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COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF PUBLIC UTILITIES

Re: Boston Edison Company's Construction Program and Capacity Needs, D.P.U. 19494

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p.33

JOINT TESTIMONY OF SUSAN FINGER AND PAUL L. CHERNICK ON BEHALF OF THE ATTORNEY GENERAL

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April 1, 1979

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§I. INTRODUCTION

Q: Please state your name, current position, and business address.

A: My name is Susan Finger. I am a graduate student at the Massachusetts Institute of Technology in an independent interdepartmental doctoral program in Energy Planning. I am a Research Assistant at the MIT Energy Laboratory where I work in electric power system reliability for the Photovoltaic Project. My office is E38-403, MIT Energy Lab, Cambridge, Massachusetts, 02139.

I received a B.A. in astronomy from the University of Pennsylvania in 1972 and an M.S. in Operations Research, also from the University of Pennsylvania, in 1974. I was a Summer Intern at the U.S. Arms Control and Disarmament Agency from 1972-1974. At MIT, I have been a teaching assistant for an introductory probability and statistics course and have been a research assistant on projects involving long range planning for electric utilities, assessment of environmental controls for new coal technologies, production costing and reliability of electric power systems, and integration of photovoltaic power systems with the electric power grid. My thesis is concerned with centralized versus dispersed power generation in electric power systems.

I am a student member of IEEE, Power Engineering Group. My publications include:

"Systematic Methodology for Comparison of Environmental Control Technologies for Coal-Fired Electric Generation," J. Gruhl, F.C. Schweppe, M.F. Ruane, S. Finger, M.I.T. Energy Lab Report #MIT-EL 76-012, November, 1976.

"SERI Photovoltaic Venture Analysis, Long Term Demand Estimation," R.D. Tabors and S. Finger with A.Burns, P.Carpenter, T. Dinwoodie, J. Tatum, G. Taylor, M.I.T. Energy Lab Report #MIT-EL 78-32, July, 1978.

"Electric Power System Production Costing and Reliability Analysis, Including Hydro-Electric, Storage and Time Dependent Power Plants," Susan Finger, M.I.T. Energy Lab Technical Report #MIT-EL-79-006, February, 1979.

I have also been a consultant to Dynatech R/D Co. on the effect of wet/dry cooling towers on power system reliability and production cost; to Stone & Webster Engineering Company on documentation for the computer model SYSGEN; and to Energy Resources Company on a reliability report.

Q: Mr. Chernick, are you the same Paul L. Chernick who has filed joint testimony with Susan C. Geller, in both Phase I and Phase II of this proceeding?

A: Yes.

Q: For the convenience of the Department and of the parties, will you please indicate for the record who is responsible for what portions of this testimony?

A: Yes. Ms. Finger is the principal author of §II, General Principles of Electric System Reliability, and Mr. Chernick is the principal author of §III, Application of General Principles to NEPOOL and New England.

§II. GENERAL PRINCIPLES OF ELECTRIC SYSTEMS RELIABILITY

Q: What is the scope of your testimony for this proceeding?

A: I will discuss (1) levels of reliability in electric power systems; (2) effects of reliability on consumers; (3) effects of reliability on system operation and cost; and (4) inclusion of reliability in long range planning. In addition, I will discuss alternative sources of generation and what measures can be used to compare them to conventional sources.

Q: Are there important distinctions between various uses of the term reliability in reference to electric power systems?

A: Yes. The reliability of a power system can refer to its ability to withstand sudden shocks, such as the loss of a large transmission line or generator, it can refer to the system's ability to meet the power demand at any instant of time, or it can refer to the system's ability to meet the energy and power demand in the long run. To distinguish among these types of reliability, normally the ability to withstand shocks is referred to as security or stability, the ability to meet the power demand is referred to as reliability, and the long term reliability is referred to as adequacy. However, these terms are not unambiguous partly because the security of a power system depends on its reliability and its reliability depends on its adequacy. In addition, each level of reliability depends on both the transmission system and the power generation system. For example, if the generators are always available, but the transmission lines fail constantly then, overall, the system is unreliable.

Q: How do these concepts relate to blackouts, brownouts and other customer impacts?

A: Most customer interuptions are caused by local distribution failures. For example, a utility pole may be knocked down in a car accident or an underground cable may be cut by a construction crew. This type of failure is difficult to prevent and impossible to predict. Most utilities try to minimize the effect of this type of failure by designing distribution systems that allow them to dispatch the electricity around faults and by using emergency maintenance crews. This level of reliability is not included in any of the reliability terms discussed above.

Widespread blackouts are usually caused by transmission failures. Lack of generation capability rarely leads to system wide blackouts. For example, the immediate cause of the recent New York City blackout was the loss of several large transmission lines due to lightning. There was sufficient power available, but the remaining lines that transmitted the power to New York became overloaded and eventually they also failed resulting in the blackout. This type of failure is included in the measure of system security.

Brownouts, or voltage reductions, occur when there is not enough electric capacity to meet the demand. Brownouts tend to occur on hot humid days when the electrical demand is high. (The problem is exacerbated because generators and transmission equipment are less efficient in hot weather.) However, the potential for brownouts exists at all times because some generators may be out of service for maintenance and other generators may fail. If, at any time, there are not enough generators to meet the load, then a brownout and ultimately rolling blackouts can occur. However, most utilities have a set of emergency procedures that they follow so that they can avoid having to reduce customer service. The reliability of a power system is a measure of how often the system is likely to be in an emergency state due to lack of generation.

The effects of long run inadequacy are harder to evaluate. Due to the structure and regulation of the U.S. utilities, there has never been a situation in which a shortage of electricity existed so that it had to be rationed or otherwise controlled.

Q: What are appropriate measures of system reliability?

A: Because system reliability has many dimensions, no single index can be used to define it. For a customer, the number of outages and the length of each outage is a good measure of the system's reliability. However, this measure is not useful to system planners whose decisions only marginally affect the reliability for any one customer. It is also difficult to measure because it is a composite of generation, transmission, and distribution reliability.

There is no index for transmission reliability. Alternative transmission plans are evaluated based on their ability to withstand a set of contingencies, such as the simultaneous loss of a large generator and transmission line. The analysis is done by making load flow studies using large computer models. (A major research effort by the utilities, EPRI, and DOE is directed toward findng better methods for evaluating transmission system reliability.)

There are many indices for evaluating generation system reliability. These include: the loss of load probability, loss of energy expectation, and frequency and duration of outages due to insufficient generation. Basically, each of these indices is a refinement of the preceding one.

The loss of load probability (LOLP) measures the expected time that the system will be unable to meet demand due to insufficient generation. A typical LOLP requirement is one day in ten years. The loss of energy expectation (LOEE) measures the magnitude of the demand that cannot be served. This is equal to the LOLP times the average magnitude of the unmet demand. Finally, the frequency and duration (FAD) of outages measures the expected number of times (frequency) and expected length of time (duration) that there will be insufficient generation. Thus, using a FAD index allows one to distinguish between an outage that lasts for a day and twenty four outages that last for one hour each. It should be noted that reliability models do not attempt to evaluate the economic and social impacts of generation short falls, but only measure the magnitude of the short-falls under differing assumptions.

Q: How is the reliability of the generation system measured?

A: Basically, the reliability of the generation system is measured by comparing the customer load with the available capacity and computing how often there is not enough capacity to meet the load. This computation can be complicated to include all the dimensions of reliability mentioned above, but the basic computation is the same for all the indices.

To do a simple computation of the system reliability, one needs to know the shape of the customer demand curve, the size of the generators, and the forced outage rate (FOR) of the generators. From the customer demand curve, one can compute the expected time that the load will be greater than any given value (this is the load duration curve shown in Figure 1). From the unit sizes and forced outage rates, one can compute the probability distribution of the available capacity. The load curve and the capacity curve can be combined using probabilistic techniques to give the loss of load probability. This is basically the model presented in Anthony Petrello's testimony.

This model can be extended so that in addition to finding the loss of load probability, one can find the loss of energy expectation, the frequency and duration of outages, the expected energy generated by each unit, and the expected cost of operating the system. All of these features are incorporated in the computer model, SYSGEN, which is used as the basis for the tables in this testimony. (It should be noted that, unlike the model presented by Petrello, SYSGEN models each unit individually rather than modelling the aggregate.)

Q: What factors affect the generation system reliability?

A: The major factors affecting the generation system reliability are the customer load shape, the generator sizes, and generator forced outage rates.

Q: How does load shape affect reliability?

A: The customer load shape affects the reliability of the system because, if the load is frequently high, then there is a greater chance that a high load state and a low capacity state will coincide. On the other hand, if load is normally low, then more capacity can be unavailable before the system reaches a critical point.

The standard measure for the relative frequency of high and low demand states is the system load factor. The load factor is essentially the average demand expressed as a percentage of the peak demand. (On Figure 1, this is the ratio of area A to the total area of the box.)

In general, for two systems with the same peak demand and same installed capacity, the one with the lower load factor will be the more reliable. This is shown in Table 1. Table 1 is based on runs made with the reliability model SYSGEN, using data from the EPRI synthetic utility representative of a current New England utility.

Q: How do forced outage rates affect reliability?

A: The forced outage rates affect system reliability in the obvious way. If two systems are identical, except that in one system the plants are much more likely to fail, then that system will have a much lower reliability.

Q: What is the relevant measure of unit forced outage rates for reliability studies?

A: The common measure is equivalent forced outage rate (EFOR), which weights deratings by their magnitude. For example, a 600 MW plant which is reduced to 500 MW for 10% of the study period, to 300 MW for 5% of the time, and is unavailable 10% of the time, would have an EFOR of:

$$(.10*100 + .05*300 + .10*600) \div 600 = 14.2\%$$

While EFOR is a convenient measure of plant reliability, it is not very useful. Two plants with the same MW rating and the same EFOR can have very different effects on reliability. For example, a 600 MW plant that was always able to deliver 515 MW, or a 600 MW plant which was fully available 85.8% of the time and completely useless the rest of the time, would both have an EFOR of 14.2%, yet the first would contribute much more to system reliability than the second. Yet most reliability models use EFOR's and assume the all-or-nothing distribution of availability. This tends to underestimate the system's reliability and to overestimate required reserves. NEPOOL apparently uses only EFOR's as descriptions of plant reliability.

Q: How does size of installed generators affect reliability?

A: If two systems have the same load shape and the same installed capacity, except that in one system each individual unit is twice as large as those in the other system, then the system with larger units will have a lower reliability. This can easily be seen in the extreme case where a system has one generator whose size equals the peak demand. Whenever the generator fails, none of the demand can be met. The effect of generator size on system reliability is shown in Table 2.

Large plants which undergo partial capability limitations and deratings behave like interdependent smaller plants. That is, the 600 MW plant described <u>supra</u> could be thought of as three small plants: a 100 MW unit with a 25% complete outage rate, a 200 MW unit with a 15% outage rate, and a 300 MW unit with a 10% outage rate, linked so that failure of the 200 MW unit causes the 100 MW unit to fail, and an outage of the 300 MW unit will take down both of the smaller units. The reliability of this combination is less than that of three separate plants with the specified outage rates, but greater than that of a single plant which is totally unavailable at the EFOR of 14.2%.

Q: Have you conducted this type of analysis for the NEPOOL system?

A: No. The data has not yet been provided by BECO.

Q: What are the inter-relationships of size of generators, forced outage rates, and load?

A: In making calculations of system reliability it is usually assumed that the customer load does not affect the outage rates of the generators. In practice, this is not strictly true because generators do have higher failure rates when they are generating at or beyond rated capacity, when ambient temperatures are high or when the system is not in a steady state. All of these conditions are likely to occur when the demand is high and thus the generators are more likely to fail when the system is experiencing its peak demand. This effect is not usually included in system reliability studies because there is almost no data available.

The relationship between unit size and forced outage rate is better documented, but there are no definitive conclusions; however, as unit size increases, the forced outage rate and repair time tend to increase also.

Q: What effect does unit size have on system operation?

A: As mentioned above, larger units tend to reduce system reliability, due to their larger forced outage rates and their inherent size. In addition, large units increase the spinning reserve requirements and complicate maintenance scheduling.

Q: How is spinning reserve affected by generator size?

A: Spinning reserve refers to the capacity that is kept in readiness in case a unit that is generating is forced out of service. The amount of capacity that is kept in spinning reserve varies from system to system, but it is usually from one to one-and-a-half times the largest unit that is currently generating. Thus, if the largest unit fails, the spinning reserve can be started up immediately to replace it. The extra spinning reserve above the capacity of the largest unit is used to build up the reserve for the next contingency after the first unit has failed.

For systems with large units, more spinning reserve is required. This means that the system must have relatively more backup capacity installed, raising the capital costs. In addition, the spinning reserve consumes fuel, and hence larger spinning reserve requirements increase the operating costs as well.

Q: How do maintenance requirements affect reliability?

A: Maintenance of units is scheduled to keep the system reliability as high as possible, so no maintenance is planned for time periods close to the expected peak demand. Large units are usually scheduled for the time periods with the lowest expected demands (spring and fall). However, because removing a large unit for maintenance can remove a substantial portion of the system's capacity and because larger units tend to have longer repair times, their maintenance can adversely affect system reliability. Table 3 and Figure 2 show the effect of maintenance on reliability for a system with large units and a system with small units.

Q: Does maintenance scheduling of nuclear plants present special problems?

A: Yes. Nuclear plants must be regularly shut down for refueling. There is an optimal time period for this operation, determined by the time of the previous refueling, the plant's capacity factor since that refueling, and other factors. Since capacity factor varies randomly with stochastic forced outages and deratings, the optimal refueling time also varies unpredictably. Unfortunately, refueling is a lengthy process, requiring around two months to complete. Only in the spring and fall valleys is there a sufficient period of low demand to permit refueling without impinging on peak periods. Therefore, nuclear plants will often require refueling either at suboptimal times or on peak. The first option increases nuclear fuel costs (if refueling is done too early) or reduces plant output (if refueling is done too late). The second option increases the cost of replacement power and further reduces nuclear plants' contribution to system reliability.

Q: Does generator size affect long-run reliability considerations as well as the short-run effects you have described above?

A: Larger units also affect system reliability in the longer run. Large units create what are called "lumpy" decisions. If the decision to build a large plant is made, then its installation date must be timed so that the cost of undercapacity while waiting for it are balanced by the cost of overcapacity once it is installed. The penalties inherent in this process are increased by uncertainty in plant timing and load growth. This is illustrated in Figure 4.

Figure 4 also shows the importance of the load projections and delays. Large plants have long lead times, so if the load projections are wrong, it is difficult or impossible to change the plant construction schedule. If small units are planned, then the response times are shorter and it is easier to match the changes in load growth.

Q: Do nuclear power plants cause any other problems in long-range capacity planning?

A: Large plants affect long-term adequacy in the same way that they affect reliability. In addition to each plant's fluctuation in performance over time, there is variation between plants, over a period of years or even over their total life time. The nuclear plants now under construction or in planning for New England are each equal to about 6% of current NEPOOL peak. If some of these plants are considerably worse-than-average performers, NEPOOL's reliability may be lower than anticipated for several years.

In principle, the same phenomenon could occur for smaller plants, but it is very unlikely that ten 200 MW units will operate considerably below par, while it would not be surprising if two 1000-MW units operated consistently at low capacity factors. This effect is increased for plant types (such as nuclear) which show large performance variance between plants.

Q: Why are large units built?

A: One argument for building large units is that there are economies of scale in generator construction; that is, the larger a generator, the cheaper per megawatt it is to build. However, this is not always the case. Figure 3 is taken from the latest Electric World survey of new power plants. This shows very clearly that there are not economies of scale for nuclear power plants. Only for coal fired power plants are there clear economies of scale. For these plants, the capital cost savings for large plants should be weighed against the additional reliability and operating costs incurred by large plants. However, most long range planning models do not do this.

Q: In making long-term decisions about what new plants to build do electric utilities consider their effects on reliability?

A: Of course. However, the extent to which reliability is included explicitly in planning models varies from utility to utility. Some utilities still use a 20% reserve margin as the reliability criterion. This is a rule of thumb that says that if the installed capacity is equal to the expected peak demand plus 20%, then the system will be reliable enough. This measure obviously does not take into account the effects of load shape, generator sizes or forced outage rates. As long as a system remains relatively constant overtime then a historically adequate reserve margin can be used as a planning criterion. However, if the power system is evolving, then a historically appropriate reserve margin may suddenly become insufficient or overly sufficient.

To overcome the drawbacks of using reserve margins as reliability indices, many utilities have started to use loss of load probability and loss of energy probability criterion in long-range planning; however, few models include reliability explicitly. The long range planning model OPTGEN, used by many New England utilities, includes a reliability constraint which relates reserve margins to loss of load probabilities based on simulation runs. Thus, it does not include the effect of any particular new unit on system reliability. If the new plant mix is similar to old plant and if the load shape is relatively constant, then it is not a bad approximation for reserve margin, but it may still choose individual capacity additions sub-optimally.

Q: What do you mean by plant mix?

A: The plant mix refers to the relative share that each type of unit has in the total installed capacity. For example, a system might have 30% base load coal, 30% intermediate coal, 25% intermediate oil and 15% gas turbines. This would be its plant mix.

Q: How is the plant mix determined in long-range planning?

A: A simple way to get a rough estimate of the plant mix can be found by drawing two graphs. One plots the cost of installing and operating a plant as a function of the percent of time that it operates. The other plots the load as a function of percent of time (the load duration curve). See Figure 5. Looking at the upper graph, one can see that the cheapest way to meet a load that lasts between

0 and 15% of the time is to build a peaking unit. Looking to the lower graph, one sees that there are 200 MW of load that last between 0 and 15% of the time.

This rough technique ignores many important variables, but it does show the importance of knowing where the load growth occurs. If the load increases by a constant 800 MW, then new base load capacity is the cheapest way to meet the new load. If the load increases by 800 MW only on the peak, then peaking units are the cheapest way to meet the new load.

Q: What are some of the factors this technique ignores?

A: The most important factor it ignores is reliability. It assumes that plants are capable of operating whenever they are required. This has two effects. One is that inefficient plants may be built. For example, from Figure 5, to qualify as base load, plant should be run to meet all loads that last between 60% and 100% of the time. In an extreme case, consider a base load plant that, before it was built, had an expected forced outage rate of 20% but which actually experienced a forced outage rate of 50%. It would not be capable of operating in the range where it was most efficient and some other choice

would have lead to a lower cost solution. Of course, one does not build a 50% reliable plant on purpose. However, this may result from building a plant of a class which collectively has an expected outage rate of 20%, but a wide variance in that rate.

In addition, this technique does not account for the additional capacity that is required when units fail and so it tends to underestimate the peaking capacity required, especially as backup for the larger base-load plants. It is desirable to make trade-offs among capital costs, operating costs, and reliability.

Q: How should capacity credit be assigned to generating units?

A: The standard measure for capacity credit is the effective load carrying capability (ELCC) of a unit. The effective load carrying capability is a function of the unit's size and forced outage rate, of the customer demand and of the other units on the system. In essence, the effective load carrying capability measures the amount of demand that the unit can serve reliably. It does not reflect how the unit is actually operated, but rather how it is capable of operating on a particular system.

Q: What parameters influence the effective load carrying capability?

A: The ELCC will vary inversely with the forced outage rate and size of the unit. It will vary directly with the unit's availability and the load.

Q: Don't you normally assume that the load and the unit's availability are independent (uncorrelated)?

A: Yes. However, for studying time dependent power plants, such as solar or wind, the correlation of load and unit availability is very important.

Q: Must a unit be available on peak in order to provide ELCC?

A: Not necessarily. Especially when maintenance fills the seasonal demand valleys, there is a wide range of times in which capacity shortages could occur; any additional capacity in these periods also decreases the annual LOLP. In addition, seasonal capacity which is available off-peak may allow for more off-peak maintenance of other units, which will then be available on-peak. Thus, a hydroelectric unit which is only available from mid-February to mid-June could substantially affect LOLP, reserve on peak, and the need for new capacity.

Q: How can you interpret the load carrying capability?

A: The ELCC is the firm capacity that can be credited to the unit and can be thought of as that unit's contribution toward meeting the peak demand.

To interpret the total value of the unit to the system, one needs more information on how the plant is operated within the system.

Q: Have you studied the load carrying capability of any nonconventional generation types?

A: Yes. I have worked on a project to evaluate grid connected photovoltaic (solar cell) power plants. In Table IV, I have plotted the ELCC for photovoltaic units in four cities for different penetrations. From Table IV, one can see that the capacity credit differs greatly from city to city depending on how the solar peak correlates with the system load.

Q: Would you anticipate similar results for wind generation, cogeneration, low head hydro and other unconventional sources?

A: Yes. In fact, GE has studied both solar and wind systems and has come to basically the same conclusions. It is reasonable to expect similar or superior results from other technology, such as cogeneration, low lead hydro, and waste-fired units. In fact, while photovoltaics would be most comparable to intermediate capacity, some of these other technologies would be more comparable to base-load capacity.

Q: Aside from smaller plant size, do dispersed generation technologies possess any intrinsic advantages?

A: Yes. Many small generators will tend to be close to the loads they serve. This results from the locational determinants of cogenerators, refuse-burning plants, and many existing small dam sites with hydroelectric potential; from the lesser environmental and logistical problems of siting small plants; and from the geometry of the situation, which insures that the average distance between randomly distributed loads and randomly distributed sources will tend to decrease as the number of sources increase. Therefore, both transmission losses and the vulnerabilitry of the system to transmission disruptions will be reduced by dispersed generator location.

TABLE I

VARIATION OF RELIABILITY WITH LOAD FACTOR

PEAK DEMAND = 5442 MW
CAPACITY = 6100 MW
MARGIN = 12%

LOAD FACTOR	LOLP	% ENERGY UNSERVED
70%	.057	.511
68%	.046	.417
60%	.024	.258

TABLE II

VARIATION OF RELIABILITY WITH UNIT SIZE

PEAK DEMAND = 5442 MW
CAPACITY = 6100 MW
LOAD FACTOR = 68%

	LOLP	% ENERGY UNSERVED
2 600 MW	.046	.417
4 300 MW	Numbers to be supplied	
12 100 MW	.029	.207

Table III: Effect of Large Plants' Maintenance Requirements

LOSS OF LOAD PROBABILITY

	Large Plants (1)		Small Plants (2)	
	Without Maintenance	With Maintenance	Without Maintenance	With Maintenance
Months				
January	NUMBERS TO BE SUPPLIED			
February	NUMBERS TO BE SUPPLIED			
March	NUMBERS TO BE SUPPLIED			
April	NUMBERS TO BE SUPPLIED			
May	NUMBERS TO BE SUPPLIED			
June	NUMBERS TO BE SUPPLIED			
July	NUMBERS TO BE SUPPLIED			
August	NUMBERS TO BE SUPPLIED			
September	NUMBERS TO BE SUPPLIED			
October	NUMBERS TO BE SUPPLIED			
November	NUMBERS TO BE SUPPLIED			
December	NUMBERS TO BE SUPPLIED			

(1) 2 600 MW Plants Plus 4900 MW Other

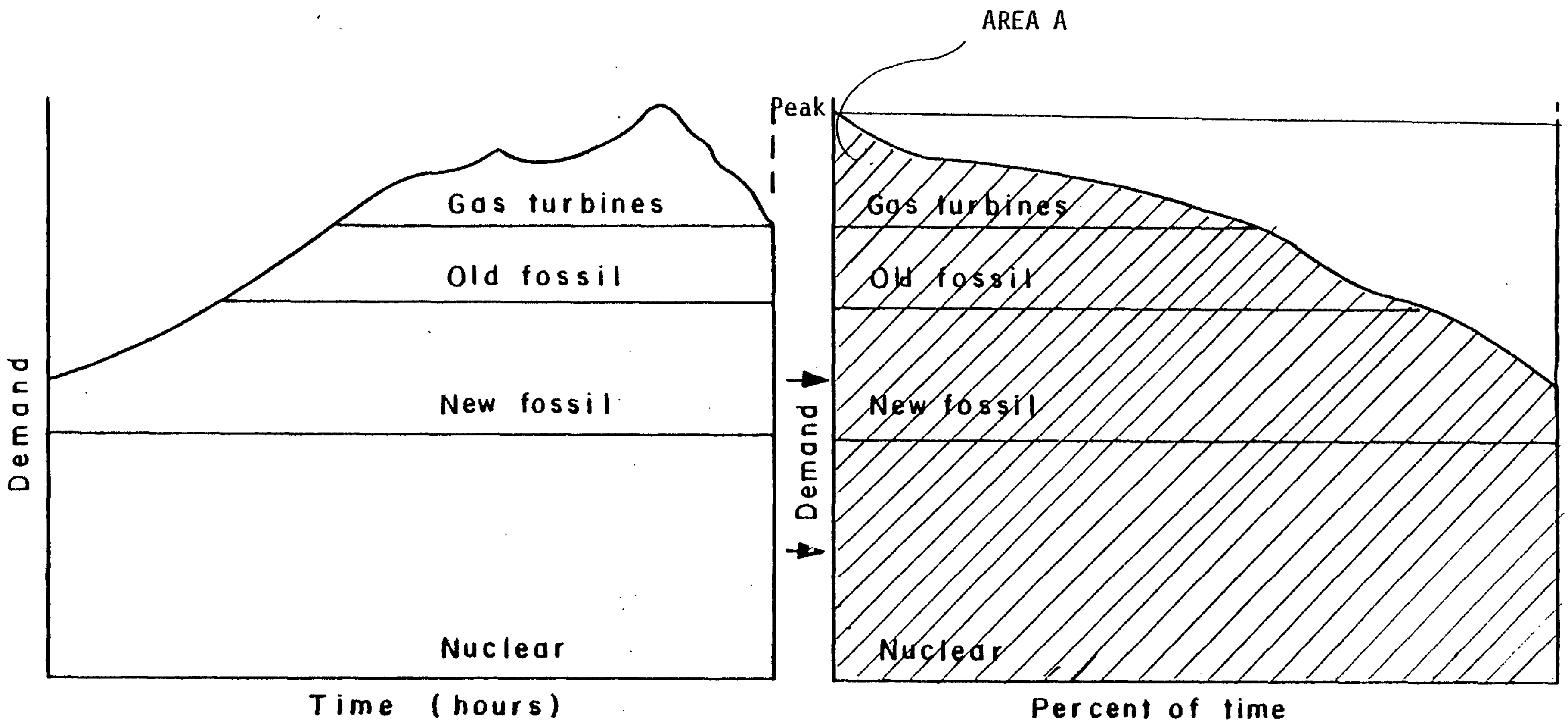
(2) 12 100 MW Plants, Plus 4900 MW Other

TABLE IV

EFFECTIVE LOAD CARRYING CAPABILITY (ELCC)
FOR PHOTOVOLTAIC PLANTS

INSTALLED CAPACITY = 6100 MW

	Photovoltaic Peak Capacity (MW and % of System)		
City MW(9%)	200 MW(3%)	400 MW(6%)	600
Omaha			
ELCC (MW)	27 MW	41 MW	47 MW
ELCC (% rated capacity)	14%	10%	8%
Miami			
ELCC (MW)	33 MW	59 MW	85 MW
ELCC (% rated capacity)	17%	15%	14%
Boston			
ELCC (MW)	63 MW	1137 MW	154 MW
ELCC (% rated capacity)	32%	28%	26%
Phoenix			
ELCC (MW)	108 MW	202 MW	289 MW
ELCC (% rated capacity)	54%	51%	48%



1.a. Typical operating schedule. 1.b. Equivalent schedule on a load duration curve.

Figure 1. Deterministic Operating Scedule.

In Figure 1.b. the ratio of area A to the total area under the straight line is the load factor.

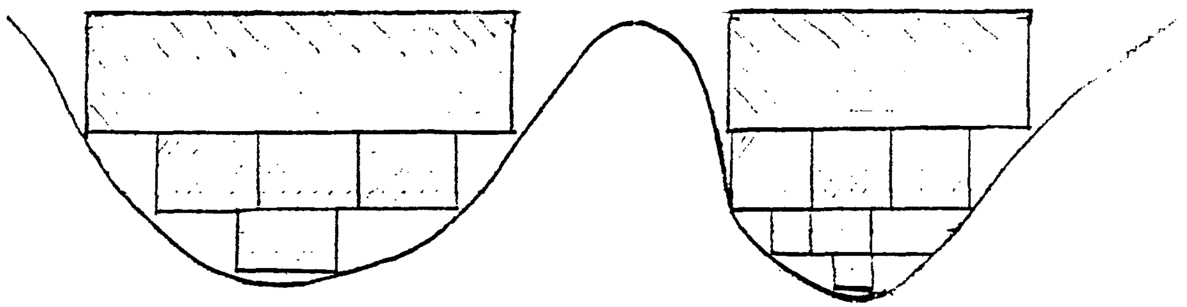


Figure 2a. With large plants

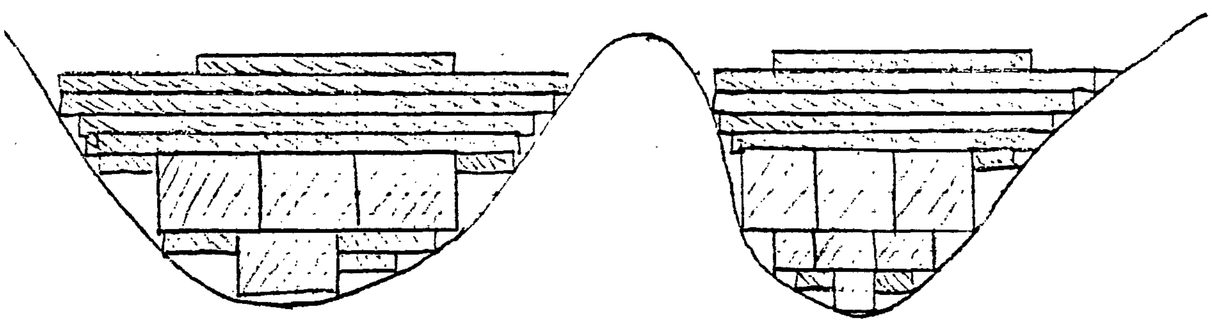


Figure 2b. With small plants

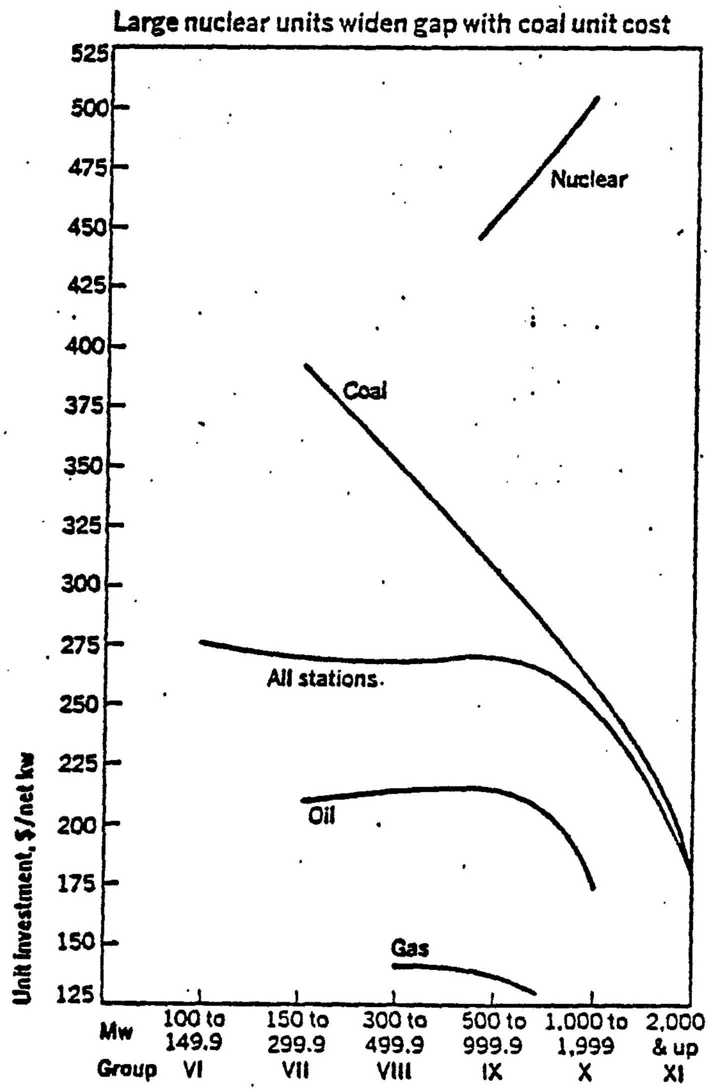
 plants held constant between cases

 plants varied between cases

Figure 2: EFFECT OF PLANT SIZE ON MAINTENANCE SCHEDULING

FIGURE 3

Source: Electrical World, November 15, 1977, p. 51, "20th Steam Station Cost Survey"



Electrical World, November 15, 1977

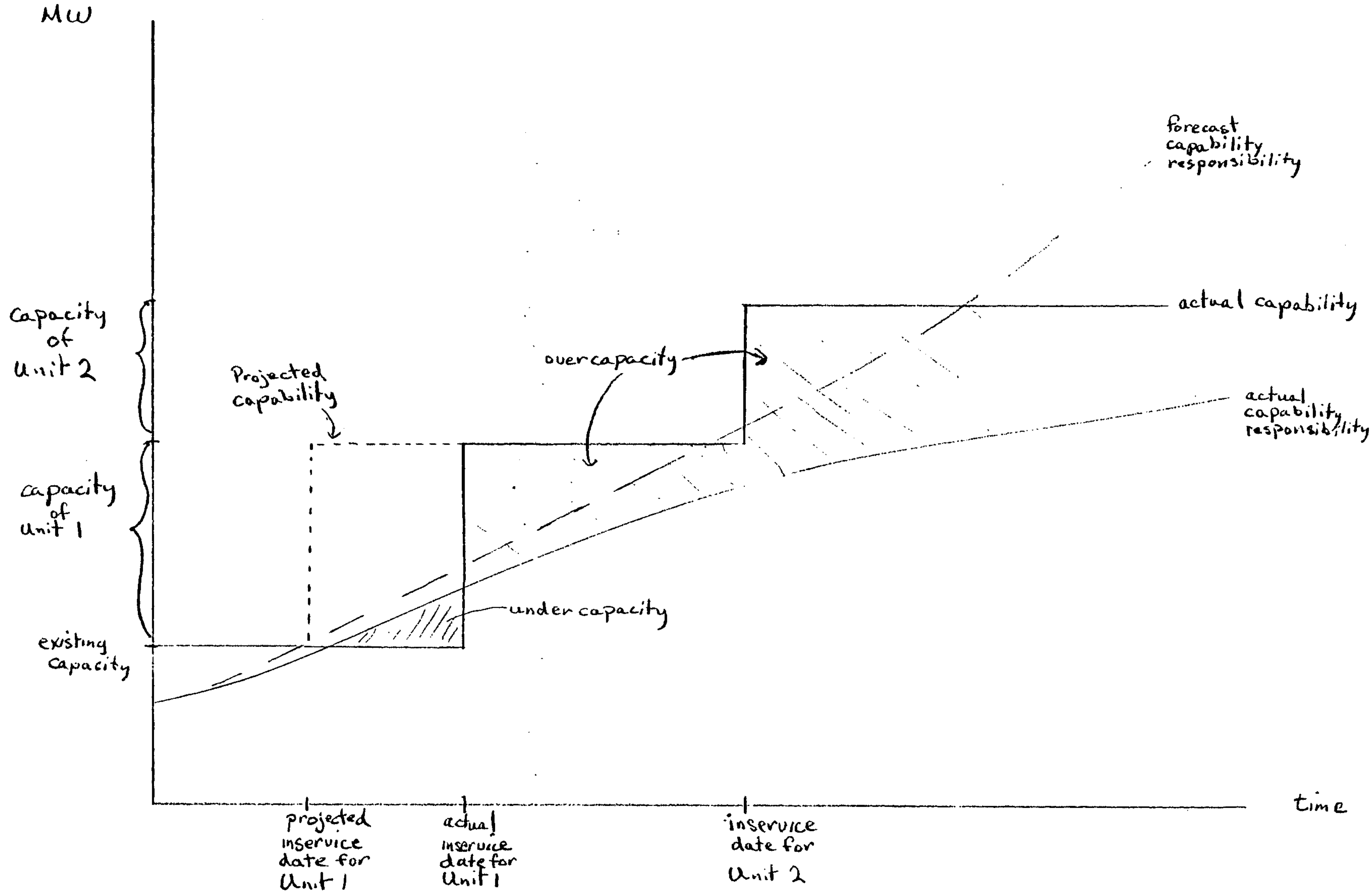
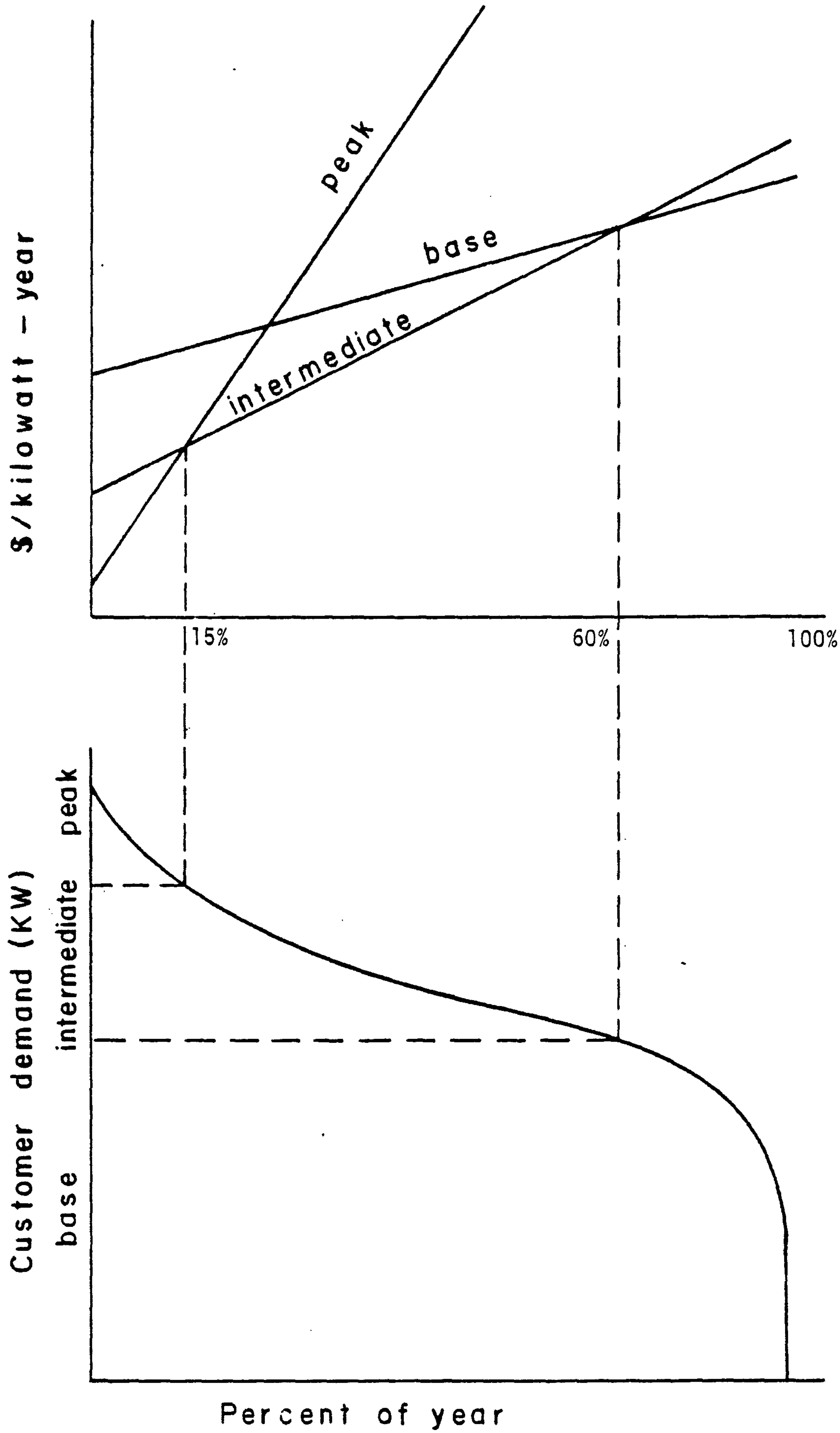


FIGURE 4: Effect on reserve margin of large plant additions, under conditions of uncertain construction time and load growth.



Optimal capacity mix for static, deterministic model

Figure 5.

III. APPLICATION OF GENERAL PRINCIPLES TO NEPOOL AND NEW ENGLAND

Q: Does NEPOOL allocate Capability Responsibility to participants in a fair and reasonable manner?

A: No. Among the incorrect, unfair, or unreasonable aspects are:

1. Failure to distinguish between various generating units' real contribution to reliability;

2. Assignment on the basis of non-coincident peak, which discriminates against smaller participants;

3. Assignment on the basis of annual peak (70%), which particularly discriminates against summer-peaking participants;

4. Assignment on the basis of average monthly peak (30%), which fails to discriminate between demand on seasonal peak and demand in other months;

5. Failure to determine whether annual peak or maintenance scheduling constitutes the binding constraint on capacity, and to allocate responsibility accordingly;

6. Inclusion of winter peaks in determining summer capability responsibility, and vice versa, thereby precluding capacity-trading between strongly seasonal utilities; and

7. Failure to recognize participants' capacity for load relief (other than interruptible contracts) in determining capability responsibility.

Q: Does NEPOOL forecast customer generation for load relief in a reasonable manner?

A: No. They project <u>no</u> customer generation. The Attorney General has identified over 55 MW of generating capacity in Massachusetts hospitals alone. If respondents are typical, there would be over 80 MW at hospitals in this state alone, in addition to other institutional, commercial and industrial establishments in Massachusetts, and all such establishments in the other five states. In terms of reliability, this generation is at least equivalent to very good peaking capacity: units are small, losses are negligible and production is dispersed. Of course, this dispersed capacity would be more valuable if NEPOOL encouraged its members to identify, organize and promote such generation. By displacing central capacity and increasing reliability, back up generators should be eligible for capacity credit from the utilities. Unfortunately, the prevailing utility rate structures, including standby charges and demand charges, operate to inhibit self-generation in any form.

Q: Please explain how utility rates inhibit self-generation.

A: There are three major pricing policies which utilities employ which discourage customers from generating electricity. First, standby, backup, or auxiliary service charges are used, in which the self-generating customer is generally charged for the same amount of utility capital costs as a customer who uses utility power. In fact, the customer may have to pay for a contract demand whether or not that demand level is used in the applicable period; the same requirement does not generally apply to non-generating customers whose demands fluctuate over time. In some cases, such as New Bedford Gas and Edison Light Company, the utility actually charges more per KW the self-generating customer does not use than it does per KW the non self-generating customer does use, and more per KWH of actual use as well. Extreme pricing policies such as these obviously discourage co-generation and self-generation. The second pricing policy of interest is the demand charge, a rate based on a customer's peak demand (over a period of 15 to 60 minutes) during some period, frequently a year. This rate feature charges the same amount (for demand) to a customer who uses (for example) 2 MW only once a year as to a customer who uses the same amount of power every day. Since generating equipment is not 100% reliable, a customer whose generator (whether in base load or peak shaving use) fails even briefly is assessed a tremendous penalty, unless the customer has backup equipment or accepts an outage. Although serving occasional demand is cheaper than serving continuous demand, especially when the demands are relatively small and, in part, subject to scheduling, this type of pricing policy remains common.

The third pricing policy involves the utilities' refusal to offer fair rates for the excess energy and capacity that some small producers would be able to provide. These rates should approximate the marginal cost of alternative energy and capacity to the utility. But BECO, for example, has offered only 80% of average energy costs, with no credit for capacity or O+M.

Q: Have the Massachusetts utilities corrected these biases in their time-of-use filings?

A: Not really. There appear to be only two legitimate arguments for demand charges, and both can be better met in other ways, especially for large customers. First, demand charges have historically been a proxy for time-of-use cost differentials; time-of-use-rates eliminate the validity of this use of demand charges. With the magnetic tape recorders which the utilities plan to install for most large users (and which are not significant expenses for such users), even weather-sensitive super-peak periods can easily be defined. Secondly, some costs are related to an individual customer's maximum demand, but these are local transmission and distribution expenses, which must be made — incurred in advance: contract payments would be a more appropriate way to cover this relatively minor expense.

Nonetheless, Massachusetts utilities are attempting to retain demand charges in their time-of-use rate filings even though they serve no useful function, and only dilute and distort the effects of time-of-use energy rates.

Q: In addition to the general reliability issues you have already discussed, are there other reasons to believe that NEPOOL's estimates of capability responsibility are overstated?

A: Yes, there are three such reasons: (1) delays in nuclear plant schedules since 1976; (2) NEPOOL's assumption that spring and fall valleys are filling in; and (3) the 1% bandwidth.

Q: Please explain the effect of delayed nuclear and other large generating plant in-service dates?

A: When the Objective Capabilities were set, NEPOOL expected several large nuclear units to come on line much earlier than they actually will. Depending on exactly what supply forecast NEPOOL used in its reliability models, NEPOOL may have believed that four additional plants (NEPCO No. 1, NEPCO No. 2, Montague No. 1, and Sears Island) would be on line in 1986. These large, immature plants, with high outage rates, contribute sizable amounts to NEPOOL's reserve requirements; without them, the necessary reserve margins would be considerably lower. Since each participant's capability responsibility is proportional to the NEPOOL Objective Capability, this overestimate persists throughout the period for which Objective Capabilities have been set.

Q: Please explain the significance of NEPOOL's forecast of spring and fall valleys.

A: NEPOOL indicates that reserve margins have been increased by as much as 1.8 percentage points due to a perceived tendency for the spring and fall valleys to become shallower, allowing less time for maintenance and increasing the probability of capacity short-falls in those periods, and ultimately requiring more capacity. In NEPOOL's methodology, this effect is reflected in the 30% of the Participant's Capability Responsibility which responds to monthly peaks.

NEPOOL claims to use the Participant's load forecasts to predict this trend, based on forecast 1978/79 load shapes (Information Response BE-II-1500-41). Participants' forecasts are generally very crude, and overstated (see the testimony of Chernick and Geller in this proceeding). This exaggeration extends to weekly peaks, as evidenced by Figure 6, taken from the December 1978 NEPEX Report. NEPOOL's weekly peak forecast, produced in Mid-January 1978, overestimated some 49 of of the 52 weekly peaks for 1978. Some of the errors in the summer and winter forecasts may be attributable to mild weather, but this explanation does not apply in the spring and fall, when the valleys were consistently 500 to 1000 MW deeper than predicted. Therefore, it appears that NEPOOL is underestimating maintenance opportunities and correspondingly overestimating required reserves.

Q: Please explain the effect of the 1% bandwith on Capability Responsibility?

A: Mr. Barstow indicates that Participants are required to provide more capacity than is indicated by their share of the original Capability Responsibility. If the actual company peaks (weighted by the arbitrary 70/30 ratio) add to less than 99% of the forecast sum of such peaks, each Participant's responsibility is increased by 1%. Given the forecasts the companies and NEPOOL use, such overestimation seems inevitable: it certainly occurred in the 1976 Objective Capabilities. Therefore, all current projections of capability responsibility are 1% higher than NEPOOL's own models indicate is necessary, in addition to the other errors noted above. This is equivalent to an increase of about 1.2 percentage points in NEPOOL's reserve margins.

Q: Does NEPOOL properly allocate operating reserve requirements to participants?

A: No. NEPOOL assigns operating reserve on the basis of peak. In fact, NEPOOL sets total pool operating reserve equal to 1.5 times the largest unit (or transmission line) currently on line. Therefore, at the very least, the owners and users of that largest unit, who receive its benefits, should also pay for the reserve it requires. If NEPOOL were maintaining operating reserve to meet a probabilistic stability target, then the size, outage rate, and other characteristics of each participant's plants should enter the assignment. Since NEPOOL does not recognize these factors, the owners of small generating plants are forced to subsidize the owners of large generating plants, and the economics of various capacity additions are distorted.

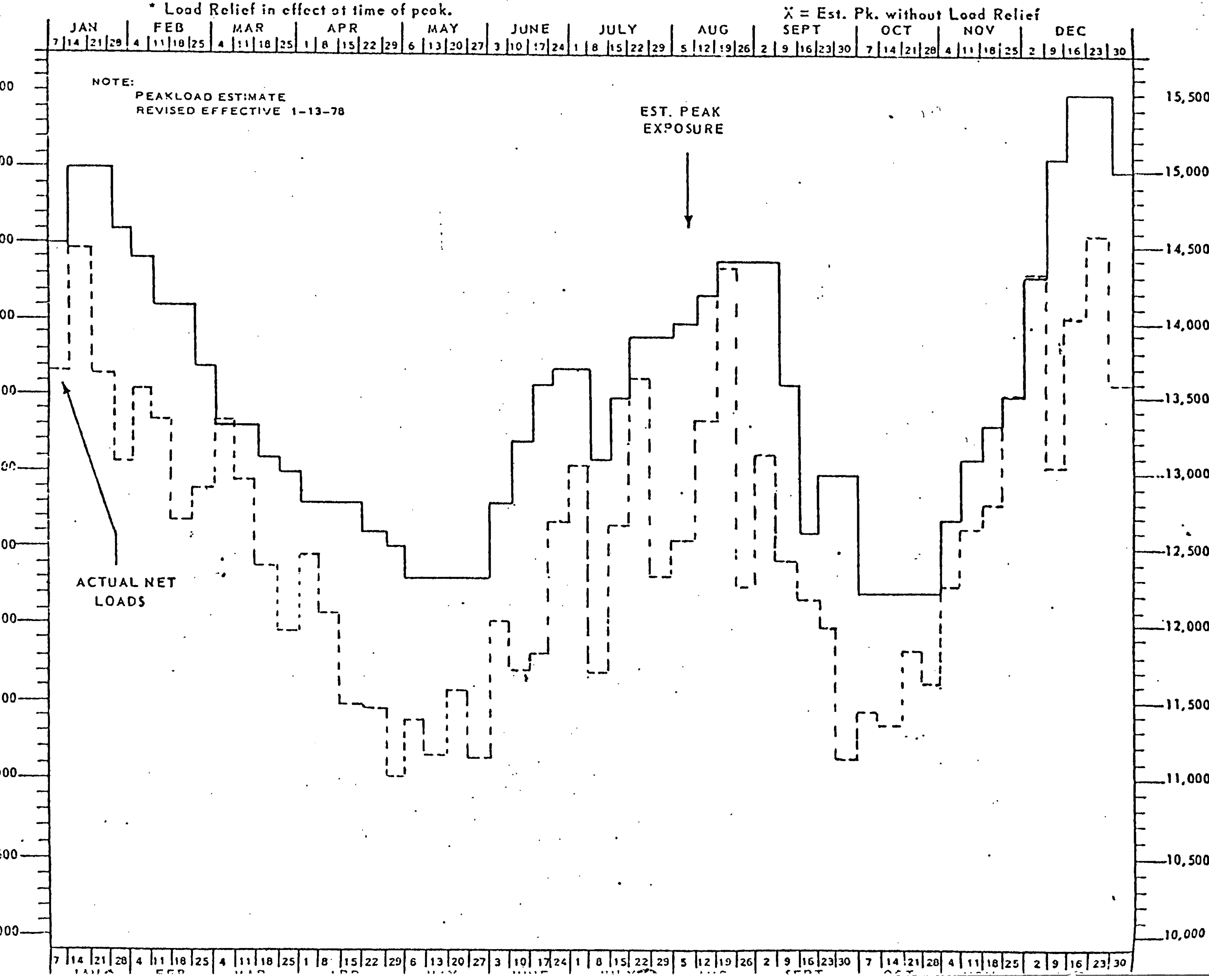
Q: Does construction of large amounts of expensive new base load capacity inhibit future innovations in generation and in conservation?

A: Yes. If a conservation or generation technique is currently competitive with existing oil-fired generation, it will probably continue to be competitive in the future. However, a technique which is now (or will soon be) cheaper for society than a new nuclear plant may not be cheaper than the operating costs of the nuclear plant in the future once the capital costs are sunk. Therefore, construction of nuclear units (and to a lesser extent, new large coal plants) may foreclose superior options, whereas operation of existing plants does not.

In addition, the lumpiness of nuclear investment decisions will produce periods of excess capacity, which will be exacerbated by use of nuclear power to substitute for existing oil generation. Under these conditions, utilities will continue to utilize their excess capacity as an excuse for denying capacity credits to decentralized generators.

Q: Does this conclude your testimony?

A: Yes, it does.


* Load Relief in effect at time of peak.
X = Est. Pk. without Load Relief
JAN
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MAR
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SEPT
OCT
NOV
DEC
NOTE:
PEAKLOAD ESTIMATE
REVISED EFFECTIVE 1-13-78
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FIGURE 6