BNL NORTHEAST ENERGY PERSPECTIVES STUDY

ISSUES IN THE FUTURE SUPPLY OF ELECTRICITY TO THE NORTHEAST

P.M. Meier, T.H. McCoy, and S. Rahman

June 1976

POLICY ANALYSIS DIVISION
NATIONAL CENTER FOR ANALYSIS OF ENERGY SYSTEMS
BROOKHAVEN NATIONAL LABORATORY
UPTON, NEW YORK 11973

Prepared for the
UNITED STATES ENERGY RESEARCH AND DEVELOPMENT ADMINISTRATION

DISCLAIMER

BNL NORTHEAST ENERGY PERSPECTIVES STUDY

BNL 50553
[General, Miscellaneous, and Progress
Reports (Nonnuclear) - TID-4500]

ISSUES IN THE FUTURE SUPPLY OF ELECTRICITY TO THE NORTHEAST

P.M. MEIER, T.H. McCOY, AND S. Rahman

June 1976

POLICY ANALYSIS DIVISION
NATIONAL CENTER FOR ANALYSIS OF ENERGY SYSTEMS
BROOKHAVEN NATIONAL LABORATORY
UPTON, NEW YORK 11973

Work supported by the Division of Biomedical and Environmental Research of the United States Energy Research and Development Administration under Contract No. E(30-1)-16 in the context of the Brookhaven National Laboratory Regional Energy Studies Program.

Printed in the United States of America
Available from
National Technical Information Service
U.S. Department of Commerce
5285 Port Royal Road
Springfield, VA 22161
Price: Printed Copy $6.50; Microfiche $3.00

October 1977 800 copies

FOREWORD

This report is one of a number of issue papers prepared as part of the Brookhaven National Laboratory Northeast Energy Perspectives Study. The analyses in these papers were performed specifically to assist us in our first integrated study of the energy future of the northeastern United States.

Topics covered by the issue papers include the potential supply of energy to the Northeast from coal, oil, natural gas, liquefied natural gas (LNG), nuclear power, municipal waste, solar energy, and wind power, and the demand for energy in the Northeast from the industrial, transportation, and residential and commercial sectors. In each case a range of estimates of energy supply or demand was constructed to reflect not only a variety of possible policy and technological developments, but also the basic uncertainties of all such future projections. The integrative analysis which relates the supply and demand picture is presented in "A Perspective on the Energy Future of the Northeast United States."

The issue papers prepared for the Northeast Energy Perspectives Study and the summary report will be available from:

National Technical Information Service
U.S. Department of Commerce
5285 Port Royal Road
Springfield, VA 22161

The issue papers and summary report are listed below.

H. Bronheim, "Future Oil Supply to the Northeast United States," BNL 50557 (June 1976).

R. J. Goettle, IV, "Alternative Patterns of Industrial Energy Consumption in the Northeast," BNL 50555 (March 1976).

R. N. Langlois, "Future Natural Gas Supply to the Northeast," BNL 50558 (April 1976).

J. Lee, "Future Residential and Commercial Energy Demand in the Northeast," BNL 50552 (March 1976).

P. M. Meier and T. H. McCoy, "Solid Waste as an Energy Source for the Northeast," BNL 50559 (June 1976).

P. M. Meier, T. H. McCoy, and S. Rahman, "Issues in the Future Supply of Electricity to the Northeast," BNL 50553 (June 1976).

B. S. Edelston and E. S. Rubin, "Current and Future Use of Coal in the Northeast," BNL 50560 (May 1976), Environmental Studies Institute, Carnegie-Mellon University, Pittsburgh, Penn.

V. L. Sailor and F. J. Shore, "The Future of Nuclear Power in the Northeast," BNL 50551 (March 1976).

G. R. Bray, S. K. Julin and J. A. Simmons, "Supply of Liquefied Natural Gas to the Northeast," BNL 50556 (April 1976), Science Applications, Inc., 1651 Old Meadow Road, McLean, Va.

System Design Concepts, Inc., "Transportation Energy Consumption and Conservation Policy Options in the Northeast," BNL 50554 (April 1976), System Design Concepts, Inc., 9 Rector Street, New York, N.Y. 10006.

J. Brainard et al., Editors, "A Perspective on the Energy Future of the Northeast United States," BNL 50550 (June 1976).

TABLE OF CONTENTS

LIST TO TABLES

LIST OF FIGURES

ACKNOWLEDGEMENT

The writers wish to express their appreciation to R. O. Bigelow, Director of Planning and Power Supply of the New England Electric System; S. H. Lull, Vice President, Northeast Utilities System; and R. B. MacKenzie, Vice President of Electrical Engineering and Planning, New York State Electric and Gas Corporation, who were not only very helpful in providing sources of information, but also gave their time to review early versions of this report.

We are also indebted to Bob Stern for his assistance in preparing the graphics, and to Georgia Irving, Adele Hough and Donna Visone for the typing of this report.

These contributions notwithstanding, however, the responsibility for the accuracy and opinions expressed in this report rests entirely with the writers.

CHAPTER I

INTRODUCTION

This assessment of the problems of the electric sector is an integral part of the BNL study on the Energy Future of the Northeast, and, as such, has some very specific and limited objectives. One should note first that the perspective of this study is regional; and thus the analysis of siting problems is not concerned with the details of site evaluation, or local environmental impacts, but rather on the wider policy issues that must be resolved at the regional scale. Thus, for example, we shall address the broad trade-offs between offshore, coastal, estuarine and inland siting--but omit any detailed analysis of the environmental or socioeconomic impacts of particular proposed sites.[1]

One of the most fundamental controversies in the electric sector concerns the future need for electric power, and almost every new generating facility proposed in recent years has sparked fierce debate as to the real need for the facility, and the methods used to project electric demands. Since the current lead time for constructing base load plants is 8 to 10 years, the utilities have to project the electric demands on their systems that many years in advance. Unfortunately, we are now at a point in the evolution of the U.S. energy system at which the prediction of future demands is particularly uncertain, and in the Northeast Energy Perspectives Study a new approach has been taken to demand projection of all energy forms. Thus it is of interest to compare the benefits of these projections of electrical demand with those made by the region's utilities.

Our electric demand projections for 1985 and 2000 are based on a consideration of specific uses of electricity, such as cooking, heating and lighting and on the future determinants of this demand, with full consideration given to such factors as inter-fuel substitution, technological development and changes in the structure of regional economic and industrial activity.

However, the preliminary nature of this paper cannot be overly stressed. Many of the activities currently under way in the BNL Regional Energy Studies Program have direct bearing on the siting of electric facilities,[2] but the results of these activities are not yet available for incorporation into this paper. Consequently, we have been limited here to a qualitative rather than quantitative discussion of many of the major issues, a deficiency that will be rectified as results do become available. Current activities germane to regional siting issues include[3]

1. Comprehensive analysis of water resource constraints, of which only the results for freshwater bodies in the Northeast are currently available. Analysis of estuarine and ocean waters is expected to be complete in the near future.

2. Implementation of a computerized, regional model of the electric sector that will allow more accurate projections of generation mix than those adopted in this report.

3. Development of a facility siting model applicable to the regional scale, based on location theory and multiple-objective planning techniques.

4. Detailed analysis of siting problems of coal fired facilities, an activity about to start as part of the National Coal Utilization Assessment, (an integrated analysis to be conducted by the Regional Energy Studies Programs of the National Laboratories).

5. Preparation of a computerized data bank covering all existing and planned power facilities and utilities in

the Northeast. The economic, environmental, technical performance and institutional information that will comprise this data bank will facilitate the sophisticated econometric and statistical studies that are necessary for quantitative analysis of policy options.

In summary, then, the major objectives of this paper are as follows:

1. A comparison of energy demand projections derived in other parts of the Northeast Energy Perspectives Study to current utility projections.

2. A discussion of the major technical issues in capacity forecasting, including system load factors, outage rates, scale economies, unit sizes, and generation mix planning.

3. A discussion of the major siting constraints faced by each type of generation in the Northeast.

4. The preparation of preliminary forecasts of the number and type of new generation facilities necessary by 1985 and 2000, and an analysis of the implications for regional siting policy.

NOTES TO CHAPTER I

1. For further discussion of the regional perspective to energy facility siting problems, see P. Meier, "Energy Facility Siting Location: A Regional Viewpoint," BNL 20435 (August 1975), Brookhaven National Laboratory, Upton, N.Y.

2. For a complete description and status of the program, see P. F. Palmedo, "The BNL Regional Energy Studies Program: Annual Report FY 1975," BNL 50478 (July 1975), Brookhaven National Laboratory, Upton, N.Y.

3. See also, P. Meier, "Research in Energy Facility Siting," BNL 20489 (July 1975), Brookhaven National Laboratory, Upton N.Y.

CHAPTER II

THE EXISTING FUEL AND CAPACITY MIX

2.1 Introduction

In this chapter we review briefly the existing fuel and capacity mix, as this has great bearing on the options available in the future. First, however, we turn to a comparison of the regional breakdowns used in the BNL Energy Perspectives Study with current utility planning arrangements.

Region I, as used by all of the issue papers in the Energy Perspectives Study, comprises the six New England States, which corresponds exactly to the area of the New England Power Pool (NEPOOL), also equivalent to the Federal Power Commission designation "coordinated power supply Region A."[1] (The equivalency of these regional definitions is also shown on Table 1.)

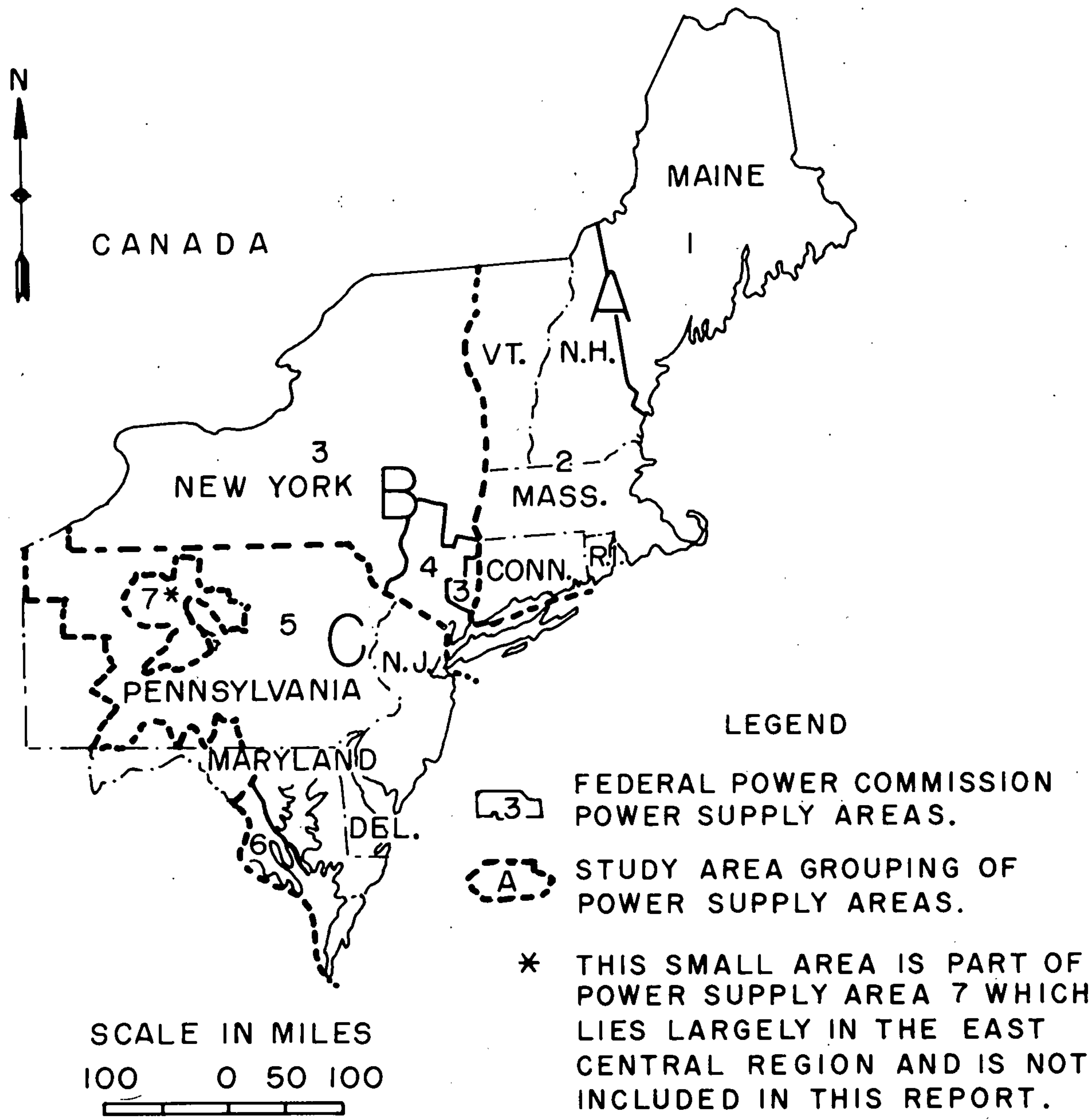
Region II consists of New York State, again exactly equivalent to the area covered by the New York Power Pool, and the FPC Coordinated Supply Area B.

The correspondence of Region III, which consists of Pennsylvania, New Jersey, Maryland, Delaware and the District of Columbia, to current utility planning arrangements is more complicated. The Mid-Atlantic Area Reliability Council (MAAC) includes all of the utilities in the Region except those serving parts of western Pennsylvania and western Maryland which belong to the East Central Area Reliability Coordination Agreement (ECAR). The latter utilities are members of either the Allegheny Power System (APS) or the Central Area Power Coordination Group (CAPCO); while all of the MAAC utilities except the Atlantic City Electric Company are members of the Pennsylvania-Jersey-Maryland Interconnection Power Pool (PJM). These arrangements are illustrated in Figure 1.

TABLE 1

REGIONAL DEFINITIONS

This Report (Consistent with BNL Energy Perspectives Study)	Power Pool	FPC "Coordinated Supply Area"	FPC "Power Supply Area"	Reliability Council
Region I (6 New England States)	NEPOOL	A	1. (Maine) 2. (Vt., N.H., Conn., R.I., Mass)	Northeast Power Co-ordinating Council (NPCC) (also includes Ontario and New Brunswick)
Region II (New York State)	NYPP	B	3. (New York State except utilities in PSA 4) 4. (Consolidated Ed. LILCO, Orange and Rockland)	
Region III (Pa.,N.J.,Md.,Del., District of Columbia)	PJM Parts of Md. & Pennsylvania in CAPCO and in APS	C	5. (All states in PJM except D.C.) 6. (D.C.)	Mid-Atlantic Area Council (MAAC)
			7. (As shown on Figure 1)	East Central Area Reliability Council (ECAR) (also includes most of Ky.,W.Va., Ohio,Mich., and Indiana)



SOURCE : REF. 1 (b)

Figure 1. Definition of power supply areas.

2.2 The Capacity Mix

The 1972 and 1975 capacity mix, disaggregated by region, is shown on Tables 2 and 3, respectively.

Several interesting features emerge from these Tables. For example, for 1975 the percentage of capacity in hydro and combustion turbine is 20.6 percent for New England, 32.8 percent for New York and 19.9 percent in PJM. However, the two large hydro plants operated by the Power Authority of the State of New York (PASNY), the Robert Moses Facilities on the St. Lawrence and Niagara Falls near Buffalo, account for 2.86 Gw of the indicated 4.03 Gw hydro total, and are operated as base load plants rather than for peaking capacity.[3] Subtracting these facilities from the 4.03 Gw total, one obtains 4.95 Gw in peaking capacity, or 18.4 percent of the total NYPP capacity. Thus, the fraction of combustion turbine and hydro peaking capacity in all three power pools is seen to be very close (all in the vicinity of 20 percent), despite the significant variations in the relative contributions of pumped storage, combustion turbine, and conventional hydro.

We also notice that Region III (PJM) has the highest percentage of conventional steam units, while nuclear units play a more important role in New England than in the other two regions.[4]

2.3 The Fuel Mix

Tables 4 and 5 show fuel consumption, in Btu equivalents, and Tables 6 and 7 electric generation, in kwh per year, for 1972 and 1975 respectively. Analysis of these four tables illustrates a number of most important features of the response of the electric sector to the changed fuel price and availability conditions that followed the 1973 oil embargo.

Inspection of Tables 6 and 7 shows that while the total energy output in the region has increased slightly (from 337 to 342 x 10^6

Table 2

1972 TOTAL INSTALLED CAPACITY

	I. New England[a]		II. New York[a]		III. PJMD[b]		Northeast	
	Gw	%	Gw	%	Gw	%	Gw	%
Hydroelectric								
Conventional	1.28	7.8	4.03	16.7	1.18	3.0	6.49	8.2
Pumped Storage	0.28	1.7	0	0	1.05	2.7	1.33	1.7
Gas Turbine	1.71	10.5	4.32	17.9	5.0	12.8	11.03	13.9
Steam Electric								
Gas Oil Coal	10.04	61.6	14.48	60.0	31.10	79.7	55.62	70.0
Nuclear	3.0	18.4	1.30	5.4	0.73	1.9	5.03	6.3
Total	16.3		24.1		39.1		79.5	

[a] Northeast Power Coordinating Council Report (April 1, 1973), Table 2. See Note 4. These are the actual 72-73 winter capacities and may be slightly higher than the capacities as of Dec. 31, 1972 depending on whether any new units started operating early in 1973.

[b] MAAC Report (April 1, 1973) and ECAR Report (April 1, 1973), see Notes 5 and 6. MAAC portion of the capacities was those existing as of Feb. 1, 1973, while ECAR portion was as of Dec. 31, 1972.

Table 3

1975 Total Installed Capacity

	I. New England[a] Gw	%	II. New York[a] Gw	%	III. PJMD[b] Gw	%	Northeast Gw	%
Hydroelectric								
conventional	1.30	6.5	4.03	15.0	0.94	2.0	6.27	6.6
pumped storage	1.63	8.2	1.00	3.7	1.29	2.7	3.92	4.1
Gas Turbine		20.6		32.8		19.9		
gas	0	0	0.05	0.2	0.30	0.6	0.35	0.4
oil	1.18	5.9	3.73	13.9	6.97	14.6	11.88	12.6
Steam Electric								
gas, oil	10.59	53.2	12.47	46.4	13.74	28.8	36.80	39.0
coal	1.06	5.3	3.26	12.1	20.05	42.0	24.37	25.8
nuclear	4.14	20.8	2.35	8.7	4.40	9.2	10.89	11.5
Total	19.90		26.89		47.69		94.48	

[a] Northeast Power Coordinating Council Report, (April 1, 1976), See Note 4.

[b] MAAC Report (April 1, 1976), See Note 5: ECAR Report (April 1976), See Note 6.

Table 4

1972 FUEL CONSUMPTION IN ELECTRICITY GENERATION

	I. New England		II. New York		III. PJMD		Northeast	
	10^{12}Btu	%	10^{12}Btu	%	10^{12}Btu	%	10^{12}Btu	%
Hydroelectric[a]	23	3.2	124	13.0	16	0.8	163	4.5
Gas Turbine								
gas	1	0.1	31	3.3	21	1.1	53	1.5
oil	19	2.6	73	7.7	84	4.2	176	4.8
Steam Electric								
gas	11	1.5	40	4.2	18	0.9	69	1.9
oil	530	73.5	470	49.4	632	31.9	1632	44.7
coal	32	4.4	143	15.0	1160	58.5	1335	36.5
nuclear	105	14.6	71	7.5	51	2.6	227	6.2
Total	721		952		1982		3655	

[a]Assuming an efficiency of about 0.8, the numbers given in this row represent the potential energy needed to generate the amount of electricity actually produced.

Source: J. Lee, Note 2, p. 7-11.

Table 5

1975 FUEL CONSUMPTION IN ELECTRICITY GENERATION

	I. New England		II. New York		III. PJMD		Northeast	
	10^{12}Btu	%	10^{12}Btu	%	10^{12}Btu	%	10^{12}Btu	%
Hydroelectric[b]	20	2.8	126	13.0	16	1.0	162	4.9
Gas Turbine								
gas[a]	1	0.1	1	0.1	2	0.1	4	0.1
oil[a]	6	0.8	33	3.4	40	2.4	79	2.4
Steam Electric								
gas[a]	2	0.3	13	1.3	10	0.6	25	0.8
oil[a]	418	59.0	517	53.5	378	22.9	1313	39.5
coal[a]	39	5.5	134	13.9	950	57.6	1123	33.8
nuclear[c]	223	31.5	142	14.7	252	15.3	617	18.6
Total	709		966		1648		3323	

[a]Based on various FPC News Releases and assuming the following average heat contents: coal - 10.85 x 10^3 Btu/lb, oil - 146 x 10^3 Btu/gal, gas - 1.0 x 10^3 Btu/cf.

[b]See footnote of Table 4.

[c]Based on various FPC New Releases and assuming an efficiency of 0.31.

Table 6

1972 ELECTRIC GENERATION BY TYPE OF FACILITY

	I. New England		II. New York		III. PJMD		Northeast	
	10^6 Mwh	%	10^6 Mwh	%	10^6 Mwh	%	10^6 Mwh	%
Hydroelectric[a]	5.1	7.5	27.5	27.0	3.6	2.1	36.2	10.7
Conventional Steam[b]	53.1	78.4	67.9	66.6	159.4	95.1	280.4	83.1
Nuclear Steam	9.5	14.0	6.5	6.4	4.7	2.8	20.7	6.1
Total	67.7		101.9		167.7		337.3	

---

[a] Pumped storage is not included because its "fuel" is the electricity produced by other types of facilities listed here and hence including pumped storage would mean counting the same electric generation twice. Furthermore, the amount of electricity generated by pumped storage is less than 1% in all three regions.

[b] Includes gas turbines.

Source: Edison Electric Institute Statistical Yearbook for 1972.

Table 7

1975 ELECTRIC GENERATION BY TYPE OF FACILITY

	I. New England		II. New York		III. PJMD		Northeast	
	10^6 Mwh	%	10^6 Mwh	%	10^6 Mwh	%	10^6 Mwh	%
Hydroelectric[a]	4.4	6.3	28.1	26.3	3.6	2.2	36.1	10.6
Gas Turbine								
gas[b]	0.05	0.07	0.04	0.03	0.1	0.06	0.2	0.06
oil[b]	0.4	0.6	2.3	2.2	2.7	1.6	5.4	1.6
Steam Electric								
gas[b]	0.15	0.2	1.0	0.9	1.0	0.6	2.2	0.6
oil[b]	40.1	57.4	48.8	45.7	33.8	20.4	122.7	35.9
coal	4.4	6.3	13.8	12.9	101.2	61.2	119.4	34.9
nuclear	20.3	29.1	12.9	12.1	22.9	13.9	56.0	16.4
Total	69.8		106.9		165.3		342.0	

[a] Conventional only. See Footnote of Table 6.

[b] In FPC News Releases, electric generation by gas turbines and by steam electric units are not separately listed, only the sum is given. However, the amount of natural gas consumed by gas turbines and the amount consumed by steam electric units are separately tabulated. Using the fact that gas turbine has an average efficiency of 0.24 and steam electric unit 0.32, we are able to compute the amount of electricity generated by the two kinds of generators.

Source: Various FPC News Releases.

Mwh), the fuel consumed has fallen from 3.65 Quads to 3.32 Quads, reflecting a more efficient use of fuel in the system as a whole. This gain in efficiency follows from two major factors. First, we note a dramatic decrease in the use of gas turbines (the fuel used in gas turbines fell from .22 Quads in 1972 to .08 Quads in 1975)--the efficiency gain here derives from the fact that steam-electric plants have a significantly higher efficiency than gas turbine units. Second, we note that a much higher fraction of the total output in 1975 is generated by nuclear power (rising from 6% in 1972 to 16% by 1975).

Another interesting feature is the dramatic decrease in the use of gas as a fuel, falling from .12 Quads in 1972 to .03 Quads in 1975. Moreover, whereas in 1972 44 percent of the gas burned was used in gas turbines, in 1975 only 11 percent was used in gas turbines. Thus, not only has the total gas consumption fallen, but it has been used more efficiently (again because steam-electric plants have higher efficiencies than gas turbines).

It should come as no surprise, then, that with a roughly constant fuel use, but significantly higher nuclear generation, the use of oil has fallen dramatically--from 1.8 Quads in 1972 to 1.4 Quads in 1975. At the same time, use of coal has also decreased from 1.33 Quads to 1.12 Quads, with most of that decrease occurring in Region III (which includes Pennsylvania).

Finally, one should note that the experience of the Northeast over the past three years has been rather different than the Nation as a whole. In 1974, electric energy consumption dropped in all three subregions of the Northeast, as illustrated on Figure 2; whereas in the Nation as a whole, electric consumption increased somewhat. Indeed, electric energy consumption in Region III dropped even further in 1975.

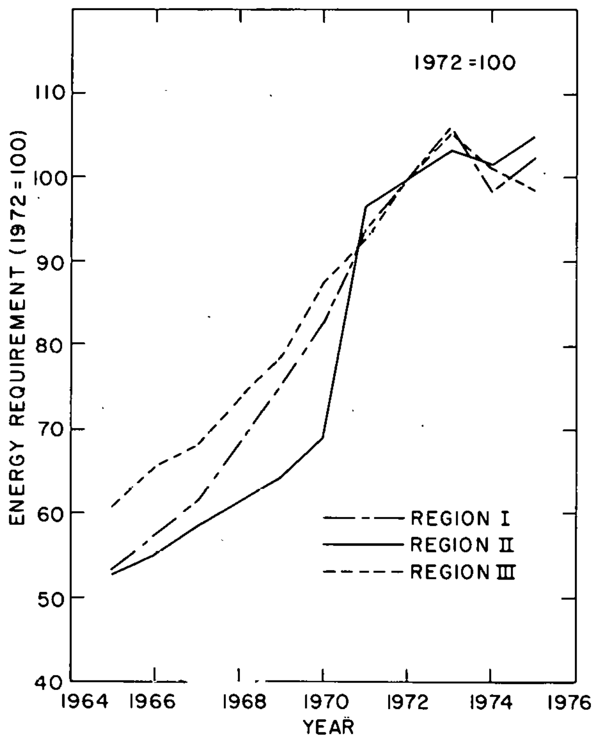


Figure 2. Impact of the oil embargo and the recession on electric energy consumption.

NOTES TO CHAPTER II

1. These FPC designations are in wide use in the electric utility industry, especially in the large number of FPC data sources.

2. J. Lee, "Energy Supply and Demand in the Northeast United States," BNL 20427 (Sept. 1975), Energy Policy Analysis Division, Brookhaven National Laboratory, Upton, N.Y.

3. The Robert Moses Plant - St. Lawrence had a plant factor of 84 percent in 1972, the Robert Moses Plant at Niagara Falls, 90 percent (see FPC "Hydro-electric Plant Construction Cost and Annual Production Expenses," 15th Annual Supplement, 1971, FPC S-232.

4. For further details on nuclear capacity in the region, see V. L. Sailor and F. J. Shore, "The Future of Nuclear Power in the Northeast," BNL 50551 (March 1976), Brookhaven National Laboratory, Upton, N.Y.

5. Northeast Power Coordinating Council, "Data on Coordinated Regional Bulk Power Supply Programs/FPC Order 383-3, Docket R-362, Appendix A-1," (April 1, 1976).

6. Mid-Atlantic Area Council, "MAAC Systems Plans/Response to Federal Power Commission Order 383-3, Docket No. R-362," (April 1, 1976).

7. East Central Area Reliability Coordination Agreement, "A Report by ECAR Bulk Power Members to the Federal Power Commission Pursuant to Docket R-362, Order 383-3," (April 1976).

THIS PAGE

WAS INTENTIONALLY

LEFT BLANK

CHAPTER III

ENERGY DEMAND FORECASTS

3.1 Introduction

In this chapter we assemble the electric demand projections made by two other issue papers prepared by the BNL Perspectives Study, and compare these to other utility, power pool, and public agency projections. Both the paper on industrial energy demand,[1] and that on residential and commercial energy demand,[2] derive a range of estimates of electric consumption for 1985 and 2000, disaggregated by three major subregions.

A number of reasons make the independent derivation of energy demands preferable to the traditional extrapolations of growth rates. The most obvious, of course, is the discontinuity in demand growth experienced by most utilities in 1974, caused by the joint effects of the deepening recession and conservation by consumers during and following the 1973-1974 oil embargo, a discontinuity illustrated on Figure 2. To utilities long accustomed to steady growth rates of around 6 to 8 percent per year (predictions that were admittedly entirely adequate during most of the sixties) such discontinuities pose severe analytical problems. To be sure, many utilities have recently turned to quite sophisticated econometric load forecasting techniques,[3] but these cannot easily deal with the impact of specific, non-price conservation policies or technological developments in end-use devices.[4]

The problem of projection is all the more troubling since very small changes in assumed growth rates can have very large overall impacts when extrapolated over 25 years; a 4 percent growth rate over 25 years results in a net increase of 166 percent; whereas a

5 percent rate results in a 238 percent increase, clearly a significant difference when translated into the number of new facilities that may or may not be needed.

A further difference between the normal utility projections and those developed for this study concerns the time horizon. We are concerned with supply-demand trends over a period of at least 25 years, whereas utility projections, or at least those that are published, rarely extend beyond ten years.[5] The effects of uncertainties in growth rates are quite different for long time horizons and it is reasonable to expect that different analytical approaches may be appropriate.[6]

3.2 NEPOOL (New England, Region I)

The energy demand projections for New England, as derived in the previously mentioned issue papers, are assembled in Table 8. One should note, however, that the totals column is greater than the sum of the industrial, commercial, and residential sectors, to account for agricultural use, street lighting, and institutional use (sewage treatment plants, water supply facilities, etc.), which were not included in the named categories. Analysis of utility data sources suggests that these miscellaneous use categories account for some 10 percent of total consumption, an estimate reflected in the totals column of Table 8.

For each year, we show a high, a medium and a low case which are the appropriate cases taken from the two issue papers. For the industrial sector, they correspond to Case III, I, and V, respectively. For both residential and commercial sectors, they correspond to base, moderate conservation and strong conservation, respectively.

How do these energy demand projections compare with other forecasts? The NEPOOL forecast,[7] which only extends to 1985, makes the following projection of energy demand:

Table 8

ENERGY DEMAND PROJECTIONS FOR NEPOOL

(New England, Region I)

(in 10^{12} Btu/yr, except where noted)

1985

	Industrial	Residential	Commercial	Total[a] 10^{12} Btu	Total[a] 10^{6} Mwh
HIGH	118	139	122	417	122
MEDIUM	100	133	101	368	108
LOW	86	120	88	323	95

2000

	Industrial	Residential	Commercial	Total[a] 10^{12} Btu	Total[a] 10^{6} Mwh
HIGH	186	227	286	769	225
MEDIUM	145	197	185	580	170
LOW	110	158	141	450	132

---

[a] See text.

1975	74×10^6 Mwh (actual)
1980	97×10^6 Mwh
1985	127×10^6 Mwh

The 1985 figure lies slightly above our high case. Another recent post embargo projection by the New England Regional Commission (NERC) Energy Program[8] is shown on Figure 3, upon which we have superimposed our 1985 and 2000 projections. As can be seen from this figure, our forecasts are of the same order of magnitude as the NEPOOL and NERC forecasts.

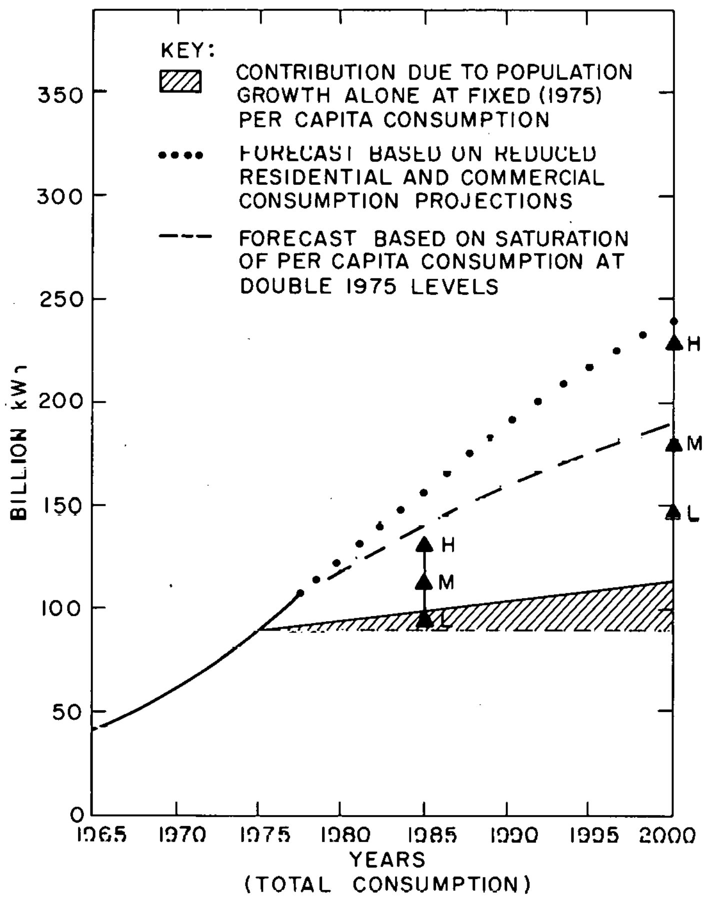


Figure 3. NEPOOL projections. Source: NERC, note 8, p. 127.

3.3 New York Power Pool (New York State, Region III)

The Region II energy projections are displayed on Table 9. The corresponding NYPP estimates of total energy demand in 10^6 Mwh, are as follows:[9]

1975	108	(actual)
1980	132	
1985	160	
1990	194	
1995	230	

These Power Pool estimates are thus seen to be in good correspondence with our own estimates, lying fairly close to our "medium" case.

Table 9

ENERGY DEMAND PROJECTIONS FOR NYPP
(New York, Region II)
(10^{12} Btu/Yr, except where noted)

1985

	Industrial	Residential	Commercial	Total[a] 10^{12} Btu	Total[a] 10^6 Mwh
HIGH	171	192	228	649	190
MEDIUM	145	181	189	566	166
LOW	122	162	164	494	145

2000

	Industrial	Residential	Commercial	Total[a] 10^{12} Btu	Total[a] 10^6 Mwh
HIGH	262	340	483	1195	350
MEDIUM	204	297	354	941	276
LOW	149	243	259	716	210

Source: NPCC, 1976, See Note 7, Chapter VI.

3.4 PJM-CAPCO-APS (Pa., N.J., Md., Del. and D.C.; Region III)

The BNL energy projections for Region III are shown on Table 10. As noted in the introduction, Region III consists of the utilities in MAAC, plus some members of CAPCO and APS serving portions of Western Maryland and Western Pennsylvania and thus comparisons become somewhat difficult. By making the necessary assumptions, however, a variety of data sources do allow an approximation;[10] with the result that current utility projections for 1985 indicate a total electric energy demand of about 330 x 10^6 Mwh, fairly close to our high case. Neither ECAR nor MAAC make projections of electric energy requirement beyond 1985, and thus no direct comparison with our 2000 projection can be made.

Table 10

ENERGY DEMAND PROJECTIONS FOR REGION III

(in 10^{12} Btu/Yr, except where noted)

1985

	Industrial	Residential	Commercial	Total[a] 10^{12} Btu	Total[a] 10^6 Mwh
HIGH	422	310	280	1113	326
MEDIUM	352	293	231	964	282
LOW	290	260	200	825	242

2000

	Industrial	Residential	Commercial	Total[a] 10^{12} Btu	Total[a] 10^6 Mwh
HIGH	673	500	638	1991	583
MEDIUM	510	433	467	1551	455
LOW	372	342	342	1162	340

---

[a] See text.

3.5 Comparisons to Econometric Projections

In view of the now fairly wide use of econometric forecasting approaches, a comparison of our projections with comparable econometric projections is also useful. On Figure 4, we present, for New England, New York, and the Mid-Atlantic regions, respectively, a comparison between our base case and Tyrell's econometric projection.[11] We note a substantial agreement in total projections, within a few percent of each other in all cases; and in individual sectoral estimates, correspondence is also reasonably close.

Finally, on Table 11 we show the regional totals. Also shown, for comparison, is the sum of the 1985 Power Pool Projections as discussed in the earlier sections of this Chapter, and the historical growth projection of Ericson,[12] which extrapolates the 1956-1961 growth ratio.

Table 11

REGIONAL TOTALS
(10^6 Mwh.)

	Low	Medium	High
1985			
BNL	481	556	638
Tyrell[a]		451	
Erikson[a]		925	
Utilities[b]		617	
2000			
BNL	682	900	1159
Tyrell		853	
Erikson		2342	

[a] Interpolated value for 1985.

[b] Based on tabulations in earlier sections.

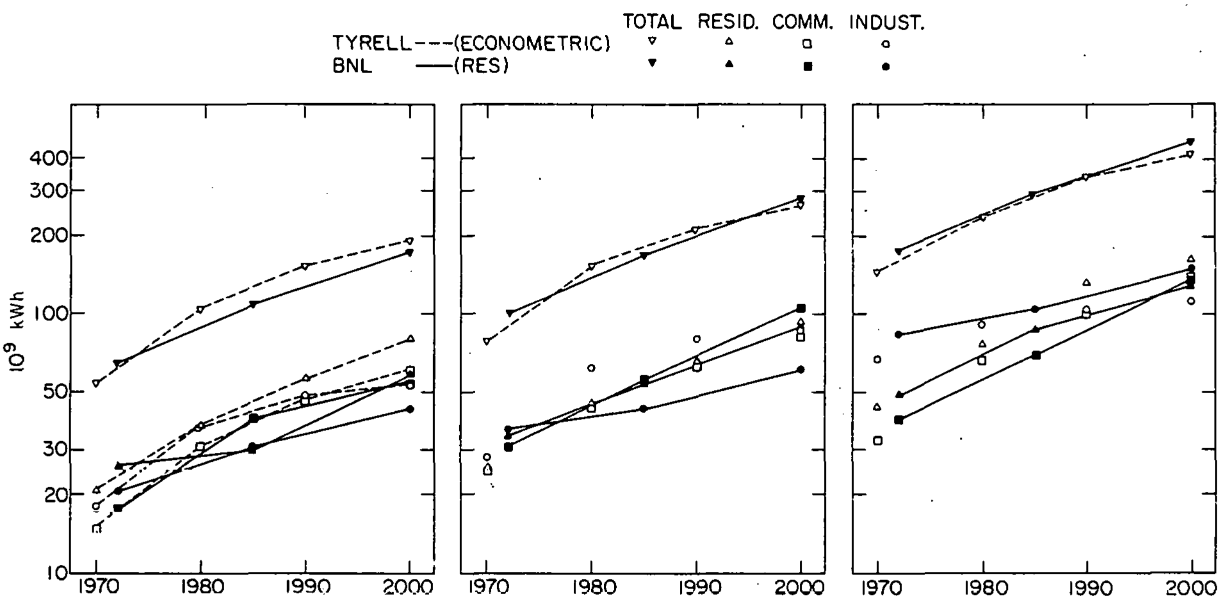


Figure 4. Comparison of BNL and econometric projections.

NOTES TO CHAPTER III

1. R. Goettle, "Alternative Patterns of Industrial Energy Consumption in the Northeast," BNL 50555 (March 1976), Brookhaven National Laboratory, Upton, N.Y.

2. J. Lee, "Future Residential and Commercial Energy Demand in the Northeast," (March 1976), Brookhaven National Laboratory, Upton, N.Y.

3. Northeast Utilities, for example, makes use of the services of Data Resources Inc. (DRI); see "Ten-and-Twenty Year Forecasts of Loads and Resources," Northeast Utilities System (Jan. 1976). For a comprehensive review of the state-of-the-art of econometric load forecasting approaches, see L.D. Taylor, "The Demand for Electricity: A Survey," The Bell Journal of Economics, 6, 1 (Spring 1975) 74.

4. For a discussion of the comparisons between the BNL and Econometric Forecasting approaches, see H. Bronheim, R. Nathans, and

P. F. Palmedo, "User's Guide for Reference Energy Systems," BNL 20426 (Nov. 1975), Brookhaven National Laboratory, Upton, N.Y.

5. As usual, there are exceptions (see, e.g., Northeast Utilities, Note 3, supra). But the reports prepared for the Reliability Councils, the most comprehensive of the uniformly prepared published statistics, is addressed primarily on the immediate 10-year period.

6. For further discussion of planning in the Electric Sector under uncertainty, see, e.g., P. Meier and P. F. Palmedo, "Planning Nuclear Energy Centers Under Technological and Demand Uncertainty," BNL 21205 (April 1976), Brookhaven National Laboratory, Upton, N.Y.

7. Northeast Power Coordinating Council, "Data on Coordinated Regional Bulk Power Supply Programs," FPC Order 383-3, Docket R-362, Appendix A, April 1, 1976.

8. "Electric Power Demand and Supply in New England," New England Regional Commission Energy Program, Technical Report 75-1 (Jan. 1975).

9. See Report of the Member Electric Corporations of the NYPP pertinent to Article VIII, Section 149-b of the Public Service Law, Vol. 1, April 1976, p.31.

10. Especially MAAC System Plans, April 1976, and ECAR Conceptual Planning Projections, April 1976. This published information was supplemented by verbal communications from utilities.

11. T. J. Tyrell, "Projections of Electricity Demand," ORNL-NSF-EP-50 (Nov. 1973), Oak Ridge National Laboratory, Oak Ridge, Tenn. The methodology is described in F. D. Mount, L. D. Chapman and T. J. Tyrell, "Electricity Demand in the U.S.A.: An Econometric Analysis," ORNL-NSF-EP-49 (June 1973), Oak Ridge National Laboratory.

12. L. E. Erickson, "Regional Analysis of the U.S. Power Industry: Vol. 3: Regional Demand Analysis and Consumption Forecast," BNWL-B-415V3 (June 1975), Battelle Pacific Northwest Laboratories, Richland, Wash.

THIS PAGE

WAS INTENTIONALLY

LEFT BLANK

CHAPTER IV

ISSUES IN CAPACITY FORECASTING

4.1 System Load Factors

The time distribution of the energy demand projected in the previous section is the first of the many significant factors linking energy demands to capacity needs. An important characterization of the time characteristics of energy demand is the annual load-duration curve, which shows the number of hours per year that a specified capacity is required. Figure 5 shows such a curve for the Baltimore Gas and Electric Company, the utility serving the Baltimore Metropolitan Area.[1] The area under the curve represents total annual energy generation, E_a, and the relationship of this quantity to the peak system load is given by the annual system load factor, SLF_a, defined as

$$SLF_a = \frac{E_a}{Mw_p \; 8760}$$

where SLF_a is the annual system load factor[2]

Mw_p is the system peak load, in Mw

E_a is the annual Energy Production, in Mwh

For example, the 1967 Baltimore Gas and Electric Company peak load was 2130 Mw, with 10,693,000 Mwh generated; hence the system load factor was .573.

Most utilities in the Northeast, in fact, have system load factors in the general range of .55 to .65; and over the past decade these load factors have increased somewhat. Figure 6 shows, for example, the increase in the annual load factor for the New England Utilities over the last 10 years; this increase is generally attributed to the increased use of air conditioning in New England, which has brought the summer subpeak to the level of the maximum winter peak. It is somewhat doubtful, however, whether such increases can

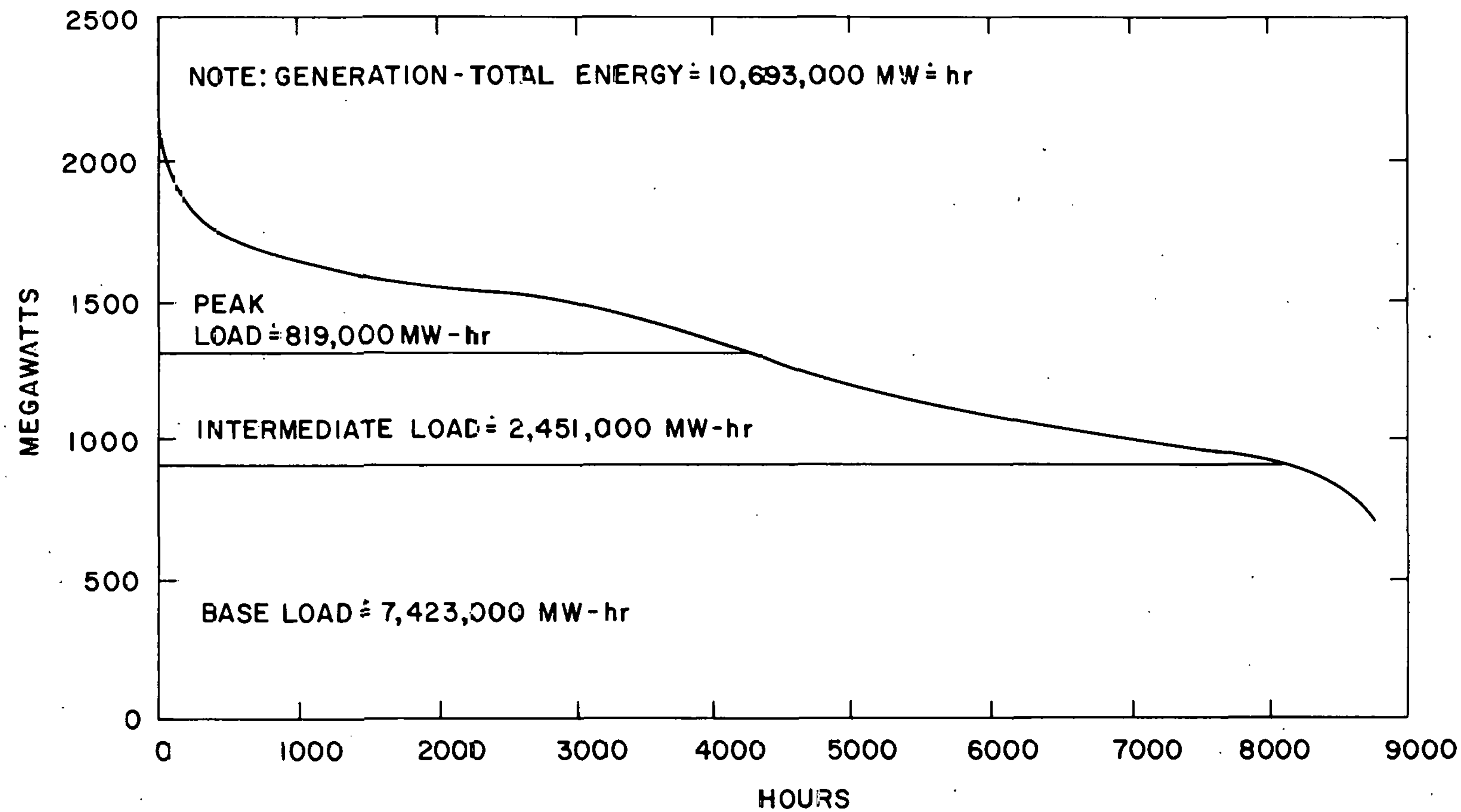


Figure 5. 1967 load duration curve, Baltimore Gas and Electric Company.

be sustained; and there is some uncertainty as to future system load factors. To be sure, some utilities are attempting to promote the use of off-peak electricity, both on a daily and seasonal basis; but the success of these efforts is linked primarily to the relative importance of the industrial use sector, which represents the largest potential market for off-peak power. Similarly, many of the load management strategies currently being proposed are directed toward the use of off-peak electricity; but again a quantitative forecast of load factor increases resulting from the implementation of specific measures is very difficult.

The weather sensitive portion of the total load, especially for space heat and air conditioning, and the resulting seasonal variations in load, thus play an important part in determining system load factors. In the New York Metropolitan area, where summer and winter peaks were roughly equal in 1960, the sharp increase in air conditioning has resulted in a distinct summer peak. In fact, load factors in the Consolidated Edison system have not decreased much over the past few decades, despite this increase in air conditioning; but this must be attributed to the aggressive promotion of electric space heat in winter to offset what would otherwise have been a more significant decline in load factor.

One might also note that simple conservation measures may decrease rather than increase system load factors. For example, the Consolidated Edison system in New York City experienced a drop of system load factor from 50.3% in 1973 to 48.7% in 1974, which is attributed to a decreased use of air conditioning on most summer days when not regarded as essential, but unchanged peak use on the few really hot and humid days. Indeed, Con Ed projects a further decline of system load factor to 47.5% by 1985.[3]

The issue of load factor is not just one of improving the utilization of system capacity, but it also has great bearing on the optimum generation mix of an electric system. This is illustrated by Figure 7, which summarizes the results of a recent study by Jordan et al.[4] using a generation planning program developed by General Electric[5] (which is used by a number of utilities in the

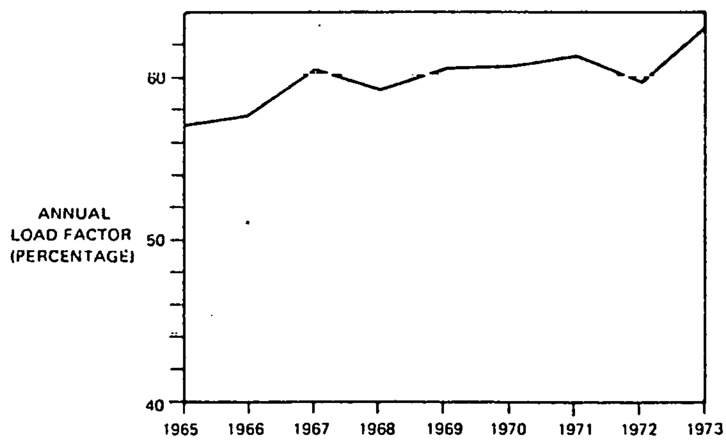


Figure 6. Average annual load factor for New England for 1965-1973. Source: Electric Utility Industry in New England; Statistical Bulletin 1973, Electric Council of New England, August 1974.

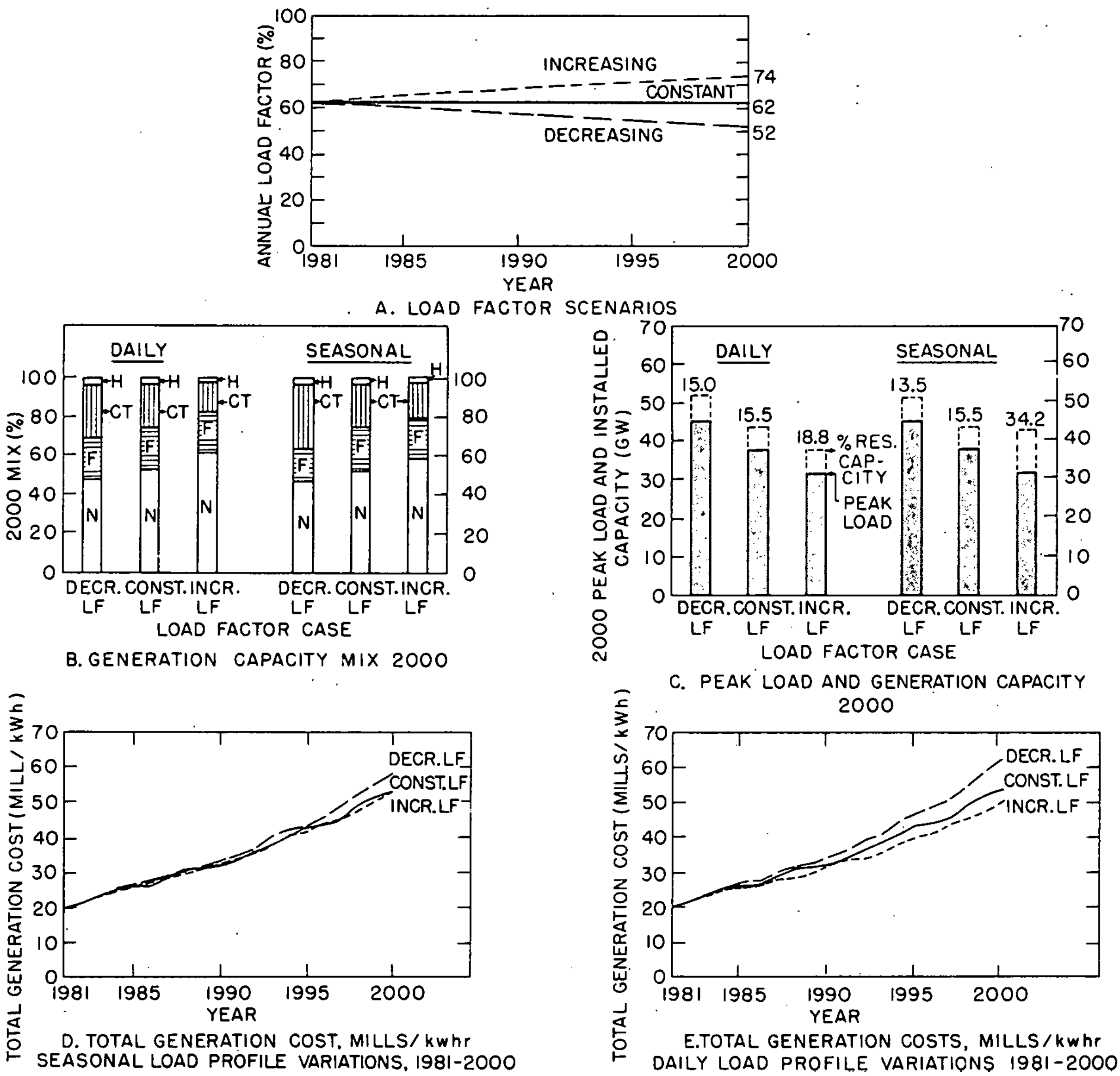


Figure 7. Impact of load factor on system planning.
Source: Jordan et al, note 4.

Northeast for planning purposes). Using this program to develop optimal 20-year capacity expansion plans for a representative (if hypothetical) system to a prescribed level of reliability under three different load factor scenarios for both daily and seasonal load variations (Figure 7, A.) resulted in the generation mix and load-capacity configurations as shown on Figure 7, B. and 7, C.[6] One sees, for example, that the installed reserve requirement necessary to maintain 1 day in 10 years loss of load probability (more of which below, in Section 4.3) increases from 15.5% in the base case to 34.5% in the increasing seasonal load factor scenario. As noted by Jordan et al., this indicates that as seasonal peak loads increase relative to the annual peak, increased installed reserves must be provided to allow adequate capacity to schedule necessary planned maintence because less "off peak" time is available for this purpose. Whereas in the base case or constant 62% load factor case maintenace was not being performed during the time of the annual peak, the increasing load factor scenarios did require that maintenance be scheduled year around. This effect is illustrated by Figure 8, showing the so called "maintenance window" as that part of a system's annual load curve which is sufficiently below the installed capacity level that units can be taken offline for maintenance without increasing the probability of load loss. However, as system load factors improve, and the annual load curve levels out, the maintenance window decreases. This could result in higher reserve margins being necessary, or less maintenance being performed (which in turn would lead to higher forced outage rates and hence also to an increase in requisit reserve margin).[8]

The results of Figure 7 also show that management of the daily load profile offers a greater potential impact on power generation costs than the seasonal load profile; although any given system would need to be carefully studied before generalized conclusions be held universally applicable.

4.2 Forced Outage Rates, Scale Economies and Unit Plant Size

Outage rates have great bearing on electric system planning in that the amount of reserve capacity required to maintain a given level of service reliability is a function of the availability of generation units. And, more obviously, the lower the outage rate,

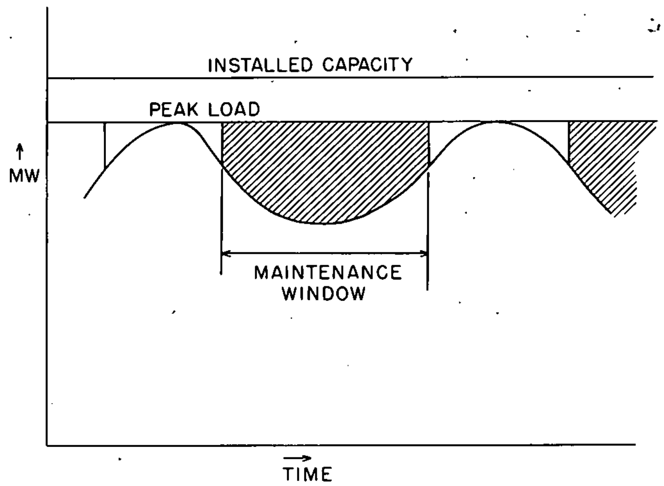


Figure 8. Maintenance window. Source: FPC, note 8.

the better is the utilization of a given piece of equipment. In general, the concern lies with so called forced outages, and the forced outage rate which is defined as

$$\frac{\text{hours on forced outage}}{\text{hours on forced outage + hours on line}}$$

whereby the days devoted to maintenance and economy shutdown are omitted from the denominator. The overall percentage availability of generation units is generally defined as

100	-	percentage of time on forced outage	-	percent of time on planned outage (or scheduled maintenance)	-	percent of time on maintenance outage

where a maintenance outage is defined as work done to prevent a forced outage, and which cannot be postponed from season to season. Scheduled maintenance, however, would be for such items as nuclear plant refueling or annual maintenance planned for off-peak seasons.

One of the controversial issues now being debated is the question of the relationship between unit size and forced outage rate, and whether or not significant differences in outage rates exist between fossil and nuclear units. If in fact larger units do have higher outage rates than smaller units, then scale economies that exist at the plant level may be offset by scale deseconomies at the system level because higher levels of reserve margin would be necessary to maintain prescribed levels of reliability in a system consisting of larger rather than smaller units. In fact, even if outage rates of larger units were the same as of smaller units, reserve margins would need to be higher in a given system of larger units than a system supplying the same load that consisted of smaller units. However, by interconnecting systems of large units, reserve margins come down again. Some published studies come to conclusions that if one takes into consideration these balancing forces, the optimally sized unit is in the 600-800 Mw range, much lower than the size range currently considered by many utilities.[9] On the other hand, the utilities point out that the data upon which such conclusions are based may be suspect; especially in regard to design and operating maturity. Since many of the large units are also very new units, some of them may still be in the shakedown phase (and have not yet reached operating maturity).[10] Similarly, since those large units that have accumulated a number of years of operating experience would tend to be those built first, they would not incorporate design features that are part of more recently built plants (i.e., the data do not reflect design maturity either).[11]

These points are well illustrated by the forced outage rate (FOR) experience of a series of coal-firec units recently built by American Electric Power (AEP), units of 1300 Mw size, currently the largest in the U.S., and of the so-called supercritical design.[12] Figure 9, adapted from Tillinghast and Dolan,[13] shows the FOR for the Amos 3, Gavin 1 and Gavin 2 units, which started commercial operation in October 73, October 74, and July 75, respectively. Design changes in Gavin 1, and later in Gavin 2, are reflected by drastic improvements in availability, illustrating quite clearly the impact of design maturity. And the curve for Amos 3 also illustrates the impact of operating maturity, with the forced outage rate exhibiting the earlier stages of the "bathtub" curve.[14]

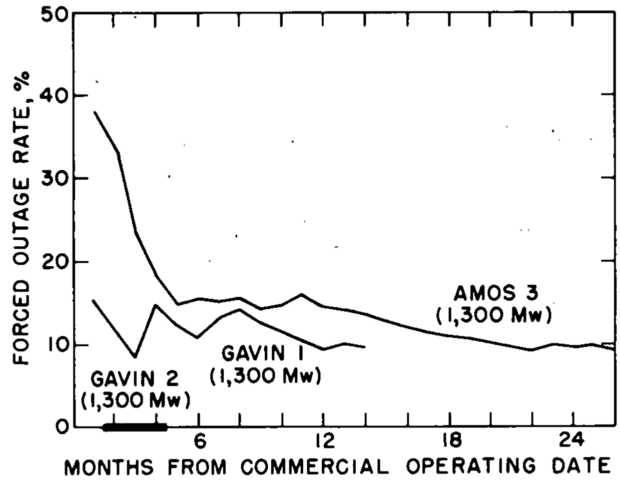


Figure 9. Forced outage rates at AEP's 1300 Mw fossil units. Source: Tillinghast and Dolan, note 13.

The most recent Annual Report of the Federal Power Commission, published in January 1976,[15] includes two tables of outage data as reported by the Edison Electric Institute, reproduced here as Tables 12 and 13. The FPC notes rather tersely that " ... while trends from these data cannot be established with confidence, it does appear that larger units are less reliable than smaller ones."[16] It might also be noted that some utilities themselves also recognize this relationship; Figure 10, showing forced outage rate assumptions as a function of age and size, is taken from an analysis used by NEPOOL generation planning studies.[17]

These points notwithstanding, it should be clear that the subject merits further analysis. Only a rigorous statistical analysis of complete, month-by-month unit reliability data, in which many of the interrelated factors that might affect outage rates are included, can address the debate in an objective way. Moreover, as noted by one recent survey of nuclear plant reliability data,[18] a serious problem in such analysis is the discrepancies in data

Table 12

Average Forced Outage Rates of all Generating Units as Reported by Edison Electric Institute

Forced outage rate[1] in percent

Period	Nuclear steam	Fossil steam	Gas turbine	Jet engine	Diesel engine	Hydro Conventional	Hydro Pumped
1960-69[2]	9.2	3.6	21	30	23	1.1	2.4
1960-70	8.2	3.9	23	31	27	.7	1.7
1960-71	8.4	4.1	24	37	26	.7	10
1960-72	7.6	4.4	26	37	26	1.0	15
1960-73[2]	8.2	4.6	29	38	28	1.2	13

[1]Forced outage rate = $\frac{\text{Forced outage hours}}{\text{Running hours + forced outage hours}}$ X 100 percent.

[2]Note that this is a 10-year cumulative period.

Table 13

Average Forced Outage Rates of Fossil Steam Generating Units as Reported by Edison Electric Institute

(By size groups (forced outage rate in percent))

Period	60-89	90-129	MW size 130-199	MW size 200-389	390-599	600-1400
1960-69	1.4	2.9	2.7	3.9	8.3	12.5
1960-70	1.5	3.2	2.8	4.2	8.0	15.7
1960-71	1.7	3.3	2.9	4.4	8.3	16.8
1960-72	1.7	3.3	3.1	4.7	8.7	16.6
1964-73	2.0	3.5	3.3	4.9	8.9	16.5

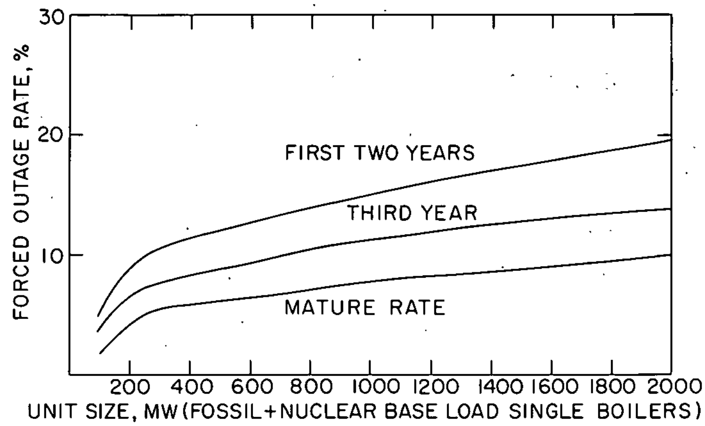


Figure 10. Outage rate assumptions. Source: Barstow et al, note 17.

sources, a resolution of which should obviously be the first order of business.[19]

As a final comment on the reasons for the growth in unit plant size, and indeed for the growing tendency for multiple units at the same site, two major factors can be postulated. The first, obviously, rests on the scale economies that exist at the unit scale. The second is based on the rapid developments in the regional transmission grid, allowing joint ownership of large units. Thus, utilities whose load growth would otherwise be too small to warrant construction of thier own large units can benefit from scale economies. Indeed, multiple ownership of units has become quite widespread in the Northeast, as indicated by Table 14; in the MAAC area, for example, the majority of base load plants built in the last decade are owned by at least two utilities.

4.3 Reserve Margins and System Reliability

Although reserve margin is often used as a gross measure of system realiability,[20] a more precise measure of generation reliability is the so-called loss of load probability (LOLP). This is

Table 14

JOINT OWNERSHIP OF GENERATING UNITS IN MAAC

Generating Stations	PSEG	JCP&L	ACE	PE	PP&L	PENELEC	ME	UGI	DPL	BGE	PEPCO
Operating											
Conemaugh (1700 Mw-coal-fired) W. Wheatfield Twp. PA	22.5		3.8	20.0	11.4	x-o	17.2	1.1	3.7	10.6	9.7
Homer City[a] (1200 Mw--coal-fired) Homer City, PA						50.0 x-o					
Keystone (1640 Mw--coal-fired) Plum Creek Twp. PA	22.8	16.7	2.5	21.0	12.3	x-o			3.7	21.0	
Peach Bottom (2200 Mw--nuclear) Peach Bottom, PA	42.5		7.5	42.5					7.5		
Three Mile Island (1700 Mw-nuclear) Londenderry Twp., PA		50.0				25.0	25.0 x-o				
Yards Creek (330 Mw-pumped-hydro) Blairstown, NJ	50.0	50.0 x-o									
Under Construction											
Forked River[b] (1100 Mw-nuclear) Lacey Township, NY		88.0 x-o	10.0								
Salem (220 Mw--nuclear) Lower Alloways Creek Twp., NJ	42.6 o		7.4 x	42.6					7.4		
Planned											
Atlantic (2300 Mw--nuclear) Little Egg Inlet, NJ	80.0 o	10.0	10.0 x								
Hope Creek (2200 Mw-nuclear) Lower Alloways Creek Twp., NJ	90.0 o		10.0 x								
Summit (1540 Mw--nuclear) New Castle, DE				15.0					85.0 x-o		

x - denotes generating station is within company's service territory.

o - denotes company responsible for construction and/or operation of generating station.

[a] New York State Electric and Gas Corporation owns half interest.

[b] Anticipated 2% ownership by Allegheny Power Cooperative, Inc.

Source· Meier & Morell, note 37

defined as the probability of occurrence of a system demand that exceeds system capability, and is often defined in terms of the yearly recurrence interval of a daily outage. Thus, LOLP of 0.1 signifies that a loss of load is expected on one day in every ten years.[21] Then, given the LOLP criterion, and the complete characteristics of the generation and transmission system, (including such factors as outage rates, the size of the system, and the degree of transmission connection within the system), one may compute the necessary reserve margin in generation capacity to maintain the given probability.[22] Table 15 shows, by way of example, the computed reserve margins necessary in the New York Power Pool for given LOLP.

Table 15

Reserve Margins in the NYPP as a Function
of Loss of Load Probability

$ISR = \frac{1}{LOLP}$	LOLP	Reserves as a Percent of Peak
1	1.00	14.5
2	0.50	16.2
3	0.33	17.2
4	0.25	17.8
5	0.20	18.5
6	0.17	18.6
7	0.14	19.2
8	0.13	19.4
9	0.11	19.8
10	0.10	20.0

Source: Kaufman, Note 19, p.11.

The current reliability norm in the electric utility industry is a LOLP of 1 day in ten years, resulting, in most systems, in a reserve margin that lies between 20 to 30 percent. But, in recent years, the question has been raised as to the justification of the 1 day in 10 years figure. Why not 1 day in 5 years, or, indeed, 1 day in 20 years? Interest in this issue stems from two further questions: the relationship between LOLP (or reserve margin) and consumer rates, and the relationship between loss of load due to generation capacity inadequacy, and the loss of load due to failure in other portions of the system.

The first question has recently been taken up by Public Utility Commission staff, and particularly by Kaufman in the case of New York.[23] Kaufman noted from the results of Table 15 that a reduction in reliability from 1 day in 10 years (ISR = 10) to 1 day in 1 year (ISR = 1) would result in a 5.5% reduction (20% to 14.5%) of reserve margin. This same reduction would reduce the necessary installed capacity in the year 2000 in the NYPP from 62.9 Gw to 60.0 Gw, implying, for example, that 2 or 3 currently planned nuclear units would not be required. However, Kaufman also noted that when the economic costs and benefits of various reliability criteria were examined, the consumer would benefit very little; a reduction from a 20.0% to 14.5% reserve margin would bring only a 2% reduction in rates after 12 years.[24] Another recent study by Telson[25] that attempted to balance the costs of excess capacity against the revenues lost in a system outage found that a 5 day in 10 year criterion would represent a more reasonable reliability target. But as we shall discuss below, LOLP is an incomplete measure of system reliability, and many power pools are using operating procedures more sophisticated than the use of a single point reliability measure would suggest.

It should be noted further that utilities also add capacity for reasons other than improving reliability, and may choose to add capacity even in face of constant or declining load for reasons of overall system economics. Thus, the existance of a reserve margin in excess of what would be required for a particular reliability norm should not necessarily be interpreted as poor management or excessive utility preoccupation with quality of service (the implications, for example, of Telson's analysis). For example, Northeast Utilities, which in 75/76 had a very high reserve margin of 81.2%[26] made careful studies with respect to continuing or delaying Millstone #2, and decided to continue on schedule even in face of temporary decline and stagnation of system load requirements (the 81.2% figure includes Millstone #2, through still under test). The reason for this is that the economies of nuclear generation vis-á-vis the oil fired capacity that would otherwise have been used are such that total revenue requirements of the system was expected to be reduced by almost $200 million, despite a further increase in reserve margin.[27] Thus the currently high reserve margins of some Northeastern power pools and utilities, as shown on Table 16, should be viewed not just as a consequence of the load growth perturbations that followed the 1973 embargo, but also in terms of the relative costs of nuclear and oil fired generation.

Table 16

Reserve Margins in the Northeast

Power Pool	Reported Reserve Margin, 1975 Peak	Anticipated Margin 1985
NEPOOL[a]	45	26
NYPP[b]	33	24
PJM[c]	29	29
Northeast Utilities	81[d]	29

[a] See NPCC, note 33.

[b] See NYPP, note 34.

[c] See MAAC, note 35.

[d] See Northeast Utilities, note 26. The figure for the 1975/1976 winter peak includes the 830 Mw of Millstone 2, that was actually still under test.

As noted previously, there is some difficulty in using a single point estimate of system reliability, such as LOLP. From the utility standpoint, a more meaningful basis of generation reliability is expressed in terms of risk of exposure to a whole series of actions in an operating procedure for conditions where generation is short; as shown on Table 17, this ranges from a change in reserve status,

Table 17

NEPEX Emergency Operating Procedure

(from Bigelow, note 28)

Normal operating procedure with the New England Power Pool requires that an operating reserve be available to the NEPEX dispatcher as follows:

1. Five-minute reserve - Reserve capacity equal to the largest loading of any unit connected to the system must be available to the dispatcher within five minutes of any contingency.

2. Thirty-minute reserve - Reserve capacity equal to 0.5 times the largest loading of any unit on the system must be available to the dispatcher within thrity minutes of any contingency.

Presently, the largest rated unit on the NEPOOL system is 767 mw; so that the total operating reserve (5-minute plus 30-minute) which should be available under normal operating conditions is 1.5 x 767, or 1,150 mw.

NEPEX has set up an emergency operating procedure (No. 4) to provide a series of actions which will be taken on the system if capacity margins are reduced below acceptable levels and there is insufficient generation to meet the load. These actions can be summarized in four steps, which are shown graphically on Figure 13 and are tabulated below:

Tablulation of NEPOOL Emergency Procedures

Step 1 is a series of actions which the dispatcher can take to mobilize all possible sources of supply but which will not be perceived by the public as having any direct impact on their service. These include bringing the thirty-minute reserve to five-minute status and arranging for all sources of emergency capacity which can be obtained from neighboring pools or from possible industrial sources. If loads grow, no further action will be taken until the thirty-minute reserve has gone to zero and the five-minute reserve has been reduced to a point that to cover the loss of the largest single unit would require remaining capacity plus relief which can be obtained by voltage reductions and removal of interruptible loads which can be effected within five minutes.

Step 2 involves actual implementation of voltage reductions of up to 5% and curtailment of contractually interruptible loads. As indicated on Figure 13, NEPOOL estimates at the time of the study were that, with a 13,000 mw peak, approximately 300 mw of relief could be realized by this method. From this point on, no further action will be taken if loads grow until the five-minute reserve is one-third of the unit, or 255 mw in this case.

Step 3 is the next level of action, which represents a substantially more significant impact on service to the public. It involves specific requests to major commercial and industrial customers to curtail load, cutback production, or even shut down on a voluntary basis. It also includes direct appeals to the public by radio and TV. It has been estimated that a little less than 500 mw of relief can be achieved by these means.

Step 4 is the final and most drastic step available when all other means of relief have been exhausted. It involves implementation of a specific program to disconnect customers directly, in order to maintain the energy balance and the integrity of the system. It is not planned to go this last step until the operating reserve approaches the zero mark. Obviously, as the system approaches this condition, its ability to withstand transient distrubances and avoid cascading blackouts has been greatly diminished by the gradual elimination of its operating reserve. This is the level upon which we are basing our design and which we have stated should not be permitted to occur more often than once in ten years.

an action not felt by the consumer, to actual disconnection of consumers.*

A useful concept in understanding generation reliability is the cumulative margin distribution function, whose derivation is illustrated on Figure 11. For a given system and a peak weekday, probability density functions can be derived for both demand and for system generation capability (Figure 11A). These two density functions can be combined to form a margin density function, which defines the probability of existence of a certain margin. LOLP, in its dimensionless probability definition, is then simply the area under the curve to the left of the zero margin point, as shown on 11B; the probability of some other margin is simply given by the integral from minus infinity to that margin, also as illustrated on Figure 11B. Indeed, integration of the margin density function results in the cumulative margin distirbution function (Figure 11C)--here the LOLP is given by the intercept of the curve with the y-axis.

The quantitative relationship between reserve margin and risk exposure, based on actual computations for the NEPOOL system, is shown on Figure 12. The horizontal axis of Figure 12 represents incremental changes in percent reserve above and below a reference value which is required for a specific risk level. The zero or reference reserve corresponds to a risk level not to exceed one day in ten years disconnecting customers and thereby interrupting load. This is a risk level which the NEPOOL Planning Committee is currently using as a basis for generation planning in New England. Given the uncertainties of the computations, the frequencies are shown in bands; thus, in the given base case the estimated frequency of having to disconnect customers due to a shortage of generating capacity falls between .05 and .1 day per year (i.e., once in ten to twenty years). Corresponding to this risk (moving vertically), the estimated frequency of radio and TV appeals and request for voluntary reductions by large customers is between .4 and .8 days per year (1 day in 1.2 to 2.5 years); and the estimated frequency of

*This discussion leans very heavily on a recent paper by Bigelow, note 28.

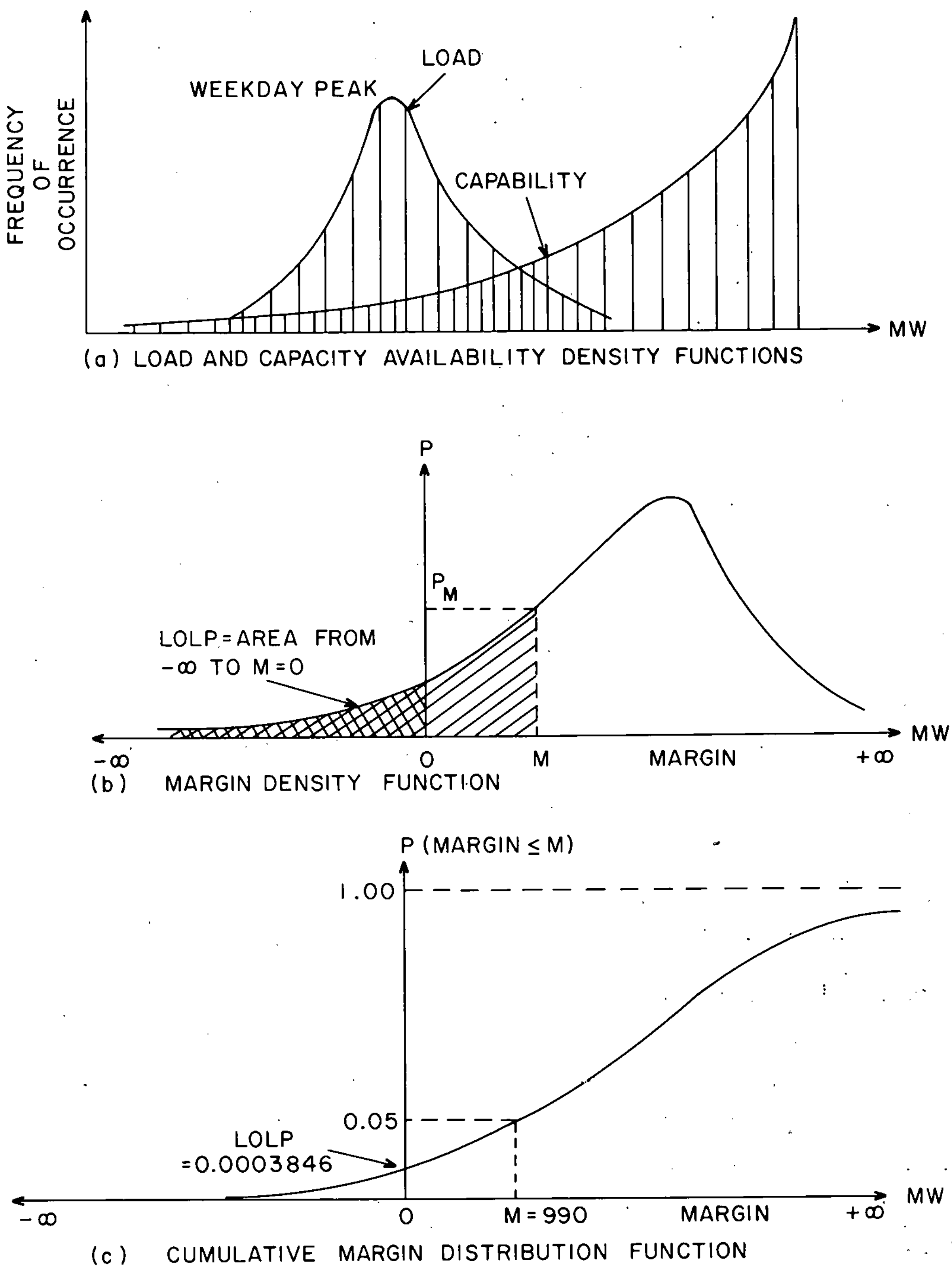


Figure 11. Definition of loss of load probability.
Source: Bigelow, note 28.

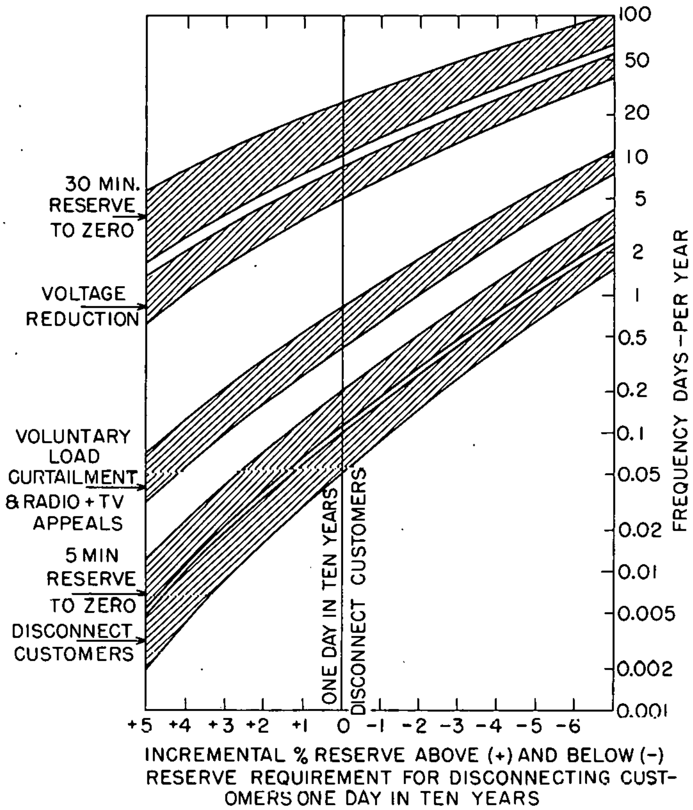
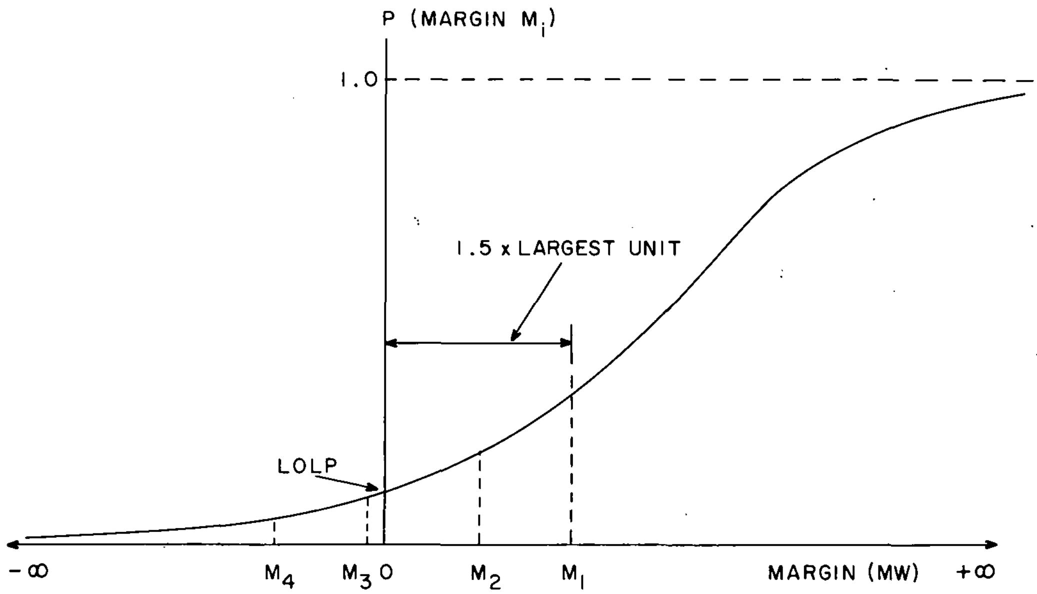


Figure 12. Risk exposure. Source: Bigelow, note 28.

voltage reductions and curtailment of interruptible loads is five to eight times per year.[29]

Suppose that one were to examine the impact of a reserve margin 5 percent less than that corresponding to disconnection on 1 day in ten years--for which one would move along the horizontal axis to the -5% point, and then move vertically upwards to ascertain the corresponding risk exposure levels. For this particular case, one would obtain a disconnection frequency of .4 to 1 times per year, and a voltage reduction 22 to 32 days per year. Note that the steps of Table 17 can also be plotted on the cumulative margin distribution function, as shown on Figure 13.

In summation then, we note the following. First, given a day in 10 years frequency of involuntary disconnection, NEPOOL is in fact



MARGIN	OPERATING PROCEDURE
M_1 OR LESS	STEP 1 - REDUCE OPERATING RESERVES
M_2 OR LESS	STEP 2 - VOLTAGE REDUCTIONS AND INTERRUPTIBLE LOADS
M_3 OR LESS	STEP 3 - INDUSTRIAL CURTAILMENTS AND APPEALS TO THE PUBLIC
M_4 OR LESS	STEP 4 - DISCONNECT CUSTOMERS

Figure 13. Operating procedures and margin distribution. Source: Bigelow, note 28.

operating under an approximately 1 day in 1 year loss of load probability criterion. Second, in terms of addressing criticisms that a one day in 10 years disconnection frequency is too conservative, one should note that the distance of the "disconnect customers" band beneath the "voluntary load curtailment and radio and TV appeal" band is at least in part a function of the effectiveness of such appeals. It seems reasonable to assume that the effectiveness of such appeals is inversely related to their frequency; repeated appeals over a short time span obviously have less impact than only occasional appeals.

The NEPOOL Planning Study upon which these computations were based also illustrates very well the impact of interconnection and maintenance scheduling of reserve margin, again given some prescribed level of reliability. Figure 14 shows required reserves for New England to meet 1 day in 10 years disconnecting customers for four

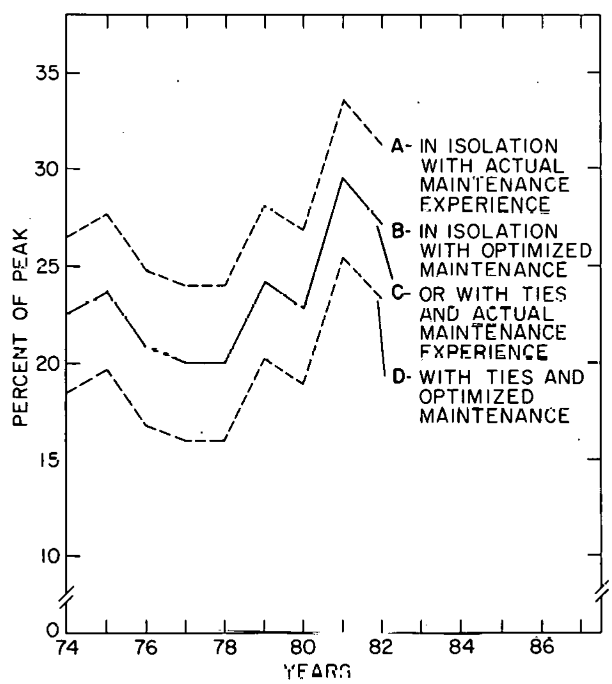


Figure 14. Impact of maintenance and interties in reserve margin. Source: Bigelow, note 28.

different cases: (a) NEPOOL in isolation, (b) NEPOOL in isolation but with optimized maintenance, (c) NEPOOL with actual maintenance experience with interconnections,[30] and (d) with interconnections and optimized maintenance. Curves b and c proved to be virtually identical, but the decrease in requisite reserve margin with optimized maintenance scheduling and inter-ties is clear.[31]

The issue of generation system failure versus transmission and distribution system failure is also not answerable in simple terms. While it is true that the most likely source of failure to the consumer in the Northeast is due to distribution system failure during severe storms, such disturbances tend to be highly localized, quite in contrast to the regional consequences of a generation capacity inadequacy. Moreover, in terms of the public perception of quality of service, disruptions caused by severe weather are more likely to be perceived as "acts of God" than as indications of utility management deficiencies, whereas brownouts and blackouts create rather serious public relations problems for the utilities. Moreover, since it is primarily residential customers who are affected by winter storms (they are the class of customer most likely to be served by overhead sub-transmission and distribution lines that are the principal victim of winter storms), their economic losses due to such failures are, in all likelihood, smaller than the losses suffered by commercial and industrial concerns affected by voltage reductions and disconnections due to system-wide generation inadequacies. Nevertheless, as noted above, much analytical work remains on the study of the trade-offs between reliability and economic impact, and clear conclusions are not possible at the present time.

As a final comment, one might note the relationship between demand projection uncertainty and reserve margin. Figures 15 and 16 show two sets of projections; one made in April 1974, before the conservation impact of the oil embargo induced price rises were felt, the other made in January 1975, at which point the impact on consumption had become more clear. The utilities were quick to delay or even cancel many new units, as the loss of revenue due to the joint effect of conservation by consumers and the recession imposed severe financial pressures. Utility concern now, however, is with the possibility that consumption and demand patterns will return to

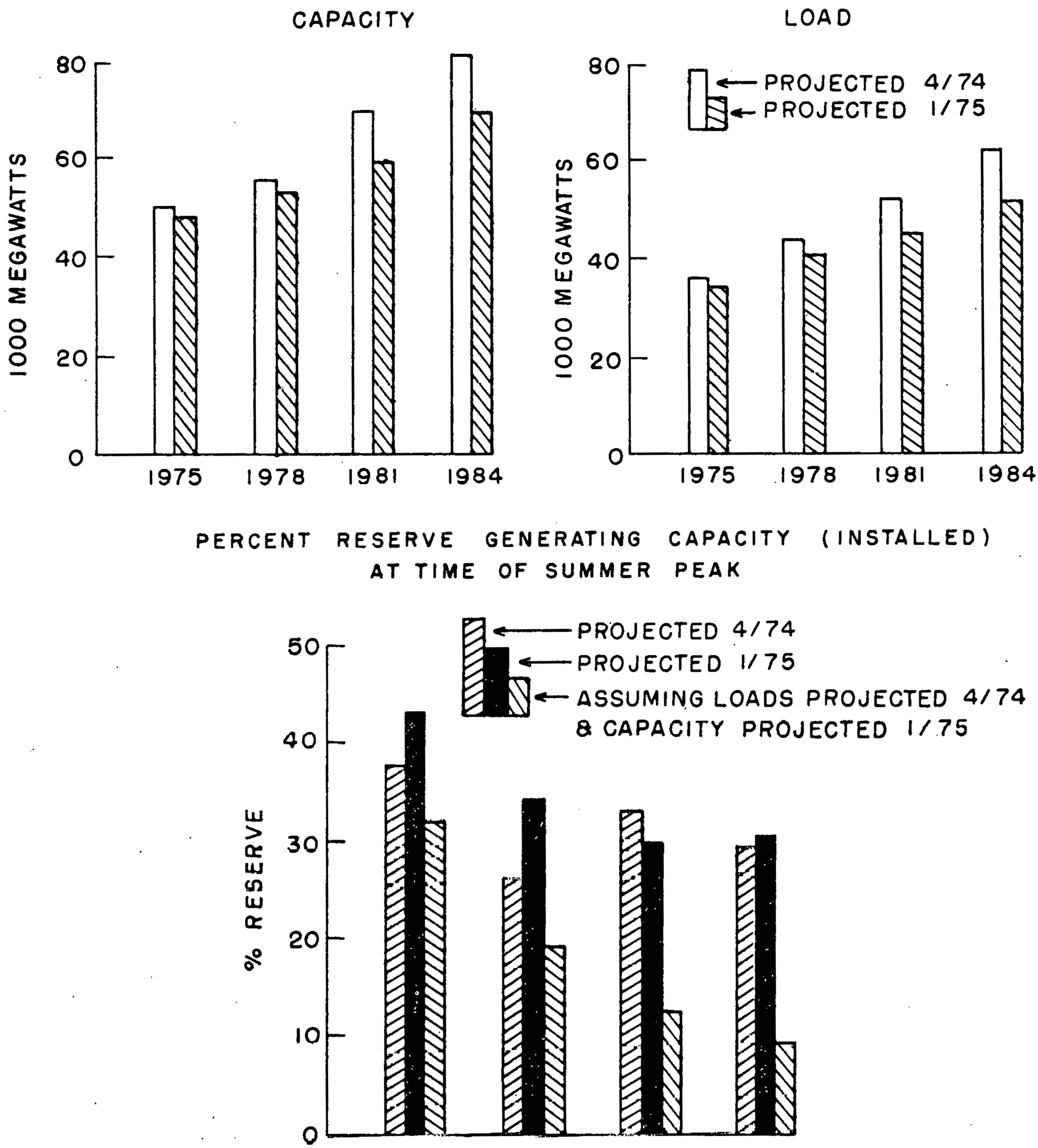


Figure 15. Reserve margins in NYPP. Source: NERC, note 36.

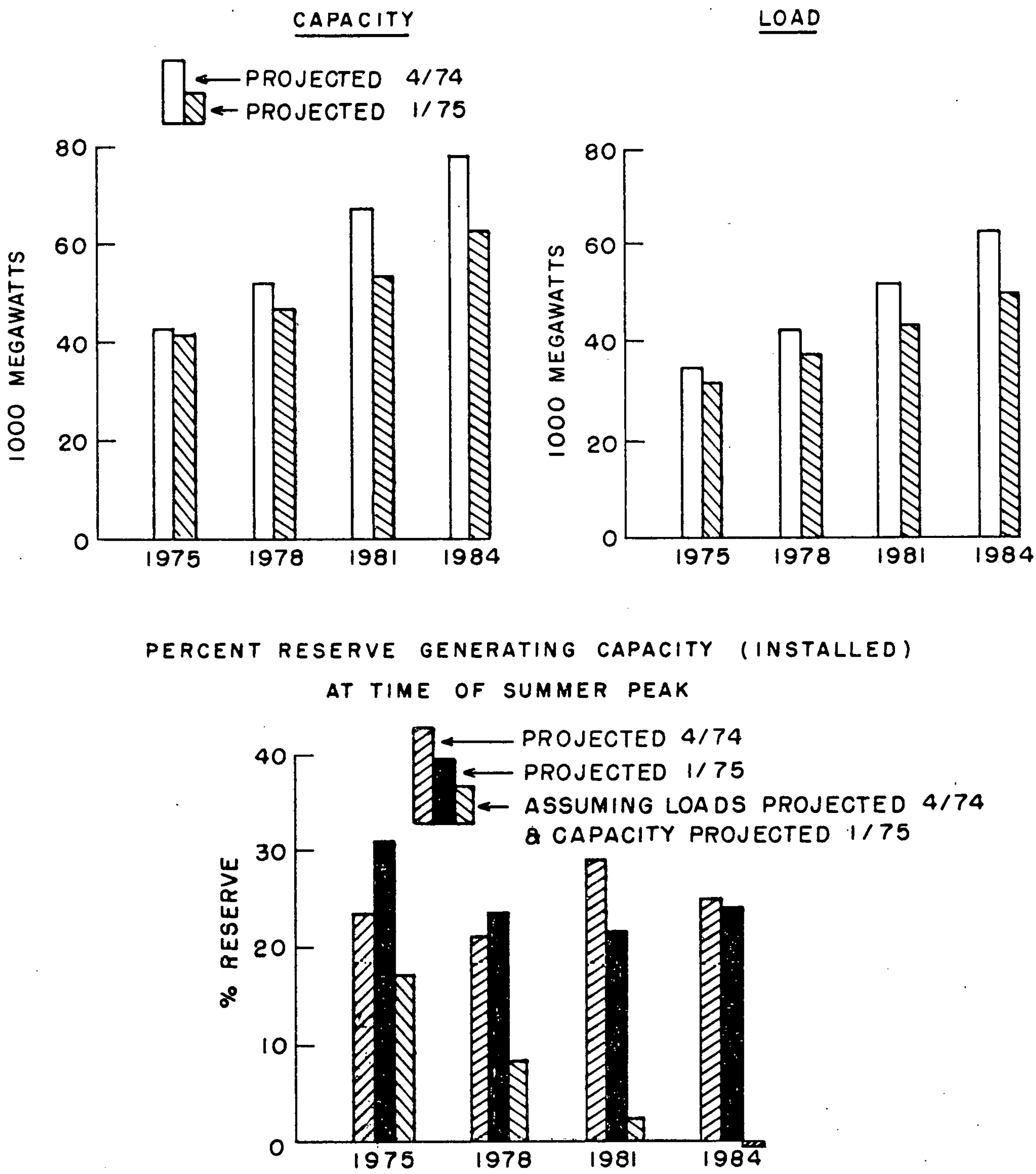


Figure 16. Reserve margins in MAAC. Source: NERC, note 36.

typical pre-embargo levels, with the result that reserve margins would be severely reduced because of the long lead time for construction of new capacity. Figure 16, for example, shows the effect of assuming 1974 load projections on 1975 capacity projections, indicating a severe reliability problem by the early 1980's. This, of course, emphasizes the urgency of being able to reduce the long lead time for new capacity, as that would then allow a more flexible planning policy, as discussed further in Chapter VII.

4.4 Generation Mix Planning

The determination of the optimal combination of different modes of generation (or "generation mix") is one of the most difficult tasks faced by the utility planner. In recent years the development of sophisticated planning tools has proceeded very rapidly and most utilities and power pools are now using computer simulation modeling as the basic tool for the determination of optimal capacity expansion and generation mix planning. Mathematical programming methods have also seen greater application in recent years, methods which serve to complement the simulation models for screening of alternatives, and for sensitivity analysis.

Although a full description of even a few of the most widely used models goes well beyond the scope of this report, a brief outline of some of the fundamental principles of generation mix optimization is indicated. The models now being used by electric utilities are considerably more complex than the following outline might suggest, but they nevertheless rest upon the same fundamental principles.

The essential feature of an optimal generation mix is that its composition of plants minimizes the levelized annual kilowatt-hour cost. In general, capital and operating costs of the various generation types are inversley related--at one end of the spectrum are base load nuclear units, having the highest capital requirements per unit of capacity, but with the lowest fuel and operating costs per unit of electricity produced; and at the other stand combustion turbines, with the lowest initial capital cost, but, due to inefficient use of fuel, also having the highest operating cost per kwh. Following Baughman and Joskow,[32] the average cost per unit of output can be expressed as follows:

$$AC = \frac{100\ k_1a + 100\ F}{U} + \frac{k_2\ H_r}{10^6} + O_c$$

where

AC = average costs in cents per kwh
k_1 = capital cost (dollars/kw)
a = annual write-off rate (1/year)
F = fixed operation and maintenance costs (\$/kw/year)
k_2 = fuel cost (cents/MM Btus)
H_r = heat rate (Btus/kwh)
U = utilization factor (hours per year)
O_c = variable operation and maintenance costs (cents/kwh).

Suppose three different types of generating units are available, varying conversely with respect to capital and operating costs. Then the average costs curves for each generation mode, plotted as a function of utilization, might be as shown on Figure 17. The minimum cost curve is given by the lower envelope of these curves, as indicated.

Now suppose that the load duration curve for the system under consideration is as given on Figure 18. The optimal capacity of each type of generation, defined as that mix which meets the load duration characteristics at minimum cost, is given by the points U_{pc}, U_{cb}, which are taken directly from the intersection points of the average production costs curves of Figure 17. It can be shown that these intersection points are given by

$$U_{cb} = \frac{100\ (k_1{}^b a + F^b - k_1{}^c a - F^c)}{\dfrac{k_2{}^c H_r{}^c - k_2{}^b H_r{}^b}{10^6} + O_c{}^c - O_c{}^c}$$

and

$$U_{pc} = \frac{100\ (k_1{}^c a + F^c - k_1{}^p a - F^p}{\dfrac{k_2{}^p H_r{}^p - k_2{}^c H_r{}^c}{10^6} + O_c{}^p - O_c{}^c}$$

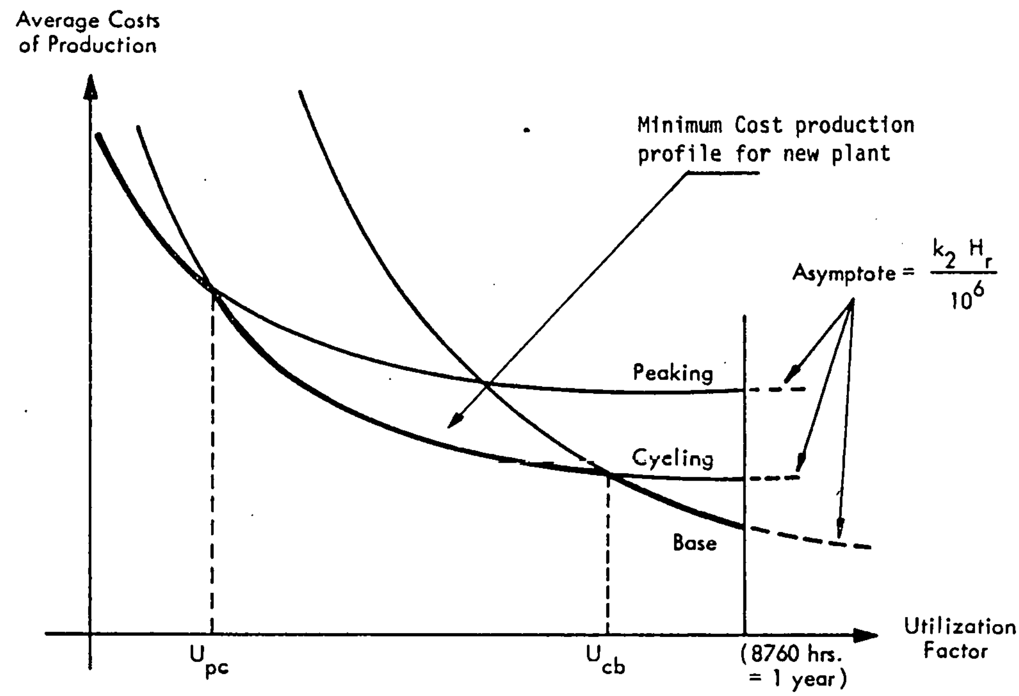


Figure 17. Average production costs (from Baughman and Joskow, Note 32, p. 15).

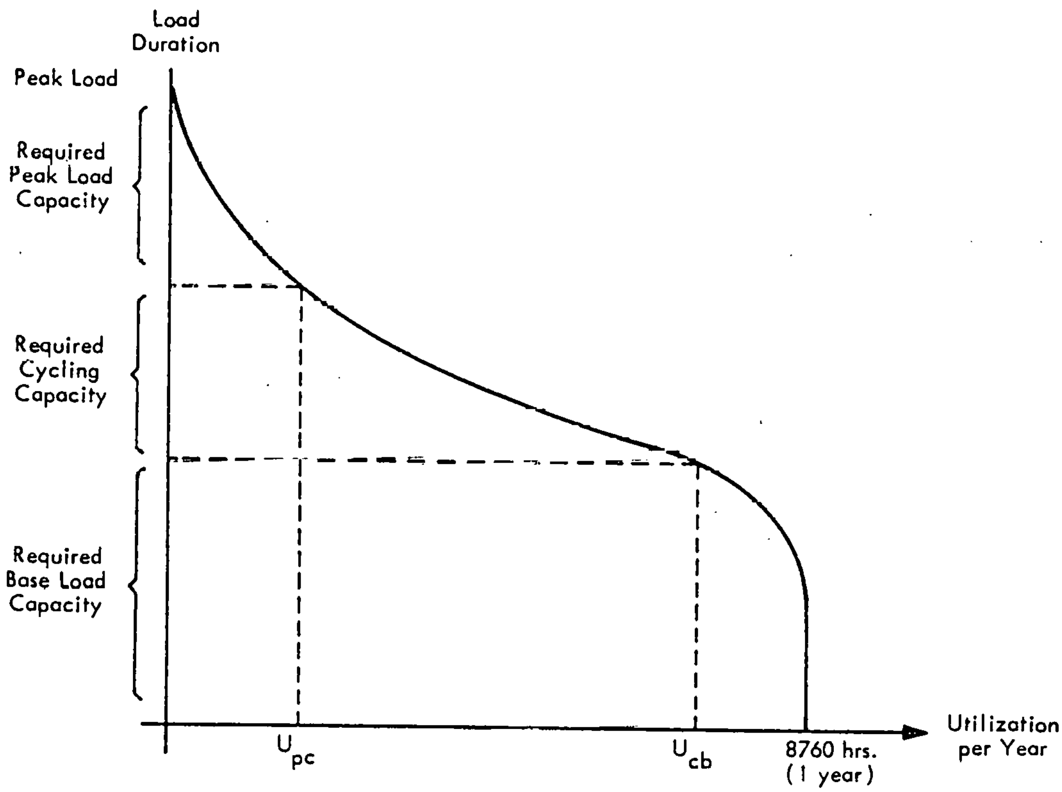


Figure 18. Determination of optimal generation mix (from Baughman and Joskow, Note 32, p. 17).

where the superscripts b, c, p denote parameter values for the base load, cycling, and peaking units, respectively.

It should then be clear that for the portion of the load corresponding to utilization factors greater than U_{cb} the minimum cost plant is of the base load category because the operating efficiency offsets the high capital costs. For $U_{cb} \leq U \leq U_{pc}$ the minimum cost plant is a cycling plant, and so on for other utilization factors and categories.

The preceding assumes that the planner is faced with a load-duration situation for which he must build three new types of plants, each of certain capacity as given by U_{cb}, U_{pc}. In an actual decision situation, however, the planner is faced with a mix of existing plants, and the question may be when to retire an existing plant and replace it by a new, more efficient facility.

For an existing plant, the initial costs are no longer relevant to a decision to replace it by a new plant. Thus, the average cost of generation per kwh for an existing plant is given by

$$AC = \frac{100\ F}{U} + \frac{k_2 H_r}{10^6} + O_c \ .$$

If for any existing plant this cost function, when plotted on Figure 17, falls completely above the minimum cost production profile for new plants, then a net savings accrues if new plant is constructed to replace the old. But if the existing plant function falls at any point below the minimum cost profile, then it is more economical to use this existing plant at those utilization levels than to replace it with additional investment in a new plant.

NOTES TO CHAPTER IV

1. Taken from "Environmental Statement, Calvert Cliffs Nuclear Power Plant, Units 1 and 2", U.S. AEC Directorate of Lecensing, April 1973.

2. In leap years, the number of hours per year is 8784!

3. See 1976 Report of member electric corporations of the New York Power Pool and the Empire State Electric Energy Research Corp. persuant to Article VIII, Section 149b of the Public Service Law, Vol. 1, p. 7-37.

4. G.A. Jordan et al, "The Impact of Load Factor on Economic Generation Patterns" presented at the 1976 American Power Conference, Chicago, Ill., April 20, 1976.

5. W.D. Marsh, R.W. Moisan and T.C. Murrell "Perspectives on the Design and Application of Generation Planning Programs" presented at the Nuclear Utilities Methods Symposium, Chattanooga, Tenn., Jan. 16-18, 1974.

6. Key assumptions included annual carrying charges on investment at an 18% levelized fixed charge rate; an independent system reliability of 1 day/year loss of load, and interconnected system reliability of 1 day/10 years; and an initial generation mix of 19 nuclear, 62 steam electric, 8 combustion turbines and 11 conventional and pumped hydro.

7. Jordan, note 4, *supra*, p. 7.

8. For further discussion of this point, See FPC Bureau of Power, "Electrical Generating Plant Availability", Staff Report, May, 1975.

9. See e.g., D.A. Huettner, and J.H. Landon, "Electric Utilities: Economies and Diseconomies of Scale", Case Western Reserve University, Research Program in Industrial Economics, Working Paper 55, July 1974, or D.A. Huettner, "Shifts of Long-Run Average Cost Curves: Theoretical and Managerial Implications", Omega, International Journal of Management Science, Vol. 1, No. 4, 1973.

10. This pattern is characteristic of many electric and mechanical machines that exhibit a relationship of failure rate with time sometines described as the "conventional bathtub curve", as shown below.

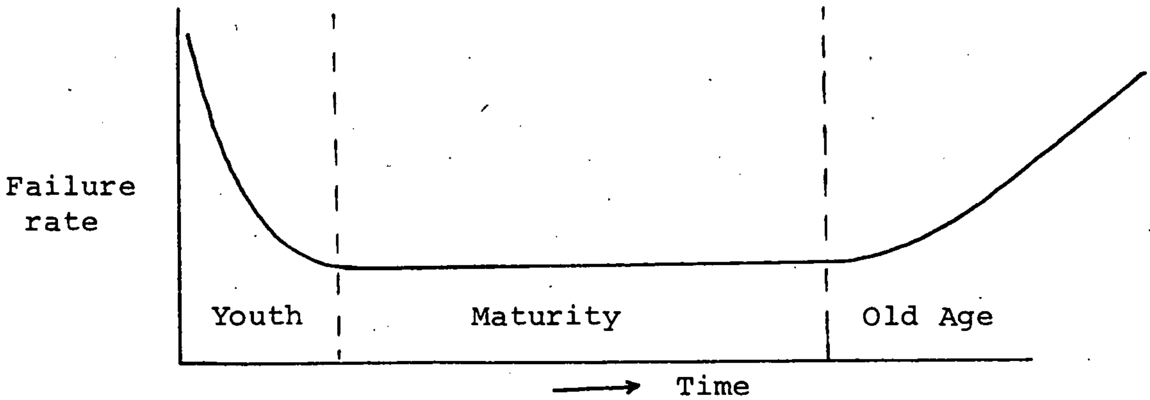


Figure 19. Relation of failure rate vs. time.

There are as usual some notable exceptions to the general pattern; the Three Mile Island plant on the Susquehanna River experienced a 90 percent availability in its first 6 months of commercial operation. Design maturity, however, may be the reason for this.

11. The operating experience of all of the nuclear plants in the Northeast is reviewed in the Appendix of V. Sailor and F. Shore, "The Future of Nuclear Power in the Northeast" BNL 50551, Brookhaven National Laboratory, Upton, New York, March 1976.

12. Supercritical plants have initial steam pressure greater than 3206 psi relative to atmospheric pressure; in theory they are more efficient than subcritical plants because the latent heat of steam drops to zero beyond 3206 psi, beyond which water turns directly to steam.

13. J. Tillinghast and J. Dolan "AEP Succeeds with Large New Units" <u>Electrical World</u>, Aug. 1, 1976, p. 28.

14. See note 12, <u>supra</u>.

15. Federal Power Commission "Annual Report, 1975" U.S. Government Printing Office, Washington, D.C., January 1976.

16. <u>Ibid</u>., p. 19.

17. Barstow, A.W., et al., "Interconnected New England Generation Study", Generation Task Force Report, No. 4, NEPLAN, Spring-

field, Mass., May 1971.

18. H.W. Kohn, "Reactor Performance Evaluations", Power Engineering, Dec. 1975. p. 52-p. 54.

19. However, as pointed out in a recent FPC analysis (note 8, supra) comparisons of the availability of recent large steam units with smaller ones built many years ago can lead to unwarranted conclusions regarding lack of progress in reliable design. It is inevitable that smaller units should be more reliable than larger ones. A steam boiler for a 100-megawatt unit is much smaller than one for a 1,000-megawatt unit. Not only is the 100-megawatt boiler smaller, but it requires fewer auxiliary devices and smaller ones for its operation. The sheer size of the larger boiler leads to greater difficulty in boilding it, in transporting it, in testing it, in operating it, and maintaining it. In all these areas, lesser reliability and availability must be expected even though the greatest attempts are made to maximize availability. For instance, a furnace and boiler designed for 1,000 megawatts may have in the neighborhood of 50 times as many linear feet of piping as a 100-megawatt boiler. If it is assumed that each foot of pipe, wherever it is used, has a certain probability of pinholes, non-uniform wall thickness, or variation in quality, then it is evident that the large boiler (with much more pipe) will be less reliable than smaller boiler. The large boiler requires many more welds than does the smaller one--again multiplying the possible number of locations where failure can occur.

20. Reserve margin is generally expressed as the difference in total system capacity minus the peak load, in terms of a percentage of the peak load.

21. This does not imply a full one day outage every 10 years, but rather an inability to meet load which may last from less than one minute to several hours.

22. This is, in fact, a very complex computation, for which there are no easy, explicit analytical expressions.

23. A. Kaufman, "Reliability Criteria - A Cost-Benefit Analysis", New York State Department of Public Service, Albany, N.Y., Office of Research Report 75-9, June, 1975.

24. It is, however, curious that Kaufman examined only a narrow range of reserve margins; especially in light of the current NYPP margin of 33%! In view of the exponential relationship between reserve margin and LOLP, one suspects that the impact on consumer rates of a change from 33 to 20% would be far in excess of 2%.

25. M. Telson, "The Economics of Alternative Levels of Reliability for Electric Power Generation", Bell Journal of Economics, Vol. 6, No. 2, Autumn, 1975, p. 679.

26. Northeast Utilities System, "Ten Year Forecast of Loads and Resources 1975-1984", January, 1976, p. 75.

27. Personal Communication from S.H. Lull, Vice President of Northeast Utilities.

28. R.O. Bigelow "Reliability Criteria for Generation Planning in New England" Presented at the Henniker Conference, August 1976.

29. Ibid., p. 3.

30. If one assumes for New England the reference criterion of one day in ten years disconnecting customers and an equivalent risk level in New York, the ties to the New York Power Pool appear to improve New England's reliability equivalent to a reserve increase of approximately four percent of peak load. As the systems grow, so must the tie capability if this relationship is to continue. On this basis, the present ties, which have a capability of approximately 1,050 mw, will be adequate to obtain all mutual reliability benefits available between New England and New York out to the early 1980's. Beyond that point, mutual benefits between these systems appear to be limited by tie capacity, unless a further increase in transfer capability is made. (Bigelow, note 28, supra.)

31. One of the important features of the study was a check of generation planning program results versus actual experience for the three years, 1971 and 1973. The results showed a good correlation when actual maintenance experience, including overruns from original schedules, was included. Data input to these runs included the most recently available forced-outage rate data, as developed from EEI statistics and applied to New England conditions.

When the program was rerun with an optimized maintenance schedule developed by the capacity planning program using estimated scheduled maintenance requirements, the results showed a substantially more reliable system than actual. The discrepancy introduced by assuming an idealized maintenance schedule appears to be equivalent to about four percent more reserve on the system. Further analysis indicated that this four percent discrepancy between program predictions and actual experience was primarily due to maintenance overruns, with optimized timing a secondary factor.

32. M.L. Baughman and P.L. Joskow, "A Regionalized Electricity Model", MIT Energy Lab, Cambridge, Mass., December, 1974.

33. Northeast Power Coordinating Council "Data on Coordinated Regional Bulk Power Supply Programs" FPC order 383-3, Docket R-362, Appendix A, April 1, 1976.

34. See Report member Electric Corporations of the NYPP pertinent to Article VIII, Section 149-b of the Public Service Law, Vol. 1, April 1976, p. 31.

35. MAAC Systems Plans, April 1976.

36. NERC: A current view of the impact of postponements and cancellations, April 1975.

37. P. Meier and D. Morell "Issues in Clustered Nuclear Siting: A comparison of a hypothetical energy center in New Jersey with dispersed nuclear siting" BNL 50561, Brookhaven National Laboratory, Oct.,1976.

CHAPTER V

GENERATING FACILITY SITING CONSTRAINTS

5.1 Water Resource Constraints

Although the Northeast is endowed with plentiful water resources in comparison to the arid areas of the U.S., the concentration of population and industry in the region makes for keen competition for this resource, particularly for recreation and urban water supply. Given the current EPA strictures against once-trhough cooling in freshwater bodies and the small demands likely to be imposed by hydroelectric generation (see below, Section 5.4), the major water resource constraint on the electric sector is the limitation on consumptive use at evaporatively cooled thermal electric generating facilities, an evaluation of which is the subject of a detailed study now in preparation by the BNL Regional Energy Studies Program.[1] Preliminary analyses show that Region III will likely face the most severe water resource limitations, and especially utilities in the Delaware River Basin will find increasing difficulty in locating inland sites for large thermal units. Indeed, it was a New Jersey utility that that was the first to consider seriously the possibility of offshore siting for nuclear capacity. By comparison, the New York Power Pool (Region II) has the abundance of the Great Lakes (Lake Erie and Lake Ontario) at its disposal. The long coastline of New England, unimpeded by the Barrier Islands that characterize the New Jersey and Delaware shores, would also appear to provide the NEPOOL utilities with considerable siting flexibility. However, in light of increasing pressures on the coastal zone, coastal siting under prospective state and federal regulation may face increasing difficulty. Moreover, much of the New England coastline is in Maine, a state that is becoming increasingly opposed to power facilities built primarily for out-of-state consumers. And, finally, the most recent development in the Seabrook controversy (see also Chapter VII), evidences the strong environmental opposition to once-through cooling at coastal sites, a mode of cooling that remains one of the major inducements to such sites.

The freshwater water resource problem in the Northeast is caused primarily by constraints on consumptive use during low flow periods in late summer, rather than a year-round water shortage. This implies, of course, that provision of storage reservoirs could, in fact, provide the necessary augmentation of low flow by storing the abundant winter and spring rainfall. Unfortunately, the construction of reservoirs in upstream areas is becoming increasingly difficult, as documented by the recent demise of the Tocks Island Project on the Delaware, which, among other uses, was also to have provided low flow augmentation flow for the Hope Creek and Limerick Nuclear Plants downstream. Preliminary results of our detailed study show that if the full potential for building low-flow augmentation reservoirs could be exploited, sufficient low flow could be provided in all river basins for many times the additional thermal generation capacity needed between now and 2000. But, if one takes the view that no further storage reservoirs can be built for flow augmentation, then utilities in Region III, especially those in western Pennsylvania and the Delaware River Basins, will face severe siting difficulties. Although this type of constraint obviously makes offshore siting an interesting alternative, there remain a number of as yet not clearly resolved technical and licensing obstacles, whose ultimate outcome is still unclear.

5.2 Constraints on Nuclear Facilities

In addition to the water resource constraints shared with fossil generation types, the two major siting constraints faced by nuclear facilities are proximity to population and seismicity.

In regional and coarse site screening studies, the nuclear Regulatory Commission Seismic Zone classification appears to be the most frequently used criterion for assessing the degree of problems likely to be encountered at the detailed engineering stage. These zones are defined as follows:[2]

Zone I - This zone includes areas of low seismicity with no known capable faults. It is expected that seismicially suitable sites will be found with little difficulty.

Zone II - This zone includes two categories: (1) areas with moderate seismicity and complex geological structures, having numerous, old, incapable faults, and (2) areas close to zones of high seismic risk, which may lead to controversial risk assessment. Detailed site-specific studies will be necessary to determine geologic/seismic site suitability.

Zone III - This zone is characterized by high seismicity, accompanied in most cases by intense, recent faulting.

The three zones represent NRC staff judgment with respect to the seismic stability of various land areas. The zones differ according to the relative difficulty of establishing the design value for the horizontal motion of the ground at the foundation of Category I structures, and are based on relative seismic risk maps and licensing experience. Consideration is given only to historical earthquake activity and known faulting; other geological factors such as karst regions and subsidence are not considered.

As indicated on Figure 20, most of the Northeast lies within Seismic Zone II. The New Jersey Coastal Plain, most of Delaware, the extreme western portion of Pennsylvania, and parts of the Upper Delaware River Basin, however, lie in the most favorable zone. Thus, one would not anticipate that seismicity would be a limiting constraint on nuclear siting in the Northeast, in contrast to some western regions and the Pacific Coast.

On the other hand, the issue of population proximity is far from clear, as well demonstrated by the recent litigation over the Bailly nuclear plant in Northern Indiana.[3] Indeed, strictly speaking, the NRC regulations in respect to population are extraordinarily simplistic, based simply on a scalar distance to the nearest center of population. Perhaps the most important deficiency is the absence of a formal mechanism for relating the issuance of a license to land use control measures beyond the area under control of the licensee. Although future growth projections in the Low Population Zone are taken into account in the licensing decision, once the license is granted neither the NRC nor the utility has any control over actual (as opposed to expected) growth in the LPZ. The environs of the Oyster Creek Plant in New Jersey constitute an excellent example of a situation where residential growth in the

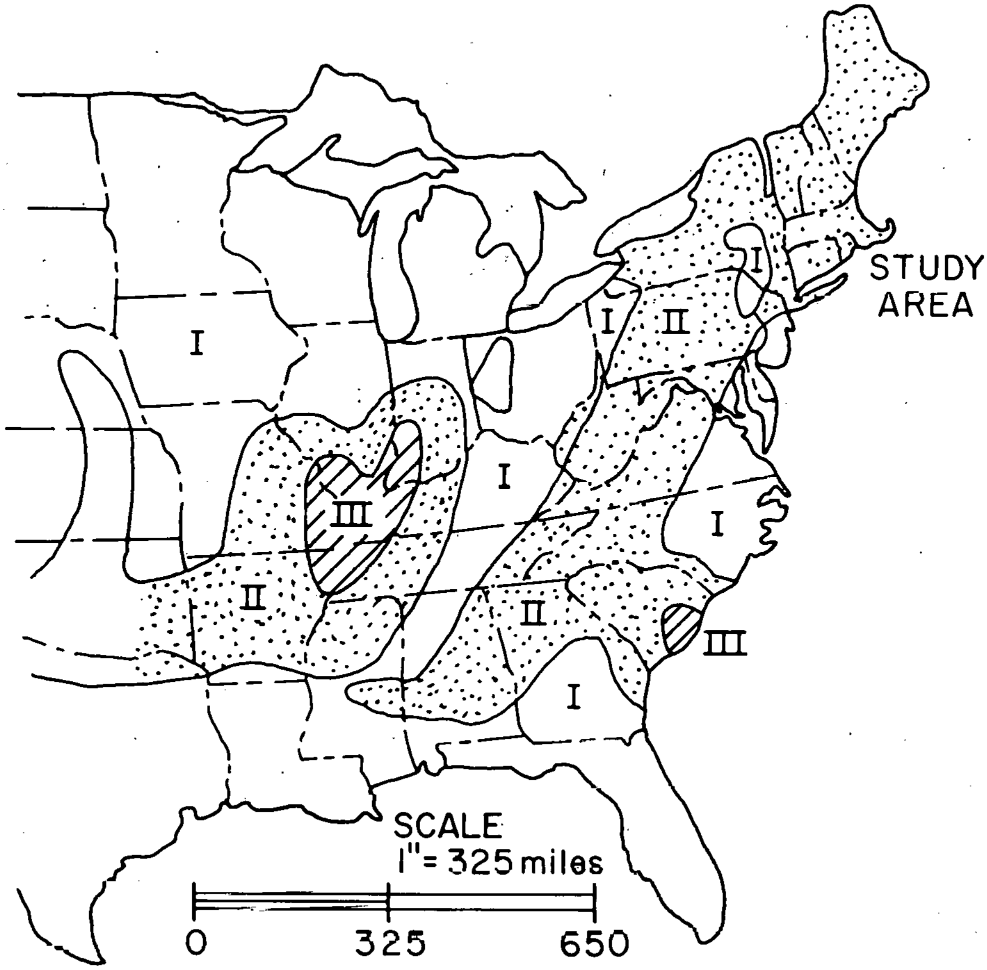


Figure 20. Seismic zones. Source: NRC, note 2, plate 4-1.

immediate vicinity of a nuclear plant has surpassed all expectations made at the time of the original licensing decision. Yet state and local governments, upon whom the burden of land use controls rightly fall, frequently lack adequate controls over the actions of private developers, and are in any event precluded by the preemptive powers of the federal NRC in matters of radiological health and safety from taking land use control actions on safety grounds.

In an interesting analysis, Piper and Heddleston examined the population-distance envelope of nuclear power reactor sites in the U.S. and overseas.[4] It appears that the population-distance envelope represented by the Indian Point, N.Y. and Zion Nuclear Plants represents the limit of acceptability in this country; proposed sites such as Ravenswood (in New York City), and Burlington and Newbold Island in New Jersey (close to the Philadelphia Metropolitan area), whose population-distance curves lie considerably above this envelope, have all been rejected (Figure 21). However, as shown on Figure 22, European practice seems to allow nuclear plants in much closer proximity to population centers, with the shown U.K. and German plants lying considerably above the Indian Point population-distance curve.[5]

NRC has recently developed a somewhat more sophisticated index for population analysis, the so-called "Site Population Factor" (SPF), based on weighting the population of each discrete annular element around a potential site with an exponential function of distance from the proposed site. NRC currently considers areas with a SPF of less than 0.2 for 30 miles (numerically equivalent to a population density of less than 200 persons per square mile uniformly distributed over a 30 mile radius) as acceptable for nuclear sites; this criterion, however, is informal, and not yet part of any official siting regulation. Figure 23 shows the 30 mile SPF contours in the Northeast, from which one may conclude that nuclear sites meeting this criterion can be found quite easily at relatively small distances from the major metropolitan areas.

Nevertheless, there is still much ambiguity concerning what is, and what is not, an acceptable proximity to population. Indeed, one possible outcome of the current nuclear safety controversy might be the limitation of nuclear reactors to truely remote sites, where

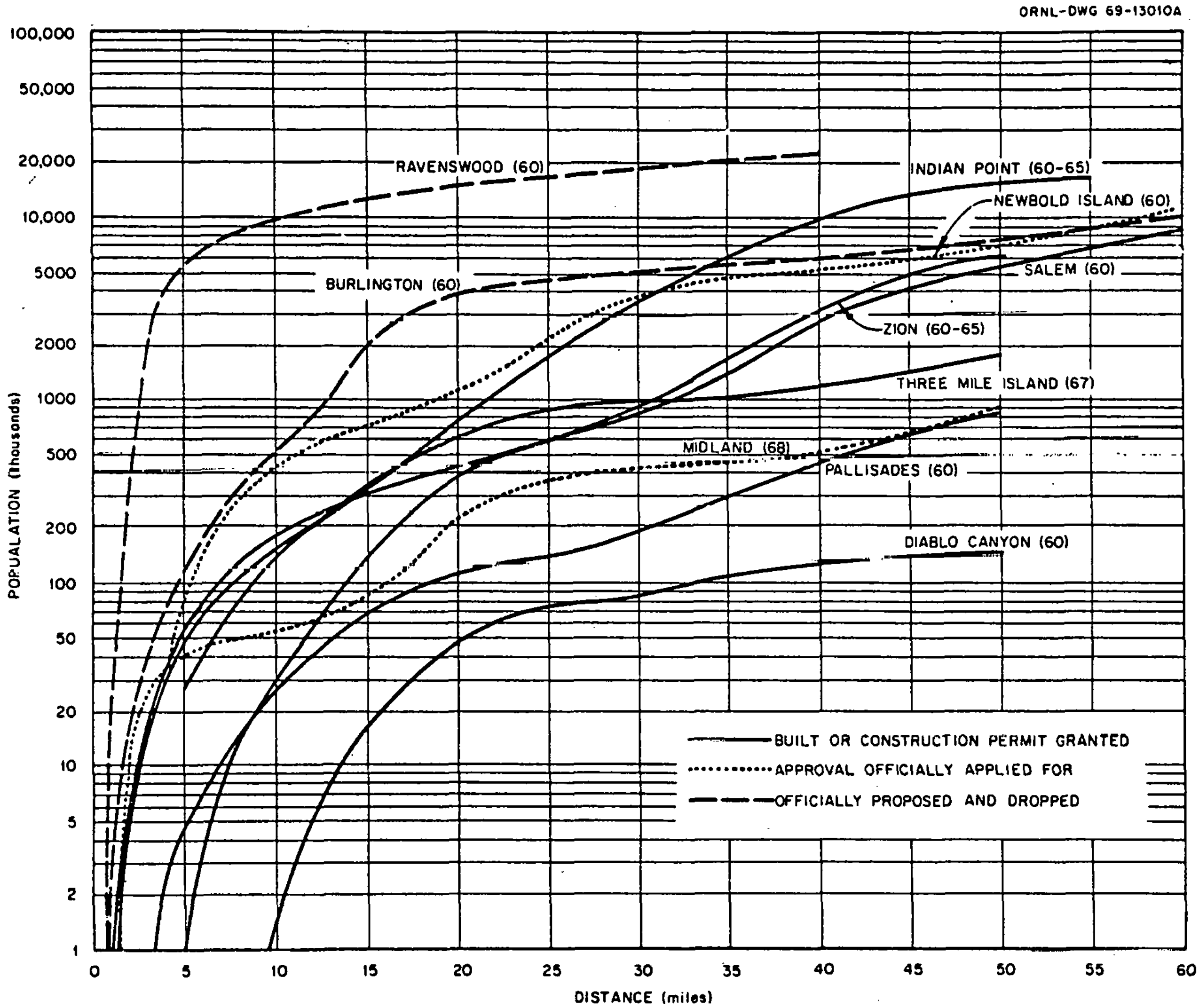


Figure 21. Cumulative population as a function of distance from nuclear plants in the U.S. (Numbers in parentheses indicate date of population information.) Source: Piper & Heddleston, note 4.

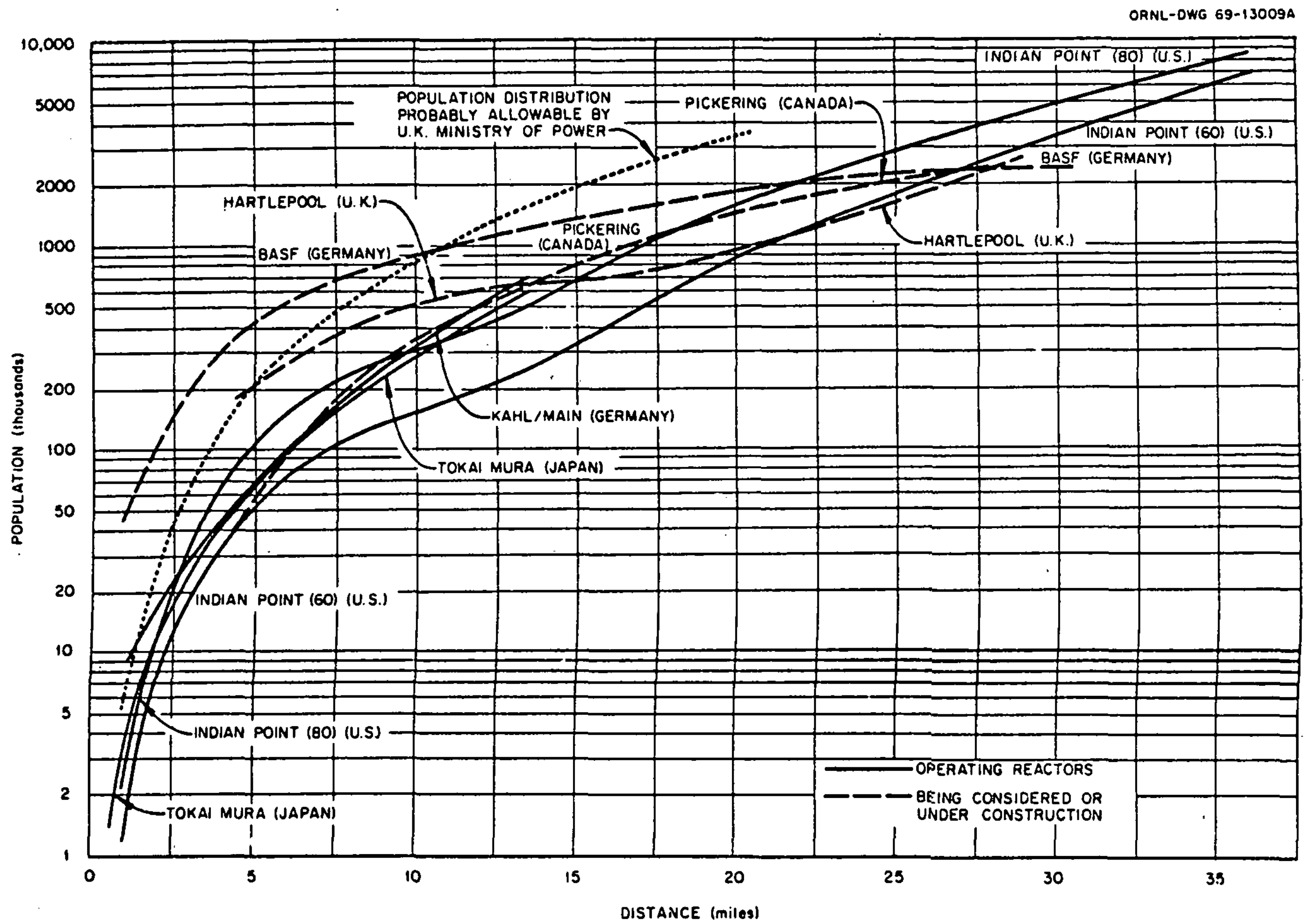


Figure 22. Cumulative population as a function of distance from existing and proposed nuclear plants abroad compared with curve for Indian Point. (Numbers in parentheses indicate date of population information.) Source: Piper & Heddleston, note 4.

REGION 1 SPF AT 30 MILES

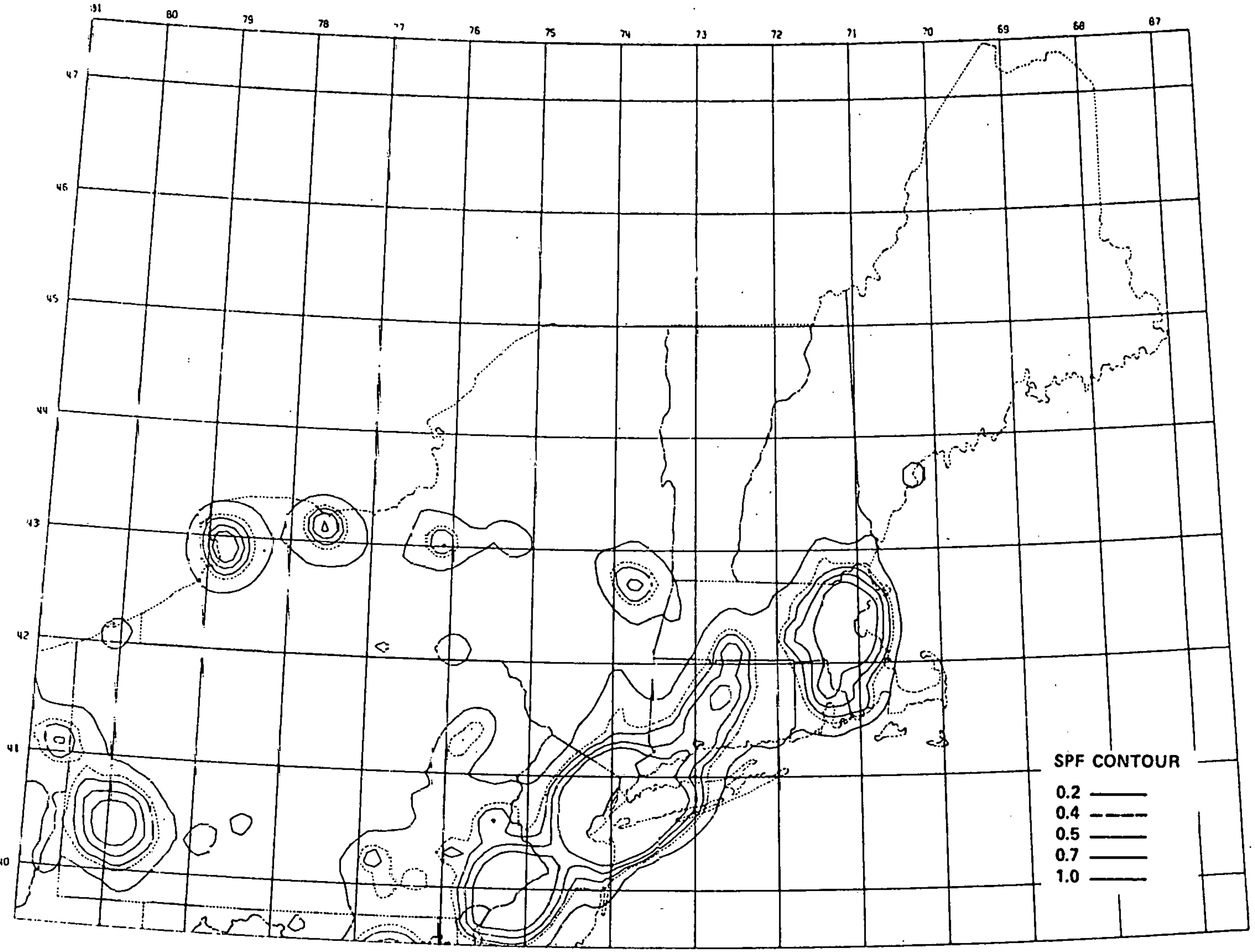


Figure 23. Site population factor. Source: Kohler et al. note 6.

the requirement might be no major population center within a buffer zone of, say, 25 to 50 miles radius. Such a definition of a remote site would necessarily restrict nuclear reactors in the Northeast to certain areas in upstate New York, or to northern Maine, as no other parts of the region have the necessary absence of population.

5.3 Constraints on Combustion Turbines[7]

Combustion turbines represent the generation type that is probably least constrained by siting considerations, and the past two decades has seen a significant rise in this type of capacity in many northeastern utilities. Difficulties in siting pumped storage facilities, exemplified by the celebrated Storm King Mountain controversy in litigation for over a decade,[8] is one major reason for this recent sharp growth in combustion turbine capacity.[9] Short lead times,[10] on the order of 18 months, have also made the addition of gas turbine capacity a convenient expedient whenever short-term capacity shortages were encountered--an important consideration in view of lead times of up to 10 years for other types of facilities. Moreover, gas turbines can be installed for the lowest capital cost per kw of capacity of all current generation technologies, and thus present some special advantages to a utility experiencing difficulties in raising capital.

Offsetting this low capital cost advantage, however, is a relatively high operating cost per kwh generated, due to a much lower efficiency of conversion.[11] Furthermore, because many northeastern utilities have a higher-than-optimal fraction of combustion turbine in their generation mix, these units are operated for many more hours per day than they ordinarily should be, resulting in, or at least being a major contributor to, the high average generation costs of the region.[12] Thus, such utilities as Consolidated Edison, which have very high gas turbine fractions, have been particularly affected by the sharp increases in fuel costs since the 1973 oil embargo.

In the past, combustion turbines have been installed primarily at existing large fossil fueled generating facilities occupying some unused corner of an existing site. Their major environmental impact, noise, is thus minimized by location in an existing industrial land use. It should also be clear that combustion turbines, because they are easily sited close to the load centers, incur lower transmission losses than, for example, hydro-electric facilities, which in the Northeast generally lie quite far from population and load centers.

But despite the ease in siting and the low capital costs per unit of capacity, we forsee that combustion turbines will represent an increasingly smaller portion of generation capacity in the future. Four reasons may be advanced for this. First, their relatively inefficient use of fuel, which, in a time of sharply rising fuel costs, may make that portion of the load served by this type of unit somewhat smaller. Indeed, evidence of decreasing use of gas turbines in the past two years was advanced in Section 2.3. This would be especially important for utilities with an already higher-than-optimal proportion of gas turbine generation. Second, the equipment manufacturers are no longer building gas turbines for stock, but only on receipt of firm orders. This has resulted in a doubling of the lead time to nearly three years, and thus no longer represents a fast solution to unexpected load increases or construction delays in installing other generation types. Third, many of the conservation measures likely to be implemented over the coming years will have as their objective the increase of system load factors (i.e., the reduction of the extreme peaks), and thus the need for peaking power generation modes would, at least in a system of optimal generation mix, decrease.[13] Finally, so-called combined cycle facilities, in which the exhaust gases from the combustion turbine portion are used to heat a boiler driving a steam turbine, have much higher overall efficiencies,[14] and this type of unit can thus be expected to gain an increasing share of the overall capacity mix.

5.4 Constraints on Hydroelectric Facilities

Hydroelectric plants in the Northeast accounted, in 1975, for only some 10.7% of the total installed capacity,[15] and few major additions of this type can be anticipated over the next few decades. This will result in a further decreasing share of this generation type.

Several reasons make significant additions in hydro capacity unlikely for the Northeast. Most of the potential for conventional hydro electric plants is already utilized, and such sites as do remain would either represent rather small capacity additions, or, if the site calls for a dam of some size, would be so controversial as to make large projections quite improbable.[16] Moreover, some of the few large potential hydro sites in the region, such as the proposed Dickey-Lincoln project on the Maine-Canadian border, are engulfed in the public power controversy (since this project is sponsored by the U.S. Corps of Engineers and opposed by the investor owned utilities) as well as being opposed by environmentalists on grounds that the intrusion into remote, unspoiled wilderness areas is unacceptable.

Large additions of pumped storage capacity also seem unlikely--they too, tend to be highly controversial (as witnessed, for example, by Storm King Mountain or Northeast Utilities' proposed site in Northwestern Connecticut); and for a number of reasons the economics of pumped hydro appear less favorable than a decade ago. Being highly capital intensive, their construction costs have soared, and they may be seriously affected by load management measures which would curtail the magnitude and extend the duration of peaks.

5.5 Constraints on Coal Generation

The Northeast is faced with a particularly vexing problem in siting coal fired electricity generation facilities. On the basis of one criterion, the optimal location of coal plants would be in western Pennsylvania at or near the mine-mouth, thereby minimizing fuel transportation costs. Yet mine-mouth location in western Pennsylvania implies in turn the need for significant transmission facilities to bring the power to the eastern load centers. Moreover, in view of the prevailing weather patterns, many of the undesirable environmental impacts resulting from stack emissions would be felt at locations at some distance to the east of such generating plants,[17] and, in fact, many eastern urban areas are currently in the average trajectories of emissions from midwest power plants. It may well be, then, that the best location for coal generating plants are near the urban areas in the East, such that emissions are forced offshore taking maximum advantage of prevailing wind patterns and atmospheric transport of emissions to offshore areas, and minimizing the need for extensive new transmission rights-of-way. But that presupposes a rail transportation system adequate for the demands placed upon it, a topic explored in more detail in the coal issue paper.[18]

The question of siting coal fired facilities in the Northeast, considering the entire set of environmental, socioeconomic and technological issues, is now under detailed study as part of the Coal Utilization Assessment being undertaken by the National Laboratories under the auspices of the ERDA Regional Studies Program. Comprehensive siting analyses will be initiated in the coming months with results expected by early 1977. The major difficulty in such an undertaking stems from the fact that coal generation cannot merely be viewed in isolation of other generation forms, since in many cases coal plants will compete with oil or nuclear generation for the available water resources.

5.6 Constraints on Oil Generation

Currently the Northeast relies on the Gulf Coast and foreign nations for its oil supply--40% from the former and 60% from the latter. Roughly 80% of the oil is transported to the region via waterways, either by tanker or by barge, while the balance arrives by pipelines.[19]

For these reasons, oil-fired power plants are faced with two major constraints. First, they must be located on the coast, on a river or near a pipeline. Second, and more importantly, the fact that a sizable percentage of their fuel originates in other countries, mostly members of the Organization of Petroleum Exporting Countries (OPEC), makes them subject to foreign oil embargo and price manipulation on the international market. Thus, in late 1973 and early 1974 the price of crude oil jumped from about $6/bbl to about $11/bbl within a month, simultaneous with an embargo imposed on this country by some members of OPEC. As a consequence, not only did the cost of electric energy rise dramatically, but some utilities had to resort to voltage reductions in order to conserve the oil supply they had on hand.[20] The possibility of another embargo in the future, the effects of which will be more severe than that of 1973-74 due to the ever-increasing dependence on imported oil, bodes ill for these utilities currently dependent, in whole or in major part, on imported oil.[21] Small wonder, then, that a utility such as the Long Island Lighting Company, currently almost exclusively dependent of imported oil,[22] views the introduction of nuclear capacity with urgency.

Moreover, in view of the fact that domestic oil production has been decreasing in recent years, the Northeast can hardly be optimistic about receiving more oil from the rest of the Nation. Unless oil is discovered within the Region, particularly on the Atlantic outer continental shelf, and developed, it will be increasingly difficult for the electric utilities in the Northeast to obtain reliable oil supplies.

NOTES TO CHAPTER V

1. J.E. Edinger, "Water Resource Constraints on Energy Facility Location in the Northeastern U.S." Forthcoming Report, Policy Analysis Division, Brookhaven National Laboratory, Upton, N.Y.

2. See NRC, "Nuclear Energy Center Site Survey - 1975", Report NUREG-0001, Pt. V, p. 216, Jan. 1976.

3. See Porter County Chapter of the Izaak Walton League v. AEC, 5 Environmental Law Reporter 20274. The Court of Appeals of the 7th Circuit set aside the approval of the plant on grounds that the Licensing Board failed to follow AEC regulations. The U.S. Supreme Court, however, in a subsequent decision, reversed the Appeals Court judgement.

4. H.B. Piper and F.A. Heddleston, "Siting Practice and Its Relation to Population", Nuclear Safety, Vol. 14, No. 6, Nov.-Dec., 1973, p. 577.

5. Indeed, when one views the plight of many central metropolitan areas with declining tax bases and high unemployment in their construction sectors, a few nuclear plants within their jurisdiction might be a not undesirable prescription (given, of course, the initial premise that nuclear plants are indeed safe). As noted by one New Jersey resident at a public meeting on nuclear energy centers "...if they are as safe as they are claimed to be, put them in Newark, where they need the tax base, the employment in the construction industry, and the electric power, and not in southern New Jersey."

6. J.E. Kohler, et al., "The Site Population Factor - A Technique for Consideration of Population in Site Comparison", U.S. Atomic Energy Commission, Report WASH 1235, Oct. 1974.

7. Combustion turbines are also often called gas turbines, but this is confusing, since the fuel may, in fact, be oil.

8. See e.g., L.J. Carter, "Con Edison; Endless Storm King Dispute Adds to Its Troubles", Science, Vol. 184, p. 1353 (June 1974).

9. Consolidated Edison of New York City, for example, has 22 percent of its total capacity in combustion turbines.

10. The lead time is defined as the interval between the decision to install and the start of commercial operation.

11. The overall average conversion efficiency (Btu electricity to Btu oil) for gas turbines is about .24, as opposed to about .32 for steam electric generating plants.

12. Under optimal conditions, gas turbines should be run only for a few hours each day to meet the extreme system peaks.

13. One often hears the argument that conservation would eliminate the need for large base load and especially nuclear plants. Unfortunately, that is the least likely outcome of successful conservation programs, because the conservation programs most likely to be successful are those focussed on increasing load factors. To be sure, there may be some decrease in base load, but the major impact would be an increase in the fraction of base capacity. The electric automobile, too, would serve more to eliminate the peaks.

14. Note also that a modern combined cycle facility may have an overall heat rate of 9100 Btu/kwhr, as opposed to a pumped storage equivalent of 12100 Btu/kwhr (based on 9200 Btu/kwh base load fossil for providing pumping energy, and a 74% efficiency of pumping-to-hydropower).

15. See Table 3, above.

16. Recall the discussion of Section 5.1 above.

17. P.F. Palmedo, "The Brookhaven National Laboratory Regional Energy Studies Program Annual Report for Fiscal Year 1975", BNL-50478. Brookhaven National Laboratory, November 1975.

18. B. Edelston and E.S. Rubin, "Current and Future Use of Coal", BNL-50560, Brookhaven National Laboratory, March 1976.

19. H. Bronheim, "A Perspective on the Energy Future of the Northeast Oil Supply", BNL-50557, Brookhaven National Laboratory, March 1976.

20. Federal Power Commission"Report on Electric Power Disturbances in First Quarter of 1974", FPC News Release 20311, May 15, 1974.

21. For a full discussion of these problems, see Bronheim, note 19, supra.

22. T.O. Carroll and P.F. Palmedo "Current and Future Energy Use in the Nassau-Suffolk Region" BNL-20683, Brookhaven National Laboratory, Upton, New York, Oct. 1975.

CHAPTER VI

TRANSMISSION

6.1 Technological Development

The development of generation technology has historically been closely linked to developments in transmission technology. The current pattern of large efficient generating units, fully exploiting the available scale economies and often many miles from their major load centers, has been made possible only by the concurrent development of high voltage transmission. Further advances in transmission technology, therefore, may well allow even greater flexibility in generation facility siting, and thus a brief review of likely developments is pertinent to the objectives of this assessment.

Over the time period considered in this study, however, it is unlikely that radical advances in transmissions technology will affect the basic pattern of the transmission grid in 2000. To be sure, under the most optimistic assumptions in regard to the commercial demonstration of cryogenic transmission, the decade 1990-2000 may see the first practical applications. However, it appears that rather large blocks of power, transmitted over very long distances, would represent the most favorable conditions for cryogenic transmission as opposed to conventional uhv transmission; one might argue, therefore, that only the creation of large, remote energy centers would justify extensive use of this technology. It is certainly unlikely that generating complexes of conventional size, say in the range of 2-6 Gw, and located 50 to 200 miles from the major load centers, would be connected to the grid by cryogenic transmission. A 50 Gw nuclear energy center located in a remote area in Upstate New York, however, designed to serve the New York Metropolitan area, would be a more realistic proposition for a cryogenic transmission line. In any event, other developments in cable transmission, such as compressed gas insulated cable, are far more likely to achieve general application in the time frame considered here.

The most probable developments, then, are to be expected in incremental improvements in already existing transmission technologies. These developments fall largely into three categories; a further increase in operating voltage levels of overhead, A.C. transmission; the further development of high voltage, D.C. transmission; and improvements in underground transmission technology. Each of these are briefly reviewed below.

The highest operating voltage in the Northeast is currently the 500 kv transmission network of the PJM Interconnection; the highest New York Power Pool and NEPOOL voltage is 345 kv. However, the New York Power Pool is in the process of constructing a 765 kv grid, although the currently completed sections are being operated at 345 kv. In fact, the only 765 kv network in the U.S. currently in operation is that of the American Electric Power (AEP) System, which presently links Indiana, Ohio, W. Virginia, and Kentucky.

In assessing the degree to which the 765 kv voltage might spread in the Northeast, a number of factors must be considered. First, there are a number of as yet unresolved environmental problems at such high voltages, and the AEP 765 kv system and the NYPP proposals have resulted in considerable controversy and concern. Electrostatic field effects, noise, and ozone production by corona discharge, in addition to radio and televesion interference, have all been raised as major issues. These effects, of course, are also present to some degree at the lower voltages--but at 765 kv these may become quite noticeable and possibly significant. The second factor to be considered is the voltage of the existing grid; for technical reasons it appears that the optimum increment in transmission voltage is roughly double the existing highest voltage; thus PJM, which has an extensive 230 kv grid, elected for 500 kv as their next voltage, whereas NEPOOL and NYPP, which have significant amounts of 345 kv line, would tend to elect 765 kv rather than 500 kv as their next increase in voltage.

Although electric power systems use alternating current (AC) because it can so easily be converted from one voltage to another with the use of transformers, there has been much recent interest in the use of direct current (DC). Voltage transformation with DC requires the use of an inverter, and, if a DC link is to be inserted into a largely AC system, expensive terminal stations containing the necessary conversion equipment (rectifiers and inverters) must be added to the cost of the DC line. The line, itself, however, may be considerably cheaper than its AC counterpart, since the number and size of the conducters required to transmit a given amount of power is less; transmission losses are lower; and less right-of-way is necessary. Clearly, over short distances, the cost of the terminal equipment exceeds the line savings; but over long distances, DC may be the indicated choice. The first high voltage overhead DC line in the U.S. is the 800 kv DC line from Oregon to California, started in 1968, which transmits some 1500 Mw of power, and two separate HVDC lines are now under consideration for linking mine-mouth generating plants in N. Dakota to load centers in the Midwest. As continued advances are made in high-voltage rectifiers and other terminal equipment, one could expect the distance necessary to justify a DC link to become considerably smaller than the present break-even point that lies in the vicinity of 500 miles. One might, thus, well anticipate one or two such lines in the Northeast by the year 2000, linking mine-mouth coal generating plants in W. Pennsylvania and W. Virginia to metropolitan load centers.[1]

Not only does DC thus have distinct advantages for overhead, high-voltage transmission, it also has advantages in underground or underwater cables. Long AC cables require expensive compensating equipment to offset the load reducing effect of capacitative charging currents, whereas DC lines can be built relatively cheaply in any length (however, terminal costs again add to the cost). Several such DC cables are in existence throughout the world, but none as yet in the U.S.[2]

6.2 Siting Problems

The aesthetic impact of large, high-voltage transmission lines has sparked many fierce controversies in the Northeast over the past decade,[3] and the prospect of a considerable number of additional long-distance lines necessary in any scenario dependent on mine-mouth coal generation or remote nuclear facilities, will in all likelihood continue the environmental opposition to such facilities.

Except in the case of a link between a hydro plant or a nuclear plant to the existing grid, which falls under the jurisdiction of the FPC in the former, and the NRC in the latter case, transmission lines are not uniformly regulated at the federal level. But over the last few years, many states in the Northeast have begun to require permits and licenses of some kind for transmission lines, and the utilities have, in response, begun to introduce improved planning techniques to select the route with least adverse environmental impact.[4]

Nevertheless, the central point of controversy is the desirability of undergrounding lines in order to mitigate the adverse aesthetic impact of overhead lines. Except for relatively low voltage distribution lines in urban and suburban areas, however, undergrounding of cross-country high-voltage lines is not only prohibitively expensive, but it is by no means clear that the overall environmental cost is any less. In wooded landscapes, for example, it is not so much the structures of the overhead transmission line as the cut of the right-of-way that is perceived, particularly in winter landscapes and in the mountainous regions that have many valuable scenic landscapes.[5] But since right-of-way clearance is also needed for the construction and maintenance of an underground cable, undergrounding in such situations is of questionable benefit. Moreover, because a trench must be dug along the entire length of the route, complete clearing of the vegetation is required, whereas in the overhead case, selective clearing may be adequate.

But, regardless of vegetative cover, construction of an underground line requires a construction activity far greater than required for overhead lines; and, because the power transmission capability of a cable is much less than that of an overhead line, one overhead line would need to be replaced by a number of cables, each in its own trench. Consequently, one is led to the conclusion that even from an environmental viewpoint, undergrounding of an overhead line in rural areas is an unsatisfactory answer, except in the most unusual circumstances, such as a river crossing in a particularly valuable scenic landscape. In most other cases, a more reasonable response is an alternative route. Indeed, it could be argued that the environmental return on the large amount of money necessary for undergrounding would be far higher if spent on other environmentally beneficial projects in the electric power industry.

In summary, then, transmission line routing problems will likely be solved by a more careful selecticn of route, with perhaps increasing regulatory requirements imposed by state agencies. Undergrounding of lines will likely be restricted to urban and suburban areas, with cross-country transmission lines still largely overhead except in some special circumstances.[6]

6.3 Current Utility Plans

Table 18 shows the total mileage of planned major transmission line additions in the Northeast during the next five years (1976-1981), disaggregated by voltage level and region. The difficulties in undergrounding is demonstrated by the fact that in the New York Power Pool, only 98.8 miles of the addition are planned as underground lines. For the MAAC portion of Region III, only 28.2 miles out of a total of 1268 miles will be buried underground.

TABLE 18

PLANNED CONSTRUCTION OF HIGH VOLTAGE TRANSMISSION LINES 1976-1981
(in miles)

	Region I	Region II	Region III	Northeast
115 kv & 138 kv	369	292	14	675
230 kv	0	104	842	946
345 kv	300	466	48	814
500 kv	0	0	637	637
765 kv	0	229	0	229
Total	669	1091	1541	3301

Source: NPCC, Note 7; MAAC and ECAR, Note 8.

Figure 24 shows the degree of major transmission interconnection (voltages of 230 kv and above) between the major regional power pools and reliability councils, noting both existing and planned additions over the next 10 years. Figure 25 shows the transfer capabilities in 1976; this is the maximum amount of power that can be scheduled beyond contracted sales and purchases with an assurance of system reliability, for interregional transfers over the transmission network for periods of up to several days.[9] Note that due to the electrical characteristics of adjoining networks, the amount of power than can be transferred across a given set of lines differs according to the direction of the flow.

6.4 Interregional Energy Transfers

This interregional transfer capability serves not only reliability objectives, but, on occasion, is used for power transfers on a more permanent basis. At the height of the oil embargo in the winter of 1973-74, large blocks of power were transmitted from midwestern and southern utilities through MACC and NYPP to NEPOOL;[10] NEPOOL, being one of the most dependent regions in the country on imported oil, was particularly affected by the embargo, and the transfer averaged 20 million kwh per day (at 1000 Mw and over), mainly at night.[11]

The generation cost differential between oil fired plants in the Northeast and coal fired plants in the interior regions of the U.S. continues, of course. Thus, the National Electric Reliability Council established a special Task Force to examine the capability of the power systems east of the Rocky Mountains to make interregional power transfers for the purpose of reducing both the use of natural gas (in the Southwest) and use of oil (in MAAC and NPCC).[12] Results of the study indicate that over the 13-week period from December 1, 1975 to February 29, 1976, imports from ECAR, MAIN, MARCA, and SERC to MAAC and NPCC (see Figure 26 for definition of these reliability council abbreviations), might be 347 and 204 Gwh/week, respectively. This would result in a displacement of 10.7 percent of MAAC energy requirements, and 5.2 percent of NPCC (U.S. portion) requirements. Note, however, that these results were based on only technical considerations, without regard for contractual and regulatory requirements.

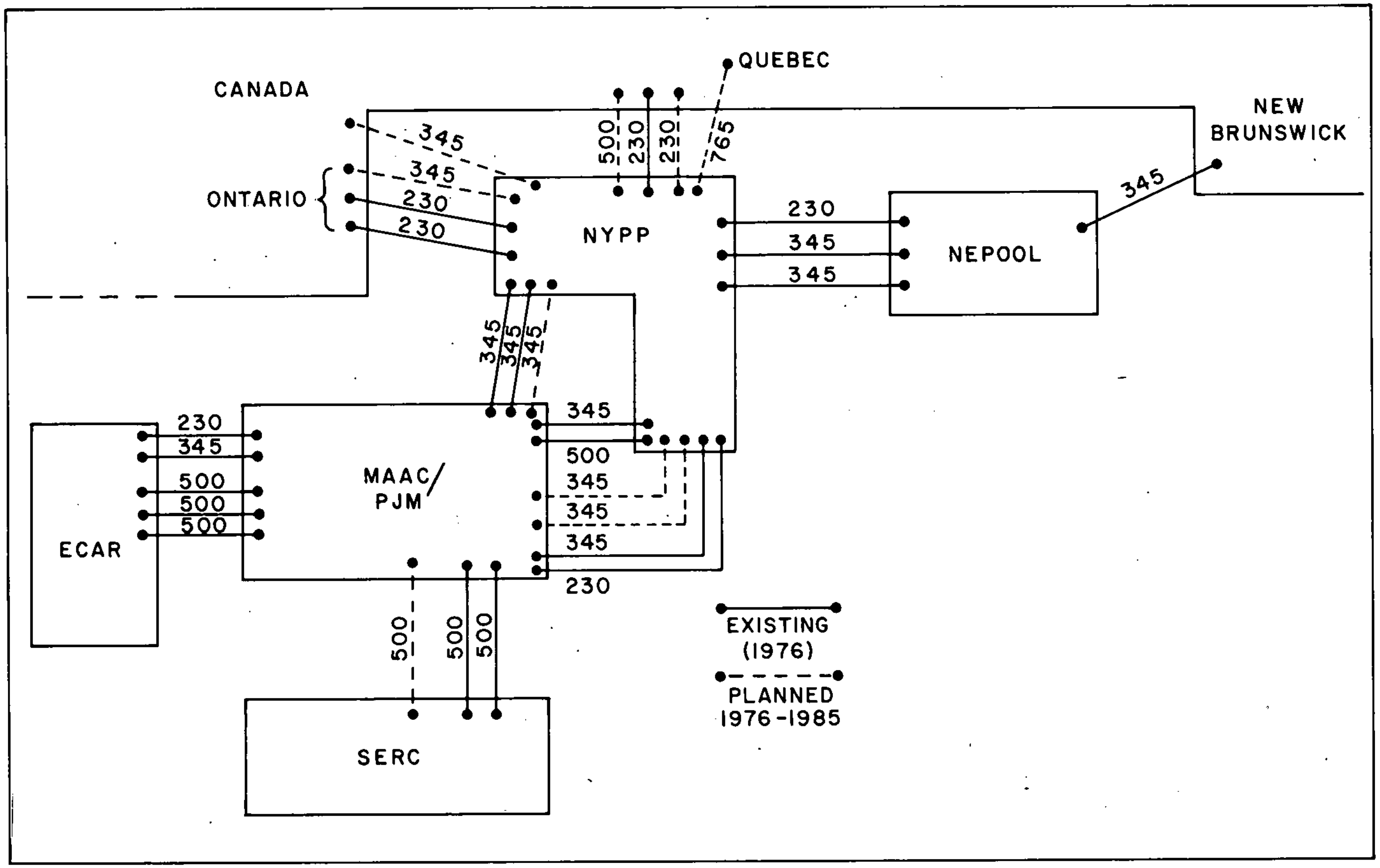


Figure 24. Inter regional transmission ties.

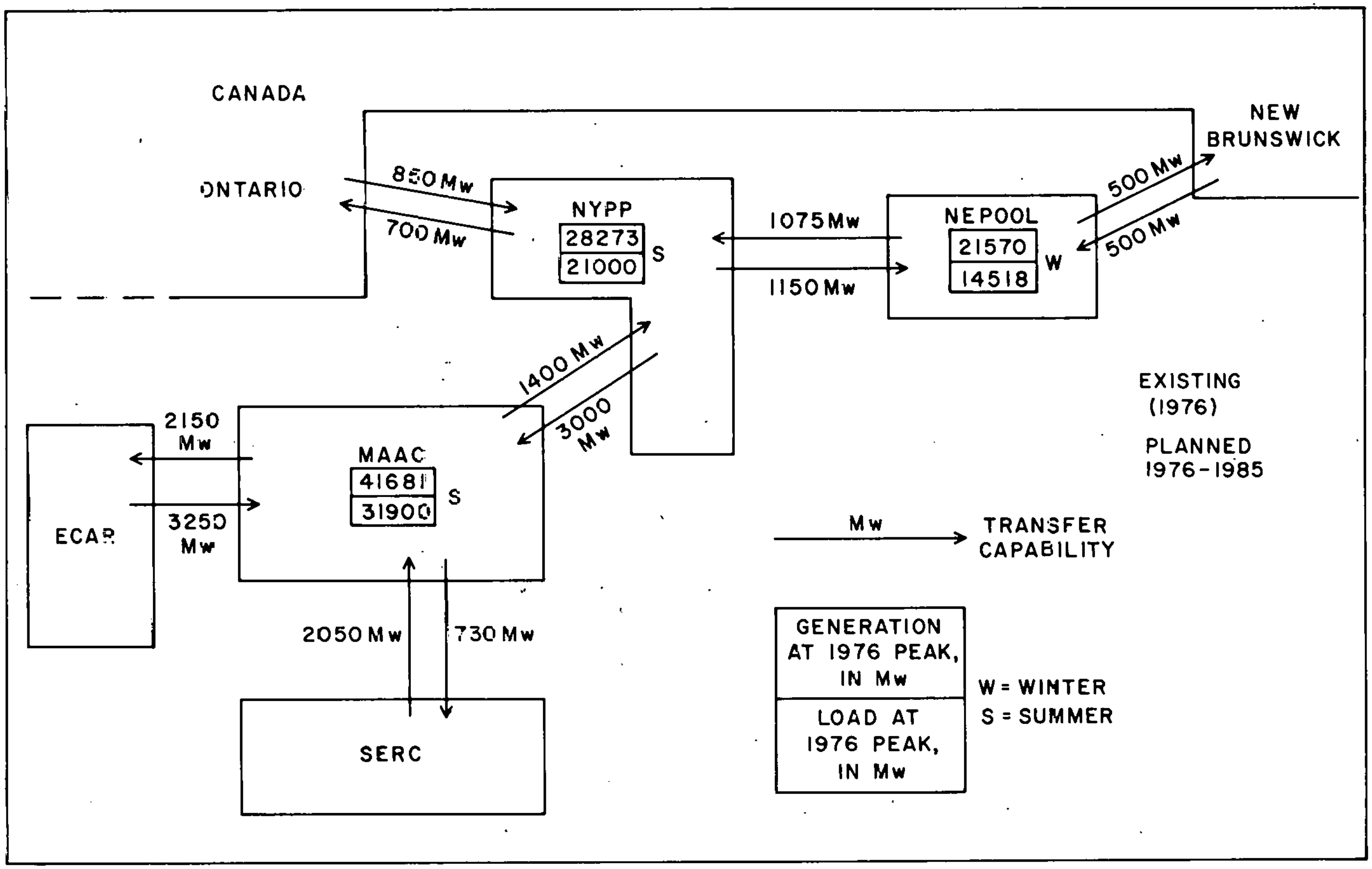


Figure 25. Emergency transfer capabilities, 1976. Source: NPCC, note 7; MAAC, note 9 and NERC, note 13.

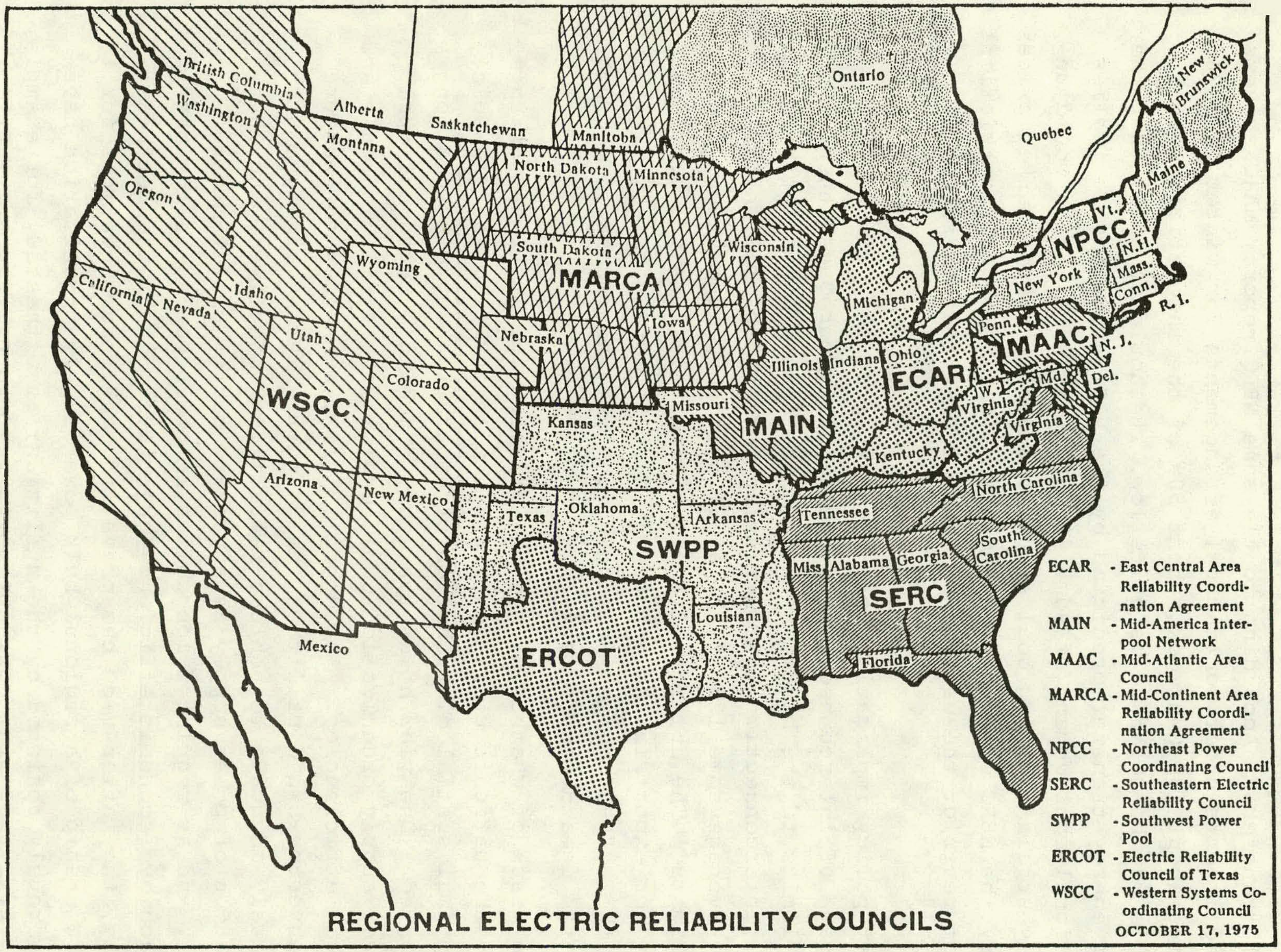


Figure 26. National Electric Reliability Council.

How does this theoretical capability compare with actual inter-regional transfers? According to the same NERC report, MAAC systems projected imports under contractual arrangements for winter 1975-76 to average about 180 Gwh/week, about 50% of the theoretical total. While this may be regarded as quite low, it should be noted that the level of energy transfer predicted by the NERC study result implies an additional coal demand of some 460,000 tons/week, which would undoubtedly strain existing coal supplies and affect spot market prices. Moreover, the NERC study also assumes that environmental restrictions would not restrict the use of available coal-fired generating capacity.[14]

What policy implications can be drawn from this discussion? As in the case of interconnection for reliability purposes, there are certain limits to the benefits that can be derived from further regional interconnection. Transmission losses (assumed in the NERC study to average some 12% of the additional coal generation) certainly impose limits. The ability of coal burning utilities to devote excess capacity for export in the future may also be more severely limited than in the 1975-76 period, during which time the recession reduced anticipated demand requirements.

The issue of whether or not the existing institutional arrangements of the nation's utilities are satisfactory from the viewpoint of an optimal spatial distribution of generating capacity has long been debated. One view holds that only a publicly owned national bulk power supply organization could exploit the available scale and geographic efficiencies. The opposite view, currently the posture of the investor-owned utilities, holds that existing arrangements are entirely adequate to achieve reliability objectives, and that organization of power supply as a private sector profit-making activity, and as regulated monopolies in power pools, is the best way to achieve economic efficiency objectives.[15] In the Northeast, certainly, the latter view has prevailed, and recommendations for pbulic ownership of a regional bulk power supply organization have been vigorously resisted by the utilities; as witnessed, for example, by opposition to a study conducted for the New England Regional Commission that recommended the creation of a regional power agency to replace NEPOOL.[16]

NOTES TO CHAPTER VI

1. A further problem in D.C. transmission is the development of a D.C. circuit breaker (see U.S. Nuclear Regulatory Commission, "Nuclear Energy Center Site Survey - 1975," Report NUREG-0001, Part III, p. 4-7 for a summary.)

2. For example, between the North and South islands of New Zealand, under the English Channel, and between Denmark and Sweden.

3. Prominent controversies include the landmark case of Greene County Planning Board vs. FPC, 455F2d412, (2nd Circuit, 1972) or the fight of the Fairfield-Litchfield Environmental Council against a proposed 345 Kv line in Southern Connecticut.

4. See e.g. Johnson, Johnson, and Roy, "Transmission and Distribution Rights of Way", Developed for the Consumer Power Co. in Michigan and widely quoted as a source document in transmission line routing.

5. P. Meier et al., "Evaluation of Power Facilities: A Planner's Handbook," Berkshire County Regional Planning Commission, Pittsfield, Mass., (Nov. 1974).

6. Project Independence, Facilities Task Force Report, Nov. 1974, notes that while the proportion of new dwellings with underground distribution connections has risen from 10 percent in 1962 to 60 percent in 1974, the cost of converting the existing overhead distribution system to underground by 1990 is on the order of $199 billion for the nation as a whole. (Pt. VII, 248)

7. Northeast Power Coordinating Council, "Data on Coordinated Regional Bulk Power Supply Programs/FPC Order 383-3, Docket R-362, Appendix "A-1", April 1, 1976.

8. Mid-Atlantic Area Council, "MAAC Systems Plans/Response to Federal Power Commission Order 383-3, Docket No. R-362," April 1, 1976. See also, East Central Area Reliability Coordination Agreement, "A Report by ECAR Bulk Power Members to the Federal Power Commission Pursuant to Docket R-362, Order 383-4," April 1, 1976.

9. For further details, see e.g. NPCC, note 7, <u>supra</u>, Section 6, p. 13.

10. See e.g. <u>Electrical World</u>, Feb. 15, 1974, p. 26.

11. <u>Ibid</u>.

12. National Electric Reliability Council "A Study of Interregional Energy Transfers 1975-1976 Winter", Oct. 1975.

13. National Electric Reliability Council "Review of Overall Adequacy and Reliability of the North American Bulk Power Systems" Oct. 1974.

14. <u>Ibid</u>, p. 4.

15. The opposing views were well documented in connection with hearings of the proposed Electric Power Coordination Act of 1971 (which died in committee during the 92nd Congress), see House, Committee on Interstate and Foreign Commerce "Power Plant Siting and Environmental Protection," 92nd Congress, First Session, Washington D.C., vs. Government Printing Office, 1971.

16. See H. Zinder and Associates "A study of the Electrical Power Situation in New England" Report to the New England Regional Commission, Sept. 1970, p. 14.

CHAPTER VII

THE FUTURE

Given the focus of the Perspectives Study on the balance of energy supply and demand in the Northeast, there are two key questions that must be examined in an assessment of the electric sector. The first, and perhaps the more urgent issue, concerns the ability of the Northeast to decrease its dependence on imported oil as a utility fuel. And the second concerns the ability of the utilities to actually meet the potential demands placed upon them, which, given the increasing difficulties in siting facilities, and the severe financial strains on utilities in a period of high interest rates, escalating construction and fuel costs and increasing controversy over adequacy of rates and regulatory lag, is by no means an assumption that should be taken for granted.

The Current Utility View of 1985

Perhaps the best starting point for our analysis is at the utilities' own view of 1985, as set forth in the various utility power pool and reliability council region reports. Indeed, given the long lead time for base load generating facilities, current planning for base load fossil and nuclear plants in fact represent an upper bound to the installed capacity of that type in 1985. In other words, it is extremely doubtful that any large base load facility for which planning has not started in 1976 could be completed by 1985.

Tables 19, 20, and 21 itemize the facilities currently planned for each of the three subregions, corresponding to NEPOOL, the New York Power Pool, and PJM plus parts of CAPCO and APS in Western Pennsylvania. These tabulations also include any currently planned retirements, and any significant de- or re-ratings of units.

Figures 27 and 28 display the generation mix in terms of total installed capacity of each generation type, and percentage, respectively, from 1975 to 1985. The most important feature is the

Table 19

PLANNED FACILITIES IN NEPOOL

YEAR	PEAK LOAD GW(E)	UTILITY	FACILITY	UNIT	TYPE	NEW UNIT CAPACITY GW(E)	YEARLY ADDINS GW(E)	TOTAL SYSTEM GW(E)	RESERVE MARGIN PERCENT
1975	12.84								
							0.00	19.90	54.98
1976	13.10								
		NEGEA+EVA	CANAL	-2	OIL	.56			
		TAUNTON	E.F.CLEARY	-9	COMB.TUR	.02			
		BRAINTREE	POTTER	-	OIL	.08			
			MISC.	-	OIL	.12			
		NORTHEAST	MILLSTONE	-2	NUCLEAR	.44			
			* MISC.	-	NUCLEAR	.04			
							1.25	21.15	61.42
1977	13.31								
			* MISC.	-	NUCLEAR	.06			
							.06	21.21	59.32
1978	14.83								
		C.MAINE	WYMAN	-4	OIL	.60			
							.60	21.81	47.04
1979	15.70								
			MISC.	-	OIL	.01			
							.01	21.81	38.94
1980	16.63								
		C.MAINE	BRUNSWICK	-	HYDRO	.01			
		MASS MNCP.	DANVERS	-	REFUSE	.08			
		NEGEA	CANNON ST.	-	COMB.TURB.	.07			
			MISC.	-	OIL	.01			
							.17	21.98	32.16
1981	17.60								
		PSC(N.H.)	SEABROOK	-1	NUCLEAR	1.15			
		PEABODY L.	WATERSRIVER	-	COMB.TURB.	.02			
		MASS MNCP.	PLAINVILLE	-	REFUSE	.08			
		MASS MNCP	STONYBROOK	-1	OIL	.23			
							1.47	23.45	33.24
1982	18.59								
		NORTHEAST	MILLSTONE	-3	NUCLEAR	1.15			
		BOSTON ED.	PILGRIM	-2	NUCLEAR	1.18			
		MASS MNCP.	STONYBROOK	-2	COMB.TURB.	.08			
							2.41	25.86	39.13
1983	19.63								
		PSC(N.H.)	SEABROOK	-2	NUCLEAR	1.15			
							1.15	27.01	37.62
1984	20.74								
		HUDSON L.P	CHERRY ST.	-	OIL	.01			
		MASS MNCP	CHERRY ST	-	OIL	.16			
		NEES	NEPCO	-1	NUCLEAR	1.15			
							1.32	28.33	36.62
1985	21.90								
							0.00	28.33	29.38

*Rerating.

Source: NPCC, 1976, See Note 7, Chapter VI.

Table 20

PLANNED FACILITIES IN NYPP

YEAR	PEAK LOAD GW(E)	UTILITY		FACILITY	UNIT	TYPE	NEW UNIT CAPACITY GW(E)	YEARLY ADDTNS GW(E)	TOTAL SYSTEM GW(E)	RESERVE MARGIN PERCENT
1975	20.00									
								0.00	26.89	34.45
1976	21.00									
		NMPC		OSWEGO	-5	OIL	.85			
		PASNY	*	FITZPATRICK	-1	NUCLEAR	.41			
		C.HUDSON	*	ROSETON	-	OIL	.04			
		CON EC	*	INDIAN PT.	-2	NUCLEAR	.01			
		PASNY		INDIAN PT.	-3	NUCLEAR	.87			
		PASNY		ASTORIA	-6	OIL	.79			
								2.97	29.86	42.18
1977	21.52									
		LILCC		NORTHPORT	-4	OIL	.39			
		NYSE+G		HOMER CITY	-3	COAL	.33			
		CON EC	*	HUDSON AVE	-	OIL	-.03			
		CON EC	*	WATERSIDE	-	OIL	-.03			
								.65	30.50	39.16
1978	22.77									
		PASNY	*	INDIAN PT.	-3	NUCLEAR	.09			
		LILCC		MITCHELLGDNS	-	REFUSE	.03			
		JAMESTOWN	*	STEELE ST.	-	COAL	-.02			
		CON EC	*	WATERSIDE	-	OIL	-.07			
								.04	30.54	34.12
1979	23.65									
		LILCC		SHOREHAM	-1	NUCLEAR	.82			
		CON EC	*	INDIAN PT.	-2	NUCLEAR	.16			
		CONSCRT.		OSWEGO	-6	OIL	.85			
								1.83	32.37	36.87
1980	24.61									
		PASNY	*	INDIAN PT.	-3	NUCLEAR	.07			
		O+RU		SHOEMAKER	-	COMB.TURB.	.13			
		CON EC	*	WATERSIDE	-7	OIL	-.05			
								.14	32.51	32.11
1981	25.60									
								0.00	32.51	27.00
1982	26.60									
		PASNY		P.HYDRO	-	HYDRO	1.00			
		PASNY		MTA FOSSIL	-	COAL	.70			
		NYSE+G		CAYUGA	-	COAL	.85			
		CONSCRT.		NINE MILE PT	-2	NUCLEAR	1.08			
								3.63	36.14	35.88
1983	27.60									
		CONSCRT.		JAMESPORT	-1	NUCLEAR	1.15			
		JAMESTOWN	*	STEELE ST.	-3	COAL	-.02			
								1.14	37.28	35.07
1984	28.64									
		CONSCRT.		STERLING	-	NUCLEAR	1.15			
		PASNY		GREENE CO.	-	NUCLEAR	1.20			
		C.HUDSON	*	DANSKAMMER	-1	OIL	-.06			
		CON EC	*	HUDSON AVE.	-	OIL	-.32			
								1.96	39.24	37.02
1985	29.76									
		CONSCRT.		JAMESPORT	-2	NUCLEAR	1.15			
		NMPC		LAKE ERIE	-1	COAL	.85			
		R G+E	*	BEEBE	-	OIL	-.03			
		CON EC	*	59TH ST.	-	OIL	-.04			
								1.94	41.18	38.36

*Rerating

Source: NPCC, 1976, see Note 7, Chapter VI.

Table 21

PLANNED FACILITIES IN PJM AND WESTERN PENNSYLVANIA AND WESTERN MARYLAND

Year	Peak Load Gw(E)	Utility	Facility	Unit	Type	New Unit Capacity Gw (E)	Yearly Addtns Gw (E)	Total System Gw (E)	Reserve Margin Percent
1975	36.85								
							0.00	47.69	29.4
1976	36.70								
		Phil.Elec.	Eddystone	-3	oil	.22			
		Phil.Elec.	Eddystone	-4	oil	.40			
		Delmarva	Easton	-	oil	.01			
		Delmarva	*McKee Run	-3	oil	.01			
		GPU	*Misc.	-	oil	- .05			
		Consort.	Salem	-1	nuclear	1.09			
		**CAPCO	Mansfield	-1	coal	.27			
		**CAPCO	Beaver Valley	-1	nuclear	.55			
							2.49	50.18	36.7
1977	39.12								
		Penn P&L	Martins Creek	-4	oil	.82			
		Baltimore	Calvert Cliff	-2	nuclear	.87			
		Baltimore	*Gould St.	-	oil	- .07			
		GPU	Gilbert	-8	oil	.13			
		GPU	*Misc.	-	oil	- .11			
		GPU	Homer City	-3	coal	.33			
		**CAPCO	Mansfield	-2	coal	.12			
		**Duquesne	Shippingport	-	nuclear	.06			
							2.14	52.32	33.8
1978	41.11								
		GPU	Three Mile Is.	-2	nuclear	.88			
		**CAPCO	*Beaver Valley	-1	nuclear	.02			
							.90	53.22	29.5
1979	43.30								
		Delmarva	Easton	-	oil	.01			
		Delmarva	Indian River	-4	coal	.40			
		Baltimore	Unassigned	-	comb.turb	.20			
		Consort.	Salem	-2	nuclear	1.12			
		**CAPCO	Mansfield	-3	coal	.16			
							1.89	55.11	27.3
1980	45.55								
		PSE&G	*Essex	-8	comb.turb.	.03			
		PSE&G	*Sewaren	-6	comb.turb.	.06			
		Ace	Unassigned	-	comb.turb.	.12			
		Baltimore	Brandon Shore	-1	oil	.61			
		Consort.	Susquehanna	-1	nuclear	1.05			
		Potomac El	Chalk Point	-4	oil	.60			
							2.47	57.58	26.4
1981	47.96								
		Phil.Elec.	Limerick	-1	nuclear	1.06			
		Phil.Elec.	*Richmond	-	oil	- .13			
		Ace	Unassigned	-	comb.turb.	.06			
		Delmarva	Unassigned	-	unknown	.57			
		Baltimore	Unassigned	-	comb.turb.	.10			
		**CAPCO	Beaver Valley	-2	nuclear	.17			
							1.82	59.40	23.9
1982	50.44								
		Phil.Elec.	Limerick	-2	nuclear	1.06			
		Ace	Unassigned	-	comb.turb.	.12			
		Baltimore	Brandon Shore	-2	oil	.61			
		Baltimore	*Westport	-	oil	- .05			
		GPU	Forked River	-1	nuclear	1.12			
		Potomac El	Dickerson	-4	coal	.80			
		Consort.	Hope Creek	-1	nuclear	1.07			
		Consort.	Susquehanna	-2	nuclear	1.05			
							5.78	65.18	29.2
1983	52.87								
		Phil.Elec.	*Chester	-	oil	- .12			
		Ace	Unassigned	-	comb.turb.	.06			
		Ace	*Deepwater	-3	oil	- .05			
		Ace	*Deepwater	-4	oil	- .05			
		Baltimore	Unassigned	-	comb.turb.	.30			
		GPU	*Williamsburg	-5	coal	- .03			
		**CAPCO	*Beaver Valley	-2	nuclear	.01			
							0.12	65.30	23.5
1984	55.51								
		PSE&G	Burlington	-	[illegible]	- .24			
		Delmarva	Unassigned	-	oil	.57			
		GPU	Seward	-7	coal	.80			
		Consort.	Hope Creek	-2	nuclear	1.07			
							2.19	67.49	21.6
1985	58.18								
		Phil.Elec.	Unassigned	-1	nuclear	1.10			
		Baltimore	Unassigned	-1	nuclear	1.20			
		Potomac El	Douglass Pt.	-1	nuclear	1.18			
		Consort.	Atlantic	-1	nuclear	1.15			
							4.63	72.12	24.0

*Rerating
**Members of ECAR

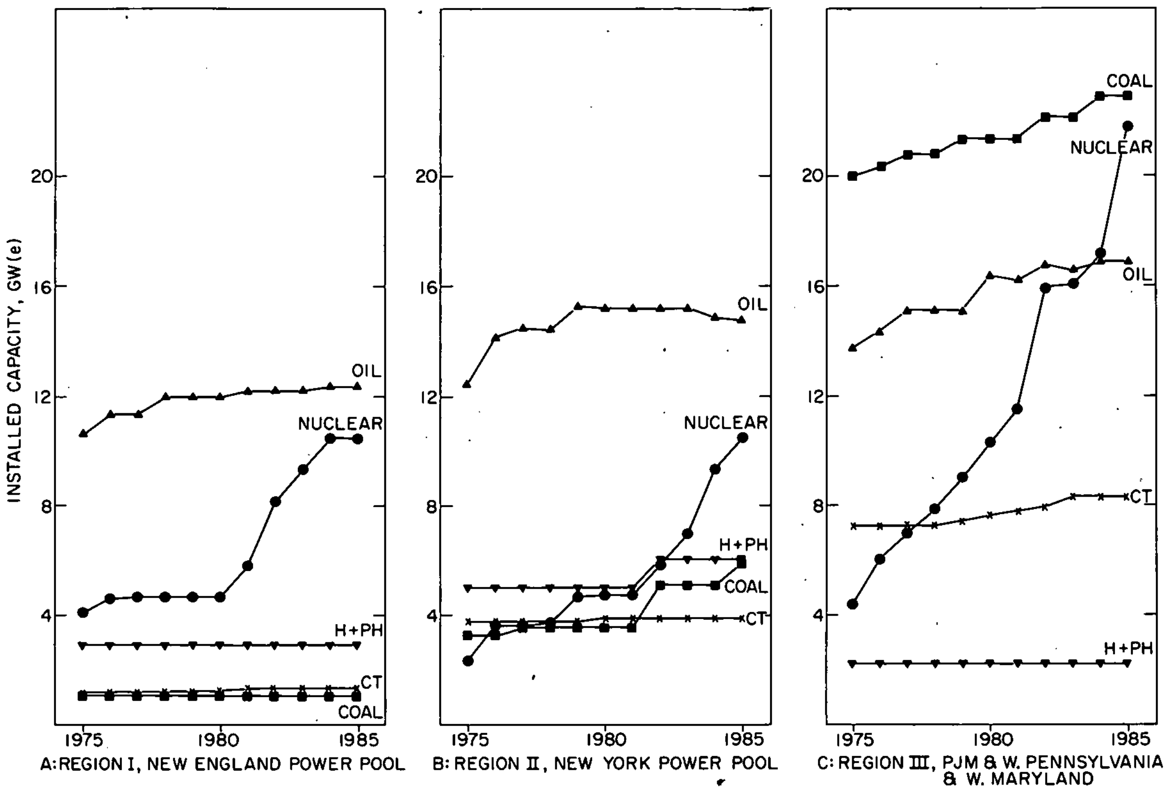


Figure 27. Installed capacity.

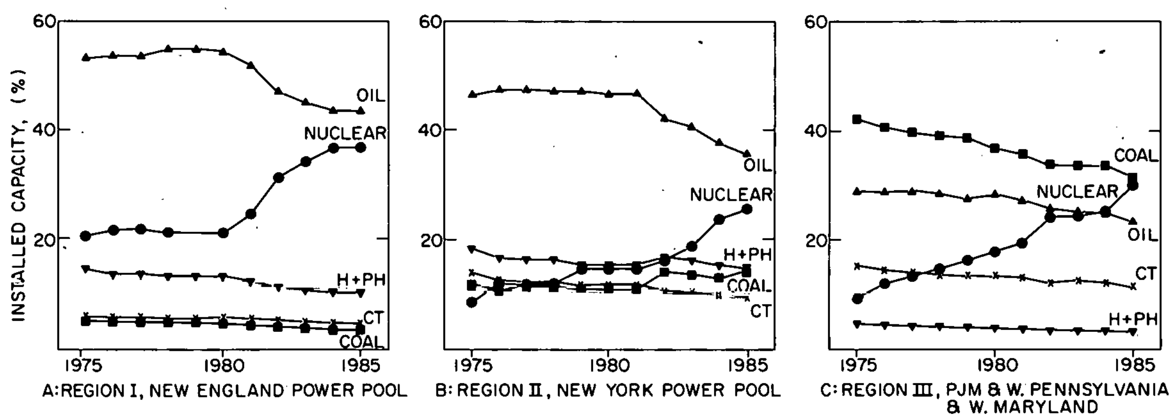


Figure 28. Generation mix.

dramatic rise in nuclear capacity, far exceeding the new coal fired capacity increments. If one translates these computations into fuel use, assuming similar efficiencies as in 1975, the results of Figures 29 and 30 emerge, showing total fuel use, in 10^{12} Btu/yr, and percentage of each fuel type, respectively. Thus, we note that in absolute terms, oil consumption barely changes (Figure 29), and coal use shows only small increases. It is clear that the bulk of new electrical demand between now and 1985 will be supplied by nuclear plants. On a relative basis (Figure 30), oil is seen to show significant decrease, which does suggest that the impact of another oil embargo might decrease somewhat with time (in New England, for example, the dependence on oil decreases from about 60% of total Btu requirements in 1975 to an estimated 47% by 1985).

Dependence on Oil

A thorough analysis of the degree to which the Northeast can reduce its dependence on imported oil, and on residual fuel oil as used by the electric utilities in particular, is the subject of more exhaustive analysis in the coal issue paper[2] and the main perspectives study report,[3] especially as it applies to the long term. But the immediate prospects for conversion of oil-fueled facilities to coal are not encouraging: even the impact of conversion of all facilities under current FEA orders of intent would, by 1985, have only marginal impact on oil consumption when viewed from the regional perspective as a whole (indicated on Figures 29 and 30 by the 1985 arrows for coal and oil fuel consumption).

Moreover, the realities of the situation suggest that utility opposition to such conversion orders, especially in the Northeast, is not about to disappear until the environmental and regulatory uncertainty is resolved (more of which below). In particular, even if it can be shown that there is an economic gain (and there is some doubt on this count, especially in New England), the issue of ash and scrubber sludge disposal, and the resolution of current ambiguities concerning emission requirements, are obvious prerequisites. Indeed, here is an excellent example of how an energy policy measure, that on narrow energy independence grounds seems eminently reasonable,

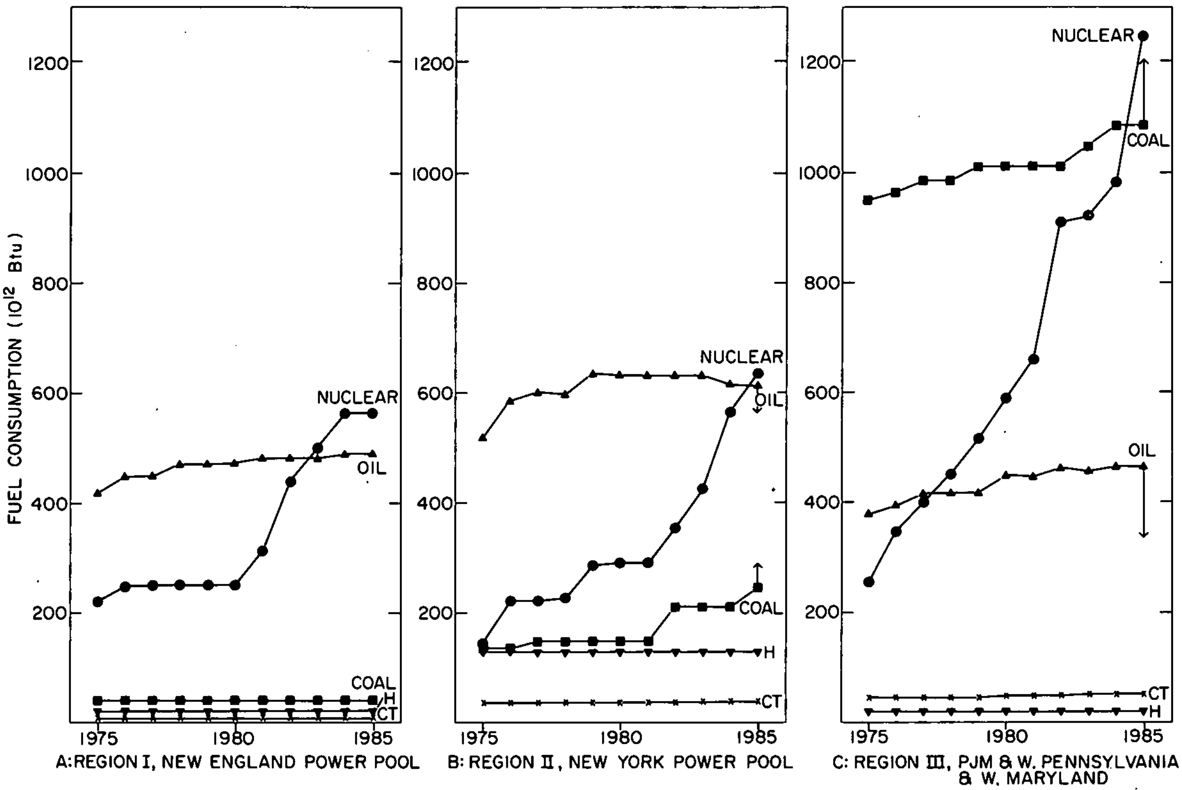


Figure 29. Fuel consumption.

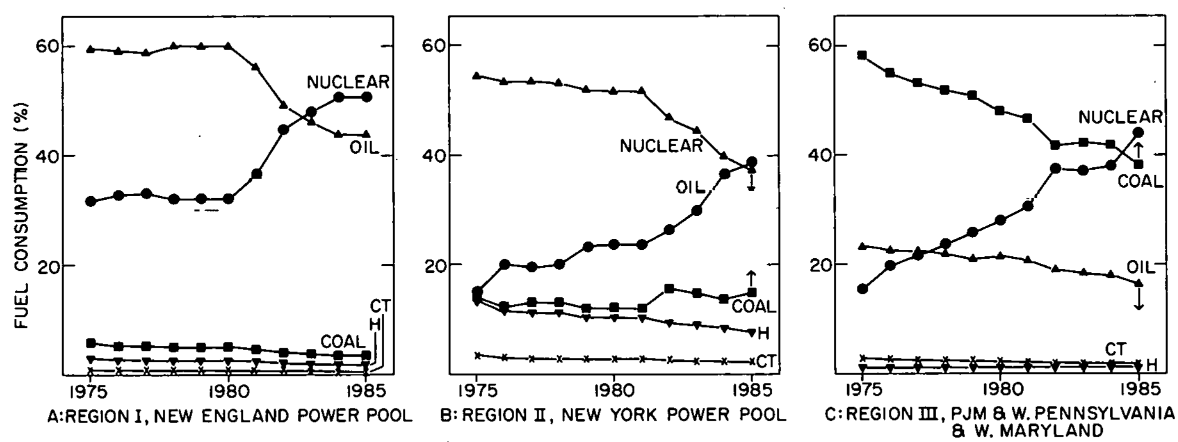


Figure 30. Fuel mix.

and desirable, seems less reasonable in light of actual environmental conditions. If the same order that mandated conversion from oil to coal also mandated the state to expedite approval of solid waste disposal facilities, then implementation would seem more likely. Unfortunately, however, the narrow regulatory jurisdiction of Federal Agencies generally precludes such a comprehensive approach.

Planning Uncertainty

There appears to be general agreement that the long lead times faced by utilities for major base load units is one of the major problems facing the electric sector. As illustrated on Figures 31 and 32, this lead time is typically 7 to 8 years for a fossil unit, and as much as 9 to 10 years for a nuclear unit; and with extensive delays in licensing now quite usual, even a 12 year lead time must be regarded as typical. However, although the inefficiency of the regulatory framework is often cast as the principal villain, a number of more rigorous quantitative analyses that went beyond mere rhetoric found that while regulatory inefficiency was indeed a significant source of delay, other problems associated with the construction of the facility were equally important. One FPC study, for example, found that while three quarters of all plants scheduled for completion from 1966-1970 were delayed more than a month, only 6% of delay factors were related to licensing problems, as opposed to 52% related to labor problems and 37% to equipment problems.[4] And in a more recent analysis, Reinschmidt and Kilcup examined the causes of construction delay of 126 generating units (of which 40 were nuclear and 86 fossil), completed or under construction between 1968 and April 1974.[5] In order of importance, the major causes of delay were found to be design changes (124 cases); environmental issues (84), labor strikes (68), labor shortages (74), late delivery (67), construction permit (63), low labor productivity (61), and public hearings (37).[6] Thus while environmental issues and public hearings are certainly important sources of delay, they do not so dominate as to support the argument that deficiencies in the institutional framework can be cast as the principal cause of delay.[7]

To be sure, reform of the institutional process must remain high on the agenda of priorities of state and federal regulatory

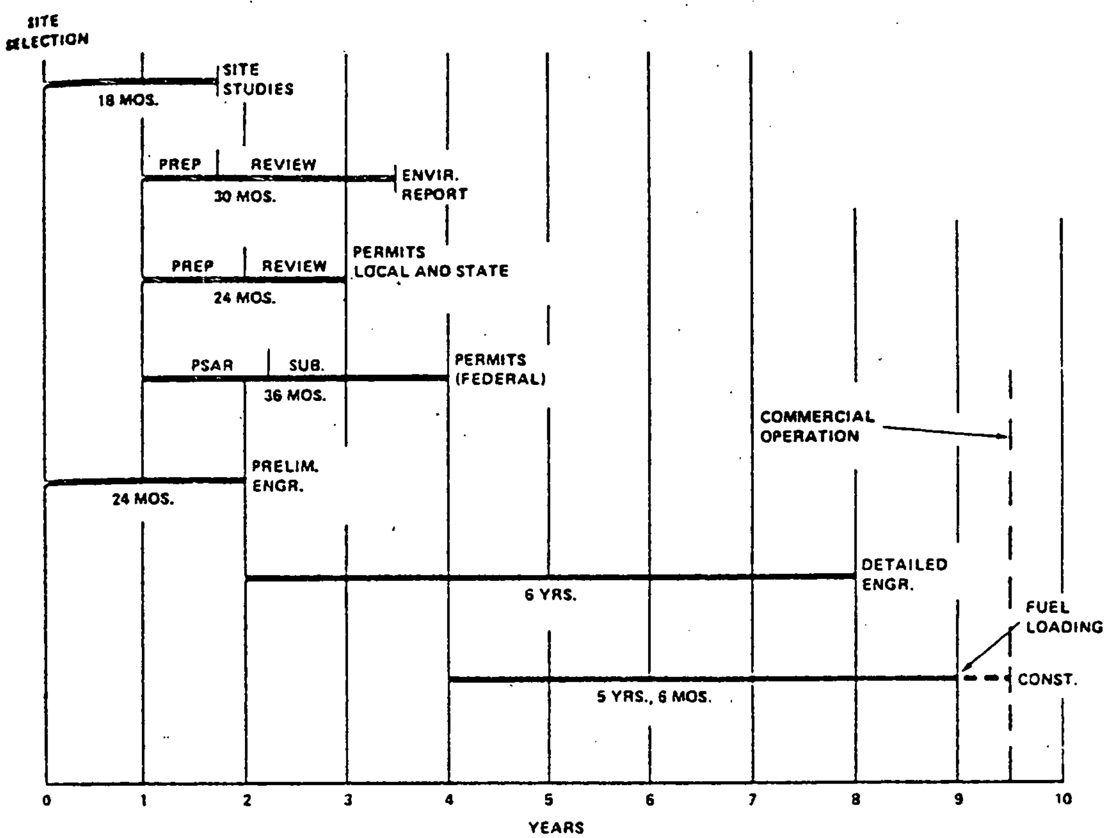


Figure 31. Typical construction schedule. 1100 Mw nuclear unites on a new site. Source: Booz, Allen, and Hamilton, note 1, p. 106-9.

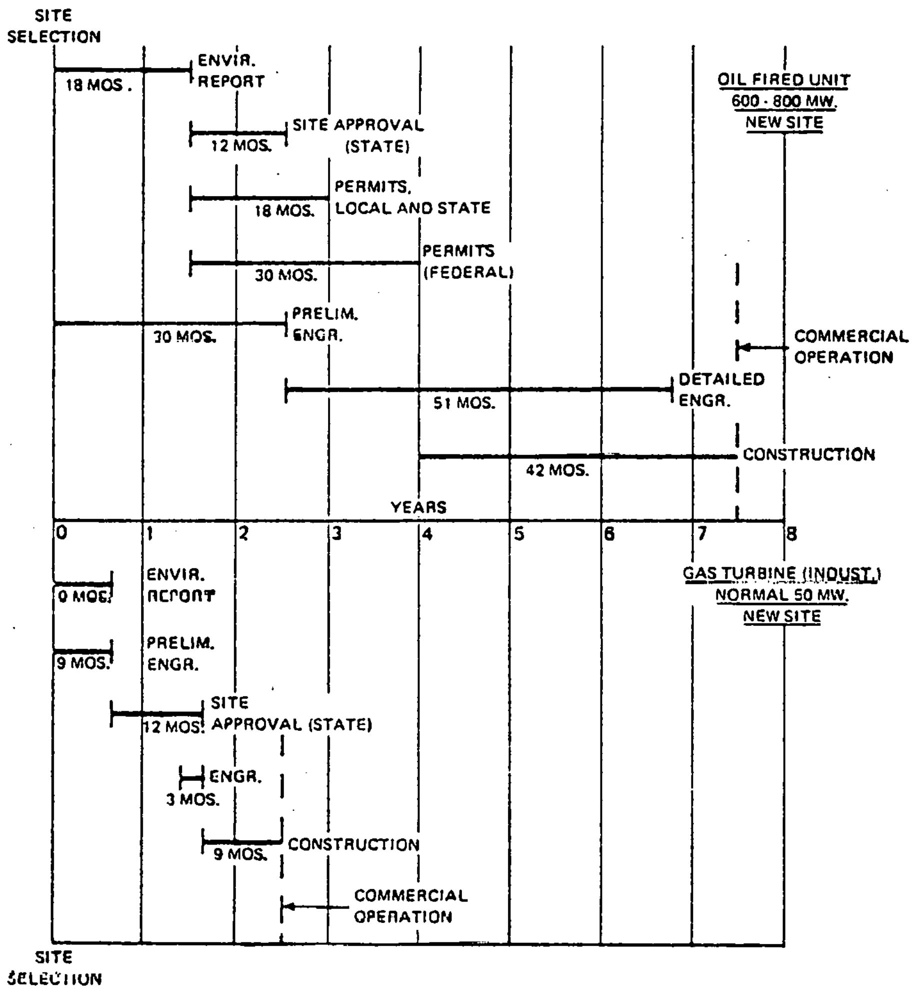


Figure 32. Typical construction schedules for fossil fueled and combustion turbine units. Source: Booz, Allen and Hamilton, note 1, p. 107-7.

agencies, especially in view of the immediate benefits that a more efficient procedure would bring. At the same time, however, it is also incumbent on the utilities, their equipment suppliers and architect-engineers to focus more attention on construction efficiency--modular, standardized construction design, inherent, for example in the floating nuclear station concept involving assembly line construction, comes immediately to mind. Moreover, as the example of the AEP 1300 Mw fossil design series discussed in Chapter IV shows very clearly, design maturity can be quickly and efficiently achieved under such an approach, thereby enhancing the subsequent operational economics of the facility as well.

One must understand, however, that it is not only the length of the regulatory process that is at issue, but also its unpredictability. As noted by a recent study by the Bar Association of New York, it is the unpredictability of delay that poses the principal impediment to rational planning:[8]

> "In the long run, then, the cure is to fashion a procedure which is not necessarily terse, but whose length and standards for decision are fairly predictable. To mandate a process which cuts off debate arbitrarily may result in judicial reversals, which are the worst sources of uncertainty because they are least predictable and can lead to the longest delays. If utilities could accurately anticipate the time needed in the licensing process and apply for all licenses well before they are needed, the problems posed by the length of the application process would largely be confined to extra legal costs. Thus, except for the AEC operating license, which must be applied for near the time of plant completion, it is uncertainty of the process, not its length, which can lead to blackouts."

Yet the type of inter-agency conflict and regulatory uncertainty that plagues the Northeastern Utilities raises is the very antithesis of a sound regional energy policy. In the nuclear power arena, for example, the experience of the Seabrook, New Hampshire, nuclear plant is almost a casebook example of how not to regulate: the most recent episode being the reported revocation of EPA approval of the cooling system, long after a construction permit had been issued by NRC (and construction actually commenced).[9] Regardless of the merit, or lack of merit, of the cooling system proposed, a well-considered and irrevocable EPA position ought to have been forthcoming at a much earlier date--whether favorable or unfavorable.

Similarly, the FEA coal conversion program must be placed in a regulatory context that is far from clear; as noted by one recent analysis of the conversion of oil facilities to coal in New England:[10]

> "...The risk of committing investment capital now, with the spectre of unforseeable future controls very foreboding, would encourage any utility to resist a conversion order indefinately. This would be especially true for those plants having limited remaining life."

Moreover, a key barrier to coal conversion in New England is the difficulty of ash and sludge disposal--at present there is only one approved site available for 10 plants in Connecticut and Massachusetts.[11]

These observations all point to an axiom of effective energy policy-making that does not appear to have penetrated sufficiently into the body politic: a rational energy policy, if it is to be effective, cannot be achieved if its compenents are assigned to single-purpose, mission oriented agencies in the absence of a forum for effecting trade-offs in an orderly and efficient manner. To be sure, there is a need for regulatory bodies to assure compliance with given standards, even in quite narrowly focussed areas. But the essence of sound energy policy-making is to integrate environmental concerns into the policy analysis stage, rather than as a post decision addendum.

John Quarles, Deputy Administrator of EPA, identified the problem in these terms

> "...Common sense would suggest that environmental and related factors should be balanced against economic and other social objectives in deciding whether further industrial growth should be permitted in a particular locality. But current regulations often obstruct or prohibit a balancing of such factors in the light of local needs and desires. Instead, we have a series of single dimension regulatory requirements, many imposed by Federal Law imposing rigid national requirements."[12]

It is not, of course, the function of the courts to perform this balancing function, even if the opponents in litigation in fact seek to use the courts in such a manner to decide environmental or policy issues.[13] The basis for judicial review of administrative action is defined in the Administrative Procedure Act: "...the reviewing court shall...hold unlawful and set aside agency action, findings, and conclusions found to be (a) arbitrary, capricious, and abuse of discretion, or otherwise not in accordance with law: . . . (e) unsupported by substantial evidence in a case subject to hearings."[14] Scrutiny of many of the landmark cases involving regulatory agency decision-making supports the argument that, in fact, the courts have not been directly deciding environmental or energy policy issues, but have properly focused on the manner in which agency decisions have been reached. And even in such cases where the courts' focus has been on an interpretation of an ambiguous statute, or statutes apparently in conflict, as for example in the Calvert Cliffs Case, focus has been on clarification of Congressional intent. Although the distinction between "clarification of intent" and creation of policy may be a fine one, power-facility related environmental decisions at the Federal level have thus far been based on statutes or common law, and, unlike many Supreme Court rulings on segregation or pornography, not on constitutional grounds.[15] This distinction is significant because a statute or common law rule can readily be changed or modified by a politically responsive branch of government.[16]

Positive prescriptions are of course much more difficult than negative criticism, and a properly comprehensive analysis goes well beyond the focus of this issue paper. The issue of how environmental concerns can be integrated into energy policy analysis has been addressed in a previous paper,[17] and some forthcoming work within the BNL Regional Studies Program will address the more thorny institutional issues that lie at the heart of effective regional energy policy-making.[18] There is, to be sure, a growing literature on the subject of regulatory reform, particularly the need for more efficient licensing procedures; but here we are arguing for much more than "one-stop" siting, since it is quite unlikely that such reforms can achieve anything more than marginal improvements if the decision-making process and the formulation of comprehensive, environmentally inclusive energy policy analysis that precedes a license application has not resolved the requisite balancing of social goals.

Lead Time and Demand Uncertainty

Whatever the attribution of reason for long lead time an understanding of the relationship of lead time to the uncertainty in demand is fundamental to sound energy planning. As an illustration, consider the range of energy demand projected for Region III (see Table 10). Assume that for each energy projection, one may derive a demand projection, and a capacity projection as shown on Table 22, based on an 0.6 system load factor and a 20% reserve margin, respectively. Then, assuming a 9 year lead time for all capacity, one may examine the impact of different actual 1985 electric demands with the investment plan that one must commit oneself to in 1976. This is shown on Table 23.

We note that at the one extreme, a 1985 plan based on the low demand results in an 11% deficiency if high demands actually occur; and at the other extreme a 62% reserve margin results if capacity investment is carried out according to the high projections and the actual 1985 demand corresponds to the low case. It is of course unlikely that either of these extremes would actually occur. If demand trends emerged that proved to be lower than expected, a construction schedule could be relaxed if necessary.[19] Conversely if demands proved to be higher than expected, one might turn to generation forms with shorter lead times. The latter response might imply heavy economic penalty, as would be the case if oil or gas turbine capacity were called in to bridge a gap in nuclear capacity (quite apart from such a course running entirely counter to stated goals of reducing reliance on imported oil). But despite costs associated with delayed construction schedules (since delays are costly, whether intentioned or unintentioned),[20] on balance it would appear that overestimation of demand in planning can be accomodated at lower cost than underestimation unless the overestimation acts as an artificial stimulus to demand.

Looking at the range of capacity uncertainty for the Northeast as a whole, Table 24 sets forth estimated capacity expansions for

Table 22

1985 ENERGY DEMAND AND CAPACITY DEMAND PROJECTIONS FOR REGION III

	Energy Demand 10^6Mwh	Peak Load[a] Gw	Capacity Demand[b] Gw
Low	242	46	55
Base	282	54	64
High	326	62	74

[a]Assuming an 0.6 system load factor
[b]Assuming a 20% reserve margin

Table 23

1985 RESERVE MARGINS FOR REGION III

		1985 Peak Load		
		Low 46 Gw	Base 54 Gw	High 62 Gw
1976 capacity investment plan for 1985	Low 55 Gw	20%	2%	-11%
	Base 64 Gw	39%	19%	3%
	High 74 Gw	61%	37%	19%

Table 24

2000 CAPACITY REQUIREMENTS

	Low		Median		High	
	10^6 Mwh	Gw	10^6 Mwh	Gw	10^6 Mwh	Gw
NEPOOL	132	23	170	30	225	40
NYPP	210	37	276	49	350	61
PJM	340	60	455	80	583	103
Total	682	120	900	159	1159	204
Northeast Load[a]		120		159		204
Total 2000 Capacity[b]		144		191		245
Existing Capacity (1975)		94.5		94.5		94.5
New Capacity Requirements 1976-2000		49.5		96.5		150.5
Planned by Utilities 1976-1985		47.6		47.6		47.6
Capacity Requirements 1986-2000		2		49		103

[a] assuming .65 system load factor

[b] assuming 20% reserve margin

the range of electrical energy demands derived in Chapter II. The requisite new capacity in the interval 1976-2000 ranges from 55 to 163 Gw, a range of over 100 units of 1000 Mw. If one subtracts those capacity increments currently planned for 1985, the capacity for which as yet undetermined sites must be found ranges from 2 to 113 Gw, a very large range of uncertainty (although many sites destined for currently cancelled units, such as Fulton and Summit, would in all likelihood still be available).

Financial Issues

Although the recent financial position of the investor-owned utilities has improved in 1976, the joint impact of the oil embargo and economic recession brought especially severe financial problems to Northeastern utilities. The reason why utilities in the Northeast were among the most seriously affected in the country follows directly from the region's unique dependence on imported oil; it is here that imported oil price increases had greatest effect on consumer bills, resulting in significant consumption reductions and therefore falling utility revenues. The combination of regulatory lag, increasing costs and falling revenues imposed a severe financial squeeze on some utilities, resulting in falling credit ratings, lower dividend payments (and, in Consolidated Edison's case, even an omitted dividend), and a significantly reduced ability to raise capital. Cancellations of capital intensive base load units was thus not just a question of falling demand expectations, but also, in many cases, of mandated cuts in capital spending.

With the economic recovery and widespread rate increases finally granted, the situation has improved significantly in 1976, and the issue has receded from its previously rather prominent position. Nevertheless, the fundamental causes of the 1974-75 fiscal squeeze have not really been addressed in a serious manner, and another oil embargo and economic recession can be expected to plunge Northeastern utilities back into the same financial problems.

Cancellation or deferment of capital expenditures, particularly for nuclear and coal fired base load units, has substantial implications on the fuel and generation mix a decade hence. If, in fact, the growth in demand for electricity does begin to rise again within the next few years, utilities may be forced to utilize the older inefficient generation units for more than merely the peak loads if demand is to be met, and to install new gas turbine capacity as the type of facility that can most rapidly be put on line. This implies not only higher fuel costs than otherwise necessary, but also has environmental consequences, since the older fossil units are also characterized by higher pollutant emissions than new capacity.[21]

NOTES TO CHAPTER VII

1. Booz, Allen, and Hamilton, "Decision Guidelines for Power Facility Siting in New England", Report to the New England Regional Commission, November 1975.

2. B. Edelston and E. Rubin "Current and Future Use of Coal in the Northeast" BNL 50560.

3. J. Brainard et al "A Perspective on the Energy Future of the Northeast United States" BNL 50550.

4. Statement by FPC Chairman J.N. Nassikas, Hearings on H.R. 5277, Subcommittee on Communications and Power of the Committee on Interstate and Foreign Commerce, 92nd Congress, 1st Session, Ser. 92-31, 32, 33 Appendix G (1971).

5. Reinschmidt, K. and Kilcup, R.G. "A Survey of Power Plant Construction Problems." Combustion, Jan. 1975, p. 14-20.

6. Considering only the 86 fossil plants, the rank order is design change (41), labor shortages (41), labor strikes (35), low labor productivity (31), late delivery (30), environmental issues (22), construction permit (16), and public hearings (10).

7. Similar findings emerge from a recent FPC analysis of delays in scheduled initial operation date of transmission lines. FPC Staff Report "Delays in Scheduled Operation of Electric Transmission Lines as of December 13, 1974" FPC News, April 18, 1975).

8. Association of the Bar of the City of New York "Electricity and the Environment: The Reform of Legal Institutions" (West Publishing Co. St. Paul, Minn. 1972).

9. As reported in the New York Times, Nov. 10, 1976.

10. Center for Energy Policy, "The Impact of Power Plant Conversion on New England Energy Policy" Background Report, May 1976 to FEA, Office of Fuel Utilization.

11. Ibid, p. 1-8.

12. Address to the 5th International Pollution Engineering Congress, Anaheim, Los Angeles, as reported in the New York Times, Nov. 15, 1976.

13. Even if it were the proper function of the courts to settle policy questions, there are some practical difficulties. As noted by G.P. Thompson "The Role of the Courts" (in E. Dolgin & T. Guilbert "Federal Environmental Law", Environmental Law Institute, July 1974, p. 235); "Courts have no affirmative ability to plan ahead to handle crises nor do they have the ability to choose those problems which deserve to be litigated. Because they are forced to wait and just react to the issues which are brought to them, it is inevitable that certain important issues will not be brought to their attention because no litigant is sufficiently interested in the problem, no money exists to bring suit, or some other reason extraneous to the issue at hand. Even if a suit is brought in an important matter, the court is largely limited by the nature of the relief which the litigants choose. This means that not only may many important issues be missed by the court system because there is no plaintiff who is willing to bring them to the attention of the court, but also even suits which are raised may not be posed in the fashion which would permit the court to afford complete relief. Thus, unless the court system were fundamentally changed to permit self-initiation (an unlikely and undesirable change), courts can only hope to be partners in the process of protecting the environment, not the leading actor."

14. For a more detailed discussion of the significance of the Administrative Procedure Act in power facility litigation, see Meier, note 18, infra.

15. See Dolgin and Guilbert, note 13, supra, p. 193.

16. In Wilderness Society v. Morton, 479 F 2d 842, 3ELR 20085 (D.C. Cir., 1973), the Court ruled that before the Alaska pipeline could be built, Congressional approval was necessary to grant the Secretary of the Interior authority to lease sufficient width for pipeline construction. Congress responded quickly, overruling the court by passing Public Law 93-153, Title I, 87 stat. 576 (1973), which removed any statutory barriers.

17. P.F. Palmedo "The Incorporation of Environmental Considerations into Energy Policy Analysis" Annual AAAS Meeting, Jan. 1975 (Published as BNL 19647).

3. See also P. Meier "Energy Facility Siting: A Regional Viewpoint" BNL 20435, August 1975.

19. A utility faced with the prospect of an unusually high reserve margin might also retire old capacity somewhat earlier, or seek to export power, or even reinstitute promotional advertising to increase the utilization of its capacity. But each of these available options implies some degree of non-optimality from the overall social or regional energy planning perspective, whatever the particular fiscal impact on the utility.

20. But recall the discussion of Chapter IV in regard to Northeast Utilities decision to proceed with Millstone #2 despite stagnant load growth.

21. This, of course, was precisely the result of the Consolidated Edison experience in the late sixties-early seventies, when every major proposed facility ended in controversy, and litigation--the major impact being a delay in retirement of older capacity. (See e.g., Congressional Testimony of C. Luce, Chairman of Consolidated Edison, in Hearings, Semate Subcommittee on Intergovernmental Relations, Committee on Government Operations, 91st Congress, 2nd session on S. 2752, Feb. - April 1970, Part 1 (Intergovernmental Coordination of Power Development and Environmental Protection Act) at 58-66.) Moreover, to take the example of the Storm King mountain case, there is no evidence that the lengthy litigation reduced peak demands in the Con Ed system. This being so, one must assume that such demands as the proposed facility would otherwise have provided were met simply by importing any deficiency from the New York Power Pool and by inefficient generation in gas turbine or old fossil capacity. In fact the construction of the Blenheim-Gilboa pumped storage facility by the Power Authority of the State of New York is seen by some observers as the direct consequence of the delays at Storm King.

THIS PAGE
WAS INTENTIONALLY
LEFT BLANK

CHAPTER VIII

CONCLUSIONS

The range of demand estimates derived by the BNL study results in a large range of estimates for future electric generation capacity. In the low case, only some 50 Gw of new capacity would be required in the entire region in the interval 1975-2000, as opposed to 150 Gw in the BNL high case. This difference is equivalent to some 83 nuclear reactors (of, say 1200 Mw each), a very large margin of uncertainty. Yet, because large base load units must currently be committed some ten years in advance of their need, the great range of uncertainty for even 1985 creates severe planning problems for the utilities. A shortening of the lead time for nuclear and fossil base load units thus becomes an urgent necessity if serious reliability problems are to be avoided (the outcome of higher than expected growth) or if the cost to the consumer implied by delayed construction schedules or the excess capacity of large reserve margins is to be avoided (the outcome of a lower than expected growth rate).

The transmission grid in the year 2000 can be expected to be more developed, and with longer, higher-voltage lines, but radically new transmission technologies are not expected to be widespread. Applications of cryogenic transmission and high-voltage DC might well be encountered in a few special circumstances, but the basic reliance on overhead AC for transmission will remain unchanged. While the use of underground distribution cables in urban and suburban areas will likely increase, undergrounding of cross-country high-voltage lines will probably be restricted to a few special situations involving particularly valuable scenic landscapes.

Becuase radical improvements in system load factor are unlikely to occur over the coming decades, there will be a continued need for new capacity additions of the peaking type. Since the region offers little additional potential for conventional hydro-electric generation, this necessarily means that additional combustion turbine capacity will continue to be needed. This, in turn, implies that a total elimination of oil as a utility fuel is also unlikely. The only fuel that could realistically be expected to replace oil in combustion turbines on a large scale would be gas produced from coal (given that natural gas supplies to the region are dwindling). The other realistic means of providing peaking capacity over the next 25 years is of course, the combination of pumped storage and nuclear or a more widespread use of combined cycle plants. But whether the latter type of facility could be coal fired is still open to some doubt; and the former option faces severe siting and cost constraints. However, since most of the oil used for electric generation in the Northeast is used in base load generation (10 times as much oil is currently used in steam electric base units as in peaking combustion turbines), and given that the replacement of oil by coal in a base load unit poses few technical problems (as opposed to the economics of a conversion, or of regulatory confusion), it is to the elimination of oil in base-load plants that one should focus the most immediate attention.

Finally, our examination of the electric sector illustrates once again the urgent need for coherent national and regional energy policy. Perhaps highest on the agenda of administrative and regulatory reform must be the resolution of inter-agency conflict that plagues the utility industry, and which unquestionably imposes costs on the consumer. It is true, of course, that certain issues do involve difficult trade-offs, and that conflicts between environmental protection goals and energy policy desiderata make decision-making difficult. But the present state of regulatory confusion is quite unacceptable, regardless of which side of a particular issue one may stand.

THE BROOKHAVEN NATIONAL LABORATORY REGIONAL ENERGY STUDIES PROGRAM

The Brookhaven National Laboratory Regional Energy Studies Program is part of a national effort supported by the U.S. Energy Research and Development Administration (ERDA) to create an energy assessment capability which is sensitive to regional conditions, perceptions, and impacts. Within ERDA, this program is supported by the Division of Technology Overview and includes, in addition to a concern for health and environmental impacts of energy systems, analysis of the complex trade-offs between economics, environmental quality, technical considerations, national security, social impacts, and institutional questions. The Brookhaven Program focuses on the Northeast including the New England states, New York, Pennsylvania, New Jersey, Maryland, Delaware, and the District of Columbia. The content of the program is determined through an identification of the major energy planning issues of the region in consultation with state and regional agencies. A major component of the program in 1976 was the Northeast Energy Perspectives Study which examined the implications of alternative energy supply-demand possibilities for the region. In 1977 a major component is the northeast portion of the National Coal Utilization Assessment carried out in collaboration with several other laboratories in other regions of the United States.