EXHIBIT Q-WMECO-II-3
Attachment A

THE COMMONWEALTH OF MASSACHUSETTS
BEFORE THE DEPARTMENT OF PUBLIC UTILITIES

RE: RULES GOVERNING RATES AND CONDITIONS FOR UTILITY PURCHASES OF POWER FROM QUALIFIYING FACILITIES	DOCKET No. 84-276

TESTIMONY OF PAUL CHERNICK
ON BEHALF OF
THE ATTORNEY GENERAL

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TESTIMONY OF PAUL CHERNICK

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THE ATTORNEY GENERAL

1 - INTRODUCTION AND QUALIFICATIONS

Q: Mr. Chernick, would you state your name, occupation and business address?

A: My name is Paul L. Chernick. I am employed as a research associate by Analysis and Inference, Inc., 10 Post Office Square, Suite 970, Boston, Massachusetts.

Q: Mr. Chernick, would you please briefly summarize your professional education and experience?

A: I received a S.B. degree from the Massachusetts Institute of Technology in June, 1974 from the Civil Engineering Department, and a S.M. degree from the Massachusetts Institute of Technology in February, 1978 in Technology and Policy. I have been elected to membership in the civil engineering honorary society Chi Epsilon, and the engineering honor society Tau Beta Pi, and to associate membership in the research honorary society Sigma Xi.

I was a Utility Analyst for the Massachusetts Attorney General for over three years, and was involved in numerous aspects of utility rate design, costing, load forecasting, and evaluation of power supply options. My work has considered, among other things, the effects of rate design and cost allocations on conservation, efficiency, and equity; the design of conservation programs; and the establishment of purchased power rates for small power producers and cogenerators; and the comparison of the costs of nuclear power to those of conservation and alternative energy development.

In my current position, I have advised a variety of clients on utility matters. My resume is attached to this testimony as Appendix A.

Q: Mr. Chernick, have you testified previously in utility proceedings?

A: Yes. I have testified over thirty-five times on utility issues before this Department and such other agencies as the Massachusetts Energy Facilities Siting Council, the Texas Public Utilities Commission, the Illinois Commerce Commission, the New Mexico Public Service Commission, the District of Columbia Public Service Commission, the New Hampshire Public Utilities Commission, the Connecticut

Department of Public Utility Control, the Michigan Public Service Commission, the Maine Public Utilities Commission, the Pennsylvania Public Utilities Commission, the Vermont Public Service Board, and the Atomic Safety and Licensing Board of the U.S. Nuclear Regulatory Commission. A detailed list of my previous testimony is contained in my resume. Subjects I have testified on include cost allocation, rate design, long range energy and demand forecasts, costs of nuclear power, conservation costs and potential effectiveness, alternative energy costs and availability, generation system reliability, fuel efficiency standards, and ratemaking for utility production investments and conservation programs.

Among the issues of particular relevance to this proceeding, I testified in the Department's previous proceeding on rates for small power producers and cogenerators (DPU 535), and in several cases involving the cost, availability, and development of alternative generation, of which the most recent example is DPU 1627. I was also active in an Analysis and Inference project for the Northeast Solar Energy Center, regarding the design of rates under PURPA Section 210.

Q: What is the subject of your testimony?

A: I have been asked by the Attorney General to review the proposal of the Executive Office of Energy Resources (EOER) regarding the rates and conditions for utility purchases of power from small power producers and cogenerators (collectively referred to as "qualifying facilities" or "QFs"), pursuant to Section 210 of the Public Utilities Regulatory Policy Act (PURPA).

Q: How is your testimony structured?

A: The following five sections consider first general issues, and then specific concerns:

- § 2 discusses the advantages of qualifying facilities as compared to other sources of power which may be available to the utilities.
- § 3 compares the treatment of QF costs to those of other utility power sources.
- § 4 considers the basic approach which should be taken with respect to QF ratesetting.
- § 5 contains my comments on the issues raised in the EOER proposal, with some suggested improvements and refinements.
- § 6 addresses issues which were not included in the EOER proposal, and again offers suggestions for improving the current or proposed regulations.

Q: Please briefly summarize your testimony.

A: The basic points which I would like to make are:

1. In most respects, utilities and their customers are better off purchasing power from QF's, rather than owning capacity or buying power from other utilities with the same expected cost.

2. In most respects, QF energy and capacity is more valuable to the utility (and its customers) than conventional utility-owned resources.

3. Present treatment of QFs is much less favorable than treatment of utility-owned capacity, or treatment of purchases from other utilities.

4. The Department should increase the incentives for development of QFs, by treating them in a manner consistent with utility-planned resources.

5. The EOER proposal represents major improvements in some important aspects of QF rate treatment, especially in locking in future rates, levelizing some rates, and rationalizing the capacity credit provisions.

6. The EOER proposal has some flaws, such as short-changing some cogenerators which use gas and oil; imposing unfair and inappropriate restrictions on capacity credits; and failing to address aspects of the cost-projection problem. While these flaws are minor

compared to the benefits of EOER proposed changes, there is no reason not to correct them, and produce an even better set of regulations.

7. There are additional errors and omissions in the present regulations which are not addressed by the EOER proposal, including the use of average (rather than marginal) losses, and failure to provide incentives for load following.

2 - COMPARING QFs TO CONVENTIONAL POWER SOURCES

2.1 - Introduction

Q: What is the purpose of this section of your testimony?

A: I will discuss various reasons for preferring to purchase power from QF's at actual or expected avoided cost, rather than having the utility make investments in central-station facilities at the same expected cost. In general, the advantages can be divided into two groups: institutional advantages, which result from the independent ownership of the QF, and technical advantages, which result from the nature of the generating facilities.

2.2 - Institutional Advantages of QF's

Q: Should utilities or ratepayers be indifferent between an expected cost of utility-owned generation, and the same cost in a QF power purchase contract?

A: No. The QF gets paid only if it produces power, while the utility and its customers must cover the cost of the utility-owned facility whether it operates well, poorly, expensively, or not at all. Therefore, the financial and economic risks (which are not necessarily the same as the power supply risks

I discuss below) of the utility plant are greater than those of a QF at the same expected costs, and under those circumstances, the small producer power would be preferable.

Q: When a contract written in this decade runs out, is it likely that utilities will have to offer higher prices to keep the QFs in operation?

A: I think not. Once cogenerators, refuse-burning plants, hydro-electric facilities, and the like have been built and operated for fifteen years, the cost of keeping them in operation should be very low. Depending on the regulatory environment (such as whether the small producers have the right to wheel power to other customers at regulated rates), the cost of fuel (for the cogenerators, in particular), and the economic viability of the user of cogenerated heat, the contracts may be renewed at the original rate, or even less.

The EOER proposal requires that any QF which sells power under a fixed rate must continue selling at short-run avoided cost after the end of the fixed-rate period. This approach offers some additional assurance that the rate will not have to be renegotiated for many years. I will propose in § 6 that this provision be changed to increase the protection for the utility and its customers.

Q: The concern has sometimes been expressed that fixed rate contracts expose the utility to a risk that it will have to pay more than the power actually turns out to be worth. Is this a problem?

A: No. The ability to lock in future energy costs is equivalent to a form of insurance: in essence, the fixed-rate QF contract is insurance against unanticipated oil price increases. Utilities, like virtually everyone else, purchase insurance with the hope that the insurance will prove to have been an unnecessary investment in hindsight, and with the expectation that the benefits of the insurance (discounted in the normal fashion) will be less than its cost. Insurance is thus a means for paying a premium to reduce risk. A fixed QF rate provides insurance against higher future costs: under EOER's proposed approach, there would not even be an expected premium for the insurance, since the expected value of fixed rates, variable rates, and avoided costs would be the same.

Another way of looking at the fixed rates is to compare the times when they turn out to be disadvantageous, in retrospect, to the times when the utility is facing problems with high costs. Under the short-run rates, the purchase rate is highest when the utility's other power sources are most expensive, and the alternative energy source does nothing to stabilize power costs. Under fixed rates, the QF is most valuable to the utility when it needs the power most

-- when other power sources are most expensive -- and least valuable when the rest of the utility's power supply is most favorable. Thus, the fixed rate is a form of insurance for the utility, and is actually more valuable to the utility than short-run rates with the same expected value. Fixed rates lock in the rates of prices competitive with projected power costs, and protect the utility from future oil price shocks, capacity shortages, and plant outages. The fact that payment is conditioned on power delivery eliminates utility risk of cancelation, poor performance, and early retirement; the risks related to the cost of building and operating the QF also remains with the owner.

Q: If the fixed rate is also a level rate, does this affect the risk to the utility?

A: Yes. The front-loading of recovery simply makes the small power producer more like utility-owned investments, which usually require more-or-less constant capital cost recovery over the life (or the early years thereof) of the plant. The majority of the risk remains with the owner: if it becomes impossible to operate the plant, the owner loses its future cash flow. However, a QF could fail (physically, or in the case of a cogenerator which loses its heat user, financially) before the expected value of the avoided costs has reached the level rate paid. In this situation, the utility purchaser will have paid more for the power delivered than that power was worth (at least on an expected value basis), but at least the payments stop when the plant stops working. If the utility owned the plant (whether it is alternative or conventional in nature), its costs continue if the plant ceases to operate for a long period, or even permanently. Thus, while the level rate is not as advantageous to the utility as the escalating fixed rate, it is still preferable to direct utility ownership of facilities at the avoided cost.

2.3 - Technological Advantages

Q: Is the development of QF capacity equivalent to providing similar amounts of energy and capacity through construction of new central station generators?

A: No. In general, the QFs will possess inherent technological advantages. New England is unlikely ever to experience the abrupt simultaneous loss of large amounts of QF power, since many small units would have to develop problems coincidentally in order to result in a supply reduction of hundreds of megawatts. Individual utility plants will frequently go off-line quite quickly and with little warning, dropping as much as 1150 MW in the case of Millstone 3 (and Seabrook 1, if it ever reaches operation); there are several existing nuclear and fossil units, each of which reduces supply by 600 to 800 MW when it becomes unavailable.

Cogenerators must, by their nature, be close to (and are often inside) the facilities which use their heat, which are often close to other economic activity (and hence other loads). Since the cogeneration will thus tend to be dispersed throughout the utility's service territory, and will tend to be close to large electrical loads, most of the power produced will not travel far before reaching the end user. Since cogenerated power usually need not flow through the transmission system, it usually can not be disconnected from demand by a transmission failure. Central generators, and out-of-region purchases, can easily be disconnected from load centers by transmission problems.

Most QFs can be brought on line within a few years of a commitment to proceed; a new coal unit would be under construction for about a decade (and a nuclear unit for much longer) before it starts to reduce oil use or increase reliability.

Q: Can you compare the relative risk of reliance on cogeneration and small power production, to the risk of building and operating large central station plants?

A: Yes, it least in general terms. The types of risks involved are quite different, and quantification is often difficult. In most respects, however, the central station plants are much riskier power sources.

Consider, for example, the availability of power in 15 years. Once a QF is built, it is likely to be available for a long time. Hydro plants are certainly not going to be relocated, and may well last a century. Most cogenerating industrial and commercial firms (or their facilities, which are often more durable than the corporate entities) will also stay in the area, for access to materials, labor, or customers; if the firms fail, both their supply contribution and their demand contribution (including their effect on residential sales and electricity sales the firms' suppliers and other related commercial and industrial activities) are lost simultaneously, so the net effect is smaller than a corresponding loss of central station capacity.

More importantly, the small power producers and cogenerators diversify the risk of outages or premature retirements much better than does a central station plant. The loss of any one QF causes a much smaller problem for New England, Massachusetts, or any particular utility than would the loss of a large thermal unit, either short-run (for a few hours, days, or weeks) or long-run (for months, years, or permanently). For example, New England operating reserves were perilously tight during several days in the summer of 1984, despite the existence of large installed reserves, largely because of simultaneous outages at a few nuclear and large fossil plants.[1] Hundreds of small power producers would have to become unavailable simultaneously to have a similar effect.

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1. NEPEX instituted actions which it considers to be emergency procedures, including the reactivation of units in deactivated reserve. See Appendix B for a detailed description.

In addition to diversifying generator outage risk, QFs diversify and reduce fuel cost and availability risk. Many QFs will not use fossil fuels, and those which do will use much less than the oil-fired utility plants they displace. As a result, Massachusetts and New England will be less vulnerable to future oil supply problems, or to oil price shocks, due to the development of QF capacity. In the longer run, the same will be true for coal, to the extent that coal-fired cogeneration displaces coal-fired condensing units.

Q: Is it possible for several QFs to become unavailable simultaneously due to a common cause?

A: Such events are certainly possible, even if rare or unlikely. A severe drought would drastically curtail hydro generation, acid rain could eventually reduce the fuel supply for wood-fired plants, and recessions in certain industries could cut back significant amounts of cogeneration.[2] But most of these events, while they might be simultaneous, would not be fast, and would allow the utilities months or years to secure alternative sources, or to implement a new round of conservation investments. Even a fairly abrupt shutdown of an entire category of QFs, such as might conceivably result from a new environmental concern with regard to trash-

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2. The cogeneration curtailment would be partially offset by reductions in sales.

to-energy plants, would only have an effect comparable to the loss of one large central unit.

Several central station units can also be taken out of service by a common cause. This is fairly obvious for nuclear plants, as evidenced by the effects of the Three Mile Island accident, or the Stone & Webster computational error which shut down Maine Yankee in 1978. Historical experience with massive curtailments of fossil unit power production has generally resulted from fuel availability problems,[3] but it is certainly conceivable that future environmental concerns could produce similar effects. From the viewpoint of reliability, or energy adequacy, the loss of all small hydro, or all wood-fired cogeneration, would be much less serious than loss of all New England nuclear units, or all coal units. If any particular utility becomes highly dependent on a single type of QF, subject to common cause outages, it would be well advised to arrange power swaps with other utilities' power purchases (or central stations) to diversify the risk. This sort of technological risk-sharing is not possible to any great extent with New England nuclear or oil plants, since they represent such a large share of total NEPOOL capacity and energy, and would be of limited effectiveness for coal capacity if conversions continue and

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3. This category would include coal strikes and the oil embargo.

new coal plants serve forecast load growth.

Q: If a utility invests in central station capacity, and the situation there turns out badly, are the ratepayers exposed to more or less risk than if the utilities rely on QFs, and those are less successful than currently expected?

A: Central station investments can fail in ways which are hardly credible for QFs. For example, as Seabrook 2 demonstrated, utilities could invest a billion dollars in a plant, without ever having it operate. The utility is not exposed to similar financial risks from QFs, since it does not pay until they generate power. The power supply risk is also smaller, because of the size and diversity of the projects. Any one QF may fail to be materialize, but it can be replaced by another facility, which may or may not require a higher rate. The downside risk from the QFs approach is primarily the possibility that somewhat higher prices must be paid than currently appears likely. The experience in Maine and California, among other states, demonstrates that large supplies of QF power are available at reasonable prices, even if the price is higher than the utility would like.

Q: Does a QF always have to be available at the time of system peak, or at times of tight operating reserves, to be considered as an alternative to new utility construction?

A: No, not at all, and for two basic reasons. First, it is important to remember that most of future investment, and most of current costs, are associated with the cost of providing energy, rather than the cost of providing reliable power. Most of the avoidable costs in existing rates are fuel costs, especially oil costs: most avoidable future investment (in dollar terms) is designed to reduction in the use of oil. Energy, particularly in the form of oil, is relatively expensive: reliability, particularly in the form of combustion turbines, is not very expensive.

Second, system reliability is a probabilistic issue. Any unit contributes to system reliability if it has any probability of generating power when it would be required to prevent customer disconnections. All realistic units have some chance of being unavailable when needed and therefore allow for the addition of less than one MW of firm load for each MW of rated capacity. In particular, large central plants are not very reliable, and due to their large size, they contribute relatively little to overall NEPOOL reliability. Since the loss of a large unit greatly increases the probability of low operating reserves, the outages of such units are more highly correlated with system distress than the outages of small units. Table 2.1 shows the derivation of the effective load carrying capacity (ELCC) for Seabrook, from the reserve margins projected by MMWEC in

DPU 1627.[4] As shown in Table 2.1, MMWEC does not expect Seabrook to be able to support firm load amounting to more than about 50% of its rated capacity. On average, NEPOOL's current capacity is expected to support firm peak load averaging about 80% of its rated capacity. Nonetheless, virtually all generators, even large nuclear units, deserve (and get) some credit for increasing reliability.

Q: Other than the value of the capacity to NEPOOL and the crediting of that capacity to individual NEPOOL members, are there reliability benefits of QFs which are not shared by large central station facilities?

A: Yes. Small producers which are located close to or within load centers will also help to protect customers against transmission failures, which have historically been responsible for more customer disconnections than has inadequacy of installed capacity. Central station plants, especially new ones, are generally located fairly far from loads, often at the end of long transmission lines. Out-of-region purchases, such as Hydro Quebec and Pt. Lepreau, are even more vulnerable to transmission problems.

Q: Should the ability of the utility or NEPOOL to dispatch a QF be a consideration in determining the value of the source?

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4. Calculations based on NEPOOL projections yield similar results.

A: Not in general. So long as the source would be dispatched under economic dispatch, the issue of whether NEPOOL can choose to dispatch is largely irrelevant. Thus, for plants with zero or negative fuel costs (e.g., hydro, wind, and solid waste plants), which would always be dispatched, the lack of "dispatchability" should not be an issue of any interest. As long as oil remains the marginal fuel on the NEPOOL system, virtually all alternatives will be base loaded. Only when oil is no longer the marginal NEPOOL fuel will the ability to turn off small producers with fuel costs higher than coal (or whatever becomes the marginal fuel source) be of any real importance.

3 - POTENTIAL FOR DEVELOPMENT OF QUALIFYING FACILITIES

Q: Do you believe that there is considerable potential for development of cogeneration and small power production?

A: There is much evidence to support that view. Before comparing the dismal state of present QF development in Massachusetts to the vast potential QF capacity in the state, it is important to remember that utility attitudes towards QFs are extremely important determinants of their success. Utility resourcefulness and success in utilizing unconventional supply sources has been dependent in the past on the utilities' situation. For example, New England utilities seem to have become much more interested in (and successful at) obtaining agreements to purchase Hydro Quebec power as Pilgrim 2 construction became less likely. Perhaps the most aggressive conservation and small power production programs in the country are found in California, where licensing and construction problems with central generating stations left the utilities with little choice but to innovate. At the moment, various utilities have little incentive to pursue QF development, since the threat of capacity shortages is an important part of the argument for Seabrook and Millstone. Once the fates of those units are determined (probably cancelation for Seabrook, and completion for Millstone 3), the utilities will be free to explore other options, and those which have been relying on Seabrook to meet their capability requirements will be searching for replacement power. It is important that the DPU rules support this trend in the next few years, rather than frustrating it.

Q: Is there any particular advantage to developing small power production and cogeneration through power purchases, rather than limiting supply otions to those directly ceveloped by the utility?

A: Yes, for at least three reasons. First, where they have been given the opportunity, independent developers have brought forth QFs in greater quantities than the utilities were able to imagine, let alone locate and develop. Second, as discussed in Section 2, most of the risk is transfered from the utility to the owner of the QF: if this can be achieved at the same expected cost as utility-owned facilities (discounted at the same rate), the utility has purchased free insurance. Third, independent ownership allows developers to invest in facilities and processes in which they have greater faith than the utilities may have. The developer of a cogeneration facility need not convince the utility that the user of the heat will be in business for 20 years in order to negotiate a reasonable contract: if the user goes out of business or moves, it is the developer (who may well be the heat user) who loses the initial investment, or earns no return on it for the period the facility lies idle. Similarly, the developer need not demonstrate the reliability of his plant in order to get a contract: if the plant does not run well, he will not earn much, but that should have little effect on the rate the utility is willing to pay per kWh.

3.1 - Alternative Energy Potential

Q: How much potential exists for development of alternative energy sources in Massachusetts?

A: Table 3.1 lists estimates of the amounts of potential capacity, typical actual or estimated capacity factors, and the resulting annual energy contribution for each source. Sources for which the potential is likely to be significantly underestimated, probably by at least at order of magnitude, are indicated with a plus (+). The actual capacity developed in each of these technologies will vary from these estimates, depending on the rates and conditions offered; the extent to which the underlying studies neglected technical and siting options;[5] and the financial, enviromental, and other problems and opportunities of each site.

Q: Does the QF potential represent a significant amounts of capacity in terms of the total needs projected by the Massachusetts utilities?

A: As illustrated in Table 3.2, the Massachusetts utilities project that they will receive a total of 278 MW from Seabrook and 329 MW from Millstone. They would also expect

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5. For example, the cogeneration study neglects all residential applications of cogeneration, and is too old (three years) to reflect recent developments in small diesel cogenerators, fuel cells, and fluidized beds.

to receive about 720 MW from Phase 2 of the Hydro Quebec interconnection. These three projects represent the major portion of NEPOOL's committed power supply, and the utilities involved generally consider them to be very important. Feasible cogeneration and small power production capacity could provide more capacity for Massachusetts than any of these projects, and quite likely more than the three projects combined.

3.2 - Response to Firm Rates

Q: If the utilities offer long-term contracts for the purchase of power from QFs at predetermined rates, what level of response might they expect?

A: It is difficult to answer that question with great specificity, since it depends on the resources, ingenuity, and finances of numerous developers, manufacturers, building owners, land owners, and others, as well as the technical problems and opportunities offered by each site. However, a similar experiment was recently conducted in Maine. The Maine utilities had previously offerred small power purchase rates based on short-term fuel costs, similar to the rates currently offerred in Massachusetts. In January 1984, the Maine PUC ordered those rates replaced with levelized contracts, with 15-year contracts paying 9.4 cents/kWh. Even though those rates have since been reduced, as cogenerators and small producers (hydro, trash-burning, and wood-burning) have backed out the utilities' most expensive sources, about 465 MW of small power sources are now under contract. NEPOOL currently projects only 188 MW's of small power in all of Maine by the end of the century; in less than a year, Maine has brought 2.5 times that much into the pipeline, and more contracts are under development.

The corresponding NEPOOL estimate for Massachusetts independent production in 1999 is 390 MW, of which only a small portion is under contract. If the Maine experience is any guide, increasing the bid price to 9 - 10 cents would be expected to double the offered power, providing another 585 MW, in addition to the substantial portion (about 240 MW) of the original 390 MW projection not yet under contract. These capacity figures refer to short-run effects: development by the end of the century, or even the end of the decade, would be expected to be larger.[6]

Of course, for small power production, Maine is better situated than Massachusetts in some important ways, including the size of the forest products industry, a good site for cogeneration. On the other hand, Massachusetts has more large commercial and institutional buildings, which may also offer good cogeneration sites, and the estimated response in Maine includes only the projects which materialized quickly in response to the higher prices: more offers would be expected as additional sources are developed.

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6. The NEPOOL projection for Maine consisted mostly (at least 109 MW) of projects for which contracts were signed before 1984. The capacity added in Maine since the new QF rates went into effect is 3.5 times the 79 MW of new capacity projected by NEPOOL. Only about 158 MW of capacity is under contract in Massachusetts: if QF rate reform here is as successful in increasing projected capacity as it was in Maine, the remaining 232 MW projected by NEPOOL would translate to 990 MW under contract by next year.

4 - TREATMENT OF OTHER UTILITY PLANNING OPTIONS

Q: Have the Massachussetts utilities been properly comparing the costs of QFs and of conventional sources?

A: No. The utilities have been very reluctant to enter into any purchase arrangement for small power sources which does not represent immediate savings compared to the cost of oil, or at least guarantee that energy costs will average less than avoided oil costs. This is a much stricter standard than is usually applied to conventional sources, and is inconsistent with the position of most of the utilities that both they and New England face capacity shortfalls within the planning horizon for new base-load capacity, especially if Seabrook 1 is canceled, which now appears to be very likely.

Q: Is it reasonable to limit QFs to short-run avoided cost, given the ratemaking treatment afforded utility plant?

A: No. Utility plant is usually planned and justified on the basis of long-run, even life-cycle, benefits. Indeed, if utilities are to remain public service corporations, with responsibilities to provide reliable power supply at reasonable costs,[7] their planning must be long term. If the utilities must make long-run decisions based on long-run projections, it is only fair and reasonable to evaluate their performance, and thus determine their cost recovery, on a similar time scale. Thus, while cost recovery may be denied due to poor planning, and cost recovery patterns over time may be varied to match costs and benefits,[8] it would be inequitable, impractical, and inappropriate to limit utility cost recovery for utility-owned power plants to after-the-fact avoided costs.

Since utilities can, and must, plan their facilities on a long-run basis, it would be inequitable and inefficient to limit QFs to cost recovery based on the short-run avoided costs. QFs also must make large capital investments, which will have limited value if the utility power purchase rate falls dramatically. As the EOER proposal is structured, the QFs retain all risks associated with their own construction and operation costs, and their own operating performance, all of which the utilities share, to some extent, with their customers. To continue the past practice of exposing the QF to the market risk of floating avoided costs would

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7. Some utilities have been much more successful in this regard than others.

8. I have recommended these actions in several proceedings, before this Commission and before other regulatory bodies.

essentially preclude independent development (and thus in most case any development) of QF capacity.

Q: Is it reasonable to limit QFs to short-run avoided cost, given the ratemaking treatment afforded to utility purchases of power from other utilties?

A: No. Power purchases between utilities are, and to a large extent must be, treated much like direct plant investments. The Commission has not attempted to limit utility cost recovery for power purchased from other utilities to avoided costs. For example, it is my understanding that the utilities' recovery of their investments for Hydro Quebec Phase I will not be limited to avoided costs. Even fairly modest proposals to redistribute the cost of purchases to better match the avoided cost benefits, such as my suggested performance standard for Pt. Lepreau in DPU 1509, have not been accepted by the Commission. If anything, the treatment of utility purchases from one another is more favorable than the treatment of their direct investments. The EOER proposals (and the improvements I suggest) simply bring the treatment of QFs more in line with Department practice for other supply sources.

Q: Do all competitive markets operate primarily on short-term price quotations?

A: No, especially those requiring large dedicated investments.

Location of processing plants may be conditioned on long-term fixed or escalating contracts. In the electric power field, both coal plant owners and mine developers may insist on long-term contracts,[9] especially when alternative markets and suppliers are not readily available. Tenants who expect to invest heavily in improving the space they rent may insist on long leases with limited escalation provisions. Thus, long-term price arrangements can and do exist in areas of active and aggressive competition.

Q: Is it practical to limit both utility and QF cost recovery to short-run avoided cost, so as to confront both power sources with a short-run competitive market?

A: I strongly doubt that it is. While there have been many proposals in recent years for the deregulation of electric utility power generation, I know of no jurisdiction which has actually adopted such a scheme. The basic problem is that investors will be reluctant to commit the tremendous amounts of capital[10] necessary to meet loads, especially for

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9. Part of the contract price may be fixed to cover capital costs, and part may be escalated to match labor costs.

10. It is important to recall that this capital investment in generation will usually be tied to a very limited local market, and is therefore fundamentally different from, and riskier than, investments in industrial plants serving national or world markets. The investor either in QF capacity or in the utility also faces the risk of eventually facing a regulated market again, should the business become too profitable, or otherwise become burdensome for consumers.

investments which require a few years to develop, and many years to pay back the initial investment, without reasonable assurance of eventual cost recovery. Certainly, QFs developers have not been very interested in supplying power without contracts, and the utilities have expressed little interest in developing generating capacity if they must assume all of the attendant risk. If a deregulated spot market for electricity keeps the lights on, it may do so with low-investment, high-fuel-cost peakers.

A shortage of electricity, or a sharp increase in the cost of local supplies, is not like shortages or price fluctuations in most other goods. Electricity usually can not be stored in large quantities, power can only be transported when and where transmission capacity is available, market imbalances can not be corrected rapidly by price changes,[11] and the effects of shortages can be very serious. Thus, the unregulated spot market can not be counted on to work as well for electricity as for other goods.

On the whole, a decision to deregulate bulk power supply, and thus to leave all suppliers of new power sources (QFs, local

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11. Retail price changes are slow, both due to regulation, and due to the long intrinsic adaptation time in customer price response: the long-run price elasticities take decades to work through the system.

utilities, and distant utilities, such as Hydro Quebec) dependent on short-run marginal costs for their cost recovery, would be both dangerous and radical. It would also be a sharp departure from existing regulatory and statutory structures.[12] As a result, a sweeping program of supply deregulation should be undertaken very cautiously, with extensive public and legislative[13] participation, if at all.

Even if the DPU wanted to move in the direction of generation deregulation, that option is not open to it with regard to the NEES companies (MECo, NEPCo, and Manchester) or the EUA companies (Montaup and EECo), due to FERC regulation of the wholesale supplier.

Q: Given the considerations you have outlined above, what approach provides the best incentives to QFs to provide power and economically displace utility fuel and investments?

A: The key is to allow the QFs to make decisions based on the same type of long-term projections on which utilities must

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12. The roles of the Energy Facilities Siting Council and of the Department's Fuel Clause Bureau would both change fundamentally under deregulation, to name only two such organizations.

13. Among other things, it would be important to secure legislation which would make it more difficult for a future DPU to undo the new power supply pricing scheme: so long as the DPU remains free to reintroduce regulation, the potential benefits of deregulation will appear to be more remote to power suppliers than will the potential dangers.

make their decisions. The EOER proposal moves significantly in this direction.

Q: How should the concepts you support in connection with setting QF rates be applied to the recovery of utility plant costs?

A: The two systems can certainly be designed in parallel, and many of the same issues arise in both contexts, although, as explained above, it is not practical to use the same ratesetting procedures for both utilities and QFs. For example, both utilities and QFs should be able to "lock in" at the time of significant construction commitment the avoided costs against which their plant will compete; neither type of producer should be limited to short-run variable avoided costs. The utility should not be blamed if oil prices turn out to be less than generally forecast, and the QF should not be penalized either.[2] On the other hand, QFs assume all of the risk of construction and operating cost overruns, and of poor performance: it seems reasonable to place much of the burden for similar problems at utility plants on the utility.[3]

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2. Rate shock problems may require that the time pattern of utility cost recover be altered to fit changed circumstances, but such considerations should not affect the utility's total compensation.

3. Indeed, this is purpose of the plant performance standard process.

The utility can not be expected to assume <u>all</u> the risks of operating its plants, so long as its monopoly position is tied to an obligation to serve, and exposes it to the likelihood that windfall profits from highly advantageous plants would eventually be regulated away. Therefore, while a QF developer who experiences a major cost overrun in construction or operation, or who builds a plant which does not operate reliably, may lose all or most of his investment, the utility in the same situation must be afforded the opportunity to demonstrate that its actions were prudent and that it could not have been expected to foresee or prevent the untoward outcome. To the extent that the utility's customers benefit when the utility's plans work out well, they must sometimes share the cost when reasonable plans go awry. Thus, ratesetting for QFs and utilities can start with the same data, the same projections, and the same principles, even though those factors must be applied in differing ways.

5 - GOALS AND APPROACHES

5.1 - Basic Objectives

Q: What should be the DPU's basic objective in setting QF rates and conditions?

A: The DPU should attempt to structure the QF/utility relationship so as to allow the QF to compete on a fair and equal basis with utility-planned and utility-owned supply options. Given current projections of rising (and risky) oil prices, capacity shortages, and expensive investments in new utility plants, the DPU should provide QFs an opportunity to solve these supply problems, if they can do so at prices competitive with utility solutions.

Q: What are the important considerations in achieving this objective?

A: First, it is important to establish Standard Offers which are relative favorable to the QF, while retaining the possibility of negotiated agreements. Second, the treatment of risk should recognize the value of the QF to the system, and the relative risk of the QF, compared to other supply options. Third, as I explained in the previous section, QFs should be able to plan their long-term investments based on long-term contract prices.

Q: Why is there any need for Standard Offers, and why should the Standard Offers be favorable to the QF?

A: Experience indicates that utilities do not voluntarily offer QFs better deals than the DPU requires. In order to get any contract at all, most QFs have had to settle for less than full avoided cost. Those which wanted floor prices have had to accept even smaller fractions of avoided cost. The low prices and the general failure to lock in future rates has resulted in severe limitations on the development of QFs in Massachusetts. Overall, it is not realistic to expect that QF's will get a better deal than the Standard Offer: QF's which need any special assistance or terms from the utility will have to settle for less than the Standard Offer. Hence, it is vital to provide the QF with a strong Standard Offer, to give it some bargaining leverage in an otherwise unequal situation.[16]

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16. Comm/Electric has agreed in at least one case to a short-run avoided-cost rate with a floor, which alleviates some of the financial problems and risks for the developer.

5.2 - Structuring the Rates

Q: How can the purchase option be structured, and which approach is preferable?

A: The two basic approaches involve (1) setting variable rates, based on short-run costs, and (2) setting fixed rates which reflect the expected costs over a lengthy period. The fixed rates can be either levelized, with the same value in each year, or escalating, so that the price in each future year approximates the current expectation of the short-run cost of power in that year. The general policy of Massachusetts utilities has been to offer very low variable rates, which include only short-run fuel costs. While the expected present value of these rates over the long term is substantial, they are subject to great uncertainty, and the response from potential developers in Massachusetts has not been overwhelming. As I discussed above, much better results have been obtained by utilities which have offered levelized contracts.

Q: Why would you expect levelized contracts to produce better results than short-run rates?

A: The fixed prices per kWh delivered are advantageous to the QF developer by removing some of the risk which the developer would bear under the variable rates. For a QF which sells its power under variable rates, reductions in fuel costs, massive coal conversions, new utility-owned construction, and many other outcomes can adversely affect financial performance, even threatening the financial viability of the owner. This risk makes financing of many facilities very difficult, or impossible, under variable rates. On the other hand, the developer may achieve windfall profits if fuel prices rise abruptly, loads increase, baseload plants perform poorly, construction of new utility-owned plants is delayed, or if other factors cause short-term costs to rise. Thus, variable rates leave the developer exposed to the risks of lower costs and leave the utility exposed to higher costs. With fixed rates, neither party is exposed to the risks associated with predictions of future oil prices: assuming that both parties are risk averse, fixed rates should always be preferred.[17]

If the fixed rates are also levelized, they front-load the recovery of the initial investment (since rates in the first few years are higher under levelized contracts than under rates set on the basis of short-run fuel costs). By speeding

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17. § 2 discusses the value of fixed rates as insurance for the utility. In addition to locking in future fuel costs, the developer also spares the utility several kinds of risk (under any rate form), including the risks associated with cost overruns in construction, with operating costs for the facility, and with energy production at the facility.

up the recovery of the initial investment, the front-loading of revenues under a levelized rate may make financing more available to the developer. The utility then benefits from rates lower than currently projected avoided costs in the later years of the contract.

5.3 - Exceptions to the Rule

Q: Are there situations in which it would not be appropriate for the DPU to aggressively pursue QF development, and in which it would therefore be appropriate to retain the existing rules for QF rates?

A: I can identify only two factual situations in which the DPU would be justified in retaining the existing minimal rules:

1. If the DPU believes that there are ample supplies of new central station capacity available, at costs well below current short-run costs.

2. If the DPU believes that there can and will be massive development of conservation programs, at costs well below current short-run costs.

If the DPU believes so strongly in the existence of either of these conditions that it is willing to risk the future of Massachusetts power supply on that belief, QF development should not be encouraged beyond the current level of incentives. If either future central station capacity or conservation is assured, economical (even at present fuel costs), and adequate for all foreseeable future needs, the DPU should also be doing its best to extricate the state's utilities from projects which are not economical at present fuel costs, such as Seabrook, Hydro Quebec, and perhaps

Millstone 3, and should be acting decisively to accelerate the more favorable alternatives.

In summary, the Commission should not reject the basic reforms suggested by EOER without, at the very least, simultaneously ordering Massachusetts utilities to disengage from Seabrook and to sell off their entitlements in the Hydro Quebec project; identifying the superior alternatives which will replace QF capacity, existing oil capacity, and the expensive utility supply plans; and indicating how those superior alternatives will be developed.

6 - IMPROVEMENTS TO THE EOER PROPOSAL

Q: What is your overall assessment of the EOER proposal?

A: In general, the regulations proposed by EOER represent a major improvement in the current Massachusetts system for setting QF rates. If the proposed regulations were adopted in their entirety, Massachusetts ratepayers would be much better off than they are under the present rules. In particular, EOER has proposed rules which

- provide for Standard Offers,
- offer QFs the certainty of long-term rates,
- provide an option for many QFs to front-load their cost recovery, and
- include a much more reasonable and attainable capacity credit than the current rules allow.

However, there are some areas in which I believe that the ratepayers would be better served by modifications in EOER's proposal.

Q: What aspects of the EOER proposals can be further improved?

A: There are seven areas in which I would suggest changes in the

EOER proposals:

1. the treatment of oil- and gas-fired cogeneration,

2. the issue of security and reliability requirements for QFs on levelized rates,

3. ratemaking options in the second half of fixed-price contracts,

4. the projection of avoided costs,

5. the treatment of capacity credits, and

6. the definition of avoidable capacity.

6.1 - Treatment of Oil- and Gas-fired Cogeneration

Q: How is the EOER's proposed treatment of oil- and gas-fired cogeneration inappropriate?

A: EOER would not allow any QF which is more than 25% fueled by oil or gas[18] to elect the levelized rate, and would restrict the access of such facilities to the fixed escalation rate, by requiring them to elect a composite rate. The composite rate would be 50% of the short-run avoided cost, plus 50% of the fixed escalation rate; if the QF preferred, it could elect to take 75% short-run rates and 25% of the fixed rate. The rationale for this restriction is that the fixed rates would not be adequate in the event of large increases in the cost of fuel, so that the QF would become unavailable (or the rate would have to be renegotiated) when the fixed rate would have been most valuable to the utility. Since the utility would not get the full benefit of the fixed rates in times of high fuel costs, the reasoning continues, it should not lock itself into paying the full fixed rate in times of low fuel costs.

EOER'sconcern is realistic. Unfortunately, the EOER solution

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18. This would have to be a cogenerator, since small power producers can not use more than 25% gas or oil.

does not really match the problem. The objective should be to ensure that a sufficient portion of the payment floats with fuel prices so that the generator will remain viable in times of high costs, and so that the utility receives comparable savings (compared to the current expectation) in times of low fuel costs. The fraction of the payment which must float is a function of

1. the percentage (POG) of the QF's fuel which is oil or gas,

2. the ratio (HRR) of the cogenerator's net heat rate[19] to the heat rates of the units whose output is avoided, and

3. the ratio (RFC) of the cogenerator's fuel cost (in $/MMBTU) to that of the avoided unit.

If the cogenerator burns the same fuel as the avoided-cost unit, and has a heat rate of 50% that of the utility unit, 50% of avoided cost will be sufficient to cover its fuel expenses. If the cogenerator uses only 50% oil, and has a heat rate 40% that of the utility unit, then only 20% of avoided cost is necessary to cover the fuel costs. For a

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19. The net heat rate of a cogenerator is the incremental increase in fuel consumption, above the level required for the thermal output. For bottoming cycles, this value may be zero; for topping cycles, it is frequently in the 4000 to 6000 BTU/kWh range.

cogenerator burning fuel 20% more expensive than the utility's fuel, at 60% of the utility heat rate, 72% of the avoided cost is necessary to cover the fuel bill.

Therefore, a different mix of fixed and variable rates is appropriate for different cogenerators. Properly matching the variable portion of the rate to the cogenerator's fuel cost, with the fixed portion available to cover fixed costs,[20] would appear to be the best solution for both the utility and the cogenerator. I would recommend that the variable fraction of the rate be set at

$$VF = POG * HRR * RFC.$$

The fraction of sales which would be at a fixed price would then be 1 - VF. If the cogenerator is unwilling or unable to provide the input values, I would suggest default values of 100%, 60%, and 125% for the three factors. Thus, any cogenerator could take 25% fixed rates, and some could take much more.

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20. The fixed portion also provides a continuing cash flow, which is further assurance that the total price of power will be at least equal to the cogenerator's fuel cost.

6.2 - Security and Reliability Requirements

Q: The EOER proposal suggests that the Department may wish to establish security and/or reliability requirements for QFs who wish to receive level energy rates. What sort of requirements would be appropriate?

A: The issue is much simpler for the reliability requirements: there is no justification for any such standard. If the QF does not produce power, it does not receive payment. I see no justification for any additional reliability requirement.

With regard to security arrangements, the situation is somewhat more complex. The only major differences between utility ownership of a plant and QF ownership of the plant, relevant to the risk that the plant will not be available late in the planned operation period, are that

1. the utility stops paying the QF if the plant stops operating, but must continue debt service (and other fixed costs) if one of its own units fails,

2. the utility faces some risk that the QF will seek to sell its production elsewhere, reserve its output for internal use, or otherwise intentionally fail to deliver power, and

3. the utility faces the risk that the QF will be sold (voluntarily or through bankruptcy) and that the new owners will intentionally fail to deliver power.

The first point is a distinct advantage of QFs, even those whose rates are levelized. Attempting to isolate the utility and its customers from the risk of technical failure on the part of the QF strikes me as excessive, considering the risks they are exposed to if the utility owns the facility. However, if insurance is available which will provide such protection at a cost low enough that it does not significantly reduce the rate of QF development, the QF would be an even sweeter deal for the utility than it would have been without the insurance. The important point here is that a good deal for the utility (levelized QF rates without technical insurance) should not be precluded in a (possibly vain) attempt to structure the perfect deal for the utility (levelized rates with insurance).

It is certainly reasonable to include contract provisions which prohibit voluntary reductions in sales (at least on the scale of a year), diversion of power to other customers, and the like. It would also be appropriate to provide the utility some protection in the event of QF sale or bankruptcy, such as the right of first refusal for purchase of the facility, and an agreement by the principal lender to continue sales under the contract in the event of foreclosure.

6.3 - The Second Half of Fixed-price Contracts

Q: How would you change ratemaking in the second half of fixed-price contracts?

A: EOER has proposed that fixed rates only extent for half of the contract term, and that the rates revert to the short term rate for the second half of the contract. If New England experiences high load growth, high oil price increases, and restricted capacity expansion options, that short term rate could be very high. Thus, when Massachusetts most needed the benefits of the inexpensive old QFs, they might well be transferred to high short-run costs. To protect ratepayers from this situation, I would recommend that the EOER regulations be amended to allow the utility to elect, at the end of the first half of the contract, whether to pay the QF for the next five years at short-run avoided cost or to pay it at the rate from the last year of the fixed schedule. At the end of the fifth year, I would allow the utility the same choice. Thus, the final year rate becomes a partial ceiling on the price paid in the second half, greatly reducing rate increases when the utility and its customers are most stressed. Since the last-year fixed rate is much lower for the levelized rate than for the fixed-escalation rate, QFs which elect levelization would be agreeing to much tighter controls on their rates in the second half of the contract: EOER's provision of an 85% discount from avoided cost for these QFs would be redundant and unnecessary under my proposal.

The QF is also entitled to a measure of protection in the second half of the contract. I would suggest that, when the utility elects to switch to short-run cost, the QF be allowed to elect a fixed rate, to form a floor on its reimbursement. The choice of that floor is somewhat arbitrary, but I would suggest a floor price of 40% of the fixed escalation price which applied in the last year of the contract's first half.

6.4 - Projection of Avoided Costs

Q: How would you change the manner in which avoided costs are projected under the EOER proposal?

A: The only clear problem with the EOER proposal in this respect is the use of escalation rates to project avoided energy costs far into the future. The utilities' running costs vary with load levels, purchase and sale contracts, supply additions, and retirements, in addition to escalation in fuel and variable O&M. Therefore, I would recommend that production costing runs be performed for at least every fifth year into the future (and more often where large changes in supply or demand are projected) for most utilities, with trending being restricted to years between the runs, and hence between major system changes. For some utilities, this level of detail may not be justified: Nantucket's marginal fuel and marginal heat rate appear to be very stable, and FG&E's supply plans may be in such flux that production costing is pointless. Thus, a utility which does not wish to perform several production costing runs should be allowed to request an exemption from this requirement in its QF ratesetting proceeding.

Q: Would performing several production costing runs represent a severe burden to most utilities?

A: No. The larger utilities perform this type of analysis on a routine basis for fuel clause and QF rate proceeding, as well as for their own planning studies. A single Seabrook proceeding may generate dozens of such runs, each covering 15 or 20 years. This process should not be burdensome for NEPCo, BECo, WMECo, Montaup, or COMM/Energy, and (in more settled times) would pose little difficulty for FG&E.

Q: In addition to the frequency of production costing runs, do you have any suggestions for the projection of avoided energy costs?

A: I am generally concerned that the avoided energy cost projections not be reduced inappropriately by utility plans to add capacity. If a utility proposes a coal plant to back out its most expensive energy sources, QFs should still be given an opportunity to back out those sources (or the coal plant), rather than being left with only the lower avoided energy costs of the coal plant or other low-cost sources. In the past, utilities have argued that their avoidable costs were low because firmly committed utility plants, such as Pilgrim 2, would back out most of their expensive oil use. Utilities must not be allowed to compare their units to the most expensive avoided costs, and to then force the QFs to compete with the lower remaining avoided costs. If the utility can back out oil at a lower cost than the QFs, it should do so; if it can not, it should not be allowed to suppress QF capacity.

The regulations need not address this issue in detail, except to require that the utility identify its capacity additions and non-QF purchases which reduce avoided cost, and the cost of those additions and purchases. The Commission might also wish to place the utilities on notice that QFs will be allowed an opportunity to back out any planned utility additions.

6.5 - Capacity Credits

Q: What comments would you like to make regarding EOER's proposal for capacity credits?

A: I would like to start by noting that the EOER proposal is a substantial improvement over the current regulations with regard to capacity credits. The current regulations essentially define eligibility so that no QF would ever be eligible for a capacity credit. The EOER proposal would allow many QF's to receive capacity credits of the proper order of magnitude. However, there are a few problems with the EOER's treatment of capacity credits:

1. EOER proposes that QFs be subjected to much more demanding standards than utility-planned plants and purchases. In particular, EOER would deny capacity credits to QFs which enter service more than four years after the utility/QF contract is signed, even though most utility generation investments take longer than four years and entail much more risk to the utility. Some QFs might be precluded from receiving capacity credits, simply because they require more than four years from commitment to operation.

2. Similarly, EOER places an unjustified burden on QFs by arbitrarily reducing or eliminating capacity credits,

when monthly power output falls below a "Target" value. Many QFs which would fail EOER's production rule would meet NEPOOL's capability credit requirements. Utility plants whose performance would fail EOER's arbitrary rule would still receive NEPOOL capacity credits and be treated as used and useful: nuclear plants are always out of service for at least a month when they refuel, and yet their owners incur no penalty for such normal outages.

3. The proposed restrictions on rerating of QFs is also inconsistent with, and much more stringent than, the treatment of similarly situated utility units. Both increases and decreases in rated capacity are frequent within NEPOOL, to reflect maturation, aging, maintenance cycles, and special problems and improvements. There is no reason to deny QFs the right to change their claimed ratings (to the extent this factor matters in payment) as often as utilities change their units' ratings.

4. EOER also double-counts avoided capacity benefits, by giving QFs the discounted value of avoided capacity prior to the in-service date of the avoided capacity, and then giving them the full cost of the capacity once it would have been on line. This error is partially counterbalanced by EOER's failure to recognize other

benefits of the QF capacity.[21]

6.5.1 Reliability, capacity and ELCC

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

A: First, it is important to recognize that the real point of interest is not capacity, in terms of demonstrated output, or of nameplate rating. The commodity which is to be rewarded is actually contribution to system reliability.[22] The reliability value of a generator to the utility system (in the case of mainland Massachusetts, the system is NEPOOL) can be expressed as the effective load carrying capability (ELCC), the additional firm load the system can carry due to the generator, without degrading reliability of service.

Utilities have often advanced complex and vague concepts of reliability assessment in their efforts to distinguish between "good capacity" (owned by the utilities) and "bad capacity" (owned by anyone else). Thus, utilities have suggested that QFs be denied credits

- unless they are "dispatchable" by the utility, even

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21. Perhaps the discounted peaker method was intended as a proxy for the other benefits.

22. It might be more useful to call the non-energy credit a "reliability credit" rather than the often misleading "capacity credit".

though the utility's own must-run units are in rate base and receive capacity credits,

- unless the QF contractually guarantees to deliver the power, or pay non-performance penalties,

- if the QF fails to perform exactly as predicted,

- if the QF fails to operate at a utility-specified availability standards, or

- if the QF is below a threshold size,

even though neither the utility's own plants nor its purchases from other utilities are held to even vaguely similar standards. EOER's proposal for capacity credits imposes similar arbitrary and discriminatory burdens on QF's.[23] Either EOER's proposal, or the utility concepts from which it derives, would interfere with incentives for QFs to improve system reliability, and should not be implemented in its present form. Even as it currently stands, the EOER capacity credit structure is superior to that of the existing regulations.

Q: Why should effective load carrying capability be the basis

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23. I doubt that any utility would accept EOER's capacity credit standards (no credit for units taking longer than four years to build, and no credit if output is falls more than 10% of maximum capacity below the capacity level for which the utility claims a credit) for determining the ratebasing of their own facilities.

for capacity credits from generating utilities?

A: ELCC or a similar probabilistic measure is necessary to accurately allocate the value of various types and sizes for generators. The measure should recognize that small (especially under a few megawatts), randomly available, independent generators are, in the aggregate, a firm source of power of high reliability, whether utility-owned plants or QFs, and regardless of the performance of individual units. Therefore, these small units can be given a capacity credit on the basis of the kWh output (actual or prorated) in the peak period of outage exposure, and require no direct measurement or special testing for the purpose of reliability credits. Power producers which are significantly correlated with demand (e.g., cogeneration equipment on heating systems) or with other producers (e.g., solar, wind) will have different reliability value per kWh than do other small producers: some will be more valuable than random units, other will be less valuable. Only stochastic computer modelling of system performance with and without each class of correlated generator can determine what the exact credits should be.

Traditional central-station technologies will also vary in their capacity value, which may be measured more conveniently on a kW basis for large units. Large units, units with high forced outage rates, and units with large maintenance requirements, will all be less valuable than small, reliable units.

6.5.2 NEPOOL capability rules should be applied fairly

Q: Does NEPOOL currently use ELCC as the basis of reliability credits?

A: No. NEPOOL capability credits to individual utilities completely ignore unit size, maintenance requirements, and forced outage rate. Only maximum demonstrated capability, as discussed in Appendix C, is used in determining the credit.

Q: Do NEPOOL capability rules assign capacity credits in a fair and appropriate manner across technologies?

A: No. NEPOOL capability assignments completely ignore such important determinants of ELCC as forced outage rate, maintenance requirements, and unit size. A large unreliable unit is treated in the same manner as a small reliable unit: a MW of either contributes equally to meeting a member's capability responsibility.

While most features of the NEPOOL capability rules tend to understate the reliability benefits of alternative energy sources (especially small and reliable ones, such as cogenerators and wood-burning plants), some of the peculiarities of those rules will tend to overstate the value of some technologies. In particular, no plant is required to demonstrate more than six hours of continuous operation at its claimed rating, and that demonstration may be from historical records, rather than from a scheduled test.[24] Therefore, wind plants should be able to receive credit for close to their entire capacity, even though they are generally acknowledged to have ELCC's of only about 20-30% of their rated capacities.

Q: Is there any reason to believe that the utilities will not get NEPOOL capability credits for their QF entitlements?

A: No. There is no rationale for denying such credits. Discrimination against QFs would appear to violate PURPA, and should be difficult to get approved by FERC, which regulates NEPOOL and is responsible for implementing PURPA. NEPOOL has treated QFs in a manner comparable to other capacity, as documented in Appendix D.

Q: Do you recommend that the Commission adopt ELCC-based reliability credits at this time?

A: No. To do so would result in some QFs receiving much smaller credits from the utility than the utility receives from NEPOOL, and others receiving much larger credits. In the

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24. Appendix C provides the NEPEX capability credit standards.

long run, the proper course is certainly to encourage NEPOOL to move towards a more rational system of reliability credits. In the meantime, the best option is probably to insist that the utilities treat QFs the same way that they treat their own, and give a MW credit for each MW of demonstrated capability, as prescribed by current NEPOOL standards.

Q: Your proposal would require period performance monitoring of each QF. Can the process be simplified for smaller QFs?

A: Yes. For small QFs, this capacity credit may be simplified by using a kWh capacity credit calculated at the average capacity factor of that technology, or for still greater simplicity, at the availability factor of a typical peaker (about 80%).

Q: How would you modify the EOER target range?

A: I would recommend discarding the target range entirely, and simply paying the QF for demonstrated capability (or per kWh delivered, for small units). The Target and Maximum scheme, while clearly well-intentioned, is complicated, arbitrary, and without purpose or foundation. When a utility builds a plant, it takes a risk that it will not work well: if it does not work, the utility may have a hard time recovering its costs. If the plant operates at half the rating (or half the capacity factor) the utility predicted, both its cost recovery and its NEPOOL credit may be halved, but I see no reason to believe that the DPU or NEPOOL would treat a below-average unit as having no reliability value.[25]

Q: What about the requirement that units enter service within four years of the contract signing?

A: This feature serves no useful function and should be deleted. The greater the interval from contract to operation, the less time the QF can elect a fixed rate since fixed rates will be set for only 15 years. This limitation will be sufficient incentive for many QF's to enter service as soon as possible. Also, it is my understanding of EOER's proposal that a QF which goes on line later than projected will have less time left on the fixed portion of its contract, but the same obligation to provide power at short-run cost (or less, under the proposals I make in § 6.3) in the second portion of the contract. Thus, a QF which contracted to sell power at a fixed rate for the period 1991-2000, and at a variable rate for 2001-2010, but did not enter service until 1996, would operate at a fixed rate for only five years, but would still have to sell at the variable rate for ten years. If the fixed rate was levelized, the QF

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25. The penalty for missing the Target is also very oddly structured, so that large penalties are incurred at arbitrary shortfalls, which may make the choice of billing periods very important. If the Target system is retained, it should at least be made smoother and less arbitrary.

would also miss the years in which that rate was most advantageous to it, and most burdensome to the utility, and yet would still provide power in the period for which the level rate was most advantageous to the utility.

Q: Since utility plants take many years to plan and construct, is it not appropriate to require that QFs inform the utilities in advance as to when and how much they will operate?

A: No. It is important to recall that the capacity credit in the EOER rules is based on the cost of a very inexpensive peaking unit, which can be brought on line within a year or so after the decision to proceed. Since the capacity credit is based on capacity which is available for short-run planning, there is no reason to require the QF to meet long-run reliability goals. The situation might be somewhat different if the capacity credit were based on the cost of a coal unit, which might take eight years from commitment to operation.

6.5.3 Credits prior to avoided additions

Q: Do the proposed rules correctly recognize the value of increased reliability prior to the time at which the utility would otherwise have to add capacity?

A: No. The EOER proposal sets the capacity rate prior to the avoided capacity in-service date[26] at the peaker cost, discounted to the year of the credit. The basic two problem with this approach is that it pays the QF for avoiding the reliability-related capacity addition both before it would have come on line (through the discounted peaker cost) and after it would have come on line (at the full peaker cost). If the only reliability benefit were the avoidance of the planned unit (or purchase, or NEPOOL deficiency charge), the full-cost payments following the on-line date would be sufficient. Just as energy costs may be levelized, the capacity cost may also be redistributed over the period of the QF contract, but avoidance of capital additions can not justify total payments of the level proposed by EOER.

Q: Is there any justification for reliability credits prior to the add-capacity date?

A: Yes. The QF's reliability contribution has some value to the utility and its customers, even when it has not yet deferred an addition or deficiency charge. The improved reliability reduces outage probabilities and costs, improves operating flexibility, reduces the costs associated with some existing capacity, and allows for short-term capacity sales. While NEPOOL and most of its Massachusetts members have more

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26. I will refer to this date as the "add-capacity date", although it may represent an anticipated purchase or deficiency, as well as new construction.

capacity than currently required by NEPOOL standards, and while they are likely to maintain this surplus throughout the decade, additional capacity continues to have some reliability value. One such value is that additional capacity, which operates at any time at which a shortage in capacity might occur, reduces the probability and expected severity of voltage reductions, customer disconnections, and related outage costs to both the customers and the utility. This is true both at the NEPOOL level and for smaller areas within the pool. On a NEPOOL basis, while the one day of generation-caused outage in ten years may be acceptable, lower outage frequencies would be preferable. Despite ample installed capacity, NEPEX was forced to take emergency actions in the Summer of 1984, due to multiple outages of large units.[27] Had more QFs been on line, the expensive deactivated units which were revived for this emergency could have been left in mothballs. Even when New England operating reserves are adequate, widespread subregional customer disconnections and voltage reductions due to bulk power supply problems have continued to occur. For example, the loss of a few large generators and transmission lines has periodically forced the shedding of load in the Southeast Massachusetts area.

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27. Appendix B to this testimony contains the NEPEX summary of these events, and my own analysis of the contribution of nuclear outages to the problems.

The costs of these outages can be considerable, and although they are very hard to quantify, there is certainly some outage costs to the customers, and hence an avoided cost due to added reliability. This avoided cost can only be determined on an overall, estimated basis, since it will rarely be possible to know whether, but for particular QFs, utility resources would have overloaded and failed, forcing voltage reductions and blackouts.

Q: How does increased reliability from QF's allow the utility to avoid costs associated with existing generators?

A: Additional capacity will facilitate the economic scheduling of planned maintenance, allow malfunctioning units to be repaired promptly, and allow nuclear units to be refueled at the most advantageous point in fuel life, rather than as required by reliability considerations.[28] This additional flexibility should lower fuel costs and maintenance costs by relaxing the reliability constraint on utility operation.

Additional reliability of bulk power supply form QFs may also reduce utility costs by allowing for the derating of some

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28. NEPEX had to reschedule some maintenance in the Summer of 1984, including the Connecticut Yankee refueling. The refuleing delay required a ramp-down as the unit's fuel ran out, resulting in lower overall capacity utilization of this very economical unit.

units' readiness (from operating reserve to hours' notice to days' notice), the mothballing of some units (i.e., placement in deactivated reserve), the earlier retirement of some units (as Edgar was retired) and/or the sale of peaking units (diesels or turbines) to utilities in other regions, or to potential cogenerators.

QF capacity may also allow the utility to reduce its fixed costs by selling off entitlements in its plants to other utilities. These unit sales are commonly practiced in New England on both the short term (as short as a few months) and the long term (as long as the life of the unit).

Q: How should the EOER proposal be amended to allow for more representative estimates of avoided reliability-related capacity costs?

A: The EOER proposal determines the capacity rate properly for years following the add-capacity date. The regulations should also provide that the annual assessments of the capacity rate shall include estimates of the short-term market price for capacity in New England. For example, MMWEC currently projects that the cost of peaker capacity will be \$20/kW-yr over the period 1986 to 1993, at which point the regional capacity surplus will be used up and the cost will rise to that of new capacity.[29] In any case, some capacity credits should be paid in all years and for all facilities which would receive capacity credits if they were owned by the utility.

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29. This projection assumes the current NEPOOL forecast and the completion of Seabrook 1, so the timing of the rate change is subject to some question.

7 - ADDITIONAL IMPROVEMENTS IN THE REGULATIONS

Q: What other modifications in the existing regulations would be appropriate, other than those suggested by EOER?

A: I have identified opportunities for improvements in eight portions of the regulations, including:

1. the criteria for qualification,
2. the list of utilities covered,
3. the circumstances under which utilities are compelled to purchase QF power,
4. the list of Energy Price Options,
5. addition of a reconciliation mechanism for short-run rates,
6. the definition of the line loss factors,
7. the treatment of marginal fuel costs, and
8. recognition of geographical diversity.

7.1 Criteria for Qualification

Q: How should the criteria for qualification in section 8.02 (1) be changed?

A: If an existing facility has been producing power in exchange for a rate less than that offered to QF's, and there is no reason to believe that it will not continue doing so, it is unnecessarily expensive to the consumer to pay the facility the higher QF rate. These existing facilities will not generally require the standard rate, or any PURPA-derived rate, to encourage production, which is the purpose of PURPA §210. Existing facilities should be eligible for avoided cost rates, incuding standard rates, only for

a. production in excess of 1980-1984 average levels, since that excess was apparently not encouraged by existing arrangements;

b. production from additional equipment within the facility; and

c. production which the facility can demonstrate to the DPU would not occur under the existing arrangements.

Point (a) would ensure that very recently developed facilities, which may have been built in expectation of PURPA-type reforms, would be eligible for avoided-cost rates for most or all of their output. These provisions should provide avoided-cost rates to existing facilities which need them, without unnecessarily increasing the cost to consumers or creating windfall profits.

7.2 Covered Utilities

Q: Which utilities should be covered by the regulations, and hence listed in section 8.02 (2)?

A: There are nine utilities which are primarily retail utilities and are clearly regulated by the DPU:

1. Boston Edison Company (BECO)
2. Western Massachusetts Electric Company (WMECO)
3. Nantucket Electric Company
4. Eastern Edison Company (EECO)
5. Fitchburg Gas and Electric Company (FGE)
6. Massachusetts Electric Company (MECO)
7. Manchester Electric Company
8. Cambridge Electric Light Company (CELCO)
9. Commonwealth Electric Company (CECO)

However, since the last two are treated as part of a single NEPOOL participant (Commonwealth Energy, or COMM/Energy), and since the proposed regulations are apparently attempting to mimic NEPEX billing, it is appropriate to use the same basic costs for both CELCO and CECO. Only losses and area-protection costs will vary from one part of Commonwealth's service territory to another; these factors will be discussed below, since they apply to several utilities. Similarly, MECo and Manchester are both total requirements customers (and affiliates) of New England Power Company (NEPCo), so it is hard to see why their basic avoided costs would differ.

In addition to the eight primarily retail utilities, the DPU also should implement the rules prescribed by PURPA §210 and by the FERC regulations with regard to NEPCO and Montaup Electric Company. The DPU definitely "has ratemaking authority" over any retail sales, NEPCO or Montaup may choose to make. [30] PURPA §210(f)(1)requires that

> "each State regulatory authority shall, after notice and opportunity for public hearing, implement [FERC's cogeneration and Small Power Production Rules] for each electric utility for which it has ratemaking authority."

This description appears to allow (or even require) the DPU to set avoided-cost rates for sales from QF's to NEPCO and Montaup, as well as applying the rules on interconnections, backup rates, and so forth required by the FERC regulations.

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30. NEPCO apparently still has some retail sales in the Commonwealth, and while the DPU has not generally chosen to exercise its authority regarding these contractual sales.

7.3 Right to Sell

Q: Which utilities should be required to purchase power from a particular QF?

A: A utility should be required to purchase power from any QF which

a. is located in the utility's retail service territory,

b. is willing to provide or pay for an interconnection with an appropriate facility of the utility (e.g., a transmission line, distribution line, or substation), or

c. provides power to the transmission or distribution system of any wholesale customer (excluding unit sales) of the utility.

The last provision recognizes the fact that a QF in Concord (a BECo wholesale all-requirements customer) will displace BECo generation costs in exactly the same way as a similar QF in Lexington. The QF is simply another delivery point for wholesale power. This provision is particularly important in allowing direct sales to NEPCO (and to a lesser extent BECo, Montaup, and WMECo) from municipal service territories. If the affiliated retail companies of NEPCo and Montaup should offer rates which are significantly different than those of the wholesale companies,[31] QFs in those territories would also have a choice of customer for their power.

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31. There is no apparent reason for such differences.

7.4 Energy Price Options

Q: What Energy Price Options would you suggest adding to section 8.04(5)(c)1?

A: The proposed regulations base energy rates on the convenient fiction that each utility company dispatches its own plants (including tiny fractions of jointly owned plants and unit sales) to meet its own load. In fact, NEPOOL dispatches all the capacity in mainland New England to meet total New England load. It follows that the real avoided energy cost due to QF production is the NEPOOL marginal energy cost, that is, system lambda. I would suggest that NEPOOL lambda be offered as a suboption to Energy Price Option 1, which is denominated as "avoided costs at the time of delivery", but is actually the quarterly[32] projection of QF effects on own-load dispatch, modified for an estimate of net purchases and sales to NEPOOL. Except for the use of two rating periods, the own-load rate is an average for the quarter.

Q: What are the practical advantages of NEPOOL system lambda as a measure of avoided cost?

A: First, the NEPOOL lambda is essentially the true short-run

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32. The regulations require at least annual determination, but the projection schedule is tied to fuel clause filings, which are generally quaterly.

avoided cost for New England. Second, under NEPOOL pricing, all generators in Massachusetts would be offered the same short-term rate at the same time: QF's in the service territory of a utility with low own-load costs would not be shut in when they can operate more efficiently than utility plants running elsewhere in Massachusetts or New England. Third, own-load dispatch pricing of purchases from QF's would encourage QF's to attempt to arrange wheeling of their power to utilities with higher calculated short-run avoided costs than those posted by their local utility. At best, this would be a nuisance, and at worse a disincentive for development of economical generation. Fourth, and perhaps most importantly, the NEPOOL rate can be used to encourage economic dispatch of QF's with that technical capability, such as trash burners, hydro plants with storage, cogenerators, wood and geothermal plants. Of course, dispatch is not an issue for QFs with running costs consistently below NEPOOL system lambda, and with sufficient fuel to operate base-loaded.

Q: Why would economic dispatch be facilitated by NEPOOL pricing, rather than own-load pricing?

A: First, the own-load dispatch price signal, if it were available, would sometimes tell the QF to increase output when only NEPOOL's least expensive units are running, and tell it to shut down when very expensive units will be brought on, or even when NEPOOL is in an operating emergency. Second, own-load dispatch is only carried out as a bookkeeping function, long after the fact, so the price signal is not available when it would be needed. There is simply no way to encourage QFs to respond in real time to system conditions (such as changing load level, utility plant outages, and the loss of inter-regional tie lines) under own-load dispatch pricing. With an instantaneous incentive (such as NEPOOL actual avoided cost), larger QF's could be notified when their power was most valuable, and could increase their revenue and their usefulness by increasing output at those times. Neither the existing nor the proposed regulations even envision any useful real-time incentives.

Q: Would the purchasing utility incur financial harm from the use of the NEPOOL rate option?

A: No, for two reasons. First, the FERC regulations (292.303d) provide that the utility which would normally purchase energy or capacity from a QF may transmit that energy of capacity to a second utility, which must then pay <u>its</u> avoided cost. Within New England, with its central dispatch, wheeling is basically a bookkeeping operation, rather than a physical process which actually requires commitment of utility resources. Thus, the Massachusetts utility which is directly connected to the QF can wheel the power to the utility (or utilities) which otherwise would pay the NEPOOL system lambda, and should receive full payment from the latter. If an additional mechanism is necessary for actual billing and crediting between utilities, its development may be left to NEPOOL, its members, and FERC, in whose jurisdiction the enforcement of this aspect of PURPA must lie. Since the substantial majority of voting power in NEPOOL is held by utilities doing business in Massachusetts, the development of the compensation mechanism should proceed quickly enough to protect the interests of those utilities.

In any case, it appears that current NEPOOL billing arrangements are sufficient to ensure that utilities which compensate QF's at NEPOOL lambda will not be penalized. A net supplier to the pool is paid its incremental cost for all power in excess of its own needs; any additional cost above the own-load dispatch cost is paid by the pool. Thus, any additional cost due to pricing of QF power on the net seller's system at NEPOOL cost would be paid from the pool. The net seller would also receive an extra saving share for each kwh provided by the QF. A net buyer, on the other hand, must pay to the pool the cost of the plants which would have run, if not for the existence of the pool. Each kwh supplied by a QF eliminates the need for the most expensive kwh of own-load energy; this avoided cost must be higher than pool lambda (and hence the price paid the QF), or else the buyer's plant would have run. The buyer may also avoid paying for more expensive classes of pool power, such as unscheduled outage or deficiency. While the net buyer does lose a savings share, this is very likely to be smaller than the difference between the price paid to the QF and the own-load marginal cost. Thus, there should be no additional cost to Massachusetts utilities, even if their use of NEPOOL's marginal cost as the basis of QF rates were unilateral.

Q: Is there any other Energy Price Option which ought to be added to § 8.04(5)(c)1?

A: Yes. The Department should add an Option which insures that QF potential, which happens to be located within the service territories of utilities with relatively low avoided costs under own-load dispatch, is made available to utilities with higher avoided costs. If the DPU lacks the ability to order utilities to wheel QF power to other utilities, some other technique must be used to achieve economic efficiency. The problem arises from the monopoly position of the utility in whose service territory the QF is located, and from the use of the fictional own-load dispatch for measuring avoided cost. One way to ensure that the QFs will be able to market power which is less expensive than the avoided cost somewhere in Massachusetts would be to require utilities to offer a note which is only slightly lower (say, 1 million) than the avoided cost of the highest cost neighbouring utility. The purchasing utility avoids the lost opportunity to sell power to its neighbour so this option would be a true avoided cost rate. To allow utilities with low avoided costs to purchase power from QFs, I would recommend thatvthis neighbouring utility option be available only to potential QFs which can demonstrate that they are not economically feasible at the other Energy Price Options.

7.5 Reconciliation

Q: Why should the.e by a reconciliation mechanism in the QF ratesetting process?

A: Quite simply, the only way that the avoided cost (under any definition) can be known is retrospectively. Fuel prices, demand levels, plant availability, the size of NEPEX saving shares, and the fraction of time a utility is selling to the pool can be estimated in advance, but the actual values can only be known after the fact. If the utility is to pay QFs for its short-run avoided cost, the prospective estimates must be reconciled with actual results. However, reconcilation would not be worth the effort if the only result were to convert unbiased forecasts to actual values.

Q: Would the reconciliation mechanism have substantial practical advantages?

A: I believe that it would have the following important benefits:

1. In times of rapidly changing fuel prices, reconciliation would protect gas/oil fired cogenerators from a price squeeze (when costs rise rapidly), and prevent windfall profits (when costs fall).

2. Reconciliation would decrease the importance of precise

forecasts of avoided costs, thereby simplifying and de-emphasizing the prospective portions of the ratesetting procedure, since any errors would be corrected over the next several months. The projection process could otherwise become highly adversarial, since any incremental gain or loss to the QFs from a change in the projected rate would be permanent.

3. Reconciliation would give better price signals to QFs; if high demand, fuel price increases, or plant outages raise the utility's costs, the QF can respond by increasing output, draining storage (in the case of hydro and biomass facilities), decreasing internal consumption, or delaying scheduled maintenance, knowing that it will eventually be compensated at higher than the posted rate. The same process would work in reverse, encouraging QF's to back down their most expensive output, perform maintenance, and increase fuel storage when power is less valuable.

4. Finally, reconciliation would decrease the extent to which the utilities, historically hostile towards competition from small power producers, could reduce the energy rate to QFs by manipulating projections and other data.

Q: Do you have any recommendation regarding the form of the reconciliation?

A: Not in any detail. The regulations might simply require the utilities to prepare reconciliation proposals for Energy Pricing Option 1. I do have a few suggestions for the structure of such proposals.

Given the seasonal nature of many QF's production, a fair reconciliation mechanism should probably either amend the billing for the earlier period (as opposed to the fuel clause reconciliation, which makes the correction in the next quarter), or else delay the correction until the same quarter of the next year, when the mix of QFs production is most likely to match that of the period in which the discrepency is created. The own-load dispatch process would be likely to delay the reconciliation considerably in any case. If there are few QFs, the first approach is preferable, since it yields the efficiency incentives discussed above. If there are many small QFs, it may be necessary to use the matching-quarters approach.

There also does not appear to be any reason for reconciliations of small discrepancies between prospective and retrospective estimates of avoided cost. Some "neutral zone" could be established around the projected rate: retrospective rates withing this zone would not require reconciliation, unless a clear pattern of biased estimation emerges.

7.6 Line Loss Factors

Q: Please describe the error in the prescription of the line loss factor in 8.04(7).

A: The regulations require that the purchase rate include a correction for average line loss at the voltage level of delivery. The inclusion of line losses in the purchase rate is correct since a kwh delivered to customers (or along the line of power flow to customers) allows the marginal utility generating unit to be backed down by one KWH plus the losses which would have been incurred in transmitting, transforming, and distributing the power.

The rules err in their use of only average, rather than avoided losses. Losses due to resistance in utility equipment increase as the square of current, so the marginal (and hence avoidable) losses associated with the last kwh sent into the transmission and distribution system are approximately twice the average losses at that load level. Appendix E to this testimony proves that the appropriate loss multiplier for purchased power rates is

$$(1+L) / (1-L),$$

where L = the ratio of losses to utility net generation.

This multiplier is always greater than one plus twice the average loss ratio, L, which is utilized by the present rules. For L=10%, the multiplier is 1.222; for L=15%, the multiplier is 1.353. In the latter example, which may well be typical of secondary distribution at peak periods, rule 8.04(7) compensates each QF kWh with the cost of 1.15 utility kwh, when it actually saves 1.353 utility kWh for each kWh the QF generates. Thus, the QF is paid a full 15% less than avoided cost under the current rules.[33]

The case for a marginal line loss adjustment is made stronger by the fact that neither the existing nor the proposed rules includes a credit for avoided transmission or distribution investment. Since one of the reasons for investment in transmission and distribution facilities is the reduction of line losses, recognizing marginal losses at least partially compensates for the omission of the T&D credit. The resultant compensation is probably still too low to reflect the full savings to the utility of not having to meet the load from central stations.

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33. The preceding discussion neglects some second-order effects, such as the increase in resistance with load and with temperature, and the no-load losses in transformers, which have indeterminate net effects on the relationship of marginal and average losses.

Not all QF's will deliver power directly to users or to appropriate points in the path of power flows to customers. Remote plants may inject power into already heavily loaded transmission facilities, increasing losses in at least part of the system. Very large plants with low surrounding load density (trash- or wood-burners, perhaps) may actually reverse flows on the local system and even require transformation to higher voltage levels. These situations do not seem to be typical, however. Most large plants will probably be cogenerators, whose power will be partly absorbed by the facility using the cogenerated heat, with the remainder used by neighboring facilities; the large industrial, commercial, or residential facilities capable of supporting cogeneration projects are unlikely to be found in very isolated areas. Similarly, many of the first hydroelectric sites to be developed will be those where hydro power was previously used by industry, and hence will be near load. Most of the current interest in wind-powered generators (in number of units, if not in annual MWH) appears to be in the form of small, backyard units, which will displace only the owner's load and perhaps that of a few neighbors.

Therefore, payment of less than the full marginal loss factor should be permited only when the utility can demonstrate that the power delivered by a particular QF (or a set of similarly situated QF's) does not provide these savings. In these situations, the actual losses to be expected from the generator to the physical loads served should be subtracted from the loss factor credit; this may, in extreme cases, result in a negative credit due to losses.

Q: Should the capacity credit loss factor be computed in the same manner?

A: Yes. The loss factor in section 8.05(5)(a) should be the average value of the marginal loss ratio during the peak period.

7.7 Marginal Fuel Costs

Q: Please describe the error in the existing regulations regarding the fuel costs to be used in §8.04 (8), and the compatibility of those costs with the fuel clause.

A: PURPA requires the use of avoided costs; therefore, the relevant fuel cost is not the average price of fuel for each generator, as used in fuel adjustment calculations, but the price which would have been paid for the additional fuel which would have been burned in each generator, if not for the QFs. The current regulations treat avoided fuel costs as if they were identical to average fuel costs.

In general, the cost of the stock of fuel on hand at a generator will not be exactly the same as the cost of replacing that fuel with additional purchases today, or this month, or next month. Because of the continuous variations in fuel prices, and the complexity of inventory and purchase policies, it may not be possible to predict the replacement cost precisely enough to improve significantly on an estimate based on the price of current purchases. It is likely that, in the long run, true replacement fuel cost will be higher than the current average stock cost more often than it is lower, but this is likely to remain an unquantifiable element of underestimation of QF rates.

A much more important problem than the minor differences in fuel stock prices results from the averaging of the marginal, avoidable fuel cost with a less expensive, supply-constrained fuel. Examples of these low-cost fuels would include natural gas, NEES' discounted oil from its NEEI subsidiary, and high-sulphur fuel whose use is constrained by environmental considerations. Since all the cheap fuel available will be used eventually in any case, the cost avoided by running the marginal unit less is the cost of the market place oil that will not be burned later because more of the cheap fuel will be left for later use. The avoided cost for these units, when they are marginal (and when they are identifiable) should be adjusted upward from the level used in the fuel clause simulations before the production costing for QF purchase rates are performed. Therefore, the statement in §8.04(8):

> The input data used to compute avoided costs will be the same as the data used to compute the fuel adjustment clause.

should simply specify consistency between the filings, and should explicitly require the use of avoidable fuel costs, where these can be distinguished readily from average fuel costs. Total hourly output, plant availability, and heat rate assumptions should be identical between the two runs, but individual plant output fuel prices will differ.

7.8 Geographical Differences in Avoided Costs

Q: Are there any special situations in which avoided costs vary between portions of a service territory?

A: Yes. There are "islands" of electric load which are poorly connected to the grid as a whole and in which a QF is more valuable than it would be elsewhere. There are four reasons for this additional value:

1. Losses involved in serving the island will tend to be high when the tielines are heavily loaded. The QF should receive credit for reducing those losses.

2. When the tie lines are very heavily loaded, generators within the island must be run to meet incremental load, even though there are cheaper power sources elsewhere on the system. The QF should be credited with the cost of the higher-cost local power which would be required if the QF were not operating on the island.

3. When the tie lines are somewhat less heavily loaded, it may still be necessary to maintain local generation operating reserve to prevent blackouts if the tie lines fail. Especially in the case of steam turbines, this reserve can be expensive, and to the extent that the QF can reduce the cost of keeping units on standby, the QF should be so credited.

4. Additional capacity is planned for some islands, and otherwise uneconomical capacity is retained in some other islands to prevent local capacity shortfalls. Thus, even in a general excess-capacity situation, strategically placed QF's may allow deferral, cancellation, or retirement of these local generators.

Some "islands" are physical entities, such as Martha's Vineyard for which Comm/Energy plans the addition of a 2.75 MW diesel (to its current 14 MW) every few years, and Gloucester where NEPCO maintains 28 MW of diesels. Other islands are solely electrical in nature. BECO has explained the must-run status of New Boston as an area-protection mechanism, to avoid leaving the metropolitan area "hanging on tie lines".

The utilities should be required to identify each island in their systems, the hours in which local generation is run (or kept in operating reserve) at added cost to protect service to the island, any quantifiable additional losses involved in serving the island as opposed to other portions of the service territory, the facilities maintained or planned to continue reliable service to the island, and the costs of those facilities. QFs which, by their fortuitous placement, allow for the deferral of capacity additions (e.g., new transmission ties, the Vineyard diesels), the retirement of otherwise uneconomical facilities, a reduction in the operation of relatively inefficient generation, or increase the reliability of service, should be paid for the costs avoided by the utility and its customers.

22-Mar-85

TABLE 2.1: SEABROOK LOAD CARRYING CAPACITY

Power Year	MMWEC Estimates of NEPOOL Reserve Levels [1] With Seabrook	Without Seabrook	NEPOOL Forecast Peak [2]	Seabrook Effective Load Carrying Capacity [3]	Seabrook ELCC/MW
	(A)	(B)	(C)	(D)	(E)
1989/90	28.40%	25.80%	17537	540.53	47.0%
1990/91	31.50%	29.70%	17986	628.33	54.6%
1991/92	29.10%	27.10%	18446	605.02	52.6%
1992/93	28.30%	26.20%	18962	585.97	51.0%
1993/94	26.90%	24.90%	19377	600.84	52.2%
1994/95	27.00%	25.00%	19900	592.13	51.5%
1995/96	30.80%	29.00%	20458	597.67	52.0%
1996/97	31.30%	29.70%	20975	620.26	53.9%
1997/98	30.80%	29.20%	21292	618.75	53.8%
1998/99	29.00%	27.50%	21471	641.81	55.8%
1999/00	29.90%	27.30%	21698	451.00	39.2%

NOTES: 1) From MMWEC Exhibit RMC-23, DPU 1627.
2) From NEPOOL (1984).
3) (C*(1+B)+1150)/(1+A) - C

TABLE 3.1: ALTERNATIVE ENERGY POTENTIAL IN MASSACHUSETTS

Energy Source	Estimated MW Capacity Potential [1]	Typical Capacity Factor (CF) low	Typical Capacity Factor (CF) high	Annual GWH Output Potential [2] low CF	Annual GWH Output Potential [2] high CF
Wind	100 +	25%	30%	219 +	263
Hydro	129	55%		622	
Wood	120	75%	80%	788	841
Solid Waste	400	60%		2102	
Cogeneration	1000 +	40%	80%	3504 +	7008
Total:	1749 +	-	-	7235 +	8112

Notes: 1. Source: Testimony of P.L. Chernick, MDPU 1627.
2. MW x CF x 8.76

Appendix B

NEPEX "Review of Summer 1984"

NEPEX

NEW ENGLAND POWER EXCHANGE
174 BRUSH HILL AVENUE
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WEST SPRINGFIELD, MASSACHUSETTS 01090-0010
TELEPHONE (413) 787-9365

ROSS McEACHARN
DIRECTOR

October 23, 1984

TO: NEPOOL Operations Committee

FROM: Ross McEacharn Ross McEacharn

SUBJECT: Review of Summer 1984

The attached report is an analysis of the load and generating capability conditions encountered this summer. It provides a record of the twelve implementations of Operating Procedure No. 4 which were required to deal with shortages of generating capacity. Also discussed are the limitations in interpool energy transfers experienced this summer.

If you have any questions on this report, please call Ken Nielsen.

EKN:mdh:LTRM10

Review of NEPOOL Generating Capability Shortages

Summer 1984

October 23, 1984

Introduction

Highlights of summer 1984 conditions are as follows:

- A NEPOOL record high peak load of 16,274 MWH in early June. This was the only instance when the load exceeded the anticipated summer peak of 16,000 MWH.
- Heavy generator maintenance outages, both scheduled and unscheduled. Total outages average 4,600 MW, with a single day high of 7,100 MW.
- Shortages of Operating Reserve requiring the implementation of Operation Procedure No. 4 (OP 4) - Action During a Capacity Deficiency - twelve times, in a total of 48 hours.
- Limitations in energy transfers from NYPP in 230 hours and from NBEPC in 280 hours.

Load

An all time high peak load of 16,274 MWH occurred on June 11, 1984. It was 436 MWH, almost 3 percent, above the previous high peak load which occurred in the winter of 1983/84. It exceeded the previous summer peak load by 598 MWH, almost 4 percent. The June 11 load was 274 MW above the estimated peak load exposure for the summer, 16,000 MWH and 2,374 MWH above what had been estimated for that week. This demonstrates the need to recognize that high summer loads can occur in early June. After mid-June, the estimated weekly peak load exposure was not reached again until the end of September. Attachment 1 contains peak load and temperature statistics.

Total net energy for load exceeded the previous year by 3.7 percent and was 4.6 percent above the official NEPOOL projection made earlier in the year. These increases reflect a healthy economy. Attachment 2 contains net energy for load statistics.

The only sustained period of high 90's temperatures occurred in early June. There was only one period, early August, when there were three successive days of low 90's. The estimated peak load exposure estimates used by NEPEX for generator maintenance planning are based on temperatures of 95^{o}F or higher and dew points of at least 70^{o}F, occurring simultaneously for four or five consecutive days. It is unusual that one such period did not occur in July, August or early September. The August peak load of 15,620 MWH (380 MWH less than the estimated peak load exposure) occurred with temperatures of 93 in Boston and 88 in Hartford, and temperatures in the 80's the previous day. Had that day been the fourth day of high 90's, its peak load would undoubtedly have exceeded the June peak of 16,274 MWH. It is concluded that there was the potential for loads significantly above the estimated peak load exposure had the weather conditions been more extreme.

Generator Outages

Annual Maintenance Schedule planning indicated early in 1984 that a shortage of generating capability would occur in the summer of 1984. A large number of scheduled outages were required. The April 1, 1984 schedule update indicated that an average of 2,100 MW would be unavailable due to scheduled outages during the June through September period. The previous twelve month average of unscheduled outages and reductions had been 3,000 MW; therefore, 3,000 MW was used as the allowance for unscheduled outages. On April 1 it was anticipated that there would be 12 weeks during the summer when there would not be adequate generating capability, after maintenance outages, to meet the estimated peak load exposure plus the operating reserve requirement.

Attachment 3 summarizes the total amount of outages which actually occurred. Fortunately, scheduled outages were reduced to an average of 1,500 MW. Improvements were accomplished through the following major schedule changes:

- Millstone Point No. 1 returned to service four weeks ahead of schedule.
- The Connecticut Yankee outage was delayed six weeks. This eliminated the overlap between Millstone Point No. 1 and Connecticut Yankee.
- Northfield No. 4 returned to service fourteen weeks ahead of schedule.
- Brayton Point No. 3&4 outages were delayed two weeks.
- Newington cancelled two weeks of outage.
- Many units were repositioned.

However, unscheduled outages and reductions were high. The average over the summer period amounted to 3,100 MW. Total generator outages averaged 4,600 MW. This is 22 percent of installed capability! Even more troublesome is the fact that total outages ranged as high as 7,100 MW, 34 percent of installed capability.

An analysis of unscheduled outages and reductions during the twelve days when OP 4 was implemented indicates that unscheduled outages averaged 3,950 MW on those days, 850 MW more than the summer average. It indicates that when all generators in the Pool are required to be in-service, and operating at maximum claimed capability, outages and reductions increase.

On the twelve OP 4 days, an average of 400 MW of ICU capability was unavailable, 27 percent of installed ICU capability. This is particularly disappointing since specific emphasis was put on ICU maintenance in preparation for the summer in order to maximize availability. Had unusual efforts not been made, the total would likely have been higher.

Shortages of Operating Reserve

Operating statistics for the twelve days when OP 4 was implemented due to shortages of Operating Reserve are presented in Attachment 4. There was only one of these days, June 11, when the peak load exceeded the advance estimate of weekly peak load exposure. Except for June 11, excessively high loads were not the cause of these shortages. The primary cause was the high generator outages discussed above.

To deal with these shortages, the Measures of OP 4 were implemented on all twelve days, and on one day, June 8, OP 4 Actions 1&2 were implemented in addition.

Measure 1 calls for the using of all available maximum claimed generating capability for energy and reserve. Steam units were ordered by NEPEX to go to maximum claimed capabilities in 39 hours and ICU's in 29 hours. However, during these hours, there were many units which did not reach maximum claimed capability. NEPOOL Billing is currently analyzing this situation and will issue a separate report to quantify these deficiencies.

Measure 2 involves the purchase of emergency/ supplemental capacity and energy from neighboring pools. Approximately 17,000 MWH, at an average cost of $83 per MW (total cost of $1,500,000) were purchased. There was only one day when NYPP did not have the generating capability necessary to provide the amount requested. NBEPC always had the generating capacity available to the limit of the tie (600 MW). Transmission constraints encountered in receiving this assistance are discussed below.

Action 2 calls for implementation of 5 percent voltage reduction where such action requires more than ten minutes to implement. There is only about 5 MW of load relief attainable in this way. Ninety-eight percent of NEPOOL voltage reduction capability can be implemented in less than 10 minutes and is part of Action 3. Action 3 was not required this summer on a NEPOOL basis. On July 7, REMVEC implemented a 5 percent voltage reduction in Boston and the North Shore to deal with low transmission voltages. This was one of several instances when low transmission voltages occurred in Eastern Massachusetts due to outages of key generators. Separate reports have been or are being prepared covering analysis of these situations.

One of the steps taken by NEPOOL Participants in preparation for generating capability shortages this summer was to activate 90 MW of capacity which had been in the deactivated reserve, retired, or non-commercial status. These units were made available for NEPEX dispatch when implementation of OP 4 was anticipated or had taken place. Attachment 5 lists these units and the energy generated.

Transfer Limitations

The normal transfer limit for the delivery of energy from NYPP to NEPOOL, determined from seasonal studies for summer 1984 was 1,925 MW. This is a maximum limit which must be reviewed daily and adjusted to reflect actual system conditions. Limitations, below the normal limit, were encountered in 230 hours. During the daytime period (0800-1800), there were 110 hours of limitations; the limit was reduced from 1,925 MW to 970 MW on the average. During nighttime hours, there were 120 hours of limitations; the limit was reduced to 800 MW on the average. About 75 percent of these limitations were due to conditions in New York, either low voltage or transmission line loadings. Further detail concerning these limitations is contained in Attachment 6. The primary effect of these limitations was on economy interchange receipts from NYPP. On the twelve days when OP 4 was implemented, there were only two days when NYPP/NEPOOL transfers were limited.

There were also a significant amount of reductions in the transfers from New Brunswick to NEPOOL and consequent lost savings on economy interchange transactions. The transfer was restricted below its nominal limit of 600 MW for 280 hours, all due to transmission constraints in New England. About 150 hours were due to low voltage at Orrington. These limitations all occurred during daytime hours and lowered the transfer limit to 550 MW on the average. The remaining 130 hours were due primarily to limitations in the Northern New England - Scobie interface. Ninety percent of these limitations occurred during the night and lowered the transfer capability from New Brunswick to 485 MW on the average. NEPOOL suffered approximately $210,000 in lost savings opportunities during the summer. On four of the twelve instances when OP 4 was implemented, transmission limitations restricted the amount of emergency assistance which could be received from New Brunswick.

As discussed above, there were a significant number of daytime hours when transfers from NYPP were limited to an average of 970 MW and from New Brunswick to 550 MW. When these limitations occur simultaneously, NEPOOL's capability to import energy is limited to a total of 1,520 MW (970 + 550). Long term contracts for the purchase and sale of capacity outside NEPOOL were a net purchase of about 600 MW. These deliveries have first priority on the use of transmission system. The remaining transfer capability available for other uses amounts to 920 MW (1,520 - 600). Therefore, for operations planning purposes, it should be recognized that there may be instances when the transfer capability available for the purchase of emergency/ supplemental capability is limited to 900 - 1,000 MW.

EKN:mdh:REP4
10/24/84

Attachment 1

Summer 1984 Weekly Peak Loads

Date	Hour Ending	Estimated Peak Load Exposure Used for Maintenance Scheduling (MWH)	Actual Peak Load (MWH)	Actual Minus Estimate Peak Load (MWH)	High Temperature (^oF) Boston	High Temperature (^oF) Hartford	Number of Preceding Days ≥ 90^oF
6/8	1400	13,600	15,077	+1,477	97	96	1
6/11	1400	13,900	16,274	+2,374	98	97	4
6/19	1500	14,800	14,171	-629	91	86	0
6/28	1400	15,000	13,989	-1,011	86	86	0
7/5	1400	15,500	13,844	-1,656	87	86	0
7/13	1200	15,700	13,823	-1,877	92	87	1
7/16	1200	16,000	14,603	-1,397	84	88	0
7/23	1400	16,000	14,853	-1,147	92	88	0
8/3	1400	16,000	14,969	-1,031	81	87	0
8/7	1400	16,000	15,617	-383	92	91	2
8/15	1500	16,000	15,620	-380	93	88	0
8/23	1200	16,000	13,786	-2,214	84	82	0
8/31	1200	16,000	15,070	-930	84	86	0
9/4	1200	16,000	12,712	-3,288	64	68	0
9/11	1400	14,000	13,811	-189	85	85	0
9/20	1400	13,600	12,754	-846	83	84	0
9/25	1400	13,200	13,909	+709	81	85	0

EKN:mdh:REP4

Attachment 2

Summer 1984 Total Net Energy for Load - 1,000 MWH

	Actual 1984	Advanced Projection 1984	Actual 1983	Actual Over Projection (%)	Actual Over Previous Year (%)
June	7,523	7,260	7,020	3.6	7.2
July	7,664	7,250	7,403	5.7	3.5
August	8,234	7,710	7,728	6.8	6.5
September	6,978	6,830	7,174	2.2	-2.7
Total	30,399	29,050	29,305	4.6	3.7

EKN:mdh:REP4
10/23/84

Attachment 3

Summary of Summer 1984 Generator Outages
(all figures in MW)

	Average Capability Out of Service on Daily Peaks		
	Scheduled	Unscheduled	Total
June	2,118	3,548	5,666
July	822	2,918	3,740
August	1,082	2,871	3,953
September	2,069	3,004	5,073
Average	1,523	3,085	4,608

EKN:mdh:REP4
10/23/84

Attachment 4

Summary of 1984 Summer Operating Reserve Shortages

Days When Operating Procedure No. 4 Was Implemented

s	6/7	6/8	6/11	6/13	6/19	6/25	8/6	8/7	8/15	9/24	9/25	9/26	Total
Load - MWH	14,336	15,077	16,274	(1) 15,301	14,171	(1) 13,234	15,505	15,451	15,620	13,711	13,909	(2) 13,750	
Outages & ctions - MW													
Scheduled	2,581	2,581	1,349	1,349	2,058	1,469	1,164	1,178	1,142	2,808	2,794	2,808	(3) 1,950
Unscheduled	3,083	3,210	3,558	4,294	4,564	5,080	3,480	4,175	3,758	4,211	3,855	4,032	3,940
Total	5,664	5,791	4,907	5,643	6,622	6,549	4,644	5,353	4,900	7,091	6,649	6,870	5,890
. Reserve - MW													
Requirement	1,275	1,275	1,275	1,275	1,275	1,275	1,224	1,163	1,245	1,245	1,245	1,245	
Actual w/o Supplemental Cap.	1,395	727	442	108	711	1,142	1,020	703	759	973	807	948	
Supplemental Cap.	100	486	533	400	200	250	355	391	600	250	200	957	
Actual Total	1,495	1,213	975	508	911	1,392	1,375	1,094	1,329	1,223	1,107	1,905	
No. 4 Implemental													
Measures	2	1-6	1-6	1-6	1-6	1-6	1&2	1-6	1&2	2	1&2	1&2	
No. of Hours	4	4	8	6	4	4	4	3	4	4	2	1	48
Actions		1-2											
No. of Hours		3											3
ly Total of plemental Purch.													
MWH	400	2,504	2,890	1,690	1,044	1,772	980	1,426	1,826	850	333	1,327	17,042
$/MWH	125	98	82	63	118	64	98	77	86	81	85	55	83
ly Gen. of ctivated Gen. - MWH	651	609	672	458	499	144	256	276	368	739	0	187	4,859

Not the peak of the day. Greatest generating capacity shortage in another hour.
Momentary peak load. Cold front caused load to decrease sharply during the remainder of the hour.
Average of the twelve days.

:mdh:REP4
23/84

Attachment 5

Generators Activated - Summer 1984

Generator	Summer Capability (MW)	Energy Generated (MWH)	Prior Status
Commercial St. 2	1.0	4	Deactivated Reserve
Wilkins 1&2	5.0	146	Deactivated Reserve
Rutland 1&2	8.5	33	Deactivated Reserve
Cabot 9	4.8	106	Deactivated Reserve
Silver Lake 13	14.0	198	Retired
Stony Brook 2B	65.0	4,783*	Non-Commercial
	98.3	5,270	

* Includes 411 MWH generated for testing purposes and at NEPEX's request due to impending capacity shortages on days when OP 4 was not implemented.

EKN:mdh:REP4
10/23/84

Attachment 6

Summer 1984 Limitations in NYPP to NEPOOL Transfers

	Low Voltage In NYPP		NYPP Transmission Loadings		Tie Line Loadings		NEPOOL Transmission Loadings		Total	
	No. Hours	Average Limit (MW)	No. Hours	Average Limit (MW)	No. Hours	Average Limit (MW)	No. Hours	Average Limit (MW)	No. Hours	Average Limit (MW)
Daytime	18	815	39	1,080	32	930	20	980	109	970
Nighttime	34	870	85	760	4	1,000			123	800
Total	52	850	124	860	36	940	20	980	232	880

Notes: "Summer 1984" includes June 1 - September 30.
"Average Limit" is the amount to which NYPP to NEPOOL transfers were limited.
The normal transfer limit during this period, determined from seasonal studies, was 1,925 MW.

EKN:mdh:REP4
10/23/84

NUCLEAR OUTAGES DURING SUMMER 1984 IMPLEMENTATION OF OPERATING PROCEDURE # 4

	07-Jun	08-Jun	11-Jun	13-Jun	19-Jun	25-Jun	06-Aug	07-Aug	15-Aug	24-Sep	25-Sep	26-Sep	Average
1. Date Op. Pro. 4 Implemented													
Gen. Outage & Reductions-MW													
2. -Scheduled	2581	2581	1349	1349	2058	1469	1164	1178	1142	2808	2794	2808	1940
3. -Unscheduled	3083	3210	3558	4294	4564	5080	3480	4175	3758	4211	3855	4032	3942
4. -Total	5664	5791	4907	5643	6622	6549	4644	5353	4900	7019	6649	6840	5882
Nuclear Outages-MW													
5. -Refueling	2301	2301	2134	2134	2638	1828	1743	1743	1239	1239	1239	1239	1815
6. -Other	0	0	0	0	0	810	167	167	671	504	504	504	277
7. -Total	2301	2301	2134	2134	2638	2638	1910	1910	1910	1743	1743	1743	2092
8. Nuclear Outages as % of Total Outages	41%	40%	43%	38%	40%	40%	41%	36%	39%	25%	26%	25%	36%

NUCLEAR OUTAGES - REFUELING

	MW-MDC Net	-----	-----	-----	-----	-----	-----	MW Unavailble (Refueling)	-----	-----	-----	-----	-----	-----	Average Available as % of Rating
CT Yankee	569	0	0	0	0	0	0	569	569	569	569	569	569	285	50%
ME Yankee	810	810	810	810	810	810	0	0	0	0	0	0	0	338	58%
Millstone 1	654	654	654	654	654	654	654	0	0	0	0	0	0	327	50%
Millstone 2	860	0	0	0	0	0	0	0	0	0	0	0	0	0	100%
Pilgrim 1	670	670	670	670	670	670	670	670	670	670	670	670	670	670	0%
VT Yankee	504	0	0	0	0	504	504	504	504	0	0	0	0	168	67%
Yankee Rowe	167	167	167	0	0	0	0	0	0	0	0	0	0	28	83%
TOTAL	4234	2301	2301	2134	2134	2638	1828	1743	1743	1239	1239	1239	1239	1815	57%

NUCLEAR OUTAGES - TOTAL

	MW-MDC Net	-----	-----	-----	-----	-----	-----	MW Unavailble (Total)	-----	-----	-----	-----	-----	-----	Average Available as % of Rating
CT Yankee	569	0	0	0	0	0	0	569	569	569	569	569	569	285	50%
ME Yankee	810	810	810	810	810	810	810	0	0	0	0	0	0	405	50%
Millstone 1	654	654	654	654	654	654	654	0	0	0	0	0	0	327	50%
Millstone 2	860	0	0	0	0	0	0	0	0	0	0	0	0	0	100%
Pilgrim 1	670	670	670	670	670	670	670	670	670	670	670	670	670	670	0%
VT Yankee	504	0	0	0	0	504	504	504	504	504	504	504	504	336	33%
Yankee Rowe	167	167	167	0	0	0	0	167	167	167	0	0	0	70	58%
TOTAL	4234	2301	2301	2134	2134	2638	2638	1910	1910	1910	1743	1743	1743	2092	51%

Sources/Notes
1. Memo: McEacharn to NEPOOL Operations Committee, 10/23/84
2. Same as 1
3. Same as 1
4. 2 + 3
5. Total of Refueling Outages Reported in NRC Grey Books for 7 New England Nuclear Units @ Reported MDC Net Rating
6. Total of Non-refueling Outages Reported in NRC Grey Books for 7 New England Nuclear Units @ Reported MDC Net Rating
7. 5 + 6

Appendix C
NEPOOL Capability Rules

Revised 12/8/69
Revised 2/10/72
Revised 3/9/72
Revised 3/22/72
Revised 12/13/73
Revised 3/21/74
Revised 4/1/75
Revised 7/29/77

Agreement by NEPOOL Companies
for
Uniform Rating and Periodic Audit of
Generating Capability

Statement of Purpose

Capability rating of all elements of power generation used by NEPOOL Operating compan is a prime necessity. Each such element and groups of element having interdependence (such as multiple units on steam header systems) must be rated at a load level that can be regularly achieved when system demands require it. Limitations that are commonly experienc because of smoke from stacks, high condenser inlet or downstream temperature, boiler tube metal temperature, river flows, net head reductions, low forebays, high tail races and pondage limitations may constitute a reduction from normal rating in the actual output obtainable. The Operations Committee therefore intends, by these provisions for Uniform Rating and Periodic Audit Testing, that unit ratings be set at levels that are regularly available within time limits prescribed, and for periods consistent with capability ratings described herein All capabilities claimed must be available for NEPEX dispatch - any capability restricted to the owner's use cannot be recognized in NEPEX dispatch or accountir All participating companies should recognize this vital factor and claim only that capabili for their units that can be reliably furnished to the exchange.

Capability data established under this Uniform Rating Plan is intended for use by NEPOO and individual member companies for the following operating and planning purposes:

a) Determining system capability of a NEPOOL participant

b) Scheduling operating capability

c) Scheduling of overhaul and maintenance outages

d) Furnishing such reports as may be authorized

To accomplish the purposes stated above, the NEPOOL Operations Committee establishe: the following rules for "Uniform Rating of Generating Capabilities," and directs the Generating Capability Task Force require and report the auditing of all Claimed Capabili Ratings as detailed in the "Periodic Capability Audit Instructions":

I. Uniform Rating of Generating Capabilities

(a) Thermal Units

Member companies will furnish Summer and Winter Net Capability ratings to NE for each of their units. Such claimed capabilities shall be supported by actual tests or logged data and shall be reliably available to NEPEX upon request.

1) Normal Net Capability

The maximum hourly average net capability at which the owner can and operate the unit for continuous service.

2) Maximum Net Capability

The maximum hourly average net capability at which the owner can and wi operate the unit for the duration of peak load periods, which shall be assum to be 8 hours for the period June 1 through September 30, and 2 hours for th rest of the year.

(b) Hydro Units

Member companies will furnish winter net capability ratings to NEPEX for each of their hydro units and/or stations. Such claimed capabilities shall be suppor by actual tests or logged data and shall be reliably available to NEPEX upon requ

1) Maximum Net Capability

The maximum hourly net average capability at which the owner can and wil operate the unit and/or station to perform the same function as alternative thermal generation on that portion of the load curve assigned to it.

II. Designations

Units will be designated by their owners in one of the following classes:

(a) Base Load Units

Units normally on the line 24 hours a day, 7 days a week

(b) Peaking Units

Units brought on the line to carry load above the capacity of the base load u

1. Maximum Net Capability of base load thermal units above the Normal Capabili
2. Peaking Hydro
3. Gas and Jet Turbine Units
4. Steam Units kept hot and manned for start, etc..

(c) Cold Reserve Units

Units not otherwise classified; essentially, the capability not readily availat such as units with steam boilers cold and, perhaps, drained, units not normally manned, etc..

Requirements for the demonstration of capability of units in the above classifications varies as described in the Instructions for Periodic Audit Testing.

III. Capability Demonstration Periods and Duration

(a) There will be Two Capability Test Periods Per Year.

1. Winter Period, from November 1 thru February 28.
2. Summer Period, from July 1 thru September 15.

(b) The Following Table Specifies The Duration In Hours Required For Tests.

TYPE	SUMMER NORMAL	SUMMER MAX	WINTER NORMAL	WINTER MAX
FOSSIL	6	6	4	2
NUCLEAR	6	6	4	2
JET ENGINE	2	1	2	1
GAS TURBINE	2	1	2	1
DIESEL	2	1	2	1
HYDRO (ALL)	0	0	2	2

IV. Capability Determination

(a) Thermal

1. Conventional Steam

Capability shall be determined for a unit individually where its eleme are independent of all others. Where several units have common elements wh could form a restriction on their combined maximum output, these unit ratin shall be determined as a group. Such common element could be a gas flue or stack serving several boilers, a steam header from several boilers serving several turbines, etc. In such a system, the amount by which each boiler and turbine or element, in case of its outage, would reduce the available capability of the group shall be determined. Units with auxiliary cooling equipment, such as spray modules or cooling towers shall have this equipment in service as required by regulatory or governmental authority during the capability test. Audit report shall indicate what auxiliary cooling equipme was in service during the audit.

2. Nuclear

Capability shall be determined for each unit based on recognizing all inherent factors, such as fuel management, governmental restrictions, etc Units with auxiliary cooling equipment, such as spray modules or cooling towe shall have this equipment in service as required by regulatory or governmenta authority during the capability test. Audit report shall indicate what auxil cooling equipment was in service during the audit.

3. Gas and Jet Turbine Units

Capability shall be determined for each unit based on rating at 90°F and 20°F for the Summer and Winter conditions, respectively, corrected for the installed elevation of the unit.

(b) Hydro

1. Conventional Hydro

Capability for each unit shall be based on median flows for the lates twenty years of record. All stations located on a common flowage such tha their outputs are interdependent shall be tested simultaneously. Hydro St with sufficient on-site storage to produce a minimum of two consecutive hou of peaking capability daily can claim this capability provided the storage pond can be brought back to normal prior to the following day's peak.

For conventional hydro where the storage pond is operated on a weekly cycle and not restored to normal full elevation on a daily basis, the plant capability shall be based on the lowest net head normally expected or experienced just prior to peak load at any time during the weekly pond cycl

This capability will normally be the average output for two consecutive hours except for stations which experience a reduction in net plant head of more than <u>1%</u> during the two-hour test period. Those stations experiencing a greater than <u>1%</u> reduction in head will report unit capabilities based on the lesser of two consecutive hours.

It is recognized that variations in hydro capability can occur at various times during the year. On low head stations, a temporary reduction in capability may be experienced due to loss of head during the spring run-o as well as other periods of the year when excessive rain or snow melt occurs. On higher head peaking and pumped storage plants, while spinning reserve capability is unimpaired, station output may be reduced during some months of the year because of the flatness of the system curve. These variations are usually known and must be taken into account in establishing day-to-day operating limits and in the planning of new capacity additions.

2. Pumped Hydro Plants

At the time of acceptance for commercial operation, each new pumped hydro station will be tested from full to minimum pond at maximum output to determine the change in plant capability with decreasing pond level and to verify the total energy content of the storage pond. A full pond pumping test will also be performed to determine the time and energy required to fill the pond. After having been initially made, these tests need not be repeated more frequently th each ten years.

Pumped storage plants which are part of an interdependent flowage shall be tested concurrently with the conventional hydro plants which they affect.

Pumped storage plants with sufficient storage to produce a minimum of two consecutive hours of peaking capability daily can claim this capability provide the storage pond can be brought back to normal prior to the following day's peak

For pumped storage plants where the storage pond must be operated on a weekly cycle and cannot be restored to normal full elevation on a daily basis, the plant capability shall be based on the lowest net head normally expected or experienced just prior to peak load at any time during the weekly pond cycle.

This capability will normally be the average output for two consecutive hours except for stations which experience a reduction in net plant head of more than 1% during the two-hour test period Those stations experiencing a greater than 1% reduction in head will report unit capabilities based on the lesser of two consecutive hours

V. Revision of Ratings

(a) Temporary Reductions

Minor reductions in unit capabilities due to temporary conditions shall not require any revision of capability ratings, but shall be made known to NEPEX Dispatch Center

(b) Failure to Demonstrate

If a reduction in capability below claimed level by 1% or more exists for two consecutive like test periods, the owner company shall submit to the NEPOOL Operations Committee (NOC) a request for a hearing or a new claimed capability, which shall be no greater than the higher of the capability demonstrated in the two test periods, seven days prior to (i) the April meeting in the case of Winter Audits, or (ii) the November meeting in the case of Summer Audits (NOC meetings are normally held during the last week of each month). In the event that no request for a hearing or no new claimed capability is submitted, NEPEX will reduce the capability rating to the higher of the capability demonstrated in the two tests, on (i) May 1 in the case of Winter Audits, or (ii) December 1 in the case of Summer Audits.

(c) Requested Changes

Revision of capability rating may be made by furnishing data of capability demonstration test to the Generating Capability Task Force. A copy of the memorandum, stating the requested capability rating, shall be sent to the Operations Committee Chairman and to NEPEX. On the first day of the following month, NEPEX shall revise their data to the requested figure, unless they have received notification from the Operations Committee that the new capability demonstration test data is not acceptable.

VI. Reports

(a) Company

The member companies will initiate, complete and report the testing of their capabilities to the Generating Capability Task Force as directed in the Periodic Audit Instructions If requested by the Generating Capability Task Force, member companies will furnish notice of the intended date of a test and accommodate the witnessing of the test by Generating Capability Task Force members or their representatives

(b) Task Force

The Generating Capability Task Force is charged by the NEPOOL Operations Committee with the responsibility and authority to require demonstration and reporting of net capability of each unit of generation, including purchased capability, as outlined in this Uniform Rating document and the Periodic Audit Instructions.

Where the Generating Capability Task Force feels it is necessary, it can, wit the approval of the NEPOOL Operations Committee, require a test be made of the station as a whole.

The Task Force is required to submit its Audit Reoort to the NEPOOL Operations Committee seven days before the date of (i) the April meeting in the case of Winter Audits, or (ii) the November meeting in the case of Summer Audits.

HHM:lrc
3-21-74

FORM 568-8.3 6-74

MEMORANDUM

To Generating Capability Audit Task Force (NEPCOL) COMPANY OR LOCATION — November 22, 1976

FROM Generating Capability Subcommittee COMPANY OR LOCATION — FILE

SUBJECT REVISED RULE INTERPRETATION

Attached please find a revised copy of the Rule Interpretation which you previously received under memorandum dated November 4, 1976. I appreciate the fact that your Task Force had some problems utilizing the original interpretation and when it got to the NEPOOL Operations Committee it was thoroughly discussed. The outcome of the discussion was to revise the Rule Interpretation as shown on the attached. Also, the Summer Audit Report was accepted with the necessary changes which are indicated by the attached Rule Interpretation.

The Generating Capability Subcommittee therefore requests that you make the necessary revisions in accordance with the attached Rule Interpretation and reissue the corrected sheets to your normal distribution.

Edward M. Keith
Chairman, NEPOOL Generating Capability Subcommittee

EMK:w
Attachment
Cc: JFC/WAH

N.B. My apologies to Frank Soley and Ross McEacharn for the inconvenience that we caused them.

FORM 100-4.1 4-10

MEMORANDUM

TO Generating Capability Audit Task Force (NEPOOL) — COMPANY OR LOCATION — November 22, 1976

FROM Generating Capability Subcommittee — COMPANY OR LOCATION — FILE

SUBJECT INSTRUCTIONS FOR INTERPRETATION OF RULES FOR PERIODIC CAPABILITY AUDIT TESTS

REVISED

RULE INTERPRETATION

In the event that a unit being audited only submits test data for a demonstration of normal capability and fails to submit test data for a demonstration of maximum capability prior to the end of the audit period, and the maximum claimed capability and the normal claimed capability are not equal per Section C - C.6 of the Instructions for Periodic Capability Audit Tests, the participant will be notified. If he fails to submit a letter adjusting the maximim claimed capability to equal the normal claimed capability, the Audit Report of the NEPOOL Generating Capability Audit Task Force will show a maximum demonstrated capability as equal to the normal demonstrated capability and a deficiency will be shown amounting to the maximum claimed capability less the normal demonstrated capability.

NOTE:

After the above has been sufficiently tested to satisfy the Generating Capability Audit Task Force of its workability, it is requested that the Generating Capability Audit Task Force recommend to the Generating Capability Subcommittee that the above section be included in the Instructions for Periodic Capability Audit Tests as Section H - 4.

NEPOOL Generating Capability Subcommittee
Edward M. Keith, Chairman
James F. Crowe
Warren A. Harvey

NOTED FEB 15 1979 W.

NOTICE OF CHANGE IN NEPOOL CLAIMED CAPABILITY

Company ______________________

Station ______________________

Unit ______________________

1. NEW UNIT

Date of Commercial Operation ______________________

Claimed Capability

Summer		Winter	
Normal	Maximum	Normal	Maximum
____MW	____MW	____MW	____MW

Nameplate Rating __________ KW

or

__________ KVA and __________ Power Factor

2. RETIREMENT

Effective Date of Retirement ______________________

Nameplate Rating __________ KW

or

__________ KVA and __________ Power Factor

3. RERATING

Effective Date of Rerating ______________________

Claimed Capability

	Summer			Winter	
	Normal	Maximum		Normal	Maximum
OLD	____MW	____MW	OLD	____MW	____MW
NEW	____MW	____MW	NEW	____MW	____MW

4. COMMENTS

____

____

____

Date This Form Submitted ______________________

By (Signed) ______________________

SEND COPIES OF THIS FORM TO THE FOLLOWING:

R. E. Charpentier, New England Power Service Company
20 Turnpike Road, Westborough, Massachusetts 01581

H. H. Mochon, Jr. - New England Power Exchange
174 Brush Hill Avenue, West Springfield, Massachusetts 01089

F. A. Soley, Boston Edison Company
800 Boylston Street, Boston, Massachusetts 02199

NX-3
2/79

Rev. 5-6-70
Rev. 11-1-72
Rev. 5-29-74
Rev. 4-1-75
Rev. 5-22-75
Rev. 7/29/77

Instructions for Periodic Capability Audit Tests of NEPOOL Generating Units

A. General

A.1) These instructions are issued by the Generating Capability Task Force, and approved by the NEPOOL Operations Committee. They prescribe the requirements and procedures for periodic demonstration and reporting of unit capabilities, in compliance with the "Agreement by NEPOOL Companies for Uniform Rating and Periodic Audit of Generating Capability" dated 7/29/77, and supersede all previous "Instructions."

B. Capability Ratings

B.1) The Agreement requires that NEPOOL companies furnish to NEPEX the normal and maximum capability rating of each unit for summer and winter periods.

B.1.a) Normal Net Capability is the maximum hourly average net capability at which the owner will operate the unit for continuous service.

B.1.b) Maximum Net Capability is the maximum hourly average net capability at which the owner will operate the unit for the duration of peak load periods, which shall be assumed to be 8 hours for the period June 1 through Sept. 30, and two hours for the rest of the year.

NOTE-All capabilities claimed must be available for NEPEX dispatch - any capability restricted to the owners use cannot be recognized in NEPEX dispatch or accounting.

B.2) Each unit must also be designated in one of the following classifications:

(A) Base Load Unit

Includes units normally on the line 24 hours a day 7 days a week.

(B) Peaking Units

Includes units brought on the line to carry load or furnish reserve above the capacity of the base load units, such as:

1) Peaking Hydro

2) Internal Combustion Units (Jet Engines, Gas Turbines, Diesels)

3) Steam units manned and hot for daily availability if required.

4) Extra capability of a base load unit above its normal rating, gained by overpressure, heaters out, etc.

(C) Cold Reserve Units

Includes units not otherwise classified; essentially the capability not readily available, such as units with steam boilers cold and perhaps drained, units not normally manned etc.

B.3) Identification

To assist in readily identifying the type of unit being audited, the following Code is to be used, in addition to a Unit Number and Station Title, when furnishing capability demonstration data:

	Code
Fossil(steam) units	F
Nuclear(steam) units	N
Jet Engine units	J
Gas Turbine units	GT
Diesel units	D
Conventional Hydro	H
Pumped Storage Hydro	PS

C. Capability demonstration requirements

C. 1) There will be Two Capability Test Periods Per Year.
1. Winter Period, from November 1 thru February 28.
2. Summer Period, from July 1 thru September 15.

C. 2) Hydro units are to be tested once a year during the winter period - all other units shall be tested twice a year - summer and winter.

C. 3) Capability demonstrations shall be initiated by the owner, and reported promptly to the Generating Capability Task Force.

C. 4) Capability demonstration may be by a specific test or from log records of normal operation.

C. 5) Capability demonstration must be during the prescribed period as above, and all reports of such tests must be submitted not later than two weeks after the end of the period.

C. 6) Duration of Capability Demonstrations

The following Table Specifies The Duration In Hours Required For Tests.

TYPE	SUMMER NORMAL	SUMMER MAX	WINTER NORMAL	WINTER MAX
FOSSIL	6	6	4	2
NUCLEAR	6	6	4	2
JET ENGINE	2	1	2	1
GAS TURBINE	2	1	2	1
DIESEL	2	1	2	1
HYDRO (ALL)	0	0	2	2

The duration of capability demonstration for purchased power shall be in accordance with the type of units producing the power, when determinable; otherwise, the fossil requirement above will apply.

One demonstration test covers both normal and maximum rating of hydro units, since only one rating is assigned. Except where normal and maximum claimed capability are the same, two separate demonstration tests are required for thermal generating units, one for normal capability and one for maximum capability.

Demonstrated capability is the average of the hourly net integrated outputs for the test periods as above except for Hydro units which experience a loss of more than 1% in net plant head. (See paragraph E.1 b and E.2 c pages 6 and 7.)

C. 7 Data to be submitted in reporting capability demonstration is as follows:

C. 7.a) Station log sheet copies marked to identify:

Company

Station

Unit Number(s) being reported on

Hours of the test

Rating demonstrated (Normal or Maximum)

Net generation (or gross and station service)

Whenever possible, meter readings should be shown, including meter factors if needed.

C. 7.b) A Capability Test Data Sheet (Form B - attached) showing hourly generation and average for the hours of the test.

C. 7.c) A Capability Audit Sheet (Form A - attached) listing the claimed capability and demonstrated capability of units.

C. 7.d) For Jet or Gas Turbine units, provide a graph of (claimed) capability vs. ambient temperature, and spot on that graph the test results.

C. 7.e) If any units fail to demonstrate at least 99% of the claimed capability, include a statement on the cause and the intended schedule of correction or re-rating. This should be in the form of a letter or page suitable for inclusion in the Audit Report. These statements do not constitute notices of re-rating or request for a hearing as required in par. F.1. a. pg. 8.

C. 7.f) The forms in section 7b and 7c and above are established to standardize reporting, thus assisting the Task Force in its audit. Copies of these forms and guide lines for them are attached to these instructions.

C.8 Data shall be submitted to :

Secretary - Generating Capability Task Force
c/o NEPEX
174 Brush Hill Avenue
West Springfield, Mass. 01089

D. Thermal Unit Capability Demonstration

D.1) Capability demonstration shall be by individual units where no interdependence with other units exists. For common header plants, all interdependent units should be claimed and demonstrated as a group. If the total claimed capability of such a group is demonstrated, failure of some individual units to demonstrate their capability will not be taken as a deficiency.

D.2) Log data of capability demonstration shall not be adjusted to standard conditions (condensing water temp. etc.) on the test report, except for Jet/Gas Turbine units.

Thermal Unit Capability Demonstration

D.3) Jet Engine and Gas Turbine units shall be assigned summer ratings of capability at 90°F and winter ratings at 20°F. Elevation of unit shall be recognized in setting these claimed capabilities.

Test data shall be adjusted to these standard ambient temperatures for reporting demonstrated capability.

Example: A unit rated 20mw at 90° is tested at 75°; the curve of output vs. ambient indicates 21mw capability at 75° - the demonstration shows 20.8 or .2mw deficiency.

Capability report should show
A claimed capability of 20mw and
A demonstrated capability of 19.8mw

E. Hydro Unit Capability Demonstration

E.1) Conventional Hydro

E.1.a) If two or more units are interelated having effect on the combined output, such units should be tested simultaneously. Stations on a common flowage should be tested simultaneously if operation of one at rated load affect capability of other.

E.1.b) The capability demonstrated will be taken as the average net output for two consecutive hours except for stations which experience a reduction in net plant head of more than 1% during the two hour test period. Such stations shall identify this situation in their capability demonstration report, and the lesser of the two hours will be

E.2) Pumped Hydro

E.2.a) New pumped hydro stations shall conduct and report on a capability demonstration from full to minimum pond at maximum claimed rating. Also the time to restore the pond from minimum to full level by pumping shall be reported. These tests shall be repeated each ten years.

E.2.b) Pumped storage plants which are part of an interrelated flowage shall be tested concurrently with the conventional hydro plants which they affect.

E.2.c) Demonstrated capability shall be the average of the net output for two consecutive hours, except for stations which experience a reduction in net plant head of more than 1% during the two hour period. For such plants, the demonstrated capabilities shall be the lesser of the two hours, and the capability demonstration report shall identify this information.

F. Failure to Demonstrate Claimed Capability

F.1) The Task Force Audit will compare demonstrated capability to the claimed capability as given in the NEPEX listing as of the end of the test period (Sept. 15 or Feb. 28). If the demonstration fails to meet claimed capability by more than 1% it will be noted as deficient on the Audit Report. If a unit is deficient more than 1% for 2 consecutive like periods the "Agreement for uniform Rating" requires that:

F.1.a) The owner must either declare a new claimed capability (See par. G.1.a below) which shall be no greater than the higher of the capabilities demonstrated in the two test periods, <u>or</u> request a hearing before the NEPOOL Operations Committee, by writing to the chairman and sending copies to NEPEX and to the chairman of the Generating Capability Task Force.

F.1.b) If the owner does not initiate one of the above actions seven days prior to the NEPEOOL Operations Committee meeting in (i) April in the case of Winter Audits, or (ii) November in the case of Summer Audits, NEPEX will reduce the listed capability to the higher of the two capabilities demonstrated, effective (i) May 1 in the case of Winter Audits, or (ii) December 1 in the case of Summer Audits.

G. <u>Revision of Claimed Capability Ratings</u>

G.1.a) Claimed capability of a unit may be revised at any time. To do so, the owner should submit the data on the NEPOOL form "Notice of Change in NEPOOL Claimed Capability" (latest version of Form NX-3), TO: (1) Chairman - NEPOOL Operations Committee, (2) Director - NEPEX, (3) Chairman - Generating Capability Task Force. A reduction in rating will be implemented by NEPEX. An increase in rating must be supported either by capability test reported in the most recent like period, or by submission of capability demonstration data to the Task Force. The Task Force will audit such data and inform NEPEX (with a copy to the Chairman of the NEPOOL Operating Committee) that the requested rating change is or is not supported by such capability demonstration.

NOTE: The full value of the new rating must be demonstrated - not 99%, the margin allowed on existing ratings.

G. 2) Capability demonstrations to substantiate a change in rating can be made any time of the year for Winter rating, but only between July 1 and Sept. 15 for summer rating.

H. <u>Other</u>

H.1) The Generating Capability Task Force may require that notification be given them of the date of an intended capability demonstration, so that they or their representative can witness the test.

H.2) When the Task Force feels it is necessary it can, with the approval of the NEPOOL Operations Committee, require a test be made of a station as a whole, or a common flowage as a whole.

H.3) The Task Force is required to submit its Audit Report to the NEPOOL Operations Committee seven days before the date of (i) the April meeting in the case of Winter Audits, or (ii) the November meeting in the case of Summer Audits. Any units for which capability demonstration data is not received within the 2 weeks following the end of the test period will appear in the Audit Report as not tested. This results in a deficiency equal to the rating of the unit, for that period.

Guide Lines for Use of GCTF Forms A and B

1) Form A Capability Audit

This form is the final listing and summation of demonstrated capabilities. Use of the following guidelines will assist in completion of a proper Audit Report.

1.a) Record generation in Megawatts - to two decimal places (761.00, 3.53, .78 etc.).

1.b) Submit Form A as Follows:

1.b.1) A summary of all company capabilities, usually showing major stations, hydro totals, etc.

1.b.2) A separate page for each station which has several items of capability in the NEPEX list. (If the station as a whole is the item quoted on the NEPEX list, a separate page is not required).

1.b.3) A listing of hydro units, and total of same.

1.c) Both Normal and Max. columns should be filled out, even if identical. This aids is summarizing NEPEX Normal and Max. capabilities.

1.d) For Jet and Gas Turbine units, list under Claimed Capability the 90°F rating for summer tests and the 20°F rating for winter tests. The demonstrated capability listed should be the claimed capability plus any excess, or minus any deficiency which was found in testing the unit at some other ambient temperature.

1.e) Under "Deficiency - if any" heading, show only failures to make claimed capability - do not show plus values.

2) <u>Form B - Capability Test Data</u>

This form assists in transferring data from Logs for the hours of the test, and showing the average output demonstrated. A copy of this form should be filled out and attached to each Form A report on unit outputs.

Appendix D

NEPOOL Documents Recognizing QF Capacity

NEW ENGLAND

SYSTEM CAPABILITIES AND ESTIMATED PEAK LOADS

1971-1981

Prepared from Estimates Collected
By the New England Planning Committee in
September, 1971

September 1, 1971

I. NEW ENGLAND AREA SYSTEM CAPABILITIES AND ESTIMATED PEAK LOADS (CONT'D)

		Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sept. 1971	Oct. 1971	Nov. 1971	Dec. 1971
16.	Nominal Pumped Storage Capability (MW)									32	32	32	32
17.	Pumped Storage Reduction (MW)									0	0	0	0
18.	Dependable Pumped Storage Capability (16 minus 17) (MW)												
	NEES									-	-	-	-
	Northeast Utilities									32	32	32	32
	Total Dependable Pumped Storage Capability (MW)									32	32	32	32
19.	Firm Puchases Within Company Sys. (MW) Appendix B Page 42									31	31	31	31
20.	Firm Purchases Outside New England Area (MW) Appendix B Page 43									478	478	478	478
21.	Firm Obligations Outside New England Area (MW) Appendix B Page 43									255	201	0	0

II. NEW ENGLAND AREA SYSTEM CAPABILITIES AND ESTIMATED PEAK LOADS (CONT'D)

	Jan. 1972	Feb. 1972	Mar. 1972	Apr. 1972	May 1972	June 1972	July 1972	Aug. 1972	Sept. 1972	Oct. 1972	Nov. 1972	Dec. 1972
5. Dependable Hydro Capability (13 minus 14) (MW) (Cont'd)												
PSNH	48	48	48	48	48	47	47	47	47	47	47	47
Vermont Group	71	71	72	87	87	74	65	65	65	73	76	73
Total Dependable Hydro Capability (MW)	1233	1213	1164	1184	1217	1223	1201	1151	1153	1194	1225	1233
6. Nominal Pumped Storage Capability (MW)	32	32	282	532	532	532	782	782	1032	1032	1032	1032
7. Pumped Storage Reduction (MW)	0	0	0	0	0	0	0	0	0	0	0	0
8. Dependable Pumped Storage Capability (16 minus 17) (MW)												
NEES	–	–	–	–	–	–	–	–	–	–	–	–
Northeast Utilities	32	32	282	532	532	532	782	782	1032	1032	1032	1032
Total Dependable Pumped Storage Capability (MW)	32	32	282	532	532	532	782	782	1032	1032	1032	1032
9. Firm Purchases Within Company System (MW) Appendix B Page 47	31	31	31	31	31	31	28	28	28	28	28	28
0. Firm Purchases Outside New England Area (MW) Appendix B Page 47	478	478	478	487	487	465	436	436	436	436	436	437

APPENDIX B

	Jan.	Feb.	Mar.	Apr.	May	June	July	Aug.	Sept. 1971	Oct. 1971	Nov. 1971	Dec. 1971
Nominal Hydro Capability (MW) (Cont'd)												
NEES									546	546	546	546
Northeast Group									242	242	242	242
PSNH									59	59	59	59
Vermont Group									91	91	91	91
Total Nominal Hydro Capability (MW)									1244	1244	1244	1244
Nominal Pumped Storage Capability (MW)												
NEES									—	—	—	—
Northeast Utilities									32	32	32	32
Total Nominal Pumped Storage Capability (MW)									32	32	32	32
Firm Purchases Within Company System (MW)												
Boston Edison									1	1	1	1
CMP Co.									10	10	10	10
Northeast Utilities									20	20	20	20
Total Firm Purchases Within Company System (MW)									31	31	31	31

APPENDIX B

	Jan. 1972	Feb. 1972	Mar. 1972	Apr. 1972	May 1972	June 1972	July 1972	Aug. 1972	Sept. 1972	Oct. 1972	Nov. 1972	Dec. 1972
Nominal Pumped Storage Capability (MW)												
NEES	–	–	–	–	–	–	–	–	–	–	–	–
Northeast Utilities	32	32	282	532	532	532	782	782	1032	1032	1032	1032
Total Nominal Pumped Storage Capability (MW)	32	32	282	532	532	532	782	782	1032	1032	1032	1032
Firm Purchases Within Company System (MW)												
Boston Edison	1	1	1	1	1	1	1	1	1	1	1	1
CMP Co.	10	10	10	10	10	10	7	7	7	7	7	7
Northeast Utilities	20	20	20	20	20	20	20	20	20	20	20	20
Total Firm Purchases Within Co. System (MW)	31	31	31	31	31	31	28	28	28	28	28	28
Firm Purchases Outside New England Area (MW)												
MEP Co.	280	280	280	280	280	280	260	260	260	260	260	260
MPS Co.	48	48	48	57	57	35	26	26	26	26	26	27
Vermont Group	150	150	150	150	150	150	150	150	150	150	150	150
Total Firm Purchases Outside New England Area (MW)	478	478	478	487	487	465	436	436	436	436	436	437
Firm Obligations Outside New England Area (MW)	–	–	–	–	–	–	–	–	–	–	–	–
Total Firm Obligations Outside New England Area (MW)	–	–	–	–	–	–	–	–	–	–	–	–

NEPLAN

New England Power Planning

174 BRUSH HILL AVENUE
P.O. BOX 10
WEST SPRINGFIELD, MASSACHUSETTS 01090
TELEPHONE (413) 787-9000

April 1, 1984

NEPOOL Planning Committee

Gentlemen:

The enclosed "NEPOOL Forecast Report of Capacity, Energy, Loads and Transmission - 1984-1999" (CELT) is the second year issue of an expanded version of our previous Load & Capacity report. It is intended to fulfill in one volume the requirements of DOE, NERC-IRS, NPCC, EEI, EFSC (Mass.) and NEPOOL.

You will note that this year's CELT Report provides data for NEPOOL and not total New England. We have, however, included in the Section I summaries Total New England Capacity and Total New England Load for reference purposes.

Sincerely,

Richard J. Bolbrock

Richard J. Bolbrock
Director

RJB/jl
Enclosure

SECTION III

NEPOOL PURCHASES & SALES AS OF JANUARY 1, 1984

RECEIVING SYSTEM	SUPPLYING SYSTEM	TYPE	FUEL	CAPABILITY - MW SUMMER	CAPABILITY - MW WINTER
CAPACITY PURCHASES (INTERNAL)					
CENTRAL MAINE POWER COMPANY	CMP INTERNAL PURCH.	PP		10.15	10.15
FITCHBURG GAS + ELECTRIC LIGHT CO.	ATLANTIC PROPERTIES	PP		.47	.47
FITCHBURG GAS + ELECTRIC LIGHT CO.	LINWEAVE	PP		3.10	3.10
BOSTON EDISON COMPANY	MDC PURCHASE	PP		1.00	1.00
			SUB-TOTAL	14.72	14.72
CAPACITY PURCHASES (EXTERNAL)					
CENTRAL MAINE POWER COMPANY	NEW BRUNSWICK	PP		100.00	100.00
VERMONT GROUP	* PASNY PURCHASE	PP		147.50	147.50
VERMONT GROUP	ONTARIO 2	PP		0.00	14.25
VERMONT GROUP	SO. CANADA PURCHASE	PP		32.90	0.00
VERMONT GROUP	ONTARIO 1	PP		4.91	4.91
VERMONT GROUP	ONTARIO 3	PP		46.18	46.18
COMMONWEALTH ELECTRIC SYSTEM	POINT LEPREAU 1	PP	UR	25.00	25.00
BOSTON EDISON COMPANY	POINT LEPREAU 1	PP	UR	100.00	100.00
MAINE ELECTRIC POWER COMPANY	NB PURCHASE 2	PP	F06	119.29	119.29
MASS. MUNICIPAL WHOLESALE ELECTRIC	POINT LEPREAU 1	PP	UR	100.00	100.00
			SUB-TOTAL	675.78	657.13
			TOTAL PURCHASES	690.50	671.85
CAPACITY SALES (INTERNAL)					
NEW HAMPSHIRE ELECTRIC COOPERATIVE	MAINE YANKEE	SP	UR	6.07	6.23
CAPACITY SALES (EXTERNAL)					
MAINE PUBLIC SERVICE COMPANY	MAINE YANKEE	SP	UR	44.06	45.17
MAINE PUBLIC SERVICE COMPANY	W.F.WYMAN 4	SP	F06	20.56	20.72
			SUB-TOTAL	64.62	65.89
			TOTAL SALES	70.69	72.12
			NET OF PURCHASES AND SALES	619.81	599.73

*REFLECTS 2.5 MW LINE LOSS.

Appendix E
Marginal Losses

Appendix E

As shown in Figure E for a simplified circuit:

$$\text{Losses} = I^2 R_L = \left(V_o^2 / R_o^2\right) R_L$$

$$\text{Output to customers} = I^2 R_o = V_o^2 / R_o$$

V_o is constant, as is R_L

$$\text{input} = \text{output} + \text{losses} = I^2\left(R_o + R_L\right)$$

$$= V_o^2 \left(R_o + R_L\right) / R_o^2$$

$$\frac{d\ (\text{input})}{d\ (R_o)} = -\ V_o^2 / R_o^2 - 2 V_o^2 R_L / R_o^3$$

$$\text{Output} = V_o^2 / R_o \Rightarrow R_o = V_o^2 / \text{output}$$

$$\frac{d\ R_o}{d\ \text{Output}} = -\ V_o^2 / (\text{output})^2 = -V_o^2 / \left(V_o^2 / R_o\right)^2$$

$$= -\ R_o^2 / V_o^2$$

$$\frac{d\ \text{Input}}{d\ \text{Output}} = \frac{d\ \text{input}}{d\ R_o} \times \frac{d\ R_o}{d\ \text{output}}$$

$$= \left(-\ V_o^2 / R_o^2 - 2\ V_o^2 R_L / R_o^3\right) \times \left(-\ R_o^2 / V_o^2\right)$$

$$= 1 + 2\ \left[\left(V_o^2 / R_o^2\right) R_L\right] \left[R_o / V_o^2\right]$$

$$= 1 + 2 \times \text{losses}/\text{output}$$

$$= 1 + 2 \times \text{losses} / (\text{input} - \text{losses})$$

$$= (\text{input} + \text{losses}) / (\text{input} - \text{losses})$$

$$= (1 + L) / (1 - L)$$

where $L = \text{losses} \div \text{input}$

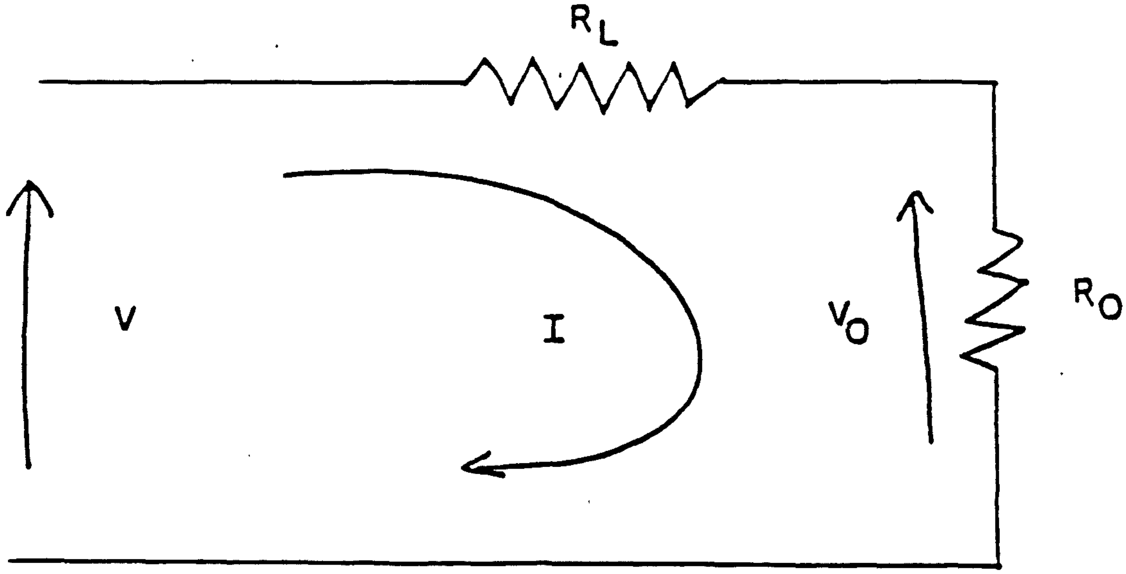

FIGURE [illegible]

22-Mar-85

TABLE 2.1: SEABROOK LOAD CARRYING CAPACITY

Power Year	MMWEC Estimates of NEPOOL Reserve Levels [1] With Seabrook	Without Seabrook	NEPOOL Forecast Peak [2]	Seabrook Effective Load Carrying Capacity [3]	Seabrook ELCC/MW
	(A)	(B)	(C)	(D)	(E)
1989/90	28.40%	25.80%	17537	540.53	47.0%
1990/91	31.50%	29.70%	17986	628.33	54.6%
1991/92	29.10%	27.10%	18446	605.02	52.6%
1992/93	28.30%	26.20%	18962	585.97	51.0%
1993/94	26.90%	24.90%	19377	600.84	52.2%
1994/95	27.00%	25.00%	19900	592.13	51.5%
1995/96	30.80%	29.00%	20458	597.67	52.0%
1996/97	31.30%	29.70%	20975	620.26	53.9%
1997/98	30.80%	29.20%	21292	618.75	53.8%
1998/99	29.00%	27.50%	21471	641.81	55.8%
1999/00	29.90%	27.30%	21698	451.00	39.2%

NOTES: 1) From MMWEC Exhibit RMC-23, DPU 1627.
2) From NEPOOL (1984).
3) (C*(1+B)+1150)/(1+A) - C

TABLE 3.1: ALTERNATIVE ENERGY POTENTIAL IN MASSACHUSETTS

Energy Source	Estimated MW Capacity Potential [1]	Typical Capacity Factor (CF) low	Typical Capacity Factor (CF) high	Annual GWH Output Potential [2] low CF	Annual GWH Output Potential [2] high CF
Wind	100 +	25%	30%	219 +	263
Hydro	129	55%		622	
Wood	120	75%	80%	788	841
Solid Waste	400	60%		2102	
Cogeneration	1000 +	40%	80%	3504 +	7008
Total:	1749 +	-	-	7235 +	8112

Notes: 1. Source: Testimony of P.L. Chernick, MDPU 1627.
2. MW x CF x 8.76

TABLE 3.2: OWNERSHIP INTERESTS IN UTILITY-PLANNED UNITS

		Millstone 3	Seabrook 1
MMWEC		55	133
New England Power Co	[1]	94	77
Western Mass. Elec. Co		141	-
Montaup Elec. Co	[2]	21	15
Commonwealth Elec. Co		-	40
Fitchburg Gas & Elec. Co		3	10
Chicopee, Mass.		16	-
Hudson, Mass.		-	1
Taunton, Mass.		-	1
TOTAL		329	278

Notes: 1. Times MECo Sales 1981/ NEPCo Sales 1981 = 66.81%
2. Times EECo Sales 1981/ Montaup Sales 1981 = 45.41%

EXHIBIT Q-WMECO-II-3
Attachment B

#45A

THE COMMONWEALTH OF MASSACHUSETTS
BEFORE THE DEPARTMENT OF PUBLIC UTILITIES

RE: RULES GOVERNING RATES AND CONDITIONS FOR UTILITY PURCHASES OF POWER FROM QUALIFIYING FACILITIES	DOCKET No. 84-276

ADDITIONAL TESTIMONY OF PAUL CHERNICK
ON BEHALF OF
THE ATTORNEY GENERAL

October 18, 1985

THE COMMONWEALTH OF MASSACHUSETTS
BEFORE THE DEPARTMENT OF PUBLIC UTILITIES

RE: RULES GOVERNING RATES AND CONDITIONS FOR UTILITY PURCHASES OF POWER FROM QUALIFIYING FACILITIES	DOCKET No. 84-276

ADDITIONAL TESTIMONY OF PAUL CHERNICK
ON BEHALF OF
THE ATTORNEY GENERAL

October 18, 1985

Table of Contents

TESTIMONY OF PAUL CHERNICK
ON BEHALF OF
THE ATTORNEY GENERAL

1 - INTRODUCTION AND QUALIFICATIONS

Q: Mr. Chernick, would you state your name, occupation and business address?

A: My name is Paul L. Chernick. I am employed as a research associate by Analysis and Inference, Inc., 10 Post Office Square, Suite 970, Boston, Massachusetts.

Q: Have you testified previously in this proceeding?

A: Yes.

Q: What is the subject of your present testimony?

A: I have been asked by the Attorney General to respond to certain issues raised by the Department in its Interim Order (which I will henceforth abbreviate IO) of September 12, 1985, regarding the rates and conditions for utility purchases of power from small power producers and cogenerators (collectively referred to as "qualifying facilities" or "QFs"), pursuant to §210 of the Public Utilities Regulatory Policy Act (PURPA).

Q: How is your testimony structured?

A: The next two sections consider major areas of concern raised by the Department's Interim Order. §2 discusses a set of issues associated with reliability: the measurement of system reliability benefits of QFs, structuring payments for QF contributions to system reliability, and assessing the risks of relying on QFs for power supply. In §3, I consider the problems of setting rates. §4 compares the benefits and risks to ratepayers of QF power, as compared to utility-supplied power, and contrasts the roles of utilities and QFs in the future of New England power supply.

Q: Please briefly summarize your testimony.

A: The basic points which I would like to make are:

1. The Department has made significant commitments to more efficient ratemaking for QFs, by supporting Standard Offers and long-term fixed rates.

2. In most respects, utilities and their customers are better off purchasing power from QFs, rather than owning capacity or buying power from other utilities with the same expected cost.

3. In most respects, QF energy and capacity is less risky,

and thus more valuable, to the utility (and its customers) than conventional utility-owned resources.

4. The treatment of QFs in EOER's original proposed rule does not fully reward them for their advantages compared to utility-owned capacity, or purchases from other utilities, and thus offers less than full avoided cost.

5. EOER original proposal (and utility suggestions) would have imposed several requirements and restrictions demanding higher performance from QFs than is demanded (or probably can be demanded in most situations) from utility plants. At the least, these requirements offer less than avoided cost. In some cases, the restrictions may discourage QF development, or would unnecessarily increase the risks to both QFs and ratepayers, reducing the value of the QFs which are developed.

6. The Department should increase the incentives for development of QFs, reflecting their value as compared to realistic utility investments, rather than hypothetical "firm" capacity.

7. New regulations governing QF rates should attempt to establish a level playing field for independent power producers with respect to utilities. Since utilities

and QF developers are very different entities, with very different responsibilities, treating QFs in a manner consistent with utility-planned resources does not (and can not) imply treating QFs and utilities in exactly the same way.

2 - RELIABILITY AND QUALIFYING FACILITIES

Q: What topics will you discuss in this section of your testimony?

A: I will start by discussing the concept of reliability, in terms of its fundamentally statistical nature, and in terms of normal utility (and consumer) experience and expectations. I will then differentiate some of the meanings of "reliability" which are of interest in power supply planning in general, and in this proceeding in particular. From this basic understanding of the nature of reliability, I will then approach the issues raised by each specific meaning of the term in the context of setting rates for QFs.

2.1 - What is Reliability?

Q: What does reliability mean in the context of utility bulk power supply?

A: Reliability is a probabilistic concept. The reliability of a system is generally described in terms of the loss-of-load probability (LOLP), which is the probability that the load on the system (which may be calculated before or after a variety of load reduction efforts) exceeds the available generating capacity (including imports and possibly net of operating reserves). It is important to remember that LOLP is a measure of chance, describing a stochastic process. There is no certainty in generation planning: no generation or purchase is totally "firm" or "reliable".

Q: Is this concept of reliability the same as that used in all other fields?

A: No. For many engineering fields, reliability is considered in a deterministic manner, without direct relation to probabilistic considerations. In transmission systems planning, for example, reliability is measured in terms of the number of adverse events (or "contingencies") the system can tolerate without shedding load. In general, no effort is made to assign probabilities to the individual contingencies, or to the loss of load.

Structural engineers design for "conservative" (pessimistic, or nearly worst-case) conditions, such as a loading of so many pounds per square foot, generally without assigning probabilities to the conditions occurring. They then add deterministic safety margins (e.g., increasing the strength of the floor by 30% over the calculated requirement), to allow for deficiencies in expectations, design, or construction.

In thinking about generation reliability, it is important to bear in mind these distinctions in terminology. When a utility builds a new transmission line, either it will provide second-contingency service to a substation, or it will not. The fact that ~~the~~ event which initiates the first contingency may also take out the new line, or that the two lines may simultaneously but independently fail, or even whether a particular line fails often, is irrelevant to whether the line has performed as expected. For generation, reliability is probabilistic, and the issue is not whether the plant was available at a particular time, but whether the probability of availability (or more precisely, the probability of being available when needed) was adequate. Actual availability in each year, month, and hour will vary, and that should be neither surprising nor disappointing.[1]

Q: What significance does the probabilistic nature of generation reliability have for this proceeding?

A: It is very important for the Department to remember that generating capability is never a certain quantity, and that the utility can only "rely" on the performance of its own plants, or power purchased from other utilities, or power from QFs, in a probabilistic sense. It is inevitable that some of the sources on which a utility places its "reliance" will be unavailable when they are needed. This is the basic rationale for my insistence on calling "reliability" what other people call "capacity": to constantly remind myself (and others) that the issue is not installed megawatts, or claimed "Dependable Ratings", but the ability to support load at a given LOLP. It is also the basis for may reminding the Department (see IO 56-57) that QFs which happen to be unavailable at the peak hour still improve relaibility, both after-the-fact by their actual availability on non-peak hours with high loads,[2] and before-the-fact by the probability that

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1. This discussion has dealt primarily with the operating reliability of units which have entered service. Comparable concepts apply to the planning reliability of plants which have not entered service.

2. The summer of 1984 capacity emergencies occurred in many hours with loads well below the summer peak, let alone the annual peak. Emergencies occurred in hours with loads as much as 19% below the peak, and the two worst reserve situations happened during loads 6% and 9% below the peak.

they would have been available at peak.

Unfortunately, the parties (the Department, EOER, and especially the utilities) tend to forget that utility plant can be said to provide "firm" and "reliable" and "dependable" capacity only because of the special definition of those terms in utility usage: by normal standards, <u>all</u> generation is non-firm, unreliable, and undependable. It is unrealistic (and inefficient) to pay QF rates based on the cost of fallible utility plant, and expect perfect capacity in return.[3]

The Department recognized in the IO that my distinction between "reliability" and "capacity" was conceptually correct, but chose to continue using "capacity" to cover both ideas (IO 33n). Unfortunately, using the term "capacity" to represent two different concepts appears to have obstructed either the Department's analysis of several QF ratesetting issues, or the Department's presentation of those issues in the IO. For example, page 57 of the IO contains the

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3. The Department suggests another rather burdensome requirement for QFs: that rates must stay the same or go down, while reliability stays the same or goes up (IO 9, point 3). Since QFs reduce risks to ratepayers, it is quite a lot to ask QF to also provide simultaneous improvements in both rates and reliability (which are usually traded off against one another, and against risk).

following statements:

> Capacity is merely the instantaneous KW capability of the generating unit.
>
> [C]apacity may have little or no value if [it] cannot be relied upon to meet the load consumers place on the system.
>
> [C]apacity can have value only if the utility can be reasonably certain that this capacity will be available at the times it is needed.

Of course, the Department is addressing very important concerns, and its observations are fundamentally correct. Unfortunately, in failing to directly describe the "value of capacity" as "system reliability", the Department may leave the impression for the reader (and may even itself believe) that an individual QF has no reliability value for the system unless its can always (or almost always, depending on how one interprets "can be relied upon" and "reasonably certain") produce the "instantaneous kW capability" it claims, whenever "it is needed". This is not the case. There is no connection between the outage rate for a small QF and its contribution to system reliability (per kWh), as I discuss in Section 2.3. In fact, no utility plant "can be relied on" to be available "when it is needed", so a careless reading of the IO would lead one to the conclusion that no utility plant has any capacity value. While careful use of language is hardly a guarantee of clear thinking, precise terminology facilitates consistent analysis and effective communication.

If the Department would like to keep its terminology closer to that usually used in utility planning and regulation, it might choose to refer to credits for contribution to "system capability" or for "load carrying", rather than reliability. In any case, it is important to distinguish between the value of a QF and its capacity.[4]

Q: How many different concepts are covered by the term "reliability", as it has been used in this proceeding?

A: There are at least four kinds of reliability, or dimensions along which the utility may or may not be able to rely on a QF, or any other energy/power source, for that matter:

1. Will it be completed and enter service, as projected?

2. Will it produce as much energy as projected?

3. How consistent will the energy availability be over time?

4. How long will the plant last?

Other divisions of the general concept into specific issues may also be used, but I believe these four topics are sufficient to address the major concerns about QF

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4. The Department has previously criticized NEPOOL's naive equation of capability with capacity (Levy 1985). In addition to the outage effects the Department discusses there, capability contributions also vary with the unit's size.

dependability, and consequences for rate design. Each of the next four subsections addresses one of these risk types.

2.2 - QF Construction Risks

Q: What is the nature of QF construction risk?

A: The basic problem is that the utility may expect a QF to be on line at a specific time, and thus make no other supply plans. If the QF is never built, or comes on line much later, or is much smaller than expected, the utility may have to replace its contribution to both energy supply and reliability. Depending on load growth, fuel prices, other QF development, conservation program development, and other factors, the absence of a few QFs may or may not be a major concern. At worst, the planning problem could result in very short-term reliability degradation, and a somewhat longer period of higher supply costs, as less desirable sources are substituted for the QFs. The Department epresses is concerns regarding QF construction risk at IO 21 and 69-71.

Q: To what extent is construction risk a problem in utility power plant construction?

A: It is a major problem. Cost overruns, construction delays, plant cancellations, and similar problems have been nearly universal in nuclear power plant construction, and have also been common in the construction of coal plants and other generating facilities (e.g., the Helms Pumped Storage plant of PG&E). New England utilities have concentrated on the construction of nuclear units for the last decade: of the nine nuclear units which were planned in the early and middle 1970's, only two have any chance of entering service, and those are many years behind schedule. The single new coal plant (Sears Island) planned in the same period has also been cancelled.

Table 1 summarizes the construction risk experience of the non-nuclear plants planned by New England utilities in the early 1970's: the sad experience of the nuclear plants is too well known to require repetition. For each unit of more than 100 MW planned in the early 1970's, Table 1 displays the expected commercial operation date (COD) of as of the first time the unit appeared in a NEPOOL or NU Load and Capacity Report available to me, ~~and~~ the actual COD or date of cancellation. The Sears Island coal plant is not included, since it appeared (and disappeared) after the period reviewed here. Besides the large number of cancellations, the other interesting data in Table 1 is the large amount of delay experienced by many projects. Only a couple of units met their targeted in-service dates, and many missed by over a year.

Some of the delays and cancellations of utility plants have resulted from changing load projections, but most have resulted from just the kind of problems which the Department and various commentors have expressed concern regarding QF construction problems: financial difficulties, cost increases, licensing and regulatory problems.

Q: What implications do these utility generation construction problems have for pricing and planning QF power?

A: Basically, construction risk is intrinsic to the electric generation process. Until a generating technology is developed which is inexpensive, modular, environmentally benign, and available off-the-shelf, generation planners will be dealing in a world of uncertainty, whether they are planning on utility construction or QF construction. Thus the Department's desire to ensure that QFs "will deliver power when expected and required by the utility" (IO 21) is only realistic to a very limited extent. Stringent penalties for QFs which miss construction targets would discourage economical QFs, unless the penalties were combined with rates well above the cost of risky utility plant construction.

Similarly, any incentive for QFs to "provide capacity in a reliable manner" (IO 56) must interpret "reliable" in a sense consistent with the predictibility of the utility construction plans which are the basis for setting the QF rate.

Q: How does ratemaking deal with utility construction risk?

A: Historically, utilities have been allowed to recover their investments in construction projects, regardless of whether those projects are completed on time (or completed at all), so long as the utility's decisions have been prudent. I know of no instance in which a utility has been held responsible for the difference between the actual cost of power supply and the the cost which would have prevailed, had the utility achieved its targeted construction program. Thus, ratepayers traditionally assume all of the planning risks (e.g., replacement power, low reliability, and "catch-up" programs) of prudent utility construction decisions, and also bear all (or at least most) of the risk for the amounts actually spent in the failed or delayed construction. Thus, cancellations and delays usually end up ~~in~~creasing rates in two ways.[5]

Q: How does NEPOOL deal with construction risks in assigning capability credits to its members?

A: NEPOOL grants capability credits to members for currently

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5. This discussion describes the traditional treatment of utility costs and risks. The Department may change this formula in the future. As I indicated in the previous hearings in this docket, there are limits on the amount of change in normal ratemaking situations which is feasible, efficient, and in the interest of the ratepayers. In any case, delaying consideration of QF ratemaking until all of the possible changes in utility ratemaking have been fully heard and resolved would prevent any substantial contribution of QF power to solving the short-term energy and reliability supply problems envisioned by NEPOOL.

demonstrated capability, based on annual or semi-annual tests. Utilities receive full credit for their plants' present output, regardless of whether the plant entered service before or after its scheduled in-service date. Despite many years of delay, there seems to be no question that the owners of Millstone 3, for example, will be (and ought to be) credited with the full reliability benefit of that plant when it finally goes commercial. The current capability is awarded, regardless of whether the demonstrated output level is above or below prior targets. Claimed and demonstrated capabilities change frequently for many units, as equipment ages and is cleaned, replaced, and upgraded, or as environmental restrictions change.

Both the Department (Levy 1985) and I have criticized aspects of the NEPOOL capability calculations, and I would hardly present the NEPOOL approach as a model for all reliability credit purposes. However, NEPOOL's practice does illustrate that the utilities are accustomed to dealing with construction risks, and that they have found no need to restrict reliability credits to plants which enter service exactly on schedule and which operate at exactly the projected rating.

Q: How does this treatment compare to the rate treatment inherent in the QF/utility relationship?

A: One of the basic tenets of all proposals for QF ratemaking is that the QF is paid only for power actually produced and reliability actually provided. This results in three kinds of improvements over the usual situation with utility-planned generation. First, the QF developer has a much stronger incentive to complete its plant than does the utility, which will usually receive some payment, regardless of whether the plant ever operates, and will generally be paid more if the plant is delayed (since the installed cost increases). Second, if the QF never comes on line, the ratepayers are left with the planning-related costs, but they need not assume any of the cost of the unit which failed. Third, if the QF comes on late, the ratepayers may have higher costs in the interim, but the delay does not result in their paying more for QF power when the unit <u>does</u> become available.

The technical nature of most QFs also mitigates the planning problems. The units tend to be small (compared to utility plants, at any rate), so the delay or cancellation of a single unit is less important than with utility plants. QFs will tend to be widely diversified in their fuel source, generation technology, and exposure to environmental regulation, so the supply plan is less vulnerable to changes in economics and regulation. The changes in nuclear regulation in the 1970's wreaked havoc with New England utility supply plans, which were highly dependent on nuclear plants; acid rain legislation could have similar effects if the utilities embarked on a new construction program of conventional coal plants. It is difficult to see how any economic or regulatory change could have a similar effect on the totality of QF supply, including hydro, wood, trash, wind, and a variety of cogeneration technologies (engines, gas turbines, conventional steam, fluidized bed, and so forth) powered by a variety of fuels (#2 oil, #6 oil, gas, coal, etc.). Finally, the short construction period of most QFs, compared to most major utility plants, greatly reduces the period of uncertainty: in most cases, QFs will either be built or abandoned, rather than sitting in the limbo which has afflicted most New England utility plants over the last decade.

Overall, the risks to ratepayers relating to construction feasibility and timing appear to be much less for QF power than for utility-supplied power, even without any special provisions for protection of the ratepayers.

Q: Can other provisions be added to further increase the degree of protection from the construction risks of QFs?

A: Yes. Two measures have been suggested which would serve this function. The first is the limitation of guaranteed rates (whether levelized or escalating) to a fixed period into the future. If fixed rates are available only for the period

1990-2005, a QF which takes longer to come on line will receive these rates for fewer years. Thus, the QF developer will have even stronger incentives to bring the plant in on or near schedule.

Second, it has been proposed that QFs be required to put up a good-faith payment (say, $10/kW) as security that the plant will be built as scheduled. I would modify the original proposal somewhat, to retain incentives for speedy completion even in cases in which the QF misses its target in-service date, and to encourage prompt cancellation of projects which are no longer viable:

1. the QF must pay $10/kW of planned nameplate capacity, within 30 days of contract award, to finalize the contract,

2. interest is accrued on the deposit at a market rate (e.g., prime rate),

3. if the QF is cancelled, or loses its site, or a critical license, before the original in-service date, the initial deposit is returned, but the accrued interest is forfeited,

4. if the QF fails to meet its in-service date target, it loses all accrued interest, and no further interest accumulates until the unit enters service, and

5. if the QF is cancelled, or loses its site, or a critical license, after the original in-service date, the initial deposit is forfeited and the contract is cancelled.

The interest foregone due to incorrectly projecting an in-service date is considerable, and will increase the incentives for realism in QF projections. Developers will have every incentive to promptly drop plans which are no longer viable.

Q: Are the penalties for late operation in the EOER rules appropriate?

A: No. EOER originally proposed a limit of four years from contract signing to operation, which may be too short for some QFs, and may require other QFs to come on line before they are really economical. EOER also proposed that the QF lose all "capacity" credits if it missed its projected operation date, which is clearly too harsh (especially since those credits are based on the cost of utility capacity, which has considerable construction risk), and which would be highly inefficient, since some completed QFs which would contribute to reliability would receive neither a reward nor an incentive to do so.

In evaluating the EOER proposal, it is useful to look back at

Table 1, and the experience of utility power plants. Surely, no one would argue that Canal #2 has no reliability value because it took 5 years to build and missed its targeted COD by seven months. The example of the MEPCo purchases is even more analogous to the QF situation: the purchases started late,[6] and missed the four year deadline, but the utilities involved quite properly paid New Brunswick for the capacity costs specified in the contract, and they received credit from NEPOOL for that capability.

If, despite the inefficiency and inequity involved, the Department is determined to punish QFs which miss their projected in-service date, the reliability credit might be constrained in some way, as by allowing the lesser of the contracted reliability credit and the short-term reliability credit. This minimum reliability credit might be applied both to QFs which come on line before their projected date, for the period from actual operation to projected operation, and to QFs which come on line later than projected, for a period after the in-service date equal to the error in the projection.

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6. I assume this reflects a delay in the startup of the Coleson Cove plant or of construction of the transmission line to New Brunswick.

2.3 - Uncertainty in QF Availability

Q: What is the nature of the risks to ratepayers from QF availability uncertainty?

A: The basic problem is that the unit, averaged over its life, may not produce (or be able to produce) as many kWh's (total or in peak-exposure periods) as previously projected. It may produce more power than expected, possibly resulting in an excess supply situation and higher costs to ratepayers. It may produce less than expected, resulting in reliability and energy-supply problems similar to those caused by construction delay, but less severe (since the plant's output is reduced, rather than eliminated).

The problem may be expressed mathematically as: there is uncertainty in the relationship of the actual probability distribution of the QF's equivalent availability factor (EAF) to the projected distribution. I use EAF, rather than capacity factor, to include QF power which is withheld due to lack of system demand, or the presence of less expensive power sources. The references to probability distributions are necessary, since the issue considered in this section is not the performance of the plant in any one day or year, but its long-term availability.[7]

Q: Do utility plants suffer from similar availability uncertainty?

A: Yes, in two regards. First, whole utility technologies may perform differently than expected. This has certainly been the experience for nuclear plants, which were projected around 1970 to operate at 80% capacity factors, and were still expected to operate above 70% in the late 1970's, are actually performing at closer to 60%.[8]

Second, the availability of individual plants clearly differs from their class norms. For example, Easterling (1979) estimated plant-related variability in capacity factor performance equivalent to ~~a~~ standard deviation of 4.3 percentage points for BWR's, 8.0 points for large PWR's, 3.6 points for small PWR's, and 7.4 points for coal plants (some of which probably results from differences in load following between plants).[9] Thus, if the average large PWR plant has a

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7. Throughout this subsection, I will refer to the system reliability effects of misestimation in QF energy production. Similar considerations generally apply for the energy cost effects.

8. Amazingly, some utilities are still projecting capacity factors above 70%, despite considerable experience to the contrary.

9. Some of Easterling's variability can be explained by factors, such as unit size, which we now know to be significant, but which

60% average long-run capacity factor, one such plant in 20 would be expected to have an average capacity factor less than 47%, and another would be expected to have an average above 73%. Variability of units within plants would make the reliability of any particular capacity addition even more uncertain.

Q: How is the uncertainty in unit reliability dealt with in the regulation of utility-owned power plants?

A: The Department has set performance standards for utilities under its jurisdiction which would allow investigations of utility performance if various reliability measures fell below historical measures of performance for comparable groups in the industry.[10] However, as indicated above, both unit and industry performance can vary from planning projections, so the performance targets may be very different than original expectations.[11] Furthermore, it appears that the utilities will not be subjected to any penalties for poor performance, unless that performance is traced to some

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were not thought to be important predictors of reliability when the plants were planned.

10. Unfortunately, the cost recovery for generation providing most of the power sold in Massachusetts is not under the jurisdiction of the Department.

11. The Department has chosen not to use prior expectations (or contemporaneous utility performance projections) as one basis for setting targets. Thus, utilities are not held to their reliability projections, even for the very weak targeting incentives in the power plant performance program.

specific imprudent utility action. No penalty has ever been proposed (so far as I know) for utility plants which are more reliable than expected. As a result, the regulation of utility plant availability does not attempt to ensure, or even encourage, the achievement of reliability projections. All planning risks due to deviations between projections and actuality are borne by the ratepayers.

In addition, the cost recovery for utility plants is generally independent of their reliability performance. It is very rare for a utility plant to perform so poorly that its costs are removed from rate base.[12]

Q: How is the uncertainty in unit reliability dealt with in the power supply contracts between utilities?

A: In general, unit contracts require the buyer to pay the costs of the unit, regardless of whether the unit turns out to be a gem or a lemon. I am not aware of any unit power contracts which provide for penalties against the seller for failure to provide the expected power output, although there may be a provision requiring good management practice (not good results) in general.

Q: How does the treatment of reliability uncertainty in these

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12. Three Mile Island is an outstanding exception to the general rule.

various utility settings compare to the risk and rate treatment inherent in the QF/utility relationship?

A: QFs impose less reliability uncertainty on utilities and their ratepayers than do utility-owned plants for three reasons. First, as I noted previously, QFs are paid only for the power they produce, so the bulk of the risk of poor performance is left to the QF. As a result, the QF operator also has a stronger incentive than the utility to maximize the reliability of its plant.

Second, most QFs (all small power producers and essentially all cogenerators likely to be developed in Massachusetts) are so small compared to the NEPOOL system that their contribution to reliability is essentially proportional to their power output, regardless of their availability. QFs may be paid fairly and appropriately for their reliability contribution on a ¢/kWh basis, without regard for whether they produce at a 30% capacity factor or a 90% capacity factor.[13] Table 2 presents my calculation of the Effective Load Carrying Capability (ELCC) for a variety of unit sizes, at a variety of forced outage rates, on the NEPOOL system. The formula is from Garver (1966), and the 425 MW value of

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13. To correct for any correlation between system load and QF output, and to encourage more output in the period when it is most likely to be useful, the ¢/kWh payment may be restricted to hours of peak exposure.

the system characteristic **m** (a measure of the present sensitivity of system reliability to changes in load or supply) is my estimate based on the analyses in NEPOOL (1985).[14] As one would expect, the ELCC of any unit declines as its forced outage rate increases, but the kWh output also decreases. For units less than 50 MW, the differences between the ELCC/kWh at high reliability and at low reliability are trivial. Even for a 100 MW unit, the ELCC/kWh at a 70% FOR is over 93% of its ELCC/kWh at a 10% FOR. For utility-size units, ELCC/kWh is lower than for the smaller units, at the same FOR, and it is much more sensitive to FOR. These relationships are illustrated in Figures 1 and 2. Hence, the payment of reliability credits in ¢/kWh captures essentially all of the system reliability effects of unit reliability uncertainty and risk for QFs below 50 MW, and most of the effects for units up to 100 MW. The Department's speculation that "quality of production . . . [may] vary significantly between supply options" (IO 71) appears to be factually important only for very large QFs, and no "uniform set of performance standards" (IO 71) is necessary. Even a simple sliding scale of capability rates

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14. The estimate of **m** is consistent with those in Garver (1966) and Kahn (1978), considering the differences in system size. Also, the ELCC for 1150 MW units at 20% FOR is consistent with NEPOOL estimates of Seabrook ELCC (see my testimony in DPU 1627). Also, my conclusions for units less than 100 MW are quite insensitive to the choice of **m**, within a range of at least 300 to 700 MW, which is broader than the uncertainty in **m** for NEPOOL.

as a function of availability is necessary for only very large QFs.

Third, QF reliability uncertainty is moderated by the same technical factors which ameliorate QF construction risk: the small size of individual units, diversity in technology, and diversity in fuel supply.

Overall, the exposure of ratepayers to overall plant reliability uncertainty appear to be much less for QF power than for utility-supplied power, even without any special provisions for protection of the ratepayers.

Q: Can other provisions be added to further increase the degree of protection from the reliability uncertainty of QFs?

A: No additional protections are necessary to assure that QFs are providing the level of reliability for which they are being paid, since they intrinsically provide more reliability than the utility plants on which their cost reimbursement is based. However, if the Department wishes to further increase the protection for ratepayers, and is not concerned that it may discourage economical QFs (and violate PURPA) by paying only utility prices for service that is much better than that provided by utilities, even more protection can be added.

The appropriate form for a reliability target mechanism would have to include the following features:

1. Performance must be measured on a cumulative basis. As discussed in the next subsection, energy production in any month or in any year is not a useful measure of the QF's reliability, since the availability of all plants varies over short periods. This variation is taken into account in calculating ELCC, required reserves, and other measures of reliability contribution. The target should only relate to long-run reliability.

2. As a corollary to (1), the cumulative performance must be compared to the target at regular intervals, and reconciliations must be made for prior penalties which are no longer appropriate in the light of long-run performance.

3. The incentive mechanism to encourage QFs to project their production accurately should not interfere with their incentives to actually produce power. Thus, the penalty for missing the projection should not eliminate or drastically reduce the reliability credit (per kWh), which would have decidedly perverse effects. Unfortunately, all such incentive provisions will necessarily interfere with pricing efficiency, since the value to the QF of increased production will vary from the expected value of the power.

4. The incentive mechanism also should not encourage QFs to either over-estimate or under-estimate their production, or it will be self-defeating. Therefore, the penalties (if any) for missing the long-run reliability target should be approximately symmetrical for over-estimation and under-estimation.

Q: Does the EOER proposal using for targets in its "capacity" credit calculation meet these criteria?

A: No. Ms. Geller and I explained the deficiencies in the EOER approach in the previous hearings in this docket, and Ms. Geller expands on that discussion in her current testimony.

2.4 - Variability in QF Availability

Q: How is the variability in QF availability different than the uncertainty in QF availability which you have already discussed?

A: In addition to the uncertainty in the overall long-run performance of any generating unit, there is a risk of variation in the annual, monthly, daily, and instanteous availability and output from the unit. In statistical terminology, "uncertainty" describes the lack of knowledge of the underlying probability distribution (say, for annual EAF), while "risk" describes the tendency of the actual outcome (e.g., one year's EAF) to wander around within the distribution. Even where the distribution is known (and there is thus no uncertainty), there can be "risk" in the statistical sense of not knowing the specific value for each year in advance.

Q: Is availability risk present for utility generating plants?

A: Yes. That risk accounts for the fact that reserve margins must be greater than the average forced outage rate of the utility plants: sometimes many more plants will be unavailable than average, and other times virtually all plants will be operable. There is considerable year-to-year variation in utility unit availability, as can be seen from examining the historical data in any Power Plant Performance Standard proceeding.

Easterling (1981) found standard deviations of annual power plant capacity factor of 10.6 percentage points for BWR's, 10.2 points for large PWR's, 9.8 points for small PWR's, and 10.6 points for coal plants. Some of this variability may reflect differences in performance between different units at the same plant, but all differences between plants (and the effects of plant maturation) are accounted for separately. Considerable variation in annual reliability is clearly experienced in all these plant types. About 60% of the data lies more than 5% of plant capacity from the plant mean output, and 30% of the data lies more than 10% of capacity from the plant mean.

Table 3 lists all of the gas turbine units of Massachusetts utilities, and the availability factor of each unit for each year for which I could obtain the data. The average availability factor and the standard deviation of availability is reported for each unit. The average unit had a standard deviation in its availability of 16.4%. If the distribution is normal, about 76% of the data lies more than 5 points from the unit mean availability, and 54% of the data lies more than 10 points of capacity from the unit mean.[15]

Both Easterling's data and the turbine data are for annual values. Monthly, daily, and instantaneous availability measures will be even more variable.

Q: How does ratemaking account for variability in utility plant availability?

A: In general, variation in availability is expected, especially in the short run of months and weeks. Even variation in annual availability is only cause for (at most) triggering of an investigation. Poor performance in any particular year generally does not result in any penalty, unless it is perceived to be due to mismanagement, and hence not the type of performance which is likely to average out in normal operation. That is, regulation accepts normal variation around the mean, and imposes penalties only for variation which is abnormal and will increase long-run total costs.

Q: How do contracts between utilities for unit power treat variation in availability?

A: For the most part, the buyer is obligated to pay its share of

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15. I have performed this analysis for gas turbines because the reliability credit for QFs is likely to be modelled on gas turbine cost and performance. Similar results would obtain for capacity factors at New England utility hydro plants, nuclear units, or coal plants, or for oil-fired stem turbine EAF's.

unit costs, regardless of whether the unit is available or generates any energy in any period.

Q: How does the intrinsic nature of QFs and their ratemaking treatment affect the risks and incentives relating to variation in availability?

A: There are four such effects, three of which I discussed previously. First, QFs are only paid for the kWh's they produce, so they are automatically penalized (and ratepayers are automatically compensated) for poor performance, and they are automatically rewarded (and the ratepayers pay more) for good performance. This arrangement gives QFs better incentives to maintain and operate their units than utilities have, while ensuring that ratepayers are charged only for the services they receive. Second, the reliability value of most QFs is proportional to their energy production, so if QFs are paid for reliability by the kWh, they will be paid in any period only for the reliability value they actually delivered, measured after the fact.[16] Third, the small size and diversity of QF technologies and fuels reduces the probability that a single event (a nuclear regulation change, a coal strike, an oil embargo, drought, transportation problems) will result in major reliability or energy supply

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16. We must recall again that reliability can only be measured probabilistically. Whether a particular unit happened to be available at the time it was needed is not a fair measure of its reliability value.

problems. Some groups of QFs will tend to correlate with one another in terms of operating problems (e.g., small hydro will be precipitation sensitive), but these will not usually be highly correlated with problems on the rest of the NEPOOL system. This point is recognized by the Department at IO 74.

Fourth, cogeneration output will actually tend to vary annually in ways which are beneficial to system reliability. Systems which supply space heating loads will tend to have the highest capacity factors in the coldest winters, when power is apt to be most needed. Systems which supply heat for commercial and industrial space and process heating will tend to produce the most power when the economy is most active, and hence when their power is most needed.

Q: Is there any room for improving the QF incentives and ratepayer protections with regard to availability variation?

A: No. QFs are already so much more beneficial than utility capacity in this dimension, that no further restrictions on QFs are justified. If QFs are to be required to provide much more stable output than utility plants, they should be paid much more than the cost of utility capacity for the high-grade reliability demanded. I see no justification (and little benefit) for demanding such extraordinary performance from QFs, and I am not sure how the Department could assign a price to such super-reliable capacity.[17]

Q: Is EOER's proposal discussed at IO 66-67, which would penalize QFs for availability which deviates from a pre-set monthly target, appropriate?

A: Absolutely not. (I understand that EOER has substantially abandoned the particular form of the original proposal, which I criticize here, due to the cited shortcomings.) Utility plants would rarely pass EOER's proposed test, which penalizes the QF for any deviation from its target, increases the penalties drastically at a deviation equivalent to 5% of the rated capacity, denies all capacity credits for QFs producing 10% of capacity less than target, and denies any additional credits for production more than 10% above the target. These tests are all to be applied on a monthly basis. Even on an annual basis, 27% of the utility gas turbines in Table 3 would receive no credit, another 27% would receive no credit for some of their reliability contribution (since they would be over the 10% cut-off), and another 20% would be subject to the enhanced penalties in the

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17. At IO 65, the Department states "Standards for operating performance are desirable to assist the utility in planning for the short-run dispatching of electricity once a QF is in operation." This is not correct. Dispatching (performed by NEPOOL, not the individual utility) does not follow contracts or expectations. Dispatchers turn plants on and off based on the actual availability of units, and based on detailed anticipation of load and maintenance conditions. The standards described by the Department would not assist the dispatchers.

5-10% deviation range. This is one example of a super-reliability rule, for which the cost of utility capacity is not an appropriate price. The rule as proposed would prevent QFs, even those which are more reliable than the avoided utility plants, from receiving full reliability credits. Either the rule has to be relaxed, or the price must be increased.

Worse still, the EOER proposal makes no sense in terms of incentives. The EOER penalty structure would be devastating for a QF which was available 100% in one month, and unavailable the next, even though that QF was contributing as much to reliability as one which was available 50% of the time in each month. There is simply no reason to encourage QFs to act in the ways which would be encouraged by the EOER rule.

Other problems with the EOER approach are discussed in the previous subsection, my previous testimony in this docket, and Ms. Geller's previous and present testimony.

Q: Do the utilities' comments shed any light on the issue of QF availability variation?

A: Most do not. Among the comments cited by the Department at IO 67-68, BECO proposes charging QFs twice for not operating (once by not paying for the power which is not received, and once by charging the QF for replacing the Qf for power which was neither received nor paid for). MECo suggests penalizing QFs for producing less than they projected before the project was started, while allowing no credit at all for any production above the target: this would compound the bias in the EOER proposal, insure that all QFs (and all utility plants, if they were treated similarly) would earn less than full credits on average, and completely ignores the facts that NEPCo uses, relies on, charges customers for, and receives NEPOOL credit for plants which operate at higher ratings and/or reliability than was previously projected.

2.5 - QF Longevity

Q: What is the nature of QF longevity risk?

A: The basic problem is that a QF may enter service, operate for a period of time, and then cease to operate, leaving the utility with a more-or-less unexpected energy and reliability problem. As the Department notes, "There are no guarantees that a QF receiving a higher payment [compared to projected annual avoided costs] initially will operate long enough to balance that higher initial payment with the lower payment in the latter portion of the contract." (IO 50). The QF may cease operation due to a technical problem (e.g., a dam bursts), an economic problem (revenues no longer cover expenses), an environmental problem (e.g., air pollution rules change), or a loss of market for a related product (i.e., a cogenerator's heat user goes out of business).[18] A secondary issue is that, if the QF is paid on a levelized basis, it will receive more than the expected value of its energy production in the early years of its life, and if it

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18. NU (Schedule A) suggests that a similar problem may arise for trash burners, in that they can lose their market for waste disposal, and thence their tipping fees. This seems to be a totally spurious suggestion. It is difficult to see how the tight waste-disposal situation in Massachusetts would suddenly disappear (unless NU believes that people are about to stop generating refuse), how a new facility would be able to beat the prices from an existing facility, or how the communities with contracts to use the trash plant for waste disposal could void their contracts.

is retired before the end of the levelization period, the ratepayers will not receive the benefit of the levelized power in all the years in which it is less expensive than expected avoided costs.

Q: To what extent is longevity risk a problem in utility power plant construction?

A: Longevity risk exists for utility plant, both in the technical sense that plants are sometimes retired before they were expected to be, and in the economic sense that consumers are thus denied the most economical years of the unit's life. It should not be surprising that "there are no guarantees" for QF longevity, since there are no corresponding guarantees for utility plants.

On the technical side, my data is most complete for nuclear units. Of the five nuclear units which entered commercial service prior to 1968, three have been prematurely retired: Indian Point at 12 years of age, Humboldt at 13 years, and Dresden 1 at 18 years. These units, like other nuclear plants, were originally expected to last 30-40 years. The other commercial nuclear unit which has been retired, Three Mile Island 2, provided only 3 months of commercial service. My data on fossil plant longevity problems is quite limited, but there are some examples of early retirements close at hand. For example, when the Edgar steam plant was retired in

1978, the oldest unit was 29 years old, and the youngest only 24. Several gas turbine units have been retired in recent years, at ages of eight to thirteen years, as opposed to the 25-33 years utilities assume these plants will last for planning purposes. On the other hand, it is often the case for utilities (and will probably also be the case for many QFs) that it is more economical to replace individual components (even steam turbines, generators, or boilers) which fail than to retire the plant and build a new one: this situation results in extremely long lives for some units. Table 4 lists some recent retirements on the NEPOOL system, and the ages of the units involved.

On the economic side, utility plant cost recovery is even more front-loaded than is levelized QF cost recovery. Figure 3 compares NU's annual ¢/kWh projection for Millstone 3 to a levelized rate, and a constant-escalation rate, all with the same present value. Figure 4 displays the cumulative present-value differences (at a 16% discount rate) between the three rates. Table 5 presents the data from Figures 3 and 4 in tabular form. Ratepayers pay more for the utility plant than the levelized QF for each of the first four years, and have paid more for the utility plant overall (in present value) throughout the first 12 years. Indeed, if the alternative to the QF is a new utility plant (particularly a capital-intensive one), rather than burning more fuel in existing plants, the levelized QF rate may be thought of as back-loaded, rather than front-loaded.

Q: How is longevity risk dealt with in ratemaking?

A: First, ratemaking creates the peculiar time pattern of cost recovery for utility plants, resulting in extensive front-loading of capital costs. Second, utilities have usually been allowed to amortize most of the remaining (undepreciated) investment in prematurely retired plant, although some or all of that recovery would presumably be denied if the regulators determined that the retirement was imprudent, or due to imprudent operation or planning.

Q: How is longevity risk dealt with in utility contracts for the purchase of power from other utilities' plants?

A: Utility unit sales contracts are based on ratemaking concepts, and result in the same extensive front-loading of costs. In general, the seller has no responsibility to the buyer (beyond "good practice") to keep the plant in operation, and has no obligation to refund any of the front-loaded costs if the unit is retired before the end of its scheduled life.

Q: In general, how are longevity risks dealt with in business relationships?

A: I am certainly not familiar with all such contractual relationships, but those which which I am familiar do not usually provide any particular protection for the buyer in the event that the seller is no longer able to deliver the product. Consider the example of a tenant with a five-year, essentially levelized lease, in a building which burns down after five years. The tenant would usually have no right to compensation for the fact that the rent paid in those three years was higher than short-term market rates, or even that it was higher than it would have been under a three-year lease. The tenant takes the risk that the landlord will be <u>unable</u> to fulfill the contract: the lease primarily provides protection if the landlord is <u>unwilling</u> to fulfill the contract, and would rather increase the rent or lease the space to another tenant. A similar distinction, between technical problems and intentional evasion of the contract, may also be useful in structuring protection of ratepayers from QF risks.

Q: What intrinsic protections do the ratepayers have from QF longevity risk?

A: There are at least four types of protection. First, since QFs are paid only for the power they produce, they have a greater incentive to keep their plants on line than do utilities, and if the plant is retired, at least the ratepayers no longer support its costs. Second, the diversity of QFs, which I have previously discussed in other contexts, reduces the chance of a wave of related early retirements, such as may be experienced in cohorts of nuclear plants. Third, for many QFs, such as hydro, trash and wind facilities, the major costs are sunk, and fuel and other variable costs are small (or in the case of trash plants, even negative): these plants are unlikely to be forced out of operation by high operating costs. QFs with significant fuel costs (especially cogenerators) will generally be covered some sort of composite rate (under the EOER proposal or several suggested modifications), which reduces the likelihood that their operating costs will shut them down prematurely. Fourth, while some cogenerators may shut down for lack of heat demand, this will generally be correlated with a reduction in load from the facility which used the heat. Indeed, unless there is a wide-spread recession, facilities with less expensive heat sources, such as those associated with cogenerators, will tend to be occupied first, so a permanent shutdown of a cogenerator would usually be associated with very weak electricity demand.

Q: Can additional mechanisms be implemented to further protect ratepayers from the longevity risks of QFs, without unduly hampering QF development?

A: Probably. EOER's proposal for an insurance pool, or some other form of "security" for the difference between the levelized rate and the expected annual avoided cost is appealing, if the cost in lost QF development or in higher required QF rates is not significant.[19] So long as the requirements place minimal burdens on QFs, the additional protection for ratepayers is desirable, Even measures with little intrinsic values (such a a requirement that QFs paint their meters blue) are acceptable, so long as they do not discourage development.

If the costs of substantial additional protection seems high, I believe that the ratepayers are not greatly disadvantaged by accepting the normal technical and economic risks of premature QF failure, since similar risks are associated with most utility-constructed plants, at higher ratepayer cost. Additional protections should really be concentrated on the factors from which the ratepayers have some protection for utility-owned plants: bad faith and malfeasance. A second lien on the facility, and the right of first refusal for purchase of the facility, either from the QF or from the major lender in the case of foreclosure, may be helpful in preventing QF operators from shutting the plant down if the levelized rate no longer covers operating costs, or if a QF owner attempts to use bankruptcy to evade the original contract and sell to a higher bidder.

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19. I would like to see a similar requirement for Seabrook and Millstone 3, as well.

3 - DEFINING AVOIDED COSTS

Q: What issues will you be addressing in this sections?

A: I will consider four topics. First, I will discuss the overall ratesetting process, on which the Department has requested comments, such as whether the rates should be set by reference to a utility cost, or through an auction. Second, I will address some basic issues in ratesetting, including how the energy rates should be determined, and whether the avoided peaker cost should escalate over time. Third, I will consider the problem of pricing and efficiency in an integrated utility system (NEPOOL), which consists of legally and financially separate utilities. Fourth, I repeat and summarize some points from my previous testimony on the importance of voltage levels in QF rate setting.

3.1 - The Ratesetting Process

Q: The Department discusses at some length the basic choice between a set-price approach to QF ratesetting, in which the Department determines a rate, based largely on data from the utility, and an auction approach, in which competition between QFs, and possibly the utility, sets the avoided cost rate (IO 46). Several of the questions on IO 47 and 48 address this choice. Must the Department choose between price setting and the auction?

A: Not at all. These two approaches are applicable to different situations, and the Department can structure a ratesetting process which utilizes the best features of each approach, where that approach is relevant.

Q: What determines whether a set price or an auction is an appropriate method for setting rates?

A: A set price is appropriate where the market-clearing price is independent of market response: that is, where the marginal-cost-based price offered for the first taker (a QF in this case) is also the price which will be offered for the last taker.[20] An auction is useful where the available quantity

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20. The Department indicates a concern that fixed rates lack appropriate incentives for QFs to determine their own cost of production (IO 46). I do not see how the QF can agree to a price less than its cost in any case, and the fact that it may receive

of the good in question (a contract with the utility) will be inadequate if it is offered at the marginal cost appropriate to the first taker.

An example might be helpful at this point. Suppose that Massachusetts utilities require 20,000 GWH of additional annual energy supply by the end of the century. Suppose further that in the absence of QF additions, all of this additional energy would be most economically provided by coal plants at 10¢/kWh, levelized.[21] Figure 5 provides a demand curve and utility supply curve which are consistent with this hypthetical.

If only 15,000 GWH are available from QFs, each QF has backed out a piece of a coal plant, and the appropriate avoided cost for each QF is 10¢/kWh. This situation is depicted in Figure 5 as Case 1. The QF supply will shift the utility load curve to the right by 15,000 GWH, so the demand curve will cross the utility supply curve at 15,000 fewer GWH, requiring less coal plant construction. Otherwise, however, the cost situation has not changed, since 10¢ coal power has been

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more than its cost is irrelevant (from an efficiency standpoint) as long as it is paid avoided cost.

21. This would be in addition any plans to back out existing oil generation, or to avoid Hydro Quebec Phase II. For simplicity, I have assumed that the energy supplied will meet the reliability constraints, as well.

replaced by 10¢ QF power.[22]

If the amount of power available from QFs is much larger, say 40,000 GWH, it would be inefficient and unnecessarily expensive to offer all of them 10¢/kWh. If the utility need only deliver 65,000 GWH or less (that is, if the QF contribution is over 20,000 GWH), the avoided cost for further QF contributions falls to 7¢/kWh. Depending on the amount of power offered, and the ability of the QFs to produce power for less than the 10¢ price, the efficient response may be to back out 20,000 GWH for some price between 7¢ and 10¢ (at Case 2 in Figure 5), or to buy more than 20,000 GWH at 7¢ (Case 3). Determining which of those points is appropriate (as well as the price and which QFs should supply the 20,000 GWH for Case 2, and the quantity for Case 3) requires an auction.

Q: How could an integrated approach to QF ratesetting be structured, so as to include both the set-price and auction options?

A: The process might have five parts:

1. Set an initial offering price and decrement, based on

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22. Of course, the utility and its customers are also gaining the diversity, insurance, and risk-shifting benefits of the QF power, so they are better off with 10¢ QF power than with 10¢ utility-owned power.

the cost of utility-supplied power. The next subsection will consider the data sources for the price projection.

2. Allow potential QFs an adequate period to respond to the price offer. Based on the experience in Maine, 90 to 120 days appears to be adequate for a significant response.

3. If the total power offered is less than the size of the decrement, accept all of the offers.

   - At this point, the QFs might be expected to but up their good-faith deposits, and to provide information necessary for the interconnection process. Thirty days should be adequate for those events.

   - If the parties can not agree on the cost of the interconnection within another 30 days, the parties may take the issue to the DPU for arbitration.

   - If the cost of the interconnection makes the QF uneconomic, the QF may reclaim its good-faith payment and withdraw its offer.

4. If the total power offered exceeds the size of the decrement, proceed to an auction.

- Inform all of the original applicants (and any additional parties who missed the first deadline) that they have another 30 days to submit a bid.

- Set a \$/kW-year price to be paid for reliability,[23] and request bids as cents/kWh for energy, averaged over the 8760 hours in a year.

- After the thirty days have run, open the bids, calculate the supply curve for QF power, and award contracts to successful bidders.

- Proceed as in (3).

5. Announce the new avoided cost, net of the power supplied by the QFs which signed contracts, put up their deposits, and completed the process of setting interconnection charges. Start a new response period, as in (1).

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23. As the Department notes (IO 43), it is difficult to compare multi-dimensional bids, which vary in more than one respect. Therefore, it is important to pin down one of the two major variables in the price to be paid: the energy price and the reliability price. In general, the cost of utility-supplied reliability appears to be easier to determine than that of utility-supplied energy. As discussed in Section 2.3, capability value per kWh does not vary significantly for most QFs as a function of availability, so reliability standards (IO 43) are not necessary. See the next subsection for how the reliability credit would be transformed to a cents/kWh price. It may also be necessary to constrain some other variables, such as the differential between ten-year and twenty-year contracts.

Q: Should this process be tied to the utility's perceived need for capacity, or to its desire to build a new generating facility, as MECo has suggested (IO 47, question 10; IO 40, 42)?

A: No. QF power is valuable regardless of whether it is backing out new construction or existing oil. The avoided cost will vary with the energy source being backed out, but QFs should still be allowed to compete with the utility to provide lower-cost and/or higher-quality power. There is nothing inherently wrong with "excess capacity", so long as it is all economical: the Department's concerns in this regard (IO 19-21) are unnecessary. Of course, the utility should not buy more at any particular price than is justified <u>at that price</u>, and it is conceivable (though unlikely) that California's transmission constraints will be repeated somewhere in Massachusetts.[24] The Department states the issue properly at IO 32.

Q: You mentioned previously that multi-dimensional prices are difficult to compare. Would this restrict all QFs to bidding for levelized rates?

A: Not necessarily. The potential bidders could be given some simple rules for bid construction, such as

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24. Overall, I would expect that the Department would prefer to deal with California's (or Maine's) embarassment of riches, rather than the rolling blackouts NEPOOL has been promising us.

- the cumulative value paid (in present value cents/kWh) at any point in time must not exceed the levelized value over the life of the contract,

- oil- and gas-fired must receive at least a minimum share (which I would base on cost considerations, but which could be fixed at 50%, as the EOER proposed) of their payment in a floating rate, rather than a fixed rate,

- utility short-run avoided costs are projected to rise at X% annually (or according to an attached table),

- oil prices are projected to rise at Y% annually (or according to another attached table), and

be told what discount rate will be used in comparing bids.[25] The QFs could then select the mix of fixed, levelized, escalating, and floating rates (based on short-run avoided costs or on oil prices) which best suited their needs, and allowed them to offer the lowest levelized prices. The actual comparison of bids would simply examine the levelized value of the offers.

Q: What is the role of negotiation in this process?

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25. I would recommend that a ratepayer discount rate on the order of 10% real (or about 15% at present inflation projections) be applied in evaluating the bids, and for other pricing purposes. This figure can be selected in the implementation hearings, and need not be specified in the present rules.

A: If there is considerable competition among QFs,[26] those which can accept lower prices or offer higher quality of service will have significant incentives to attempt to negotiate separate deals with the utility, and thus avoid the uncertainties of the bidding process, or the gradually falling decremental prices. This has been the result in other states, including Maine, which have stimulated the QF market with Standard Offers and long-term fixed rates.

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26. If there is little competition, QF pricing is relatively unimportant, since they would then never be major influences on most utilities' costs.

3.2 - Determining Prices

Q: Are there always both energy and reliability benefits from QFs?

A: Yes. In the short term, the energy benefit consists primarily of backing out expensive fuels. In the long term, the energy benefit may continue to be reduced fuel consumption, if all the plants the utilities are consisdering adding are less expensive than the marginal fuel <u>after</u> the plants' addition, or it may be the cost of the proposed plants, net of their reliability value. It currently appears that the "long term" for energy may begin around 1989, when several utilities are proposing to participate in a gas-burning combined cycle plant (which has been described as a base-load plant, although these facilities are generally operated in intermediate or peaking modes) in Rhode Island. Other proposed capacity additions against which QFs may compete include the Hydro Quebec Phase 2 interconnection,[27] and the small coal plants various utilities have proposed for the mid-1990's.

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27. The fact that the interconnection was over-subscribed suggests that utilities will be able to sell their entitlements at full cost, so the HQ investment remains avoidable even after it is built.

In the short term, the reliability benefit is composed of a mix of improved service and reduced costs, as I discussed in my original testimony (pages 65 - 70).[28] The most recent estimate of the value of these costs is from MMWEC, which estimates that the market price of peaking capacity will be about $20/kW into the early 1990's, at which point MMWEC expects new capacity to be required. Appendix A is an excerpt from recent MMWEC projections of the costs of incremental capacity entitlements from new and existing plants. In the longer term, the reliability benefit can be directly tied to the cost of the avoided peaker.

Q: EOER has suggested escalating the cost of the avoided peaker over time, essentially assuming that the avoided peaker in each year is a new one. The utilities have asserted that the cost should not escalate. How should the peaker cost be treated?

A: That question may most easily be answered by considering just what is avoided by the presence of the QF on the system for one year. A QF which supplies the reliability equivalent of one kW of utility peaker (which may be more or less than one installed kW of QF capacity) for the year 1990, for example, results in the delay of a kW of peaker capacity addition from

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28. For this reason, the power-purchase contract discussed by the Department at IO 58 need not be longer than short-term utility capacity contracts (perhaps six months) to justify a short-run capability credit.

1990 to 1991. The savings are thus the present-value effect of shifting each year's cost back by one year, and thus discounting them at an appropriate consumer discount rate, while increasing each year's cost by the rate of inflation. The savings due to the 1990 QF reliability contribution are thus the 1990 capital cost of the equivalent utility peaker, times the difference between the discount rate and the inflation rate. I have repeatedly estimated the this real (inflation-adjusted) discount rate to be at least 10%, and I have yet to see any substantive evidence to the contrary. The appropriate discount rate would certainly be somewhat higher than 10% for such high-risk investments as nuclear power plants, but 10% might be about right for safer investments in peakers.

With the annual savings corrected to recognize that QF capability in each year defers, rather than eliminates, the need for peaker construction, it is then appropriate to follow EOER's suggestion and escalate the reliability credit with inflation. The QF gets credit in 1990 for moving 1990 peakers back to 1991, credit in 1991 for moving 1991 peakers back to 1992, and so on. If the QF lasts for a short portion of the peaker's expected life, it receives a smaller credit than it would under the utilities' approximation to the correct treatment.[29] If the QF lasts longer than the peaker would have, it has replaced more than one full peaker, and deserves credit for doing so. The escalating real cost approach achieves these ends. Table 6 illustrates the calculation of the real, escalating capacity-related credit, and Figure 6 compares the EOER nominal-escalating proposal, the utility nominal-constant proposal, and my real-escalating proposal for capital-related credits.

On a related topic, it is important to remember that the price paid for QF contributions to system reliability should reflect the cost of firm load-carrying capability from utility-owned peakers. Therefore, the annual cost of the utility plant (depreciation, return, income taxes, property taxes, O&M) must be stated per kW ELCC, not in $/kW installed capacity.[30] The ELCC of the peaker is likely to be about equal to its claimed capacity (summer capacities appear to be controlling) times its availability factor.

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29. Recall that the utility solution assumes that the need for the utility capacity is eliminated, rather than simply delayed, and therefore gives the QF credit for the full carrying cost of the peaker in the first year, and does not escalate the credit. Within the implicit utility assumptions, this treatment is consistent: if we assume that the peaker has been cancelled, not just pushed back a year, then the QF deserves credit for eliminating the 1990 peaker, not just in 1990, but throughout its life. Of course, if the peaker has not been eliminated, but only delayed a few years, the utility method pays too much.

30. Again, we see the danger of conceptualizing the reliability credit as a "capacity" credit.

Q: How would you suggest setting peak/off-peak energy price differentials, and distributing the reliability credit over various time periods within the year?

A: I would not suggest attempting to project these parameters for the length of the QF contract. Instead, I recommend that the contracts specify the average energy price to be paid,[31] and the total reliability credit in $/kW-year. The utility, with the approval of the Department, should retain the right to distribute the rate incentives within the year in a manner which reflects changes in utility cost patterns over time. For QFs with appropriate metering and communication equipment (and the ability to shift output, as for trash burners, wood-fired plants, and some cogenerators and hydro units), the rates may even be set in real time, with the utility informing QFs when energy costs are high or when reliability is low. In this way, the QF has an assured income stream (assuming that it can achieve its expected power production), but the utility can still provide appropriate incentives for production at the time of highest value.[32]

Q: Would setting the initial price and decrement impose

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31. The price should be averaged over the 8760 hours, rather than over kWh's purchased from QFs, or sold to ratepayers, both of which are more heavily weighted to the on-peak period, and both of which would be more difficult for the QF to project.

32. Since there is an overall price contraint, the incentives can not perfectly follow the changing value of power. However, as in retail rate design, the rates can convey useful signals.

unacceptable administrative burdens on the utilities and the Department?

A: I think not. Formal hearings would be required for setting the prices and decrements: to reduce delays and complications due to noticing requirements, perhaps a single docket for each utility could remain open to deal with periodic rate settings; changes in the standard offers; approval of interconnection charges and T&D credits; QF complaints about the utility; and similar matters.[33] In the ratesetting process, much of the relevant data, such as oil prices, inflation rates, and interest rates, would come from standard sources (primarily the econometric forecasting agencies). The estimated construction costs of peakers can be compared to the cost of units actually constructed in recent years, and to the inflation-adjusted costs of the New England turbines added in the 1970's. The operating costs and characteristics of peakers can be determined from the units in operation in New England.

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33. The process could be simplified greatly if a single rate were applied to all QFs in Massachusetts, based on the benefit of the QFs to NEPOOL. At the very least, the rates in effect for other utiliites will serve as a reasonableness check on utility proposals, especially if the Department adopts an efficiency standard in dealing with the utility/NEPOOL duality. See Subsection 4.3. Even with separate ratesetting for each utility, the 60 production costing runs the Department discusses (IO 34) would not be burdensome: the many utility sensitivity runs for their Seabrook case presentations involved comparable numbers of runs for each case.

The potential problems arise in connection with utility projections for the cost of intermediate or base-load plants. The Department expresses its concern that utilities may intentionally underestimate their avoided costs to sabotage QF development (IO 45).[34] Indeed, utilities do seem to be extremely (and perhaps irrationally) threatened by the prospect of being forced to allow large numbers of QFs onto their systems. To reduce the utilities willingness to intentionally underestimate the cost of power from new plants,[35] I would recommend that the Department put the utilities on notice that they will be held responsible for building the plants they have promised.[36] After all, the utility has some obligation to produce the plant it promised to serve the ratepayers who are denied QF power on the strength of a utility's representation that its plant would be less expensive. If the utility does not have enough confidence in its own estimates to stand behind them, it

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34. The Department's specific concern that utilities will be driven to dishonesty by the threat of "potential erosion of . . . electricity sales through competition from QFs" can be eliminated by restricting many of the favorable provisions of the new rules to simulataneous purchase and sale arrangements, as discussed below.

35. This is not a new problem, as witnessed by virtually every utility estimate for a nuclear plant's construction cost or capacity factor in the last decade.

36. In the case of NEPCo/MECo and Montaup/EECo, the Department may require a stipulation from the utility that it is confident enough in its projections to be bound by them before FERC.

should not use those estimates to supress QFs which are willing to deliver power at a guaranteed price.

Q: Are you suggesting that the utility should be held accountable for building and operating, exactly as predicted, any projected plant which is not backed out of the supply plan by QF power?

A: Not quite. The precise treatment of honest errors in utility cost projection, which are not due to imprudence, must be determeined in the context of the overall ratemaking scheme. Conditions -- regulation, interest rates, inflation rates -- really do change, and some reasonable and responsible estimates will prove to be wrong, after the fact. Utilities are not QFs, and under anything like traditional rate-of-return regulation it would be inappropriate to shift the same risks onto utilities ~~that~~ are assumed by QFs. At the very least, I would recommend that the utilities be required to justify the final delivered cost (as result of construction cost, O&M, insurance, additions, fuel, and capacity factor) of power from their plants with reference to the estimates which were used in QF proceedings, demonstrating that each discrepancy was neither foreseeable nor reasonably avoidable.

Q: The Department expresses its concern that the utility-planned plant "may not represent the optimal, cost-effective choice" (IO 40). Is this a problem, and how can it be corrected?

A: It is possible that the utility will either underestimate the cost of its power supply options, to discourage QF development, or overestimate the cost of optimal power supply options, as by ignoring such unconventional alternatives as conservation. Underestimation will be discouraged, but not prevented, by the prospect that the utility will be held to its projection. Overestimation will be discouraged, but not prevented, by the general utility antipathy towards QF development. As a further check on the utility projections, parties should be allowed to dispute the cost projections used in the utility's proposed rates.

The Department's concern at IO 40 appears to be directed toward the possibility that the real avoided cost is not a utility plant at all, but another QF. The hybrid fixed-price/auction process I have proposed should ameliorate this problem.

MECo (pages 7-8) suggests that utilities should select the least cost supply options, and alleges that it will intentionally post an avoided cost which will "[fail] to take into account the possible availability of less costly options", so QFs will be paid more than they are worth. MECo's reasoning is hard to understand. If it intends to implement a conservation program, it can present the load and

supply effects of that program as part of its avoided cost analysis; if it does not intend to implement such a program (perhaps because the technologies do not yet exist, or because it would not be cost effective), the program is not an option for planning in 1985 or 1986. This vague concern that not all options are available in advance did not prevent NEES from committing to a massive, long-term commitment to Hydro Quebec Phase 2, in terms of both capital costs and a contract rate formula. In any case, MECo's concern is academic, since no utility in Massachusetts has indicated any substantial commitment to least-cost supply planning, nor has any such utility announced a conservation program which would exploit all (or a major fraction) of economical conservation opportunities.

Q: Do you have any other suggestions for improving the cost-estimation process?

A: Yes. Consideration of QF power sales and of the effects of QF development on utility revenue are often complicated by attempting to treat to disparate arrangements as if they were equivalent. QF power can be (and under the FERC regulations implementing PURPA §210, must be) purchased under either net purchase and sale (P&S), in which the QF buys or sells the difference between its output and the requirements of any associated facilities;[37] or simultaneous P&S, in which the QF sells all of its power (other than that consumed in the power generation process itself) to the utility, and purchases all power for any associated facilities, as if the QF did not exist. In general, the simultaneous P&S arrangement has several strong advanges:

1. It reduces threat of revenue erosion (IO 45), and thus reduces the incentives for utility opposition to cost-effective QF development.

2. It simplifies the pricing of QF power, since the utility can be reasonably assured that it will receive all of the power that the QF is capable of generating. This will tend to reduce the incidence of undesirable negative correlation between system load and QF generation.

3. It reduces the probability that QF power purchased at levelized rates will become unavailable when costs rise.

4. It simplifies the process of costing out incremental T&D investments; since the associated facilities remain normal customers, any T&D investments necessary for their interconnection are covered by their rates, and

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37. The major concern is with the heat user for a cogenerator, which will often be under the same ownership as the QF.

need not be charged to the QF.

5. It eliminates the problems of establishing backup, maintenance, and other special rates for QFs. These rates would be difficult to establish fairly, due the the vast differences in performance characteristics of QFs.

3.3 - NEPOOL vs. Utility Pricing

Q: The Department discusses NEPOOL system lambda at pages 24-27 of the IO. What importance do you attach to the NEPOOL lambda?

A: The specific discussion of the NEPOOL lambda is in my initial testimony in this docket was largely addressed to short-run costing. Since the Department has indicated that utilities will probably be required to offer standardized long-term fixed rates, the short-run pricing issues are less important, and I will concentrate here on the significance of lambda for long-term rates. In that context, NEPOOL lambda is important in two respects:

1. NEPOOL lambda is the actual avoided energy cost in the short run, and is therefore the appropriate reference for determining peak periods and peak/off-peak differentials.

2. If a particular utility's own-load dispatch does not closely match the NEPOOL lambda, at least on average, then the utility's short-run avoided cost (which may be important in pricing energy for the first several years of a long term contract, until the time a plant-related cost is avoidable) is likely to be a purchase or sale arrangement with another NEPOOL member.

Q: Earlier in this proceeding, you presented extensive testimony on the importance of using NEPOOL costs in setting QF rates. What was the utilities' response to your testimony?

A: The utilities expressed their opposition to use of NEPOOL costs, on the extremely flimsy grounds that their bills from NEPOOL do not directly reflect NEPOOL costs. They made no attempt to refute, and in some cases actually agreed with, my statements regarding the problems of the own-load dispatch pricing:

- One utility may be sending price signals to its QFs to reduce production, due to low own-load dispatch, while a neighboring utility is encouraging production. In the summer of 1984, as NEPOOL faced a capacity emergency and was using gas turbines extensively, the own-load costs of a strongly winter-peaking utility (especially one whose units happened to be available over the summer) would have indicated that QFs should go out for maintenance.

- NEPOOL lambda reflects the actual avoided cost due to a QF, while the own-load dispatch is an accounting fiction. Efficiency demands use of the real economic cost, rather than an accounting construct.

- Own-load dispatch cost information is not available in real time (because it is ficticious, and must be fabricated), so sending appropriate price signals to QFs in response to system conditions can only be accomplished by use of NEPOOL costs.

- Utility plants are dispatched to minimize NEPOOL costs, and pricing QFs to some other standard would be inefficient.

- Own-load pricing will tend to lock up QF power which would be economical for New England, or another Massachusetts utility, simply because it is located in the service territory of a low-avoided cost utility.

The Department has also recognized the ineffiency which results from NEPOOL's unrealistic own-load dispatch methodology (Levy 1985, DPU 1985). The basic reform of the energy pricing system the Department has proposed (Levy 1985, page 5) would solve many of the problems I have listed, since each utility's lambda (which does not really exist currently) would be very close to the NEPOOL lambda.[38]

Q: Which of these considerations are most important?

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38. I suspect that some form of preferential treatment for scheduled outages will still be necessary in order to encourage coordination of maintenance schedules. The Department is correct in pointing out the problems with the existing system of outage service. The Department's proposal for reforming capability responsibility is also a step in the right direction, but it fails to recognize the importance of unit size in determining system capability; as structured, the proposal would penalize small utilities, reward large ones, and necessitate an inefficient and confusing system of universal joint ownership.

A: The dispatching signals are clearly important, especially for larger QFs and those which can adjust output to maximize the value of a limited fuel supply (e.g., hydro, trash). However, appropriate time-of-supply signals can be imposed on top of the contract price, regardless of how it is set, so dispatching efficiency can be dealt with in later proceedings.

The really serious problem is that of locked-in power, as the Department notes at IO 88-89. If MECo and NEPCo, for example, are allowed to suppress QFs in their service territories by offering only rates based on projected fuel costs for coal plants and some of NEPOOL's least expensive oil units, while other utilities are building new coal and combined cycle plants, and while NEPCo's own peakers are actually operating to keep the lights on in New England, a serious inefficiency will have arisen. Optimal power supply planning requires the development of all economic QFs in New England, and the Department's rules should not allow the utilities to obstruct that objective.

Q: How can the problem of locked-in power be avoided?

A: There are three full solutions, and one partial solution.

1. Require all utilities to pay QFs the NEPOOL avoided cost, which in the short run is NEPOOL lambda (plus a

reliability credit), and in the long term is the most expensive capacity the QF can back out.

2. Require all utilities, whose costs are lower than NEPOOL's, to offer an avoided cost rate based on avoiding the lost sales opportunity to utilities with higher rates. This might be as simple as the highest rate offered by any contiguous utility, minus a mill/kWh for administrative expenses.

3. Exempt from the preceding requirements any utility which agrees to wheel power from a QF to another utility without any markup in the price. Contrary to a popular misconception,[39] wheeling within New England is a bookkeeping transaction, which does not affect the flow of power. Thus, the cost of interconnecting a QF is independent of the institutional arrangement for buying the power: a QF is as likely to reduce losses and T&D investments on the local system, whether the power is purchased by the local utilty or a remote one. Note that, while the Department can not order wheeling, it can offer wheeling as an alternative to other requirements which utilities may find more burdensome.

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39. For example, the Department's statement that "Wheeling, like any other transmission serve, has a cost. In order to transmit electricity, the utility company must make investments . . . " (IO 89).

4. As a partial solution, price all energy at the NEPOOL lambda, until the first economical capital plant addition. The value of power after the first plant addition may also be significantly different for NEPOOL than for the utility, especially if the utility-planned plant is resource constrained (e.g., fuel is available for only one unit, or environmental constraints will hamper additional developments), but this will be difficult to determine, since the non-Massachusetts utilities will not be answerable to the Department for their cost projections.

Q: Will it be more difficult to project the NEPOOL lambda than to project individual utility avoided costs?

A: It should not be any harder. The same types of production costing programs are applicable to NEPOOL as to any individual utility. In fact, since NEPOOL's participation in short-term power purchases is more limited (by transmission constraints) than that of its individual members, the modeling task may be much simpler. In addition, the Department would only have to review one NEPOOL projection, as opposed to roughly a half-dozen individual utility projections.

3.4 - Recognizing Voltage Level

Q: How does voltage level affect proper QF rates?

A: In general, the lower the voltage level of delivery, the more advantageous the power. QFs which delivery power directly to the secondary system both avoid line losses and reduce required investments in T&D. The Department discusses T&D costs at some length in the IO, but does not mention line losses. As I discussed in my earlier testimony, line losses should be calculated on a marginal basis, rather than on an average basis, to fully reflect the value of the QF power.

Q: How should the Department deal with the differences in the T&D costs and benefits of various QFs?

A: Given the much greater resources of the utilities, and their essentially adversarial role with respect to QFs, I believe that it would be appropriate to start with the presumption that all QFs are entitled to a T&D credit from the utility to which they deliver their power (regardless of whether this is the utility which actually purchases the power). Until the utilities demonstrate to the contrary, this base-line credit should be the marginal T&D costs (by voltage level) provided in the utility's last response to PURPA §133, converted to cents/kWh by dividing the annual cost by the utility's on-peak energy deliveries per kW.[40] Where the utility believes that a QF will not produce these savings, or will actually increase costs, it should be provided an opportunity to present that evidence to the Department, before the final contract is signed. Since the T&D costs and credits will usually be small compared to the bulk power value of the QF, the adjudication of T&D costs should rarely impede developments.

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40. This procedure mimics the load factor which creates the utility's estimated cost/kW. The cost/kW of meeting T&D loads rises with the load factor.

4 - THE DIFFERENCES BETWEEN UTILITIES AND QF'S

4.1 - Comparing Benefits and Risks

Q: Please summarize the benefits of QF power purchased under long-term fixed rate contracts, as compared to utility-owned power, or power purchased under conventional utility contracts.

A: The major benefits of QF's are as follows:

1. Ratepayer exposure to several kinds of energy cost risks, which may resulting paying higher-than-projected costs per kWh for power delivered from individual utility sources, are reduced or eliminated, because the QF rate per kWh delivered is fixed (or partially fixed) at the time the contract is signed, including the risks of

   - construction cost overruns,
   - fuel price increases,
   - changes in financing costs,
   - increased O&M, and
   - unexpected capital additions.

2. Ratepayer exposure to several kinds of energy cost risks, which may resulting paying higher-than-projected costs per kWh for power delivered from individual utility sources, are reduced or eliminated, because the QF is paid only for kWh delivered:

   - cancellation,

   - amortization of prematurely retired plant, and

   - poor plant availability.

3. QFs tend to be small, and hence make a greater contribution to system reliability than larger utility plants of equivalent availability.

4. Small QFs' contributions to system reliability are essentially proportional to their availability, while that of utility-scale plants decreases rapidly as availability decreases.

5. The large number and technical diversity of QFs makes them less vulnerable to common-cause outages than are utility plants.

6. QFs increase the stability and predictability of utility costs and rates.

7. The output of cogenerators will tend to correlate with economic and weather conditions (depending on the use

of the associated heat), and will therefore tend to be most abundant when it is most needed.

8. Many QFs can be constructed and in service before much progress can be achieved on the next New England base load unit.[41]

Q: Are there comparable advantages for QF power with respect to recent inter-utility contracts, such as Hydro Quebec?

A: Yes. Hydro Quebec contract prices are strongly tied to the cost of oil, and provide little protection against oil price increases. Hydro Quebec~~'s~~ rates to New England utilities will also increase when non-oil-price events (unit outages, inservice date delays) increase the cost of other NEPOOL power sources. The NEPOOL utilities are also committed to paying for an expensive transmission line, regardless of whether the HQ system is actually capable of supplying the expected power. In addition, the large capacity of the transmission line contributes rather little to NEPOOL reliability.

Q: Are there risks associated with QFs which are greater than the corresponding risks for utility-owned power?

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41. The utilities appear to recognize that a baseload plant cannot be brought into service soon, since they are seriously considering building an expensive intermediate/peaking combined cycle plant.

A: Yes. Since QFs are owned by entities other than the utility, an additional level of misfeasance or malfeasance is possible. QFs may fail for technical reasons which utilities might have avoided. More significantly, QFs may fail for financial reasons: protections for the ratepayers in the event of QF financial distress are valuable, particularly in the form of guarantees which allow the utility to assume ownership or operation of the QF. If contracts and bidding procedures are improperly structured, some QF developers and operators may try to take advantage of the utility and its customers, for example through voluntary bankruptcy.

The institutional structure of QFs also introduces possible communication problems. The QF developer may not give the utility as much warning of a change in construction schedule, or of a major maintenance outage, or of a premature retirement, as the utility would have for one of its own plants.

Q: Are there other disadvantages in QF development of power supplies?

A: Yes. To the extent that a utility's investors face smaller risks than QF investors (due to the limited, but significant, ratepayer guarantee of utility recovery of prudent costs), the utility should be able to develop many of the same facilities as the QF developer, but at a lower cost.[42] This is the classic risk/return trade-off: if the ratepayers assume the additional risk of having the utility own the plants, they should be able to get power at somewhat lower rates.

QF developers can also be expected to charge whatever they can get for their power. Utilities are generally expected (and more-or-less required) to provide service at "the lowest possible cost". If there are resources which are much less expensive than the market-clearing price, it is in the interest of the ratepayers to have them developed by the utility, rather than as QFs.

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42. Of course, the lack of institutional flexibility may limit a utility's actual ability to develop QF-like units. The failure of Massachusetts utilities to build and operate their own cogeneration facilities may result from such inflexibility. If the utility <u>will not</u> develop QF-like plants, it is hardly important that the utility's cost of capital <u>would have</u> made such development cheaper than the QF power.

4.2 - Future Roles

Q: How should the Department attempt to balance the roles of QFs and utilities in the future?

A: The Department should strive to establish a level, but not necessarily symmetrical, playing field for the two types of power suppliers. The utilities should be expected to do their best (defined as the best that can reasonably be demanded of a large, regulated monopoly) to further the interest of their ratepayers, and they should be rewarded or penalized based on the quality of those efforts, which is not necessarily equivalent to the quality of the outcome. QFs should be allowed the opportunity to provide the utility with power at a lower cost than the utilities can provide themselves. The QFs must bear the cost both of imprudence (as must the utilities) and of prudent but unfortunate decisions (unlike utilities, but like any other company in a competitive market).

The differences between these two institutions can be illustrated with a homey analogy. Suppose you send an agent (a child, or an employee) to purchase something (say, a quart of milk) on your behalf. You have a set of expectations for that agent:

- If milk is unavailable (or priced much higher than expected) at the supermarket, the agent should obtain a suitable substitute, or check back for further instructions.

- If the price is lower (or slightly higher) than projected, you expect your agent to charge you only for the actual cost, not to keep (or pay) the difference.

- If checking the price of milk at the convenience store on the way to the supermarket seems worth the trouble, you expect your agent to buy the milk at the lowest available price, and to charge you only that price.

- If the agent is negligent or irresponsible in bringing the milk back (e.g., leaves it on top of a video game, or drinks it), you have every right to appropriately penalize him or her for the failure to deliver.

- If the agent fails to deliver usable milk for reasons beyond his or her control (e.g., the milk was spoiled when purchased), you expect to pay the costs, anyway.

Contrast these responses with your expectations if your milk is delivered by a commercial service:

- The milkman delivers milk at his posted price. If that price has increased, or he runs out of the product you ordered, he has no responsibility to anticipate your needs and desires by selecting a substitute.

- If the service can find a less expensive source of milk, it has no obligation to lower the price it said it would charge you. It may do so, to keep you as a satisfied customer, but you have no recourse (other than finding another supplier in the future).

- If the service fails to deliver milk, or delivers unusable milk, you have no responsiblity to pay for it, regardless of whether the service was at fault.

The utility acts (or should act) as the agent of the ratepayers: the Department has the responsibility of (among other things) acting as the ratepayers' voice in communicating their needs and desires to the utility, and in applying rewards and penalties for the quality of the utility's efforts on behalf of the ratepayers. The QF is a vendor, responsible for complying with a contract, is paid only to the extent that the contracted services are delivered, and has no responsibility to seek out opportunities for the ratepayers.

Q: Should utilities be in the business of owning and operating QFs?

A: Utilities should be encouraged to develop QF-like facilities in the normal manner, or with risk-taking partners, as part of a least-cost supply strategy. There is no reason that a utility can not own a small hydro site (several do), cogeneration equipment delivering heat to other entities (Cambridge Electric does, and other utilities in Massachusetts previously did so), portions of a trash-to-energy plant, and so on. Institutional convenience, financing ability, operating experience and control, and tax status will determine whether the cost of power is sufficiently reduced by utility ownership to compensate for the increased risk due to utility ownership.

In exceptional circumstances, utilities should be given the option of proceeding with particularly risky or questionable investments on a QF-like basis, as the Department indicated it would allow the Seabrook participants to proceed (DPU 84-152). The California PUC has also allowed utilities to build some unconventional projects, with cost recovery at a fixed cents/kWh level. This permits utilities to pursue projects in which they have more faith than the regulators do, or which the utility strongly desires for other reasons, such as building morale. These QF-like arrangements should not be applied to projects whose benefits the Department would prefer to keep with the ratepayers (that is, anything which appears to be less expensive than incremental costs, and not excessively risky), and the aggregate size of these projects should not be substantial enough to distract the utility's priorities from serving the needs of the ratepayers.

General decisions concerning changes in the fundamental ratemaking treatment of future utility plant investments (except in such special cases as those cited above) should be dealt with in proceedings specifically designated for that purpose, and with great care.

Q: Does this conclude your additional testimony?

A: Yes.

5 - BIBLIOGRAPHY

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4. NEPOOL, Review of the NEPOOL Reliability Criterion with Respect to the Required Amount of Installed Generating Capacity, 1984.

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TABLES AND FIGURES

TABLE 1: NON NUCLEAR ELECTRIC PLANT SCHEDULES, 1969-74.

Date of 1st Report [1]	Plant [2]	MW Nominal Capacity	First Estimated COD	Actual COD	Total Months Delay
8/69	Montville # 6	402	Jun-71	Jul-71	1
	Northfield # 1	250	Sep-71	Mar-73	18
	Northfield # 2	250	Nov-71	Oct-73	23
	Northfield # 3	250	Dec-71	Aug-73	20
	Northfield # 4	250	Feb-72	Nov-72	9
5/70	Middleton # 4	400	Jun-73	Jul-73	1
3/71	Salem Harbour # 4	465	Oct-72	Aug-72	-2
	E.F.Cleary	50 - 20	Jul-73	Dec-75	29
	Brayton Point # 4	465	Dec-73	Dec-74 *	12
	Bear Swamp # 1	300	May-74	Nov-74 *	6
	Newington NH	400	Jun-74	Jun-74	0
	Bear Swamp # 2	300	Jul-74	Oct-74 *	3
	Mystic # 7	600	Nov-74	Jun-75	7
	Coke Works (New Haven)	400	May-75	Aug-75	3
	Canal # 2	560	Jul-75	Feb-76	7
	Stamford (NU)	400	May-75	CANC. BY 8/71	
8/71	CT Grp Undecided [3]	251	Jul-75	CANC. BY 10/74	
2/72	North Shore # 1 [4]	1200	Nov-77	CANC. BY 12/75	
	MEPCo Pur. # 2 Start	200	Jan-75	Jun-76	5
	MEPCo Pur. # 2 Increase	200	Jul-75	Oct-75	3
	CMP Undet. (= Wyman 4)	600	Nov-77	Dec-78	13
3/73	Potter Station [5]	26	Oct-77	CANC. BY 10/73	
	North Shore # 2	820	Jun-80	CANC. BY 3/74	
10/73	NU Fuel Cells [6]	260	Jul-80	CANC. BY 12/75	
	Canal # 3	835	Jul-81	CANC. BY 12/75	
3/74	Boston Edison Gas Turbine	220	Nov-75	CANC. BY 12/75	

Sources: NEPLAN Load & Capacity Reports, 1971 to 1978
NU Load and Capacity Reviews, 1969-70.
EIA Steam Electric Plant Construction Cost and Annual Production Expenses

Notes: * Estimated COD in [illegible] 1974.
[1] Date of [illegible] Load and Capacity Review 1969-70 or NEPLAN L & C Report in which plant was first reported.
[2] Plants [illegible] MW that was added to the [illegible] units by 1974.
[3] Assumed [illegible] as Devon [illegible] in later listings.
[4] Renamed Salem Harbour # [illegible] March 1974.
[5] A smaller [illegible] unit [illegible] listed at the same time was completed.
[6] Reduced to [illegible] MW before it was cancelled.

TABLE 2: EFFECTIVE LOAD CARRYING CAPABILITY

INPUTS:

MW	n	EFOR	AVE MW	SUM	ELCC	ELCC.MW	ELCC/ AVE MW	ELCC MW/SUM+.-
1	425	10.0%	0.9	0.788	0.900	90.0%	100.0%	0.876
1	425	20.0%	0.8	0.701	0.800	80.0%	100.0%	0.876
1	425	30.0%	0.7	0.613	0.700	70.0%	100.0%	0.876
1	425	40.0%	0.6	0.526	0.600	60.0%	100.0%	0.876
1	425	50.0%	0.5	0.438	0.500	50.0%	99.9%	0.875
1	425	60.0%	0.4	0.350	0.400	40.0%	99.9%	0.875
1	425	70.0%	0.3	0.263	0.300	30.0%	99.9%	0.875
10	425	10.0%	9	7.884	8.989	89.9%	99.9%	0.875
10	425	20.0%	8	7.008	7.981	79.8%	99.8%	0.874
10	425	30.0%	7	6.132	6.975	69.8%	99.6%	0.873
10	425	40.0%	6	5.256	5.970	59.7%	99.5%	0.872
10	425	50.0%	5	4.380	4.971	49.7%	99.4%	0.871
10	425	60.0%	4	3.504	3.972	39.7%	99.3%	0.870
10	425	70.0%	3	2.628	2.975	29.8%	99.2%	0.869
25	425	10.0%	22.5	19.710	22.433	89.7%	99.7%	0.873
25	425	20.0%	20.0	17.520	19.981	79.9%	99.4%	0.871
25	425	30.0%	17.5	15.330	17.344	69.4%	99.1%	0.868
25	425	40.0%	15.0	[illegible]	[illegible]	[illegible]	98.8%	0.866
25	425	50.0%	12.5	[illegible]	[illegible]	49.3%	98.5%	0.863
25	425	60.0%	10.0	[illegible]	[illegible]	[illegible]	98.2%	0.861
25	425	70.0%	7.5	[illegible]	[illegible]	29.4%	98.0%	[illegible]
50	425	[illegible]	45	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
50	425	20.0%	40	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
50	425	30.0%	35	[illegible]	[illegible]	68.7%	[illegible]	[illegible]
50	425	40.0%	30	[illegible]	[illegible]	58.6%	[illegible]	[illegible]
50	425	50.0%	25	21.900	[illegible]	48.5%	[illegible]	0.850
50	425	60.0%	20	17.520	19.300	38.6%	96.5%	0.845
50	425	70.0%	15	13.140	14.332	[illegible]	95.5%	0.841
75	425	10.0%	67.5	[illegible]	[illegible]	[illegible]	[illegible]	0.868
75	425	[illegible]	60.0	52.560	[illegible]	[illegible]	[illegible]	0.860
75	425	30.0%	52.5	45.990	51.079	68.1%	[illegible]	[illegible]
75	425	40.0%	45.0	39.420	43.395	57.9%	[illegible]	[illegible]
75	425	50.0%	37.5	32.850	35.648	[illegible]	[illegible]	[illegible]
75	425	60.0%	30.0	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
75	425	70.0%	22.5	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
100	425	[illegible]	90	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
100	425	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
100	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
100	[illegible]	40.0%	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
100	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
100	425	60.0%	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
100	425	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	425	[illegible]	360	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	420	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

TABLE 2: EFFECTIVE LOAD CARRYING CAPABILITY

INPUTS:

MW	#	EFOR	AVE MW	GWH	ELCC	ELCC/MW	ELCC/ AVE MW	ELCC MW/GWH
600	425	40.0%	360	315.36	257.01	42.8%	71.4%	0.625
600	425	50.0%	300	262.80	201.89	33.6%	67.3%	0.590
600	425	60.0%	240	210.24	153.12	25.5%	63.8%	0.559
600	425	70.0%	180	157.68	109.36	18.2%	60.8%	0.532
1150	425	10.0%	1035	906.66	778.30	67.7%	75.2%	0.853
1150	425	20.0%	920	805.92	583.35	50.7%	63.4%	0.555
1150	425	30.0%	805	705.18	450.12	39.1%	55.9%	0.490
1150	425	40.0%	690	604.44	348.85	30.3%	50.6%	0.445
1150	425	50.0%	575	503.70	267.10	23.2%	46.5%	0.407
1150	425	60.0%	460	402.96	198.53	17.3%	43.2%	0.378
1150	425	70.0%	345	302.22	139.59	12.1%	40.5%	0.354

TABLE 3: AVAILABILITY FACTORS, NEW ENGLAND GAS TURBINES: 1971-84

Plant	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984	AVERAGE	STDRD DEV.
Branford 10 [1]	78.6%	97.0%	72.2%	98.4%	95.8%	97.7%	95.8%	94.7%	91.1%	86.5%	31.8%	72.7%	0.0%		81.7%	25.3%
Cos Cob 10	94.1%	96.8%	59.7%	96.6%	10.0%	98.2%	100.0%	100.0%	93.6%	82.1%	85.0%	95.2%	100.0%	100.0%	86.5%	23.7%
Cos Cob 11	98.1%	92.3%	60.6%	90.0%	96.0%	91.2%	90.5%	83.1%	97.4%	97.2%	96.5%	95.0%	97.2%	99.1%	93.2%	5.4%
Cos Cob 12	70.7%	96.4%	80.3%	92.1%	94.0%	95.9%	98.9%	91.9%	94.0%	98.5%	88.8%	91.6%	8.6%	7.8%	79.3%	29.9%
Devon 10	97.9%	97.0%	94.8%	96.6%	95.7%	96.0%	98.4%	92.9%	98.9%	96.5%	94.6%	98.2%	98.2%	57.6%	93.1%	10.3%
Doreen 10	98.8%	98.0%	95.9%	96.1%	82.1%	99.5%	97.4%	98.7%	95.7%	97.2%	97.1%	98.8%	99.5%	98.7%	96.7%	4.2%
Enfield 10	97.5%	93.9%	97.5%	90.7%	80.3%	98.3%	99.0%	98.8%	97.7%	96.3%	98.7%	98.5%	99.0%	94.7%	95.8%	4.9%
Franklin Drive 10	93.1%	99.4%	99.0%	96.0%	96.1%	99.0%	97.3%	98.6%	97.7%	98.0%	97.8%	96.0%	97.1%	97.6%	97.3%	1.6%
Middletown 10	90.7%	73.3%	97.7%	92.4%	93.8%	74.9%	99.9%	98.6%	97.8%	8.6%	0.0%	0.0%	25.0%	98.1%	67.9%	38.8%
Norwalk Hbr 10	36.7%	95.0%	87.0%	94.4%	60.0%	11.8%	94.0%	99.5%	98.9%	98.5%	98.7%	98.8%	5.3%	91.1%	75.6%	32.3%
Silver Lake 10	94.0%	98.7%	97.3%	98.6%	90.9%	50.9%	100.0%	99.6%	99.3%						93.3%	11.8%
Silver Lake 11 [2]	94.9%	99.5%	96.7%	14.5%	96.7%	98.8%	14.5%								87.9%	21.9%
Silver Lake 12	90.3%	92.8%	94.6%	49.5%	90.4%	99.7%	95.7%	99.9%	99.5%	90.9%	87.5%	70.0%	100.0%	100.0%	89.2%	13.6%
Silver Lake 13	98.3%	99.1%	95.4%	94.2%	72.7%	99.9%	99.8%	97.9%	99.9%						95.2%	8.2%
South Meadow 11	95.5%	68.9%	90.2%	96.2%	99.5%	96.4%	90.4%	98.6%	31.4%	92.6%	94.8%	55.3%	0.0%	54.5%	78.9%	26.2%
South Meadow 12	91.5%	96.7%	94.1%	97.3%	95.6%	99.4%	96.5%	99.9%	99.7%	99.3%	98.9%	88.8%	97.0%	96.6%	95.7%	4.7%
South Meadow 13	96.3%	80.3%	95.7%	98.3%	98.5%	98.9%	95.8%	99.6%	99.1%	99.9%	95.8%	94.0%	96.8%	98.6%	96.3%	4.7%
South Meadow 14	93.0%	94.4%	78.4%	97.5%	99.8%	99.0%	99.8%	98.7%	98.7%	99.1%	99.8%	97.2%	97.3%	96.5%	96.1%	5.3%
Torrington 10	97.6%	98.3%	75.5%	97.0%	95.2%	96.0%	98.3%	98.2%	95.5%	98.3%	89.3%	78.8%	0.0%	73.7%	85.2%	25.1%
Tracey 10	99.3%	97.4%	96.5%	90.2%	93.9%	98.1%	100.0%	90.1%	98.5%						95.9%	3.4%
Tunnel 10	97.6%	97.0%	97.7%	93.4%	97.7%	95.3%	98.6%	98.9%	98.4%	97.6%	93.2%	98.7%	99.6%	76.8%	95.8%	5.6%
E. Springfield 10	92.6%	99.2%	95.6%	97.5%	97.3%	98.8%	96.3%	99.5%	96.7%						97.4%	2.3%
W. Springfield 10	67.0%	99.0%	75.5%	99.7%	95.7%	96.6%	98.8%	96.4%	99.4%	97.7%	95.	97.0%	98.4%	98.1%	94.0%	9.5%
Woodland Road 10	76.7%	82.4%	98.4%	93.1%	97.6%	98.4%	99.7%	99.3%	99.5%	99.0%	93.	94.6%	56.5%	52.3%	88.8%	15.4%
L St. # 1-1		94.4%	90.5%	91.3%	84.3%	80.0%	72.6%	83.7%	86.7%	80.5%	89.	96.3%	99.5%		92.0%	6.1%
Mystic # 1-1		44.3%	95.2%	93.5%	98.7%	96.1%	99.3%	99.7%	95.2%	94.4%	97.	96.0%	99.3%		94.2%	15.1%
Edgar # 1-1		72.6%	73.9%	97.2%	77.8%	93.9%	94.1%	99.9%	80.5%	40.0%	84.8%	92.7%	74.6%		82.2%	15.5%
Edgar # 1-2		95.6%	65.3%	97.3%	75.8%	91.2%	95.6%	60.5%	95.0%	74.5%	96.3%	60.4%	0.0%		77.1%	25.1%
Framingham # 1-1			77.2%	99.7%	79.1%	89.0%	99.2%	97.1%	90.0%	62.5%	93.2%	93.7%	84.0%		87.7%	10.7%
Framingham # 1-2			99.7%	96.8%	74.7%	99.7%	95.6%	90.4%	0.0%	3.3%	88.9%	93.4%	67.6%		73.6%	35.2%
Framingham # 1-3			74.8%	77.0%	74.7%	93.3%	94.2%	100.0%	94.4%	79.1%	87.6%	96.3%	94.2%		88.3%	9.6%
Medway # 1-1, 1-1			77.3%	50.3%	61.6%	91.3%	97.7%	68.6%	44.3%	0.0%	0.0%	0.0%	44.6%		46.1%	31.9%
Medway # 1-1, 1-2			46.2%	56.1%	91.7%	88.4%	96.3%	99.5%	77.3%	0.0%	0.0%	17.9%	41.7%		55.5%	34.7%
Medway # 1-2, 1-1			90.3%	93.5%	79.0%	94.2%	96.3%	60.4%	77.5%	61.6%	59.7%	63.3%	23.8%		71.3%	19.7%
Medway # 1-2, 1-2			90.1%	79.3%	81.0%	95.4%	94.1%	86.7%	62.2%	71.7%	65.7%	55.4%	30.6%		74.0%	18.3%
Medway # 1-3, 1-1			81.0%	55.0%	70.6%	91.7%	95.3%	34.6%	0.0%	0.0%	70.3%	77.3%	45.7%		54.1%	34.0%
Medway # 1-3, 1-2			91.4%	73.2%	70.8%	90.0%	98.5%	98.8%	35.2%	0.0%	50.7%	45.0%	16.7%		60.4%	34.1%
Somerset 1	91.3%	99.3%	77.5%	98.9%	94.2%	94.1%	99.8%	99.5%	99.6%	96.2%	94.7%	98.2%			94.8%	7.3%
Somerset 2	95.7%	95.9%	87.4%	94.4%	94.3%	92.9%	72.1%	97.8%	98.6%	98.1%	97.5%	94.1%			93.4%	7.8%
															----	----
														AVERAGES:	84.6%	15.4%

NOTES: 1. Retired [illegible] 1984.
2. Silver Lake 11 did not generate [illegible] 1978 and 1979.

SOURCES: NU, [illegible] Power Facilities Forecast, [illegible] 1985.
Boston Edison, Performance Program [illegible] 1979-84 [illegible] Historical Performance Data, 1984 Filing.
Boston Edison, 1977, Supplement [illegible]
Boston Edison, 1976 Forecast, [illegible]
Montaup Electric Co., Table [illegible] 1976, [illegible] and 1983.

AVAIL FAC [illegible]

TABLE 4: NEPOOL RETIREMENTS [1]

Type	Unit	Left Service	Date Retired [2]	In Service Date	Operating Life [4]
GT	Oxbridge 2		07-Aug-83	Jun-71	12
GT	Oxbridge 1		07-Aug-83	Jun-71	12
GT	Silver Lake 11	1977	30-Apr-81	1969	12 (8)
GT	Tracey		30-Apr-81	1968	13
GT	Silver Lake 10		31-Dec-82	1969	14
GT	Silver Lake 12 [3]		31-Dec-82	1968	14
GT	East Springfield 10		30-Apr-81	1967	14
GT	Branford 10	1982	01-Jul-84	02-Jul-69	15 (12.5)
GT	Holyoke Jet 10		01-Jul-84	1964	21
GT	Danielson 1		30-Apr-81	1954	27
GT	Thompsonville 1		30-Apr-81	1953	28
GT	Thompsonville 2		30-Apr-81	1953	28
IC	Lynnway		15-Sep-83	1969	16
ST	Edgar 4		31-Dec-79	1961	18
ST	Edgar 4		31-Dec-79	1959	20
ST	Edgar 4		31-Dec-79	1957	22
ST	L Street 120 [illegible]		01-Mar-81	1939	42
ST	Daniel Street 3,5-7		01-Nov-83	1920	64

Notes: 1. All retirements listed in NEPOOL LSC Reports, 1979-1985, for which I could find in-service dates.
2. Data generated from NEPOOL LSC Reports, FF Reports.
3. Ran about 14 hours on emergency in the [illegible] of 1984.
4. June assumed for dates identified by year. Figures in parentheses are life to end of service.

TABLE 5: COST RECOVERY COMPARISONS (CTS/KWH)

Year	Utility Cost Recovery Conventional Ratemaking	Levelized Costs 16%	Fixed Escalation 6%	CUMULATIVE PRESENT VALUE (A) Utility Ratemaking	(B) Levelzd Costs	(C) Fixed Escal.	DIFFERENCES (Fig. 4) (A)-(B)	(A)-(C)	(B)-(C)
1	17.6	14.8	9.6	15.2	12.8	8.3	2.4	6.9	4.5
2	16.4	14.8	10.2	27.3	23.8	15.9	3.5	11.4	7.9
3	15.7	14.8	10.8	37.4	33.3	22.8	4.0	14.5	10.5
4	15.2	14.8	11.5	45.8	41.6	29.2	4.2	16.6	12.3
5	14.6	14.8	12.2	52.7	48.6	35.0	4.1	17.7	13.6
6	13.1	14.8	12.9	58.1	54.7	40.3	3.4	17.8	14.4
7	12.8	14.8	13.7	62.6	59.9	45.1	2.7	17.5	14.8
8	12.7	14.8	14.5	66.5	64.5	49.5	2.0	17.0	14.9
9	12.5	14.8	15.4	69.8	68.4	53.6	1.4	16.2	14.8
10	12.3	14.8	16.3	72.6	71.7	57.3	0.9	15.3	14.5
11	12.4	14.8	17.3	75.0	74.6	60.6	0.4	14.4	14.0
12	12.6	14.8	18.3	77.2	77.1	63.7	.0	13.4	13.4
13	12.8	14.8	19.4	79.0	79.3	66.5	-0.3	12.5	12.7
14	12.9	14.8	20.5	80.6	81.1	69.1	-0.5	11.5	12.0
15	13.1	14.8	21.9	82.0	82.7	71.5	-0.7	10.6	11.3
16	13.5	14.8	23.1	83.3	84.1	73.6	-0.8	9.7	10.5
17	13.6	14.8	24.5	84.4	85.3	75.6	-0.9	8.8	9.7
18	13.9	14.8	25.9	85.4	86.5	77.4	-1.1	8.0	9.0
19	14.3	14.8	27.5	86.2	[illegible]	78.8	-1.0	7.2	8.2
20	15.7	14.8	29.2	87.0	88.0	80.5	-1.0	6.5	[illegible]
21	16.1	14.8	30.9	87.7	88.6	81.9	-0.9	5.9	[illegible]
22	16.4	14.8	32.8	88.4	89.2	83.1	-0.8	5.2	[illegible]
23	16.9	14.8	34.7	88.9	89.7	84.3	-0.8	4.6	[illegible]
24	17.2	14.8	36.8	89.4	90.1	85.3	-0.7	4.1	4.8
25	17.7	14.8	39.0	89.8	90.5	86.3	-0.6	3.6	4.2
26	18.2	14.8	41.4	90.2	90.8	87.2	-0.6	3.1	3.6
27	18.7	14.8	43.9	90.5	91.1	87.9	-0.5	2.6	3.1
28	19.2	14.8	46.5	90.9	91.3	88.7	-0.4	2.2	2.6
29	19.8	14.8	49.3	91.1	91.5	89.3	-0.4	1.8	2.2
30	20.5	14.8	52.2	91.4	91.7	90.0	-0.3	1.4	1.7
31	21.2	14.8	55.4	91.6	91.8	90.5	-0.2	1.1	1.3
32	21.9	14.8	58.7	91.8	91.9	91.0	-0.2	0.8	1.0
33	22.7	14.8	62.2	92.0	92.1	91.5	-0.1	0.5	0.6
34	23.6	14.8	65.9	[illegible]	92.2	91.9	-0.1	0.2	[illegible]
35	24.5	14.8	69.9	[illegible]	92.2	92.3	0.0	-0.1	[illegible]

Pres. value [illegible] [illegible] 92.29
@16%

TABLE 6: COMPARISON OF CREDIT CALCULATIONS FOR QF's ENTERING SERVICE IN 1991 [1], [2]

Year	Utility Nominal Constant Peaker Costs [3]	EDEP Nominal-Escalating [4]	Real-Escalating [5]
1989			
1990			
1991	115	92.9	47.8
1992	111	98.5	50.7
1993	106	104.4	53.8
1994	101	110.7	57.0
1995	96	117.3	60.4
1996	91	124.3	64.0
1997	86	131.8	67.9
1998	81	139.7	71.9
1999	76	148.1	76.2
2000	71	157.0	80.9
2001	67	166.4	85.7
2002	63	176.4	90.8
2003	[illegible]	187.0	96.3
2004	58	198.7	102.1
2005	55	210.1	108.2
2006	54	222.7	114.7
2007	[illegible]	236.1	121.6
2008	[illegible]	250.2	128.9
2009	[illegible]	265.2	[illegible]
2010	[illegible]	281.1	144.8
2011	53	298.0	[illegible]

PV @15% 555.23

Levelized: 92.92 130.[illegible] [illegible]

Notes: 1. ... in $ ... Peaker Capacity ...
2. Costs not corrected for Peaker [illegible] would be about 13% higher in [illegible] terms
3. From [illegible] comments [illegible] Appendix [illegible] estimates are lower than [illegible] despite higher finance costs [illegible]
4. Assumes [illegible] escalation.
5. Assumes [illegible] escalation rate.

Fig. 1: ELCC/KWH vs FOR

QF's and Utility Plants

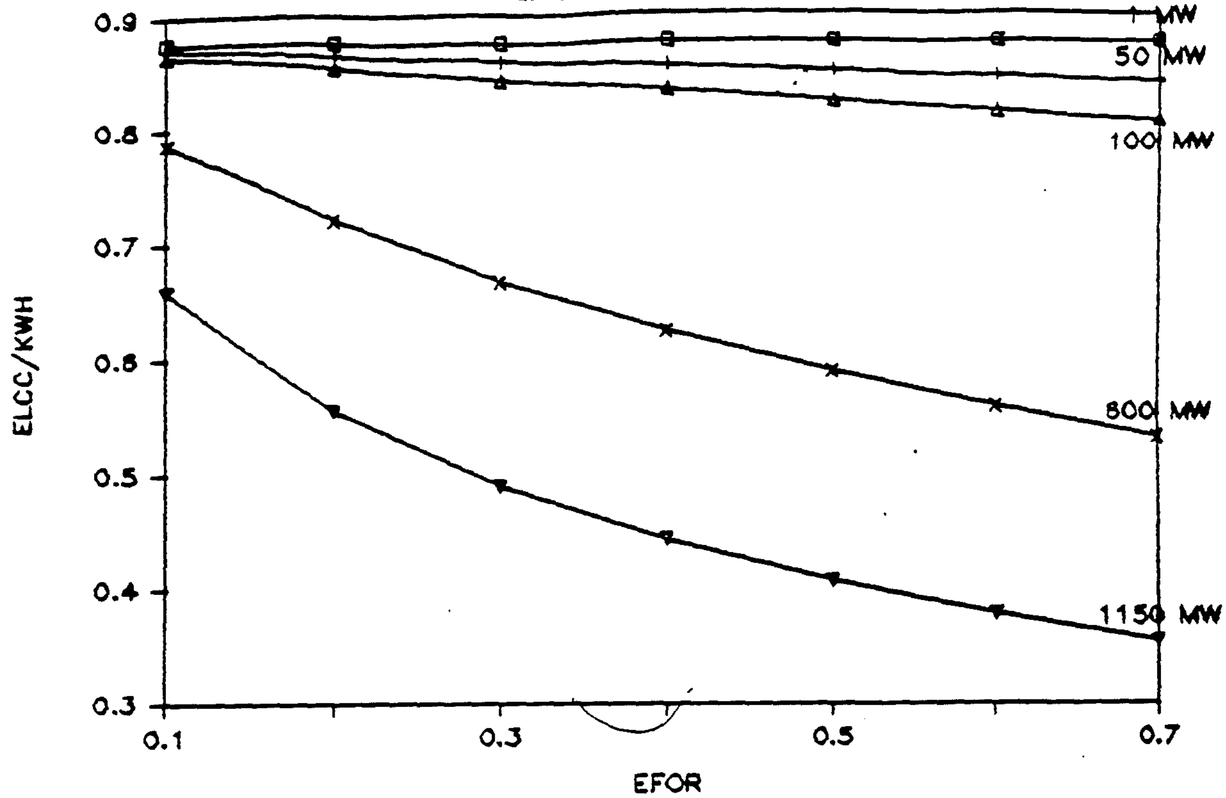


Fig. 2: ELCC/KWH vs FOR

Various Size QF's

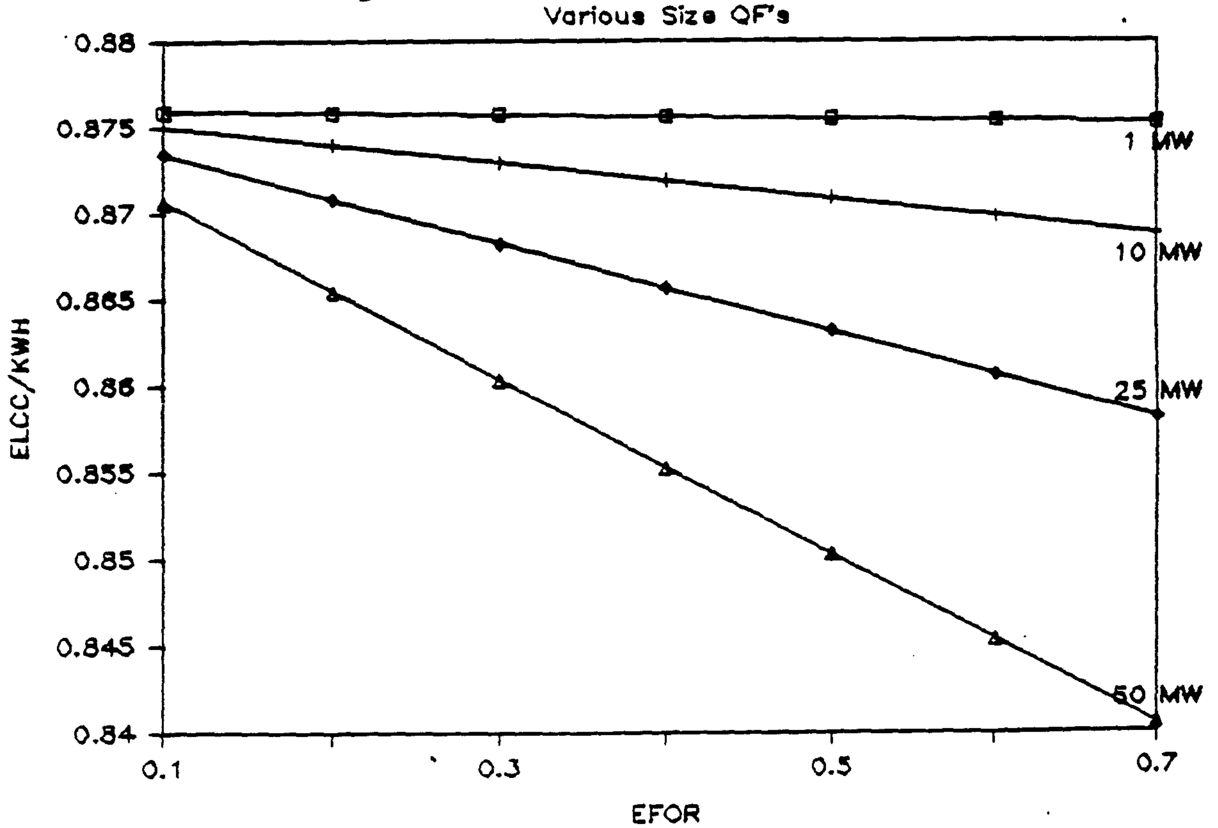


Fig.3: Comparison of Cost Recovery

Conventional, Escalated, Levelized

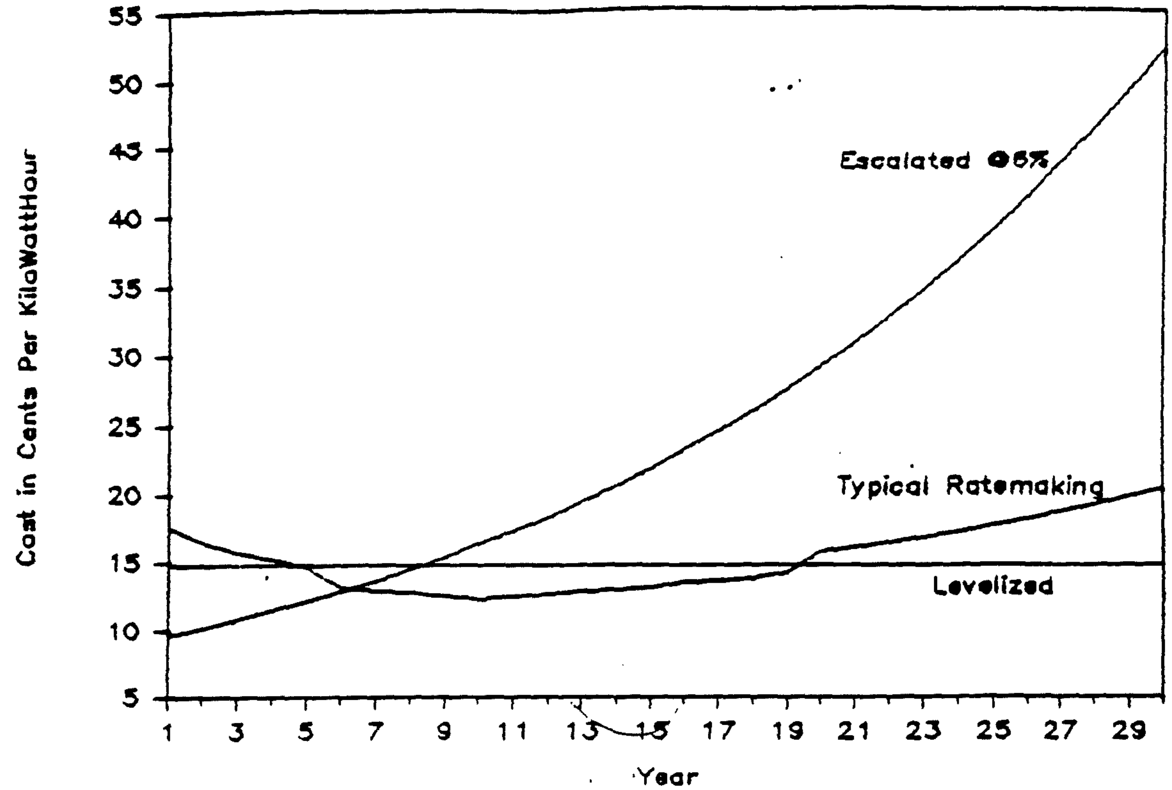


Fig. 4: Cumulative Present Value

Differences

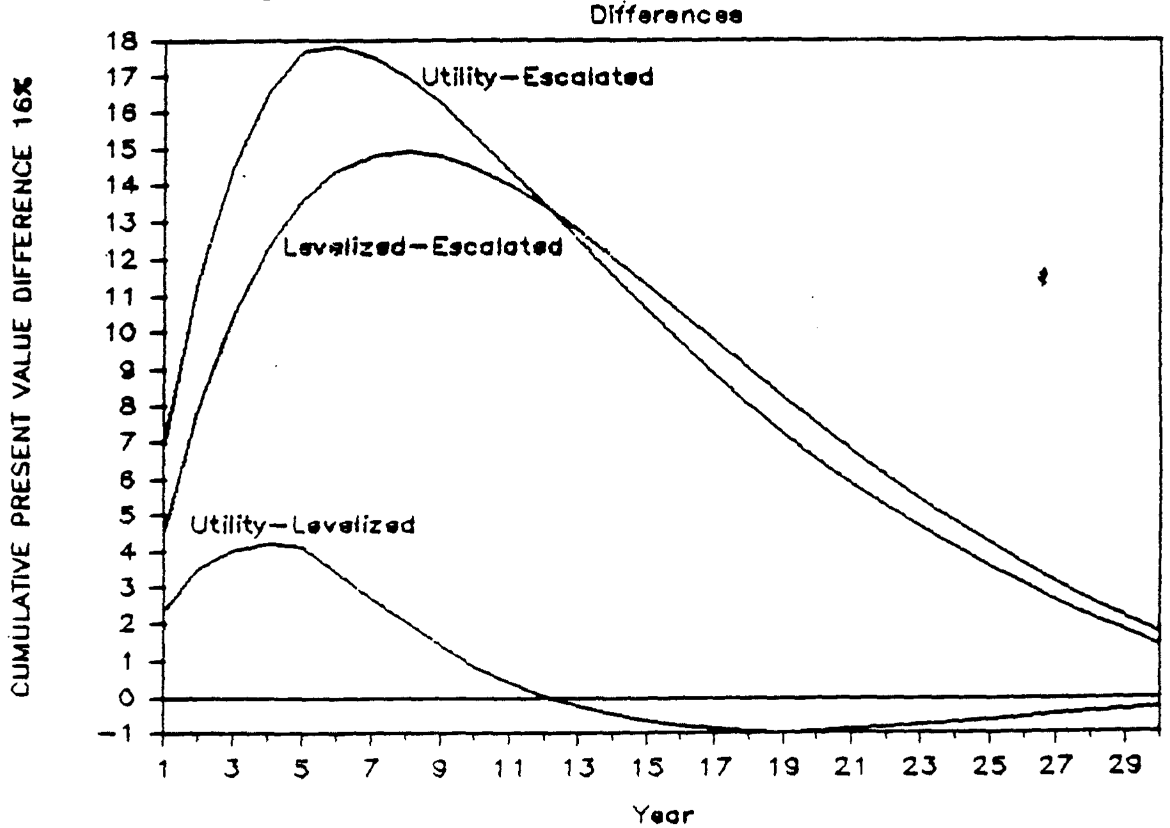


Fig. 5: DEMAND AND SUPPLY

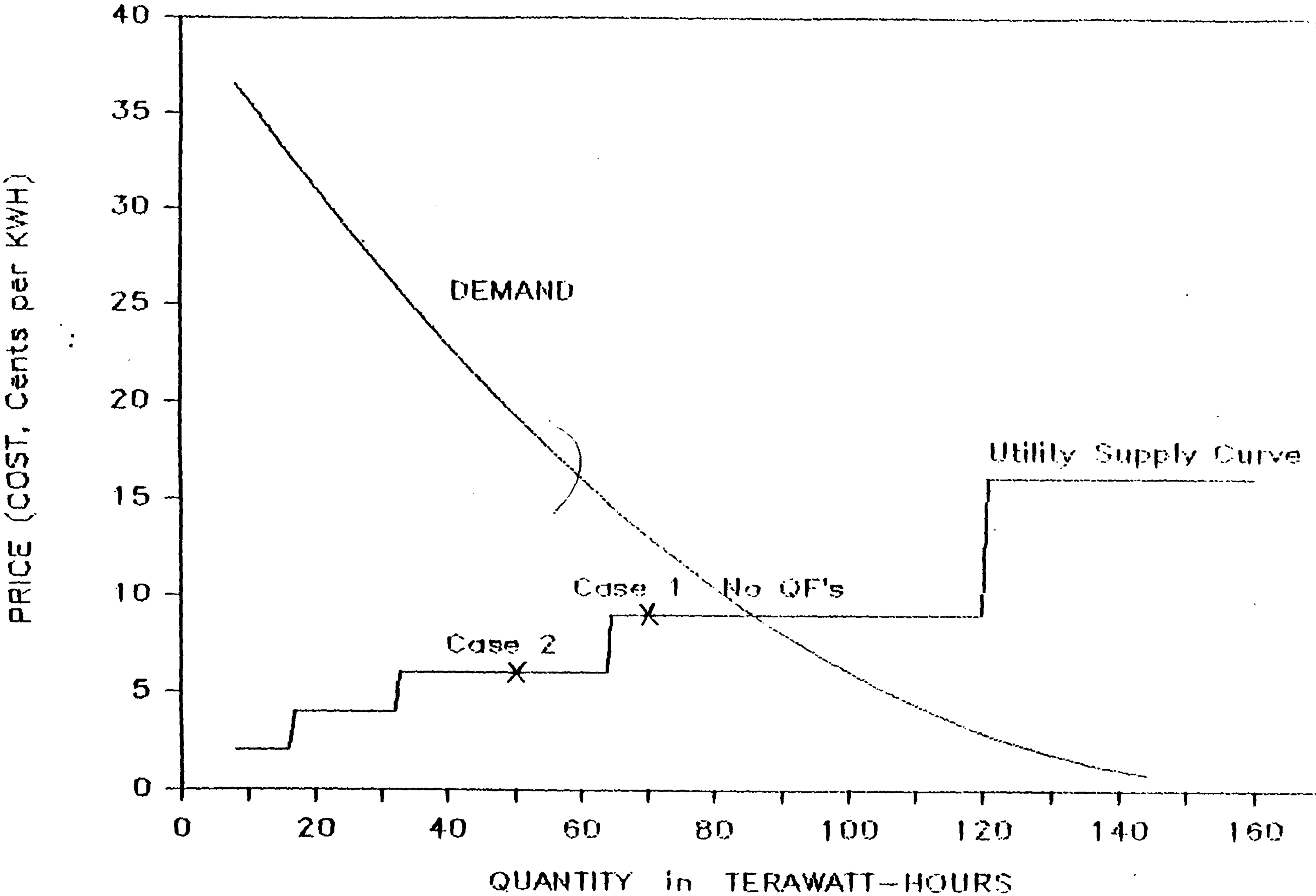
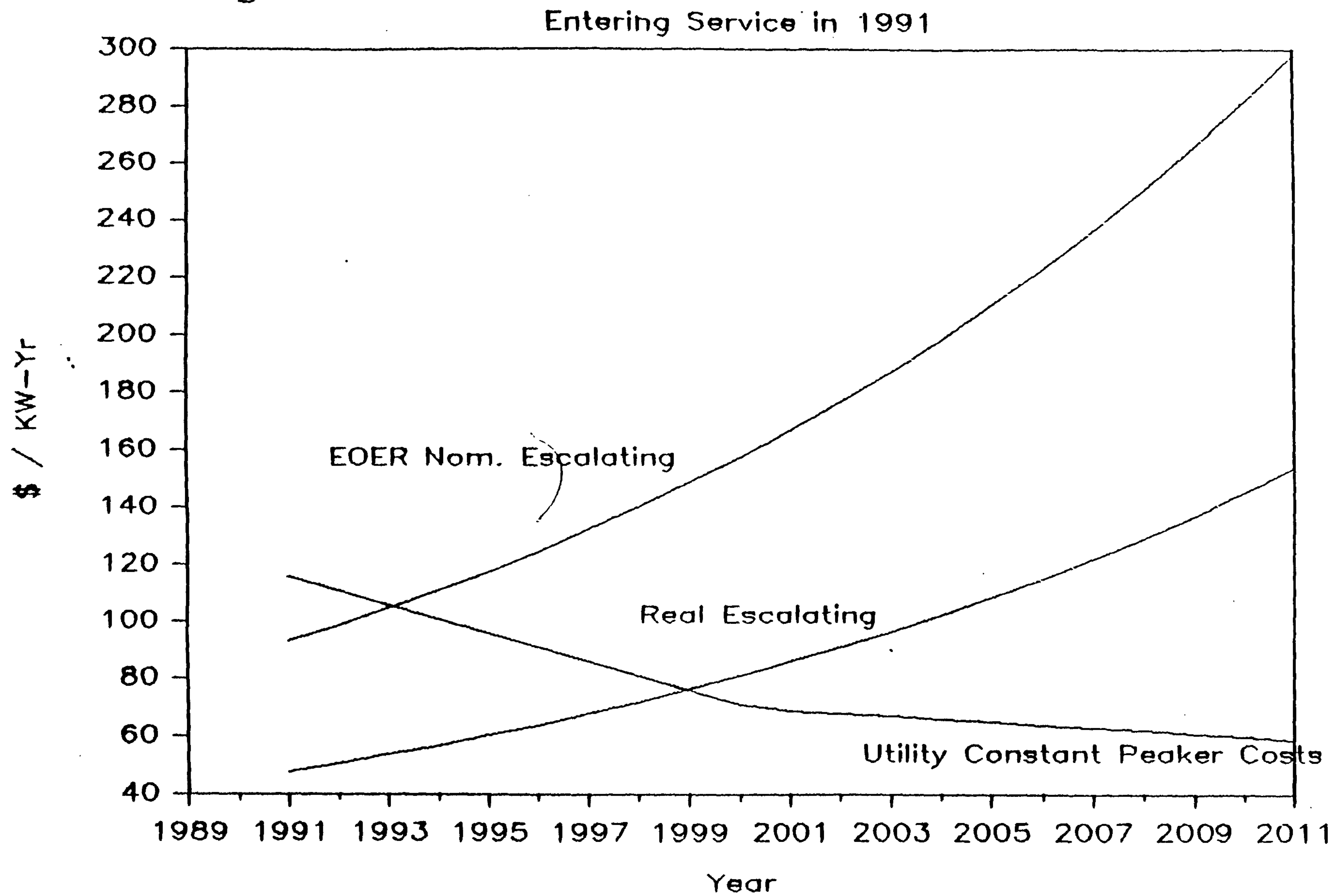


Fig. 6: Credit Calculations for QF's



APPENDIX A:

SHORT RUN CAPACITY COSTS

MMWEC PROJECTIONS

ANALYSIS AND INFERENCE INC — RESEARCH AND CONSULTING
10 POST OFFICE SQUARE [illegible] BOSTON MASSACHUSETTS 02109 [illegible] 542 [illegible]

MMWEC
Massachusetts Municipal Wholesale Electric Company
Stony Brook Energy Center Post Office Box 426 Ludlow, Massachusetts 01056
(413)589-0141 589-0801

October 2, 1985

****
* Response Requested *
* By November 1, 1985 *
****

Mr. Everett Lutzy, Acting Manager
Hull Municipal Lighting Plant
15 Edgewater Road
Hull, MA 02045

Dear Mr. Lutzy:

For the past several months, MMWEC staff has been developing a Cogeneration and Small Power Producers Power Purchase Program. Under this program, MMWEC would purchase power from qualifying cogenerators and small power producers and sell that power to participating member systems at each system's avoided cost. This program has been designed to help members meet their long term power supply requirements. At the same time the program will encourage the development of cogeneration and small power production and fulfill your responsibilities and MMWEC's under applicable federal and state laws.

Both the MMWEC Board of Directors and the Board's Planning and Operations Committee have been briefed on this program. At their September meeting, the P & O Committee voted to approve the program as presented by the staff. Before the program can begin, member systems must sign up to purchase power at their avoided cost. This letter, however, is not a recommendation to sign up for this program. Rather, this letter and its attachments are intended to provide an initial description of the program, to present Hull Municipal Lighting Plant's avoided cost as calculated by MMWEC and to list the assumptions used in calculating Hull's avoided cost.

Please review this information carefully. If you would like to change any of the power supply assumptions or would like more detailed information, please notify Dave LaPlante at MMWEC and a new avoided cost, incorporating the new assumptions, can be calculated. This interim step is being taken to insure that, when MMWEC presents a recommendation to Hull for final vote on participation in the program, you have already had a chance to review the avoided costs in the recommendation.

Very truly yours,

William H. Dunn, Jr., Manager
Power Management Division

RECEIVED OCT 4 1985

WHD/KAP/lbl

DESCRIPTION OF ATTACHMENTS

Hull Municipal Lighting Plant

MMWEC'S COGENERATION/SMALL POWER PRODUCERS
POWER PURCHASE PROGRAM

The avoided costs and the assumptions used to calculate them are described in several attachments.

Attachment 1 is a description of the Cogeneration and Small Power Producers purchase program.

Attachment 2 lists Hull's avoided costs. Avoided costs were calculated for power years 1985/86-2004/05. The avoided costs for each year were calculated for four separate time periods, on-peak summer, on-peak winter, off-peak summer, and off-peak winter. Each of these rates were then levelized to determine levelized time of day rates for time periods of 20, 19, 18 and 17 years, respectively.

Attachment 3 lists the unit additions assumed in the study. These unit additions are those required above Hull's firm capacity commitments to economically meet forecasted load and reserves. Through 1993/94, we assumed that capacity or energy needs could be met through the purchase of existing intermediate or peaking units. In the long term we assumed those needs would be met through the construction of new coal, combined cycle or peaking capacity. This is the first avoided cost study in which a new combined cycle was assumed available. Lower oil price projections make it an economic alternative to coal, at least until 2000.

Attachment 4 lists the fuel price assumptions used in the study. These fuel price projections are significantly lower than past projections. The lower fuel price projections make these avoided costs lower than past avoided cost projections.

Attachment 5 is a load and capacity summary for Hull for the entire period. Please note that the forcast recently filed with the Massachusetts Energy Facilities Siting Council was used in this analysis.

Attachment 6 lists the capital cost of the unit additions used in the analysis.

Attachment 6

CAPITAL COST OF UNIT ADDITIONS

	Existing Units			New Units		
Year	Middletown 4*	NU GT*	($/KW-YR)	Combined Cycle	Gas Turbine	New Coal
1985/86	43.00	16.85				
86/87	43.00	17.87				
87/88	43.00	18.94				
88/89	43.00	20.07				
89/90	43.00	21.28				
90/91	43.00	22.55				
91/92	43.00	23.91				
92/93	43.00	25.34				
93/94	43.00	26.86				
94/95				212.55	139.70	306.03**
95/96				215.51	140.31	647.48
96/97				218.66	140.96	705.03
97/98				259.61	171.23	382.18
98/99				263.18	171.96	810.12
99/00				266.98	172.73	882.23
00/01				317.10	210.44	884.52
01/02				321.41	211.31	886.95
02/03				326.00	212.22	889.54
03/04				387.32	259.20	892.31
04/05				392.53	259.70	895.25

* Units assumed unavailable after 1993/94.
** Low costs caused by financing interest past C.O.D.