EC

Riverside Steam and Electric
DPU 88-123
Exhibit PLC-1

COMMONWEALTH OF MASSACHUSETTS
BEFORE THE DEPARTMENT OF PUBLIC UTILITIES

DIRECT TESTIMONY OF

PAUL CHERNICK
PLC, Inc.

ON BEHALF OF THE

RIVERSIDE STEAM AND ELECTRIC COMPANY

JULY 24, 1989

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1. QUALIFICATIONS AND INTRODUCTION

1.1 Qualifications

Q: Please state your name and business address.

A: My name is Paul L. Chernick. I am President of PLC, Inc., 18 Tremont Street, Suite 703, Boston, Massachusetts.

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

A: I received an S.B. degree from the Massachusetts Institute of Technology in June, 1974 from the Civil Engineering Department, and an 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.

As a Research Associate at Analysis and Inference, Inc., and in my current position as President of PLC, Inc., I have advised a variety of clients on utility matters. My work has considered, among other things, revenue allocation and ratemaking.

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

A: Yes. I have testified approximately sixty times on utility issues before such agencies as the Massachusetts Energy Facilities Siting Council, the Maine Public Utilities Commission, the Texas Public Utilities Commission, the Illinois Commerce Commission, the Vermont Public Service Board, the District of Columbia Public Service Commission, the New Mexico Public Service Commission, the Pennsylvania Public Utilities Commission, the Federal Energy Regulatory Commission, the Boston Public Improvements Commission, the Rhode Island Public Utilities Commission, the New Hampshire Public Utilities Commission, the Michigan Public Service Commission, the Connecticut Department of Public Utility Control, the Minnesota Public Utilities Commission, and the Atomic Safety and Licensing Board of the U.S. Nuclear Regulatory Commission.

Subjects I have testified on include cost allocation, rate design, marginal cost estimation, long range energy and demand forecasts, costs of nuclear power, conservation costs and potential effectiveness, generation system reliability, fuel efficiency standards, and ratemaking for utility production investments and conservation programs.

I have testified approximately 26 times before the Massachusetts Department of Public Utilities (DPU) on topics including rate design, capacity planning, and ratemaking. I testified on avoided cost calculation methodologies and related issues in ratemaking for qualifying facilities (QFs) in the DPU's rulemakings in Dockets DPU 535 and DPU 84-276.

1.2 Introduction

Q: What is the purpose of this testimony?

A: The purpose of this testimony is to review the reasonableness of the assumptions, analyses and presentations of Northeast Utilities (NU) and its subsidiary Western Massachusetts Electric Company (WMECO) in their filings with the DPU, and in their negotiation of an Electricity Purchase Agreement with Riverside Steam & Electric Company (Riverside). Riverside proposed to build a 34 MW fluidized-bed coal-fired cogenerator to serve the Holyoke district heating system and to sell power to WMECO.[1] The contract was signed in October 1986, and NU filed for approval of the contract in October 1987. NU's filings with the DPU, and particularly its avoided-cost estimates and its defense of those estimates, were critical to the DPU's rejection of the 10/86 contract between the two parties in DPU 88-19. NU's rejection of a revised contract

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[1]The proposed power purchase contracts would have been between Riverside and WMECO. However, the avoided cost runs were conducted at the NU level, and the utility staff involved in the analyses and negotiations were employees of the NU service company. Due to the NU Generation and Transmission (G&T) Agreement, the incremental costs of WMECO and the other NU operating companies are identical, and are calculated on the basis of NU combined loads, resources, and dispatch. Due to this lack of distinction between the two, I use the terms "NU" and "WMECO" essentially interchangeably in this testimony.

offered by Riverside in April of 1988 was also supported by its avoided cost estimates.

I am familiar with the factual background of this dispute, having provided expert analyses for Riverside in DPU 88-19 and in an earlier phase of this proceeding, DPU 88-123.

Q: What is the major conclusion of your analysis?

A: I have concluded that NU's December 1987 calculation of its avoided costs was based on unreasonable and undisclosed assumptions. Further, these assumptions were in violation of DPU requirements. As a result of the unreasonableness of these assumptions, the avoided cost NU used to calculate the economics of the Riverside contract was lower than the avoided cost it should reasonably have used, and the Riverside contract appeared uneconomical. Had this calculation been done as required by the DPU, and with otherwise reasonable assumptions, the economic analysis would have more positively affected the negotiations between WMECo and Riverside, as well as the decision in DPU 88-19.

Q: Please describe the nature of the unreasonable assumptions on which NU's avoided cost calculation was based.

A: NU effectively deceived the DPU and Riverside by misrepresenting, or failing to disclose in both the 10/86 contract and 4/88 proposal, the following three assumptions which were critical to its calculation of avoided costs:

1. NU told the DPU it was assuming its nuclear units would achieve mature capacity factors of 70%. It was actually

assuming much higher capacity factors, on the order of 75%. Had the 70% nuclear capacity factor been used in the calculation of the avoided costs of the Riverside contract, as the DPU required, the 25 year economics of the Riverside 10/86 contract and 4/88 proposal would have improved 2-3 percentage points.

2. NU failed to inform the DPU that it was assuming, for purposes of its avoided-cost calculations, the availability of substantial quantities of low cost economy energy. Such disclosures are required by the DPU rules. In addition, NU's assumptions regarding the availability of substantial quantities and low prices of economy purchases were unreasonable, given recent NEPOOL forecasts of load and supply. When the economics of the Riverside contract are calculated without these economy purchases, the 25 year economics improve by an additional 2-3 percentage points.

3. NU described the projected nuclear capacity factors used in the calculation of its avoided costs as if they were independent of the availability of QF power, an assumption which is consistent with the requirements of the DPU. In fact, the avoided cost calculations were based on capacity factors for nuclear (and other baseload) units that were lower when QF capacity (such as Riverside) was available than when it was not. Further, this cheap nuclear and coal generated power is

backed out when QF power is available, while the amount of economy purchases is not affected. NU assumes there will be no revenue from the sale of the nuclear and coal plant capacity backed out by the QF power. When the 25 year economics of the Riverside contract were adjusted to incorporate revenues from the sale of excess power from these plants, they improved by about 3 percentage points.

NU's treatment of all of these issues was unrealistic and unreasonable, and its failure to describe properly its avoided cost calculations violated DPU regulations.

Q: Did NU make any other assumptions detrimental to Riverside?

A: Yes. NU further understated the avoided costs of the Riverside 10/86 contract and 4/88 proposal in several other ways. NU included energy from Seabrook in its production costing runs, used a reference oil price lower than its expected price of oil, included plants in its generating mix after the end of their projected useful lives, omitted any sales of economy power and treated life extensions as if they were the only avoidable capacity.

Correcting for Seabrook and the oil price assumption alone improves the 25 year contract ratio by another 2-3 percentage points.

Had all of the elements of the analysis been reasonably performed, NU's avoided cost projections and its analysis of the economics of Riverside would have been significantly different than the projections and analyses on which NU relied and which NU submitted to the DPU. I estimate that the cumulative effect of correcting NU's unreasonable assumptions and other errors would be to reduce the ratio of the proposed April 1988 contract price to NU's avoided cost over 25 years from the 107% estimated by NU to 96%, and to advance the break-even date from the thirtieth year of the contract to the twenty-second year.[2]

Q: How is the remainder of this testimony structured?

A: Section 2 of this testimony briefly discusses the 12/87 testimony of NU, the subsequent DPU decision in Docket 88-19, the revised contract offer submitted by Riverside to WMECo in 4/88. This section has been included to clarify the assumptions and actions of NU as a basis for the detailed analysis presented in Sections 3 through 6.

Sections 3 through 6 highlight NU's treatment of various elements in the calculation of its avoided costs and of the economics of the Riverside contract. For each of Sections 3 through 5, I first present what (if anything) NU said it was doing on a particular topic (NU's representations), and discuss what NU has previously done in earlier avoided cost calculations. This is followed by a discussion of what NU actually did (NU's assumptions), and an analysis of the actual

[2]Similarly, the cost ratio for the 10/86 contract over thirty years would fall from 109% to slightly under 100%. The two pricing structures are described in more detail below.

situation as it contrasts with NU's representation of the situation. The final element in each section addresses the effect of NU's assumptions on the economics of the Riverside contract.

Section 3 demonstrates that NU used capacity factors for its nuclear plants which were much higher than those it said it was using (correcting this error improves the economics of the Riverside contract by 2-3 percentage points). Section 4 establishes that NU unreasonably assumed the availability of significant amounts of economy energy at very low prices. Correcting this error improves the economics of the Riverside contract by another 2-3 percentage points.

Section 5 shows that in the case where QF power is assumed to be available, NU backs out cheap nuclear and coal generated power while it continues to make economy purchases. Correcting for this error improves the economics of the Riverside contract by about 3 percentage points.

Section 6 highlights other understatements of NU's calculated avoided costs, like the inclusion of Seabrook power and using reference rather than expected oil prices. Correcting only for these two errors improves the economics of the Riverside contract by another 2-3 percentage points. In addition, Section 6 looks at five other significant errors (see page 6) which I have not attempted to quantify.

The tables referenced in this document are compiled in Exhibits PLC-3 and PLC-4. Exhibit PLC-3 contains the various economic analyses (labeled as "Table E.x"), while Exhibit PLC-4 contains the calculations underlying my analysis. The latter computations are labeled as "Table Y.x", where Y is the section of this testimony to which the table relates.

NU's responses to Riverside's discovery in this proceeding are referred to as IR R-x, where x is the number of the response.

2. NU's DECEMBER 1987 AVOIDED-COST ANALYSIS

Q: On what avoided-cost estimate does your review concentrate?

A: My analysis focused on the Production Simulation Model (ProSim Model) which NU used to calculate the avoided costs filed in response to DPU discovery questions in DPU 88-19, 12/87. Most of the detailed assumptions at issue in this proceeding were not documented prior to the discovery requests in this case. In response to these requests, NU provided the input and output of the ProSim Model, including a pair of runs which appear to be the basis for the avoided cost projection in DPU 88-19.

Under DPU rules, each estimate of a utility's avoided fuel costs is calculated by the comparison of a Base Case and a Change Case. The Base Case is essentially the utility's current expectation of future demand and supply.[3] The Change Case is supposed to represent the operation of the utility's system with the addition of a group of QFs and without whatever planned supply additions would be avoided by the QFs. The 12/87 Change Case represents the availability of 238 MW of qualifying facility (QF) power in each hour. The primary impact of the availability of this QF capacity is that NU can avoid life extensions on Montville 5, West Springfield 3, and Middletown 2. These life extensions were (and are) scheduled

[3]The production costing runs compute fuel and related variable O&M costs, so the important inputs are those which relate to energy supply and output, rather than to peak load and capacity.

for the period 1995-98, with costs reflected in rates as early as 1991.

Total avoided costs are computed as the sum of:

(1) fuel and variable O&M costs: the difference in cost between the Base and Change Case production costing model runs,

(2) capacity costs: the cost of a hypothetical peaking unit added in the first year of capacity need (assumed to be 1998 in the 12/87 filing),

(3) capitalized energy: the difference between the cost of the projected avoided units and the cost of the hypothetical peaker, and

(4) losses.[4]

Throughout this testimony, I will refer to NU's original 12/87 production costing computation as "Run 1." In response to Riverside discovery requests in the current case, NU produced two variants on the original production cost simulation in response to IR R-45. One variant (which I will call Run 2) reduces the Base Case mature nuclear capacity factors to 70% from the higher levels assumed in Run 1. The second variant (Run 3) uses the Run 2 nuclear capacity factors and also eliminates economy energy purchases. From these

[4]DPU regulations also provide for a credit to QFs to reflect the additional off-system economy energy sales made possible by the QF energy. NU has always maintained that this credit should be zero.

calculations supplied by NU, I have further examined the effects of other corrections documented in this testimony.

Q: How were the 12/87 avoided cost projections introduced into DPU 88-19?

A: WMECO originally filed the 10/86 contract in October 1987 with a series of three cost-benefit analyses (each of which contained variations for reference, low and high oil costs), reflecting NU's avoided cost estimates at various stages of the negotiation process with Riverside. These are presented in Briefing Documents A, B, and C in WMECO's 10/87 filing with the DPU. The proposed Riverside contract was cost-effective under the two earlier analyses but not cost-effective under the cost-benefit analysis based on the avoided cost estimates which had been filed in October 1986 for WMECO's first solicitation of bids for power from QFs.

Riverside filed comments on WMECO's 10/87 filing, including the testimony of William B. Marcus, which (among other things) pointed out that:

- NU's avoided costs were based on an oil price forecast which was now out-dated, and which was considerably lower than current oil price projections,
- NU was assuming that the first capitalized energy project which the QFs could replace would be the repowering of Devon 5 and 6 as a gasification-combined-cycle (GCC) coal plant in 2003, even though NU was scheduling the life-extension investments for several years earlier, and
- NU was assuming 70% mature capacity factors for its nuclear units, which in most cases was higher than could be justified from the past performance of the same or similar units.

In discovery filed in DPU 88-19, the DPU requested that NU provide a new avoided cost calculation using the 8/87 DRI fuel price forecast, and assuming the avoidance of the life extensions.

In the 12/87 discovery response, NU provided (in Briefing Document D) the avoided cost projections at issue in this proceeding. These projections in turn formed the basis for the rejection of the original 10/86 Riverside contract by the DPU, and NU's rejection of Riverside's 4/88 proposed contract revisions. The new calculation of the avoided costs generally appeared to comply with the DPU's request, but as discovery in this proceeding revealed, the projections in Briefing Document D contained undisclosed and unexplained changes from earlier briefing documents.

The major components of the 12/87 avoided cost estimate at Riverside's voltage level (115 kV) are shown in Table 2.1.

Q: What was the effect of the 12/87 avoided cost projections on the apparent economics of the Riverside project?

A: Under this set of avoided cost projections, the Riverside project appears to be less economical than continued use of NU's existing and planned resources. Table E.1 compares the 12/87 avoided cost estimates to the 10/86 contract prices and to the contract prices offered by Riverside to WMECO in 4/88.[5]

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[5]The contract is stated in terms of the GNP inflator. I use the GNP inflation rates assumed by NU.

The comparisons shown in Table E.1 are essentially identical to those performed by NU, except that Table E.1 is stated in cents/kWh, rather than in millions of dollars annually.[6]

NU's 12/87 analysis concluded that the 25 year present value contract ratio was 117% for the 10/86 contract. Based on this analysis of the 10/86 contract, the DPU in DPU 88-19 (January, 1988) rejected the initial contract which had been signed by Riverside and WMECO.

Q: What was the result of the DPU's decision?

A: The DPU suggested that the parties attempt to renegotiate the contract (DPU 88-19, page 33). Riverside then submitted the revised contract proposal to WMECO in an attempt to achieve such renegotiation. Based on its comparison of the 4/88 offer to the 12/87 avoided cost estimates (with a 25 year present value contract ratio of 107%), NU rejected the offer. NU's estimate of avoided costs was critical to the decision of the DPU in DPU 88-19, and to NU's rejection of the contract renegotiation proposal presented by Riverside.

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[6] NU gets slightly different ratios in some cases. For example, the 25-year contract ratio for the 10/86 offer presented by NU was 117 as compared to 117.17 presented in Table E.1. Similarly NU's contract ratio for the 4/88 proposal was 106 compared to 106.66 in E.1. I believe these differences are due to NU's inclusion of all of 1990 in their analysis, a one year difference in the timing of the 3.6 cent reduction in the contract price, and round-off. (I assumed throughout that Riverside would have started operation on 11/1/90. Somewhat earlier operation was assumed when NU filed the 10/86 contract.)

3. NU's NUCLEAR CAPACITY FACTORS

3.1 NU's Representations

Q: What nuclear capacity factors did NU represent that it used in the calculation of the avoided costs for the 12/87 and subsequent filings?

A: NU's presentation never left any doubt that it had assumed 70% mature nuclear capacity factors. The DPU discovery in DPU 88-19 requested:

> In the Company's computations of its avoided costs, please provide all relevant assumptions, with sources defined, including, but not limited to: . . . source of unit performance criteria used in avoided energy cost calculations. (i.e., historic or expected)
>
> (Information Request DPU-1, Q-DPU-1)

NU's formal response to the DPU discovery request was silent as to the assumed nuclear capacity factors. However, just four days after the discovery response was filed, NU responded to Riverside's comments, and presented evidence that NU's average nuclear capacity factor had been about 70% and insisted that "what the Company is using" was reasonable. (Stillinger Comments, December 7, 1987, page 7) In the same paragraph, NU compared its "goals for nuclear performance in the near and long term," or capacity factors, to the NEPOOL Performance Incentive Program. The target unit availability for nuclear units in the NEPOOL Plan is 70.6% (IR R-15, Attachment 5). These comments unambiguously indicated that NU was using 70% mature nuclear capacity factors in its calculations.

NU repeated that it was using a 70% mature nuclear capacity factor in the 12/87 avoided-cost estimate, in the 4/26/88 letter from Brian Curry to Paul Tsongas (page 4), rejecting Riverside's proposed revision to the contract. NU stated:

> We assume mature nuclear units will operate at an average annual capacity factor of 70% in the long term.

In the DPU's decision in 88-19, the Department clearly believed that NU was using a nuclear capacity factor of 70% (DPU 88-19, p. 19)("WMECO...contends that its 70% capacity factor assumption is realistic and consistent with the historical performance of the company's nuclear units..."), and relied on the use of that figure. In the Motion to Dismiss filed 6/88, NU cited the DPU approval of the avoided cost calculations (including explicit approval of a 70% nuclear capacity factor) as approval of NU's assumptions.

3.2 <u>NU's Nuclear Capacity Factor Assumptions</u>

Q: What nuclear capacity factors did NU use in its 12/87 calculation of avoided costs?

A: Although it said it was using a 70% capacity factor, NU actually used significantly higher nuclear capacity factors. Indeed, the nuclear capacity factors were significantly higher than NU had used in previous years. As shown in Exhibit PLC-5 the 1985 and 1986 avoided cost estimates, internal and regulatory, all use capacity factors which are less than the

12/87 assumptions. In the 12/87 filing NU raised the capacity factor projection from 70% to 75%. The capacity factors NU actually used in each year of the Base Case are shown in Table 3.3, and in the Change Case in Table 3.4.[7] Exhibit PLC-7 presents NU's summary of the Base Case capacity factors, which are consistent with my results.

In the Base Case, Table 3.3 shows that NU assumed nuclear capacity factors which varied from year to year (with refueling schedules) but which averaged much more than 70%. NU assumed that from 1990 to 1997 the capacity factors for Millstone 1, Massachusetts Yankee, Vermont Yankee and Maine Yankee vary between 77% and 80%, and that Millstone 2 and Connecticut Yankee's mature capacity factors vary between 74% and 75%. The capacity factors for Vermont Yankee, Maine Yankee and Seabrook stabilize at 70% after 1997, and at 75% for the Millstone plants and Connecticut Yankee. which make up 90% of NU's nuclear capacity. Massachusetts Yankee is assumed to be retired in 1998 (as NU has generally indicated in EFSC filings and elsewhere.) The use of these individual nuclear capacity factors resulted in the use, for the purposes of the Base Case avoided cost calculation, of an average nuclear capacity factor for the mature units of 76.35% in

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[7]These tables are derived from NU's production costing run outputs, which were provided in a form comparable to Exhibit PLC-6.

1990-97, and of about 74.5% thereafter.[8] Thus, NU used capacity factors which averaged 5-6 percentage points higher than those approved by the DPU.

A similar analysis of the Change Case presented in Table 3.4 confirms that NU assumed mature capacity factors which are higher than those approved by the DPU. In 1990-97, Millstone 1, Massachusetts Yankee, Vermont Yankee and Maine Yankee the mature capacity factors vary between 73% and 78%, and Millstone 2 and Connecticut Yankee's mature capacity factors vary between 71% and 74%. These individual nuclear capacity factor assumptions resulted in the use of an average 1990-97 mature nuclear capacity factor of 74.65% in the Change Case avoided cost calculation.[9]

Q: What is the significance of NU's nuclear capacity factor assumptions?

A: Not only do these assumptions represent a major departure from what NU claimed to be using, they also represent a major departure from the 70% mature capacity factor approved by the DPU and used in previous NU filings, including WMECO's filing in DPU 85-270 (Millstone 3 cost recovery) and WMECO's 10/86 avoided cost projections, as summarized by NU in Exhibit PLC-

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[8]The annual average after 1998 fluctuates between 74.4% and 74.6%. After 2007, the retirement of older units increases the weighted averages, which rise towards 75%.

[9]The effect of the difference between the nuclear capacity factors used in the Base and Change cases will be discussed in Section 5 of this testimony.

5.

NU made this change, even though the DPU's discovery request did not ask NU to increase projected nuclear capacity factors, and even though no such increase was noted in NU's 12/87 responses,[10] nor at any time until Riverside was able to compel disclosure through discovery filed in this proceeding in March 1989.

Q: Were NU's assumptions regarding nuclear capacity factors at issue in DPU 88-19?

A: Riverside's comments on WMECO's analysis of the 10/86 contract questioned the use of a 70% nuclear capacity factor. Based on NU's prior practice, Mr. Marcus stated that NU was using a mature nuclear capacity factor of 70%. At that time, Mr. Marcus was advocating lower mature capacity factors of 63.3% to 68.5% for the Millstone units 1 and 2 based on their historical performance, and mature capacity factors of 60% for Millstone 3 and Seabrook based on their lack of operating history and the experience of comparable units. Using these factors would have resulted in production of 589 fewer GWH of annual nuclear electric generation than NU assumed.

Indeed, NU assumed a 70% mature capacity factor in previous analyses, as NU demonstrates in IR R-5, which is attached as Exhibit PLC-5. Table 3.1 lists the annual nuclear capacity factors assumed by NU in DPU 85-270, in which NU

[10] As noted above, the DPU specifically asked NU to explain its important capacity factor assumptions.

attempted to demonstrate that Millstone 3, soon to come into service, was economically useful.[11] In this case, most units were assumed to operate at 70% in most years, and all were assumed to operate at 70% in every year after 1995. This analysis was performed by NU in March 1986.

Q: Are the differences between the 70% nuclear capacity factors NU said it had used, and the 75% capacity figures it actually used, significant compared to the range of capacity factors in dispute in 88-19?

A: Yes. The 5% increase in NU's average nuclear capacity factors produces 1177 GWH/year of additional baseload generation. This difference is twice as large as the difference between Mr. Marcus's recommendation and the 70% value NU claimed to be using.

3.3 <u>Actual Unit Performance</u>

Q: How well have NU's nuclear power plants and entitlements actually performed?

A: Table 3.5 lists the lifetime nuclear capacity factors of NU's nuclear plants. The capacity factors are computed at the capacity ratings used in NU's capacity planning and production costing runs. They are further weighted by NU's entitlement in each plant. Note that Millstone 3 has less than three

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[11] Exhibit PLC-6 provides examples of the data used in preparing Table 3.1.

years of operating experience. Seabrook has no operating history and is not shown on this table.

Table 3.5 shows that the weighted average capacity factor of the plants with significant operating history is about 69%. Individual lifetime capacity factors for Millstone 2 and Maine Yankee are between 65% and 67%, for Massachusetts Yankee and Vermont Yankee are about 69%, and for Millstone 1 and Connecticut Yankee are between 72% and 74%. Millstone 3 was not included in this calculation due to its short operating history.

Q: Of the NU units with significant operating experience, which is most similar to Millstone 3 and Seabrook, for which little or no actual experience is available?

A: Millstone 2 and Maine Yankee, like Millstone 3 and Seabrook, are fairly large, New England, ocean-cooled Pressurized Water Reactors. Their capacity factors have both averaged approximately 66%.

3.4 <u>Effect on Riverside Economics</u>

Q: What effect did NU's use of high nuclear capacity factors have on the economics of the Riverside contract?

A: The effect of NU's high nuclear capacity factor assumptions on the calculation of avoided costs is illustrated by comparing Tables E.1 and E.2. Table E.1 presents the calculation of the avoided fuel costs presented in the 12/87 avoided cost projection, from NU's ProSim model Run 1. Table

E.2 presents the calculation of the avoided fuel costs provided in response to IR R-45 (NU's ProSim model Run 2), in which NU reduced its mature nuclear capacity factors to the 70% value approved by the DPU. Comparison of these two tables reveals that basing the avoided cost projections on 70% nuclear capacity factors (without correction for any other assumptions) improves the 25 year present-value ratio of contract price to projected avoided cost (the "contract ratio") by about 2.4 percentage points to 113% for the 10/86 contract and 104% for the 4/88 proposal.[12]

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[12] I use the 25-year contract term throughout this testimony to summarize the effects of changing various assumptions. The DPU's decision in Northeast Landfill case February 11, 1988 determined that an evaluation period longer than 20 years is appropriate for a QF project with technical and environmental advantages comparable to those of the Riverside project. The decision in DPU 88-19 found that 30 years was an excessive analysis period, at least on the record in that case. The contract ratio for each year is given in Tables E.x, PLC-3.

4. NU'S ASSUMED ECONOMY PURCHASES

4.1 <u>NU's Representations</u>

Q: What is economy energy?

A: Economy energy is unscheduled purchases of power from other utilities at prices below NU's marginal costs. These purchases are made on a short-term basis, to suit the economics and the convenience of the utilities and are not subject to long term contractual obligations of supply or price.

Q: What was NU's stated assumption concerning the availability of economy purchases?

A: None of NU's avoided cost filings provided any statement regarding the source of anticipated purchases of economy energy at the magnitude and price assumed to be available.

Q: What does the most recent Energy Resources Siting Council (EFSC) filing indicate about economy purchases by NU?

A: The 4/87 EFSC filing (the most recent filing available at the time the 12/87 avoided cost calculations were performed) provides no projection of the availability of economy energy to NU, or its use by NU. The only reference in that filing to bulk power purchases is found on page III-8, which states in part that:

> In 1986, NU purchased about 500,000 MWh of economic coal-fired energy ... It is anticipated that future purchases of coal power from the west will be reduced from levels experienced in prior years because of the addition of Millstone Unit 3.

The 1986 and 1988 EFSC filings contained similar statements, with different historical power purchase reports.

Q: What obligations did NU have to report its assumptions regarding the amount, price and source of economy energy it could or would purchase from other utilities?

A: DPU regulations (220 CMR 8.05(2)(c)) specifically require that where "data and assumptions used in the [avoided cost] calculation are different from those used in the most recent demand forecast and resource supply plan filed with the Energy Facilities Siting Council ("EFSC"), the utility must provide a full explanation for the differences."

4.2 NU's Assumptions Regarding Economy Energy Purchases

Q: What did NU actually assume about the availability of economy purchases in its 12/87 calculation of avoided costs?

A: NU assumed that significant amounts of economy energy would be available for purchase at attractive prices.[13] Table 4.1 shows NU's assumed purchases of economy energy from other utilities. The projected quantities purchased grow steadily to over 2 million GWH in 1997, after which the purchases abruptly end. This is four times the 1986 level, and is certainly not a reduction as projected in the EFSC filing. The purchases in 1997 are equivalent to the output of 339 MW of nuclear capacity operating at a 70% capacity factor, or an

[13] In some cases, the prices are so attractive as to be implausible.

increase of all NU nuclear capacity factors by about 9 percentage points. The total purchases in the 1990-97 period are equivalent to 219 MW per year of nuclear capacity at a 70% capacity factor.

Q: Are these assumptions consistent with NU's previous assumptions?

A: No. As shown in Exhibit PLC-5, prior to 1987 NU had projected economy purchases for only 5 years into the future, as opposed to the 10 years in the 12/87 filing.

Q: How did the economy energy purchases vary from the Base Case to the Change Case?

A: The amount of economy purchases do not vary between the Base and Change cases presented in NU's 12/87 calculation of avoided cost, even though NU's own less expensive nuclear and coal power generation are backed out in the Change Case. (For a discussion of this back-out, see Section 5.)

Q: Is this a reasonable result?

A: No. Nuclear plants costing less than one cent per kWh are backed down by the model in the Change Case for run 1, yet the model shows continued purchase of short-term economy energy, including purchases of oil-fired power at up to 4.8 cents/kWh. It is simply wrong to assume that economy energy will continue to be purchased while NU's own baseload plants are backed down. NU's treatment of economy purchases clearly distorts the apparent impact of QF power on the resulting dispatch of the power supply, and thus the avoided fuel costs.

Finally, the input data NU supplied for the ProSim model runs do not appear to specify the availability and price of the economy power. It is possible, indeed it seems likely, that the economy purchases were simply specified exogenously and that economy energy is treated as if it were a must-run power source. In reality, economy purchases are the exact opposite of must-run, since NU need never take them. The inclusion of economy purchases in this way is highly unreasonable. I might add that NU failed to respond to Riverside's discovery request for the support for this economy purchase input data.[14] NU has not established any basis for its assumptions.

Q: Were the prices assumed for the economy purchases consistent with the prices of NU's own generation?

A: No. Table 4.1 presents the projected fuel costs of Mt. Tom, NU's existing coal unit, and of Middletown 2, a moderately low-cost oil unit, for comparison with the coal and oil economy purchase prices, respectively.

The cost escalation for NU's assumed nuclear-powered purchased energy is very odd. Nuclear-powered purchased energy is assumed to cost the same amount in 1997 as in 1990. However, since nuclear power is inexpensive compared to other fuels and the purchases assumed are relatively small, the

[14]NU provided sample contracts, but these samples do not support the purchase assumptions because they do not specify future prices or quantities.

impact of this odd price forecast is minimal.

The price of economy purchases based on coal-fired power rises more slowly than the cost of power from Mt. Tom (31% for the purchases versus 43% for Mt. Tom over the 1990-97 period). The situation for oil-fired economy purchase power is more extreme: the price assumed for economy oil purchases is assumed to rise 35%, as compared to an escalation of 71% for the cost of power from Middletown 2.

Q: Was it reasonable for NU to assume that the cost of economy coal, and especially oil purchases will rise more slowly than NU's own plants' fuel costs at the same time that NU dramatically increases its consumption of such economy energy?

A: No. The current supply of excess power is generally tight, and getting tighter, both within the New England region and outside of it. Table 6.4 shows NEPOOL estimates of baseload power as a percentage of peak demand for the period 1990-2004. NEPOOL predicts that the ratio of baseload capacity to peak demand in New England will steadily decline from 63% in 1990 to 45% in 2004, given current projections of demand and supply. A similar pattern is projected for New York and for the PJM power pool.

The decline in supply relative to load is likely to translate into higher costs and faster price growth for purchased power as compared with NU's own fuel costs, not slower growth as NU has assumed. First, the cost of fuel delivered to other northeastern power plants will grow at the same rate as NU's fuel costs. These plants generally have the same fuel supply, and while there are differences in transportation costs between plants, the growth in the costs should be equal. Second, prices will rise as the plants with lower operating costs are used up, and additional capacity is sought from more expensive units. Therefore, prices of economy purchases should rise faster than NU's own plants using equivalent fuel.

Q: Please summarize your review of NU's treatment of economy purchases.

A: NU assumed economy purchases that were significantly higher than its previous projections, and higher than its EFSC supply plans. It was unreasonable for NU to project purchase prices which escalate at a lower rate than NU's own less expensive baseload fuel price projection and to force its production costing model to use the purchases regardless of cost. Finally, in failing to provide an explanation for the incorporation of these large power purchases in its avoided cost calculations, NU violated the filing requirements of 220 CMR 8.05.

4.3 Effect on Riverside Economics

Q: What were the effects of NU's assumptions concerning the availability of economy purchases on the economics of the Riverside contract?

A: The effect of this assumption was to artificially lower NU's avoided costs. The magnitude of this effect can be seen by comparing Tables E.2 and E.3 which represent Run 2 and Run 3 of the ProSim model, respectively. The difference between Runs 2 and 3 is that in Run 3 NU removes the purchases of economy power from both the Base and Change cases.[15] Elimination of the economy purchases improves the 25 year present value contract ratio by an additional 2-3 percentage points to 111% for the 10/86 contract and 102% for the 4/88 proposal.

[15]Except for economy purchases, Runs 2 and 3 are identical.

5. REDUCTIONS IN NUCLEAR AND COAL GENERATION DUE TO QF AVAILABILITY

5.1 <u>NU's Representations</u>

Q: Did NU indicate in any way that baseload nuclear and coal generation might be affected by the availability of QF power?

A: No. NU makes absolutely no mention of changes in nuclear or coal capacity factors between the Base Case (no QF power available) and Change Case (QF power available) of each of its model runs. NU reports only one set of capacity factors for its nuclear plants.

Q: Was the possibility of changes in baseload generation between the Base Case and Change Case ever specifically addressed in DPU 88-19?

A: No. However, an extensive record on nuclear capacity factors was developed and nowhere in that record does NU indicate that nuclear generation will be affected by the presence of QF power. In Brian Curry's April 26, 1988 letter to Paul Tsongas, Mr. Curry refers to a single capacity factor for each year for Millstone 3 (page 4). In "WMECO Comments on the Testimony of I. C. Bupp and W. A. Marcus Re: The Riverside Cogeneration Project," Mr. Stillinger makes no mention of two sets of capacity factors. Again, in NU's response to IR R-5, where NU specifically addresses the inputs to its various avoided cost filings, a single average capacity factor is reported as an input to each avoided cost calculation. Nowhere does NU make any distinction between Base Case and

Change Case nuclear capacity factors.

5.2 <u>NU's Assumptions</u>

Q: What did NU in fact assume concerning the reduction in nuclear and coal generation due to QF availability?

A: In NU's analysis, the amount of electricity generated by NU's baseload nuclear and coal units is lower in the Change Case than in the Base Case. NU's assumptions regarding nuclear capacity factors in DPU 88-19 are detailed in Tables 3.3 and 3.4. Differences in coal generation in the Base Case and Change Case of each run are calculated in Tables 5.3 through 5.11. NU essentially assumes that QF power backs out cheap nuclear and coal generation, <u>and</u> that baseload nuclear reactors and coal plants would be turned down as a result. Implicit in this assumption is the implausible belief that nuclear and coal-fired energy is neither economic for ratepayers in the New England region nor could it be sold to other utilities above cost.

Q: Do you agree that nuclear and coal generation is uneconomic for New England ratepayers and other utilities?

A: No. Nuclear and coal plants are without question among NU's (and New England's) cheapest sources of electricity in any given hour. Therefore, it is inconceivable that a 238 MW reduction in load would cause NU to generate significantly less of this baseload power. Even if NU could not use the electricity generated by its nuclear plants to back out oil-fired generation on its own system because of must-run requirements, or shut-down and start-up times associated with these units, NU would be able to sell its nuclear power to another utility at a price at least equal to the cost of energy from a low-cost oil-fired plant. In fact, NU currently makes such sales on a regular basis for periods of days, weeks, or months to match its load and supply conditions. The same is true of NU's coal generation.

5.3 Effect on Riverside Economics

Q: What was the effect of NU's assumptions regarding nuclear and coal generation on the economics of the Riverside contract?

A: These assumptions decrease NU's avoided costs and make the Riverside contract offer appear relatively more expensive.

Q: How would the relationship between NU's avoided costs and Riverside's contract offers change if NU corrected its assumptions?

A: Correcting NU's assumptions would reduce the 25 year contract ratio for the 10/86 contract and the 4/88 proposal by approximately 3 percentage points to 107% and 99%, respectively. See Table E.4.

Q: How did you approximate this impact?

A: I calculated this effect by assuming that the baseload generation would operate at the same capacity factor in the Change Case as it had in the Base Case. This is essentially what really happens given the composition of New England generating capacity. QF energy really backs out oil-fired generation and similar high-cost energy sources, not nuclear and coal-fired baseload generation. Under realistic assumptions, the high-cost energy being backed out would be from NU units, or NU would sell short-term energy and/or demand services (from the QFs, from the baseload units, or some other mix of units) to other New England utilities at a price reflecting the savings to the purchasing utility.

In either case, the value of the QF energy is tied to the cost of oil-fired generation. To approximate that cost, I conservatively used the fuel costs of Norwalk 2, one of NU's least-expensive oil-fired units. The increase in the avoided cost for the entire QF contribution (238 MW, or 2,084,880 MWH) is thus, for each baseload plant backed out by NU, the product of (1) the difference in the baseload unit's generation from the Base Case to the Change Case, times (2) the difference in fuel cost between Norwalk 2 and the baseload unit.[16] The total increase in avoided costs is then divided by total QF generation to restate the increase in cents/kWh. Tables 5.1 through 5.11 provide the details of these calculations. The correction in avoided cost for backed-out nuclear generation (column 8 in Table 5.1) was added to the correction for backed-out coal generation (column 10 in Table 5.2), and this

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[16]I treated the nuclear capacity as a single block of power for this analysis, due to the similarity in costs across units and due to the fact that ProSim provided an average fuel cost for all nuclear units.

total was added to the avoided cost projections in Table E.3, to produce the avoided costs in Table E.4 which are thereby corrected for the reduction in nuclear and coal capacity factors.

6. NU's OTHER UNDERSTATEMENTS OF AVOIDED COSTS

Q: Except for the specific problems you address in Sections 3 through 5, was NU's projection of avoided costs in December 1987 an unbiased estimate?

A: No. A number of other assumptions were biased towards understating the avoided costs. These assumptions include:

- the inclusion of Seabrook capacity in NU's supply plan,
- the use (in the Spring 1988 analysis) of avoided costs based on DRI's "reference" fuel prices rather than the higher values from DRI's expected fuel prices,
- the assumption that existing power plants would operate beyond the end of their depreciation lives,
- the assumptions that none of NU's surplus capacity or energy would be resold, and that no additional power freed up by QFs could be sold at a profit, and
- the treatment of the life extensions as the only avoidable capacity.

The individual effect of other assumptions may have been small enough that the use of each of those assumptions may not have produced unreasonable results <u>by itself</u>. Some of the effects which were neglected are difficult to quantify, and might best be dealt with as non-price factors. Nonetheless, the analysis upon which NU based its rejection of Riverside's proposed contract in the spring of 1988 was biased by the assumptions listed above, as well as by those detailed in Sections 3 through 5, and hence contributed to NU's unreasonable rejection of Riverside's proposed contract.

6.1 <u>Inclusion of Seabrook</u>

Q: Was the inclusion of Seabrook in NU's supply plan for the 12/87 avoided cost estimate reasonable?

A: No. The DPU indicated in its decision in DPU 84-152 (April 1985) that completion of Seabrook was far from a certainty. The status of the plant was, and remains, too uncertain to justify its inclusion as committed capacity.

Q: How has the DPU treated the inclusion of Seabrook capacity in avoided-cost calculations in the past?

A: The DPU has repeatedly rejected the inclusion of Seabrook in supply plans for the determination of avoided costs or marginal costs, in at least the following cases:

- DPU 87-50-A/87-51-A (p. 6) (May 6, 1988),
- DPU 87-260 (p. 154) (June 30, 1988)
- DPU 87-221-A (p. 60) (May 31, 1988), and
- DPU 88-135/151 (p. 191) (January 31, 1988).

Q: Did the DPU require the recalculation of avoided costs or marginal costs in all these cases, to remove Seabrook?

A: No. In some cases, the DPU recognized that the small amount of Seabrook owned by a particular utility would have only a minor effect on the avoided cost. For NU, Seabrook represents only 47 MW, and while its inclusion understates avoided costs, the effect was small compared to the total understatement of NU's avoided costs due to NU's other errors. Thus, NU might have acted reasonably in failing to recalculate its 12/87 avoided costs, simply to remove Seabrook, for the purposes of negotiations with Riverside. However, had NU recalculated its avoided costs to correct its other unreasonable and more significant assumptions, it would have also been compelled to remove Seabrook generation.

Q: How much did NU reduce its avoided cost projection by including Seabrook in its supply plan?

A: I do not have a production costing run which determines this change directly. However, I have estimated the Seabrook effect in Table 6.1 by assuming that (1) the change in projected avoided costs per GWH of lost nuclear generation due to the elimination of Seabrook would be the same as (2) the change in projected avoided costs per GWH of lost nuclear generation due to the reduction of nuclear capacity factors from the 75% target to the 70% target, between Run 1 and Run 2.

Table E.5 indicates that removing Seabrook's generation from NU's projected supply would decrease the cost ratio by about 0.6 percentage points, to 98% after 25 years for the 4/88 contract offer and to 107% after 25 years for the 10/86 contract.

6.2 <u>Fuel Price Assumptions</u>

Q: What fuel price projection did NU rely on in rejecting Riverside's proposed contract revision in 4/88?

A: NU used DRI's reference (or median) oil price projection.

Q: Was this the best-estimate or expected-value oil price projection available to NU at that time?

A: No. The DRI oil price forecast used as the basis for the 12/87 avoided cost estimate also provided "high" and "low" price projections. The 12/87 avoided cost calculations were performed for all three price levels.

As discussed by NU, in response to IR DPU-2-1 in DPU 88-19, DRI's estimates of the probability distribution of the oil price projections are equivalent to assuming that the high and low cases have 20% probabilities of occurring, and that the reference case has a 60% probability of occurring. Table 6.6 compares NU's estimates of the present value of revenue requirements for the 10/86 Riverside contract offer, for NU's 12/87 avoided cost projections using low, reference and high fuel price forecasts, and the expected value of those projections, weighted by their estimated probability of occurrence. For each time period, the expected cost of the contract is less than the cost under the reference fuel price projection. Over 25 years, the difference between expected and reference fuel cases is about 3%, which would translate into a reduction of close to 3 percentage points on the contract cost ratio.

Q: Have you determined the effect of replacing NU's reference fuel costs with expected fuel costs in the partially corrected avoided-cost runs discussed above?

A: Yes. In Table 6.2, I calculate expected oil prices as a percentage of projected reference oil prices. In Table 6.3, I re-estimate NU's 12/87 avoided costs using expected oil prices. As shown in Table E.6, adding the incremental effect of this change to the avoided costs in Table E.5 yields corrected 25 year contract ratios of 105% for the 10/86 contract and of 96% for the 4/88 contract offer.

6.3 Power Plant Life Assumptions

Q: What does NU assume about the useful lives of its power plants, in calculating its avoided costs?

A: NU includes many units in its resource mix beyond the date they are expected to be retired for depreciation purposes. Table 6.5 lists the plants which are included in NU's calculation of avoided costs beyond their retirement date and expresses their capacity as a percentage of total capacity. Table 6.5 excludes units which are scheduled for life extensions or for repowering.

Q: What is the DPU's precedent on assuming useful lives for generating units?

A: The DPU requires that utilities use the depreciation lives of their generating units as the best estimate of useful operating lives (DPU 88-250, p. 141).[17]

[17] Utilities may revise their projections of useful life, on the presentation of "engineering and economic analysis" (Id.). It appears that such revision would be applied both to avoided cost projections and to depreciation rates, since the DPU indicates that the same useful life estimate should the basis of both supply

Q: What is the effect on the economics of the Riverside contracts of NU's assumption that some units will operate beyond the end of their depreciation lives?

A: This assumption reduced the avoided costs that NU used to reject Riverside's contracts. I do not have the necessary data so I have not calculated the magnitude of this reduction. However, the amount of capacity involved is not trivial. In 2015, the capacity from plants which have been included beyond their retirement dates is equal to 16% of NU's total capacity in that year, and includes 147 MW of baseload capacity from Mt. Tom.[18]

6.4 Off-System Sales

Q: How did NU treat off-system sales, either those due to the availability of QF capacity and energy, or those which would have occurred regardless of the QFs?

A: NU ignores any sales beyond current commitments.

Q: What is the result of NU's decision?

A: Ignoring the possibility of off-system sales tends to further understate the value of QF capacity and energy. Some fraction of the capacity and energy freed up by QF availability would be sold at more than its fuel cost. Some amount of NU's

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planning and depreciation accounting (Id.).

[18] Mt. Tom represents three times as much baseload capacity as does NU's share of Seabrook.

surplus capacity is likely to be sold, with or without additional QF energy.

Q: What is your basis for assuming that some capacity and energy can be sold for more than cost?

A: Very simply, NU has no incentive to sell for less than cost, and has several options for structuring deals to earn a margin over fuel costs. For example, IR R-37, which is attached as Exhibit PLC-9, describes the process by which NU prices sales "to maximize benefits to the NU Companies' customers," and indicates that NU requires that each "transaction . . . provides benefits to both parties." Similarly, WMECO's response to Information Request AG8-014 in DPU 88-250 states that NU charges an "energy reservation" charge, which is priced competitively at up to $10/MWh.

If sales could not be quantified, they at least represented another positive non-price factor which should have weighed in favor of Riverside.

6.5 <u>Treatment of Avoidable Supply</u>

Q: How did NU treat the determination of avoidable supply, and the estimation of capitalized energy?

A: In the 12/87 estimate, NU assumed that the life extensions would be permanently avoided by the QF capacity. This assumption implied that the QFs would not be able to back out more expensive capacity in later years, such as combined cycle repowering of the Devon units in 1999-2003, a firm purchase from Hydro-Quebec at coal-based prices in 2001-2010, and the installation of 3000 MW of new gasification combined-cycle (GCC) coal plants between 2008 and 2015. The avoidable units are the basis for the capitalized energy costs in the avoided cost projections.

Q: Does NU's assumption regarding avoidable capacity represent a realistic and efficient planning response to the addition of QF capacity?

A: No. The life extensions represent relatively inexpensive capacity. While QF generation should enable NU to reduce revenue requirements by avoiding the capitalized energy costs of the life extensions in the early 1990s, it is likely that the life extensions would be good investments around the turn of the century when NU is planning new intermediate and baseload capacity. When Mr. Marcus (in Riverside's 11/87 filing) suggested that NU treat the life extensions as avoidable, he demonstrated the effect of that treatment by deferring the life extensions until the planned in-service date of a more expensive capacity addition. He assumed that the life extensions would occur when the alternative was an expensive addition of new capacity. This is a realistic and efficient treatment of avoided supply additions; if QF energy is added to NU's system, NU should (and in all likely would) use that energy to avoid the most expensive combination of capitalized energy costs. In general, backing out the most expensive mix of capacity additions produces lower revenue requirements, and higher avoided-cost estimates, than would avoiding any fixed or arbitrary group of capacity.

NU's treatment of avoided capacity deprives the QFs of the opportunity to back out the baseload capacity NU expects to add early in the next century. However, the existence of those new baseload units in the NU production costing runs reduces the avoided fuel costs. Thus, NU computes avoided capitalized energy cost on the basis of the low-capital-cost intermediate life extension capacity, and computes the avoided fuel costs based on the addition of the low-fuel-cost baseload plants. This gives the QFs the short end of the stick with regard to both fuel and capitalized energy.

Q: Is there any reason to believe that the delay of the life extensions would not be technically feasible?

A: No. Either the plants could be operated at low load factors for several years, largely as cold reserve, or they could be temporarily mothballed and then refurbished and returned to service when needed. NU has extensive experience with the resuscitation of "retired" capacity, including Devon 3-6 and a number of combustion turbines, some of which had been retired for several years prior to their return to service.[19]

Q: Would the permanent retirement of Middletown 2, West Springfield 3, and Montville 5 be inconsistent with NU's

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[19]Silver Lake 11 was removed from service in 1977. Until the last couple of years, NU had no plans to bring the unit back into service. NU returned Silver Lake 11 to operation in 1988.

announced policy?

A: Yes. Mr. Stillinger testified that NU "does not believe that it is sound public policy to abandon (even temporarily) existing energy facilities and sites in order to establish new ones" (Stillinger Comments, December 7, 1987, page 10). As NU has done with Devon, Silver Lake, and other units, it would normally keep the potential life-extension units available for future service, to avoid the need to build more expensive new capacity.

Q: What is the result of NU's treatment of avoidable supply additions?

A: NU almost certainly further understated the 12/87 avoided cost projection. I am not able to quantify this understatement without additional production costing runs and updated estimates of new plant costs.

Q: Does this conclude your testimony?

A: Yes.

Filed with DPU
July 24/89.

TABLE E.1: NORTHEAST UTILITIES ESTIMATED AVOIDED COSTS
VERSUS RIVERSIDE CONTRACT PROPOSED IN 10/86 AND IN 4/88
BASE CASE: NU AVOIDED COSTS, RUN 1: DPU 88-19, 12/87

YEAR	TOTAL AVOIDED COSTS	10/86 CONTRACT: WEIGHTED CONTRACT RATE	10/86 CONTRACT: CONTRACT RATE / AVOIDED COSTS	10/86 CONTRACT: CUMMULATIVE RATIO OF PRESENT VALUES	4/88 OFFER: WEIGHTED CONTRACT RATE	4/88 OFFER: CONTRACT RATE / AVOIDED COSTS	4/88 OFFER: CUMMULATIVE RATIO OF PRESENT VALUES
	[1]	[2]	[3]	[4]	[5]	[6]	[7]
1990 (1/6)	0.5	1.2	229.87%	229.87%	1.2	229.69%	229.69%
1991	3.7	7.7	209.35%	212.20%	7.7	209.02%	211.89%
1992	3.4	8.0	237.52%	222.75%	8.0	237.39%	222.52%
1993	5.0	8.4	167.19%	202.73%	8.3	165.51%	201.97%
1994	5.2	8.9	170.01%	194.42%	8.6	165.19%	192.63%
1995	6.0	9.4	157.21%	186.68%	9.0	150.42%	183.84%
1996	5.9	9.9	168.52%	183.84%	9.4	159.22%	179.99%
1997	7.8	10.5	134.30%	175.98%	9.7	124.42%	171.17%
1998	7.9	11.1	140.39%	171.46%	10.1	127.96%	165.68%
1999	9.2	11.6	125.45%	166.00%	10.5	113.78%	159.52%
2000	10.8	12.2	112.76%	160.05%	10.9	101.14%	152.99%
2001	11.2	12.8	114.52%	155.74%	11.0	98.32%	147.81%
2002	12.4	13.5	109.21%	151.71%	11.5	93.44%	143.09%
2003	13.7	14.2	103.52%	147.84%	12.1	88.50%	138.71%
2004	15.1	14.9	98.30%	144.22%	12.8	84.59%	134.70%
2005	16.7	15.7	93.88%	140.73%	13.4	80.18%	130.92%
2006	18.1	16.5	91.06%	137.57%	14.1	77.84%	127.54%
2007	19.9	17.4	87.55%	134.59%	14.8	74.67%	124.39%
2008	21.5	18.3	85.27%	131.88%	15.6	72.74%	121.54%
2009	22.8	19.2	84.22%	129.48%	16.4	71.97%	119.05%
2010	23.8	19.5	81.97%	127.33%	17.2	72.42%	116.92%
2011	25.7	17.4	67.76%	124.79%	14.5	56.43%	114.35%
2012	27.6	18.3	66.22%	122.46%	15.2	55.05%	111.98%
2013	28.2	19.1	67.74%	120.51%	16.0	56.66%	110.01%
2014	29.6	20.1	67.80%	118.79%	16.8	56.58%	108.26%
2015	31.4	21.2	67.51%	117.23%	17.6	56.09%	106.66%
2016	33.5	22.1	65.90%	115.76%	18.5	55.14%	105.18%
2017	36.1	23.3	64.60%	114.37%	19.4	53.83%	103.78%
2018	38.7	24.4	63.05%	113.04%	20.4	52.68%	102.47%
2019	41.6	25.6	61.49%	111.78%	21.4	51.42%	101.21%
2020	44.7	27.0	60.45%	110.59%	22.5	50.32%	100.03%
20 YEAR PV	54.6	69.5	127.29%		63.9	116.92%	
22 YEAR PV	59.4	72.7	122.41%		66.5	111.98%	
25 YEAR PV	65.7	77.0	117.17%		70.1	106.66%	
30 YEAR PV	74.9	82.8	110.53%		75.0	100.03%	

TABLE E.2: NORTHEAST UTILITIES ESTIMATED AVOIDED COSTS
VERSUS RIVERSIDE CONTRACT PROPOSED IN 10/86 AND IN 4/88
RUN 2: 70% NUCLEAR CAPACITY FACTORS ONLY

		----------10/86 CONTRACT----------			----------4/88 OFFER----------		
YEAR	TOTAL AVOIDED COSTS	WEIGHTED CONTRACT RATE	CONTRACT RATE ------------ AVOIDED COSTS	CUMMULATIVE RATIO OF PRESENT VALUES	WEIGHTED CONTRACT RATE	CONTRACT RATE ------------ AVOIDED COSTS	CUMMULATIVE RATIO OF PRESENT VALUES
	[1]	[2]	[3]	[4]	[5]	[6]	[7]
1990 (1/6)	0.6	1.2	194.68%	194.68%	1.2	196.23%	196.23%
1991	3.9	7.7	197.44%	197.02%	7.8	198.85%	198.45%
1992	4.1	8.0	195.12%	196.17%	8.1	196.71%	197.67%
1993	5.3	8.4	158.49%	183.22%	8.4	158.26%	184.13%
1994	5.6	8.9	158.93%	177.21%	8.7	155.77%	177.11%
1995	6.1	9.4	154.10%	172.67%	9.1	148.73%	171.53%
1996	6.8	9.9	145.59%	168.18%	9.4	138.75%	166.10%
1997	7.9	10.5	132.91%	162.95%	9.8	124.21%	159.88%
1998	8.1	11.1	137.04%	159.81%	10.2	125.99%	155.77%
1999	9.3	11.6	124.73%	155.88%	10.6	114.12%	151.10%
2000	10.6	12.2	115.09%	151.65%	11.0	104.13%	146.22%
2001	11.6	12.8	110.34%	147.80%	11.1	95.60%	141.50%
2002	12.8	13.5	105.47%	144.19%	11.7	91.06%	137.19%
2003	13.9	14.2	102.16%	140.93%	12.2	88.13%	133.39%
2004	15.1	14.9	98.68%	137.94%	12.9	85.26%	129.97%
2005	17.3	15.7	90.75%	134.70%	13.5	78.21%	126.42%
2006	18.6	16.5	88.71%	131.82%	14.2	76.53%	123.29%
2007	20.1	17.4	86.57%	129.21%	15.0	74.50%	120.47%
2008	21.7	18.3	84.33%	126.81%	15.8	72.60%	117.91%
2009	23.4	19.2	82.05%	124.58%	16.6	70.76%	115.56%
2010	24.1	19.5	80.91%	122.65%	17.4	72.14%	113.63%
2011	26.0	17.4	66.92%	120.34%	14.7	56.36%	111.25%
2012	27.6	18.3	66.30%	118.26%	15.4	55.75%	109.11%
2013	28.9	19.1	66.09%	116.42%	16.2	55.90%	107.24%
2014	29.8	20.1	67.45%	114.87%	17.0	56.93%	105.63%
2015	32.0	21.2	66.25%	113.40%	17.8	55.66%	104.13%
2016	34.3	22.3	64.90%	112.03%	18.7	54.53%	102.72%
2017	36.8	23.4	63.51%	110.73%	19.6	53.36%	101.39%
2018	39.6	24.5	61.97%	109.48%	20.6	52.07%	100.13%
2019	42.6	25.8	60.49%	108.30%	21.7	50.82%	98.93%
2020	45.6	27.1	59.34%	107.17%	22.7	49.85%	97.80%
20 YEAR PV	56.7	69.5	122.61%		64.4	113.63%	
22 YEAR PV	61.5	72.7	118.22%		67.1	109.11%	
25 YEAR PV	67.9	77.0	113.36%		70.7	104.13%	
30 YEAR PV	77.4	82.9	107.11%		75.7	97.80%	

TABLE E.3: NORTHEAST UTILITIES ESTIMATED AVOIDED COSTS
VERSUS RIVERSIDE CONTRACT PROPOSED IN 10/86 AND IN 4/88
RUN 3: 70% NUCLEAR CAPACITY FACTORS AND NO ECONOMY PURCHASES

		---10/86 CONTRACT---			---4/88 OFFER---		
YEAR	TOTAL AVOIDED COSTS	WEIGHTED CONTRACT RATE	CONTRACT RATE / AVOIDED COSTS	CUMMULATIVE RATIO OF PRESENT VALUES	WEIGHTED CONTRACT RATE	CONTRACT RATE / AVOIDED COSTS	CUMMULATIVE RATIO OF PRESENT VALUES
	[1]	[2]	[3]	[4]	[5]	[6]	[7]
1990 (1/6)	0.7	1.2	184.95%	184.95%	1.2	186.42%	186.42%
1991	4.2	7.7	183.33%	183.57%	7.8	184.64%	184.91%
1992	4.5	8.0	177.78%	180.95%	8.1	179.23%	182.34%
1993	5.7	8.4	147.37%	169.47%	8.4	147.16%	170.31%
1994	5.9	8.9	150.85%	164.95%	8.7	147.85%	164.85%
1995	6.7	9.4	140.30%	160.02%	9.1	135.41%	158.96%
1996	7.4	9.9	133.78%	155.65%	9.4	127.50%	153.72%
1997	8.7	10.5	120.69%	150.37%	9.8	112.79%	147.54%
1998	8.1	11.1	137.04%	148.87%	10.2	125.99%	145.10%
1999	9.3	11.6	124.73%	146.33%	10.6	114.12%	141.84%
2000	10.6	12.2	115.09%	143.27%	11.0	104.13%	138.14%
2001	11.6	12.8	110.34%	140.35%	11.1	95.60%	134.37%
2002	12.8	13.5	105.47%	137.51%	11.7	91.06%	130.85%
2003	13.9	14.2	102.16%	134.89%	12.2	88.13%	127.67%
2004	15.1	14.9	98.68%	132.43%	12.9	85.26%	124.79%
2005	17.3	15.7	90.75%	129.68%	13.5	78.21%	121.71%
2006	18.6	16.5	88.71%	127.20%	14.2	76.53%	118.98%
2007	20.1	17.4	86.57%	124.93%	15.0	74.50%	116.49%
2008	21.7	18.3	84.33%	122.83%	15.8	72.60%	114.21%
2009	23.4	19.2	82.05%	120.87%	16.6	70.76%	112.11%
2010	24.1	19.5	80.91%	119.15%	17.4	72.14%	110.39%
2011	26.0	17.4	66.92%	117.04%	14.7	56.36%	108.20%
2012	27.6	18.3	66.30%	115.14%	15.4	55.75%	106.24%
2013	28.9	19.1	66.09%	113.46%	16.2	55.90%	104.51%
2014	29.8	20.1	67.45%	112.03%	17.0	56.93%	103.03%
2015	32.0	21.2	66.25%	110.69%	17.8	55.66%	101.64%
2016	34.3	22.3	64.90%	109.42%	18.7	54.53%	100.33%
2017	36.8	23.4	63.51%	108.21%	19.6	53.36%	99.09%
2018	39.6	24.5	61.97%	107.06%	20.6	52.07%	97.92%
2019	42.6	25.8	60.49%	105.96%	21.7	50.82%	96.80%
2020	45.6	27.1	59.34%	104.91%	22.7	49.85%	95.74%
20 YEAR PV	58.4	69.5	119.11%		64.4	110.39%	
22 YEAR PV	63.2	72.7	115.10%		67.1	106.24%	
25 YEAR PV	69.6	77.0	110.64%		70.7	101.64%	
30 YEAR PV	79.0	82.9	104.85%		75.7	95.74%	

TABLE E.4: NORTHEAST UTILITIES ESTIMATED AVOIDED COSTS
VERSUS RIVERSIDE CONTRACT PROPOSED IN 10/86 AND IN 4/88
70% NUCLEAR CAPACITY FACTORS AND NO ECONOMY PURCHASES PLUS ADJUSTMENTS
FOR NUCLEAR AND COAL GENERATION

		10/86 CONTRACT			4/88 OFFER		
YEAR	TOTAL AVOIDED COSTS	WEIGHTED CONTRACT RATE	CONTRACT RATE / AVOIDED COSTS	CUMMULATIVE RATIO OF PRESENT VALUES	WEIGHTED CONTRACT RATE	CONTRACT RATE / AVOIDED COSTS	CUMMULATIVE RATIO OF PRESENT VALUES
	[1]	[2]	[3]	[4]	[5]	[6]	[7]
1990 (1/6)	0.7	1.2	175.92%	175.92%	1.2	177.32%	177.32%
1991	4.5	7.7	170.14%	170.98%	7.8	171.35%	172.22%
1992	5.0	8.0	159.24%	165.55%	8.1	160.53%	166.82%
1993	6.0	8.4	141.09%	157.44%	8.4	140.89%	158.22%
1994	6.2	8.9	143.26%	154.05%	8.7	140.42%	153.97%
1995	6.9	9.4	135.67%	150.48%	9.1	130.95%	149.49%
1996	7.6	9.9	130.75%	147.29%	9.4	124.61%	145.47%
1997	8.9	10.5	117.34%	142.97%	9.8	110.13%	140.28%
1998	8.2	11.1	134.99%	142.10%	10.2	124.11%	138.51%
1999	9.4	11.6	122.33%	140.13%	10.6	112.39%	135.83%
2000	10.6	12.2	114.70%	137.72%	11.0	103.77%	132.80%
2001	12.1	12.8	106.14%	134.93%	11.1	91.96%	129.18%
2002	13.2	13.5	102.20%	132.28%	11.7	88.23%	125.87%
2003	14.3	14.2	98.97%	129.83%	12.2	85.37%	122.88%
2004	15.7	14.9	94.96%	127.46%	12.9	82.05%	120.10%
2005	17.5	15.7	89.56%	125.01%	13.5	77.18%	117.33%
2006	19.0	16.5	86.92%	122.75%	14.2	74.99%	114.81%
2007	20.3	17.4	85.60%	120.72%	15.0	73.67%	112.56%
2008	21.9	18.3	83.47%	118.83%	15.8	71.85%	110.50%
2009	23.3	19.2	82.26%	117.13%	16.6	70.93%	108.65%
2010	24.4	19.5	79.93%	115.56%	17.4	71.26%	107.07%
2011	26.2	17.4	66.45%	113.62%	14.7	55.96%	105.04%
2012	28.0	18.3	65.45%	111.84%	15.4	55.03%	103.20%
2013	28.9	19.1	65.99%	110.31%	16.2	55.82%	101.61%
2014	31.0	20.1	64.79%	108.88%	17.0	54.68%	100.14%
2015	33.5	21.2	63.28%	107.52%	17.8	53.17%	98.73%
2016	34.3	22.3	64.90%	106.38%	18.7	54.53%	97.54%
2017	36.8	23.4	63.51%	105.28%	19.6	53.36%	96.41%
2018	39.6	24.5	61.97%	104.23%	20.6	52.07%	95.33%
2019	42.6	25.8	60.49%	103.22%	21.7	50.82%	94.30%
2020	45.6	27.1	59.34%	102.26%	22.7	49.85%	93.32%
20 YEAR PV	60.2	69.5	115.53%		64.4	107.07%	
22 YEAR PV	65.1	72.7	111.81%		67.1	103.20%	
25 YEAR PV	71.6	77.0	107.48%		70.7	98.73%	
30 YEAR PV	81.1	82.9	102.21%		75.7	93.32%	

TABLE E.5: NORTHEAST UTILITIES ESTIMATED AVOIDED COSTS
VERSUS RIVERSIDE CONTRACT PROPOSED IN 10/86 AND IN 4/88
70% NUCLEAR CAPACITY FACTORS AND NO ECONOMY PURCHASES PLUS ADJUSTMENTS
FOR NUCLEAR AND COAL GENERATION AND FOR NO SEABROOK GENERATION

		10/86 CONTRACT			4/88 OFFER		
YEAR	TOTAL AVOIDED COSTS	WEIGHTED CONTRACT RATE	CONTRACT RATE / AVOIDED COSTS	CUMMULATIVE RATIO OF PRESENT VALUES	WEIGHTED CONTRACT RATE	CONTRACT RATE / AVOIDED COSTS	CUMMULATIVE RATIO OF PRESENT VALUES
	[1]	[2]	[3]	[4]	[5]	[6]	[7]
1990 (1/6)	0.7	1.2	172.99%	172.99%	1.2	174.36%	174.36%
1991	4.6	7.7	165.91%	166.94%	7.8	167.10%	168.15%
1992	5.2	8.0	154.18%	161.01%	8.1	155.44%	162.25%
1993	6.0	8.4	139.94%	154.11%	8.4	139.73%	154.88%
1994	6.3	8.9	141.22%	151.05%	8.7	138.42%	150.97%
1995	7.0	9.4	134.60%	147.88%	9.1	129.91%	146.91%
1996	7.7	9.9	128.36%	144.32%	9.4	122.81%	143.02%
1997	8.9	10.5	117.60%	140.87%	9.8	109.90%	138.22%
1998	8.3	11.1	134.44%	140.17%	10.2	123.60%	136.63%
1999	9.4	11.6	122.97%	138.44%	10.6	112.51%	134.20%
2000	10.5	12.2	115.67%	136.32%	11.0	104.65%	131.45%
2001	12.1	12.8	105.37%	133.59%	11.1	91.29%	127.90%
2002	13.3	13.5	101.60%	131.02%	11.7	87.72%	124.67%
2003	14.4	14.2	98.87%	128.67%	12.2	85.30%	121.79%
2004	15.7	14.9	95.19%	126.42%	12.9	82.25%	119.12%
2005	17.6	15.7	88.97%	124.01%	13.5	76.68%	116.39%
2006	19.1	16.5	86.54%	121.79%	14.2	74.66%	113.91%
2007	20.3	17.4	85.57%	119.82%	15.0	73.64%	111.72%
2008	21.9	18.3	83.44%	117.99%	15.8	71.83%	109.71%
2009	23.5	19.2	81.85%	116.31%	16.6	70.58%	107.89%
2010	24.4	19.5	79.86%	114.78%	17.4	71.20%	106.35%
2011	26.2	17.4	66.38%	112.88%	14.7	55.91%	104.36%
2012	27.8	18.3	65.78%	111.16%	15.4	55.30%	102.57%
2013	29.1	19.1	65.57%	109.64%	16.2	55.47%	101.00%
2014	31.0	20.1	64.93%	108.25%	17.0	54.80%	99.55%
2015	33.8	21.2	62.80%	106.89%	17.8	52.76%	98.15%
2016	34.3	22.3	64.90%	105.77%	18.7	54.53%	96.98%
2017	36.8	23.4	63.51%	104.69%	19.6	53.36%	95.87%
2018	39.6	24.5	61.97%	103.66%	20.6	52.07%	94.81%
2019	42.6	25.8	60.49%	102.67%	21.7	50.82%	93.80%
2020	45.6	27.1	59.34%	101.72%	22.7	49.85%	92.84%
20 YEAR PV	60.6	69.5	114.75%		64.4	106.35%	
22 YEAR PV	65.5	72.7	111.13%		67.1	102.57%	
25 YEAR PV	72.1	77.0	106.85%		70.7	98.15%	
30 YEAR PV	81.5	82.9	101.68%		75.7	92.84%	

TABLE E.6: NORTHEAST UTILITIES ESTIMATED AVOIDED COSTS
VERSUS RIVERSIDE CONTRACT PROPOSED IN 10/86 AND IN 4/88
70% NUCLEAR CAPACITY FACTORS AND NO ECONOMY PURCHASES PLUS ADJUSTMENTS
FOR NUCLEAR AND COAL GENERATION AND FOR NO SEABROOK GENERATION
BASED ON EXPECTED OIL PRICES

		10/86 CONTRACT			4/88 OFFER		
YEAR	TOTAL AVOIDED COSTS	WEIGHTED CONTRACT RATE	CONTRACT RATE / AVOIDED COSTS	CUMMULATIVE RATIO OF PRESENT VALUES	WEIGHTED CONTRACT RATE	CONTRACT RATE / AVOIDED COSTS	CUMMULATIVE RATIO OF PRESENT VALUES
	[1]	[2]	[3]	[4]	[5]	[6]	[7]
1990 (1/6)	0.8	1.2	145.21%	145.21%	1.2	146.36%	146.36%
1991	5.2	7.7	148.45%	147.95%	7.8	149.51%	149.03%
1992	6.3	8.0	127.77%	138.24%	8.1	128.81%	139.30%
1993	6.5	8.4	130.17%	135.74%	8.4	129.98%	136.41%
1994	6.6	8.9	134.13%	135.38%	8.7	131.47%	135.30%
1995	7.2	9.4	131.38%	134.66%	9.1	126.80%	133.78%
1996	8.6	9.9	115.49%	131.53%	9.4	110.07%	129.90%
1997	9.0	10.5	116.68%	129.54%	9.8	109.04%	127.10%
1998	7.8	11.1	142.37%	130.81%	10.2	131.36%	127.50%
1999	8.9	11.6	130.18%	130.75%	10.6	119.11%	126.75%
2000	9.8	12.2	124.19%	130.21%	11.0	112.36%	125.56%
2001	12.1	12.8	105.45%	128.11%	11.1	91.36%	122.66%
2002	13.3	13.5	101.21%	126.02%	11.7	87.38%	119.92%
2003	14.2	14.2	99.92%	124.20%	12.2	86.19%	117.56%
2004	15.4	14.9	96.45%	122.42%	12.9	83.33%	115.36%
2005	18.1	15.7	86.65%	120.13%	13.5	74.68%	112.75%
2006	19.5	16.5	84.61%	118.04%	14.2	72.99%	110.41%
2007	20.5	17.4	84.76%	116.27%	15.0	72.95%	108.42%
2008	22.1	18.3	82.88%	114.63%	15.8	71.35%	106.59%
2009	23.9	19.2	80.48%	113.06%	16.6	69.40%	104.88%
2010	24.4	19.5	79.87%	111.70%	17.4	71.21%	103.50%
2011	26.1	17.4	66.67%	109.99%	14.7	56.15%	101.69%
2012	27.2	18.3	67.37%	108.51%	15.4	56.64%	100.13%
2013	29.2	19.1	65.33%	107.09%	16.2	55.26%	98.65%
2014	30.4	20.1	66.03%	105.86%	17.0	55.72%	97.36%
2015	33.7	21.2	62.90%	104.61%	17.8	52.85%	96.06%
2016	34.4	22.3	64.75%	103.56%	18.7	54.41%	94.96%
2017	36.8	23.4	63.47%	102.57%	19.6	53.33%	93.93%
2018	39.8	24.5	61.62%	101.59%	20.6	51.77%	92.92%
2019	43.0	25.8	59.90%	100.64%	21.7	50.33%	91.95%
2020	46.0	27.1	58.78%	99.74%	22.7	49.39%	91.03%
20 YEAR PV	62.3	69.5	111.68%		64.4	103.50%	
22 YEAR PV	67.1	72.7	108.48%		67.1	100.13%	
25 YEAR PV	73.6	77.0	104.58%		70.7	96.06%	
30 YEAR PV	83.1	82.9	99.70%		75.7	91.03%	

EXHIBIT PLC-4

TABLES TO ACCOMPANY EXHIBIT PLC-2:

UNDERLYING CALCULATIONS

TABLE 2.1: NORTHEAST UTILITIES ESTIMATED AVOIDED COSTS, RUN 1: DPU 88-19

YEAR	FUEL O&M	T&D LOSSES	CAPITALIZED ENERGY	SAVINGS SHARE	CAPACITY VALUE	TOTAL AVOIDED COSTS
	[1]	[2]	[3]	[4]	[5]	[6]
1990 (1/6)	0.5	0.0	0.0	0.0	0.0	0.5
1991	3.4	0.0	0.3	0.0	0.0	3.7
1992	3.1	0.0	0.3	0.0	0.0	3.4
1993	3.9	0.0	1.1	0.0	0.0	5.0
1994	4.0	0.0	1.2	0.0	0.0	5.2
1995	4.6	0.0	1.3	0.0	0.0	6.0
1996	4.5	0.0	1.4	0.0	0.0	5.9
1997	6.3	0.0	1.5	0.0	0.0	7.8
1998	6.3	0.0	0.6	0.0	1.0	7.9
1999	7.5	0.0	0.7	0.0	1.0	9.2
2000	9.0	0.0	0.7	0.0	1.1	10.8
2001	9.2	0.0	0.8	0.0	1.2	11.2
2002	10.3	0.0	0.8	0.0	1.3	12.4
2003	11.5	0.0	0.9	0.0	1.3	13.7
2004	12.7	0.0	0.9	0.0	1.4	15.1
2005	14.2	0.0	1.0	0.0	1.5	16.7
2006	15.4	0.0	1.0	0.0	1.7	18.1
2007	16.9	0.0	1.1	0.0	1.8	19.9
2008	18.3	0.0	1.2	0.0	1.9	21.5
2009	19.5	0.0	1.3	0.0	2.0	22.8
2010	20.3	0.0	1.3	0.0	2.2	23.8
2011	21.9	0.0	1.4	0.0	2.3	25.7
2012	23.6	0.0	1.5	0.0	2.5	27.6
2013	23.9	0.0	1.6	0.0	2.7	28.2
2014	25.1	0.0	1.7	0.0	2.9	29.6
2015	26.5	0.0	1.8	0.0	3.1	31.4
2016	28.3	0.0	2.0	0.0	3.3	33.5
2017	30.4	0.0	2.1	0.0	3.5	36.1
2018	32.7	0.0	2.2	0.0	3.8	38.7
2019	35.2	0.0	2.4	0.0	4.0	41.6
2020	37.8	0.0	2.5	0.0	4.3	44.7
20 YEAR PV	45.3	0.1	5.6	0.0	3.6	54.6
22 YEAR PV	49.5	0.1	5.9	0.0	4.0	59.4
25 YEAR PV	54.8	0.1	6.2	0.0	4.6	65.7
30 YEAR PV	62.6	0.1	6.8	0.0	5.5	74.9

SOURCE: BRIEFING DOCUMENT D, in response to DPU discovery in 88-19.

ABLE 3.1: NUCLEAR CAPACITY FACTORS 85-270 (IR-R-1), BASE CASE

LANT	MW	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	AVG. 1990-1997
MILLSTONE 1	636.5	85%	68%	85%	69%	82%	72%	70%	70%	70%	70%	70%	70%	70%	75%
MILLSTONE 2	830.2	74%	79%	69%	69%	85%	69%	70%	70%	70%	70%	70%	70%	70%	73%
MILLSTONE 3	751.4	65%	65%	70%	70%	70%	70%	70%	70%	70%	70%	70%	70%	70%	69%
CT YANKEE	247.1	68%	84%	69%	69%	85%	69%	70%	70%	70%	70%	70%	70%	70%	73%
MA YANKEE	53.3	71%	70%	70%	70%	70%	70%	70%	70%						70%
VT YANKEE	55.0	85%	70%	70%	70%	70%	70%	70%	70%	70%	70%	70%	70%	70%	72%
ME YANKEE	110.1	85%	70%	70%	70%	70%	70%	70%	70%	70%	70%	70%	70%	70%	72%
SEABROOK 1	46.7	65%	64%	65%	70%	70%	70%	70%	70%	70%	70%	70%	70%	70%	68%
WTD. AV.		74.00%	72.06%	73.02%	69.37%	78.72%	70.07%	70.00%	70.00%	70.00%	70.00%	70.00%	70.00%	70.00%	72.15%
WTD. AV. W/O M-3 AND S-1		77.71%	75.00%	74.38%	69.11%	82.32%	70.10%	70.00%	70.00%	70.00%	70.00%	70.00%	70.00%	70.00%	73.58%

TABLE 3.2: NUCLEAR CAPACITY FACTORS 85-270 (IR-R-1), CHANGE CASE

PLANT	MW	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	AVG. 1990-97
MILLSTONE 1	636.5	90%	72%	88%	70%	85%	72%	70%	70%	70%	70%	70%	70%	70%	77%
MILLSTONE 2	830.2	76%	80%	69%	69%	85%	69%	70%	70%	70%	70%	70%	70%	70%	74%
MILLSTONE 3	751.4														
CT YANKEE	247.1	70%	87%	70%	69%	87%	70%	71%	71%	71%	71%	70%	71%	71%	74%
MA YANKEE	53.3	72%	70%	70%	70%	71%	71%	69%	72%						71%
VT YANKEE	55.0	85%	70%	70%	70%	70%	70%	70%	70%	70%	69%	71%	69%	72%	72%
ME YANKEE	110.1	85%	70%	70%	70%	70%	70%	70%	69%	71%	70%	70%	70%	69%	72%
SEABROOK 1	46.7	69%	67%	67%	71%	72%	71%	71%	71%	70%	71%	70%	70%	71%	70%
WTD. AV.		80.23%	76.89%	75.30%	69.48%	83.31%	70.27%	70.12%	70.15%	70.19%	70.12%	70.03%	70.10%	70.15%	74.47%
WTD. AV. W/O M-3 AND S-1		80.50%	77.13%	75.50%	69.44%	83.59%	70.26%	70.10%	70.13%	70.19%	70.10%	70.03%	70.10%	70.13%	74.58%

TABLE 3.3: RUN 1: DPU 88-19 (IR-R-3), BASE CASE CAPACITY FACTORS

PLANT	MW	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	AVG. 1990-97
MILLSTONE 1	636.5	88.16%	70.80%	87.39%	70.25%	87.69%	70.62%	87.22%	70.49%	74.95%	74.95%	75.18%	74.99%	74.99%	79.08%
MILLSTONE 2	834.7	83.06%	70.82%	67.11%	86.93%	66.71%	66.84%	87.01%	66.70%	74.38%	74.46%	74.60%	74.47%	74.46%	74.40%
MILLSTONE 3	749.0	65.02%	65.01%	69.84%	69.93%	69.98%	70.05%	70.00%	70.05%	74.98%	75.01%	75.20%	75.00%	75.00%	68.73%
CT YANKEE	247.1	69.70%	81.30%	76.28%	70.20%	73.40%	83.79%	70.13%	70.08%	74.94%	75.02%	75.23%	75.00%	74.99%	74.36%
MA YANKEE	53.4	73.78%	73.80%	87.63%	74.34%	74.23%	78.58%	82.48%	74.29%	0.96%					77.39%
VT YANKEE	54.2	73.41%	87.07%	73.22%	74.24%	88.07%	73.85%	73.99%	88.04%	69.86%	69.94%	69.99%	69.96%	69.87%	78.99%
ME YANKEE	111.1	74.88%	74.87%	86.87%	73.20%	73.23%	87.01%	73.08%	80.80%	70.02%	70.03%	70.24%	70.05%	70.03%	77.99%
SEABROOK 1	46.7	64.35%	66.46%	65.42%	65.42%	65.22%	70.12%	69.77%	70.67%	69.90%	69.80%	69.95%	69.77%	69.96%	67.18%
WTD. AV.		77.07%	70.64%	74.71%	75.45%	73.91%	71.38%	79.66%	70.02%	74.38%	74.43%	74.61%	74.43%	74.43%	74.10%
WTD. AV. W/O M-3 AND S-1		82.04%	72.92%	76.81%	77.83%	75.63%	71.92%	83.64%	69.99%	72.24%	72.26%	72.44%	72.27%	72.27%	76.35%

TABLE 3.4: RUN 1: DPU 88-19 (IR-R-3), CHANGE CASE CAPACITY FACTORS

PLANT	MW	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	AVG. 1990-97
MILLSTONE 1	636.5	85.00%	67.81%	83.14%	67.73%	84.22%	69.05%	87.22%	70.49%	74.48%	74.35%	74.77%	74.47%	74.89%	76.83%
MILLSTONE 2	834.7	82.13%	69.57%	64.69%	86.54%	66.35%	66.31%	86.76%	66.76%	74.35%	74.42%	74.58%	74.46%	74.45%	73.64%
MILLSTONE 3	749.0	64.89%	64.41%	68.37%	68.52%	68.43%	68.93%	68.65%	69.39%	74.87%	74.80%	75.06%	74.92%	74.91%	67.70%
CT YANKEE	247.1	66.69%	78.64%	73.84%	69.53%	72.86%	70.06%	69.37%	69.88%	74.91%	74.91%	75.23%	74.97%	74.96%	71.36%
MA YANKEE	53.4	71.83%	70.43%	81.60%	70.44%	69.67%	75.24%	78.04%	71.08%	0.88%					73.54%
VT YANKEE	54.2	71.43%	84.97%	67.92%	70.49%	82.66%	71.20%	70.04%	84.46%	68.81%	68.90%	69.05%	69.24%	69.57%	75.40%
ME YANKEE	111.1	74.80%	74.69%	85.93%	73.05%	72.42%	86.17%	70.76%	80.32%	70.01%	69.98%	70.17%	70.02%	70.01%	77.27%
SEABROOK 1	46.7	57.47%	60.73%	54.54%	61.02%	62.68%	68.61%	65.49%	68.76%	69.46%	68.62%	69.25%	69.06%	69.45%	62.41%
WTD. AV.		75.54%	68.94%	71.91%	74.06%	72.24%	69.13%	78.82%	69.65%	74.20%	74.16%	74.43%	74.25%	74.36%	72.54%
WTD. AV. W/O M-3 AND S-1		80.10%	70.90%	73.70%	76.52%	73.95%	69.21%	83.07%	69.77%	72.04%	72.00%	72.26%	72.08%	72.22%	74.65%

TABLE 3.5: NORTHEAST UTILITY'S HISTORICAL NUCLEAR CAPACITY FACTORS

			----LIFETIME DATA THROUGH 4/30/89----		
UNIT	WINTER RATING	NU'S ENTITLEMENT	HOURS	NET ELECTRIC OUTPUT	CAPACITY FACTOR
	[1]	[2]	[3]	[4]	[5]
MILLSTONE 1	636.5	636.5	161,471	74,570	72.56%
MILLSTONE 2	834.7	834.7	116,999	64,789	66.34%
MILLSTONE 3	1149.0	749.0	26,495	22,973	75.46%
CT YANKEE	582.0	247.1	186,983	80,302	73.79%
MA YANKEE	175.5	53.4	249,428	30,318	69.26%
VT YANKEE	520.0	54.2	145,586	52,083	68.80%
ME YANKEE	855.0	111.1	144,420	80,722	65.37%
AVERAGE (WEIGHTED BY [2]) FOR ALL UNITS EXCEPT MILLSTONE 3					69.43%
AVERAGE (WEIGHTED BY [2]*[3]) FOR ALL UNITS					70.31%

NOTES:

[1]: CAPACITY FROM PRO SIM MODEL RUN. ADJUSTED BY NU OWNERSHIP SHARES REPORTED IN JAN 1, 1988 CELT REPORT FOR ALL PLANTS.

[2]: FROM IR-R-3.

[3], [4]: FROM THE MAY 1989 NRC GREY BOOK.

[5]: [4]/[3]/[1]*1000.

TABLE 4.1: RUN 1 (IR-R-3): DPU 88-19, BASE AND CHANGE CASE ECONOMY PURCHASES

		1990			1991			1992		
		DOLLARS	MWHR	$/MWHR	DOLLARS	MWHR	$/MWHR	DOLLARS	MWHR	$/MWHR
BASE AND CHANGE	NUCL.	$148,500	27000	$5.50	$608,400	63000	$9.66	$625,200	50400	$12.40
	COAL	$8,035,200	360000	$22.32	$14,284,300	612000	$23.34	$14,479,200	612000	$23.66
	OIL	$2,272,000	64000	$35.50	$12,793,600	352000	$36.35	$9,459,200	256000	$36.95
	TOTAL	$10,455,700	451000	$23.18	$27,686,300	1027000	$26.96	$24,563,600	918400	$26.75
BASE CASE:										
MIDDLETOWN 2 (OIL)				$38.58			$41.44			$44.46
MT TOM (COAL)				$27.21			$28.18			$30.45
CHANGE CASE:										
MIDDLETOWN 2 (OIL)				$38.87			$41.81			$44.69
MT TOM (COAL)				$27.59			$28.58			$30.97

		1993			1994			1995		
		DOLLARS	MWHR	$/MWHR	DOLLARS	MWHR	$/MWHR	DOLLARS	MWHR	$/MWHR
BASE AND CHANGE	NUCL.	$732,300	62400	$11.74	$710,000	73800	$9.62	$531,600	58200	$9.13
	COAL	$18,216,000	720000	$25.30	$20,088,000	792000	$25.36	$23,587,200	864000	$27.30
	OIL	$10,835,200	288000	$37.62	$23,289,600	576000	$40.43	$34,022,400	768000	$44.30
	TOTAL	$29,784,000	1070400	$27.83	$44,087,600	1441800	$30.58	$58,141,200	1690200	$34.40
BASE CASE:										
MIDDLETOWN 2 (OIL)				$47.97			$51.19			$53.81
MT TOM (COAL)				$31.61			$33.04			$34.81
CHANGE CASE:										
MIDDLETOWN 2 (OIL)				$48.15			$51.47			$54.23
MT TOM (COAL)				$32.01			$33.69			$35.20

TABLE 4.1: RUN 1 (IR-R-3): DPU 88-19, BASE AND CHANGE CASE ECONOMY PURCHASES

		1996			1997		
		DOLLARS	MWHR	$/MWHR	DOLLARS	MWHR	$/MWHR
BASE AND CHANGE	NUCL.	$500,800	61200	$8.18	$350,400	64800	$5.41
	COAL	$24,451,200	864000	$28.30	$25,315,200	864000	$29.30
	OIL	$52,838,400	1142000	$46.27	$55,142,400	1152000	$47.87
	TOTAL	$77,790,400	2077200	$37.45	$80,808,000	2080800	$38.84
BASE CASE:							
MIDDLETOWN 2 (OIL)				$58.38			$65.72
MT TOM (COAL)				$36.94			$38.85
CHANGE CASE:							
MIDDLETOWN 2 (OIL)				$59.08			$66.36
MT TOM (COAL)				$37.64			$39.21

TABLE 5.1: CHANGE IN AVOIDED COSTS DUE TO CHANGES IN NUCLEAR GENERATION FROM BASE TO CHANGE CASE

YEAR	BASE CASE MWHR	CHANGE CASE MWHR	CHANGE IN MWHRS	AVERAGE $/MWHR NUCLEAR	AVERAGE $/MWHR OIL	TOTAL $ CHANGE IN AVOIDED COST	CHANGE IN AVOIDED COST, $/MWHR	CHANGE IN AVOIDED COST, CENTS/KWH
	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]
1990	16,483,842	16,352,862	130,980	7.73	35.69	3,661,262	1.76	0.1756
1991	16,507,967	16,316,890	191,077	7.20	38.65	6,009,142	2.88	0.2882
1992	16,851,506	16,577,072	274,434	6.96	41.51	9,482,581	4.55	0.4548
1993	16,842,274	16,716,991	125,283	6.62	44.42	4,735,607	2.27	0.2271
1994	16,810,048	16,675,862	134,186	6.47	47.24	5,469,760	2.62	0.2624
1995	16,802,746	16,717,153	85,593	6.48	50.05	3,728,657	1.79	0.1788
1996	16,904,040	16,855,825	48,215	6.62	53.76	2,272,713	1.09	0.1090
1997	16,718,952	16,652,630	66,322	6.94	61.20	3,598,769	1.73	0.1726
1998	16,471,900	16,451,039	20,861	7.30	61.10	1,122,226	0.54	0.0538
1999	16,469,386	16,436,821	32,565	7.71	74.99	2,190,882	1.05	0.1051
2000	16,499,711	16,482,907	16,804	8.14	92.02	1,409,551	0.68	0.0676
2001	16,486,962	16,468,984	17,978	8.58	103.94	1,714,323	0.82	0.0822
2002	16,311,109	16,301,582	9,527	9.05	116.27	1,021,427	0.49	0.0490
2003	16,494,638	16,482,691	11,947	9.55	128.80	1,424,657	0.68	0.0683
2004	16,511,960	16,498,603	13,357	10.08	143.21	1,778,160	0.85	0.0853
2005	16,498,347	16,489,256	9,091	10.64	157.53	1,335,402	0.64	0.0641
2006	16,498,234	16,491,399	6,835	11.22	172.51	1,102,354	0.53	0.0529
2007	15,737,925	15,735,909	2,016	11.90	186.62	352,222	0.17	0.0169
2008	14,666,952	14,653,360	13,592	12.41	199.17	2,538,438	1.22	0.1218
2009	13,961,382	13,960,363	1,019	13.09	212.08	202,768	0.10	0.0097
2010	13,961,869	13,961,138	731	13.81	225.26	154,566	0.07	0.0074
2011	10,069,461	10,069,223	238	13.44	235.38	52,340	0.03	0.0025
2012	10,060,148	10,059,780	368	14.18	250.35	87,096	0.04	0.0042
2013	10,040,191	10,039,950	241	14.94	267.30	60,818	0.03	0.0029
2014	10,041,337	10,041,099	238	15.76	286.43	64,417	0.03	0.0031
2015	4,973,774	4,963,639	10,135	18.34	303.70	2,892,099	1.39	0.1387

[1]: IR-R-45: From NU Production Simulation Model, Total Nuclear Generation, Base Case (Run 3 for 1990-1997 (70% Nuclear Capacity Factor, No Purchases), Run 2 (70% Nuclear Capacity Factor Only) for 1998-2015).

[2]: IR-R-45: From NU Production Simulation Model, Total Nuclear Generation, Change Case, Run 3 1990-1997, Run 2 1998-2015.

[3]: [1]-[2].

[4]: IR-R-45: Total Nuclear $/Total Nuclear MWH (Base Case, Run 3 1990-1997, Run 2 1998-2015).

[5]: IR-R-45: From NU Production Simulation Model, Norwalk 2 $/MWH (Average of Base and Change Cases, Run 3 1990-1997, Run 2 1998-2015).

[6]: ([3]x[5])-([3]x[4]).

[7]: [6]/2,084,880.

[8]: [7]/10.

TABLE 5.2: TOTAL IMPACT ON AVOIDED COSTS OF CHANGES IN COAL GENERATION
FROM THE BASE TO THE CHANGE CASE

YEAR	MT TOM	COHQ	GCC4-1	GCC4-2	GCC4-3	GCC4-4	GCC4-5	GCC4-6	GCC6-1	TOTAL
	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]
1990	0.03									0.03
1991	0.04									0.04
1992	0.07									0.07
1993	0.03									0.03
1994	0.05									0.05
1995	0.05									0.05
1996	0.06									0.06
1997	0.04									0.04
1998	0.07									0.07
1999	0.04									0.04
2000	-0.03									-0.03
2001	0.10	0.28								0.38
2002	0.17	0.19								0.36
2003	0.17	0.21								0.38
2004	0.27	0.24								0.51
2005	0.03	0.14								0.17
2006	0.16	0.17								0.33
2007	0.08	0.13								0.21
2008	0.14	-0.04	0.01							0.10
2009	-0.12	0.01	0.04							-0.07
2010	0.10	0.02	0.14	0.02						0.29
2011	0.07		0.10	0.00	0.01					0.18
2012	0.26		0.08	-0.01	0.02					0.36
2013	-0.14		0.09	-0.01	-0.05	0.15				0.04
2014	0.34		0.41	0.02	0.10	-0.13	0.48			1.22
2015	0.43		0.16	0.48	0.05	0.06	-0.16	0.01	0.34	1.36

NOTES:

[1]: TABLE 5.3, COLUMN [6].
[2]: TABLE 5.4, COLUMN [6].
[3]: TABLE 5.5, COLUMN [6].
[4]: TABLE 5.6, COLUMN [6].
[5]: TABLE 5.7, COLUMN [6].
[6]: TABLE 5.8, COLUMN [6].
[7]: TABLE 5.9, COLUMN [6].
[8]: TABLE 5.10, COLUMN [6].
[9]: TABLE 5.11, COLUMN [6].

NOTES TO TABLE 5.3 - 5.11

[1]: IR-R-45: From NU Production Simulation Model, Base Case, Run 2 (70% Nuclear C.F. Only).
[2]: IR-R-45: From NU Production Simulation Model, Change Case, Run 2.
[3]: IR-R-45: From NU Production Simulation Model, Run 2.
[4]: IR-R-45: From NU Production Simulation Model, Norwalk 2 $/MWH, Run 2.
[5]: (([1]-[2])x[4])-(([1]-[2])x[3]).
[6]: [5]/20,848,300.

TABLE 5.3: MOUNT TOM COAL IMPACT ON AVOIDED COSTS OF CHANGES IN GENERATION FROM BASE TO CHANGE CASE

YEAR	BASE CASE MWHR	CHANGE CASE MWHR	BASE $/MWH	OIL $/MWHR	TOTAL $ CHANGE IN AVOIDED COST	CHANGE IN AVOIDED COST, CENTS/KWH
	[1]	[2]	[3]	[4]	[5]	[6]
1990	653,348	573,790	26.37	35.69	701,304	0.0336
1991	641,855	568,308	28.01	38.65	782,540	0.0375
1992	579,030	457,257	29.67	41.51	1,441,792	0.0692
1993	607,552	565,440	31.31	44.42	552,088	0.0265
1994	639,018	566,608	32.81	47.24	1,044,514	0.0501
1995	621,267	554,474	34.60	50.05	1,031,618	0.0495
1996	654,082	579,999	36.35	53.76	1,303,339	0.0625
1997	620,377	585,708	38.64	61.20	782,133	0.0375
1998	662,476	592,318	40.66	61.10	1,434,030	0.0688
1999	664,415	639,317	43.00	74.99	802,385	0.0385
2000	855,489	869,278	45.50	92.02	(641,464)	-0.0308
2001	1,035,993	999,904	48.28	103.94	2,008,533	0.0963
2002	1,071,107	1,015,187	51.06	116.27	3,646,264	0.1749
2003	1,077,591	1,030,433	54.01	128.30	3,526,947	0.1692
2004	1,073,452	1,007,370	57.18	143.21	5,641,692	0.2706
2005	1,055,357	1,049,298	60.45	157.53	588,208	0.0282
2006	1,073,110	1,046,709	64.32	172.51	3,397,117	0.1629
2007	1,080,270	1,065,348	68.31	186.62	1,706,195	0.0818
2008	1,088,092	1,065,212	72.66	199.17	2,394,549	0.1388
2009	1,065,268	1,083,356	77.25	212.08	(2,438,715)	-0.1170
2010	1,080,030	1,065,641	82.19	225.26	2,173,014	0.1042
2011	1,087,993	1,078,221	87.33	235.88	1,451,631	0.0696
2012	1,092,732	1,057,809	92.97	250.85	5,513,643	0.2645
2013	1,050,756	1,068,327	98.99	267.30	(2,957,287)	-0.1418
2014	1,073,748	1,034,187	105.28	286.43	7,166,277	0.3437
2015	1,079,987	1,033,594	112.06	303.70	8,890,523	0.4264

TABLE 5.4: HYDRO QUEBEC PURCHASE (AT COAL PRICE) IMPACT ON AVOIDED COSTS OF CHANGES IN GENERATION FROM BASE TO CHANGE CASE

YEAR	BASE CASE MWHR	CHANGE CASE MWHR	BASE $/MWH	OIL $/MWHR	TOTAL $ CHANGE IN AVOIDED COST	CHANGE IN AVOIDED COST, CENTS/KWH
	[1]	[2]	[3]	[4]	[5]	[6]
2001	2,898,387	2,318,668	30.36	103.94	5,365,325	0.2813
2002	2,961,686	2,915,669	32.15	116.27	3,870,720	0.1857
2003	2,965,142	2,918,673	34.19	128.30	4,396,432	0.2109
2004	2,965,343	2,919,966	36.21	143.21	4,908,610	0.2354
2005	2,964,501	2,940,323	38.36	157.53	2,893,209	0.1388
2006	2,967,247	2,940,807	40.82	172.51	3,481,751	0.1670
2007	2,971,510	2,952,744	43.39	186.62	2,687,760	0.1289
2008	2,379,444	2,385,204	46.17	199.17	(881,280)	-0.0423
2009	2,376,539	2,374,943	49.09	212.08	260,124	0.0125
[illegible]	[illegible]	[illegible]	[illegible]	225.25	499,293	0.0239

TABLE 5.5: GCC4-1 IMPACT ON AVOIDED COSTS OF CHANGES IN GENERATION
FROM BASE TO CHANGE CASE

YEAR	BASE CASE MWHR	CHANGE CASE MWHR	BASE $/MWH	OIL $/MWHR	TOTAL $ CHANGE IN AVOIDED COST	CHANGE IN AVOIDED COST, CENTS/KWH
	[1]	[2]	[3]	[4]	[5]	[6]
2008	1,190,305	1,189,216	73.29	199.17	137,083	0.0066
2009	2,404,099	2,398,398	77.86	212.08	765,160	0.0367
2010	2,539,227	2,519,240	82.76	225.26	2,848,048	0.1366
2011	2,671,985	2,657,783	88.03	235.38	2,099,766	0.1007
2012	2,680,646	2,669,435	93.67	250.85	1,762,145	0.0845
2013	2,672,211	2,660,672	99.59	267.30	1,935,148	0.0928
2014	2,668,350	2,621,279	105.99	286.43	8,493,256	0.4074
2015	2,669,288	2,651,640	112.30	303.70	3,368,915	0.1616

TABLE 5.6: GCC4-2 IMPACT ON AVOIDED COSTS OF CHANGES IN GENERATION
FROM BASE TO CHANGE CASE

YEAR	BASE CASE MWHR	CHANGE CASE MWHR	BASE $/MWH	OIL $/MWHR	TOTAL $ CHANGE IN AVOIDED COST	CHANGE IN AVOIDED COST, CENTS/KWH
	[1]	[2]	[3]	[4]	[5]	[6]
2010	2,393,142	2,389,607	82.31	225.255	503,543	0.0242
2011	2,429,611	2,429,209	87.71	235.380	59,564	0.0029
2012	2,562,602	2,564,085	93.34	250.850	(233,587)	-0.0112
2013	2,678,454	2,679,322	99.25	267.295	(145,363)	-0.0070
2014	2,681,334	2,679,043	105.61	286.425	414,247	0.0199
2015	2,671,667	2,619,651	112.79	303.695	9,930,114	0.4763

TABLE 5.7: GCC4-3 IMPACT ON AVOIDED COSTS OF CHANGES IN GENERATION
FROM BASE TO CHANGE CASE

YEAR	BASE CASE MWHR	CHANGE CASE MWHR	BASE $/MWH	OIL $/MWHR	TOTAL $ CHANGE IN AVOIDED COST	CHANGE IN AVOIDED COST, CENTS/KWH
	[1]	[2]	[3]	[4]	[5]	[6]
2011	2,403,714	2,402,375	88.09	235.380	197,391	0.0095
2012	2,428,491	2,425,905	93.66	250.850	406,493	0.0195
2013	2,538,258	2,544,962	99.62	267.295	(1,124,093)	-0.0539
2014	2,569,274	2,657,979	106.00	286.425	2,037,900	0.0977
2015	2,572,731	2,567,479	112.79	303.695	1,002.633	0.0481

TABLE 5.8: GCC4-4 IMPACT ON AVOIDED COSTS OF CHANGES IN GENERATION
FROM BASE TO CHANGE CASE

YEAR	BASE CASE MWHR	CHANGE CASE MWHR	BASE $/MWH	OIL $/MWHR	TOTAL $ CHANGE IN AVOIDED COST	CHANGE IN AVOIDED COST, CENTS/KWH
	[1]	[2]	[3]	[4]	[5]	[6]
2013	2,376,752	2,358,088	99.77	267.295	3,126,687	0.1500
2014	2,414,446	2,429,537	105.64	286.425	(2,728,226)	-0.1309
2015	2,537,327	2,530,464	112.82	303.695	1,309,975	0.0628

TABLE 5.9: GCC4-5 IMPACT ON AVOIDED COSTS OF CHANGES IN GENERATION
FROM BASE TO CHANGE CASE

YEAR	BASE CASE MWHR	CHANGE CASE MWHR	BASE $/MWH	OIL $/MWHR	TOTAL $ CHANGE IN AVOIDED COST	CHANGE IN AVOIDED COST, CENTS/KWH
	[1]	[2]	[3]	[4]	[5]	[6]
2014	2,380,198	2,324,397	106.15	286.425	10,059,525	0.4825
2015	2,403,320	2,420,398	112.33	303.695	(3,259,592)	-0.1563

TABLE 5.10: GCC4-6 IMPACT ON AVOIDED COSTS OF CHANGES IN GENERATION
FROM BASE TO CHANGE CASE

YEAR	BASE CASE MWHR	CHANGE CASE MWHR	BASE $/MWH	OIL $/MWHR	TOTAL $ CHANGE IN AVOIDED COST	CHANGE IN AVOIDED COST, CENTS/KWH
	[1]	[2]	[3]	[4]	[5]	[6]
2015	2,393,553	2392904	112.92	303.695	123,813	0.0059

TABLE 5.11: GCC6-1 IMPACT ON AVOIDED COSTS OF CHANGES IN GENERATION
FROM BASE TO CHANGE CASE

YEAR	BASE CASE MWHR	CHANGE CASE MWHR	BASE $/MWH	OIL $/MWHR	TOTAL $ CHANGE IN AVOIDED COST	CHANGE IN AVOIDED COST, CENTS/KWH
	[1]	[2]	[3]	[4]	[5]	[6]
2015	3,561,384	3,524,978	112.71	303.70	7,048,492	0.3381

TABLE 6.1: IMPACT OF SEABROOK GENERATION ON NORTHEAST UTILITY'S AVOIDED COSTS.

YEAR	TOTAL NUCLEAR GENERATION BASE CASE RUN 1	TOTAL NUCLEAR GENERATION BASE CASE RUN 2	CHANGE IN NUCLEAR GENERATION	SEABROOK GENERATION RUN 2	RATIO OF [4] TO [3]	AVOIDED COSTS RUN 1	AVOIDED COSTS RUN 2	CHANGE IN AVOIDED COSTS	CHANGE DUE TO SEABROOK
	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]
1990	18,449,344	16,474,119	1,975,225	258,518	13.09%	3.25	3.80	0.55	0.07
1991	16,910,774	16,481,547	429,227	267,312	62.28%	3.71	3.90	0.19	0.12
1992	17,933,192	16,798,192	1,135,000	268,079	23.62%	3.40	4.10	0.70	0.16
1993	18,061,577	16,798,950	1,262,627	266,912	21.14%	5.07	5.30	0.23	0.05
1994	17,691,777	16,747,914	943,863	265,106	28.09%	5.28	5.60	0.32	0.09
1995	17,086,079	16,738,487	347,592	285,073	82.01%	6.03	6.10	0.07	0.06
1996	19,121,857	16,859,741	2,262,116	288,820	12.77%	5.93	6.80	0.87	0.11
1997	16,761,435	16,642,726	118,709	285,809	240.76%	7.89	7.90	0.01	0.02
1998	17,462,945	16,471,900	991,045	283,798	28.64%	7.98	8.10	0.12	0.03
1999	17,468,003	16,469,386	998,617	274,786	27.52%	9.34	9.30	-0.04	-0.01
2000	17,511,283	16,499,711	1,011,572	275,725	27.26%	10.93	10.60	-0.33	-0.09
2001	17,469,584	16,486,962	982,622	274,958	27.98%	11.29	11.60	0.31	0.09
2002	17,469,358	16,311,109	1,158,249	286,213	24.71%	12.49	12.80	0.31	0.08
2003	17,470,431	16,494,638	975,793	286,654	29.38%	13.85	13.90	0.05	0.01
2004	17,522,010	16,511,960	1,010,050	287,606	28.47%	15.24	15.10	-0.14	-0.04
2005	17,509,291	16,498,347	1,010,944	286,705	28.36%	16.90	17.30	0.40	0.11
2006	17,509,541	16,498,234	1,011,307	286,820	28.36%	18.31	18.60	0.29	0.08
2007	16,648,282	15,737,925	910,357	286,885	31.51%	20.08	20.10	0.02	0.01
2008	15,617,937	14,666,952	950,985	287,913	30.28%	21.68	21.70	0.02	0.01
2009	14,873,046	13,961,382	911,664	286,385	31.47%	23.03	23.40	0.37	0.12
2010	14,872,625	13,961,869	910,756	286,885	31.50%	24.03	24.10	0.07	0.02
2011	10,721,053	10,069,461	651,592	286,385	44.03%	25.94	26.00	0.06	0.03
2012	10,720,430	10,060,148	660,282	287,913	43.60%	27.92	27.60	-0.32	-0.14
2013	10,691,301	10,040,191	651,110	286,835	44.06%	28.48	28.90	0.42	0.18
2014	10,691,081	10,041,337	649,744	286,885	44.15%	29.95	29.80	-0.15	-0.06
2015	5,286,062	4,973,774	312,288	286,885	91.87%	31.72	32.00	0.28	0.26

NOTES:

[1]: IR-R-3: FROM NU PRO SIM MODEL, BASE CASE, RUN 1 (D.P.U. 88-19).
[2]: IR-R-3: FROM NU PRO SIM MODEL, BASE CASE, RUN 2: 1990-2015.
[3]: [1]-[2].
[4]: IR-R-45: FROM NU PRO SIM MODEL, BASE CASE, RUN 3: 1990-1997, RUN 2: 1998-2015.
[5]: [4]/[3].
[6]: FROM TABLE E.1, COLUMN [1].
[7]: FROM TABLE E.2, COLUMN [1].
[8]: [7]-[6].
[9]: [5]*[8].

TABLE 6.2: RATIO OF BASE TO EXPECTED OIL PRICES

YEAR	---1.0% SULFUR OIL: 6.22 MMBTU/BBL--- (DOLLARS PER BARREL) LOW	BASE	HIGH	EXPECTED	RATIO OF BASE TO EXPECTED
	[1]	[2]	[3]	[4]	[5]
1990	12.23	22.81	31.91	22.51	98.70%
1991	12.55	24.76	36.09	24.58	99.29%
1992	13.01	26.56	42.67	27.07	101.93%
1993	13.71	28.46	51.39	30.10	105.75%
1994	14.19	30.35	59.02	32.85	108.24%
1995	15.66	32.25	68.02	36.09	111.89%
1996	17.83	34.62	76.05	39.55	114.23%
1997	19.57	39.36	84.46	44.42	112.86%
1998	20.86	45.06	93.56	49.92	110.79%
1999	22.51	51.70	100.72	55.67	107.67%
2000	25.32	59.28	109.81	62.59	105.59%
2001	27.95	66.40	120.46	69.52	104.70%
2002	31.89	74.46	131.10	77.27	103.78%
2003	34.26	82.05	141.74	84.43	102.90%
2004	38.67	91.06	151.42	92.65	101.75%
2005	41.73	100.55	163.03	101.28	100.73%
2006	46.03	109.56	174.64	109.87	100.28%
2007	52.06	118.57	186.25	118.80	100.20%
2008	57.53	126.63	198.83	127.25	100.49%
2009	64.05	134.69	212.37	136.10	101.05%
2010	69.65	142.28	225.92	144.48	101.55%
2011	76.68	150.82	239.94	153.82	101.99%
2012	86.13	159.36	253.49	163.54	102.62%
2013	93.63	168.84	265.10	173.05	102.49%
2014	102.85	178.80	278.65	183.58	102.67%
2015	111.55	189.71	291.22	194.38	102.46%
2016	118.99	200.14	305.74	205.03	102.44%
2017	127.35	211.53	320.25	216.44	102.32%
2018	132.93	222.91	335.73	227.48	102.05%
2019	138.51	235.24	350.24	238.89	101.55%
2020	145.01	247.57	366.69	250.88	101.34%

NOTES:

[1] - [3]: From WMECO's response to the DPU's first information request.

[4]: [1]*20% + [2]*60% + [3]*20%.

[5]: [4]/[2].

TABLE 6.3: NORTHEAST UTILITIES ESTIMATED AVOIDED COSTS, RUN 1: DPU 88-19
USING EXPECTED RATHER THAN REFERENCE FUEL PROJECTIONS

YEAR	FUEL O&M	T&D LOSSES	CAPITALIZED ENERGY	SAVINGS SHARE	CAPACITY VALUE	TOTAL AVOIDED COSTS
	[1]	[2]	[3]	[4]	[5]	[6]
1990 (1/6)	0.5	0.0	0.0	0.0	0.0	0.5
1991	3.4	0.0	0.3	0.0	0.0	3.7
1992	3.1	0.0	0.3	0.0	0.0	3.4
1993	4.1	0.0	1.1	0.0	0.0	5.2
1994	4.4	0.0	1.2	0.0	0.0	5.6
1995	5.2	0.0	1.3	0.0	0.0	6.5
1996	5.1	0.0	1.4	0.0	0.0	6.5
1997	7.1	0.0	1.5	0.0	0.0	8.6
1998	7.0	0.0	0.6	0.0	1.0	8.6
1999	8.1	0.0	0.7	0.0	1.0	9.8
2000	9.5	0.0	0.7	0.0	1.1	11.3
2001	9.6	0.0	0.8	0.0	1.2	11.6
2002	10.7	0.0	0.8	0.0	1.3	12.7
2003	11.8	0.0	0.9	0.0	1.3	14.0
2004	12.9	0.0	0.9	0.0	1.4	15.3
2005	14.3	0.0	1.0	0.0	1.5	16.8
2006	15.4	0.0	1.0	0.0	1.7	18.2
2007	17.0	0.0	1.1	0.0	1.8	19.9
2008	18.4	0.0	1.2	0.0	1.9	21.6
2009	19.7	0.0	1.3	0.0	2.0	23.0
2010	20.6	0.0	1.3	0.0	2.2	24.1
2011	22.4	0.0	1.4	0.0	2.3	26.1
2012	24.3	0.0	1.5	0.0	2.5	28.3
2013	24.5	0.0	1.6	0.0	2.7	28.8
2014	25.7	0.0	1.7	0.0	2.9	30.3
2015	27.1	0.0	1.8	0.0	3.1	32.1
2016	28.9	0.0	2.0	0.0	3.3	34.2
2017	31.1	0.0	2.1	0.0	3.5	36.8
2018	33.4	0.0	2.2	0.0	3.8	39.4
2019	35.7	0.0	2.4	0.0	4.0	42.2
2020	38.3	0.0	2.5	0.0	4.3	45.2
20 YEAR PV	47.4	0.1	5.6	0.0	3.6	56.7
22 YEAR PV	51.6	0.1	5.9	0.0	4.0	61.6
25 YEAR PV	57.1	0.1	6.2	0.0	4.6	68.0
30 YEAR PV	65.0	0.1	6.8	0.0	5.5	77.4

TABLE 6.4: BASELOAD POWER AS A PERCENTAGE OF PEAK DEMAND, 1990-2004

	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004
1. BASELOAD POWER (AUGUST)															
A. NUCLEAR	6509	6509	6509	6509	6509	6509	6509	6509	6509	6509	6509	6509	6509	6509	6509
B. COAL	2760	2760	2760	2760	2760	2760	2760	2760	2760	2760	2639	2639	2639	2590	2590
C. WOOD	52	52	52	52	52	52	52	52	52	52	52	52	52	52	52
D. 50% OF MEDIAN HYDRO	696	709	709	709	709	709	709	709	709	709	709	709	709	709	709
E. 50% OF NON-UTILITY HYDRO	114	117	119	119	119	119	119	119	119	119	119	119	119	119	119
F. NON-UTILITY THERMAL	1442	1590	1622	1622	1623	1623	1623	1623	1623	1623	1623	1623	1623	1623	1623
G. NET PURCHASES AND SALES	1209	2601	2120	2122	1945	1902	1902	1902	1902	1902	1902	652	652	652	652
TOTAL	12782	14337	13891	13893	13717	13674	13674	13674	13674	13674	13553	12303	12303	12254	12254
2. PEAK DEMAND (SUMMER)	20300	20740	21180	21641	22147	22689	23203	23668	24115	24686	25340	25766	26205	26668	27261
3. RATIO OF BASELOAD TO PEAK	62.97%	69.13%	65.58%	64.20%	61.93%	60.26%	58.93%	57.77%	56.70%	55.39%	53.48%	47.75%	46.95%	45.95%	44.95%

NOTES:
[1]: NEPOOL APRIL 1, 1989 CELT REPORT, page 3.
[2]: CELT REPORT, page 7.
[3]: [1]/[2].

TABLE 6.5: CAPACITY FROM PLANTS WHICH HAVE REACHED THE END OF THEIR USEFUL LIVES, BASE CASE RUN 2

		1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
1. COAL											
	MT. TOM				147.0	147.0	147.0	147.0	147.0	147.0	147.0
2. OIL											
	DEVON 7		104.8	104.8	104.8	104.8	104.8	104.8	104.8	104.8	104.8
	DEVON 8		104.8	104.8	104.8	104.8	104.8	104.8	104.8	104.8	104.8
	MIDDLETOWN 2	115.4	115.4	115.4	115.4	115.4	115.4	115.4	115.4	115.4	115.4
	MIDDLETOWN 3							230.7	230.7	230.7	230.7
	MIDDLETOWN 4										
	MONTVILLE 6										
	NORWALK 1							157.7	157.7	157.7	157.7
	NORWALK 2							167.3	167.3	167.3	167.3
3. TOTAL		115.4	325.0	325.0	472.0	472.0	472.0	1027.7	1027.7	1027.7	1027.7
4. TOTAL CAPACITY		7901.4	8124.4	8180.0	8780.0	8780.0	9004.0	9100.0	9196.0	9429.0	9414.4
5. RETIRED AS % OF TOTAL CAPACITY		1.5%	4.0%	4.0%	5.4%	5.4%	5.2%	11.3%	11.2%	10.9%	10.9%

SOURCES: EXHIBIT DPU-20 IN DPU #88-250, AND IR-R-3: PRODUCTION SIMULATION MODEL RUN 1.

TABLE 6.5: CAPACITY FROM PLANTS WHICH HAVE REACHED THE END OF THEIR USEFUL LIVES, BASE CASE RUN 2

		2008	2009	2010	2011	2012	2013	2014	2015
1. COAL									
	MT. TOM	147.0	147.0	147.0	147.0	147.0	147.0	147.0	147.0
2. OIL									
	DEVON 7	104.8	104.8	104.8	104.8	104.8	104.8	104.8	104.8
	DEVON 8	104.8	104.8	104.8	104.8	104.8	104.8	104.8	104.8
	MIDDLETOWN 2	115.4	115.4	115.4	115.4	115.4	115.4	115.4	115.4
	MIDDLETOWN 3	230.7	230.7	230.7	230.7	230.7	230.7	230.7	230.7
	MIDDLETOWN 4						384.5	384.5	384.5
	MONTVILLE 6				394.1	394.1	394.1	394.1	394.1
	NORWALK 1	157.7	157.7	157.7	157.7	157.7	157.7	157.7	157.7
	NORWALK 2	167.3	167.3	167.3	167.3	167.3	167.3	167.3	167.3
3. TOTAL		1027.7	1027.7	1027.7	1421.8	1421.8	1806.3	1806.3	1806.3
4. TOTAL CAPACITY		9752.7	9937.6	10337.6	10197.1	10526.1	10926.1	11326.1	11566.8
5. RETIRED AS % OF TOTAL CAPACITY		10.5%	10.3%	9.9%	13.9%	13.5%	16.5%	15.9%	15.6%

TABLE 6.6: RIVERSIDE ECONOMICS UNDER DIFFERENT OIL PRICE ASSUMPTIONS, 10/86 CONTRACT

CASE	OIL PRICE	ESTIMATED CUMULATIVE REVENUE REQUIREMENTS DIFFERENCES (PRESENT VALUE)		
		AFTER 20 YEARS	AFTER 25 YEARS	AFTER 30 YEARS
1.	LOW	112,694,000	114,856,000	114,589,000
2.	REFERENCE	43,192,000	32,963,000	23,158,000
3.	HIGH	(53,845,000)	(75,906,000)	(97,084,000)
4.	EXPECTED (20/60/20)	37,685,000	27,567,800	17,395,800

SOURCE: BRIEFING DOCUMENT D, in response to DPU discovery in 88-19.

EXHIBIT PLC-5

THE COMMONWEALTH OF MASSACHUSETTS

DEPARTMENT OF PUBLIC UTILITIES

WESTERN MASSACHUSETTS ELECTRIC COMPANY

DOCKET NO. DPU 88-250

APPLICATION FOR RATE RELIEF

TESTIMONY OF

WILLIAM L. STILLINGER

ON BEHALF OF APPLICANT

DECEMBER 1988

UNIT/RESOURCE DESCRIPTION	DISPATCH SEQUENCE	CAPACITY RATING (MW) (1)	TARGET AVAILABILITY %	EFFECTIVE AVAILABLE CAPACITY (MW)	CUMULATIVE DISPATCH LEVEL (MW)	MUST RUN STATUS	AVERAGE ANNUAL FUEL COST MILLS/kWh
RIVER HYDRO	1	274.6	41.0	112.6	0.0	YES	0.0
PRIVATE POWER PRODUCER	2	449.0	77.0	345.7	112.6	YES	71.6
VT YANKEE	3	54.1	68.7	37.2	458.3	YES	8.0
MILLSTONE 2	4	787.6	70.1	552.1	495.5	YES	8.0
ME. YANKEE	5	111.1	82.5	91.7	1,047.6	YES	8.0
MASS YANKEE	6	52.7	82.5	43.5	1,139.3	YES	9.0
MILLSTONE 3	7	669.4	70.1	469.2	1,182.8	YES	9.0
MILLSTONE 1	8	586.1	68.7	402.7	1,652.0	YES	12.0
CONN YANKEE	9	249.2	82.5	205.6	2,054.7	YES	12.0
MT. TOM	10	91.4	88.6	81.0	2,260.3	NO	18.0
W. SPRINGFIELD 3	11	108.3	88.6	96.0	2,341.3	NO	24.8
MONTVILLE 5	12	51.3	88.6	45.5	2,437.3	NO	24.8
NORWALK 1 & 2	13	291.0	88.6	257.8	2,482.8	NO	26.0
DEVON 7 & 8	14	209.6	88.6	185.7	2,740.6	NO	26.9
NEW HAVEN HARBOR	15	25.0	79.1	19.8	2,926.3	NO	27.8
MIDDLETOWN 3	16	154.3	79.1	122.1	2,946.1	NO	28.6
MIDDLETOWN 2	17	89.2	88.6	79.0	3,068.2	NO	29.1
DEVON 3 & 6	18	35.6	92.6	33.0	3,147.2	NO	29.3
MONTVILLE 6	19	215.0	84.8	182.3	3,180.2	NO	31.9
DEVON 4,5 & MIDD. 1	20	41.2	92.6	38.2	3,362.5	NO	32.4
POWER PURCHASE	21	220.0	100.0	220.0	3,400.7	NO	34.5
MIDDLETOWN 4	22	257.2	90.0	231.5	3,620.7	NO	34.6
W. SRINGFIELD 1&2	23	25.8	92.6	23.9	3,852.2	NO	39.2
VARIOUS SMALL ICU'S*	24	259.1	82.8	214.5	3,876.1	NO	75.3
COS COB 10-12 & SHOW 11-14	25	136.4	75.2	102.6	4,090.6	NO	93.6
TOTAL RESOURCES		5,444.2		4,193.2			

* DEVON 10, MONTVILLE 10&11, NORWALK HARBOR 10, MIDDLETOWN 10, W.SPRINGFIELD 10, TUNNEL 10, SILVER LAKE 10-13, DOREEN 10, FRANKLIN DRIVE 10, WOODLAND ROAD 10, TORRINGTON TERMINAL 10, NORWICH, BRANFORD 10 AND TRACY.

NOTES: (1) NET OF LONG AND SHORT TERM CAPACITY SALES.

EXHIBIT PLC-6

ANNUAL SUMMARY 1991 (YEAR 6)

	UNIT ID	CAP	DOLLARS	MWHR	STARTS HOT	STARTS COLD	HRS RUN	MBTU-RUN	BOILER BANK HRS	CAP FCTR	OUTPT FCTR	AVAIL	AVG RATE	AVG HT RATE
NUCLEAR														
MILL 1	1	636.5	32583826.	3908507.	0.	1.	7032.	39088252.	0.	0.70	0.97	0.80	8.34	10001.
MILL 2	2	834.7	33894603.	5124581.	0.	1.	7104.	51249335.	0.	0.70	1.00	0.82	6.61	10001.
MILL 3	3	749.0	28936670.	4322866.	0.	1.	7032.	43232041.	0.	0.66	0.99	0.66	6.69	10001.
C YANK	4	247.1	12233810.	1525348.	0.	0.	8160.	15254188.	0.	0.70	0.99	0.92	8.02	10000.
M YANK	5	53.4	2770801.	332540.	0.	1.	7368.	3325441.	0.	0.71	0.98	0.84	8.33	10000.
VTYANK	6	54.2	2249115.	334129.	0.	0.	8760.	3341295.	0.	0.70	1.00	0.84	6.73	10000.
MEYANK	7	111.1	3580091.	684351.	0.	1.	7536.	6843546.	0.	0.70	1.00	0.86	5.23	10000.
SEA 1	8	46.7	2628252.	275645.	0.	1.	6696.	2756557.	0.	0.67	0.98	0.76	9.53	10000.
TOTAL		2732.7	118877167.	16507967.										
COAL														
MT TOM	100	91.4	17979221.	641855.	33.	2.	7690.	6183174.	334.	0.80	0.99	0.96	28.01	9661.
TOTAL		91.4	17979221.	641855.										
OIL														
MIDD 1	201	18.2	829488.	17977.	46.	8.	1425.	188025.	546.	0.11	0.77	0.96	46.14	10584.
MIDD 2	202	109.8	10669298.	258706.	61.	12.	3610.	2430463.	710.	0.27	0.71	0.96	41.24	9453.
MIDD 3	203	219.5	34387844.	830294.	0.	11.	6162.	7854027.	0.	0.43	0.70	0.90	41.42	9492.
MIDD 4	204	365.9	11919901.	239373.	37.	11.	1213.	2646365.	461.	0.07	0.58	0.94	49.80	11377.
MTVL 5	205	72.9	3341169.	86207.	57.	4.	1623.	833580.	475.	0.13	0.80	0.34	38.76	9754.
MTVL 6	206	364.6	24133482.	542054.	81.	17.	2850.	5963726.	1153.	0.17	0.58	0.94	44.52	11159.
NORH 1	207	157.7	34449405.	888946.	37.	3.	6657.	8605310.	400.	0.64	0.93	0.90	38.75	9730.
NORH 2	208	167.3	33453025.	869615.	30.	7.	6374.	8357776.	352.	0.59	0.89	0.96	38.47	9660.
DEV #3	209	20.4	1249989.	29214.	82.	11.	1763.	309505.	640.	0.16	0.89	0.96	42.79	10743.
DEV #4	210	14.9	405249.	8192.	48.	26.	670.	95863.	672.	0.06	0.90	0.96	49.47	12246.
DEV #5	211	14.6	637579.	13288.	65.	20.	1077.	154376.	778.	0.10	0.95	0.92	47.98	11952.
DEV #6	212	20.4	1299695.	30400.	80.	11.	1825.	322115.	638.	0.17	0.90	0.92	42.75	10736.
DEV #7	213	104.8	19098103.	490535.	80.	7.	5472.	4775752.	933.	0.53	0.94	0.96	38.93	9783.
DEV #8	214	104.8	15903061.	404225.	66.	11.	4304.	3975172.	764.	0.44	0.99	0.96	39.34	9887.
HSPR 1	215	14.8	606514.	13031.	43.	10.	1311.	149755.	531.	0.10	0.71	0.96	46.54	11653.
HSPR 2	216	14.8	501402.	10539.	36.	7.	1181.	124087.	442.	0.08	0.64	0.92	47.58	11928.
HSPR 3	217	108.3	23037839.	640366.	74.	3.	6634.	6346120.	731.	0.67	0.96	0.96	35.98	9936.
NHHCR	221	25.0	5455675.	145868.	17.	6.	6397.	1368493.	183.	0.67	0.99	0.92	37.40	9406.
NENGTN	220	200.0	0.	0.	0.	0.	0.	0.	0.	0.0	0.0	1.00	0.0	0.
BPHBR1	222	39.6	0.	0.	0.	0.	0.	0.	0.	0.0	0.0	1.00	0.0	0.
BPHBR2	223	79.4	0.	0.	0.	0.	0.	0.	0.	0.0	0.0	1.00	0.0	0.
TOTAL		1893.7	221378716.	5518828.										
ICU														
MIDDJT	301	21.1	476778.	5363.	0.	122.	424.	72488.	0.	0.03	0.86	0.98	88.91	13605.
TORRJT	302	22.0	0.	0.	0.	0.	0.	0.	0.	0.0	0.0	0.98	0.0	0.
FRDRJT	303	22.0	6.	0.	0.	31.	107.	1.	0.	0.00	0.00	0.98	85.16	13107.
MTVL 0	304	5.3	72071.	1250.	1.	159.	541.	12015.	1.	0.03	0.95	0.96	57.66	9701.
NORKGT	305	16.3	143919.	1430.	0.	48.	118.	23656.	0.	0.01	0.89	0.98	100.67	17215.
NORMCH	306	15.9	0.	0.	0.	0.	0.	0.	0.	0.0	0.0	0.98	0.0	0.
DEV JT	307	18.8	201595.	1947.	0.	74.	201.	30765.	0.	0.01	0.79	0.98	103.53	15942.
HSPRJT	308	22.0	412998.	4466.	0.	107.	350.	62634.	0.	0.02	0.83	0.98	92.47	14119.
SVLG12	309	17.8	0.	0.	0.	0.	0.	0.	0.	0.0	0.0	0.98	0.0	0.
DOR JT	310	21.2	6.	0.	0.	31.	108.	1.	0.	0.00	0.00	0.98	83.68	12867.
MD JET	311	21.2	0.	0.	0.	0.	0.	0.	0.	0.0	0.0	0.98	0.0	0.
TUNJET	313	22.0	0.	0.	0.	0.	0.	0.	0.	0.0	0.0	0.98	0.0	0.
CCJET1	315	24.0	253776.	2737.	0.	99.	287.	38816.	0.	0.01	0.55	0.88	92.73	14277.
CCJET2	316	24.0	240691.	2608.	0.	92.	278.	36802.	0.	0.01	0.54	0.88	92.30	14200.
CCJET3	317	24.0	137478.	1440.	0.	62.	153.	20990.	0.	0.01	0.54	0.88	95.48	14682.
SMHJT1	318	42.0	813146.	8595.	1.	142.	463.	124091.	1.	0.02	0.59	0.98	94.61	14543.
SMHJT2	319	42.0	300281.	3061.	0.	60.	161.	45903.	0.	0.01	0.60	0.88	98.10	15117.
SMHJT3	320	42.0	419886.	4385.	0.	81.	221.	64305.	0.	0.01	0.63	0.98	95.75	14779.
SMHJT4	321	42.0	599324.	6256.	0.	114.	323.	91565.	0.	0.02	0.61	0.98	95.80	14751.
TOTAL		323.5	4071956.	43537.										

EXHIBIT PLC-7

RESPONSE TO RSECO INFORMATION REQUEST DATED JANUARY 13, 1989

Q-RSECO-05: Please identify and explain all material changes in the input assumptions to the production costing runs for the replacement/avoided fuel cost between each consecutive pair of the following cost estimates:

a. August 1985;
b. April 1986;
c. DPU 85-270;
d. DPU 84-276-B (October 1986);
e. DPU 88-19 (December 1987);
f. Connecticut DPUC 88-04-02 (April 1988); and
g. DPU 86-218 (August 1988);

and explain the basis for each change.

Response: The changes to input assumptions for the seven referenced replacement power/avoided cost estimates, which are envisioned by the Company to be possible material changes, are summarized on Attachment 1. The assumptions used in preparation of these referenced estimates were current at the time of developing such estimates, and were likewise used in other planning studies conducted concurrently by the Company.

The following information briefly explains the basis for these planning assumptions.

- Load Forecasts - These forecasts are as filed by the Company with the MEFSC on April 1 of each year. A copy of those forecast reports can be made available to the requester as supplemental materials if determined necessary. The attached Exhibit A is a graphical display of the peak load and energy requirements of each load forecast for the period 1985-1997.

- Fuel Prices - the fuel price forecast used by the Company is the most recent DRI long term price forecast available at the time of the study. The attached Exhibit B is a graphical display of each DRI forecast for the period 1986-2010.

- Financials - The cost of capital and return on common equity used in each study depends on the vintage of the study and the extent of regulations being responded to at that time. The numbers are either: the most current used by the Company for long-term financial planning purposes (e.g., Aug. 85, 85-270, Apr. 86), consistent with CT DPUC regulatory requirements (e.g., 88-04-02), or that approved by the MDPU in the Company's most recent rate case (e.g., 84-276-B, 88-19, or 86-218).

- Block Size and Avoided Capacity - The block size and avoided capacity evaluated is either specific to the study (e.g., 85-270), determined by the NU Companies as appropriate to the circumstances at the time of the study (i.e., no specific regulations for Aug. 85 or Apr. 86), or specific to regulatory dictates (e.g., 84-276-3, 88-19, 88-04-02 or 86-218).

- Nuclear Capacity Factors - the bases for these assumptions and changes thereto are provided in the Company's response to Q-RSECO-19.

- Power Purchase Forecast Period - The power purchase forecast period is compatible with and limited to that used by the Company for financial planning purposes. The Company officially lengthened its internal forecasting period from 5 to 10 years beyond its one year budgeting period beginning in 1987.

ATTACHMENT 1
SUMMARY OF ASSUMPTIONS FOR SELECTED SYSTEM COST CALCULATIONS

	INTERNAL PLANNING (AUG 85)	DPU 85-270 (MAR 86)	INTERNAL PLANNING (APR 86)	DPU 84-276-B (OCT 86)	DPU 88-19 (DEC 87)	CT DPUC 88-04-02 (APR 88)	DPU 86-218 (AUG 88)
A. Purpose of Calculation	Block 1 Avoided Costs	Millstone 3 Analysis	Block 1 Avoided Costs	WMECO RFP Ceiling Prices	DPU Request	3rd Annual Filing	WMECO RFP Ceiling Prices
B. Date of Load Forecast Used (See Exhibit A)	1985	1985	1986	1986	1987	1988	1988
C. DRI Oil Price Forecast #6 oil in 1992 ($/bbl) (See Exhibit B)	Sum. 85 35.52	Spr. 86 22.86	Spr. 86 22.86	Fall 86 22.51	Fall 87 26.56	Spr. 88 24.99	Sum. 88 24.44
D. Cost of Money/							
Discount Rate (pct.)	14.43	14.05	11.15	11.37	10.32	11.26	10.01
Return on Equity (pct.)	15.90	16.50	13.00	13.00	12.50	12.50	12.78
E. Assumed Block Size (MW)	450	742	450	220	297.7	50	297.7
F. Avoided Capacity	1998-Coal (300) 2001-Coal (150)	Avoid Gas Turbines in 1993, 1994, 1995, 1996, 1997, 1999	1997-Defer Repowering 2003-Avoid GCCC	2003-Defer Repowering 2007-Avoid GCCC	Life. Ext. 95-Mont 5 98-W.Spr. 3 98-Midd. 2	2001-Combined Cycle-Nat. Gas	Cont. Oper: 95-Mont 5 98-W.Spr. 3 98-Midd. 2
G. Nuclear Capacity Factor Assumptions:							
– Number weeks planned maintenance	8-10	8-10	8-10	8-10	8-10	7-8	7-8
– Availability between planned outages (pct.)	85	85	85	85	87	87	87
– LT. Cap. Fct. (pct.)	70	70	70	70	75	75	75
H. Millstone 3 Capacity Factor Maturation Schedule							
	'86 60	60	60	60	–	'89 68	68
	'87 63	63	63	63	–	'90 79	79
	'88-91 65	65	65	65	65	'91 73	73
	'92 and beyond 70	70	70	70	-70	'92 and beyond 75	75
I. Embedded QF MW	69	547	82	533	560	560	558
J. Ending Year of Daily Power Purchases	'90	'90	'91	'91	'97	'98	'98

EXHIBIT A-1

NU SUMMER PEAK LOAD FORECASTS

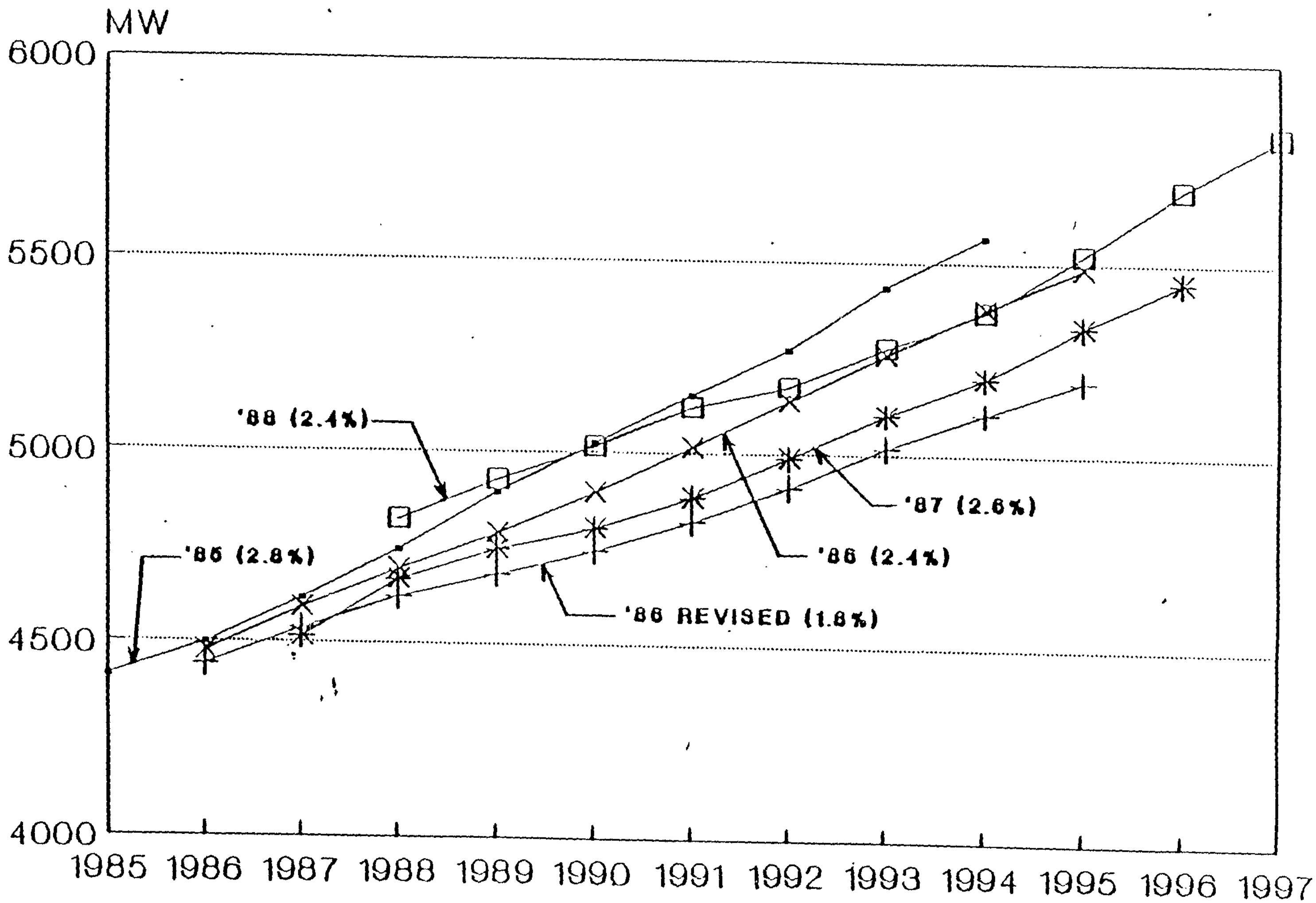

EXHIBIT A-2

NU ENERGY FORECASTS

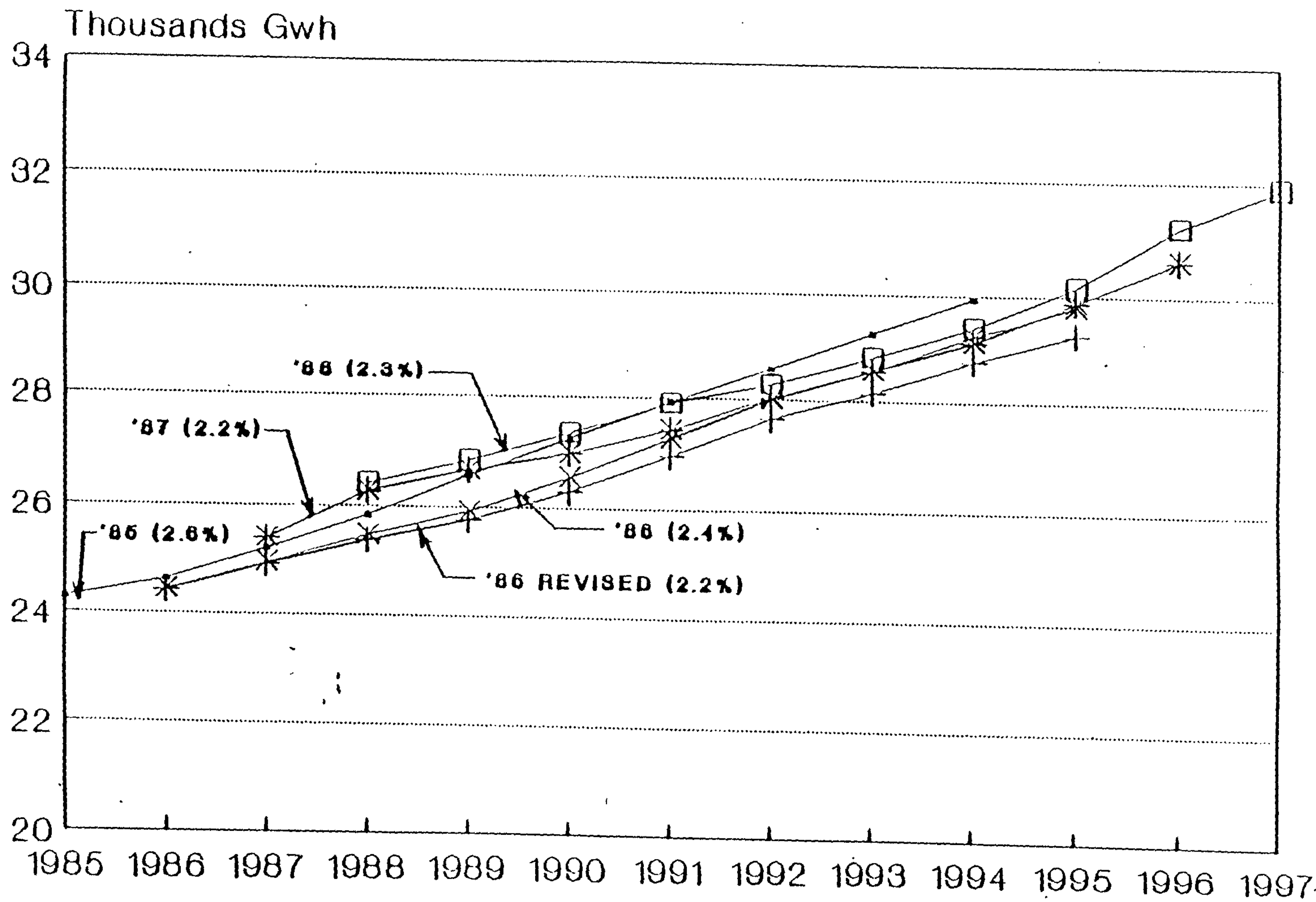

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EXHIBIT B

DRI FUEL FORECAST: NO.6 OIL-1.0% SULFUR

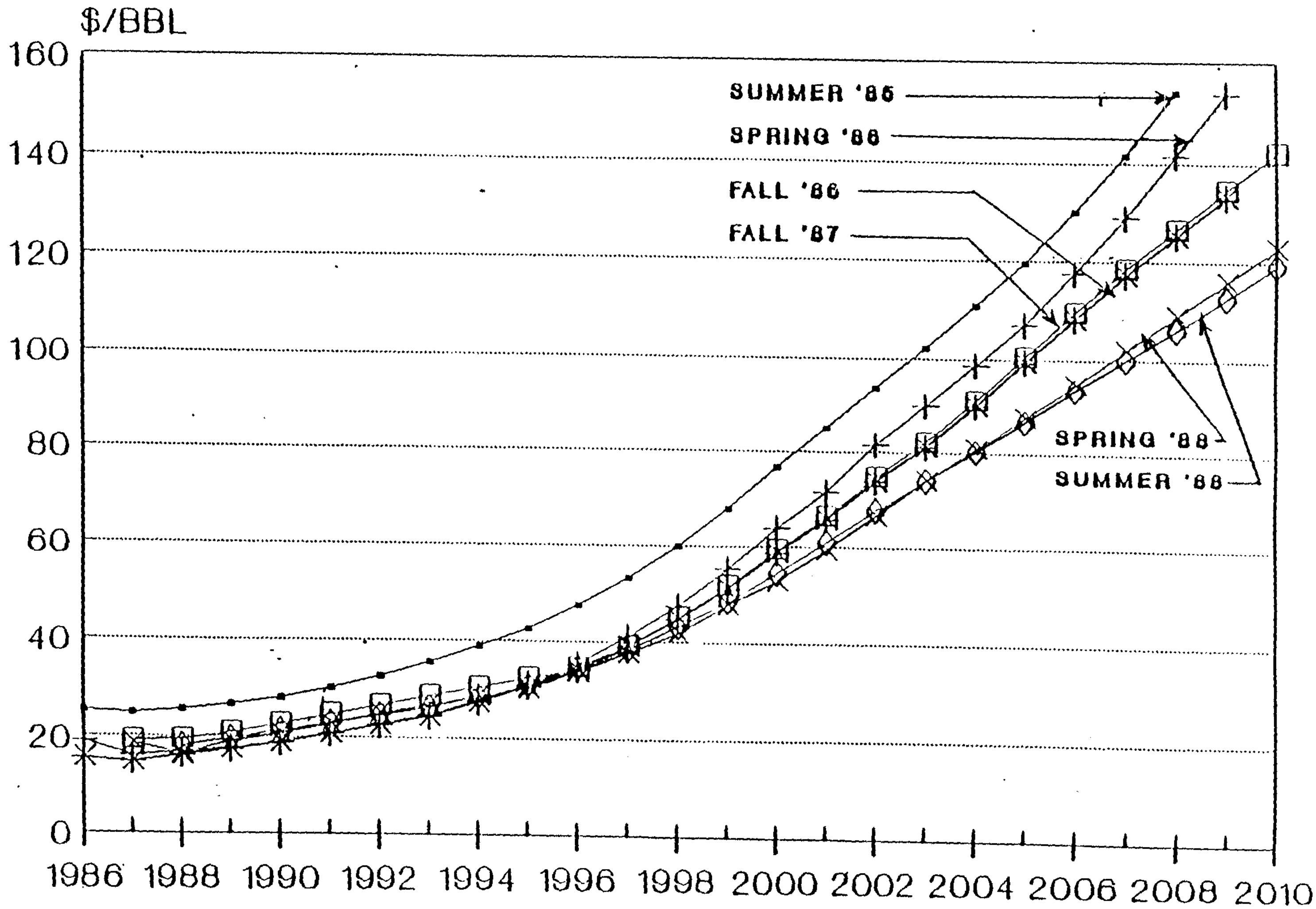

EXHIBIT PLC-8

RESPONSE TO RSECO INFORMATION REQUEST DATED JANUARY 13, 1989

Q-RSECO-16: Please specify the nuclear capacity factors which Mr. Stillinger referred to as "what the Company is using in its avoided cost calculations," on page 7 of his testimony in DPU 88-19, filed on or about December 7, 1987.

Response: The referenced nuclear capacity factors are provided in Table 1 attached, for the ten-year period 1988-1997. Beyond that period, Millstone Units 1, 2, and 3 and Connecticut Yankee are each assumed to operate at an annual capacity factor of 75 percent; Vermont and Maine Yankee and Seabrook are each assumed to operate at 70 percent capacity; and Mass Yankee is assumed retired. The basis of these assumptions is discussed in the Company's response to Q-RSECO-19.

Table 1

CAPACITY FACTORS (%)

UNIT	MW	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	AVG
MILL 1	636.5	87	70	88	71	87	70	88	71	87	70	78.9
MILL 2	834.7	67	67	83	71	67	87	67	67	87	67	73.0
MILL 3	749.0	65	65	65	65	70	70	70	70	70	70	68.0
C YANK	247.1	88	70	70	81	76	70	73	84	70	70	75.2
M YANK	53.4	72	87	74	74	88	74	74	79	82	74	77.8
VT YANK	54.2	87	73	73	87	73	74	88	74	74	88	79.1
ME YANK	111.1	73	87	75	75	87	73	73	87	73	81	78.4
SEA 1	46.7	-	55	64	66	65	65	65	70	70	71	65.7
TOTAL MW	2732.7											
WEIGHTED AVERAGE		72.6	67.6	75.9	69.6	73.5	74.3	72.9	70.3	78.4	68.8	

EXHIBIT PLC-9

REPONSE TO RSECO INFORMATION REQUEST DATED JANUARY 13, 1989

Q-RSECO-37: Please provide a narrative explanation of NU's process for securing, pricing, and making interchange sales, including firm and non-firm sales of capacity and energy.

Response:

The NU Companies have participated in the bulk power market since the early 1970's, and their business relationships with utilities in this marketplace are long-standing. These relationships are extensive and the NU Companies' process for selling capacity and energy has been refined over time to enhance these relationships and cannot be described easily in writing.

Simplistically, the process for entering into contractual arrangements for the sale of capacity and energy can be summarized as follows:

- The NU system's capacity and energy position is forecast in the short- and long-term based on the most current forecast of loads and resources. This forecasted capacity and energy position is used to determine the amount and type of capacity and associated energy the NU Companies will offer for sale to other utilities.
- Discuss with interested and/or potential buyers their capacity and energy mix needs. This discussion would include the amount with consideration of capacity and energy costs.
- Assess the competition in the bulk power market.
- Develop a mix of generating units for sale to meet buyers' need for capacity and energy, and price the offer to maximize benefits to the NU Companies' customers. Pricing must, however, recognize competition in the bulk power market and FERC's cost of service requirement for pricing.
- The net benefit to the NU Companies' customers from a proposed sale of capacity and energy is determined by comparing the capacity cost revenues to the increased energy production costs.
- Make an offer of capacity and energy to the prospective buyer(s).
- Revise and/or negotiate a transaction that provides mutual economic benefits to both parties, including conditions and/or availability criteria to protect the NU Companies' customers' interests.
- Seek approval of the transaction from the FERC and, if necessary, the Connecticut DPUC and the Massachusetts DPU.

ASE-LOAD CAPACITY COMPARED TO PEAK DEMAND FOR NEW YORK AND MAAC [1]

YEAR	INSTALLED GENERATION CAPACITY (MW) [2]		PEAK DEMAND SUMMER (MW)		RATIO	
	NY	MAAC	NY	MAAC	NY	MAAC
1987	10505	29231	24570	40526	42.76%	72.13%
1988	11587	29232	24310	39581	47.66%	73.85%
1989	12282	29248	24700	40067	49.72%	73.00%
1990	12398	29278	25170	40655	49.26%	72.02%
1991	12423	30183	25580	41215	48.57%	73.23%
1992	12423	30823	25940	41739	47.89%	73.85%
1993	12427	30823	26300	42308	47.25%	72.85%
1994	12427	30823	26640	42826	46.65%	71.97%
1995	12427	30823	27000	43347	46.03%	71.11%
1996	12427	30823	27340	43918	45.45%	70.18%
1997	12592	30823	27680	44491	45.49%	69.28%

NOTES:
[1]: ALL DATA FROM NERC, 1988 ELECTRICITY SUPPLY & DEMAND.
[2]: NUCLEAR + COAL + 1/2 HYDRO.