission (R-362) dated March 31, 1971, and the "New York Power Pool Study #11 - 1980 Transmission Study."

1/ New York Power Pool Operating Policy #6-0 effective June 25, 1971.

SUMMARY OF RECOMMENDATIONS

1. The utilities intend to install 20,200 MW of generating capacity during the next 10 years. Of this total, Consolidated Edison plans to install about 5,800 MW. Generating units, representing over 5,400 megawatts (MW) of planned generating capacity and scheduled for installation within the next 10 years, have not been sited.[1/] The utilities must determine and acquire these sites very quickly if their schedules are to be met.

2. Nine major transmission links are needed during the next 10 years, their timing depending in part upon the successful siting of power generating units. These lines must be planned and rights-of-way or permits acquired in time to meet system needs. Plans must be soon completed to permit any joint financing that will be required.

3. The Consolidated Edison Company must review its internal transmission capability to permit the utility to receive 3,800 MW that may be available for import before 1980.

4. Better use must be made of existing and new transmission rights-of-way. Within the necessary environmental constraints, every corridor must be used to the fullest reasonable capacity. Any new 345 kV line built must be considered, and possibly constructed, for eventual 765 kV operation. Existing lines must be reviewed for possible upgrading so that the need for new corridors is minimized.

1/ These figures exclude contributions made by gas turbines.

5. Ties with other areas must be strengthened, particularly to New England, New Jersey and Pennsylvania. Existing connections often do not permit sufficient flows of emergency power. Present plans, if carried out, represent considerable improvement but must be reviewed for even greater capability.

6. A flexibility of fuels must be maintained. Any fuel, whether oil, gas or coal, can suddenly become scarce because of strikes, weather conditions, environmental restrictions or political developments, national and international. Utilities must plan for use of alternate fuels if such conditions should occur.

7. More efficient generation must be designed to make better use of the limited number of sites, to lower costs and to lessen the effect upon the environment. Combined cycle systems seem to offer promise and should be tried. Research and development on magnetohydrodynamics (MHD), fuel cells, breeder reactors, fusion power, and other new types of generation must be accelerated.

8. Maintenance of older machines must be improved.

9. Utilities and responsible State and Federal regulatory agencies must make greater efforts to help rationalize the present chaotic licensing and permit situation.

10. Greater progress must be made toward single system planning for the entire State. To date, the goal of achieving low cost electricity in the face of inflation and environmental restrictions has been visualized primarily as a matter of exploiting the economies of scale inherent in larger and larger generating

units[1/] and higher voltage transmission. The larger generating units are characterized by lower fixed costs as well as a more efficient use of fuel. Essential to this concept is the ability to transmit the power from the generating unit over high capacity transmission lines.

The system planning required for the years to come must review the entire concept of economies of scale. What is needed is an effort to determine the optimum size generating unit. Perhaps it is as large as 1,100 MW, or even larger. Perhaps not. Such an effort must consider that large units create large problems when they break down. It may no longer be true that bigness can be equated with goodness. If not, system planners must acknowledge the fact in their plans for the future. If true, now appears to be a good time to reaffirm the premise since large units often go beyond the need or ability of a small company to construct. Joint ownership and financial cooperation amongst members of the New York Power Pool would thus become more commonplace. Under such conditions, the Pool would have to develop an equitable means of allocating costs since New York State would become more and more like a single huge service area.

1/ A large generating unit is defined here as having a capacity of 800 MW or greater.

A LOOK INTO THE FUTURE

Load and Capacity

The New York Power Pool expects to add approximately 20,200 MW of new generation capacity[1/] in the 1971-1980 period. The load growth in this decade is estimated to be slightly over 12,800 MW, or 6.1 percent per year, compounded. If the generation plan is completed on schedule, the projected reserve margins will range between 21.8 percent and 33.1 percent of peak load for the summer period and 34.5 percent through 44.6 percent for the winter period.

A system of the size and type of the New York Power Pool should have a reserve margin of 20 to 25 percent to maintain the proper reliability level. Therefore, if the member systems of the New York Power Pool were able to complete the scheduled generation on time, the reserves in New York State would be adequate.

An ever-increasing lead time (the planning and construction period) is required for new generating additions, due mostly to environmental restraints. The staff's evaluation of the planned additions indicates that many delays can be expected in implementing these plans. In this report, staff has attempted to evaluate realistically the time frame in which the new generation additions can be expected to be completed. After accounting for probable delays, the staff's estimated reserve margins are much lower,

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1/ The Pool will, however, retire about 2,000 MW of small, old units.

ranging between 14.3 percent (1972) and 25.7 percent of peak load during the summer periods and 26.0 percent to 37.9 percent for the winter periods. Tables Ia and Ib show the comparisons of statewide reserves as forecast by the individual Pool members and as estimated by the staff for both the summer and winter periods.

TABLE Ia

STATEWIDE RESERVES (1971-1980)

SUMMER PERIOD

	Total Available Capacity (MW)		Reserves (MW)		Reserves (% Peak Load)	
Year	NYPP 1/	Staff 2/	NYPP 1/	Staff 2/	NYPP 1/	Staff 2/
1971 3/	22269	22269	4200	4200	23.2	23.2
1972	24053	22580	4303	2830	21.8	14.3
1973	26619	25794	5592	4767	26.6	22.6
1974	28964	26466	6607	4109	29.6	18.4
1975	30084	28411	6359	4686	26.8	19.8
1976	32222	30618	7153	5549	28.5	22.1
1977	34783	33229	8337	6783	31.5	25.7
1978	36871	34001	8989	6119	32.2	22.0
1979	39061	37295	9706	7940	33.1	27.0
1980	40746	37935	9846	7035	31.9	22.8

1/ NYPP forecast represents individual company plans if implemented as scheduled.
2/ Staff forecast represents effect of delays in plan implementation as estimated by staff.
3/ Actual summer 1971 data.

TABLE 1b

STATEWIDE RESERVES (1971-1980)

WINTER PERIOD

Year	Total Available Capacity (MW)		Reserves (MW)		Reserves (% Peak Load)	
	NYPP 1/	Staff 2/	NYPP 1/	Staff 2/	NYPP 1/	Staff 2/
1971	22214	22214	4580	4580	26.0	26.0
1972	25381	23908	6685	5212	35.8	27.9
1973	26738	24913	6863	6038	34.5	30.4
1974	30372	27874	9313	6815	44.2	32.4
1975	30612	28939	8316	6643	37.3	29.8
1976	32772	31168	9250	7646	39.3	32.5
1977	35750	34196	10934	9389	44.1	37.9
1978	37820	34120	11662	7962	44.6	30.4
1979	39204	36438	11630	8864	42.2	32.1
1980	41890	39079	12838	10027	44.2	34.5

1/ NYPP forecast represents individual company plans if implemented as scheduled.

2/ Staff forecast represents effect of delays in plan implementation as estimated by staff.

The winter capacity on a statewide basis for the years 1971 to 1980 appears adequate to meet the State's power needs. The statewide margins during the summer period fall slightly below the recommended level in the first half of the period (1972-1975), but are adequate in the latter half (1976-1980).

Next summer will probably be the most critical time during the next 10 years, with a probable reserve of 2,830 MW, only 14.3 percent of the estimated peak, a figure well below the desired 20 to 25 percent. This situation has been brought about by the anticipated delays in the start-up dates for Consolidated Edison's 873 MW Indian Point No. 2 unit, and the 600 MW Bowline Point No. 1 unit, jointly owned by Consolidated Edison and Orange and Rockland Utilities, Inc.

The above staff analysis is formulated on a statewide or one-system basis. However, except in emergencies each company must look primarily to its own resources (including firm purchase agreements) and can rely on neighbors only to the extent surpluses may be available. In analyzing individual companies, the staff has found the Consolidated Edison situation to be most critical. During the summer period, the largest electric utility in New York State is expected to have reserve margins well below the recommended level during the entire decade studied. Tables IIa and IIb show the comparison of company and staff forecast of Consolidated Edison reserve margins for both the summer and winter periods.

TABLE IIa

CONSOLIDATED EDISON COMPANY RESERVES (1971-1980)

SUMMER PERIOD

Year	Total Available Capacity (MW)		Reserves (MW)		Reserves (% Peak Load)	
	Con.Ed. 1/	Staff 2/	Con.Ed. 1/	Staff 2/	Con.Ed. 1/	Staff 2/
1971 3/	9509	9509	1709	1709	21.9	21.9
1972	10031	8758 4/	1481	208	17.3	2.4
1973	10585	10585	1635	1635	18.3	18.3
1974	12050	10377	2650	977	28.2	10.4
1975	12050	10377	2200	527	22.3	5.4
1976	12459	12275	2159	1975	21.0	19.2
1977	13544	12790	2794	2040	26.0	19.0
1978	14180	12810	2980	1610	26.6	14.4
1979	14095	13159	2445	1509	21.0	13.0
1980	15105	13154	3005	1024	24.8	8.5

1/ Represents Consolidated Edison forecasts if all plans are implemented on schedule.
2/ Staff forecast represents effect of delays in plan implementation as estimated by staff.
3/ Actual summer 1971 data.
4/ See following discussion of delays in completion of capacity scheduled for 1972 summer.

TABLE IIb

CONSOLIDATED EDISON COMPANY RESERVES (1971-1980)

WINTER PERIOD

Year	Total Available Capacity (MW)		Reserves (MW)		Reserves (% Peak Load)	
	Con Ed.1/	Staff2/	Con.Ed.1/	Staff2/	Con Ed.1/	Staff2/
1971	8500	8500	2275	2275	36.6	36.6
1972	9823	8550	3323	2050	51.1	31.5
1973	9247	9247	2447	2447	36.0	36.0
1974	11505	9832	4380	2707	61.5	38.0
1975	11460	9787	3985	2312	53.3	30.9
1976	11969	11785	4144	3960	53.0	50.6
1977	12701	11947	4526	3772	55.4	46.1
1978	13507	12137	4957	3587	58.0	42.0
1979	13412	12476	4462	3526	49.9	39.4
1980	14442	12461	5092	3111	54.5	33.3

Consolidated Edison is a summer peaking company; its summer peak is estimated to exceed the winter peak by 1,900 to 2,800 MW. The winter reserve appears adequate but that for the summer appears scanty for each year, and worst of all next year. Summer reserves are so low as to be critical in the whole 1971-1975 period, and the situation appears to be deteriorating instead of

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1/ Represents Consolidated Edison forecast if all plans are implemented on schedule.

2/ Staff forecast represents effect of delays in plan implementation as estimated by staff.

improving. At this time, the major problem confronting Consolidated Edison is the acquisition of sites for future base load generating stations. Thus, even the higher reserves shown for 1976-1980 are in doubt. While there are problems on other systems in the State, they are minor in comparison to those of Consolidated Edison. The other New York utilities have not had the siting problems that Consolidated Edison has had. Their problems are smaller and far less immediate.

While the Consolidated Edison generation picture is not improving, the outlook is somewhat brighter for bulk power transmission from upstate into its territory as discussed later in this report.

A CLOSER EXAMINATION OF EACH UTILITY

Appendix I, "Load, Capacity and Reserve Margins for New York State 1971-1980" shows the estimated reserve for each of the electric utilities if their plans are implemented as scheduled. It also shows the effect of delays in certain plants as anticipated by the staff. Appendix II details all the proposed capacity additions as planned for the 1971-1980 period.

The following commentary is based on data supplied by these two Appendices (numbers I and II).

Central Hudson Gas & Electric Corporation

This utility's indicated reserve margins for 1975 and after drop below the desired 20 percent of forecast peak load.

During this period (1975-1980) the reserves range between 4 and 17 percent. Capacity needs in the early part of the period are small enough to be met easily by purchases or through the installation of additional gas turbine units. A capacity addition will probably be required by the summer of 1978, since estimated reserve in that year falls to 7 percent. Even though site availability does not seem to be a problem, specific planning for this unit should be started by early 1972 to assure that the schedule can be met.

Consolidated Edison Company of New York, Inc.

Consolidated Edison, the largest electric utility in the State, will have reserve margins for the next 10 years ranging from 2.4 percent to 19.2 percent of its forecast peak load after taking into account probable delays in implementing its generation plan. The situation may be more serious when one realizes that after its present construction schedule is completed, the company will probably have problems obtaining suitable generating sites for future units. The most critical year for Consolidated Edison is 1972. The company had planned to have 1,621 MW of additional capacity available for the summer of 1972; barge mounted gas turbines - 348 MW, Indian Point No. 2 - 873 MW, and Bowline Point No. 1 - 400 MW.[1/]

1/ Consolidated Edison's share of this 600 MW unit is 400 MW.

Recent events make it highly unlikely that either Indian Point No. 2 or Bowline Point No. 1 will be available for the 1972 summer. Even before the recent Calvert Cliffs [1/] decision, the likelihood of Indian Point No. 2 being on line for the 1972 summer needs was marginal; now it seems almost impossible. Although the company recently loaded fuel in Indian Point No. 2, a recent fire delayed the plant start-up anywhere from three to six months. Add to these delays the need for subcritical testing and a complete environmental impact review, and the staff was forced to the conclusion that base load operation of the facility would be delayed beyond 1972. Consolidated Edison is still optimistic that the plant will be on line sometime during the summer of 1972. The staff hopes that the company is correct in its expectation, but at this time this does not appear probable. The estimated delay

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1/ On July 23, 1971, the United States Court of Appeals for the District of Columbia Circuit rendered its decision in Calvert Cliffs' Coordinating Committee, Inc., et al. v. United States Atomic Energy Commission, et al., Nos. 24,839 and 24,871, holding that Atomic Energy Commission regulations for the implementation of the National Environmental Policy Act of 1969 (NEPA) in AEC licensing proceedings did not comply in several specified respects with the dictates of that Act, and remanding the proceedings to the Commission for rule making consistent with the Court's opinion.

Pursuant to this ruling, the AEC revised its regulations so that in the conduct of a nuclear generating station proceeding, the Atomic Safety and Licensing Board will consider and determine, in addition to the issues pertaining to radiological health and safety and the common defense and security, procedures for implementation of the National Environmental Policy Act of 1969.

for Indian Point No. 2 is based on these considerations:

1. The Atomic Energy Commission has only a relatively small staff to carry the additional work load of evaluating environmental considerations. At this time,[1/] no budget action has been taken to finance extra staff, but approximately 30 people have been transferred from the General Manager's office to this environmental function.

2. The present Atomic Safety and Licensing Boards have not had time to build up general environmental expertise, their backgrounds having related primarily to radiological hazards. Lengthy explanations will be required to clarify technical points to these boards.

3. Intervenors will probably be granted substantial periods to review testimony and prepare additional questions on such items as cost - benefit analyses of nuclear plants, alternative cooling methods, land-use compatibility, esthetics, recreational facilities, and the emergency core cooling systems now being revaluated in light of the interim criteria established by the AEC.

4. The damage caused by the fire has raised questions regarding the adequacy of the unit's planned redundancy in safety features, a subject which will certainly attract the attention of both the AEC and the intervenors.

1/ November 1, 1971.

Staff believes that the Bowline Point No. 1 unit, being built on an Orange and Rockland site as a joint plant with Consolidated Edison, probably will not be available at the beginning of the 1972 summer period. The time lost due to a 1969-70 General Electric strike has delayed the delivery and ultimate installation of the turbine-generator. However, Orange and Rockland and General Electric have high hopes of getting this plant installed by July 1, 1972. To do so requires that the ordinary 9 to 12 month installation time be compressed to four months.

Without the 1,273 MW associated with the two above mentioned plants, Consolidated Edison's reserve will shrink to a little over 200 MW or 2.4 percent of its forecast peak load. This situation is critical when one recalls the forced outages and deratings experienced in the 1971 summer period. At the time of the weekly company peak, such lost capacity ranged between 1,200 to 2,500 MW.

For the remaining years of the 1970's (1973-1980) staff has analyzed the planned construction schedule for Consolidated Edison and has assumed the following contingencies:

1. Indian Point No. 3 (873 MW) - This unit, scheduled for 1973 summer operation, has been slipped past the 1975 summer since it is a nuclear unit, affected by the same licensing problems as Indian Point No. 2.

2. Astoria No. 6 (800 MW) - Originally scheduled for the summer of 1974, this unit may slip past the 1975 summer due to difficulties in meeting New York City air pollution requirements.

Construction has not progressed to the point where sufficient lead time is available to meet the original schedule.

3. Power Authority - State of New York (PASNY) Pumped Storage - 500 MW[1/] - Public opposition to this proposed plant has arisen, and some delays and uncertainties may result. It seems prudent to assume a delay of at least two years past the originally scheduled 1977 in service date.

4. Fossil Unit (800 MW) - The site for this proposed 1977 unit has not been determined. In fact, Consolidated Edison does not own a site for this plant, and the assumption must be that it will not be constructed in time to be available prior to 1980.

5. Nuclear No. 4 (1,115 MW) - This planned 1980 addition probably cannot be in service in that year since no site has yet been determined.

Staff also believes that prior to 1976, Consolidated Edison will not have an adequate reserve to meet the loss of its largest unit, Ravenswood No. 3 (1,000 MW), a contingency by no means remote. Until Consolidated Edison solves the vibration problems inherent in the design of this large unit, one must appraise the adequacy of the reserves of this utility both on the assumptions of operability and non-operability of Ravenswood No. 3.

To ameliorate power shortages, Consolidated Edison's incoming transmission capacity must be increased so that power

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1/ This is peaking capacity which PASNY has agreed to sell Consolidated Edison from output of this 1,000 MW plant.

purchases will be available over these lines. Without such increased capacity, Consolidated Edison's customers may expect frequent voltage reductions and occasional load shedding at least through the summer of 1975. There has been much public discussion of halting the growth of demand for electricity in New York City; various suggestions for forcing a reduction of consumption have been advanced. Up to this point, however, the public seems to prefer occasional load shedding to any legal restrictions on amount or type of consumption.

Long Island Lighting Company

The Shoreham nuclear unit has been rescheduled for 1977 in light of delays encountered to date plus the impact of the recent Calvert Cliffs decision. LILCO's contingency plans call for installation of gas turbine capacity in 1974-75 to protect against this delay. No problems are anticipated in siting these units and the LILCO reserve margins will be adequate if the Shoreham unit is delayed only to 1977. Any additional delay could have serious effects on LILCO and Consolidated Edison because LILCO would be dependent on power transfers from the New York Power Pool system, transfers that must use the same transmission capability as is needed to supply Consolidated Edison, a utility expected to be in frequent need of assistance itself. In fact, as this report was being finalized, the Long Island Lighting Company announced that it would add a fourth unit (386 MW) at its Northport site to be ready in 1975. LILCO's recent changes to its schedule are not reflected in Appendix I.

New York State Electric and Gas Corporation

The following contingencies were assumed to affect the New York State Electric and Gas capacity:

1. PASNY-Fitzpatrick Unit (250 MW[1/]) - This unit will probably slip past the winter of 1974; it is nuclear and will be subject to the same delays caused by the previously mentioned Calvert Cliffs decision.

2. 1976 Fossil Unit (600 MW) - The staff has assumed a delay of this unit to 1977 because no site has yet been specified, and five years seems a minimum lead time.

3. Bell Nuclear Unit (830 MW) - Due to the environmental problems associated with this particular site plus the additional delays that may be caused by the Calvert Cliffs decision, staff has assumed that this unit will be placed in service after 1980.

Based on the above assumptions, the New York State Electric and Gas reserve margins for the winter period 1974-80 are inadequate. For the period the reserves range from none to 15.2 percent. The neighboring companies will have sufficient capacity in the early years to assist New York State Electric and Gas, thus minimizing the effect of these deficiencies. However, a backup plan must be developed to replace the Bell unit if it is to be delayed as assumed. If the plant is not replaced, the 1979 and 1980 reserve margins become negative.

1/ New York State Electric and Gas share of this 825 MW unit is initially 250 MW.

Niagara Mohawk Power Corporation

The following contingencies were assumed for Niagara Mohawk:

1. PASNY-Fitzpatrick Unit (250 MW[1/]) - The Fitzpatrick unit has been delayed past the 1974 winter for reasons previously stated.

2. Nine Mile No. 2 (1,000 MW) - The staff has assumed delays of this unit past the winter of 1978 for the same reasons affecting all other proposed nuclear plants. Niagara Mohawk is optimistic that this unit will be on line by winter of 1977, but until the problems caused by the Calvert Cliffs decision are resolved, the staff assumed the above delay.

After accounting for these contingencies Niagara Mohawk will still be in a good position as to reserve margins. The 18.8 percent margins for the 1978 winter is the lowest estimated for this decade.

Orange and Rockland Utilities, Inc.

Orange and Rockland's planned capacity additions are adequate through 1975 but reserves may shrink to an estimated 8.5 percent in 1976. The company's requirements after that date are expected to be met by a 300 MW fossil unit[2/] in 1977 and a 400 MW fossil unit[2/] in 1979, both at sites yet undetermined. If these capacity additions or equivalents are not made, a serious deficiency will result. Installed capacity will be less than

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1/ Niagara Mohawk's share of this 825 MW unit is initially 250 MW.

2/ Probably in the form of a share of a larger unit; sizes below 600 MW are considered uneconomical today.

the forecast peak load in 1977 (a negative reserve) and each succeeding year while the additions are delayed. Site availability within the Orange and Rockland area may well become a problem; early identification of potential sites must be made and specific planning commenced so that the 1977 and 1979 in-service dates can be met. Because of probable licensing difficulties associated with any site selected in the Orange and Rockland franchise area, an alternate or contingency plan should be developed to assure that sufficient capacity additions can be made in this time period. The staff has assumed the initial operation date of the 1977 unit will be delayed one year because no site has yet been identified.

Rochester Gas and Electric Corporation

This utility appears to be in an excellent position through most of the 10-year period. Its reserves for the winter period range between 22 to 57 percent and for the summer period from 21 to 57 percent. The only addition anticipated is the Ginna No. 2 nuclear unit in 1979. A site exists for this unit and sufficient lead time remains to resolve potential delays; no slippage has been assumed. We believe Rochester's reserves are likely to be adequate throughout this time period.

PROJECTED CAPACITY

Generation Mix

During the next decade (1971-1980), the members of the New York Power Pool have planned generating capacity additions totaling approximately 20,200 MW consisting of Nuclear - 8,820 MW;

Conventional Fossil Fired Steam - 7,250 MW; Pumped Storage Hydro - 2,000 MW; and Gas Turbine/Combined Cycle - 2,130 MW. Table III lists the planned large-unit additions for those units having known sites. For a more comprehensive listing, see Appendix II which lists all additions making up the 20,200 MW planned for the decade. Appendix III lists the individual generating stations and capacities as of July, 1971.

TABLE III

PLANNED LARGE-UNIT GENERATING CAPACITY HAVING KNOWN SITES

Company	Unit	Type*	Size (MW)	Estimated In Service Date
Central Hudson	Roseton 1 ⊕	F	600	1972
	Roseton 2 ⊕	F	600	1973
Consolidated Edison	Indian Pt. 2	N	873	1972
	Indian Pt. 3	N	873	1974
	Astoria 6	F	800	1974
Long Island Lighting Company	Northport 3	F	386	1972
	Shoreham	N	820	1976
New York State Electric and Gas	Bell	N	830	1978
Niagara Mohawk	Oswego 5	F	875	1974
	Nine Mile 2	N	1,000	1977
Orange and Rockland	Bowline Pt. 1 △	F	600	1972
	Bowline Pt. 2 △	F	600	1974
Rochester Gas and Electric	Ginna 2	N	1,000	1979
Power Authority of the State of New York	Gilboa	PSH	1,000	1972-3
	Schoharie	PSH	1,000	1977
	Fitzpatrick	N	825	1973

*F - Fossil
N - Nuclear
PSH - Pumped Storage Hydro

⊕ Joint Venture with Consolidated Edison and Niagara Mohawk.
△ Joint Venture with Consolidated Edison.

During this 10-year period, the Pool's capacity will almost double from a present 22,000 MW to 41,000 MW in 1980, after allowing for scheduled retirements. A significant change is expected in the generation mix as shown in Table IV.

TABLE IV

NEW YORK POWER POOL GENERATION MIX - 1971 AND 1980

	1971[1/]		1980	
	MW	%	MW	%
Conventional Hydro	4,080	18.2	4,058	9.9
Nuclear	1,185	5.3	10,006	24.4
Conventional Steam	14,041	62.9	19,773	48.2
Pumped Storage Hydro	-	-	2,000	4.9
Gas Turbine and Diesel	3,029	13.6	5,164	12.6
	22,335	100.0	41,001	100.0

There are apparently no more large conventional hydro sites to be developed in New York State and no utility in the State has plans at this time to do so. Conceivably, redevelopment of existing hydro plants when current federal licenses expire will add modestly to hydro totals, but no work is yet being done along these lines. Current plans call for a significant increase in nuclear power; almost 45 percent of all planned additions will be nuclear. Another important feature is the planned 2,000 MW of pumped storage hydro capacity. This type of peaking power is economical when operated with a low cost base load generation,

1/ Edison Electric Institute reports on total U.S.A. electric utility industry for 1969 as follows: Hydro 17.3%, Conventional Steam 81.4%, Nuclear 1.0% and Internal Combustion 0.3%.

i.e., conventional hydro or nuclear. Approximately three kilowatt-hours (kWh) of pumping power are required to obtain two kWh of useful peaking power. If the three kWh can be furnished from a low-cost source, the high value of the two kWh on-peak will make this type of operation economical.[1/] Appendix IV shows the generation capacity by type for the years 1971 and 1980 for each of the individual electric companies.

At this time, capacity totaling 6,500 MW is planned for the late 1970's at sites still undetermined (see Appendix II), 75 percent of it by companies serving southeastern New York.[2/] This fact is significant because power plant siting has been most difficult and controversial in this area. The utilities affected will continue to experience obstacles and delays in finding and qualifying adequate sites for the implementation of their plans.

The changing generation mix will have an effect upon costs, reliability and fuel supply as discussed below, but the time is past when a utility can plan its generation on these factors alone. Under present conditions, with a severe deficiency in reserves over the next few years and a seeming inability to secure the many licenses and permits required for large plants, the utilities have resorted to expedients, installing whatever

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1/ Pumped storage is a special type of hydroelectric plant which utilizes a reversible pump-hydro turbine, operating as a pump during off peak hours taking power from the grid and pumping water to an elevated reservoir. During the peak hours this water head drives this same pump as a hydro turbine thereby producing power for the system. The inherent inefficiencies of pumping and driving the unit as a turbine plus transmission loss results in an approximate input power requirement of 3 kWh for every 2 kWh output.

2/ This figure includes 1,100 MW of gas turbines capacity.

generation could be licensed to operate, almost without regard to cost. Thus the installation of a large number of small gas turbines can be expected, at least for the next few years. Interestingly, the rising demand for such units is beginning to produce better performance. Manufacturers are offering gas turbine units of higher reliability and with lower heat rates, thus resulting in both greater economy and improved environmental quality. The combined cycle type of generating unit, in which the waste heat from a gas turbine is utilized in a small conventional steam turbine, is now expected to have heat rates that are competitive with those of large conventional steam installations.

Optimum Mix

Table V below shows the relative characteristics of the various types of generation considered.

TABLE V

FACTORS AFFECTING RELIABILITY AND COSTS

Unit Type	Unit Size	Capital Cost	Forced Outage Rates	Production Costs
Nuclear	Large	High	High	Low
Fossil	Medium	Medium	Medium	Medium
Gas Turbines	Small	Low	Low	High
Pumped Storage Hydro	Small	Low	Low	Variable[1]

As can be seen from Table V, for each type of generation, there are counter-balancing effects. For example, gas turbines can be installed for relatively low capital costs but have high energy costs. Nuclear plants have high capital costs but low

1/ Depends on cost of pumping power.

energy costs. Reliability comparisons will always favor small unit sizes; therefore, gas turbines and pumped storage hydro units are preferable in that respect.

The object of a proposed generation plan is to select a mix which will result in the lowest overall costs but still meet the reliability criteria. It is obvious that with so many interdependent factors, there may be serveal combinations of mix which will satisfy this goal. Optimum mix is closely related to the load characteristics of the system under study, i.e., optimum mix for a system whose load factor is 70 percent will vary from that for a system whose load factor is 50 percent. The former system requires more base load generation while the latter system can justify more peaking type generation.

Later in this report, various types of generation mixes will be considered and cost analyses presented.

Reliability

The reliability criterion of the New York Power Pool assumes the probability of a loss of load occurring one day in a period of 10 years. Sufficient generation must be available to meet this reliability criterion.

Three basic factors affect the amount of reserve required to meet the above reliability standard:

A. Size of unit

B. Forced outage rates[1/]

C. Unavailability - due to maintenance and/or fueling

Each generation type has its unique reliability characteristics varying according to unit size and other parameters. New steam units so large as to approach scale frontiers or new types of combined cycle machines would require a larger installed reserve than medium-sized conventional units because of probable higher forced outage rates. Thus the amount of installed capacity, including reserve, must vary according to the nature of the generation mix if a fixed standard or reliability is to be maintained.

GENERATION ECONOMIC CONSIDERATIONS

Today's Cost of Generation

The total cost of generation consists of production costs and fixed costs. Production costs include primarily fuel, operating labor and maintenance expenses, while the fixed costs include those costs that are related to the capital investment, i.e., depreciation, taxes and return on investment. A tabulation of representative generation costs is indicated in Table VI.

1/ The forced outage rate is defined as being equal to forced outage hours divided by the sum of service hours and forced outage hours. The resulting answer is then multiplied by 100.

TABLE VI

COST OF GENERATION

Company	Type	Fuel	Costs - cents per kilowatthour: Fuel	Operation & Maintenance	Fixed[1/] Charges	Total
Con. Edison[2/]	Steam	Fossil	0.632	0.262	0.419	1.313
	Gas Tb.	Oil-Gas	1.127	0.258	1.259	2.636
	Nuclear	Uranium	0.375	0.216	0.863	1.454
Niagara Mohawk[3/]	Steam	Coal	0.534	0.103	0.286	0.923
	Steam	Oil	0.400	0.104	0.286	0.790
	Gas Tb.	Oil-Gas	1.110	0.115	1.874	3.099
	Nuclear	Uranium	0.227	0.069	0.694	0.990
	Hydro	-	-	0.104	0.452	0.556
LILCO[3/]	Steam	Oil	0.385	0.105	0.339	0.828
	Gas Tb.	Oil-Gas	1.018	0.169	1.985	3.172
Rochester Gas & Electric[3/]	Nuclear	Uranium	0.186	0.162	0.414	0.762

1/ High fixed charges do not necessarily indicate large investments. More often they indicate that the units did not produce many kilowatthours in the period.
Fixed charges were calculated by staff and based on 7% rate of return.

2/ Six months ending 6/30/71.

3/ Twelve months ending 6/30/71.

One should note the higher fuel costs for Consolidated Edison's oil-fired units relative to Niagara Mohawk and Long Island Lighting's units. This fact is due primarily to two factors, (1) higher system heat rate, which is a measure of fuel required to produce a kilowatt hour of power, and (2) the high cost of the fuel itself due to pollution regulations of the New York City area. The higher heat rates are related to deferred retirements of oil generating units resulting primarily from the delay in meeting its construction schedule for new generation. These delays also have an adverse effect on Consolidated Edison's maintenance costs which are higher than the other utilities by a factor of approximately two and one-half.

The vast difference in fixed cost for the various nuclear units is due to the range in availability of the units. This difference reflects the significant downtime of Niagara Mohawk's Nine-Mile Point unit and Consolidated Edison's Indian Point No.1 unit in the period reported.

Economic Selection of Generation Type

The selection of the most economic generation type becomes extremely complex and difficult in this present era of legal delays and escalating costs of construction and fossil fuels. With the emphasis on clean fuels, the choice for base load operation usually is a choice between fossil oil and nuclear generating units. Nuclear power offers the advantage of low cost fuel (usually as low as 2 to 2.5 mills/kWh). Nevertheless, it is high in capital

costs as the result of long lead times, radiation safeguards and heat rejection systems more costly than those used for other forms of power generation. Fossil units are also experiencing longer lead times and added first cost to satisfy environmental considerations of thermal heat rejection and stack emissions. The added first cost for a nuclear unit as opposed to a base load fossil unit can add from $50/kW to over a $100/kW to the cost of nuclear power, depending on the size of unit, type of fossil fuel (Oil or Coal), location and delays.

An overall estimate of capital and production costs for alternative generating types installed in the mid 1970's is shown in Table VII. Certain assumptions were made regarding unit size for the pumped storage and gas turbine power block to permit a fair economic comparison.

New peaking power requirements can be accommodated by gas turbines or pumped storage units. As previously indicated, gas turbines are low investment - high fuel costs units while pumped storage units are higher in first cost with fuel costs varying in relation to the fuel costs of the generating unit supplying the pumping power during the off-peak hours.

The sensitivity to the source of pumping power is demonstrated in Table VII. There is an added cost differential of 6.5 mills/kWh in the production costs incurred in pumping with a fossil unit versus nuclear. Pumped storage units also have longer lead times than gas turbines and have met with considerable environmental resistance.

TABLE VII

ESTIMATED CAPITAL AND PRODUCTION

COST FOR THE MID 70's

Unit Type	Unit Size	Capital Cost Dollars/kW	Production Cost[1/] Mills/kWh
Nuclear	800 MW	$350	2.8
Fossil-Oil[2/]	800 MW	$250	7.0
Gas Turbines[3/]	800 MW	$120	14.2
Pumped Storage[4/]	800 MW	$175	10.0 (Pumped with Fossil) 3.5 (Pumped with Nuclear)

1/ Includes fuel, operating labor and maintenance.

2/ Burning low sulfur oil costing 70¢/million Btu and with a heat rate of 9,300 Btu/kWh.

3/ Sixteen 50 MW gas turbines burning No. 2 distillate fuel costing 90¢/million Btu and with a heat rate of 13,000 Btu/kWh.

4/ Four 200 MW units - fuel cost based on 3:2 power ratio between base loaded unit providing pumping power during off peak hours and pumped storage output. A heat rate of 9,300 Btu/kWh was assumed for the pumping unit using oil costing 70¢/million Btu.

The total generation costs of a unit are the summation of fixed and production costs and can be determined from Table VII. The fixed costs include the rate of return on investment, depreciation, taxes and insurance and are represented as a percentage of the investment; this percentage of investment is defined as the fixed charge factor. On a unitized basis, i.e., mills per kWh, these fixed costs are inversely proportional to the unit operating hours. Production costs include fuel, operating labor and maintenance and are relatively independent of operating hours.

To illustrate the effect of operating hours, the total generation cost on a unitized basis, will be calculated for an 800 MW nuclear unit operating at 5,000 and 7,500 hours annually and compared. Assume for the purposes of these calculations that the fixed charge factor is 18 percent.

NUCLEAR POWER

Annual Operation - 5,000 Hours at 800 MW Rated Load

Fixed Cost[1/] = (0.18x$350x1000 mills/$1)/5,000 Hrs. =	12.6 mills/kWh
Production Cost = (See Table VII)	2.8 mills/kWh
Total Nuclear Generation Cost for 5,000 hours	15.4 mills/kWh

Annual Operation - 7,500 Hours at 800 MW Rated Load

Fixed Cost =(0.18x$350x1000 mills/$1)/7,500 Hrs. =	8.4 mills/kWh
Production Cost = (See Table VII) =	2.8 mills/kWh
Total Nuclear Generation Cost for 7,500 hours	11.2 mills/kWh

The difference in operating costs between 5,000 and 7,500 annual operating hours for an 800 MW nuclear unit, is quite substantial, i.e., 4.2 mills/kWh, and points out the obvious benefit of operating high investment - low fuel cost generation types at high capacity factors.

1/ Investment Cost is $350/kW. See Table VII.

This benefit is not as pronounced for low investment - high fuel cost generation, such as gas turbines, where fuel costs govern the total generation costs. For example, operating 800 MW of gas turbines at 5,000 and 7,500 hours would yield:

GAS TURBINE POWER

Annual Operation - 5,000 Hours at 800 MW Rated Load

Fixed Cost = (.18x$120x1000 mills/$1)/5,000	=	4.3 mills/kWh
Production Cost (See Table VII)	=	14.2 mills/kWh
Total Generation Cost		18.5 mills/kWh

Annual Operation - 7,500 Hours at 800 MW Rated Load

Fixed Cost = (.18x$120x1000 mills/$1)/7,500	=	2.9 mills/kWh
Production Cost (See Table VII)	=	14.2 mills/kWh
Total Generation Cost		17.1 mills/kWh

Here the change in generation costs between 5,000 and 7,500 gas turbine operating hours is quite small relative to nuclear units, showing the marked influence of the high fuel cost.

A cost comparison of nuclear versus gas turbine power generation for 5,000 or 7,500 annual operating hours illustrates the economic realities of not applying gas turbines for base-loaded operation. The cost benefit of operating an 800 MW nuclear unit as opposed to 800 MW of gas turbines for 7,500 hours is $35,300,000 annually.1/

A generalized working curve for total generation costs as a function of operating hours is given in Figure 1 using Table VII as a basis. This curve was developed in a fashion similar to

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1/ $\left[(17.1-11.2 \text{ mills/kWh})\ (800{,}000 \text{ kW})\ \frac{(7500 \text{ hours})}{1000 \text{ mills/\$}}\right] = \$35{,}300{,}000$

the examples previously given which summed the fixed and production costs for different forms of power generation. Also shown in Figure 1 are the total generation costs for fossil units, to provide a more inclusive economic comparison among the three major types of generation, i.e., nuclear, fossil and gas turbine units.

To illustrate the application of Figure 1, the difference in total annual generation costs will be determined for the three types of generation shown in Figure 1, at 7,000 annual hours of operation. Since the basis of the curve is 800,000 kW of installed capacity the annual output is: 800,000kW x 7,000 hours = $5,600 \times 10^6$ kWh.

From Figure 1, the approximate unitized generation costs at 7,000 hours are:

Nuclear	-	11.80 mills/kWh = \$.0118/kWh
Fossil	-	13.30 mills/kWh = \$.0133/kWh
Gas Turbines	-	17.30 mills/kWh = \$.0173/kWh

Then the annual costs, for each type of generation evaluated, on a total dollar basis are:

Nuclear	- 5600×10^6kWh x	\$0.0118/kWh = \$66,000,000
Fossil	- 5600×10^6kWh x	\$0.0133/kWh = \$74,500,000
Gas Turbines	- 5600×10^6kWh x	\$0.0173/kWh = \$97,000,000

On the above basis, the annual cost differential between an 800,000 kW nuclear and fossil unit is \$8,500,000. This difference is a continuous cost that would be borne by the rate payer annually for the book life of the equipment.

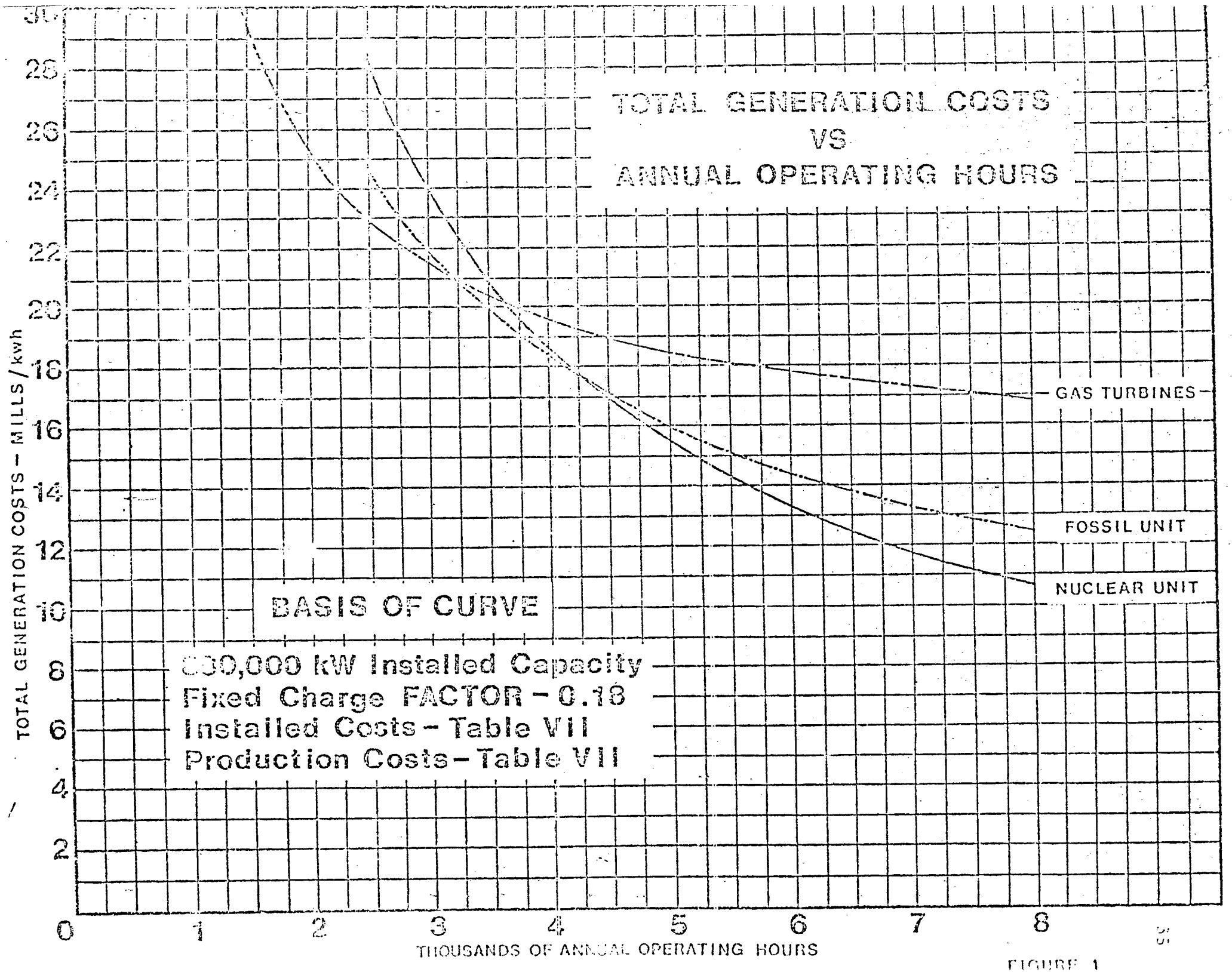
TOTAL GENERATION COSTS
VS
ANNUAL OPERATING HOURS
GAS TURBINES
FOSSIL UNIT
NUCLEAR UNIT
BASIS OF CURVE
600,000 kW Installed Capacity
Fixed Charge FACTOR - 0.18
Installed Costs - Table VII
Production Costs - Table VII
TOTAL GENERATION COSTS - MILLS / kwh
THOUSANDS OF ANNUAL OPERATING HOURS
0
1
2
3
4
5
6
7
8
2
4
6
8
10
12
14
16
18
20
22
24
26
28
30

FIGURE 1

Estimated Generation Costs Without Nuclear Expansion

In view of the Calvert Cliffs decision and ever-changing standards surrounding nuclear power plants, it is appropriate to estimate the economic effects of various alternatives to the proposed nuclear expansion for the New York Power Pool in the period of 1971-1980. During this period approximately 8,800 MW of nuclear power is planned. Assuming that units near completion (Indian Point No. 2 & 3 and Fitzpatrick) will ultimately go commercial, the nuclear power remaining for evaluation is approximately 6,000 MW. Therefore, the economic penalty of a non-nuclear expansion will involve 6,000 MW of alternative generation types. The alternatives considered in lieu of a 6,000 MW nuclear expansion are:

A. Install 6,000 MW of base load fossil units.

B. Install 4,000 MW of base load fossil units and 2,000 MW of gas turbine units.

C. Install 6,000 MW of gas turbine units.

The economic analysis will utilize the assumptions made in Table VII and the resultant generation costs plotted in Figure 1, namely:

1. Installation Cost for:	Nuclear Units	- $350/kW
	Fossil Units	- $250/kW
	Gas Tur. Units	- $120/kW
2. Production Cost for:	Nuclear Units	- 2.8 mills/kWh
	Fossil Units	- 7.0 mills/kWh
	Gas Tur. Units	-14.2 mills/kWh

During the expansion period (1971-1980), the 6,000 MW of new generation would consist of various unit sizes and would be installed in different years. Therefore, the estimated installation and production costs assumed are for the mid 70's which represent an average value.

In the base case of the nuclear expansion, an 80% capacity factor was assumed. This yields a total output of about 42,000 x 10^6kWh.[1/] Therefore, each alternative must be evaluated for the same total generation output, i.e., 42,000 x 10^6 kWh.

With the foregoing assumptions as a basis, the economic evaluation for the alternative generation plans are the following:

Alternative A - Install 6,000 MW of Base Load Fossil Units

The capacity factor for the new fossil units is assumed to be 80% which is equivalent to operating the units at their rated capacity for 7,000 hours. On this basis, the total generation costs (fixed plus production costs) can be determined from Figure 1 and compared to the total nuclear costs, which are also taken from Figure 1 at 7,000 annual operating hours a year. On a unitized basis the generation costs are:

Fossil Generation Cost - 13.30 mills/kWh = \$.0133/kWh

Nuclear Generation Cost - 11.80 mills/kWh = \$.0118/kWh

In total dollars the annual generation costs are:

Fossil: (\$.0133/kWhx42,000x10^6kWh) = \$560,000,000

Nuclear: (\$.0118/kWhx42,000x10^6kWh) = \$495,000,000

1/ [(0.80)(8760 hours)(6,000,000kW)] = 42,048x10^6 kWh

Therefore, the annual economic penalty for installing 6,000 MW of fossil units in lieu of comparable nuclear generation is $65,000,000.

If it is assumed that all 6,000 MW of generation are installed by 1980, this added cost of $65,000,000 will be incurred by the rate payer annually in 1980 and each subsequent year for the book life of the equipment.

Alternative B - Install 4,000 MW Fossil and 2,000 MW of Gas Turbines

In this alternative, it is also assumed that the 4,000 MW fossil addition will operate at an 80% load factor (7,000 hours) and the 2,000 MW of gas turbines at 1,500 hours annually. On this basis, the total output in kilowatt-hours for the expansion generation capacity is:

Fossil	= .80x8,760x4,000,000	=	$28,000 \times 10^6$ kWh
Gas Turbines	= 1,500x2,000,000	=	$3,000 \times 10^6$ kWh
Total		=	$31,000 \times 10^6$ kWh

The difference in generation output between the nuclear expansion and Alternative B is $11,000 \times 10^6$ kWh. This difference of $11,000 \times 10^6$ kWh will have to be made up from existing capacity or from purchases if there is no spare existing capacity. It will be assumed that the cost of existing generation is 10 mills/kWh. The total system generation cost associated with the Alternative B expansion is the individual generation type output multiplied by its associated unit cost taken from Figure 1, i.e.,

New Fossil	-	$28,000 \times 10^6$ kWh x \$.0133/kWh	= \$372,000,000
New Gas Turbines	-	$3,000 \times 10^6$ kWh x \$.029/kWh	= \$ 87,000,000
Existing	-	$11,000 \times 10^6$ kWh x \$.01/kWh	= \$110,000,000
Total Generation Costs for Alternative B			= \$569,000,000

Therefore, the added annual cost for generation with a 6,000 MW combination fossil and gas turbine expansion versus nuclear is \$74,000,000.

Obviously, in a more rigorous analysis, it would have to be determined whether the existing system capacity could produce an additional $11,000 \times 10^6$ kWh. If not, the cost differential would be much greater as the result of increased gas turbine operating hours or additional purchases.

Alternative C - Install 6,000 MW of Gas Turbines

In this alternative it is assumed that the total output would be derived from gas turbines, which means they would operate 7,000 hours a year at rated capacity. From Figure 1, the total generation costs are 17.3 mills/kWh. The total dollar cost for this mode of operation is:

$$(42,000 \times 10^6 \text{kWh} \times \$.0173) = \$725,000,000$$

The difference in total generation cost for an all gas turbine expansion versus nuclear becomes \$230,000,000. Furthermore, an attempt to operate gas turbines at such a high load factor would undoubtedly result in very high maintenance costs.

Alternative C, in essence, represents an exercise in futility, merely emphasizing the misapplication of gas turbines for base load generation and is more an anticipated response to the question of, "Why not install gas turbines instead of nuclear plants?"

A summary of the economic evaluation of the base nuclear expansion Alternatives A, B, C, is tabulated below:

TABLE VIII

ANALYSIS OF DIFFERENT FORMS OF GENERATION EXPANSION

Expansion Plan	Output Million kWh	Generation Cost
Base - 6,000 MW Nuclear	42,000	$495,000,000
A - 6,000 MW Fossil	42,000	$560,000,000
B - 4,000 MW Fossil 2,000 MW Gas Turbine	42,000	$569,000,000
C - 6,000 MW Gas Turbine	42,000	$725,000,000

The above analysis is a simplified approach to a complex problem which ultimately must be solved via a computerized generation study. However, it does point out in "ballpark" figures how costs can change, depending upon the type of units installed and thereby the need for the optimum generation mix. A more detailed analysis would also include mid-range operation alternatives such as combined cycles, small steam plants and steam injection systems which could provide economically viable solutions.

The generation mix that will exist in 1980 will not depend entirely on considerations of economics or reliability. Unavailability of a particular type of fuel, inability to finance high-investment types of units or an obligation to schedule daily operation of generating units on the basis of least pollution instead of least incremental operating cost are all factors that can influence the types of generation that will be installed and thereby affect the costs of production.

Delay Associated Costs

As previously indicated, environmental considerations and opposition to power generation facilities have created monumental delays in meeting construction and operation schedules. Heretofore, most delays have been associated with nuclear power plants, although Consolidated Edison has also met with resistance in the installation of fossil units in the New York City area, and staff assumes that opposition to fossil units will increase. Obviously, these delays are not without consequences to the rate payer.

Basically, the consequential costs associated with delays of power plants fall into three categories:

1. Added Production Costs
2. Added Fixed Costs
3. Added Escalation Costs

The added production costs are primarily related to the following:

1. Increase utilization of old inefficient units with high heat rates.
2. Necessity of purchasing high cost energy from neighboring systems.
3. Purchase of additional gas turbines as an interim measure.

In general, delays in getting the plant on line will force the utilities to operate their existing equipment at higher capacity factors than dictated by good operating practice, and indeed, in some cases, retirement of old inefficient units may have to be deferred. Thus, plants with heat rates in the 14,000 to 16,000 Btu/kWh range and even higher would be utilized. Gas turbines purchased as a stop gap measure generate power at approximate heat

rates of 13,000 to 15,000 Btu's/kWh with either light distillate or light residual fuels; such fuels are more costly than the heavy residual oils burned in conventional fossil units. Energy purchased from neighboring utilities generally runs as high as 15 mills/kWh. An estimate made in a recent staff study, indicates the additional fuel costs caused by a one-year delay in an 800 MW nuclear unit would be approximately $30,000,000 and for an 800 MW fossil unit, $5,500,000 due to operation of less efficient units utilizing higher cost fuels.[1/] Sometimes the utilities must install capacity which is more expensive than purchased power because: (1) the utility must maintain an adequate power reserve as dictated by the New York Power Pool (12% Upstate; 14% Downstate) and (2) purchased power may simply not be available.

The added fixed cost due to forced installation of gas turbines is related to the fact that if a utility were able to implement its fossil or nuclear construction schedule, such gas turbine capacity would not be needed for the delay affected period, if at all. For example, assume that a utility would have approximately 20 percent reserve capacity after the installation of a new 800 MW nuclear unit. Obviously, if this unit were delayed the utility would try to install only those gas turbines, which in combination with purchased power, would maintain the necessary reserve and get the utility through the power crunch until the nuclear plant became operational. To purchase the whole 800 MW of gas turbine capacity would create excessive, high cost capability which would have a further adverse effect on the cost of power to the consumer.

1/ Staff study of delay in construction of LILCO's 820 MW Shoreham Nuclear Plant.

For the purposes of illustration, assume that in conjunction with outside purchases, 240 MW of gas turbine capability were required to maintain minimum reserves for the delay-affected year. As in previous examples, the fixed cost associated with the additional gas turbines is equal to a carrying charge of 18 percent of this additional investment. Assuming an installed cost of $120/kW, the added fixed cost, due to a one-year delay of an 800 MW base load unit and the subsequent installation of 240 MW of gas turbine capacity is:

0.18 x 240,000 kW x $120/kW = $5,200,000.

Another delay associated cost is caused by the fact that construction and most equipment costs go up each year. Using an average escalation cost of 6 percent, which is probably conservative, the added inflationary costs due to a one-year delay are: 1/

Fossil: 0.06 x 800,000 kW x $250/kW = $12,000,000.

Nuclear: 0.06 x 800,000 kW x $350/kW = $16,800,000.

Thus, the additional annual cost, due to a cost escalation caused by a one year delay in the fossil or nuclear base load unit on the basis of the same fixed charge factor of 0.18, is seen in the following calculations:

800 MW Fossil: 0.18 x $12,000,000 = $2,160,000.

800 MW Nuclear: 0.18 x $16,800,000 = $3,020,000.

As noted, these costs are due essentially to inflation. Clearly, these costs are not incurred until the base load unit becom operational.

1/ This excludes the increase due to Interest During Construction.

In summary, a one year delay in an 800 MW base load unit (nuclear or fossil) has short term and long term cost effects. Short term effects are listed in the following table (Table IX):

TABLE IX

Short-Term Cost Effect of a One-Year Delay in the Installation of an 800 MW Base Load Power Plant.

Gas Turbine Substitution for:	Fossil	Nuclear
Added Production Costs	$5,500,000	$30,000,000
Added fixed cost associated with assumed 240,000 kW of gas turbine capacity	5,200,000	5,200,000
	$10,700,000	$35,200,000

As seen from Table IX the consumer would pay an additional $10,700,000 due to a one-year delay in an 800 MW fossil unit or $35,200,000 due to the same delay in an 800 MW nuclear unit.

For long term, the burden of added cost is not as clear. Regardless of whether the gas turbine capacity is used, the consumer will be burdened with fixed escalation charges due to inflation which in the previous examples amounted to $2,160,000 or $3,020,000 annually. Should the 240 MW of gas turbine capacity remain idle for several years after start-up of the base load units, the consumer will also be paying fixed charges on a delay-caused investment, amounting to $5,200,000.

Should the gas turbines eventually be required for peaking purposes, this added cost will become a needed investment, not idle capacity. Nevertheless, the installation of gas turbines for short-term use defeats good system planning and certainty adds nothing to the design of an optimum generation mix.

The preceding examples were used for purposes of illustration and as such were quite simplified, but they do take account of the initial cost and penalties for delay of base load generation units and demonstrate the importance of choosing and achieving the proper generation mix for a given power system.

FUEL SUPPLY

The major factors affecting the choice of fuels for power generation are:

1. Fuel Cost
2. Fuel Availability
3. Fuel Cleanliness

The above parameters are interrelated in that cost is affected by the laws of supply and demand, and the need of cleaner fuels has made some of the more desirable fuels less available and more costly.

This past year has demonstrated the following effects. Coal has increased in price from 30¢/million Btu to an average of 55¢/million Btu for some utilities; the added cost to the consumer for this increase is approximately 2.5 mills/kWh. Due to the unavilability of quality coal, many utilities have converted to oil firing, while still retaining their coal facilities as an alternate fuel back up.

Utilities in the New York City area are obligated to burn oil with a sulphur content of no more than 0.3%, by October 1972. This requirement obviously has availability and added cost connotations. The demand for low sulphur oil has increased

the cost of oil even more dramatically than coal, with some utilities paying as much as 80¢/million Btu.

The northeast utilities are almost completely dependent on foreign oil supplies for power generation, creating a problem of unavailability in the event of curtailment from these sources. A prolonged curtailment could have serious consequences on the power supply of New York State.

Tying these factors together indicates a need for a low cost reliable fuel supply which remains within the control of the utility. A nuclear plant would permit such control, providing more diversified fuel supply sources while satisfying the cost, availability and cleanliness considerations.

PROJECTED BULK POWER TRANSMISSION

The objective of any long range transmission plan is to provide a system that meets the desired reliability criteria, and results in minimum requirements for new circuits and additional rights-of-way. The latter requirements are not necessarily optimum from an economic viewpoint but are goals based on environmental standards.

The final transmission system should be capable of meeting these basic criteria:

(1) The network should be capable of supplying the load with the required degree of reliability.

(2) There should be no "bottled capacity", i.e., all generation, within reason, should be able to operate without exceeding the capability of any segments of the transmission system.

(3) The transmission network should be capable of transferring power between the extremities of the state under adverse conditions. The amount of power to be transferred should be consistent with the reserve available in the sending area and the possible needs of the receiving area. For example, the total operating reserve in the Upstate areas should be transferrable to Southeast New York.

These criteria are essential if single - system planning is to become a reality in New York State.

The Existing Transmission System

The existing New York bulk transmission system is shown in Figure 2. Also shown are transmission projects which have already been committed and scheduled for completion in the near future.

New York State's high voltage network is under continuous development. At this time, much of the capability of the cross-state transmission system is vested in the two 345 KV circuits which extend from the Niagara area to New York City. (The section between Utica and Albany consists of only one 345 kV circuit but is paralleled by two 230 kV circuits).

Historically, the normal power flow within the New York system has been from west to east. This condition will prevail as long as the power deficient eastern New York area is unable to construct sufficient new generation and remains dependent on the other areas of the state.

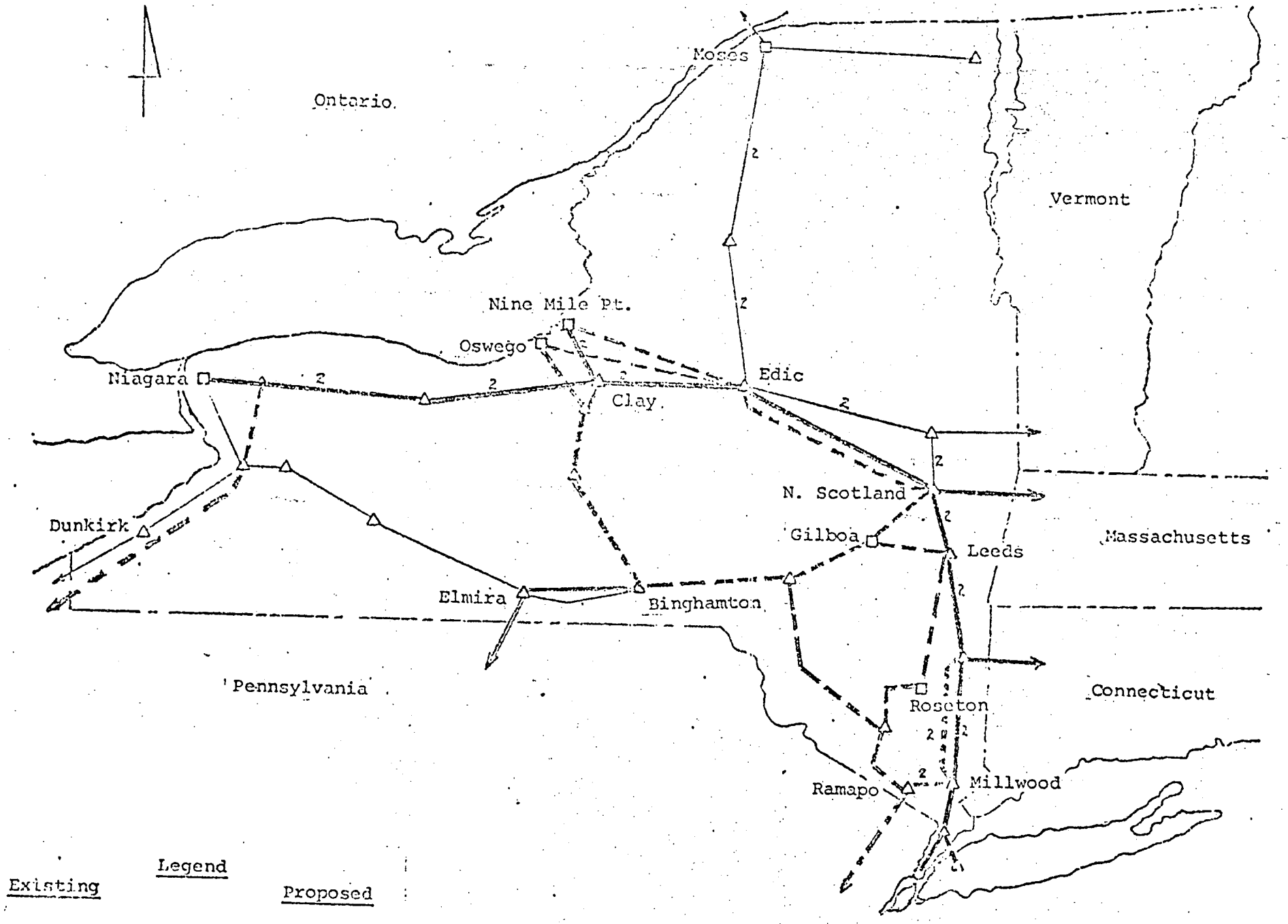

FIGURE 2

NEW YORK POWER POOL
EHV TRANSMISSION SYSTEM 1971-80

The ability to transfer power from west to east and then to southeastern New York is presently governed by the limitations in the ties between Utica and Albany (Central-East) and between Albany and New York City (Upstate-Southeast ties). Of specific concern are the lines between the Pleasant Valley and Millwood substations.

These ties operate electrically in series, so that the lower of the two limitations is the controlling factor and will be determined by the particular load and generation conditions existing in the eastern New York area at any given time. Based on the 1971 system, the transmission network is capable of a transfer of 1,500 MW from Central to East and 1,200 MW from Upstate to Southeast New York.

The greatest problem of the existing transmission system is its inability to transfer enough power to Consolidated Edison from the upstate area during the summer periods. In the 1970 summer season there were occasions when excess capacity was available upstate or in the Canadian provinces, but transmission limitations prohibited its transfer to the Consolidated Edison system, forcing the latter into voltage reductions.

To increase the ability to transfer power between areas of the State, the transmission system must be strengthened. Since the generation deficiencies now present in the Consolidated Edison system are expected to continue, strong transmission ties will

be required to the other areas so that maximum power transfers can be made. As stated, Consolidated Edison can import 1,200 MW from the upstate areas; with the proposed transmission additions planned for the 1970's this import limit will be increased to 3,800 MW. The existing limit represents 14 percent of Consolidated Edison's 1971 peak load while the new limit will be 31 percent of its 1980 forecast peak load, a limit considered adequate by most system planners.

System Additions

The following major transmission additions (345 kV except where noted) are planned for the 1971-80 period:

1. Edic-New Scotland (Design for future 765 kV operation, but operated initially at 345 kV)
2. Binghamton-Syracuse
3. Buffalo-Erie[1/]
4. Pleasant Valley-Connecticut[1/]
5. Fitzpatrick-Edic
6. Oswego-Syracuse (Designed for future 765 kV)
7. Pleasant Valley-Carmel-Millwood (2 circuits)
8. Southern Tier line
9. Branchburg, New Jersey-Ramapo (500 kV)[1/]
10. Brooklyn-Hudson, New Jersey and Ramapo-New Milford, New Jersey[1/]
11. Ramapo-Millwood (2 circuits)

When these additions are completed the transmission network will have the following capabilities:

1/ Interconnections with neighboring pools.

	TRANSFER LIMITS	
	NORMAL	EMERGENCY
Upstate to Southeast N.Y.	3500 MW	3800 MW
Southeast N.Y. to Upstate	2200 MW	3000 MW

The present 1,200 MW transfer limit to southeastern New York equals approximately 14% of Consolidated Edison's 1971 peak load. The 3800 MW transfer limit, after the system additions, represents approximately 31% of Consolidated Edison's 1980 forecast peak load, a considerable improvement over the present situation.

Transfer Limits

The prime consideration in any plan must be to assure sufficient transmission capacity into metropolitan New York, a high-density load area accounting for 38% of the entire New York State load in 1980. The proposed transmission system provides for an emergency transfer limit of 3,800 MW between upstate and southeastern New York. This capability extends only to the boundaries of the Consolidated Edison system; internal reinforcements within its system must be continually monitored so that this capability may be effectively employed. Specifically, the cable system between Sprain Brook substation in southern Westchester County and New York City should be reviewed to assure that its capacity remains consistent with the capacity of the overhead system bringing in power from the north.

Use of Existing System

Environmental considerations dictate that maximum use be made of existing rights-of-way. With regard to future transmission lines, the initial consideration should be to eliminate

lower voltage lines and utilize their rights-of-way for the proposed new high voltage lines. This application will be limited, of course, to the instances where it can be done without affecting reliability, and where it is environmentally acceptable to do so.

The New York Power Pool already has or is building a number of ties to other systems. Several interconnections have been assumed in this study which will further strengthen ties to the neighboring areas. The most significant links include a 345 kV tie between Buffalo and Erie, Pennsylvania; an additional 345 kV tie between Pleasant Valley, N.Y. and Connecticut; a 345 kV cable tie between Hudson, New Jersey, and Farragut, New York, and a 345 kV tie between Ramapo and New Milford, New Jersey.

Priority should be given to additional ties between the New York City and New Jersey systems as well as between the Long Island and the Connecticut system[1/], assuming that these other systems progress with their own internal system reinforcements so as to be in a safe position to exchange assistance when required.

Future 765 kV

The Pool's studies, to date, do not demonstrate a requirement for a 765 kV system prior to 1980. The critical consideration is not necessarily to have a 765 kV network in operation by that date but to have the goal formed and interim construction compatible with that goal so that a 765 kV network will be available when load growth demands it.

1/ There is now one 300 MW tie across Long Island Sound.

The long range studies must be completed and the optimum configuration of the future 765 kV grid must be determined. Selected 345 kV lines could be designed for later 765 kV operation as indicated by this long range plan. Some progress has been made in this respect; the proposed Oswego-Edic line and the Edic-New Scotland line will be designed for ultimate 765 kV operation. In addition, a section of the New Scotland-Northfield Mt. line is designed for 765 kV. This will provide a future 765 kV path from New England to Eastern New York on to Central New York. It will be desirable to establish a parallel path across the southern New York border and intermediate ties between the two paths.

Serious consideration should be given to possible 765 kV design for the Binghamton-Syracuse line, the Buffalo-Erie line and any proposed tie to Ontario or Quebec.

Conclusion

Recognizing that uncertainty can never be eliminated from a 10 year plan, staff finds too much uncertainty in the 1971-80 plan of the New York Power Pool. Major units totaling over 5,400 MW still have no designated sites. The internal transmission capacity of Consolidated Edison company may need to be strengthened. The utilities are still not making maximum use of rights-of-way; they are just beginning to plan for adequate interconnections with other pools. Single system planning must become a reality.

The major generation problem areas, in providing an adequate power supply for the coming decade can be categorized as follows:

1. Siting
2. Implementation of generation mix
3. Improved availability of existing equipment

Due to the expansion of the lead times, sites must be identified as early as possible. Site tailored environmental standards are required to ensure adequate protection of the environment. The existing overall legal procedures for obtaining permits and licensing a generation plant at a given site are overly complicated and must be streamlined. The associated delays are costing the consumer hundreds of millions of dollars.

The implementation of the planned nuclear capacity for the next decade is extremely critical not only for economic reasons, but also in terms of a reliable fuel supply under which the utilities can exercise reasonable control.

Availability of generation equipment must be improved through a more comprehensive program of upgrading existing operating and maintenance procedures.

APPENDIX I

LOAD, CAPACITY AND RESERVE MARGINS FOR NEW YORK STATE 1971-1980

Central Hudson Gas & Electric Corporation

Load, Capacity and Reserves (MW)

Summer

	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980
Forecast Peak Load	540	630	690	755	825	905	990	1080	1185	1300
Total Available Capacity	656	718	919	919	919	994	1159	1159	1244	1349
Estimated Reserve - MW	116	88	229	164	94	89	169	79	59	49
- %	21.5	14	33	22	11	10	17	7	5	4

Effect of Contingencies

Contingency

None

Estimated Reserve - MW

Load, Capacity and Reserves (MW)

Winter

	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980
Forecast Peak Load	600	645	710	775	850	930	1020	1120	1225	1340
Total Available Capacity	684	771	931	931	976	1051	1171	1231	1326	1411
Estimated Reserve - MW	84	126	221	156	126	121	151	111	101	71
- %	14	20	31	20	15	13	15	10	8	5

Effect of Contingencies

Contingency

None

Estimated Reserve - MW

Load, Capacity and Reserves (MW)

Summer

	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980
Forecast Peak Load	7800	8550	8950	9400	9850	10300	10750	11200	11650	12100
Total Available Capacity	9509	10031	10585	12050	12050	12459	13544	14180	14095	15105
Estimated Reserve - MW	1709	1481	1635	2650	2200	2159	2794	2980	2445	3005
- %	21.9	17.3	18.3	28.2	22.3	21.0	26.0	26.6	21.0	24.8

Effect of Contingencies

Contingency										
1. Indian Pt. #2		(873)								
2. Bowline Pt. #1		(400)								
3. Indian Pt. #3				(873)	(873)					
4. Astoria #6				(800)	(800)					
5. Uprate Ind. Pt. #1 & #2						(184)	(254)	(70)	(136)	(66)
6. PASNY Pumped Storage							(500)	(500)		
7. Fossil unit								(800)	(800)	(800)
8. Nuclear #4										(1115)
Total Available Capacity	9509	8758	10585	10377	10377	12275	12790	12810	13159	13124
Estimated Reserve - MW	1709	208	1635	977	527	1975	2040	1610	1509	1024
- %	21.9	2.4	18.3	10.4	5.4	19.2	19.0	14.4	13.0	8.5

Load, Capacity and Reserves (MW)

Winter

	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980
Forecast Peak Load	6225	6500	6800	7125	7475	7825	8175	8550	8950	9350
Total Available Capacity	8500	9823	9247	11505	11460	11969	12701	13507	13412	14442
Estimated Reserve - MW	2275	3323	2447	4380	3985	4144	4526	4957	4462	5092
- %	36.6	51.1	36.0	61.5	53.3	53.0	55.4	58.0	49.9	54.5

Effect of Contingencies

Contingency										
1. Indian Pt. #2		(873)								
2. Bowline #1		(400)								
3. Indian Pt. #3				(873)	(873)					
4. Astoria #6				(800)	(800)					
5. Uprate Ind. Pt. #1 & #2						(184)	(254)	(70)	(136)	(66)
6. PASNY Pumped Storage							(500)	(500)		
7. Fossil unit								(800)	(800)	(800)
8. Nuclear #4										(1115)
Total Available Capacity	8500	8550	9247	9832	9787	11785	11947	12137	12476	12461
Estimated Reserve - MW	2275	2050	2447	2707	2312	3960	3772	3587	3526	3111
- %	36.6	31.5	36.0	34.0	30.9	50.6	46.1	42.0	39.4	33.3

Load, Capacity and Reserves (MW)

Summer

	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980
Forecast Peak Load	2341	2665	2880	3100	3325	3565	3820	4095	4385	4690
Total Available Capacity	2835	3273	3273	3533	3933	4553	4553	4833	5173	5773
Estimated Reserve - MW	494	608	393	433	608	988	733	738	788	1083
- %	21.1	22.8	13.7	14.0	18.3	27.7	19.2	18.0	18.0	23.1

Effect of Contingencies

Contingency										
1. Shoreham						(820)				
Total Available Capacity	2835	3273	3273	3533	3733	3733	4553	4833	5173	5773
Estimated Reserve - MW	494	608	393	433	608	168	733	738	788	1083
- %	21.1	22.8	13.7	14.0	18.3	4.7	19.2	18.0	18.0	23.1

Load, Capacity and Reserves (MW)

Winter

	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980
Forecast Peak Load	2280	2440	2580	2730	2890	3040	3230	3430	3640	3850
Total Available Capacity	2900	3386	3386	3646	3846	4666	4666	4946	5286	5886
Estimated Reserve - MW	620	946	806	916	956	1626	1436	1516	1646	2036
- %	27.2	38.8	31.2	33.6	33.1	53.5	44.5	44.2	45.2	52.9

Effect of Contingencies

Contingency										
1. Shoreham						(820)				
Total Available Capacity	2900	3386	3386	3646	3846	3846	4666	4946	5286	5886
Estimated Reserve - MW	620	946	806	916	956	806	1436	1516	1646	2036
- %	27.2	38.8	31.2	33.6	33.1	26.5	44.5	44.2	45.2	52.9

New York State Electric and Gas

Load, Capacity and Reserves (MW)

Summer

	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980
Forecast Peak Load	1350	1479	1593	1717	1850	1994	2146	2307	2475	2650
Total Available Capacity	1538	1855	2161	2501	2466	3031	2995	2960	3755	3745
Estimated Reserve - MW	188	376	568	784	616	1037	849	653	1280	1095
- %	13.9	25.4	35.7	45.7	33.3	52.0	39.6	28.3	51.7	41.3

Effect of Contingencies

Contingency										
1. 1976 Unit						(600)				
2. Fitzpatrick (NYSE & G Share)				(225)						
3. Bell									(830)	(830)
Total Available Capacity	1538	1855	2161	2276	2466	2431	2995	2960	2925	2915
Estimated Reserve - MW	188	376	568	559	616	437	849	653	450	265
- %	13.9	25.4	35.7	32.6	33.3	21.9	39.6	28.3	18.2	10.0

Load, Capacity and Reserves (MW)

Winter

	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980
Forecast Peak Load	1641	1769	1908	2056	2215	2387	2569	2761	2962	3172
Total Available Capacity	1983	2161	2501	2466	2431	2995	2960	3755	3745	3732
Estimated Reserve - MW	342	392	593	410	216	608	391	994	783	560
- %	20.8	22.2	31.1	19.9	9.8	25.5	15.2	36.0	26.4	17.7

Effect of Contingencies

Contingency										
1. 1976 Unit						(600)				
2. Fitzpatrick (NYSE & G Share)			(250)	(225)						
3. Bell								(830)	(830)	(830)
Total Available Capacity	1983	2161	2251	2241	2431	2395	2960	2925	2915	2902
Estimated Reserve - MW	342	392	343	185	216	8	391	164	-47	-270
- %	20.8	22.2	18.0	9.0	9.8	0.3	15.2	5.9	--	--

Load, Capacity and Reserves (MW)

Summer

	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980
Forecast Peak Load	4295	4328	4538	4768	4998	5208	5428	5678	5908	6153
Total Available Capacity	5223	5303	6090	6050	6885	7011	6890	7929	7916	7903
Estimated Reserve - MW	928	975	1552	1282	1887	1803	1462	2251	2008	1750
- %	21.6	22.5	34.2	26.9	37.8	34.6	26.9	39.6	34.0	28.4

Effect of Contingencies

Contingency										
1. Fitzpatrick (NM Share)			(250)	(225)						
2. Nine Mile #2								(1000)		
Total Available Capacity	5223	5303	5840	5825	6885	7011	6890	6929	7916	7903
Estimated Reserve - MW	928	975	1302	1057	1887	1803	1462	1251	2008	1750
- %	21.6	22.5	28.7	22.2	37.8	34.6	26.9	22.0	34.0	28.4

Load, Capacity and Reserve (MW)
Winter

	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980
orecast Peak Load	4,623	4,853	5,103	5,353	5,588	5,838	6,098	6,368	6,638	6,933
otal Available Capacity	5,581	6,273	7,064	7,898	7,858	7,883	8,602	8,564	8,551	9,538
stimated Reserve - MW	958	1,420	1,961	2,545	2,270	2,045	2,504	2,196	1,913	2,605
- %	20.7	29.3	38.4	47.5	40.6	35.0	41.1	34.5	28.8	37.

Effect of Contingencies

ontingency										
.. Fitzpatrick (NM share)			(250)	(225)						
:. Nine Mile #2							(1000)	(1000)		
otal Available Capacity	5,581	6,273	6,814	7,673	7,858	7,883	7,602	7,564	8,551	9,538
timated Reserve-Mw	958	1,420	1,711	2,320	2,270	2,045	1,504	1,196	1,913	2,605
-%	20.7	29.3	33.5	43.3	40.6	35.0	24.7	18.8	28.8	37.6

Load, Capacity and Reserves (MW)
Summer

	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980
Forecast Peak Load	524	619	691	770	859	954	1,060	1,177	1,307	1,452
Total Available Capacity	625	835	835	1,035	1,035	1,035	1,335	1,335	1,735	1,735
Estimated Reserve - MW	101	216	144	265	176	81	275	158	428	283
%	19.2	34.9	20.8	34.4	20.5	8.5	25.9	13.4	32.8	19.

Effect of Contingencies

Contingency										
1. Bowline Pt. #1		(200)								
2. 1977 unit							(300)			
Total Available Capacity	625	635	835	1,035	1,035	1,035	1,035	1,335	1,735	1,735
Estimated Reserve - MW	101	16	144	265	176	81	-25	158	428	283
%	19.2	2.6	20.8	34.4	20.5	8.5	-	13.4	32.8	19.5

Load, Capacity and Reserve (MW)
Winter

	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980
orecast Peak Load	469	518	572	631	696	769	848	938	1,034	1,141
otal Available Capacity	587	848	848	1,048	1,048	1,048	1,348	1,348	1,748	1,748
stimated Reserve-MW	118	330	276	417	352	279	500	410	714	607
-%	25.2	63.7	48.3	66.1	50.6	36.3	59.0	43.7	69.1	53.2

Effect of Contingencies

ontingency

1. Bowline Pt. #1 - (no effect - 6 mo. slippage only assumed)
2. 1977 unit (300)

otal Available Capacity	587	848	848	1,048	1,048	1,048	1,048	1,348	1,748	1,748
stimated Reserve - MW	118	330	276	417	352	279	200	410	714	607
-%	25.2	63.7	48.3	66.1	50.6	36.3	23.6	43.7	69.1	53.2

Rochester Gas & Electric Corporation

Load, Capacity and Reserves (MW)
Summer

	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980
Forecast Peak Load	790	876	946	1,022	1,105	1,192	1,288	1,392	1,502	1,624
Total Available Capacity	936	1,066	1,409	1,404	1,399	1,467	1,585	1,728	2,371	2,364
Estimated Reserve - MW	146	190	463	382	294	275	297	336	869	740
- %	18.5	21.7	48.9	37.4	26.6	23.1	23.1	24.1	57.9	45.6

Effect of Contingencies

Contingency

None

Estimated Reserve - MW	146	190	463	382	294	275	297	336	869	740
- %	18.5	21.7	48.9	37.4	26.6	23.1	23.1	24.1	57.9	45.6

Load, Capacity and Reserves (MW)
Winter

	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980
Forecast Peak Load	832	893	958	1,029	1,104	1,185	1,274	1,374	1,485	1,603
Total Available Capacity	1,007	1,122	1,389	1,381	1,371	1,463	1,555	1,697	2,339	2,336
Estimated Reserve - MW	175	229	431	352	267	278	281	323	854	733
- %	21.0	25.6	45.0	34.2	24.2	23.5	22.1	23.5	57.5	45.7

Effect of Contingencies

Contingency

None

Estimated Reserve - MW	175	229	431	352	267	278	281	323	854	733
- %	21.0	25.6	45.0	34.2	24.2	23.5	22.1	23.5	57.5	45.7

Statewide

Load, Capacity and Reserve (MW)

Summer

	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980
Forecast Peak Load (Coincident)	18,069	19,750	21,027	22,357	23,725	25,069	26,446	27,882	29,355	30,900
Total Available Capacity	22,269	24,053	26,619	28,964	30,084	32,222	34,783	36,871	39,061	40,746
Estimated Reserve - MW	4,200	4,303	5,592	6,607	6,359	7,153	8,337	8,989	9,706	9,846
- %	23.2	21.8	26.6	29.6	26.8	28.5	31.5	32.2	33.1	31.9

Effect of Contingencies

Contingency										
1. Indian Pt. #2		(873)								
2. Bowline Pt. #1		(600)								
3. Fitzpatrick			(825)	(825)						
4. Indian Pt. #3				(873)	(873)					
5. Astoria #6				(800)	(800)					
6. Indian Pt. Uprate						(184)	(254)	(70)	(136)	(66)
7. NYSE&G '76 unit						(600)				
8. Nine Mile #2								(1000)		
9. Shoreham						(820)				
10. PASNY PSH							(1000)	(1000)		
11. O&R '77 unit							(300)			
12. C.E. Fossil unit										
13. Bell Unit								(800)	(800)	(800)
14. Nuclear #4									(830)	(830)
										(1115)
Total Available Capacity	22,269	22,580	25,794	26,466	28,411	30,618	33,229	34,001	37,295	37,935
Estimated Reserve-MW	4,200	2,830	4,767	4,109	4,686	5,549	6,783	6,119	7,940	7,035
-%	23.2	14.3	22.6	18.4	19.8	22.1	25.7	22.0	27.0	22.8

Statewide

Load, Capacity and Reserves (MW)

Winter

	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980
Forecast Peak Load	17,634	18,696	18,875	21,059	22,296	23,522	24,807	26,158	27,574	29,052
Total Available Capacity	22,214	25,381	26,738	30,372	30,612	32,772	35,750	37,820	39,204	41,890
Estimated Reserve-MW	4,580	6,685	6,863	9,313	8,316	9,250	10,943	11,662	11,630	12,838
-%	26.0	35.8	34.5	44.2	37.3	39.3	44.1	44.6	42.2	44.2

Effect of Contingencies

Contingency										
1. Indian Pt. #2		(873)								
2. Bowline Pt. #1		(600)								
3. Fitzpatrick			(825)	(825)						
4. Indian Pt. #3				(873)	(873)					
5. Astoria #6				(800)	(800)					
6. Indian Pt. Uprate						(184)	(254)	(70)	(136)	(66)
7. NYSEGG						(600)				
8. Nine Mile #2							(1000)	(1000)		
9. Shoreham						(820)				
10. PASNY PSH								(1000)	(1000)	
11. O&R '77 unit							(300)			
12. CE Fossil Unit								(800)	(800)	(800)
13. Bell Unit								(830)	(830)	(830)
14. Nuclear #4										(1115)
Total Available Capacity	22,214	23,908	24,913	27,874	28,939	31,168	34,196	34,120	36,438	39,079
Estimated Reserve - MW	4,580	5,212	6,038	6,815	6,643	7,646	9,389	7,962	8,864	10,027
- %	26.0	27.9	30.4	32.4	29.8	32.5	37.9	30.4	32.1	34.5

GENERATING CAPACITY ADDITIONS (1971-80)

Company	Unit Location	Type	Date of Service	Size (MW)
Central Hudson Gas & Electric Corporation	Roseton 1 (1)	Fossil	Nov. 1972	600
	Roseton 2 (1)	Fossil	May 1973	600
Consolidated Edison Company of New York, Inc.	Indian Pt. 2	Nuclear	1972	873
	Barges	Gas Turbines	1972	348
	Indian Pt. 3	Nuclear	1974	873
	Astoria 6	Fossil	1974	800
	Ind. Pt. 2&3 Uprate	Nuclear	1976	184
	Undetermined	Combined Cycle	1976	400
	Undetermined	Combined Cycle	1977	200
	Ind. Pt. 2&3 Uprate	Nuclear	1977	70
	Undetermined	Fossil	1978	800
	Ind. Pt. 2&3 Uprate	Nuclear	1978	66
	Undetermined	Nuclear	1980	1,115
Long Island Lighting Company	Northport 3	Fossil	June 1972	386
	Glenwood	Gas Turbines	May 1972	107
	Undetermined	Gas Turbines	1974	260
	Undetermined	Gas Turbines	1975	200
	Shoreham	Nuclear	1976	820
	Undetermined	Gas Turbines	1978	280
	Undetermined	Gas Turbines	1979	340
	Undetermined	Fossil	1980	600

Company	Unit Location	Type	Date of Service	Size (MW)
New York State Electric & Gas Corporation	Homer City Uprate	Fossil	1971	37
	Homer City Uprate	Fossil	1972	90
	Undetermined	Fossil	1976	600
	Bell	Nuclear	1978	830
Niagara Mohawk Power Corp.	Nine Mile Uprate	Nuclear	1971	100
	Oswego 5	Fossil	1974	875
	Nine Mile 2	Nuclear	1977	1,000
	Undetermined	Nuclear	1980	1,000
Orange and Rockland Utilities, Inc.	Bowline Pt. 1 (2)	Fossil	1972	600
	Bowline Pt. 2 (2)	Fossil	1974	600
	Undetermined	Fossil	1977	300
	Undetermined	Fossil	1979	400
Rochester Gas and Electric Corp.	Ginna Uprate	Nuclear	1971	65
	Ginna 2	Nuclear	1979	1,000
Power Authority of the State of New York	Gilboa	PSH (3)	1972-73	1,000
	Fitzpatrick	Nuclear	1973	825
	Schoharie	PSH (3)	1977	1,000

Notes:

(1) Joint owned - Central Hudson (20%) - Niagara Mohawk (40%) - Consolidated Edison (40%).

(2) Joint owned - Consolidated Edison (66 2/3%) - Orange and Rockland (33 1/3%).

Individual Generating Station Capability Summary

At July, 1971

Company	Station and Type	Capability-MW Summer	Capability-MW Winter
Central Hudson	**Thermal (Conventional)**		
	Danskammer	511	511
	Poughkeepsie	10	10
	Total Thermal Conventional	521	521
	Gas Turbines		
	Coxsackie	18	24
	South Cairo	18	24
	Total Gas Turbines	36	48
	Hydro		
	Neversink	27	27
	High Falls	2	2
	Dashville	5	5
	Sturgeon Pool	15	15
	Total Hydro	49	49
	Diesel		
	Danskammer	5	5
	Total Capability	611	623
Consolidated Edison	**Thermal (Conventional)**		
	Arthur Kill	806	831
	Astoria	1,453	1,484
	East River	692	702
	Hell Gate	315	331
	Hudson Avenue	661	691
	Kent Avenue	86	90
	Ravenswood	1,769	1,779
	Sherman Creek	135	140
	Waterside	498	522
	59th Street	121	127
	74th Street	149	149
	Total Thermal Conv.	6,685	6,846

Company	Station and Type	Capability-MW Summer	Capability-MW Winter
Consolidated Edison (Cont'd)	Nuclear		
	Indian Point	260	265
	Gas Turbines		
	Arthur Kill	16	19
	Astoria	645	792
	Hudson Avenue	82	99
	Indian Point	35	43
	Kent Avenue	22	30
	Ravenswood	412	467
	Waterside	34	42
	59th Street	34	42
	74th Street	34	42
	Total Gas Turbine (Exc. Barges)	1,291	1,549
	Gas Turbine (Barges)		
	Gowanus	636	776
	Total Gas Turbine	1,927	2,325
	Total Capability	8,872	9,436
Long Island Lighting Company	Thermal (Conventional)		
	E.F. Barrett	398	402
	Glenwood	392	397
	Port Jefferson	490	498
	Far Rockaway	115	115
	Northport	772	772
	Total Thermal Conv.	2,167	2,184
	Gas Turbines		
	E.F. Barrett	342	399
	Glenwood	17	21
	Port Jefferson	17	21
	Northport	17	21
	Shoreham	49	56
	West Babylon	112	127
	Misc. Gas Turbines	46	58
	Total Gas Turbines	600	703
	Diesel	13	13
	Total Capability	2,780	2,900

Company	Station and Type	Capability-MW Summer	Capability-MW Winter
N.Y.S.E.&G.	Thermal (Conventional)		
	Goudey	158	158
	Greenidge	197	197
	Jennison	73	73
	Hickling	86	86
	Milliken	290	290
	Homer City (1/2 Share)	550	550
	Total Thermal Conv.	1,354	1,354
	Hydro		
	Misc. Smaller Stations	39	39
	Diesel	13	13
	Total Capability	1,406	1,406
Niagara Mohawk	Thermal (Conventional)		
	Oswego	407	407
	Huntley	875	875
	Dunkirk	676	676
	Albany	437	437
	Total Thermal Conv.	2,395	2,395
	Nuclear		
	Nine Mile Point	501	501
	Gas Turbines		
	Albany	165	180
	Rotterdam	160	180
	Total Gas Turbines	325	360
	Hydro		
	Colton	28	28
	Trenton	30	30
	School Street	29	29
	Sherman Island	29	29
	Spier Falls	50	50
	Stewarts Bridge	36	36
	Misc. Smaller Stations	495	484
	Total Hydro	697	686
	Diesel	11	11
	Total Capability	3,929	3,953

Company	Station and Type	Capability-MW Summer	Capability-MW Winter
Orange & Rockland	Thermal (Conventional		
	Lovett	517	518
	Hydro		
	Grahamsville	18	18
	Rio	10	10
	Swinging Bridge	12	12
	Mongaup	4	4
	Total Hydro	44	44
	Gas Turbines		
	Shoemaker	37	43
	Hillburn	37	43
	Total Gas Turbines	74	86
	Total Capability	635	648
Rochester G&E	Thermal (Conventional)		
	Russell	272	272
	Bee bee	194	182
	Station No. 8	6	6
	Total Thermal Conv.	472	460
	Nuclear		
	Ginna	425	425
	Gas Turbines		
	Station No. 3	17	19
	Station No. 9	17	19
	Total Gas Turbines	34	36
	Hydro		
	Station No. 5	42	42
	Misc. Smaller Stations	11	11
	Total Hydro	53	53
	Diesel		
	Ginna	5	5
	Total Capability	989	981

GENERATION MIX - INDIVIDUAL COMPANIES

1971 GENERATION MIX

Utility	PSH	Hydro	Fossil	Nuclear	Diesel-GT	Total
Central Hudson Gas & Electric Corporation	-	49	521	-	41	611
Consolidated Edison Company of New York, Inc.	-	-	6615	260	1913	8788
Long Island Lighting Company	-	-	2167	-	613	2780
New York State Electric & Gas Corporation	-	40	1354	-	13	1407
Niagara Mohawk Power Corp.	-	691	2395	500	336	3922
Orange and Rockland Utilities, Inc.	-	44	517	-	74	635
Rochester Gas and Electric Corporation	-	53	472	425	39	989
Power Authority of the State of New York	-	3203	-	-	-	3203
Totals - MW	-	4080	14041	1185	3029	22335
- %	-	18.2	62.9	5.3	13.6	100.0

GENERATION MIX - INDIVIDUAL COMPANIES

1980 GENERATION MIX

Utility	PSH[2/]	Hydro	Fossil	Nuclear	Diesel-GT	Total
Central Hudson Gas & Electric Corporation	-	27	991	-	41	1059
Consolidated Edison Company of New York, Inc.	-	-	7876	3441	2861[1/]	14178
Long Island Lighting Company	-	-	3153	820	1800	5773
New York State Electric & Gas Corporation	-	40	2044	830	13	2927
Niagara Mohawk Power Corp.	-	691	3630	2600	336	7257
Orange and Rockland Utilities, Inc.	-	44	1617	-	74	1735
Rochester Gas and Electric Corporation	-	53	462	1490	39	2044
Power Authority of the State of New York	2000	3203	-	825	-	6028
Totals - MW	2000	4058	19773	10006	5164	41001
- %	4.9	9.9	48.2	24.4	12.6	100.0

1/ Combined Cycle Included.

2/ Pumped Storage Hydro.

13-3 (3)