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Electric Generation Capacity in New England in 1995

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Abstract

This study uses a capacity planning model to determine an optimal mix of generating plants for New England in the year 1995. The results indicate that New England has excess capacity in the generation of intermediate load and insufficient capacity in the generation of base load. The current intermediate load capacity is almost entirely oil-fired, and in 1995 it will have an average age of 35 years. The implication of the model is that the intermediate capacity is obsolete.

I. *Introduction*

The purpose of this study is to examine New England electric generating capacity anticipated for 1995 in order to determine its adequacy to meet demand at a reasonable cost. The question of adequacy of electric generating capacity is one that has been widely discussed. At issue is whether or not utilities should construct new capacity. The politically popular view is that no new electricity generating plants will be necessary in the foreseeable future. This view now shared publicly by New England utilities requires a threefold strategy. Once the 1,150 megawatt (MW) Seabrook nuclear plant is on line, all additional capacity in New England will come from 1) purchases, primarily from Canada, 2) cogeneration from private sources, 3) conservation.

To evaluate this strategy, the assumptions behind it must be examined. Then using a capacity planning model, the optimal mix of the generating plant based on data supplied by the New England Power Pool (NEPOOL)[1]

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[1]NEPOOL is the coordinating organization for New England utilities. It controls all dispatching of electricity in the region.

is estimated. The optimal mix is then compared with the expected mix that will exist in the year 1995 with the conclusion that the current New England strategy is both risky and nonoptimal.

New England is a particularly interesting area in which to study electric power generation for a number of reasons. It has turned from a nongrowth area to a growth area with the lowest level of unemployment in the United States. New England's growth has come in the hi-tech area with its significant dependency on electricity. Furthermore, New England uses a mixture of fuels to generate electricity that is far from the average of the United States as a whole. For example, the generation of electricity by fuel in 1985 was as follows:

Exhibit 1

ELECTRICITY GENERATION BY FUEL SOURCE — 1985[2]
(percent)

	Nuclear	*Coal*	*Oil*	*Gas*	*Hydro*	*Purchases*
United States	15.5	56.8	4.1	11.8	11.4	.4
New England	28.9	17.2	31.1	4.9	4.3	13.6

New England places heavy reliance on nuclear, oil, and external electricity purchases, whereas, the United States as a whole relies on coal. Even the 17.2 percent coal generation in New England is relatively new, for most of it comes from recently converted oil plants. No new coal generation plant has been built in New England over the past 20 years nor are there any plans for a future plant.

New England's somewhat unique fuel mix has been dictated by circumstances. Oil was the fuel of choice because it was easily transported here from oil producing countries (primarily Saudi Arabia). Nuclear was developed for many reasons, including the inaccessibility of coal and gas and the strong nuclear industries centered in New England (for example: General Electric, Electric Boat, and Combustion Engineering). Finally, purchases have strongly increased because of surplus power available from Canada.

II. *Ingredients of the Model*

Capacity planning models (CPM) are typically used to determine when new capacity should be added. These models, however, have wider applications, for they can also be used by energy analysts and policy makers to evaluate the adequacy and efficiency of current or future capacity. There

[2]*Nuclear Power Facts and Figures*, April, 1986, Atomic Industrial Forum, Inc. Bethesda, Maryland. Electric Utility Industry in New England, Electric Council of New England, Bedford, Massachusetts, 1984.

are many ways of approaching capacity planning as described in a survey paper [2]. Methodologies include linear programming [2], mixed integer programming [1], dynamic programming [9], and probabilistic simulation with linear models, [3, 4, 11, 13]. Each approach has its limitations. The recent mixed integer programming model [1] employing Benders' decomposition seems promising; although, only medium scale problems have been tested.

To examine future capacity in New England, a probabilistic integer model was developed. It is not intended to be a general or powerful planning model; however, it covers the key features of the capacity planning problem and has special structures which can be exploited by appropriate algorithms. The model details are given in Appendices 1 and 2. The major assumptions used in the model are as follows:

1. Demand

The key issue in capacity planning is expected demand. CPMs are typically driven by peak demand; that is, the greatest hour's demand during the year. During the 1960s and up to 1973, peak demand in New England grew at a 6 percent rate. New England suffered from a blackout as well as many brownouts as a result of insufficient capacity. To overcome this problem many peaking units were added to the system and several nuclear plants were ordered. In 1975, as a result of the Arab oil embargo and the heavy use of oil in New England for generating electricity, electricity prices went up, causing demand to drop precipitously. For the period 1977-1983 demand growth averaged 1 percent; although, the United States average was 2.5 percent. Since 1983 New England demand has recovered, and over the last three years has averaged 5 percent. At the same time, United States demand averaged 3 percent.

For planning purposes, NEPOOL forecasts peak demand growing at 2 percent. This is greater than the 1.5 percent increase that the region's two major utilities, New England Electric System and Northeast Utilities, predict for their areas. On the other hand, neither of these predictions is in line with those suggested by Sioshansi [10]. He shows that United States demand is closely related to GNP. The shock caused by the Arab oil embargo and high oil prices that so strongly affected New England only changed the intercept in the long-range peak demand curve and not the slope. Based on this argument, New England peak should increase by at least 2.6 percent — the predicted GNP growth rate. Since New England is an area of high use of electricity because of its hi-tech orientation, it is reasonable to expect that demand will increase at a rate exceeding the national average.

Why do NEPOOL and the region's two major utilities predict a growth rate in demand so much lower than the econometrically derived rate of Sioshansi? One answer is the politics of new generating capacity. There is a small, vociferous group opposing new capacity. This is evident in the current impasse at Seabrook and in the results of the recent Maine referenda. Predictions of low demand mean that new capacity is unnecessary in the immediate future. No position is taken on this problem and NEPOOL estimates are accepted for this study's model. Note, however, that the 2 per-

Exhibit 2

SEASONAL LOAD DURATION CURVE
IN FIVE PIECE-WISE LINEAR SEGMENTS
FOR 1995

	LDC_1	LDC_2	LDC_3	LDC_4
T_{j1} (Hours)	169.51	144.26	100.30	230.17
T_{j2}	828.26	341.64	570.50	904.47
T_{j3}	1,109.89	1,622.79	1,714.77	1,681.04
T_{j4}	2,094.83	2,075.02	2,132.84	2,109.85
T_{j5}	2,190.00	2,190.00	2,190.00	2,190.00
$Q_{j\,max}$ (MW)	19,365.48	21,560.96	20,300.56	21,158.95
Q_{j1}	17,428.93	19,404.86	18,270.50	19,043.06
Q_{j2}	15,492.40	17,750.00	16,240.46	16,927.18
Q_{j3}	13,555.85	10,360.07	10,150.32	12,695.41
Q_{j4}	8,679.99	8,624.46	8,120.25	10,579.54
Q_{j5}	6,619.99	6,468.37	6,090.20	8,463.63

cent demand increase poses significant costs if it is too low but only minor costs if it is too high.

The year 1995 is considered. Given long lead times in construction, if capacity needs to be altered by 1995, plans must be started now. NEPOOL estimates that the region's peak will go from its current winter peak to a summer peak. It further estimates that the load duration curves will be changed moderately. The load duration curve (LDC) is a plot of the level of the load versus the duration for which the load equals or exceeds that level. This study's model assumes seasonal LDCs as predicted by NEPOOL.

To model the LDCs, let LDC_1 cover the months of March to May, LDC_2 June to August, LDC_3 September to November, and LDC_4 December to February. Each of the four LDCs is approximated from the NEPOOL estimates in five piece-wise linear segments. The values are shown in Exhibit 2.

2. Generating Units

The current New England strategy requires that additional demand be met by external purchases, cogeneration, and conservation. The purchase strategy depends on construction of a high voltage line through New England. There is considerable opposition to this line so timely construction is not yet assured. Cogeneration requires that private industry construct generating plants with the choice essentially limited to oil and gas as a fuel. This means greater reliance on fuels that have caused New England problems in the past. Current estimates by the Central Research Institute of Japan indicate that oil supplies will again be tight during the 1990s [7]. If this estimate is realistic, then the New England strategy is very risky. Given current low electricity prices, conservation must be forced. Whether this will be politically acceptable is not clear.

Current New England generating capacity is heavily dependent upon oil and is also aging rapidly. Exhibit 3 shows that the average age of generating plants is 21 years. This is less than the national average which in 1985 was estimated to be 25 years. With no additions, however, the New England average for nonnuclear plants will increase rapidly. Aged plants are likely to be less efficient and less reliable than newer plants.

Also note that there are basically three categories of plants: peak, intermediate, and base load. Peak plants are intended to operate for up to 3 hours a day during the highest energy use periods. Some peak load plants may only operate during 4-5 months of the year at peak times, and thus their use is limited. If they were not available, however, the results would be a brownout or blackout during the hottest and coldest periods of the year. Peak generators must be able to start-up and produce electricity rapidly.

Types of plants that are suitable for peaking are the gas turbine—a jet engine attached to a generator, hydroelectric dams, and pumped hydro storage. Pumped hydro storage is a reservoir that is filled during the night by pumping water up to the reservoir. It is run down through turbines during peak times. Pumped storage is thus a type of battery or storage facility for excess electricity generated during the night [6].

Intermediate load plants are used during the daylight and evening hours before and during peaking periods, usually for 8-12 hours on week days. They are typically plants that can be cycled and are generally fossil fuel plants using coal, gas, or oil.

Base load plants are meant to run continuously. During the night hours when demand is low, excess electricity can be used to charge pumped storage facilities or the plant output can be reduced. Although New England still uses some oil in base load, only coal or nuclear are expected to be efficient in this category.

To determine the mix of plants needed in the future, NEPOOL cost data for the construction and operation of new plants is used. From NEPOOL estimates, three types of plants are selected for the model: a 100 MW gas turbine for peaking, a 600 MW coal-fired plant for intermediate load, and a 1,150 MW nuclear-fired plant for base load.

Three types of plants were selected for several reasons including availability of cost data and simplicity of modeling. While gas turbines are fueled by oil derivatives, their restricted use limits cost in the event of possible future oil shocks. In addition, their efficiency can be improved through a secondary recovery method sometimes called combined cycle. Hydro and pumped hydro can be lower cost alternatives, but they are difficult to model without specific knowledge about individual reservoir charcteristics [6].

The choice of a 600 MW coal plant for intermediate load and a 1,150 MW nuclear plant for base load was made on the basis of restricted choice. Cur-

Exhibit 3

WEIGHTED AVERAGE CAPACITY AND AGE OF NEW ENGLAND GENERATING UNITS (1985)

State	Capacity Average Age	Peak	Steam	Hydro	Pumped Hydro	Nuclear	Total
Maine	MV	70	1,069	218		847	2,204
	Age	1963	1969	1941		1972	1967
New Hampshire	MV	90	1,058	77			1,225
	Age	1969	1967	1928			1965
Vermont	MV	101	81	530		496	1,208
	Age	1965	1974	1940		1972	1957
Massachusetts	MV	613	6,831	212	1,584	839	10,079
	Age	1971	1966	1946	1973	1970	1967
Connecticut	MV	395	3,328	130		2,087	5,940
	Age	1969	1964	1937		1971	1966
TOTALS		1,269	12,367	1,167	1,584	4,269	20,656
NEW ENGLAND		1969	1966	1940	1973	1971	1966

Note: Rhode Island units have been included in Massachusetts.

rently, oil and gas are competitive with coal; however, the Fuel Use Act of 1978 does not allow utilities to construct new oil or gas plants. Even if the law was changed, grave doubts about the stability of oil prices in the future would lead us to reject new oil or gas plants. Nuclear cannot be used for intermediate load, so coal was the choice by default.

For base load the choice is coal or nuclear. Current total lifetime cost estimates for nuclear plants are somewhat less than for coal plants because of the requirement of flue gas desulferization (scrubbers) on new plants. Scrubbers can increase costs by 30 percent and reduce availability by 10 percent. Technological advances on the removal of sulfur and other chemicals from coal can change this relationship in the future.

The reader may wonder if nuclear is still a viable option in the United States regardless of its total costs. The last year that a nuclear plant destined for completion was ordered was 1973. There have been no nuclear plant orders since 1979. This is in sharp contrast with nuclear power in most developed countries, especially France, Sweden, Japan, and Russia where nuclear construction and development is continuing. Thus, we believe that the current United States nuclear malaise is temporary; that is, it will last until either demand increases significantly or oil prices climb significantly.

3. Availability

Meeting demand, as determined by the LDC, depends upon having sufficient units available. Availability depends upon planned maintenance and forced outages, and these in turn depend upon the types of unit involved. Coal plants with scrubbers have had a poor availability record as have certain nuclear plants (1985 nuclear availability in the United States averaged 65 percent; whereas, in Europe it was about 82 percent).[2] If there is insufficient available capacity, then the system must either reduce voltage (brownout) or shut down (blackout). These events have dire consequences.

As a result, required capacity is based on a probability of a shut down; that is, Loss of Load Probability (LOLP). For NEPOOL this is 24 hours in 2.2 years. Given the LOLP requirement and the availability of each unit, the necessary capacity to meet demand can be determined. By subtracting required capacity from actual capacity, it is possible to calculate an estimate of excess capacity. Excess capacity is often cited as a reason not to construct additional capacity, but the concept is often misapplied. For example, in New England for July 1986, the margin reserve[3] available was 27 percent and the required reserve was 17 percent, leaving 10 percent excess reserve. Nevertheless, because of plant outage in July 1986, all New England available units were in full operation, and the region had to import electricity to avoid a brownout. On the other hand, when Seabrook is on line, required reserves will increase to about 21 percent because of the size of Seabrook and Millstone 3. This will reduce excess reserve. This study will show that there is little association between minimum cost and excess reserve.

[3]Capacity minus peak divided by peak.

III. *Test of the Model*

The model is run with NEPOOL estimates for 1995 peak demand and quarterly LDCs. As previously stated, only three types of units are used: 100 MW gas turbines, 600 MW coal, and 1,150 MW nuclear plants. The probabilistic simulation based on Appendices 1 and 2 using LDCs of Exhibit 2 and capital costs from Exhibit 4 gives the results shown in Exhibit 5. The lowest cost combination is 77 gas turbines and 17 nuclear plants. Intermediate coal plants are not selected by the model.

These results bring up two important points:

1. Intermediate generating plants are unnecessary. At first this may seem counterintuitive for all utilities use intermediate generation. The issue, however, is whether the output of base load can be curtailed. Currently, nuclear engineers resist load reduction on base plants, yet manufacturer's evidence says that this is both safe and reasonable.[4]
2. The margin reserve and excess capacity calculations may lead to the assumption that added capacity is unnecessary when the opposite is true.

In Exhibit 5, the margin reserve seems insensitive to cost. The reason excess capacity calculations may be misleading is that a single number cannot easily represent the many variables that make up the excess capacity valuation.

Exhibit 6 shows a sensitivity analysis of changes in costs. The result is quite insensitive to cost increases in oil or coal and nuclear construction. If nuclear construction costs increase 20 percent and coal costs do not, then two coal plants replace one nuclear plant. If oil costs increase 20 percent, then 17 gas turbine plants are replaced by two coal plants. What can be reasonably expected? A significant increase in oil prices has been widely predicted [7]. Although United States nuclear construction costs have escalated dramatically, up to 50 percent of the total cost in currently completed plants is interest charges including AFUDC [8]. The current lower interest rates suggest that future plants might cost less than current plants.

In Exhibit 7, New England actual and forecast capacity is shown along with model results. Although the model required 77 times 100 MW or 7,700

[4]Any power plant can be run at less than full capacity. For fossil fuel plants this is normally done by fuel reduction; in nuclear plants it is often done by sending the heat to a cooling source. The usual minimum level is about 30 percent of capacity. Base load coal plants are not designed for cycling so they are less efficient at low operating levels. Considerable debate exists over running nuclear plants at less than full capacity; however, Mueller [5] has shown that the plants are designed to efficiently handle reduced loads. The range assumed here is

	Minimum	Maximum
Nuclear	318 MW	1,150 MW
Coal	132 MW	600 MW
Gas Turbine	25 MW	100 MW

Exhibit 4

CAPITAL AND OPERATING COSTS* AND FORCED OUTAGE PROBABILITIES

	Capacity (Q_i)	Capital Cost Per Year (B_i)	a_0 $/Hours	a_1 $/MWH	a_2 $/MWH^2	Forced Outage Probabilities PF_i
1. Gas Turbine (30 year life)	100 MW	$ .2239x10^7	$2.5436x10^3	$57.5460	$ .1174	0.100
2. Coal (40 year life)	600 MW	$ 7.8976x10^7	$1.4408x10^4	$ .6075	$3.7097x10^{-2}	0.144
3. Nuclear (40 year life)	1,150 MW	$21.7577x10^7	$8.7302x10^2	$10.1450	$1.2510x10^{-3}	0.156

*Operating Costs = $\int [a_{i0} + a_{i1} q(t) + a_{i2} q^2(t)]\, dt$

The data are derived from "Summary of Generation Task Force Long Range Study Assumptions," NEPLANN and GTF, March, 1986, NEPOOL, West Springfield, MA.

Exhibit 5

OPTIMAL GENERATING MIX
GIVEN NUMBER OF BASE GENERATING UNITS

N_3	$[N_1\ N_2\ N_3]$	Cost x 10^{10}	[Installed Capacity Minus Annual Peak] Divided By Annual Peak Times 100%
21	[38 0 21]	.620539	29.64
20	[48 0 20]	.605441	28.94
19	[56 0 19]	.592796	27.32
18	[77 0 17]	.584987	27.09
17	[67 0 18]	.582137	26.39
16	[68 2 16]	.582900	22.45
15	[72 3 15]	.587678	21.75
14	[63 6 14]	.595148	20.59
13	[68 7 13]	.604889	20.36
12	[66 9 12]	.617053	19.67

N_1 = number of peaking units
N_2 = number of intermediate generating units
N_3 = number of base generating units

Annual peak for 1995 is 21,560 MW

Exhibit 6

SENSITIVITY ANALYSIS AT OPTIMAL COST

	N_1	N_2	N_3	Cost x 10^{10}
Increase Nuclear Capital Cost 10%	68	2	16	.617712
Increase Nuclear Capital Cost 20%	68	2	16	.652524
Increase Coal Capital Cost 10%	77	0	17	.582137
Increase Coal Capital Cost 20%	77	0	17	.582137
Increase Gas Turbine Fuel by 10%	69	1	17	.586714
Increase Gas Turbine Fuel by 20%	60	2	17	.590004
Initial Optimal [Exhibit 5]	77	0	17	.582137

Exhibit 7

NEW ENGLAND CAPACITY (MW)

	Actual 1986	Forecast 1995	Model Forecast 1995	New Construction
PEAK				
Gas Turbine and Diesel	1,222	968	4,804	3,379
Hydro	1,315	1,309	1,309	
Pumped Hydro	1,587	1,587	1,587	
Oil*	224			
	4,348	3,864	7,700	3,379
INTERMEDIATE				
Coal	147	147		
Combined Cycle	457	457		
Oil*	3,662	3,900		
	4,266	4,504		
BASE				
Nuclear	5,379	6,528	16,778	10,250
Coal	2,625	2,625	2,772	
Oil*	4,745	4,214		
	12,749	13,367	19,550	10,250
Totals	21,363	21,735	27,250	13,629
Customer Generation	370	1,837		
Purchases	743	1,687		
Grand Total	22,476	25,259	27,250	13,629

*Estimates for categories. During most of the year oil plants do not produce electricity continuously.
**Includes combined cycle.

MW in gas turbine, the lowest cost would be achieved by using currently available hydro. The results indicate that the region should construct 34 gas turbines and 9 nuclear plants. Interestingly, 8 New England nuclear plants that had gone through preliminary planning, including site preparation and units ordered, have been canceled over the last 10 years. In effect, this forecast suggests that the region's planning in the past was correct except for timing. If the model result were accomplished, 8,114 MWs of oil-fired plants would be retired. This is 32 percent of total capacity which is a first estimate of obsolete plants. It also represents the extent to which New England is dependent upon oil for nonpeaking periods. Note that the estimates do not account for either external purchases or cogeneration. Purchases, primarily from Quebec, could reduce the need for nuclear plants by two, and cogeneration could reduce peak requirements by 18 gas turbines. The net result would be additions of 16 gas turbines and 7 nuclear plants by 1995.

After adjusting for current plants, the model results emphasize one point: New England has far too little nonoil base load and far too much oil intermediate load capacity. This point transcends this study's use of nuclear for base load. The reader can substitute 800 MW coal plants for the nuclear plants without significantly changing the mix that is predicted.

IV. *Summary*

This study reports results of a capacity planning study of New England electric generating capacity in the year 1995. Currently, New England utilities plan to meet their generation requirements by assuming that there will be a 2 percent growth rate in demand over the next 8 years, and that this modest increase can be met by imports from Canada and cogeneration. There are no plans to construct new generation plants in the entire region over the next 8 years. This situation has developed in spite of the fact that New England has gone from a depressed region to one of the most dynamic in the nation in terms of growth and employment.

Using the demand data supplied by NEPOOL and accepting the implicit 2 percent growth rate, a model was constructed and run on the basis of three types of plants: gas turbines for peak load, coal plants for intermediate load, and nuclear plants for base load. The results indicated that New England should be constructing at this time approximately 16, 100 MW gas turbines and 7, 1,150 MW nuclear plants. There are currently 8 partially or fully developed nuclear plant sites in New England. This strategy would entail retiring 8,114 MW of current oil-fired capacity that by 1995 will have an average age of about 35 years.

The major result of the model is that New England has far too much oil-based intermediate load capacity and far too little base load capacity. Whether this base load capacity is coal or nuclear is less important. Also, whether the peak load is met by gas turbines or hydro or pumped hydro or even wind is not as important as our current overemphasis on oil-based intermediate load capacity.

The current New England strategy of reliance on low growth in electricity demand and low future oil prices could turn out to be devastating to New England's future. It is a subject that requires more consideration than it has currently been given.

Appendix 1

MODEL STRUCTURE

As described in the text, there are three categories of plants. Let N_1, N_2, and N_3 represent the number of peak, intermediate, and base load generating units in the system. Let B_i denote the capital cost of a unit in category i, $Q_{i\,max}$ the capacity in MW of a unit in category i. Assume the following relationship:

$$(B_1/Q_{1\,max}) > (B_2/Q_{2\,max}) > (B_3/Q_{3\,max})$$

The cost for operating a unit in category i at the level q KW for an hour is given by

$$f_i(q_i) = a_{i0} + a_{i1}q_i + a_{i2}q^2; \qquad i = 1,2,3 \tag{1}$$

These quadratic operating cost functions are derived by curve fitting of heat ratio data.

All the units are subject to random forced outages which are specified by forced outage probabilities, PF_i where i = 1,2,3. Assuming forced outages of different units are independent, then the probability of having M_i units available out of N_i installed units for all the categories is

$$Pr(M_1,M_2,M_3:N_1,N_2,N_3) = \prod_{i=1}^{3} [\binom{N_i}{M_i}(1-PF_i)^{M_i} PF^{(N_i-M_i)}] \tag{2}$$

The available capacity in this case is given by

$$QA(M_1,M_2,M_3) = \sum_{i=1}^{3} M_iQ_{i\,max} \tag{3}$$

The number of hours that load exceeds available capacity, denoted as $h(j,M_1,M_2,M_3)$, can be read directly from LDC. That is

$$h(j,M_1,M_2,M_3) = LDC_j(QA(M_1,M_2,M_3)) \tag{4}$$

The expected number of hours that load exceeds available capacity, the Loss of Load Hours (LOLH), is thus

$$LOLH(j,N_1,N_2,N_3) = \sum_{M_3=0}^{N_3} \sum_{M_2=0}^{N_2} \sum_{M_1=0}^{N_1} Pr(M_1,M_2,M_3:N_1,N_2,N_3)\, h(j,M_1,M_2,M_3) \tag{5}$$

for season j, given (N_1,N_2,N_3) as the installed capacity. Finally, the Loss of Load

Probability (LOLP) for a year can be calculated as

$$LOLP(N_1,N_2,N_3) = \sum_{j=1}^{4} LOLH(j,N_1,N_2,N_3)/8{,}760 \quad (6)$$

The expected total cost to be minimized is given by

$$CT(N_1,N_2,N_3) = \sum_{j=1}^{3} NB + \sum_{j=1}^{4} CE(j,N_1,N_2,N_3) \quad (7)$$

where the first part is the capital cost, and the second part is the operating cost, with $CE(j,N_1,N_2,N_3)$ being the expected operating cost for season j given (N_1,N_2,N_3) as the installed capacity. CE is given by

$$CE(j,N_1,N_2,N_3) = \sum_{M_3=0}^{N_3} \sum_{M_2=0}^{N_2} \sum_{M_1=0}^{N_1} Pr(M_1,M_2,M_3:N_1,N_2,N_3)\ CO(j,M_1,M_2,M_3) \quad (8)$$

In the above equation, $CO(j,M_1,M_2,M_3)$ is the minimal operating cost for season j given (M_1,M_2M_3) as the available capacity.

To obtain $CO(j,M_1,M_2,M_3)$, it is observed that for a fixed load level q and the given set of available units (M_1,M_2,M_3), the operating cost depends on how many units are actually in operation, and the generating levels of those operating units. This is the issue of "Loading Procedure." The Incremental Loading Procedure was adopted and $CO(j,M_1,M_2,M_3)$ was calculated by solving another minimization problem that is summarized in Appendix 2.[5]

The above procedure in treating random forced outages is called "probabilistic simulation" since it considers the effects of all forced outage possibilities in a probabilistic way. Its name is taken from [2, 3, 11] under the same context but with a different solution methodology.[6]

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[5]The calculation of system marginal operating cost depends heavily on the set of generating units that are committed. In [12], the authors implicitly assumed that all the available units in the subset "Q" will affect the marginal operating cost when unit 1 is considered, where Q is the subset of units having at least one common marginal cost value with unit i. However, this is not the case. Consequently, the results obtained in [12] are not correct.

[6]For details of the program, please write to the Bureau of Utility Research, University of Connecticut, U-41F, Storrs, CT 06268.

Appendix 2

LOADING PROCEDURES

The calculation of operating costs $CO(j,M_1,M_2,M_3)$ depends heavily on the manner by which various units are brought to generation; that is, the loading procedure. The two loading procedures typically used are merit order loading and incremental loading. The widely adopted method used in capacity planning is merit order loading in which generating units are loaded according to their average operating costs evaluated at their rated capacities. This method can be extended to include uncertain demands and uncertain forced outages by using the concept of "equivalent load duration curves [2, 3, 11]."

In incremental loading, the units to be loaded are generally determined by using a two-level approach. The high level problem finds the set of units to be loaded. The low level problem, on the other hand, allocates the demand among those selected sets of units by equating their marginal costs. It can be shown that the equality of marginal costs is a necessary condition for minimizing the operating costs. Because of this, the incremental loading procedure is used for short-term scheduling of units for generation (the two levels of the so-called "unit commitment" and "economic dispatch").

In this model, the incremental loading is handled by using the two-level approach just mentioned. For a given set of units to be loaded (n_1,n_2,n_3), the lower level problem can be solved by equating the marginal costs. To find the optimal set of units to be loaded (NOP_1,NOP_2,NOP_3), the process starts with some initial tuple (n_1,n_2,n_3), and iterates with respect to n_1,n_2,n_3. Each time an n_i is increased by one. This is done until a point is reached where by further increasing any n_i, cost cannot be lowered. From the cost functions of the three types of units considered in Exhibit 3, note that it is cheaper to use all the available nuclear capacity before using any coal capacity, and it is cheaper to use all the available nuclear and coal capacity before using any gas turbine capacity. Thus, the above procedure can be simplified, and an algorithm has been developed to find the optimal NOP_i for a fixed demand q. The generating cost can be obtained by integrating the cost over the time axis of a LDC.

Incremental loading gives better results but requires substantial complexity in the algorithm; whereas, merit order loading gives rough approximations but is simpler to calculate. Researchers have tried to develop theoretical results using incremental loading [11] without much success. In this study incremental loading is used.

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Differentiating Geographic Areas by Socioeconomic Characteristics

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Abstract

A detailed methodology is provided which describes how to use factor analysis and cluster analysis techniques to differentiate small geographic areas on the basis of well-established sociological constructs. The process includes (1) the definition and selection process of the variables to be included, (2) the application of factor analysis methods which results in the replacement of the original set of variables with a smaller set of new variables that retain most of the original information, and (3) a method of clustering the original objects into relatively homogeneous groups based on the new set of variables. The specific application described is the differentiation of Rhode Island into groups of census tracts using data from the 1980 U.S. Census of Population and Housing.

I. *Introduction*

Market penetration studies commonly aggregate population and utilization data to existing, politically-defined geographic units for the calculation of utilization rates and market share statistics. Such units as cities and towns, judicial districts, and counties are often used because they are available, well-defined and require the least amount of effort to calculate the desired statistics. These areas suffer from one serious drawback. Because the boundaries are determined from political perspectives, the variability of the statistical measures used is greater within the units than among them. This results in a loss of descriptive power and hides meaningful differences. Better geographical units would be those that are demographically homogeneous. When such units are defined, the utilization measures would be more interpretable and useful to those involved in marketing and evaluation studies.

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