June 1, 1974

50-410

TESTIMONY OF DAVID K. OWENS
OF THE FEDERAL POWER COMMISSION
BEFORE THE ATOMIC SAFETY AND LICENSING BOARD
AEC DOCKET NO. 50-410

Hearing

My name is David K. Owens. I reside in Washington, D. C. I am employed on the staff of the Federal Power Commission as an Electrical Engineer. I joined the Commission in May 1970. My primary duties in my present position are to analyze and evaluate the adequacy and reliability of electric power supply planning by utilities, power pools, and regional reliability councils.

Prior to joining the Federal Power Commission, I was employed by General Electric Company in Philadelphia, Pennsylvania, as an Electrical Engineer. I was assigned to the Company's Medium Voltage Switchgear Department where I was responsible for filling utility orders for circuit breakers, disconnect switches, and other types of metalclad switchgear and electrically coordinating this equipment with relays and associated devices.

I worked for Philadelphia Electric Company during the summers of 1967 and 1968, assisting Test Engineers in their daily plant routine. My title was junior technical assistant.

I received my Bachelor of Science in Electrical Engineering from Howard University in June 1969. Since my graduation, I have taken several graduate level engineering courses at General Electric Company in Philadelphia and the Graduate School of the U. S. Department of Agriculture in Washington, D. C. I am a member of the Institute of Electronics and Electrical Engineers (IEEE) and its power sub-group.

The intent of my testimony in these proceedings is to discuss the need for the generating capacity to be provided by the Nine Mile Point Nuclear Station Unit No. 2 of the Niagara Mohawk Power Corporation. I will also discuss in general the need for capacity reserve in power supply planning and its relationship to electrical power system reliability.

It is important, first, to define some of the terminology and concepts relating to the reliability of bulk power supply. Power system reliability is dependent upon the bulk power supply facilities, consisting of generating plants, transmission lines and bulk power substations which collectively furnish power to major points of distribution. The fundamental prerequisite for reliable power system operation is adequate bulk power supply facilities to meet both the demand requirements (measured in megawatts or kilowatts) and energy requirements (measured in megawatt-hours or kilowatt-hours) of system load.

Bulk power supply facilities are most often planned to meet the demand requirements rather than the energy requirements. Demand refers to the rate at which a customer takes energy from the electric system. A customer with a demand of 100 kilowatts takes energy from the system at the rate of 100 kilowatt-hours per hour. The maximum demand of a customer is the maximum rate at which he takes energy. It is usually measured as the average rate of use of energy during the one hour period in which that average is highest. The

maximum demand on a system is usually spoken of as the peak load on that system.

To supply the electricity that must be available continuously and instantaneously to the consumer in whatever amounts he desires, the growing requirements of electricity users must be anticipated well in advance and provision made to meet these demands when they occur.

Measures of Power Supply Adequacy

To provide the uninterrupted service that consumers expect and rely upon, all power systems must maintain or have access to more generating capacity than the expected demand. The excess capacity is called reserve. It is the difference between the power supply capability of a system and the largest value of demand that the system will experience in a year. When reserve capacity is expressed as a percentage of the peak demand, it is called percent reserve. A percent reserve of zero means that a system will have no elasticity at the time of its peak demand: any load greater than that predicted will exceed the capability of the supply system; any failure of a generator or of a transmission line supplying purchased power will result in demand exceeding the capability of supply. Reserves are needed to provide for various contingencies. Some of these are as follows:

(1) To replace generating capacity that has been forced out or removed from service because of failure.

(2) To replace generating capacity on scheduled maintenance.

(3) To supply loads that exceed the forecast.

(4) To furnish additional power supply capability to meet estimated demand because of environmental restrictions on generator output, not foreseen in the process of planning capacity additions.

(5) To replace delayed capacity additions.

(6) To furnish additional power supply capability to meet estimated demand because the capacity of individual generators has been reduced due to unusual ambient air and water temperature conditions.

The magnitude of the generation reserve depends upon the nature of the system, the characteristics of the load and the quality of service desired. It varies from system to system. Several methods are used by electric utilities to determine the size of generation reserve.

1. Standard Percent Reserve

One technique is to plan to have capacity to provide a percent reserve equal to or in excess of some predetermined standard. The Federal Power Commission has found that many power systems plan on a reserve between 15 and 25 percent. It must be emphasized that a reserve in this range does not indicate a utility will always have sufficient capability to meet load patterns. If a reserve in this range has proved adequate in the recent past, it is highly probable that it will be sufficient in the very near future.

However, there is always some risk that the expected load will exceed the available generating capability. No system is perfectly reliable. There is always the possibility of unavoidable accidents to generating facilities and forced outages of generator units.

The Applicant, along with the six other major privately owned utilities within New York State and the Power Authority of the State of New York, are members of the New York Power Pool (NYPP):

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

As a member of the NYPP, Niagara Mohawk's reserve margin objective is 18% of its annual peak load. 1/

2. Loss-of-Load Probability (LOLP) Method

Another technique commonly employed by electric utilities to determine generation reserve levels is the loss-of-load probability method. This method takes into account the sizes and types of units, their forced outage rates, and the shape of the load duration curve. An excellent summary of this probability technique is in Part II of FPC's 1970 National Power Survey. 2/

The result of the LOLP calculation is the probability that generating capacity will be less than the demand during the period under study. A nominal value of satisfactory LOLP often used by utilities is "one day in ten years" which means that in a ten-year period, the sum of all

intervals during which load exceeds capacity will not exceed more than one day in a ten-year period (or capacity will be insufficient to supply the daily peak load on one day in ten years). <u>To plan for a relatively constant LOLP would have the effect of providing for a consistent level (but not a constant level) of generation reserve</u>.

The Northeast Power Coordinating Councils response to FPC Docket R-362 specifies that each of its four areas, of which the New York Power Pool (NYPP) is one, will plan ". . . reserves to provide for a probability of loss-of-load not in excess of 1 day in 10 years without emergency support from other areas, either within or outside of the council."

As mentioned previously, LOLP calculations depend upon the forced outage rates of generating units. The forced outage rate (FOR) equals the hours a unit is forced out (FOH) divided by the service hours (SH) plus the FOH and expressed as a percent:

$$FOR = \frac{FOH}{FOH + SH} \times 100$$

Records of forced outage data are kept by the electric utility industry and reported to the Edison Electric Institute (EEI). Some typical statistics published by EEI are shown in Exhibit (DKO-1) __________.

A system which experiences high forced outage rates and has or is planning to install larger generating units would require higher capacity reserve margins to provide against loss-of-load than the same system with smaller units and lower forced outage rates.

No mathematical formula is readily available that relates percent reserve to loss-of-load probability for all systems. Even for one system the relationship would not be simple to state, as it depends

on the shape of the load duration curve and the number, size and kinds of units. To illustrate this point, results of separate probability studies performed on two groups of systems are shown in Exhibit (DKO-2) ___. An inspection of these curves indicates that a 21% reserve margin is required for a level of reliability equivalent to one occasion in ten years on the New England System. To maintain this same level of reliability, MARCA (Mid-Continent Area Reliability Coordination Agreement) systems appear to need a reserve of approximately 12%.

The uncertainty concerning the slippage or delay of the in-service dates of scheduled generator additions is seriously affecting planned reserve margins. Recent experience has shown a high degree of probability that the scheduled in-service dates of future units will be delayed.[3/] In order for an electric utility to protect itself against delays, planned reserve margins must be increased. Some utilities include the probability of delay analytically in their generation planning programs, and others simply state that they schedule their resources to allow for possible unpredictable delays. In any case, the planned installed generation reserve margin is greater than the expected installed reserve margin. Part II of FPC's 1970 National Power Survey for the Northeast states that ". . . future reserve allowances are normally increased by 5 to 10 percent of the anticipated peaks as a contingency against unforeseen construction delays or estimating errors." [4/]

## Consequences of Insufficient Reserve

The consequences of insufficient reserve are manifold. It can lead to small scale interruptions or widespread blackouts, affecting

a few individuals or leading to situations affecting the health, safety, and economic well-being of large numbers of people. The life of individuals dependent upon iron lungs, artificial kidney machines, and other life-sustaining equipment will be endangered. Manufacturing activities involving electric heating, constant temperature conditions, and electric drive and controls will be interrupted, with possible spoilage of work in process. Other manufacturing activities will be interrupted but may suffer no more than loss of time and the losses that accompany unscheduled stoppages. The effect of the interruption depends upon time of occurrence, part of the system and the area affected, the magnitude of the power deficiency and the state of the system before the interruption.

There are several methods that can be used by a utility to bring available generating capacity and load into closer step when reserve is insufficient. Some methods are geared toward maximizing the output of generating plants; others involve curtailment of load.

A list of the contingency plans submitted by utilities in response to FPC Order No. 445 (Docket R-405) is summarized in an FPC publication entitled "Contingency Planning of Utilities", dated June 1972. All systems adhere to basic procedures that assure orderly response so as to minimize customer inconvenience and avoid prolonged danger to public health and safety. The basic order of response generally adopted is as follows:

1. When possible, purchase from neighboring utilities sufficient capability to meet the forecast peak load

plus an adequate reserve margin to cover forecast error and reasonable contingencies.

2. Operate all generating facilities at maximum ratings.
3. Maximize emergency purchases from interconnected systems to the extent that transmission line loadings permit.
4. Reduce all nonessential electric power usage at all utility-owned power plants and office facilities.
5. Discontinue service to contractually interruptible loads.
6. Request voluntary reduction of nonessential loads of large commercial and industrial customers.
7. Reduce voltage up to 5% as required (8% in some areas if in real trouble
8. Make a public request through the news media for all customers to limit electric usage.
9. Manually disconnect selected low priority loads as required. Rotate load disconnection if the shortage is expected to extend for more than several hours.

Controlled response to power system disturbances and power shortages through Step 9 is frequently referred to as "Brownouts." These brownouts are instrumental in avoiding widespread system "Blackouts." A "Blackout" is the uncontrolled loss of electric power to a given area and normally is the result of a system becoming isolated due to the failure of overloaded transmission lines when the isolated area has more load than generation.

Need for Capacity to be Provided by Niagara Mohawk
Power Corporation's Nine Mile Point Nuclear Unit No. 2

(1) The Intervenor states that there is not sufficient need for power which applicant projects to be produced at NMP2 beginning in 1978 . . .

a. For the Niagara Mohawk Power Corportation system, the percent reserve will be 20.2% at the time of the expected 1978-79 winter peak, if Nine Mile Point No. 2 (NMP2) is unavailable. Based upon the 18.0% reserve requirement for each member of the NYPP, this reserve is adequate. Less than adequate reserve results if NMP2 slips past the expected 1979-80 winter peak load. Reserve without the unit is reduced to 15.1% of the estimated peak load as illustrated in Exhibit (DKO-3) _____.

The reliability of the reserve must be evaluated with respect to the conditions under which it obtains. For the winter 1978-79 these conditions are:

(1) All generating units are available for service

(2) The estimated capacity available from outside sources is in fact available.

The first assumption can be examined in the light of recent experience on the Niagara Mohawk system. During the winter 1972-73 peak week (week ending 12/23/72), 497 MW or 10.3% of Niagara Mohawk's installed capacity was unavailable due to forced outages. Unit deratings

during this period totaled 288 MW; thus, the total unavailable capacity was 785 MW or 20.2% of the total installed capacity. A summary of these conditions follows:

| | MEGAWATTS |
|---|---|
| Installed Capacity | 3,929 |
| Net Purchased Capacity | 1,994 |
| Total Capacity | 5,923 |
| Peak Load | 4,827 |
| Reserve | 1,096 |
| Reserve - % of Peak Load | 22.7 |
| Unavailable Capacity: | |
| Forced Outages | 497 |
| Unit Deratings | 288 |
| TOTAL | 785 |
| Margin Available | 311 |
| Margin Available - % of P.L. | 6.4 |

The second assumption is that 2,003 MW of net purchased capacity will be available for the winter 1978-79 peak. While the contracts were undoubtedly made in good faith by the sellers, delivery will be contingent upon the ability of the seller to actually provide the power. It is pertinent to mention here that 1,984 MW of the expected 2,003 MW of net purchased capacity will be from the Power Authority of the State of New York (PASNY). Breakabeen pumped-storage (1,000 MW) is scheduled to be added to the PASNY system in the summer 1978. Generator units are prone to slippage;

if the project slips past the winter 1978-79 peak it might have the effect of reducing sales to Niagara Mohawk.

If the project doesn't slip, even in the best of circumstances the initial months of operation of a generating unit can be expected to provide more than the usual number of difficulties, as faults in materials, design and construction evidence themselves, and as plant operators learn the characteristics of the equipment. This initial period of unreliability, which may extend for several years, is well-known to the industry and has even received a name: the maturity period. Statistics collected on a nation-wide basis by the Edison Electric Institute support the conclusion that a new unit is less dependable than one that has been in service for several years and has had the "bugs" discovered and corrected. Exhibit (DKO-4)______ provides support for this assertion.

b. For the NYPP, the percent reserve will be 27.0% at the time of the 1979 summer peak, if Nine Mile Point No. 2 is not available. Exhibit (DKO-5)____ shows that the total installed capacity of all the generators on the New York interconnected network will be 36,008 MW and the net power available from other systems will be 671 MW, making a total of 36,679 MW available to meet demand. With an expected demand of 28,870 MW the reserve capability

will be 7,809 MW which is 27.0% of the expected demand. To evaluate this reserve, it is appropriate to consider generator unit reliability experienced on the New York system and the availability of purchased power from outside sources.

Exhibit (DKO-6) ______ shows that for the past 3 years at the time of the summer peak, significant amounts of generating capacity have been unavailable for service. The average amount for 3 years is 3,670 MW; that is, it is wholly reasonable to reduce the hoped-for 7,809 MW reserve by 3,670 MW on the basis of actual experience. It is also possible, again on the basis of experience, that the 7,809-MW reserve could be reduced by 4,104 MW, which was the maximum amount of capability that was unavailable. That the New York area has had considerable difficulty in meeting the load demand in recent years because of insufficient available capacity is illustrated in Exhibit (DKO-7) ______ which shows a list of load reduction events carried out by NYPP companies. Shown in the Exhibit are the responses to FPC Order 331-1 by the NYPP and specific instances of Consolidated Edison Co. (Con Ed) and the Long Island Lighting Company (LILCO). When the NYPP goes into voltage reduction, usually most or all of the member companies are involved.

The following units are included in the 7,809 MW of expected reserve for 1979 summer:

| | | |
|---|---|---|
| Breakabeen Pumped Storage | (7/78) | 1,000 MW |
| Cornwall Pumped Storage | (5/79) | 1,000 MW |
| | | 2,000 |

Considering the slippage of one or both projects is not unreasonable. Consideration must be given also to the initial period of operation of these units since, during the initial months of operation of a generating unit, it can be expected to provide more than the usual number of difficulties as discussed in (1) a.

The 671 MW of net purchased capacity included in the 7,809 MW of expected reserve is contingent upon the sellers' ability to furnish the power. This 671 MW is based upon 821 MW of purchase capacity from Canadian sources and 150 MW of sales to the Vermont Public Service Board; 800 MW of the purchased capacity will come from Hydro Quebec. This 800 MW is transmitted into the New York system over two existing 115-kilovolt circuits, one existing 230-kilovolt circuit, and one 765-kilovolt circuit yet to be built.

To summarize, then, of the total 36,679 MW claimed for the summer 1979 peak period, the following elements must be considered questionable in some degree:

| AMOUNT | COMMENT |
|---|---|
| 3,670 MW | Average amount unavailable, past 3 years |
| 1,000 MW | Cornwall pumped storage, scheduled for 5/79 |
| 671 MW | Net purchased power |
| 5,341 MW | |

This total of 5,341 doubtful MW is to be compared with the 7,809 MW reserve hoped for if NMP2 is not available. This comparison results in a reserve of 2,468 MW or 8.5% of the expected 28,870-megawatt load demand should all the doubtful power be unavailable. However, to predicate the construction licensing of NMP2 on the simultaneous occurrence of three incidents may appear as an overstatement. But suppose only the more reasonably possible events are totaled:

| | |
|---|---|
| 3,670 MW | Average amount unavailable, past 3 years |
| 1,000 MW | Cornwall pumped storage, schedule slips or unit fails |
| 4,670 MW | Reasonably doubtful, total |

This last table shows that of the 7,809 MW reserve (w/o NMP2), 4,670 MW can be readily considered unreliable. This results in an operating reserve of 3,139 MW or 10.9% of the expected peak load.

In 1970, despite a predicted reserve of 28.5% in July, the NYPP reported to the Federal Power Commission (under Order 331-1) that it had to institute 3-5% voltage reductions--an average of 6½-7 hrs. each day of the period July 28-31, 1970, because of insufficient capacity to meet load.

(2) The Intervenor states that the Applicant's calculation of need based on reserve margin criteria described by the Northeast Power Coordinating Council is too conservative and that criteria and particularly the criterion that reserve margins of on-hand base load generating capacity of 20% is an arbitrary criterion since it ignores the Applicant's load factor.

As mentioned previously, the Northeast Power Coordinating Council's response to FPC Docket R-362 states that the NYPP will plan ". . . reserves to provide a probability of loss-of-load not in excess of 1 day in 10 years without emergency support from other areas, either within or outside the council."

To reiterate, the result of the LOLP calculation is the probability that generating capacity will be less than the demand during the period under study. A LOLP of "one day in ten years" means that in a ten-year period, the sum of all intervals during which load exceeds capacity will not exceed 24 hrs. more than once in a ten-year period or, capacity will be insufficient to supply the daily peak load on one day in ten years.

The percent reserve requirement necessary to maintain a LOLP of "one day in ten years" is not the same for all systems as it depends on the type, number, and size of generating units, their forced outage rates, and the shape of the load duration curve. Furthermore, the percent reserve requirements necessary to give a LOLP of "one day in ten years" can be expected to change with time, reflecting changes in the sizes and

types of units and their forced outage rates. To plan for a relatively constant LOLP would have the effect for providing for a consistent level of generation reserve.

The reliability of a power system is not a linear function of the reserve margin. A small decrease in reserve margin may exponentially increase the risk of a loss of load, or stated conversely, a decrease in reserve margin will exponentially reduce the reliability. An example of this non-linear relationship is shown in Exhibit (DKO-2) __________.

To meet the NPCC reliability criterion, the NYPP's installed reserve requirement is approximately 20% of the New York State interconnected network's coincident peak load. To maintain the 20% reserve requirement, NYPP members agree to maintain installed capacity at least equal to that required to meet an 18% reserve during the member's most recent peak.[5/] The four upstate New York (UPNY) systems are winter peaking: New York Electric and Gas Corp., Niagara Mohawk Power Corp., PASNY, and Rochester Gas and Electric Corp.; and the four downstate systems (SENY) are summer peaking: Central Hudson Gas and Electric Corp., Con Ed, LILCO, and Orange and Rockland Utilities, Inc. The 18% reserve objective takes into account the differences in annual peaks (diversity) between the UPNY systems and the SENY systems.

To perform a LOLP calculation on a system the size of the NYPP would require at least the following:

1. The capability of all generators installed on the New York interconnected network.

2. Forced outage rates of generating units

3. Maintenance requirements

4. Load model based upon historical load data from each Pool member

Load Forecasting

(3) The Intervenor states that the Applicant's calculation of demand is based on erroneous assumptions of load growth due to a growth in population, due to growth and per capita use, and high volume that is industrial use.

First, I find this contention quite ambiguous. There are a variety of methods used throughout the electric utility industry to forecast loads. The choice depends to a large extent on the load characteristics of a utility's franchise area. One method is to plot historical data, fit a curve to the points, and project this curve into the future. Another method is to stratify the historical data into blocks according to the type of load, geographical location or other pertinent components. Load growth in each of the blocks is projected separately and the components are finally integrated into a total forecast. A third method is to correlate load growth with other variables, such as changes in population or expansion of the economy. The only real test of the value of a load forecast method is its accuracy.

The accuracy of Niagara Mohawk Power Corporation and the NYPP forecast is shown in Exhibits (DKO-8) ______ through (DKO-10) ________ which are comparisons of predicted loads and actual loads. These comparisons indicate reasonable projections and reflects prudent planning procedures. Load predictions must be recognized for what they are: estimates of the future.

Exhibit (DKO-11) _________ is a plot of Niagara Mohawk's historical loads from 1965 to 1972, reflecting an annual load growth of 3.4 percent. The plot also shows the projected loads for the period from 1973 to 1980 and corroborates the reasonableness of the Applicant's load forecast.

The New York Power Pool's historical summer loads from 1967 to 1972 are plotted on semi-log coordinates in Exhibit (DKO-12). The plot also shows the projected loads for the period 1973 to 1980. The dotted extension of the 1967-1972 load growth includes the load projections to 1980 quite satisfactorily, and the growth rate is considered valid to 1980.

Interregional Ties

(4) The Intervenor states that inadequate consideration is given by the Applicant to obtaining power from available interconnections with other suppliers and other systems.

The Applicant belongs to the Northeast Power Coordinating Council (NPCC), a regional coordinating group operating in the States of New York, Maine, New Hampshire, Rhode Island, Massachusetts, Connecticut, and Vermont and the New Brunswick and Ontario Canadian provinces. To the south is the Mid-Atlantic Area Council (MAAC) and to the west, the East Central Area Reliability Coordination Agreement (ECAR).

Each of the coordinating groups that NPCC has interconnections with has several large capacity additions scheduled for the summer 1979 and 1980. Exhibit (DKO-13) ___________ shows planned reserves for summer 1979 and 1980 for NPCC and neighboring areas as reported in the April 1, 1973, Docket R-362, response to the Federal Power Commission. Data on Hydro Quebec reserve capability was not available in this report. The reserve margins will depend considerably on when scheduled generator additions will actually go into commercial operation and on what their capability limitations may be. A reasonable estimate on this can be obtained by listing all of the scheduled capability that is in doubt. It would be optimistic to assume that all of this will be available on time. On the other hand,

it would be overly pessimistic to assume that none of it will be available. A middle value is a reasonable estimate. Exhibit (DKO-14) ________ shows capacity unavailable at the time of system peak for areas that are interconnected with NYPP.

It must be stressed that although short-term emergency relief from MAAC and ECAR to provide for contingencies normally experienced by interconnected systems may be available to NPCC, the NYPP and its members, a proportionate amount of reserve must be maintained by each of these areas based upon their own loads.

## Data Sources

The data for my analysis of the adequacy of power supply for the Niagara Mohawk Power Corporation and the New York Power Pool came from the following FPC sources:

(1) FPC Form 12 - This form is the annual power system statement filed by each power company or system which generates all or part of its power requirements and whose net annual energy for its system is greater than 20,000,000 kWh. This document lists generating capacity and production by plants, individual generating unit characteristics, energy transactions with other utilities, hourly load data for three specified weeks, high voltage line capability and loading for specified months, and future load estimates. The filing date is May 1 and six copies, which are attested by a company officer to certify accuracy, completeness, and truthfulness, are filed at the appropriate FPC regional office.

The data reported is reviewed and verified by the Regional Engineer's staff by checking for consistency with previously filed forms and applying staff knowledge of the power systems in the appropriate geographic region. The verified forms are then sent to the Washington, D. C. office for filing and public use.

(2) FPC Form 12-E - This form is the monthly power system statement filed by each utility or formal pool. It includes recent revisions in generation additions and load forecasts. It is verified and filed according to the same procedure as for the Form 12 above.

(3) Northeast Power Coordinating Council's (NPCC) Response to Docket R-362 (Order 383-2) - This report is filed annually on April 1 with FPC. The 1973 report is the fourth annual report since the order was initiated. It contains information regarding ten-year projections of loads and bulk power supply facilities expansion.

(4) New York Area Responses to FPC Docket R-361 (Order 331-1) - This order requires utilities to report interruptions of electric power service caused by an outage of any generating unit or of electric facilities operating at 69 kV or higher and resulting in a load loss of 100 MW or more, or half of the annual system peak load, for 15 minutes or longer. The Order also requires utilities to report situations which do not necessarily involve power interruptions, such as voltage reductions or other load curtailments, requests by utilities to the public for voluntary reductions in electricity use, and any accident to system facilities constituting an unusual hazard to the bulk electric power supply system.

## FOOTNOTES

1/ Niagara Mohawk Power Corporation Environmental Report, page 1.2-3.

2/ 1970 National Power Survey, Part II, Electric Power in the Northeast, 1970-1980-1990, pp. II-1-52 to II-1-58.

3/ FPC News Release No. 19050 dated March 7, 1973, on Delays in Scheduled Commercial Operation of Electric Generating Units.

4/ Ibid., page II-1-58.

5/ Niagara Mohawk Power Corporation Environmental Report, page 1.2-3.

## GENERATING UNIT AVAILABILITY
## AS REPORTED BY EEI

| UNIT TYPE | FOR* | EFOR 1/ | SERVICE FACTOR 3/ | CAPACITY FACTOR 4/ | OUTPUT FACTOR 5/ |
|---|---|---|---|---|---|
| Nuclear | 8.39 | 11.60 | 75.16 | 64.91% | 88.25% |
| Fossil Greater Than 600 MW | 16.8 | 21.88 | 70.97 | 57.68% | 80.51% |
| Gas Turbines | 24.4 2/ | 24.50 2/ | 15.52 | 12.21% | 77.61% |

1/ Equivalent Forced Outage Rate is the FOR adjusted for partial forced outages.

2/ May be high for units with low service factors.

3/ Service factor = (Service hours/8760 hrs.) x 100.

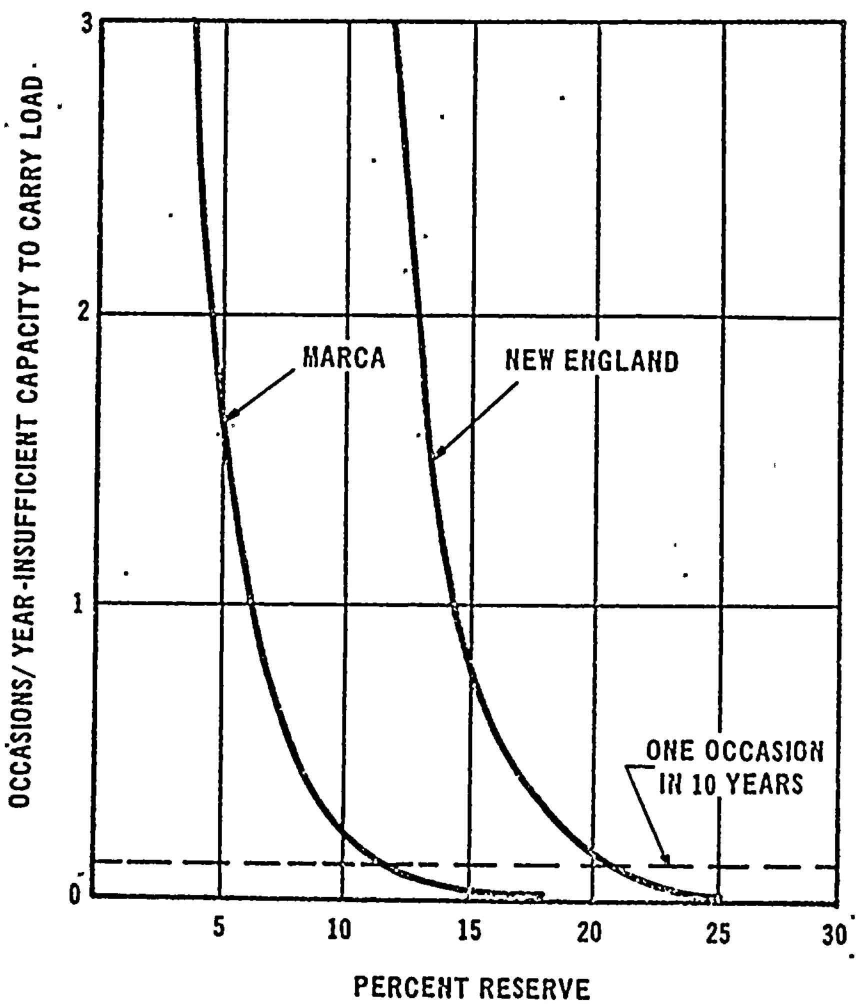
4/ Capacity factor = (MWh output/(Unit Capability x 8760)) x 100%.

5/ Output factor = (MWh output/(Unit Capability x Service hours)) x 100%.

* Forced Outage rate.

SOURCE: Report on Equipment Availability for the Twelve-Year Period 1960-1971 by Edison Electric Institute, Publication No. 72-44, November 1972.

## RELIABILITY RELATIONSHIP VS. PERCENT RESERVE




SOURCE: National Electric Reliability Council - "Review of Overall Adequacy and Reliability of the North American Bulk Power Systems," September 1972.

*Mid-Continent Area Reliability Coordination Agreement, the Reliability Council for the West Central Region.

NIAGARA MOHAWK POWER CORPORATION
1978 AND 1979 WINTER CONDITIONS
WITH AND W/O NINE MILE POINT NO. 2

| | 1978-79 Winter Conditions | | 1979-80 Winter Conditions | |
|---|---|---|---|---|
| | With Nine Mile Point No. 2 (MEGAWATTS) | W/O Nine Mile Point No. 2 (MEGAWATTS) | With Nine Mile Point No. 2 (MEGAWATTS) | W/O Nine Mile Point No. 2 (MEGAWATTS) |
| Capacity as of March 1, 1973 1/ | 3,914 | 3,914 | 3,914 | 3,914 |
| Net of Purchases and Sales 3/ | 2,003 | 2,003 | 1,972 | 1,972 |
| CH Roseton No. 1 2/ | 180 | 180 | 180 | 180 |
| CH Roseton No. 2 2/ | 180 | 180 | 180 | 180 |
| NM Oswego Unit No. 5 | 850 | 850 | 850 | 850 |
| NM Oswego Unit No. 6 | 850 | 850 | 850 | 850 |
| NM Nine Mile Point No. 2 | 1,100 | --- | 1,100 | --- |
| Total Capacity | 9,077 | 7,977 | 9,046 | 7,946 |
| Peak Load | 6,635 | 6,635 | 6,905 | 6,905 |
| Reserve | 2,442 | 1,342 | 2,141 | 1,041 |
| Reserve as % of Peak Load | 36.8 | 20.2 | 31.0 | 15.1 |

Note:
CH - Central Hudson Gas and Electric Corporation
NM - Niagara Mohawk Power Corporation

1/ Based upon information reported in NPCC's Docket R-362, April 1, 1973 Report. This capacity is somewhat less than previous ratings since the New York Power Pool (NYPP) has rerated some of its units.

2/ NM's share of each unit is 240 MW until 1977; in 1977, NM's share of Roseton is reduced by 120 MW.

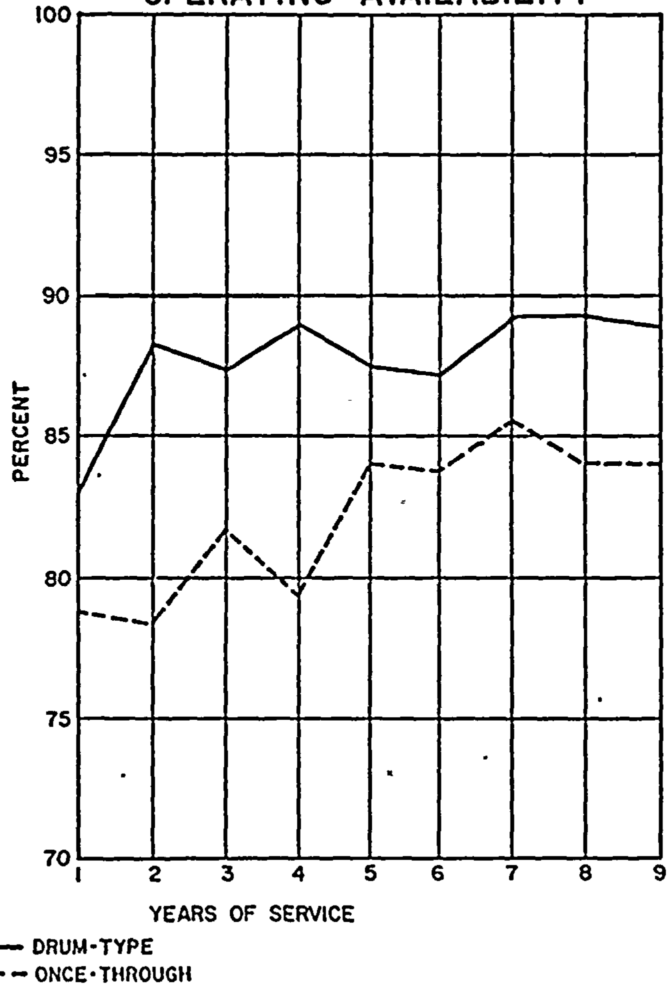
3/ Based upon information reported in AEC's Final Environmental Statement for Nine Mile Point Nuclear Station Unit No. 2.

Exhibit (DKO-3)

# MATURITY TRENDS FOR FOSSIL UNITS GREATER THAN 200 MW

## DRUM-TYPE AND ONCE-THROUGH UNITS
## UNIT YEAR AVERAGES
## 1960-1969

### OPERATING AVAILABILITY




### SAMPLE TABLE

| YEARS IN SERVICE | DRUM-TYPE NO. OF UNITS | ONCE-THROUGH NO. OF UNITS |
|---|---|---|
| 1 | 49 | 38 |
| 2 | 53 | 33 |
| 3 | 63 | 18 |
| 4 | 69 | 14 |
| 5 | 73 | 13 |
| 6 | 77 | 11 |
| 7 | 82 | 9 |
| 8 | 70 | 7 |
| 9 | 63 | 6 |

SOURCE: Report on Equipment Availability for the Ten-Year Period 1960-1969 by Edison Electric Institute, Publication No. 70-26, November, 1970.

### FORCED OUTAGE RATE

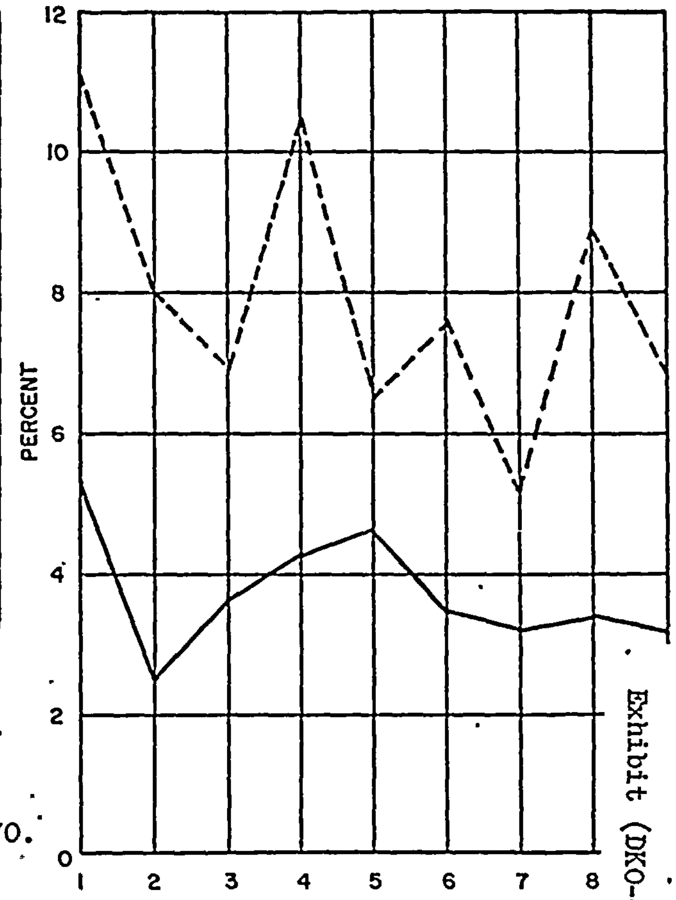



Exhibit (DKO-4)

## NEW YORK AREA
## 1979 AND 1980 SUMMER CONDITIONS
## WITH AND W/O NINE MILE POINT NO. 2 1/

| | | 1979 Summer Conditions | | 1980 Summer Conditions | |
|---|---|---|---|---|---|
| | | With Nine Mile Point No. 2 (MEGAWATTS) | W/O Nine Mile Point No. 2 (MEGAWATTS) | With Nine Mile Point No. 2 (MEGAWATTS) | W/O Nine Mile Point No. 2 (MEGAWATTS) |
| 1978 Summer Capacity | | 34,304 | 34,304 | 34,304 | 34,304 |
| Net of Purchases and Sales | | 671 | 671 | 669 | 669 |
| NM | Nine Mile Point No. 2 | 1,100 | --- | 1,100 | --- |
| CE | Indian Point No. 2 Uprating | 35 | 35 | 35 | 35 |
| CE | Indian Point No. 3 Uprating | 35 | 35 | 35 | 35 |
| CE | Cornwall Units Nos. 1-4 | 1,000 | 1,000 | 1,000 | 1,000 |
| LILCO | Location Undetermined | 200 | 200 | 200 | 200 |
| O&R | Location Undetermined | 600 | 600 | 600 | 600 |
| CE | Waterside Units Nos. 4-7 | -166 | -166 | -166 | -166 |
| CE | Cornwall Units Nos. 5-8 | | | 1,000 | 1,000 |
| NYSE&G | Bell | | | 830 | 830 |
| CE | Indian Point No. 2 Uprating | | | 33 | 33 |
| CE | Indian Point No. 3 Uprating | | | 33 | 33 |
| LILCO | Location Undetermined | | | 300 | 300 |
| Total Capacity | | 37,779 | 36,679 | 39,973 | 38,873 |
| Peak Load | | 28,870 | 28,870 | 30,380 | 30,380 |
| Reserve | | 8,909 | 7,809 | 9,593 | 8,493 |
| Reserve as % of Peak Load | | 30.9 | 27.0 | 31.6 | 28.0 |

Note: NM - Niagara Mohawk Power Corporation
CE - Consolidated Edison Company of N. Y., Inc.
LILCO - Long Island Lighting Company
O&R - Orange & Rockland Utilities, Inc.
NYSE&G - New York State Electric and Gas Corporation

1/ Based upon NPCC's Docket R-362 (Order 383-2), Report to FPC, dated April 1, 1973.

Exhibit (DKO-5)

NEW YORK AREA
ACTUAL LOAD AND CAPACITY SITUATION
AT TIME OF ANNUAL PEAK 1970 - 1972

| | 1970 Megawatts | 1971 Megawatts | 1972 Megawatts |
|---|---|---|---|
| Total Capacity | 21,889 | 22,100 | 23,542 |
| Peak Load | 17,037 | 18,146 | 18,943 |
| Gross Margin | 4,852 | 3,954 | 4,599 |
| Gross Margin - % of Load | 28.5 | 21.8 | 24.3 |
| Scheduled Maintenance: | | | |
| Scheduled Maintenance | 135 | 490 | 315 |
| Forced Maintenance | 2,324 | 880 | 1,332 |
| Variation of Hydro From Median | -48 | -148 | -45 |
| Unavailable for All Other Reasons | 1,693 | 2,104 | 1,889 |
| TOTAL | 4,104 | 3,326 | 3,581 |
| Margin After Maintenance | 748 | 628 | 1,018 |
| Margin After Maintenance - % of Load | 4.4 | 3.5 | 5.4 |

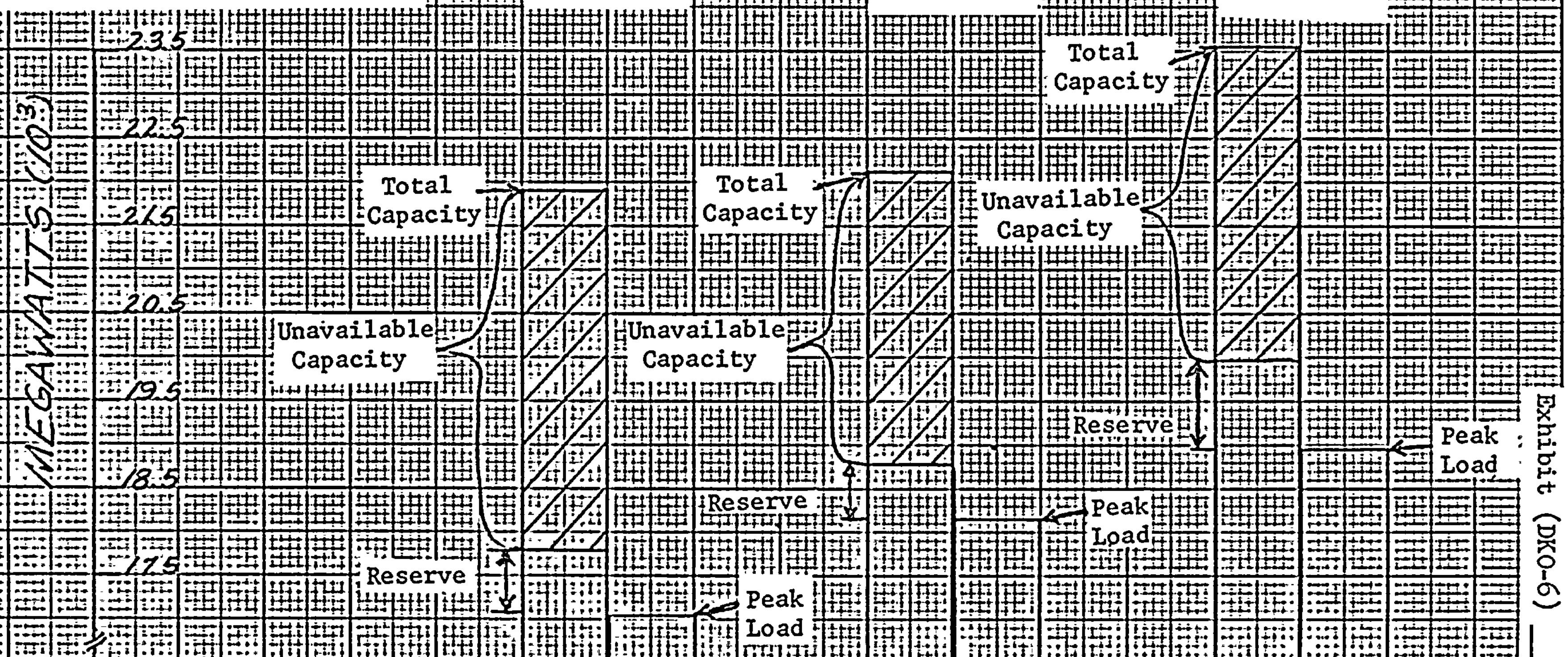



Exhibit (DKO-6)

Exhibit (DKO-7) _____

## NEW YORK AREA
## LOAD REDUCTION MEASURES

| Date | Utility Or Pool | Cause | Voltage Reduced Percent | Estimated Duration Hours |
|---|---|---|---|---|
| 1973 | | | | |
| 6/12 | Con Ed | Insufficient Capacity | 5 2/ | 4 |
| 6/12 | NYPP | Curtailments were implemented to assist Con Ed in meeting estimated demand | 5 | 7 |
| 6/11 | Con Ed | Equipment outages coupled with high temperatures | 3-5-8 | 8-3/4 |
| 6/11 | NYPP | Curtailments were implemented to assist Con Ed in meeting estimated demand | 5 | 8 |
| 1972 | | | | |
| 8/24 | Con Ed | Insufficient Capacity | 5 | 2-1/2 |
| 7/20 | Con Ed | Insufficient Capacity | 5 | 3 |
| 7/17 | Con Ed | Insufficient Capacity | 5 | 3 |
| 7/12 | Con Ed | Critically loaded sub-station feeders | 5 | 4 |
| 5/24 | Con Ed | Precautionary measure due to transmission loss | 3 | 3/4 |
| 2/25 | NYPP | Insufficient Capacity | 5 1/ | 5 |
| 1971 | | | | |
| 9/9 | Con Ed | Heavy summer load | 3 | 1-1/2 |
| 8/18 | Con Ed | Upstate New York and New England transmission disturbance | 8 | N.R. |
| 7/7 | Con Ed | Forced outage of Ravenswood Unit No. 3 | 3-5 | 2-1/4 |

# NEW YORK AREA
## LOAD REDUCTION MEASURES

| Date | Utility Or Pool | Cause | Voltage Reduced Percent | Estimated Duration Hours |
|---|---|---|---|---|
| 1971 | | | | |
| 7/1 | Con Ed | Prevent possible overloading of incoming tie lines | 3 | 1-1/2 |
| 6/30 | Con Ed | Heavy loads and large amounts of unavailable capacity | 3 | 3-1/2 |
| 6/7 | Con Ed | Heavy loads and large amounts of unavailable capacity | 3 | 1 |
| 5/19 | Con Ed | Circuit breaker failure | 3 | 1/2 - 1 |
| 2/5 | Con Ed | Precautionary measure | 3-5 | 5-1/2 |
| 2/1 | NYPP | Insuffcient Capacity | 3-5 2/ | 15 3/ |
| 1/28 | NYPP | Insufficient Capacity | 5 2/ | 8-1/2 - 10 |
| 1/27 | NYPP | Insufficient Capacity | 5 | 2-1/2 - 4 |
| 1/21 | NYPP | Insufficient Capacity | 5 | 2-4-1/4 |
| 1/18 | NYPP | Insufficient Capacity | 5 | 3-1/2 - 6-1/2 |
| 1970 | | | | |
| 9/25 | Con Ed/ NYPP | Insufficient Capacity | 3-5 | 4-6 |
| 9/24 | Con Ed/ NYPP | Insufficient Capacity | 5 | 8-1/2 - 10 |
| 9/23 | Con Ed/ NYPP | Insufficient Capacity | 3-5-8 2/ | 12 |
| 9/22 | Con Ed/ NYPP | Insufficient Capacity | 3-5-8 2/ 4/ | 6-1/2 - 9 |
| 9/4 | Con Ed | Insufficient Capacity | 3-5 2/ | 3-1/2 - 6 |

NEW YORK AREA
LOAD REDUCTION MEASURES

| Date 1970 | Utility Or Pool | Cause | Voltage Reduced Percent | Estimated Duration Hours |
|---|---|---|---|---|
| 8/20 | Con Ed | Insufficient Capacity | 3 | 2 |
| 8/17 | Con Ed | Insufficient Capacity. | 3-5-8 2/ | 2 - 7-1/2 |
| 8/17 | LILCO | Insufficient Capacity | 3 | 3 |
| 8/14 | Con Ed/ NYPP | Insufficient Capacity | 3-5 2/ | 7 |
| 8/13 | Con Ed/ NYPP | Insufficient Capacity | 3-5 2/ | 4 - 7 |
| 7/31 | Con Ed/ NYPP | Insufficient Capacity | 3-5 2/ | 6-1/2 |
| 7/30 | Con Ed/ NYPP | Insufficient Capacity | 3-5 2/ | 6-1/2 - 7 |
| 7/29 | Con Ed/ NYPP | Insufficient Capacity | 3-5 2/ | 6-1/2 - 7 |
| 7/28 | Con Ed/ NYPP | Insufficient Capacity | 3-5 2/ | 5-1/2 - 8 |
| 7/27 | Con Ed | Insufficient Capacity | 3 | 4 |

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1/ Request made of large customers to curtail non-essential usage.

2/ Appeals were made to large customers and the general public to reduce electricity use.

3/ Pool members reduced voltage for various periods; time given is for Con Ed.

4/ Selective interruption of noncritical loads.

## NIAGARA MOHAWK POWER CORPORATION
## LOAD FORECASTS AND ACTUAL LOADS
## INTEGRATED PEAK HOUR DEMAND IN MEGAWATTS
## PREDICTED COMPARED TO ACTUAL

| Forecast Furnished In FPC Form 12 for Year Ending | Period | Predicted Peak In → 1965 | 1966 | 1967 | 1968 | 1969 | 1970 | 1971 | 1972 |
|---|---|---|---|---|---|---|---|---|---|
| 1965 | Summer | | N.R. | N.R. | N.R. | N.R. | | | |
| | Winter | | 3870 | 4000 | 4130 | 4260 | | | |
| 1966 | Summer | | | N.R. | N.R. | N.R. | N.R. | | |
| | Winter | | | 4170 | 4350 | 4520 | 4700 | | |
| 1967 | Summer | | | | 3820 | 4000 | 4210 | 4400 | |
| | Winter | | | | 4240 | 4450 | 4700 | 4900 | |
| 1968 | Summer | | | | | 4050 | 4210 | 4400 | 4570 |
| | Winter | | | | | 4500 | 4700 | 4900 | 5100 |
| 1969 | Summer | | | | | | 4210 | 4400 | 4590 |
| | Winter | | | | | | 4700 | 4900 | 5130 |
| 1970 | Summer | | | | | | | 4400 | 4590 |
| | Winter | | | | | | | 4900 | 5130 |
| 1971 | Summer | | | | | | | | 4390 |
| | Winter | | | | | | | | 4910 |
| Actual Peak 1/ | Summer | 3357 | 3463 | 3670 | 3855 | 4930 | 4169 | 4300 | 4392 |
| | Winter | 3701 | 3987 | 3971 | 4335 | 4442 | 4614 | 4551 | 4827 |

N.R. - Not Reported
1/ As reported in FPC Form 12, Schedule 14 for the respective year

Exhibit (DKO-8)

NEW YORK AREA
LOAD FORECASTS AND ACTUAL LOADS
COINCIDENT AREA PEAK LOAD IN MEGAWATTS
PREDICTED COMPARED TO ACTUAL

| NPCC Forecast Made In Year | | | Predicted Peak In → 1967 | 1968 | 1969 | 1970 | 1971 | 1972 |
|---|---|---|---|---|---|---|---|---|
| 1968 | (OCT) 1/ | Summer | | | 16480 | 17420 | 18330 | 19220 |
| | | Winter | | 15310 | 16080 | 16920 | 17760 | 18660 |
| 1969 | (MAR) 1/ | Summer | | | 16660 | 17700 | 18730 | 19660 |
| | | Winter | | | 16220 | 17130 | 18040 | 18950 |
| 1969 | (SEPT) 1/ | Summer | | | | 17630 | 18700 | 19780 |
| | | Winter | | | 16200 | 17030 | 17950 | 19000 |
| 1970 | (MAR) 1/ | Summer | | | | 17700 | 18800 | 20010 |
| | | Winter | | | | 17080 | 18015 | 19110 |
| 1970 | (AUG) 2/ | Summer | | | | 17710 | 18800 | 20010 |
| | | Winter | | | | 17140 | 18070 | 19130 |
| 1971 | (MAR) 2/ | Summer | | | | | 18880 | 20040 |
| | | Winter | | | | | 18020 | 19050 |
| 1971 | (SEPT) 2/ | Summer | | | | | | 20050 |
| | | Winter | | | | | 17950 | 18990 |
| 1972 | (MAR) 2/ | Summer | | | | | | 19510 |
| | | Winter | | | | | | 18540 |
| 1972 | (OCT) 1/ | Summer | | | | | | |
| | | Winter | | | | | | 18470 |
| Actual Peak | | Summer | 14119 | 15499 | 16716 | 17037 | 18146 | 18943 |
| | | Winter | 14462 | 15211 | 16028 | 16675 | 16774 | 17706 |

1/ Northeast Power Coordinating Council (NPCC) Load and Capacity Report.
2/ NPCC Order 383-2 Report to the Federal Power Commission.

Exhibit (DKO-9)

Exhibit (DKO-10) ______

## ACCURACY OF LOAD FORECASTS

| PERIOD | | Forecast Load MW 1/ | Actual Load MW | Difference Between Forecasts and Actual Loads MW | Percent |
|---|---|---|---|---|---|
| | | NIAGARA MOHAWK POWER CORPORATION | | | |
| 1966 | Winter | 3870 | 3987 | -117 | -2.94 |
| 1967 | Winter | 4170 | 3971 | +199 | +5.02 |
| 1968 | Winter | 4240 | 4335 | - 95 | -2.20 |
| 1969 | Winter | 4500 | 4442 | + 58 | +1.31 |
| 1970 | Winter | 4700 | 4614 | + 86 | +1.87 |
| 1971 | Winter | 4900 | 4551 | +349 | +7.67 |
| 1972 | Winter | 4910 | 4827 | + 83 | +1.72 |
| | AVERAGE ERROR FOR 7 YEAR PERIOD | | | + 80 | +1.78 |
| | | NEW YORK AREA | | | |
| 1968 | Summer | 15310 | 15499 | -189 | -1.22 |
| 1969 | Summer | 16200 | 16716 | -516 | -3.09 |
| 1970 | Summer | 17140 | 17037 | +103 | + .61 |
| 1971 | Summer | 17950 | 18146 | -196 | -1.08 |
| 1972 | Summer | 18470 | 18943 | -473 | -2.50 |
| | AVERAGE ERROR FOR 5 YEAR PERIOD | | | -254 | -1.46 |

1/ Most recent forecast preceeding peak load period.

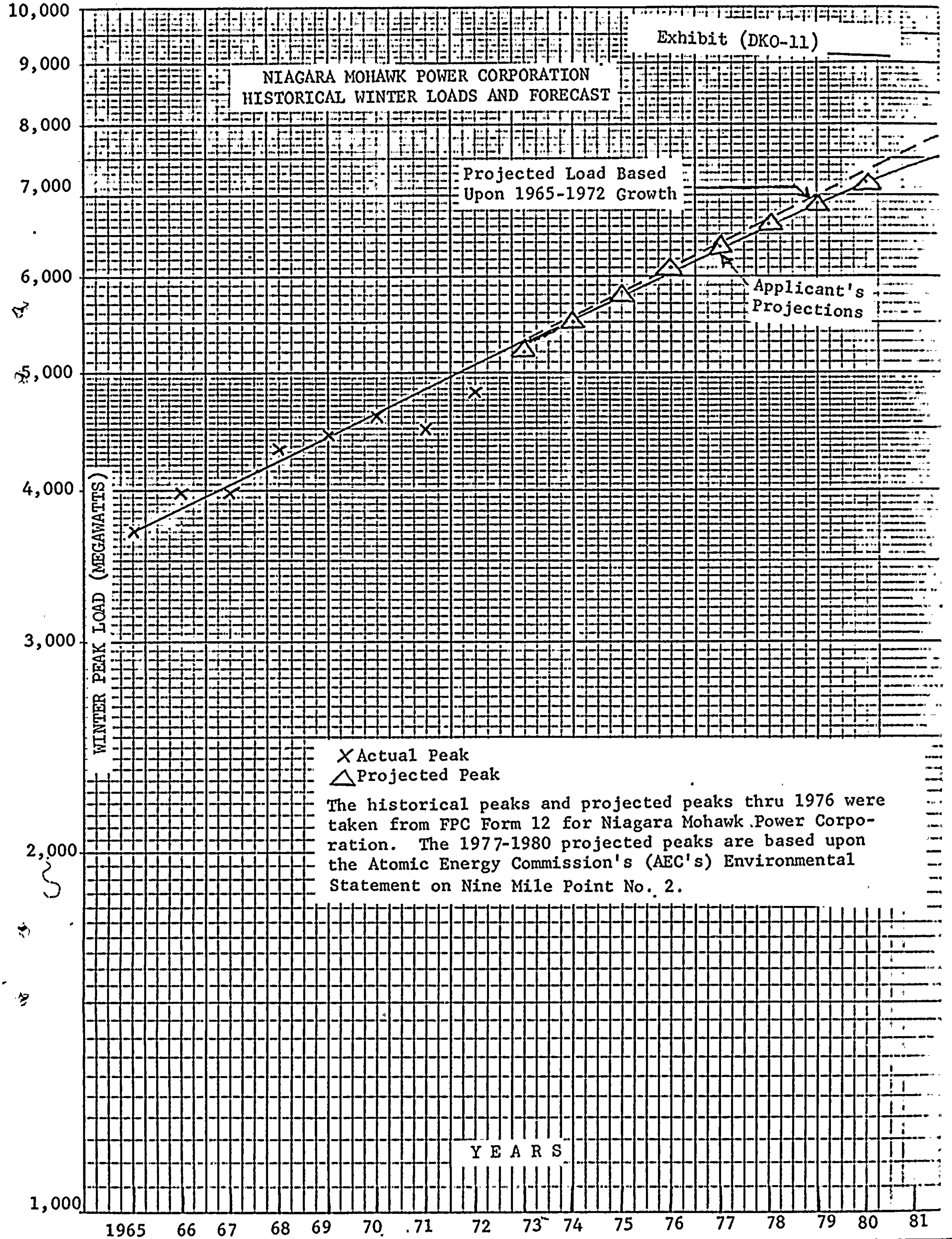
Exhibit (DKO-11)
NIAGARA MOHAWK POWER CORPORATION
HISTORICAL WINTER LOADS AND FORECAST
Projected Load Based Upon 1965-1972 Growth
Applicant's Projections
WINTER PEAK LOAD (MEGAWATTS)
10,000
9,000
8,000
7,000
6,000
5,000
4,000
3,000
2,000
1,000
X Actual Peak
△ Projected Peak
The historical peaks and projected peaks thru 1976 were taken from FPC Form 12 for Niagara Mohawk Power Corporation. The 1977-1980 projected peaks are based upon the Atomic Energy Commission's (AEC's) Environmental Statement on Nine Mile Point No. 2.
YEARS
1965
66
67
68
69
70
71
72
73
74
75
76
77
78
79
80
81

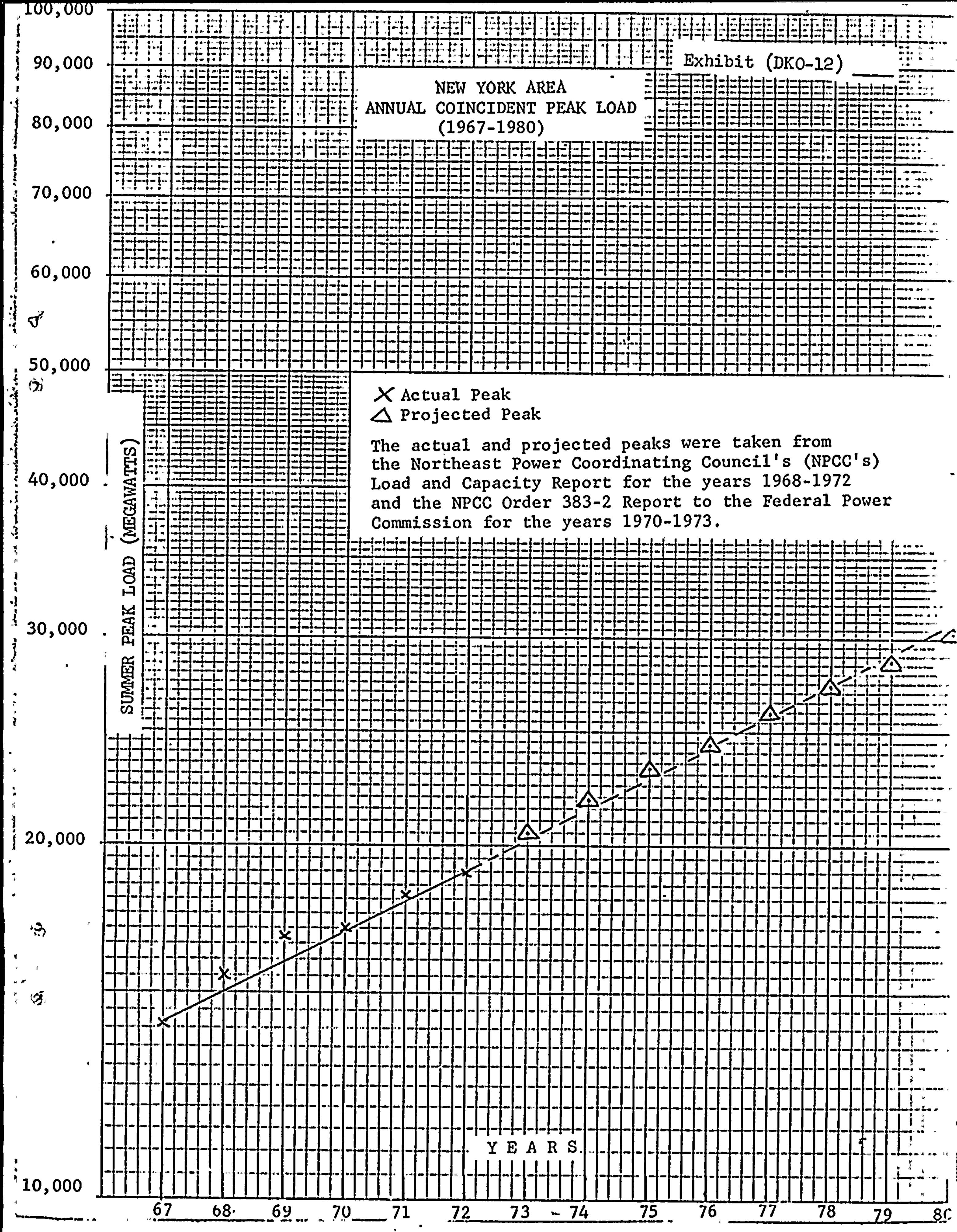
Exhibit (DKO-12)
NEW YORK AREA
ANNUAL COINCIDENT PEAK LOAD
(1967-1980)
X Actual Peak
△ Projected Peak
The actual and projected peaks were taken from the Northeast Power Coordinating Council's (NPCC's) Load and Capacity Report for the years 1968-1972 and the NPCC Order 383-2 Report to the Federal Power Commission for the years 1970-1973.
SUMMER PEAK LOAD (MEGAWATTS)
100,000
90,000
80,000
70,000
60,000
50,000
40,000
30,000
20,000
10,000
YEARS
67
68
69
70
71
72
73
74
75
76
77
78
79
80

TABLE I

Expected Reserves, Summer of 1979
August Peak

| Group | Peak Load (MW) | Reserve - MW Optimistic | Reserve - MW Pessimistic | Reserve - % Optimistic | Reserve - % Pessimistic |
|---|---|---|---|---|---|
| NPCC | 64,460 | 25,066 | 1/ | 38.9 | 1/ |
| MAAC | 48,230 | 12,336 | 9,111 2/ | 25.6 | 18.9 2/ |
| ECAR | 81,046 | 17,697 | 14,377 3/ | 21.8 | 17.7 3/ |
| N. Y. | 28,648 | 9,131 | 7,031 4/ | 31.8 | 24.6 4/ |
| N. E. | 20,123 | 6,091 | 3,761 5/ | 30.3 | 18.7 5/ |
| Ontario | 14,930 | 8,853 | 7,570 6/ | 59.3 | 50.7 6/ |

1/ Pessimistic value not determined.

2/ Does not include Newbold Island No. 1, 1,100 MW nuclear unit scheduled for June 1979; Limerick No. 1, 1,055 MW nuclear unit scheduled for September 1978; and Forked River No. 1, 1,070 MW nuclear unit scheduled for December 1978.

3/ Does not include Western Region, 1,300 MW coal-fired unit scheduled for October 1978; Perry No. 1, 1,205 MW nuclear unit scheduled for April 1979; and Midland No. 2, 815 MW nuclear unit scheduled for June 1979.

4/ Does not include Nine Mile Point No. 2, 1,100 MW nuclear unit scheduled for November 1978; and Cornwall Unit Nos. 1-4, 1,000 MW pumped storage scheduled for April 1971.

5/ Does not include Pilgrim No. 2, 1,180 MW nuclear unit scheduled for November 1978; Millstone Point No. 3, 1,150 MW nuclear unit scheduled May 1979.

6/ Does not include 1st New Station No. 1 (E-11), 538 MW undetermined, April 1, 1979; and Bruce No. 4, 745 MW nuclear unit scheduled for June 1, 1979.

TABLE II

Expected Reserves, Summer of 1980
August Peak

| Group | Peak Load (MW) | Reserve - MW Optimistic | Reserve - MW Pessimistic | Reserve - % Optimistic | Reserve - % Pessimistic |
|---|---|---|---|---|---|
| NPCC | 68,610 | 28,210 | 1/ | 41.4 | 1/ |
| MAAC | 51,820 | 13,727 | 9,302 2/ | 26.5 | 18.0 2 |
| ECAR | 86,678 | 19,170 | 15,515 3/ | 22.1 | 17.9 3 |
| N. Y. | 30,146 | 9,827 | 7,997 4/ | 32.6 | 26.5 4 |
| N. E. | 21,672 | 7,752 | 4,537 5/ | 35.8 | 20.9 5 |
| Ontario | 15,974 | 9,400 | 7,810 6/ | 58.9 | 48.9 6 |

1/ Pessimistic value not determined.

2/ Does not include Atlantic No. 1, 1,150 MW nuclear unit scheduled for June 1980; Susquehanna No. 1, 1,120 MW nuclear unit scheduled for December 1979; Limerick No. 2, 1,055 MW nuclear unit scheduled for March 1980; and Douglas Point No. 1, 1,100 MW nuclear unit scheduled for March 1980.

3/ Does not include Western Region, 1,300 MW coal-fired unit scheduled for April 1980; Perry No. 2, 1,205 MW nuclear unit also scheduled for April 1980; and Fermi No. 2, 1,150 MW nuclear unit scheduled for June 1980.

4/ Does not include Cornwall Nos. 5-8, 1,000 MW pumped storage unit for September 1979; and Bell 830 MW nuclear unit, December 1979.

5/ Does not include Seabrook nuclear unit, 1,150 MW scheduled for November 1979; Pilgrim No. 3, 1,180 MW nuclear unit scheduled for June 1980; and North Shore No. 2, 885 MW oil-fired unit scheduled for June 1980.

6/ Does not include 1st New Station Nos. 2 & 3, 538 MW each scheduled for October 1979 and April 1980, respectively; and 2nd New Station No. 1, 514 MW unit scheduled for April 1980.

Exhibit (DKO-14) ___

## CAPACITY UNAVAILABLE AT TIME OF SYSTEM PEAK

### NEW ENGLAND AREA 1/

| Peak Period | Capacity Unavailable MW | Capacity Unavailable % of Total Capability |
|---|---|---|
| Winter 1969-1970 | 786 | 6.23 |
| Winter 1970-1971 | 664 | 4.87 |
| Winter 1971-1972 | 905 | 6.23 |
| Winter 1972-1973 | 2635 | 15.95 |

### ONTARIO - EAST SYSTEM 1/

| Peak Period | Capacity Unavailable MW | Capacity Unavailable % of Total Capability |
|---|---|---|
| Winter 1969-1970 | 780 | 6.91 |
| Winter 1970-1971 | 1030 | 8.37 |
| Winter 1971-1972 | 1241 | 9.05 |
| Winter 1972-1973 | 1651 | 11.52 |

### EAST CENTRAL AREA RELIABILITY COORDINATION AGREEMENT

| Peak Period | Capacity Unavailable MW | Capacity Unavailable % of Total Capability |
|---|---|---|
| Summer 1970 2/ | 6279 | 12.51 |
| Summer 1971 3/ | 6395 | 12.05 |
| Summer 1972 4/ | 8449 | 14.31 |

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1/ Responses of Northeast Power Coordinating Council (NPCC) dated April 1, 1971, April 1, 1972, and April 1, 1973, to FPC Docket R-362, Order 383-2.

2/ Response of East Central Area Reliability Coordination Agreement (ECAR) dated April 1, 1972.

3/ ECAR "Load and Capacity Appraisal Winter 1970-1971, With a Preliminary Appraisal of Summer 1971 and a Review of Summer 1970" November 10, 1970, Document 70-GRP-33A.

4/ ECAR "Load and Capacity Appraisal Winter 1972-73, with a Preliminary Appraisal of Summer 1973 and a Review of Summer 1972" November 1972, Document 72-GRP-33A.