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THE COMMONWEALTH OF MASSACHUSETTS

BEFORE THE DEPARTMENT OF PUBLIC UTILITIES

RE: WESTERN MASSACHUSETTS ELECTRIC COMPANY

DOCKET No. 85-270

# TESTIMONY OF PAUL CHERNICK ON BEHALF OF THE ATTORNEY GENERAL

March 19, 1986

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# TESTIMONY OF PAUL CHERNICK

## 1 INTRODUCTION AND QUALIFICATIONS

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

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

### 1.1 Qualifications

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

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

I was a Utility Analyst for the Massachusetts Attorney General for over three years, and was involved in numerous aspects of utility rate design, costing, load forecasting, and evaluation of power supply options. My work has considered, among other things, the effects of rate design and cost allocations on conservation, efficiency, and equity.

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

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

A: Yes. I have testified approximately forty times on utility issues before this Department and such other agencies as the Massachusetts Energy Facilities Siting Council, the Texas Public Utilities Commission, the Illinois Commerce Commission, the New Mexico Public Service Commission, the District of Columbia Public Service Commission, the New Hampshire Public Utilities Commission, the Connecticut Department of Public Utility Control, the Michigan Public Service Commission, the Maine Public Utilities Commission, the Vermont Public Service Board, the Pennsylvania Public Utilities Commission, the Federal Energy Regulatory Commission, and the Atomic Safety and Licensing Board of the U.S. Nuclear Regulatory Commission. A detailed list of my previous testimony is contained in my resume. Subjects I have testified on include cost allocation, rate design, long range energy and demand forecasts, costs of nuclear power, conservation costs and potential effectiveness, generation system reliability, fuel efficiency standards, and ratemaking for utility production investments and conservation programs.

Q: Do you have a track record of accurate predictions in capacity planning?

A: Several of my criticisms of utility projections have been confirmed by subsequent events or by the utilities themselves. In the late 1970's, I pointed out numerous errors in the load forecasts of several New England utilities, and of the New England Power Pool (NEPOOL), and predicted that growth rates would be lower than the utilities expected. Many of my suggested changes have been incorporated in subsequent forecasts, load growth has almost universally been lower than the utility forecast, and the utility forecasts have been revised downward repeatedly. Figures 1.1, 1.2, and 1.3 display the history of load forecasts since 1974 for NEPOOL, Western Massachusetts Electric (WMECO), and Northeast Utilities (NU), respectively.

My projections of nuclear power plant construction costs and schedules have also proven to be more accurate than those of the utilities. In June 1979, when Boston Edison was projecting a cost of $1.895 billion for Pilgrim 2, I projected a cost between $3.40 and $4.93 billion. Boston Edison's final cost estimate (issued when Pilgrim 2 was canceled in September 1981) stood at $4.0 billion.

Early in 1980, Public Service of New Hampshire (PSNH) was projecting in-service dates for Seabrook of about 4/83 and 2/85, at a total cost of $2.8 billion. I predicted in-service dates of 10/85 and 10/87, with a cost $7.8 billion. By late 1982, PSNH was projecting in-service dates of 2/84 and 5/86, with a total cost of $3.6 billion, while I projected dates of about 3/86 and 6/89, and a cost of about $9.6 billion.[1] Before Seabrook 2 was conditionally canceled in 1984, PSNH's cost estimates had risen to $9.0 billion, with in-service dates of 7/85 and 12/90, while PSNH's architect/engineers released an estimate of $10.1 billion.

In several pieces of testimony in the late 1970's and early 1980's (including MDPU 19845, MDPU 20055, MDPU 20248, and NHPSC 81-312)[2] I projected continuing nuclear capital additions, continuing real escalation in nuclear O&M, and mature capacity factors for large pressurized water reactors (PWRs) of around 60%, well below the 72% - 80% estimates used by the utilities.[3] Most utilities now include in their analyses of nuclear economics some capital additions, escalating real O&M for at least a few years, and mature

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1. Within two months of my projection, PSNH revised its estimates to values of 12/84, 7/87, and $5.2 billion.

2. Complete citations to these cases are contained in my resume, attached as Appendix A.

3. So far as I know, I was the first analyst to propose explicit allowances for nuclear capital additions. Utilities had previously recognized capital additions only as an element of the fixed charge rate, if at all.

capacity factors in the 60 - 70% range. Thus, the industry has adjusted its projections substantially towards my earlier predictions, even though its projections are still often very optimistic. The 60% PWR capacity factor figure, in particular, has been widely accepted by regulators (such as the California Energy Commission) and even utilities (such as Commonwealth Edison and Central Maine Power). While my original analyses (and the studies I relied on) were based on data only through 1978, experience in 1979-84 confirms the patterns of large capital additions, rapid O&M escalation, and low capacity factors.

Q: Have you authored any publications on utility ratemaking issues?

A: Yes. I authored Report 77-1 for the Technology and Policy Program of the Massachusetts Institute of Technology, Optimal Pricing for Peak Loads and Joint Production: Theory and Applications to Diverse Conditions. I also authored a paper with Michael B. Meyer "An Improved Methodology for Making Capacity/Energy Allocation for Generation and Transmission Plant", which won an Institute Award from the Institute for Public Utilities. My paper "Revenue Stability Target Ratemaking" was published in Public Utilities Fortnightly, and another article "Opening the Utility Market to Conservation: A Competitive Approach" was presented at the 1984 national conference of the International Association of Energy Economists, and was published in the conference proceedings. These publications are listed in my resume.

## 1.2 The Subject and Structure of this Testimony

Q: What is the subject of your testimony?

A: I have been asked to review the propriety of placing Millstone 3 in ratebase, or of otherwise reflecting the cost of that unit in the rates of the Western Massachusetts Electric Company (WMECO). I have specifically been asked to review the prudence of generation planning decisions regarding Millstone 3 taken by WMECO's parent company, Northeast Utilities (NU); the need for Millstone 3 to provide reliable service; the likely benefits of the unit to WMECO ratepayers; and appropriate ratemaking approaches in light of the results of that analysis.

Q: How is your testimony structured?

A: The last portion of this first Section provides a brief summary of the history of Millstone 3. The remainder of my testimony can be grouped into three parts.

The first part consists of the next three sections, which address the prudence of WMECO's generation planning process. Section 2 reviews the industry literature during the planning and construction of Millstone 3. Section 3 presents and analyzes the data on nuclear power plants construction and operating costs which should have informed NU's decisions to proceed with Millstone 3, and with its ownership share. Section 4 compares realistic cost projections for Millstone 3 power to those for other power sources, as of 1978 and 1980.

The second part of the testimony concerns the present and future value of Millstone 3 to ratepayers. The first two sections in that part discuss the two possible justifications for Millstone 3: the reliability benefits and the reductions in fuel costs. Section 5 discusses the magnitude and timing of the reliability benefits of Millstone 3, which may also be thought of as the "need for power" or the requirement that adequate capacity be available to meet peak loads with an adequate reserve margin. In the Section 6, I consider the unit's cost-effectiveness, which primarily results from the replacement of more expensive fossil fuels, in the near term and over the course of its useful life. Section 7 of this testimony provides the derivation of my estimates of Millstone 3's likely operating costs and capacity factor, which are required to assess its effect on fuel costs.

The final portion of the testimony concerns ratemaking issues. Section 8 discusses the range of options available to the Commission in phasing in those costs of Millstone 3 which are to be borne by ratepayers. In the final section, I summarize my conclusions regarding the prudence of, the need for, and the economic benefits of, Millstone 3, and make recommendations regarding the disposition of WMECO's rate increase request, including specific phase-ratemaking proposals.

### 1.3 A Short History of Millstone 3

Q: Please summarize the history of Millstone 3 construction.

A: Table 1.1 lists some summary data on Millstone 3 projections and progress, from March 1974 to December 1985: the quarterly estimates for in-service date and total project cost, actual annual disbursements, man-hours expended and percent complete.[4] The data was compiled from the EIA-254 Quarterly Reports and from IR-AG-3-12 (pp. 1-5).

Figures 1.4 and 1.5 illustrate the successive changes in cost and schedule estimated for Millstone 3. The official cost estimates are listed in Table 1.3.

Construction on the unit began in May of 1974.[5] Figures 1.6 and 1.7 indicate the progress made by percent completion and annual rate of increase in percent complete. Construction was slow until about the middle of 1981 when it started to pick up rapidly, especially during 1982.

Annual Construction Expenditures and Man-hours Expended follow a similar pattern over time: Manhours Expended begin to rise in the first quarter of 1981, and almost doubled in

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4. Data for man-hours expended was not available until March of 1979.

5. NRC Yellow Book, 1982.

the third quarter of 1982 increasing gradually from there. Annual Project Expenditures started picking up during 1979 and increased rapidly from 1980 to 1982.

Millstone 3 was ordered in February 1973, was issued a Limited Work Authorization in June of 1974 and a Construction Permit two months later. In November, 1985 the unit received a low power operating license; in January, 1986 it received a full power license.

Table 1.2 allows comparison of Millstone 3 to other recent nuclear plant costs on a cost per kilowatt basis. The plants listed were under construction in January, 1984. A few of the plants have since been cancelled or suspended. The median cost per kilowatt of this cohort (including the cancelled units) is about $2622/Kw: the cost of Millstone 3 in $/Kw comes out above the median, but well below the top of the range. Millstone 3 is a fairly expensive nuclear unit, but not an extraordinarily expensive one.

## 2 THE DETERIORATION OF NUCLEAR POWER ECONOMICS: THE LITERATURE

Q: How have you organized your review of the nuclear industry literature?

A: I have divided the review into three periods. First, I will examine the state of knowledge about the nuclear power costs in the early 1970's, when NU was pursuing licensing for Millstone 3. Second, I will consider the literature for 1973 to 1978, a period which ends during the Millstone 3 construction slowdown and just before the Three Mile Island accident. Finally, I will review the literature after TMI and into the early 1980's.

This review demonstrates what NU should have known at important points in the planning and construction of Millstone 3, particularly as regards the reliability of nuclear cost and schedule projections, and more generally about the problems of the nuclear industry. This information has an important bearing on the reasonableness of NU's projected cost of Millstone 3, and thus of the reasonableness of NU's decisions to continue with construction of its share of Millstone 3, rather than selling or canceling.

## 2.1 Infancy of the Industry: Experience to 1972

Q: What was known about nuclear economics in the early 1970's?

A: There was very little hard data, since only a few units had been completed except under turnkey contracts, which placed most of the burden of cost overruns on the manufacturer of the nuclear steam supply system. Operating data on O&M and capacity factors was also quite limited: the first commercial-size units (over 250 MW) had entered service in 1968. Based on this limited experience, there was both good news and bad news. On the bright side, the completed units were generally perceived to be economically competitive with the obvious alternatives, especially where coal presented transport and environmental problems. Forecasts of future plant costs indicated that nuclear units would remain competitive. On the darker side, any reasonably alert utility should have been aware of four crucial facts:

1. Nuclear cost estimates were unreliable and almost always understated,

2. Nuclear plant construction costs were increasing, so that the units ordered, started, or completed in any year were more expensive than those of the year before,

3. Nuclear plant construction schedules were increasing, and the times from order to construction permit, and

from permit to commercial operation, grew longer for each new cohort of plants, and

4. Nuclear schedules were unpredictable and usually stretched out well beyond the expectations of the owners and their architect/engineers.

Q: On what do you base your statement that utilities should have known in 1972 that nuclear cost and schedule estimates were likely to be unreliable and understated?

A: I have two sources. First, there is the data itself, which I present in Section 3. Second, it was common knowledge within the utility industry that nuclear plant costs and schedules had been subject to what were then considered to be shocking amounts of escalation and slippage. Representatives of one architect/engineer (or A/E), Gilbert Associates, identified a large number of problems facing nuclear construction:

> The utility industry, about eight years ago, believed that a large light water reactor plant could be built for $125 per kilowatt or less. Today plants to be completed about eight years hence are generally being estimated at close to $400 per kilowatt, which is more than a 300 percent increase in expected costs over an eight-year period. Nuclear plant costs, then, have not merely evolved in eight years; they have exploded.
>
> Of course, not all utility executives accept estimates of $400 per kilowatt for their future plants. They believe that they can build plants for less. Maybe they can. Perhaps they are more fortunate than most utilities with regard to such factors as construction labor, site availability, and environmental opposition within their service areas. On the other hand, maybe they are continuing the industry's past record of underestimating nuclear plant costs.

> Any analysis of past and current estimates quickly indicates the fact that almost all past estimates and many current estimates are far below what will actually be experienced. . . .
>
> This analysis, which covers 1968 estimates for plants to be completed in the early 1970's on which adequate cost data could be compiled, shows that original cost estimates were about $150 per kilowatt lower than will actually be experienced for those plants. . .
>
> The full cost impact of environmental and safeguards backfitting has not yet been realized. In fact, the door has just been opened to cost increases resulting from environmental activity.
>
> While it is true that very few new safeguards have been introduced since 1968, existing requirements have been broadened, and the study depth extended. There is no real indication of policy change nor saturation of areas requiring design analyses for contingency situations. The cost of providing a "safe plant" will continue to increase in the foreseeable future.
>
> This will probably add a significant amount each year to plant cost. (McTague, et al. 1972)

The same problem was described by employees of another A/E (Burns and Roe) as

> The rising trend of construction and capital costs for new electrical generating plants is a matter of major importance and of increasing concern to the entire utility industry. (Roe and Young 1972)

Those authors discussed several reasons for the increased costs, including construction delays and unanticipated complexity of work, especially for nuclear plants, and observed that

> Of course current licensing problems with nuclear plants must be cleared up if [potential nuclear] cost advantages are to be realized,

and concluded that

> In summary, still another crisis is at hand in the electrical generating industry. Continuation of the rapid growth which has been occurring in capital costs will make financing and provision of badly needed increases in electrical generating capacity even more difficult to achieve. The task is clear, but the solutions will not come easily. A combined effort by business, labor, government and the public will be necessary if the rapid growth of plant costs is to be controlled . . .

**Electrical World**'s annual series of nuclear surveys indicated similar concerns. For example, the 1971 survey, entitled "Nuclear Schedules Face Uncertainty", observed that

> The big news is the continuing stretchout in schedules. In last year's survey, 1975 was the "big year," with more than 20,000 Mw scheduled for commercial operation. Reappraisals during the year now place the total for 1975 at only 13,049 Mw, and shift the peak to 1977. . .
>
> The National Environmental Policy Act, and particularly the Calvert Cliff court decision forcing new AEC interpretation of that law, have recently added even more dramatic uncertainties to plant schedules. Indeed, says Walter Mitchell III, VP of Southern Nuclear Engineering, pending changes in licensing procedures brought about by the Calvert Cliff's decision may soon make obsolete many of the schedule dates tabulated on the following pages.

and the 1972 survey, although it was headlined "Lead Times Stabilizing", noted that

> 58 units in this year's listing show scheduled completion dates that have been set back since last year.
>
> Some optimism has been shown in the schedules reported by utilities for 1974-75, suggests Mitchell. "Several 1975 schedules look hard to meet," he says. Perhaps significantly, only two units are now scheduled for 1976.

The Federal Power Commission (FPC) also recognized and publicized the problems of the nuclear power industry. In the **National Power Survey**, in 1970, the FPC observed

> Because the nuclear industry is in a stage of dynamic growth, it is difficult to establish precise data for the present and future costs of nuclear plants. The nuclear industry today is characterized by an unprecedented commitment of new technology which has been reflected in capital costs attributed to delayed deliveries of vital components, the introduction of new or more stringent codes and standards, changes in regulatory requirements, and the extension of construction schedules coupled with current high interest rates and escalation in costs of labor, equipment and materials.[6]
>
> An indication of the escalation in estimated capital costs for a 1,000 mw LWR plant is provided in Table II-11 which shows that the approximately $135 per kw estimates for this size plant made in March 1967 had increased to about $220 per kw when estimated in June of 1968, and to more than $320 in 1970. It will be noted that the estimates for virtually all of the components of the plant direct and indirect costs increased substantially. These increases in combination with lengthening construction schedules, labor rates and interest costs resulted in an estimated overall plant cost in 1970 of almost 2 1/2 times that estimated in 1967. . . .
>
> It is estimated that cost reductions will accrue in the future through increased business volume and acquired experiences in construction techniques and component design factors. These reductions could be in the order of $10-$15/kw. Other factors that can have a profound influence on cost are licensing requirements, site preparation, cooling water requirements, labor productivity, and rates, inflation, etc. that make future predictions highly unpredictable.
>
> The very large capital requirements for nuclear plants make their costs sensitive to interest rates,taxes, insurance, depreciation, etc. The

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6. In 1970, inflation was running around 5%, and corporate bonds were yielding 8-9%.

> comparatively long periods required for licensing and construction can cause considerable variations in interest during construction. Slippage in construction schedules, regardless of the reasons, thus can result in a significant increase in the capital cost of a nuclear plant. Adhering to the shortest possible schedule of construction is one of the most serious problems facing the industry now and in the foreseeable future. (pages IV-1-56 to 58)

The report also quoted some of the concerns of Philip Sporn, Chairman of American Electric Power (page II-4-22), and included the following disclaimer below a chart of projected nuclear plant costs:

> IN THE PERIOD SINCE THE CHART WAS PRODUCED (JANUARY 1, 1968) COSTS HAVE BEEN RISING SHARPLY: CONSIDER THIS FACT WHEN REFERRING TO CHART. (page II-1-33)

The FPC also commented on the rising costs of nuclear plants in the introduction to the 1970 edition of the annual **Steam Plant Books** (FPC, various), the FPC staff provided a summary that would be repeated, in almost the same terms, year after year:

> In the first nine months of 1971, [announcements for new capacity additions] were 69% fossil and 31% nuclear . . ., illustrating the continuing acceptance of nuclear power by utilities, despite sharp capital cost increases and well publicized licensing difficulties. In the 1965-68 period, the average capital cost of nuclear units ordered was about $150/kWe. However, as a result of longer construction periods, added environmental equipment and high rates of escalation, the capital costs of nuclear units ordered in 1970 has been estimated to average about $250/kWe, by the time they come into operation. For 1971 the comparable figure has been estimated to be about $300/kWe. . .
>
> In 1970, the increasing national concern for the environment began to affect nuclear projects. Environmental organizations intervened in a number of licensing proceedings; AEC regulations on

> radioactive discharges were criticized as too permissive; and the National Environmental Policy Act of 1969 required new AEC procedures and the preparation of environmental statements for each plant. In 1971, in the Calvert Cliffs decision, the courts held that the AEC's environmental review procedures were inadequate, raising the prospect of regulatory delays for a significant number of new nuclear units.
>
> Delays of a year or more from scheduled commercial operation dates are being experienced for many nuclear units. The causes include technical and construction problems, increasingly detailed AEC reviews, the inexperience of many utilities and their architect-engineers with nuclear power, and the impact of environmental legislation and opposition.

This, and each of the subsequent revisions in expectations, seems to have been a surprise to the FPC staff, which accompanied each announcement with its judgment that growth in nuclear capacity was inevitable and desirable.

Q: How should these facts have affected the behavior of NU in 1972 and throughout the Millstone 3 planning and construction?

A: NU should have realized that its cost estimates, which were methodologically similar to earlier, understated estimates, were also subject to significant overruns. Recent acknowledgements by the utilities themselves make it clear that many nuclear cost estimates were never intended to be predictions of the final cost of the plant: they were budget targets and cost-control documents. This issue is discussed at some length in Meyer (1984). Employees of Management Analysis Corporation (MAC), in testimony filed by Central

Maine Power and Maine Public Service in their 1984 rate cases, summarize this practice with respect to Seabrook:

> PSNH established schedules that required superior effort. This strategy is generally appropriate because it demands the best possible performance from contractors. (Dittmar and Ward, 1984, page 25)

The MAC analysis further considered the tradeoffs between conservative and optimistic estimates, and explained the construction management advantages of intentionally optimistic estimates:

> If a budget is based on an overly conservative (high) estimate which establishes easily attained goals, a project's cost is likely to rise to fulfill the prediction. The use of aggressive targets is a management approach which, when reasonably applied, provides incentive for improving performance. If unrealistic cost or schedule targets are maintained too long, a project can be affected adversely. In such situations, it is difficult to hold people accountable for goals that they know are unrealistic. Morale problems may occur which could reduce productivity, cause delays or increase cost. A more serious consequence of managing to unrealistically aggressive targets may occur if activities are improperly sequenced such that work cannot be accomplished efficiently because of artificially induced constraints. (Ibid, page IV-6)

Southern California Edison, lead participant in the San Onofre plant, has reported that it actually kept two sets of cost estimates during much of the construction of San Onofre 2 and 3. One set was used for discussions with contractors and for other public purposes, while a higher set of estimates was used for top-level management purposes. The higher set included estimates of "possible future growth," because

> In late 1974, Edison project management recognized that due to the constantly changing nuclear industry regulatory and economic environment, in addition to the exposures due to specifically identifiable causes, the project costs would likely be impacted by many other unknowns.

In January 1975, when San Onofre 2 and 3 were scheduled to be complete in 5.5 and 6.75 years, respectively, SCE included "possible future growth" of about 50% of the total budget, in addition to conventional contingencies of about 8% in the public budget.

United Illuminating, a participant in both the Seabrook and Millstone 3 projects, has also acknowledged this practice, as demonstrated by the testimony of its President and other officials before the Connecticut Public Utilities Control Authority, filed 8/1/84:

> The project management estimate, used by the project manager to control construction of the facility, should be established as a challenging but achievable goal. Depending upon the degree of challenge desired, the project management estimate should have a probability of 10% to 30% of not being exceeded . . . [T]he project management estimate serves the need to maintain tight project controls . . .

Unfortunately, much less than 10% of nuclear cost estimates have been achieved, so the cost control function seems to have been overdone. It also appears that nuclear cost estimates routinely exclude effects of future, pending, and newly effective regulations which have not yet been reflected in the plant drawings, and of the other complications of building a nuclear plant.

Q: Why are you certain that NU could have identified these problems?

A: Because I spotted these problems when I first became involved in nuclear generation planning issues, under circumstances much less favorable than those of NU's staff. My initial observations were based on only a couple of cost estimate histories, I had no access to the utility literature or other utilities, and I had not had the personal experience with nuclear cost and schedule overruns NU gained in the construction of its earlier units, Connecticut Yankee, Millstone 1, and Millstone 2 (at which construction started in 1970). Nonetheless, the pattern of substantial cost overruns and delays was quite obvious. The calculation of cost ratios, myopia factors, and duration ratios (which will be discussed in more detail in the next Section) were simple ways of quantifying very important phenomena, requiring no strong assumptions or complex calculations. I can not imagine why any utility planning and building nuclear units would not have noticed the same problems.

Q: Is it your opinion that NU's decision to commit to Millstone 3 construction was imprudent?

A: Not necessarily. It would certainly have been imprudent for any utility to embark on a major nuclear construction program, on the assumption that its engineering cost estimates were likely to be accurate predictions of the final cost, and without making any provisions to re-examine the quality of the estimate and the economics of the project. It is possible that pursuing construction of Millstone 3, coupled with a commitment to due diligence in the future, may have been a reasonable decision in 1972 and through the time Millstone 3 received its construction permit in August of 1974.

Q: Considering the problems you have described, how could such a commitment have been reasonable?

A: While nuclear power had serious problems, so did the other conventional generation alternatives which were perceived to be available in 1972. Oil prices were expected to rise, although not nearly as much as they actually rose later in the decade. There was considerable uncertainty regarding the extent and cost of future environmental constraints on coal combustion. Several power supply options available today were not generally considered to be on the table in 1972. New England hydro potential seemed trivial compared to the perceived need, although a very alert utility would have foreseen some of the forces which later moderated growth. Fostering conservation and customer-owned power generation was simply anathema to utilities in the early 1970's: while the economies of scale and technical progress which made load growth beneficial in the 1950's and 1960's (and had then made conservation and cogeneration undesirable) had probably run their course by 1972, this general phenomenon would have been more difficult to identify (and less certain) than the specific problems of nuclear power. The perceived importance of economies of scale had become utility dogma, and it would have required considerable courage and vision for any utility to abandon construction of the large plants then in planning, in favor of smaller alternatives. Thus, it is hard to say that NU erred in committing its resources to Millstone 3, without allowing a certain amount of hindsight to influence our judgment.

Q: What then is the ultimate significance of the state of the nuclear industry in 1972, in terms of the issues in this case?

A: NU should have recognized from the beginning that its projections for Millstone 3 were subject to tremendous uncertainty. With this recognition, NU should have been prepared to carefully monitor the state of the nuclear industry and the economics of Millstone 3, and been prepared to react appropriately if the historical trends continued or accelerated.

## 2.2 The Long Decline: 1973-1978

Q: You have described the problems of the nuclear industry in the early 1970's. How had the situation changed by the end of 1978?

A: There were three kinds of important developments in this period. First, all the problems which I described above persisted and expanded. Second, the direct and indirect effects of the first oil price shock started to change the basic environment in which utilities operated. Third, Millstone 3 received its construction permit in August 1974.

Q: Did the industry literature reflect the persistence of the previous problems with nuclear cost estimation?

A: Yes. These problems were reflected in **Power Engineering**, **Electrical World**, publications of the Federal Power Commission, the comments of nuclear architect/engineers (A/Es), and other sources within the nuclear and utility industries. These sources were widely available, and referred to, within the industry.

### 2.2.1 Power Engineering

Q: What information on the problems of the nuclear industry were reflected in **Power Engineering**?

A: The Senior Editor of **Power Engineering** magazine wrote that:

> The nuclear power industry continues to miss schedules, and more slippage appears to be ahead. . . Based on past performance and anticipating new impediments, it seems unlikely that [the current construction] target will be met.
>
> Low [construction] time estimates have been characteristic of both the AEC and the utility forecasts. Part has been due to tight targeting and part to external causes. Both are understandable in moderation. It taxes reason, however, to explain all the announcements of new plants in the past three years that estimated commercial operation in six to eight years . . .
>
> The great bulk of recently announced plants are now planned for 8 to 10 years, and considerable additional slippage lies ahead for these units. . .
>
> The AEC still is changing the important ground rules, . . . and the nuclear community seems to profit little from some pretty plain and important lessons of recent history. . .
>
> More likely, of course, the schedule [of nuclear additions in 1979-81] will not hold. . . (Olds 1973)

Millstone 3 was one of the "new plants in the past three years that estimated commercial operation in six to eight years",[7] with more aggressive schedules than "The great bulk

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7. NU's first estimate for Millstone 3 was dated July 1971, for an April 1978 COD, 6.75 years later. The **Electrical World** surveys list Millstone 3 as being announced on February 10,

of recently announced plants . . . now planned for 8 to 10 years," for which "considerable additional slippage lies ahead". The next year, Olds headlined his review "Power Plant Capital Costs Going Out of Sight" (Olds 1974). In that article, he presented extensive data on nuclear cost estimates, and subsequent revisions, for the period 1965-74, and computed that estimates had been rising 26% annually since 1970:

> From the mid-1960's on, power plant capital costs have risen faster than estimators can get their numbers changed. In spite of intensive study by many experts, the skyrocket performance of plant costs has defied complete analysis. . .
>
> It is obvious . . . that as plants get closer to their completion dates, their reported costs tend to jump. It may be expected that the 1967-68 averages [for plants ordered in those years] will increase still further.

Olds also warned that:

> In spite of the steep increase in estimated costs, these probably will fall far short of the actual completed plant costs unless there is a sharp break in the influences that are forcing costs up so dramatically. . .
>
> In general, the 26% increase rate since 1970 reflects four factors: (1) inflation in cost of labor, material, services and money; (2) increase in scope, or material content of plants. . . ; (3) recognition that base line estimates in 1965-69 were far too low; and (4) belated recognition that slippage was of major proportions. . .
>
> The influence of the regulatory arm [of the AEC] on schedules still is totally unpredictable. The branch has kept a moving target before the utilities for a long time while proclaiming

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1973: completion was then scheduled for May 1979, 6.25 years later.

> standardization and schedule shortening. As of May, the record shows that the 54 plants holding construction permits have been slipping their fuel loading dates at the rate of 0.37 months per month.

Another year later, the same author reviewed the history of nuclear plant schedules and concluded:

> . . . schedule slippage has been going on for a decade. . . A study of the 10 years of changes in nuclear plant status thus discloses a steady increase in estimated time to complete plants, and that these estimates have been about two years too optimistic all along . . . Slippage became worrisome in 1969 when, in just that year, an average of one plant in six slipped a year. . . The average slippage per plant, as announced, generally increased steadily through 1973. Then in 1974, 201 net plant years of slippage were announced, nearly half of the 10-year total for the 226 plants. (Olds 1975)

Things did not improve dramatically the next year, either:

> While the slippage in the nuclear program in 1975 was less than it was in 1974, it was not comfortably less, and was larger than for any other year except 1974. Setbacks were spread about evenly over the whole year, and were most severe for plants that had been ordered in the 1971-74 years. . .
>
> Costs continue to grow at a rapid rate, and the postponed plants are going to be much higher in cost as each year passes. . .
>
> [In 1970-75,] AEC's regulatory people kept promising shorter licensing, but kept taking longer. In addition, a torrent of guides and procedural changes forced additional delays on the industry. It took time to digest the changes, to retrofit the engineering, the procedures, and to retrofit in the field. The moving target exercise was a tragedy. . .
>
> These years thus were particularly difficult ones for the industry. Accurate scheduling was impossible, and costs sped upward without any possibility of control by the industry. . .
>
> When the AEC was dissolved, an important nuclear advocate was lost. (Olds 1976)

The next year, Olds commented extensively on the growth in safety regulation:

> [H]ow safe is safe enough [for nuclear plants]? This question has been asked but never answered in terms of a limit to be placed on NRC requirements. Consequently, as long as a reviewer can conceive of a way to reduce pollution or risk, he is likely to require it. . .
>
> [Adding 1975 and 1976 to the regulatory picture] can best be described as ratcheting gone wild. During 1976, an average of three new requirements having significant impact on NSSS design were issued by the NRC every month. Obviously this situation has a severe adverse impact; imagine the picture by the end of the 12-year period now needed to get a plant on line. . .
>
> Where all this ratcheting will end is anybody's guess. The primary cause is the open-ended [Atomic Energy] Act that more or less directs reviewers to ratchet, and creates an ungovernable situation. . .
>
> Replication . . . met with some success until a regulatory ratchet was applied to the process. . . [A]n expensive change was required of [a duplicate] plant. In turn, this was whipsawed back on the original plant, which now was under construction. (Olds 1977)

Whether or not one accepts Olds' characterization of the need for this level of safety regulation, his description of its effects (compounded by the failure of utilities to acknowledge the regulatory problems they faced) appears to be accurate. The next year, Olds (1978) reached his most graphic in describing the problems of the industry. The lead-in included the observations that:

> starting in 1974, announcements of setbacks in nuclear plant schedules began in earnest. Most of the apparent delays, however, reflected the fact that many plants at that time carried unrealistic completion dates and had no chance of meeting them.

> This has continued throughout 1976-77, but with an additional feature. Real lead time has continued to increase at about one year per year; hence, the published schedules still are running behind. Plant costs now are time-dominated and increase as fast as lead time ...

The body of the article went on to remark:

> Table 1 shows what has happened to the schedules of the 66 nuclear units that had gone into commercial operation by the end of 1977, and gives an estimate of probable completions in 1978. From the data in this table, it will be shown that during the four years, 1974-77, lead time for these units from NSSS order to commercial operation was increasing by nearly one year per year. Subsequent tables will look at units scheduled for later years . . .
>
> [In 1970-1972] There were some hints of future trouble, but there were always the promises that the course for nuclear plants would be smoothed out and shortened. The industry could not be criticized severely for having too much optimism at that time. . .
>
> By 1973, however, hardly anyone should have hoped for lead times for new bookings as low as nine years. Beyond 1973, there were hopes for reduced times via standardization of plant designs, multiple orders for identical units, standardized licensing reviews, pre-licensed shop-fabricated units, and other good things promised by Washington. Largely, these hopes for time reductions have been thwarted thus far.

### 2.2.2 Electrical World

Q: Did the series of **Electrical World** annual reviews continue in this period?

A: Yes. Nuclear surveys were published in October of 1973 through 1975. From 1976 on, the survey was published in

January of the following year. The prose portions of these documents are worth reading in their entirety, to establish the pattern of continuing concern, optimism, and dashed hopes. Some highlights include:

1973: "Nuclear Survey: A Record Year"

> Reactor orders soar but lead times slip.
>
> Schedule slippage among previously committed plants is a continuing problem. Of the units committed before Sept. 15, 1972, but not yet in commercial service, 63 units were reported this year with no schedule change, 45 had been set back one year, 6 two years, and 2 three years.

1974: "Nuclear Survey: Orders and Cancellations"

> Mixed bag of statistics shows commitments to new units running about as predicted, but mid-year inflationary forces caused widespread cancellations and delays in construction programs. . .
>
> Unfortunately, these figures do not openly reveal the crisis in the nuclear power industry that is being caused by spiraling inflation; they appear, instead, to herald a healthy industrial posture. . .
>
> The most important truths in the industry today are not to be found in growth-rate statistics, but in reports of cancellations, indefinite postponements, and scheduled construction stretchouts. . .
>
> As utilities have moved to cover financial situations by paring construction budgets, changes in nuclear schedules were occurring almost daily during the late summer. . .
>
> When the tabulation closed, 75 units (or about 36% of the 206 listed) had new completion dates that were at least one year later than originally planned. A few of these are plants under construction where construction has lagged schedule, but the vast majority are utility-ordered stretchouts and average about 2 years for each delayed unit. . .

Last year, AEC licensing delays and intervention by small groups of diehards with talented lawyers represented the major challenges to nuclear power. This year, the old problems have not gone away, but the major contention comes from pervasive financial conditions that are not exclusively nuclear.

1975: "Nuclear Survey: Cancellations and Delays"

Industry falters as uncertainties mount in the areas of financial commitments, load-growth demands, regulatory delays, fuel-cycle inadequacies, and unpredictable social and political hindrances.

The year covered by this report (Sept. 15, 1974 to Sept. 15, 1975) ended on a downward trend. Two major stations were indefinitely postponed late in the period, and this wiped out slight gains that had been posted earlier. The net result: a narrow loss . . .

Uncertainty is now the name of the game as utility executives scramble to hold on to what they see in their load-growth predictions, balanced against what they can afford. . .

Soaring costs have been charged with forcing seven major units off the schedules this year. . .

Utility executives are well aware that delays are going to be costly; nevertheless, within the period covered by this report, 84 units (90,048 Mw, or 72% of all capacity scheduled to go on line after 1975) has been delayed for periods ranging from one to seven years.

1977: "Nuclear Survey: Market Still Depressed"

About 67,000 Mw of nuclear capacity were deferred in 1975 and at least 40,000 Mw in 1976. This means that almost all future nuclear additions have been rescheduled.

Above all, potential reactor buyers now want assurance from the government that, once they have approved designs and construction permits, they can proceed with assurance that their nuclear plants will be licensed and permitted to operate effectively.

> Based on NRC's performance, the utilities are widely convinced that they cannot manage their own economic destinies in such an uncertain environment; therefore, they are being scared away from nuclear power.

The 1978 **Electrical World** review reflected increasing gloom:

> This year's nuclear survey . . .tends to reinforce the gloom of the "big four" manufacturers that was expressed last year in both trade journals and the popular press. . .
>
> Several dates for scheduled commercial operation of plants have been postponed - some indefinitely - and there have also been cancellations. . .
>
> FPL announced in mid-1977 that it would not commit itself to any future nuclear plants as of that time. The utility cited regulatory uncertainties at both state and federal levels as its principal reason. . .
>
> The Omaha Public Power District told **Electrical World** that its overriding reasons for canceling Ft. Calhoun 2 were (1) excessively high estimated cost per installed kw, (2) lower-than-expected load growth projected for its service area, and (3) a more than $200-million interest charge on capital before commercial operation would begin. . .
>
> The number of "indefinites" has dropped over the past year from nine to seven, with an accompanying "decrease" of almost 2,000 Mw in generating capacity. But this encouraging portent could be canceled when one realizes that the chance of all - or any - of the "indefinites" being built is slim indeed. (**Electrical World**, "1978 Nuclear Plant Survey")

### 2.2.3 Federal Power Commission

Q: Did the series of FPC reviews continue during the 1973-1978 period?

A: Yes. The **Steam Plant Book** observed:

In the 1965-1968 period, the average capital cost of nuclear units ordered was about $150/kWe. However, it was estimated that the average capital cost of nuclear units ordered in 1972 would be about $429/kWe by the time that units come on-line; an increase attributable to such factors as inadequate quality control in manufacturing and in field construction, labor problems, added environmental equipment and high rates of escalation. For 1973 the comparable figure was estimated to be slightly higher at about $449/kWe. . .

Increasing national concern for the environment continues to affect nuclear projects. Following the 1971 Calvert Cliffs decision, the Atomic Energy Commission issued a revised statement of policy and amended its regulations to broaden the scope of environmental issues it will consider in licensing proceedings. . .

Delays of two to four years from scheduled commercial operation dates are being experienced for many nuclear units, due to late delivery of equipment by manufacturers; faulty installation of equipment; strikes by manufacturer's employees, construction employees, or electric system employees; inclement weather; as well as increasingly detailed AEC reviews, and the inexperience of many utilities and their architect engineers with nuclear power. These and other difficulties have prompted some utilities to reassess their nuclear plans. Although many problems confront the utilities in their nuclear planning, prompting some utilities to reassess their nuclear plants, they are proceeding with increasing emphasis on nuclear plant additions to their system generation mix. (1972, pages XIV - XV)

In the 1969-1973 period, the average capital cost of nuclear units ordered was approximately $427/KWe. However, since 1970 nuclear plant construction costs have been escalating at more than 15 percent a year. The latest updated (March 1975) average capital cost of nuclear units ordered in 1973 was projected to be about $608/KWe by the time the units are completed and placed in commercial operation. This increasing cost trend of nuclear units is attributable to such factors as increased design complexity, inadequate quality control in manufacturing and in field construction, shortage of skilled labor, added environmental equipment to meet newly established environmental and safety standards, and escalating costs of equipment, materials and wages. For 1974 the comparable figure was estimated to be slightly higher at about $627/KWe. With projected production costs of about 5.0 mills/kWh for these units, the total cost of electricity generation from nuclear plants ordered in 1974 will be in the neighborhood of 20-22 mills/kWh. The average capital cost for nuclear units in operation on December 31, 1973 was $204/KWe. . .

Increasing national concern for the environment continues to affect nuclear projects. Following the 1971 Calvert Cliffs decision, the AEC issued a revised statement of policy and amended its regulations to broaden the scope of environmental issues it will consider in licensing proceedings. The broadened environmental protection requirements, mandated by Federal legislation, increased the length of time required to process environmental impact statements. License applications on which licensing action had been taken had to be reexamined and a more extensive environmental review performed. Increasing requirements for environmental protection and plant safety features contributed to significant delays in scheduled lead times of many nuclear units. However, the principal cause is attributable to delays in construction, i.e., late delivery of equipment by manufacturers; faulty installation of equipment; strikes by manufacturer's employees, construction employees, or electric system employees; inclement weather; increasingly detailed AEC reviews, and the inexperience of many utilities and their architect engineers with nuclear power. Although many problems confront the utilities in their nuclear planning, prompting some utilities to reassess their nuclear plans, they are proceeding with increasing emphasis on nuclear plant additions to their system generation mix. (1973, pages XV - XVI)

Projected nuclear plant investment costs which have been escalating at more than 15 percent per year since 1970 continued at that pace during 1974. The latest updated (March 1976) average capital cost of nuclear units ordered in 1974 was projected to be about $690/kwe when the units are completed and placed in commercial operation. This increasing cost trend of nuclear units is attributable to such factors as increased design complexity, inadequate quality control in manufacturing and in field construction, shortage of skilled labor, added environmental equipment to meet newly established more stringent environmental and safety standards,

> and escalating costs of equipment, materials and wages. For 1975 the comparable figure was estimated to be slightly higher at about $694/KWe. (1974, pages XV - XVI)

The 1974 report also repeated the second paragraph I quoted from the 1973 report, verbatim. The language of subsequent **Steam Plant Book** prose summary, now published by the Federal Energy Regulatory Commission (FERC), repeated the same set of explanations for new and higher sets of numbers:

> Projected nuclear plant investment costs which have been trending upward since 1970 increased again in 1975. The latest updated (January 1977) average capital cost of nuclear units ordered in 1975 was projected to be about $766/KWe by the time the units are completed and placed in commercial operation. This increasing cost trend of nuclear units is attributable to such factors as increased design complexity, inadequate quality control in manufacturing and in field construction, shortage of skilled labor, added environmental equipment to meet newly established more stringent environmental and safety standards, and escalating costs of equipment, materials and wages. For units ordered in 1976 the comparable figure was estimated to be about $797/KWe. (1975, pages XIII - XIV; published 1/78)

> Projected nuclear plant investment costs which have been trending upward since 1970 increased again in 1977. The latest updated (January 1978) average capital cost of nuclear units ordered in 1977 was projected to be about $829/KWe by the time the units are completed and placed in commercial operation. This increasing cost trend of nuclear units is attributable to such factors as increased design complexity, inadequate quality control in manufacturing and in field construction, shortage of skilled labor, added environmental equipment to meet newly established more stringent environmental and safety standards, and escalating costs of equipment, materials and wages. (1977, page XIII; published 12/78)

The language of the 1976 report was identical to that in the 1975 report, which was issued after the 1976 data was available.

### 2.2.4 Views of the Architect/Engineers

Q: In the mid-1970's, did the nuclear architect/engineers continue to describe the problems of the industry, and to identify the past pattern of cost increases?

A: Yes, although they were loath to admit that their current efforts were subject to the same problems:

> All of us know that power generation costs and prices have run rampant since 1969, but many may not realize how much they have changed. . . Projected [nuclear power unit investment] costs . . . have increased about four times since early 1969, an average of 21% per year compounded. . . In 1969, it was assumed that a nuclear unit could be placed in service about six years after authorization. Today the time span between authorization and the expected date of commercial service is slightly over nine years. (Brandfon 1976)
>
> Increases in power plant costs between estimating dates of 1969 and 1978 can be attributed to inflation and to statutory and regulatory requirements. About 22 percent of the increase is due to inflation and 78 percent due [sic] to statutory and regulatory changes.
>
> Over a twelve-year period in operating dates (1976-1988) estimated power plant investment requirements have increased by a factor of approximately seven. . .
>
> [These estimates] do not include any sums specifically intended to cover future, and presently unknown, additional safety or environmental requirements. However, in view of

our past experience with the continual ratcheting of environmental and safety requirements and economic and political uncertainties, they do include contingency items of about . . . 17 percent for a nuclear plant. (Bennett and Kettler 1978)

. . . Harold E. Vann, vice president-power, United Engineers & Constructors [said] "The 10-year schedule for nuclear plants is not compatible with the time period between investment made and revenues received . . . The high investment cost also complicated this problem. It is commonly known in the investment community that announcement of expansion plans adversely affects the price of a utility's equity. (**Nuclear Industry** 1977a)

Ebasco Services Incorporated is projecting that "there will be few domestic nuclear power plants announced by utilities in 1977. This opinion is based on the conditional nature of new construction permits, and [fuel cycle concerns.]" (ibid.)

Bechtel said "it anticipates regulatory agencies will continue to change licensing criteria and it therefore seems unlikely that nuclear units will become standardized." (ibid.)

Ebasco especially wanted to note its concern with the indicated trend of review and backfitting of operating plants to meet current guides. "We believe," it said, "that a broad policy of requiring retrofit without a demonstrated need, or benefit to the public commensurate with cost, is detrimental to the public interest at a time when public concern for energy independence should be answered with an accelerated commitment to nuclear power." (ibid.)

Brown & Root's senior vice president, M. M. Finch, sees prospects for shortening [nuclear] power plant construction schedules as "unlikely." Expecting costs and scheduling to escalate in the future as they have in the past, Finch believes that this will change only with the recognition of the absolute necessity of the nuclear option. "If we are to have a viable nuclear industry," Finch warns, " there must be an absolute commitment to resolving the many significant items that have been plaguing the nuclear industry for so long." (Meanwhile, just <u>maintaining</u> construction schedules is a more realistic hope, Finch says, because the "barriers" to shortening schedules are formidable.) (Jacobson 1977; parentheses and emphasis in original)

### 2.2.5 Other observers within the industry

Q: What other observers within the nuclear and utility industries commented on the problems of nuclear power?

A: Some other examples from the nuclear literature of this period include:

> [T]he trend of nuclear plant costs [for plants ordered in the 1960's] was more or less correctly anticipated, but the absolute magnitude seems to have been badly misestimated. For example, in 1968 the reactors were expected to cost only $180/kw. Our actual estimate of cost of reactors ordered that year is about $430/kw. . . [both in constant] 1973 dollars; i.e., there has been a systematic discrepancy of more than a factor of 2. . . [T]his difference between expected and actual costs has not been narrowing with time. Indeed it has been growing. . . [We] predict, taking the more conservative of the two [regression] estimates, that reactor cost will continue to increase at an average rate of $34 [constant 1973 dollars] per year, if nothing happens to change the relative impact of the various independent variables. (Bupp, et al., 1974)

> For nuclear plants, . . . both the derived curve and the specific plant data suggest that the error in cost prediction was increasing rapidly through the latter half of the 1960's [from 37% overruns for plants completed in 1971 to 115% for plants completed in 1975], largely because plants begun in the mid-to-late sixties were delayed and made more costly by imposition of unanticipated environmental and safety-related requirements . . . ; unexpected inflation also played a significant role. (Blake, et al., 1976)

> [W]ere it not for these [recent sharp increases in fuel costs], the long-run economic viability of nuclear reactors as a competitive generating alternative would indeed be questionable. . . All things considered, it appears that purely on economic grounds and ignoring capital shortage problems resulting from state regulation of

> electricity rates, the future of the U.S. nuclear reactor industry is less bright than recent government forecasts indicate. (Joskow and Baughman 1976)

Some of the utilities which had been involved in nuclear development started to pull out, citing the very real problems which they faced. For example:

> A major concern in our efforts to meet the increasing need for electricity is being able to build new plants on schedule and at the planned cost. A key factor is the delay by the red tape of regulatory bodies. Sometimes, as was the case this year, this tangle of delay is just too much. In July, we canceled plans to build a second nuclear reactor at Crystal River. Our first nuclear unit [Crystal River 3] was originally scheduled to be in operation by April 1972. This plant is now delayed to late 1974, over 2 1/2 years behind schedule. As a result, we are now forced to plan for more oil-fueled plants than we had originally intended in order to meet our customer demands for electricity. (Florida Power Corporation, 1972 Annual Report)

> Florida Power Corporation has announced it has abandoned its plans to construct the unnamed two-unit nuclear station it had scheduled for operation in the mid-1980's. . . "We believe nuclear power still holds the promise of being the long-range answer to adequate electric supplies as well as a means of achieving national energy independence." FPC president Andrew Hines said . . . "However, we feel it is not in our customers' best interest at this time to proceed with our previously announced plans. There is too much governmental uncertainty as well as an almost unknown cost factor for construction for us to plunge ahead into the morass." . . . In 1973, the projected cost of the facility was $1.4 billion. More recent estimates had set the cost of construction as $2.6 billion, and the utility said there was strong indication that escalation would continue in the years ahead. (**Nuclear News** 1976)

Florida Power and Light was a bit more colorful in its description of the problems which resulted in the cancellation of the South Dade units:

> . . . Robert Uhrig, vice president for nuclear and general engineering, said he didn't see how any utility "that has to defend its actions to a public service commission could justify a business decision to 'go nuclear' in the present environment". . . "The nuclear licensing process has been destabilized to the point where sound business decisions cannot be exercised with respect to nuclear facilities. Sound business is dependent upon predictable time schedules and costs, and neither is present in today's era of uncertainty." (**Nuclear Industry** 1977b)

Q: Were similar observations made by economic consultants to the industry?

A: Yes. The Atomic Industrial Forum (AIF) published a study (Perl 1978) by National Economic Research Associates (NERA) which found, among other things, that nuclear plant costs were increasing at an annual rate of 10% above general inflation. NERA concluded that nuclear power would be cheaper than coal, but only after <u>assuming</u> that the escalation in nuclear costs would stop abruptly. The study recognized that its "estimates are highly uncertain and hinge upon a number of speculative assumptions" and invited its readers to "substitute your judgment for" NERA's. Indeed, NERA acknowledged that "If the historic pattern continues and if the cost of coal facilities escalates at a lower rate than nuclear, eventually nuclear will become an uneconomic technology." Many of the results of the NERA study indicated that the nuclear industry was in grave difficulty in 1978, and could only be saved by dramatic improvements compared to past performance.

Q: Are you aware of any detailed assessments by nuclear utilities of the problems they faced in this period?

A: Yes. Detroit Edison has prepared a report on the construction of its Fermi 2 nuclear power plant (Detroit Edison 1983), which presents an overview of nuclear regulation in the 1970's. Chapter 10 of that report, entitled "1978: Nuclear Design Changes", includes the following observations, written in the present tense:

> For Fermi 2 and other nuclear plants in construction, numerous additional government and industry standards leading to changes in reactor design, quality assurance practices and new equipment have a drastic effect on cost. Regulations for nuclear plants grow to 784 in 1978 from 277 in 1975. As a result, the real cost to construct nuclear power plants in the United States increases by an alarming 142 percent from the end of 1971 to the end of 1978. During this time, Fermi 2's construction costs increase nearly 150 percent in real dollars. This escalation occurs even after removing inflation in the costs of standard construction inputs--labor, materials, and equipment.
>
> Nuclear design changes, in particular, are characterized by "ripple effects" that carry beyond the immediate component or system being altered. The result is that the total impact on cost is inevitably larger than the sum of the parts. Moreover, many of the changes at Fermi 2 and other nuclear plants are mandated during construction, as new safety rules emerge. This "ratcheting" of regulations during construction greatly complicates the design and construction efforts.
>
> Fermi 2, in fact, is being built in an "environment of constant change" that makes the control or even estimation of costs extremely difficult. The result is that the construction process falls prey to logistical problems that magnify the direct impacts of increased standards. Construction contracts must be let on a "cost-plus fixed-fee" basis, backfits during construction are common, and this often means construction workers cannot be efficiently deployed and labor productivity

suffers. These problems would continue throughout the duration of the project.

Cost-plus fixed-fee contracts become unavoidable at Fermi 2. Although some construction contracts provide for a fixed price - usually tied to an agreed upon inflation index - such arrangements are not feasible when the scope of the work is subject to continuing significant changes. . .

Changes in quality-assurance regulations beginning in 1970 have a severe affect on Fermi 2's cost and schedule. It is truly a balancing act to control costs and, at the same time, ensure that the design is reliable, safe and meets licensing requirements. Increased engineering costs are the smallest part of the impact resulting from compliance with the new quality-assurance regulations.

As quality-assurance standards become more complex and the growth of regulations causes design changes in the mid-1970's, the impact on Fermi 2 is far-reaching, especially when construction is in progress. Previously purchased material must be replaced, usually at higher prices. Already completed construction work is torn down and reassembled according to new specifications. Valuable time is lost while construction crews wait for new equipment and materials to be delivered.

Another result of design and quality-assurance changes is the negative impact they sometimes have on labor productivity. Some construction workers lose motivation to do good work if they become frustrated by design changes that cause constant retrofitting of already completed tasks.

#### 2.2.6 Other forces

Q: Taken as a whole, were these observations any different from those you described in the previous section?

A: Yes, in two respects. First, the general tenor of the comments moved perceptibly over the years, from an early sense of annoyance and puzzlement with these cost and schedule problems, to a later sense of deeper concern. Second, the continuing assurances that last year was the end of the trend, and that next year would see the industry turn around, were beginning to wear a little thin. The initial observations emphasized that the problems were a bit more complex than the industry had thought, but now they were largely under control and the "learning curve" could take over, leading the industry to faster, cheaper construction, and better cost estimation. By the late 1970's, the regular reader of the utility magazines would have been through several cycles of bad news, followed by promises of better results in the short term, followed by more delays and overruns, and by some familiar promises.[8] In addition, the learning curve seemed to have largely disappeared from the discussion: the problem for the foreseeable future was to stop the slippage.

Q: What new problems had arisen since 1972?

A: The oil embargo of 1973 and subsequent dramatic rise in oil prices had several important effects in the 1974-78 period.[9] On the one hand, it improved the relative economics of any

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8. Many authors also continued to express surprise at the size of the increases, even after the pattern had persisted for a decade. Also, even in the middle of a recitation of the industry's woes, many authors paused to express their faith in the need for nuclear power, and in the eventual recovery of the industry.

9. Those effects extended beyond 1978, as well.

technology which promised to reduce oil consumption. On the other hand, it greatly increased the cost of electricity, particularly in New England; reduced load growth to virtually unprecedented levels (often to negative growth); encouraged conservation actions and the development of conservation technologies; increased inflation; and greatly increased the financial stress on utilities.

Q: What was the effect of reduced load growth on nuclear construction?

A: The changes in most utility load forecasts[10] had two effects. First, the reduced need for power plants made it harder to justify building any new generation, including nuclear plants, and raised the possibility that new units might not be needed for long periods after they entered service. Second, lower sales resulted in reduced internal generation of funds, which compounded the financial stress caused by the higher oil prices themselves.

Q: How did conservation affect nuclear power in the 1974-78 period?

A: The reduction in load growth after 1973 was largely due to conservation, of course: this demonstrated that continual increases in electricity consumption were not inevitable. In particular, it became clear in the first few years of higher

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10. Those of NU, WMECO, and NEPOOL are illustrated in Figures 1.1, 1.2, and 1.3.

energy prices that conservation was an alternative to new power supplies, and that conservation could be encouraged by higher prices and by organized regulatory and incentive programs.[11] For the most part, the results of those programs not apparent until the late 1970's, and there was considerable hope in the utility industry in 1976 (and even later) that the conservation effects of the last few years would soon disappear, overtaken by a wave of "pent-up demand".

Q: What other changes occurred in the mid-1970's other than those related to the increase in oil prices?

A: The March 1975 cable fire at the Brown's Ferry nuclear power plant, as the most serious accident to that time at a commercial light water reactor, seems to have been a sort of watershed for the newly formed NRC in two respects. First, it alerted the agency to the possibility that significant safety problems could slip past its initial screening, and thus be present in units under construction or even in operation. Second, it must have driven home the point that those problems would not disappear if the NRC ignored them; a major design flaw could have disastrous consequences for the credibility of the agency and the industry which it was charged with regulating, however gently. Thus, nuclear safety regulation was bound to intensify, rather than relax,

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11. Section 4.2 discusses some of the studies and programs from that period.

despite the (probably correct) perception of the industry that regulation was killing it and despite all political representations to the contrary.

Q: Did the interest in organized conservation programs as alternatives to conventional energy sources produce tangible results in this time period?

A: Some significant programs started up in this period. Examples would include the Federal appliance efficiency standards, higher thermal integrity standards in new building codes, and California's efforts in governmental and utility-sponsored conservation programs.[12] These efforts indicated that it was possible to foster conservation, and established energy efficiency as a power supply option.

Q: How did regulatory scrutiny affect nuclear power?

A: State regulators started to inquire as to the need for the construction programs; the protection of the programs was frequently presented by the utilities as a major reason for rate relief. This scrutiny took many forms. In California, for example, the Sundesert nuclear plant was subjected to lengthy state hearings which led to its rejection and cancellation in 1978. The Wisconsin PSC undertook similar reviews of the need for planned facilities in that state, and concluded that further nuclear investments were

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12. Section 4.2 describes some of the conservation programs proposed or in effect in this period.

inappropriate, which finally resulted in the cancellation of three nuclear units in that state.[13] More careful regulatory oversight was clearly emerging by 1978.

Q: Did Millstone 3 experience many of the problems which plagued the industry in this period?

A: Yes. As shown in Table 1.1, the Millstone 3 cost estimate increased four times between 1973 and 1978, for a total increase of 29.5%, or 13.2% annually. Meanwhile, the in-service date of the unit had slipped by 13 months before it received its construction permit in 1974, 36 months between the permit and the October 1977 delay, and another 4 years in 1977. As demonstrated by Figures 1.1 through 1.3, the load forecasts for the NU and for the region were falling rapidly.

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13. The chairman of the Wisconsin commission at that time, Charles Cicchetti, later testified on cost recovery mechanisms in MDPU 906 on behalf of Boston Edison. Prof. Cicchetti testified in some detail that he was aware, and utility managers should have been aware, in the early to mid-70's of several of the problems regarding nuclear plant cost overruns and schedule slippage, and utility financial stress discussed above.

## 2.3 TMI and the End of Hope: 1979 and Beyond

Q: What significant dates for the planning of Millstone 3 are included in the post-1978 period?

A: The April 1979 accident at Three Mile Island (TMI) foreclosed the possibility of rapid improvements in nuclear construction and regulatory environments. The Millstone 3 cost estimate was revised upward by 30% in July 1980. That revision occurred over a year after the TMI accident, giving NU time to absorb the results of that event. Millstone 3 construction, which was slowed down in October 1977, did not return to full levels until late in 1981, so NU's financial commitment to Millstone 3 was not rising very rapidly in 1979, 1980, or early 1981.

Q: What important developments occurred for Millstone 3, in 1979 and after?

A: Three groups of events took place. First, NU received some important warnings regarding its nuclear construction program, including information about the costs and schedule of the Seabrook units. Second, the TMI accident further accelerated the ongoing changes in nuclear regulation. Third, the general deterioration in the economics of nuclear power continued, accompanied by a virtual torrent of plant cancellations.

Q: What warning signals regarding its Millstone 3 investment were presented to NU in this same period?

A: There were several such signals. In EFSC 78-17, 80-17, and DPU 19494, I pointed out some of the errors in NU's load forecast. Appendices I and J are copies of my testimony in those dockets. In the second phase of MDPU 19494, and again in NRC 50-471 and DPU 20055,[14] I produced an analysis of the (then new) NEPOOL forecasting methodology, and (with Susan Geller) a review of the forecasts of all the major NEPOOL participants. Our testimony discussed numerous errors in each of these forecasts, which in most cases were both poorly documented and over-optimistic. Figures 1.1 to 1.3 demonstrate that our overall criticism was well taken, and that the NEPOOL forecast has indeed declined substantially both before and since those reviews. NU (through CL&P) was also a party to DPU 20055, in which my testimony pointed out the history of nuclear power plant cost escalation, schedule slippage, and overruns. While the data base available to me at that time was extremely limited, I was able to present cost estimate histories for six completed units[15] and four more still under construction; both groups demonstrated cost overruns and schedule delays representative of those found in the more complete data sets presented in this testimony. In

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14. All of these testimonies were filed in 1979 or early 1980.

15. The utilities, including CL&P, refused to provide further cost estimate histories, even for Maine and Vermont Yankee.

addition, I presented the results of the early regression analysis by Mooz (1978), which found that the construction costs of nuclear power plants receiving construction permits were increasing at $141/kw annually, in 1976 dollars. Again, if NU were somehow unaware of the trends in nuclear costs, in cost overruns, and in schedule slippage, prior to MDPU 20055, it could hardly have been unaware of them after early in 1980.[16]

Q: What significant developments affected the nuclear industry nationally in this period?

A: There were several important events or trends:

1. The cost estimates continued to increase, and the schedules continued to slip, for those units which were not canceled.

2. Nuclear unit cancellations, which first exceeded new orders in 1975, were continuing at unprecedented rates in the late 1970's and especially in 1980, while the last new orders occurred in 1978.

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16. The utilities' own presentation in MDPU 20055 contained some similar information, and revealed a lack of critical analysis in the utilities' construction planning. In particular, John Gmeiner, testifying for Montaup, attached to his testimony a copy of a NERA study (Perl 1978), and of an EBASCO study (Bennett and Kettler 1978), both of which are quoted in Section 2.2 of this testimony. Unfortunately, the utilities, including NU, took to heart the optimistic projections of these studies and ignored the dismal recitations of the industry's past and current problems.

3. The regulatory response to the accident at Three Mile Island, and other NRC actions, dashed any hope of rapid recovery in the industry, and accelerated many of the previous adverse trends.

Q: How did NRC regulation change in this period?

A: Even before the TMI accident, the NRC was demonstrating a more cautious attitude towards potential safety problems. Where problems and solutions were identifiable, the NRC was increasingly reluctant to allow plants to operate without the solutions. The best example of this trend was the order which shut down several units in 1978, after an error was found in a Stone and Webster seismic design program. While this action by the NRC was widely criticized within the industry as "over-reaction," that criticism was largely ended by the TMI accident.

The accident at TMI further increased the NRC's reluctance to take unnecessary risks with potential safety problems at reactors under construction or in operation. It was widely perceived that another TMI-scale accident might well be a fatal blow to commercial nuclear power development, and almost any cost imposed on individual plants was preferable to collapse of the industry. While the post-TMI regulatory reaction was not a sharp break from the past trend, the accident was a clear indication that the trend was not about to moderate in the near future.

Q: Did the utility industry literature continue to reflect the problems of the industry?

A: Yes. From **Electrical World**'s 1979 Nuclear Plant Survey comes these observations:

> If you were disturbed by the statistics contained in last year's nuclear-plant survey, the 1979 roundup won't help to settle your stomach. Unit cancellations, delays, and postponements are on the rise, while the total number of reactor commitments, through 1995, has dropped alarmingly.
>
> Another very disturbing element is the large number of postponements and delays in commercial operation, ranging from one year to as long as six years, with a concomitant increase - from seven to eleven - in the number of units now in the "indefinite" column. Just as discouraging is a new listing: two units in the "work suspended" designation.
>
> Although we usually endeavor to be upbeat and optimistic in seeking the oft-elusive silver lining in a cloudy report, this time around offers us an unprecedented challenge.

The 1980 Survey, headlined "No reactors sold; More Cancellations", was more terse:

> Since last year's survey, the commercial operation dates of some 80 units have been postponed, from one year to indefinitely, and nuclear commitments are down from last year's 195 units . . . to 193 units . . .

**The Steam Plant Book** continued its review of the state of the industry in the 1978 edition, which was published in December 1980:

> Projected nuclear plant investment costs which have been trending upward since 1970 increased again in 1978. The latest average capital cost of nuclear units ordered in 1978 was projected to be about $920/kWe (1978 dollars) by the time the units are completed and placed in commercial operation. An

> insufficient number of units were ordered in 1978 to provide a trend indicative for that specific year. The cost per kW of installed capacity ranged from $815/kW to $1070/kW in 1978 dollars. The overall increasing cost trend of nuclear units is attributable to such factors as increased design complexity, inadequate quality control in manufacturing and in field construction, shortage of skilled labor, added environmental equipment to meet newly established, more stringent environmental and safety standards, and escalating costs of equipment, materials and wages. (page xv)

The nuclear A/Es were not silent, either. From Burns and Roe came the following observations:

> It is clear that nuclear power is in deep trouble. . . In the first eight months of 1979 alone, 67 nuclear plants were either deferred or canceled, and the Nuclear Regulatory Commission has imposed a temporary moratorium on the licensing of nuclear power plants.

The author continued by explaining why nuclear costs are so much less certain than coal costs:

> The nuclear plant cost [projection] has a wider range [than the coal plant estimate] because it is felt that there is greater uncertainty in estimating future costs of nuclear plants than there is with coal plants.
>
> These cost projections . . . are based on . . . current known regulatory requirements. It is important to keep this in mind because actual . . . regulatory requirements experienced over the life of a project are likely to be different. . .
>
> Today's estimates for the 1992 plants are more than 10 times as large as the estimates that were made in 1969 for nuclear units scheduled to start up in 1976. Although the projected costs of nuclear and coal costs are very high, the nation's options are limited, at least through the end of the century.
>
> This study of available cost data for U.S. power plants has indicated that costs are likely to increase significantly for all types of plants over the next several years, at least. The base cost numbers have been established, and major reasons

for cost increase have been identified. From this point, it can be said that the final actual costs of nuclear plants now underway are expected to be 3 to 4 times as high as the original estimates. . .

In 1974 and 1975, . . . less than 3 million engineering man-hours were required for a single unit plant. Today, the figure is about 4.5 million man-hours for the single unit plant. The earlier studies showed 11-12 craft man-hours per kilowatt of capacity in the single unit plant; today, the craft man-hours exceed 15 per kilowatt. . .

As a final point, it was noted during the course of this detailed cost study that the available actual cost data often do not reflect the ultimate total capital costs. This is true to the extent that costs are not updated to include subsequent expenditures for compliance with new regulations. (Budwani 1980)

## 3 NUCLEAR POWER PLANT DELAYS AND COST OVERRUNS: INDUSTRY EXPERIENCE AND FORESEEABLE EFFECTS ON MILLSTONE 3 COSTS

Q: How have you structured your review of the data on nuclear power plant economics during the planning and construction of Millstone 3?

A: I have examined three time periods: the early 1970's, the end of 1977, and the middle of 1980. The first period corresponds to the decision to start the Millstone 3 project; the second period coincides with the October 1977 decision to delay Millstone 3 to 1986; and the third period reflects the state of the world after the Three Mile Island accident and before the resumption of full construction at Millstone 3 in 1981.

### 3.1 Nuclear Cost Overruns and Schedule Slippage in the Early 1970's

Q: What information was available regarding nuclear power plant cost estimates in the early 1970's?

A: Table 3.1 summarizes the cost estimate histories of all the commercial nuclear power plants which were in commercial operation by the end of 1972, and which were built without any extraordinary cost guarantees.[17] For each of these six units, Table 3.1 lists the actual commercial operation date (COD), the actual construction cost, the date of the first cost estimate for which I was able to obtain suitable data, and the estimated cost and COD for that estimate. It is certainly not difficult to determine that both the cost estimates and construction schedules of these units grew significantly during their planning and construction.

The cost and schedule history data is drawn from the database listed in Appendix B, which shows all of the changes in cost or schedule indicated in cost estimate history summaries provided by the Energy Information Administration (EIA).

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17. I have excluded both the turnkey plants, for which the manufacturers provided at least partial cost caps, and the reactors for which the federal government provided cost sharing. In addition, I have no detailed cost estimate data for either San Onofre 1 or Connecticut Yankee.

Those summaries are condensations of the Quarterly Construction Progress Reports (Form HQ-254 and Form EIA-254) filed by most nuclear utilities with the Atomic Energy Commission (AEC), and later with its successor agencies, the Energy Research and Development Administration (ERDA) and EIA. This data base also includes later estimates for these units. Where important data was missing from the HQ-254's, data from various published sources was used.[18] Final cost information is generally from reports to the FPC and the FERC, and the commercial operation date (COD) information is from NRC figures.

To quantify the extent of the errors in cost and schedule estimation for these six units, I have computed four statistics for each estimate: the projected years to COD (or "duration") at the time of the estimate, the ratio of final cost to the projected cost at the time of the estimate (the "cost ratio"); the cost ratio expressed as a growth rate, annualized by the estimated time to completion (the "myopia factor"); and the ratio of the actual remaining time until commercial operation to the projected time (the "duration ratio"). These terms are all fairly self-explanatory, except for myopia, which is defined as

$$(\text{cost ratio})^{(1/\text{estimated duration})}$$

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18. These sources included the AEC/ERDA annual **Nuclear Industry**, the **Nuclear News** World List of Nuclear Power Plants, and occasionally data from the utilities.

Roughly speaking, the average myopia indicates that the actual cost of these units was typically 18% greater than the estimate, for each year that construction was expected to take. The cost ratio demonstrates that the average plant cost over twice as much to complete as initially estimated, while the duration ratio indicates that the plants took almost half again as long as was projected.

Q: Why do you present the data and the results in this form?

A: The raw data on cost estimate histories indicate that cost overruns and schedule slippage was routine, and nearly universal. This relationship would be clearly apparent to any observer. It is more difficult to determine (and particularly to quantify) just what lesson the observer should have learned from the data. I do not believe, for example, that it is fair to assume that each utility involved in (or observing) nuclear construction should have done regression analyses on the cost trends, as were later performed by Bupp, et al., Komanoff, and Perl. Those are fairly sophisticated approaches, which are sensitive to the exact data and functional forms used in the analyses. Looking at the percentage cost overrun, or annualizing that value, or comparing actual and projected construction durations, all strike me as being simple, obvious ways of summarizing the large and growing experience of nuclear construction. These were the kinds of questions which I asked, and the kind of analyses I undertook, when I first found out in 1978 and 1979 that nuclear plant cost and schedule estimates were frequently incorrect.[19] I am not suggesting that NU should have performed exactly the same summary calculations that I present in this testimony, but I am suggesting that NU should have examined the uncertainties and contingencies involved in nuclear investments,[20] that they should have done some simple analysis of the historical data, and that the same general conclusions could have been reached through several types of analysis, including an informal examination of the data. Therefore, I believe that it is appropriate to judge NU's prudence as if it had these calculations, since its staff would have been familiar with the industry literature and with the nuclear cost data and should have noted (formally or informally, rigorously or intuitively) the same patterns and relationships I present.

Q: What do these results imply for Millstone 3?

A: If the nuclear industry's ability to forecast costs had not improved, it would be appropriate to apply these results to the initial cost and schedule estimates for Millstone 3 ($400 million and a COD of 4/78, or 6.75 years from the 7/71

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19. The fact that these trends were apparent to me as soon as I became involved in utility planning issues in 1978, indicates just how clear they should have been to people long involved in the industry and with wider access to industry data and publications.

20. As I have shown in the previous section, the utility industry literature provided ample notice that nuclear plant construction was subject to unusual problems.

estimate date), to produce revised or corrected estimates. Multiplying $400 million by the average cost ratio of 2.11 produces a corrected cost estimate of $844 million. However, the estimated duration for Millstone 3 was somewhat longer than for the units in Table 3.1, so applying the average myopia factor of 18.4% for 6.75 years would produce a cost ratio of 3.127, and a Millstone 3 cost of $1251 million. Finally, multiplying the estimated Millstone 3 duration by the average duration ratio of 1.444 produces a corrected duration estimate of 9.75 years, and a COD of 4/81. Thus, NU management should have known that, if the factors which had caused other nuclear power plant estimates to be incorrect also operated for Millstone 3, it would be considerably more expensive and time-consuming to construct than was implied by the official projections from NU and the architect/engineer (A/E), Stone & Webster (S&W).

Q: Have you performed any other analyses of the nuclear power plant cost and schedule information available by the end of 1972?

A: Yes. Table 3.2 repeats the duration analysis in Table 3.1, but for the turnkey and demonstration units excluded from the previous table. As would be expected, the cost estimates for the turnkey units tended to be considerably more stable than for the conventionally priced units, but the two demonstration units for which I have data are even worse than the later commercial units. The duration ratio for this entire set is nearly as bad as for the commercial units.

Table 3.3 lists the units which were under construction as of the end of 1972, and for which at least two cost or schedule estimates were available. For each unit, these tables list the earliest available estimate and the most recent estimate as of the end of 1972. I have computed two summary statistics. The first statistic is the "cost growth rate", simply the annual rate of increase in the cost estimate, from the first projection to the most recent. The second statistic is the "progress ratio", which is the ratio of progress towards completion (the decrease in projected months to operation), divided by elapsed months, both calculated from the first available estimate to the most recent estimate as of 12/72. The data from which this analysis is taken may also be found in Appendix B. To calculate the effect on Millstone 3 if these trends had extended to its cost and schedule evolution, we may divide the projection of 6.75 years by the experience-weighted[21] average progress ratio of 45%, to yield a corrected duration of 15 years (indicating that Millstone 3 would have been completed in July 1986 -- very nearly correct, it appears) and increase the cost estimate of $400 million by 15 years of cost growth at 18.6% annually, for a final cost of $5.17 billion.[22]

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21. Throughout this testimony, whenever averages are calculated on both a simple and an experience-weighted basis, I use the weighted averages in the text.

22. If Millstone 3 goes commercial in May 1986 at a cost of $3.825 billion, its cost will have escalated at 16.4% annually since the 7/71 estimate. Alternatively, it may be said that the cost of Millstone 3 increased at 18.6% for 13.24 years, until November 1984.

Q: Do you mean that a prudent utility would have expected Millstone 3 to be completed in 1986 at a cost of over $5 billion?

A: No. By 1972, I would have expected a prudent utility to know that <u>if recent experience continued</u>, Millstone 3 would be completed much later than was then projected, and at a much higher cost. That prudent utility would also have known that, even if the historical experience moderated considerably, Millstone 3 would take a long time to build and would be very expensive, and that completion of the unit at anything like the official cost estimate would require a radical change in the nuclear construction environment.

Q: Are there any particular reasons to believe that NU knew, or should have known, that nuclear cost and schedule estimates were subject to very large overruns?

A: Yes. The cost and schedule estimate histories for New England nuclear units which entered commercial operation by 1972 are listed in Table 3.5.[23] The cost data for Connecticut Yankee and Millstone 1 reflect their turnkey status. The Maine Yankee actual data is somewhat understated since it was declared "commercial" at 75% power. NU was certainly aware of the history of these units, particularly since it is the lead owner for Connecticut Yankee, and the sole owner of Millstone 1.

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23. Yankee Rowe is omitted for lack of data.

In light of both the national and the regional experience with completed nuclear plants, and the national experience with those still under construction, it would not have been reasonable to place much faith in the quality of conventional cost estimates for Millstone 3.

## 3.2 The Implications for Millstone 3 of Nuclear Cost Overruns in the Mid-1970's

Q: You have described the cost and schedule overruns experienced in the nuclear industry by the early 1970's. How had the situation changed by the end of 1977?

A: Millstone 3 actually received its construction permit in August 1974, which eliminated one source of uncertainty in its schedule and cost. Also, late in 1977, NU decided to reduce the rate of construction at Millstone 3 due to financial considerations. This slowdown resulted in a four-year delay in the scheduled in-service date, to May 1986, with some options for attempting to meet an earlier COD.

Q: How have you analyzed the history of cost overruns in the nuclear industry through 1977?

A: Table 3.6 updates to the end of 1977 the previous analysis (Table 3.1) of cost overruns in completed nuclear units. Table 3.6 differs in three ways from the analyses in the previous section, all reflecting the changes in the status of Millstone 3 since the early 1970's. First, since Millstone 3 had received a construction permit (CP) by this time, and had reached 18% reported completion, the summary statistics are computed from the estimate closest to 18% reported completion, to the actual cost (or completion date).

Second, since NU had voluntarily slipped the Millstone 3 schedule by four years, there was an unusual, even unprecedented, amount of slack in the critical path. The slippage of the Millstone 3 schedule from the May 1986 COD was therefore likely to be less than the usual nuclear schedule slippage.[24] Therefore, I have not included duration ratios in Table 3.6, since they would be expected to reveal little about likely Millstone 3 slippage.

Third, some of the historically observed cost overruns were due to schedule slippage, which results in higher costs from inflation and AFUDC accrual. If the Millstone 3 schedule did not slip, but it were otherwise like past units in the accuracy of its forecasts, its cost would increase in proportion to the <u>real</u> (inflation-adjusted) cost ratios of the other units. These real duration ratios, and corresponding real annual growth rates, are calculated in Table 3.6, for an 8% deflator. This 8% rate is an approximation of inflation rates for the inputs to nuclear construction in this period, and of AFUDC rates. Inflation rates actually varied over time, expected inflation rates were slightly lower than actuals, and AFUDC rates varied widely both over time and between utilities (utilities with CWIP in rate base would have very low effective AFUDC rates, for example). The 8% rate is typical of the adjustments used

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24. In hindsight, we can see that the slippage certainly has been minimal, barring any special problems in startup testing.

by analysts within the nuclear industry, including Westinghouse (1977) and UE&C in its comparison of plant costs in a 1982 Seabrook cost estimate update.

Fourth, the real cost ratio is annualized by the use of an annual cost growth rate, rather than by the myopia ratio. The difference between these two statistics is that the annual growth rate is the average annual increase over the actual construction duration, while the myopia factor is the average annual growth in cost over the expected construction duration. We would expect the myopia factor to be larger, in real terms, for units which experienced large schedule slippage, and were therefore exposed to greater changes in regulatory requirements. If we assume that NU had good reason to believe that it could prevent its Millstone 3 schedule from slipping much, it would be inappropriate to assume that Millstone 3 would be exposed to regulatory changes beyond the eight-year duration projected in 1978. Therefore, I have annualized the cost growth for completed plants by their actual durations: applying this rate of cost growth to the projected Millstone 3 duration is equivalent to assuming that its cost problems will parallel those of previous plants, except for the lack of slippage.

Fifth, since no duration ratios are calculated, turnkey plants (for which there are no meaningful cost data) are excluded entirely from the analysis.

Q: What are the results of this analysis?

A: The average nominal cost ratio for the completed plants is 2.03, and the average myopia factor is 27%. The cost results are not very different than those in the previous analysis, through 1972. On a real (inflation-adjusted) basis, the average cost ratio was 1.68, and the annual growth rate was 10%. Most of the real cost increases were between 30% and 150%, with a few outliers on either side.[25]

If the $2 billion cost estimate for Millstone 3 changed as much after the July 1978 estimate as did those of the 42 units in Table 3.6, increasing by the same nominal ratio as had the completed units, it would have cost $4 billion. Due to the long remaining construction duration, repeating the historical myopia experience would produce a much higher cost, close to $13 billion.

If the Millstone 3 cost estimate changed as much as the completed units in real terms, but without any schedule slippage, it would have cost $3.35 billion. But since

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25. Three of the real cost ratios (Turkey Point 3, Surry 2, and Peach Bottom 3) are less than unity, apparently indicating that the units were completed for a lower real cost than had been forecast. This result is an artifact of the division of costs between twin units: in each of the three cases, the twin experienced an estimated real cost increase, bringing the average ratio for the plant above unity. In addition, my approximation to the combined effects of inflation and AFUDC is certain to produce underestimates of real cost growth for some units. This is particularly true of units which had large amounts of CWIP in rate base, so that COD slippage had a smaller direct effect on the cost; and for units for which AFUDC accounting rules changed, primarily from gross to net AFUDC, and from AFUDC to CWIP in ratebase, resulting in smaller apparent cost increases.

Millstone 3 had a much longer construction schedule than most of the units in Table 3.6, it was therefore more vulnerable to regulatory change. Applying the average annual growth rate of 10% for the 7.84 years of remaining construction NU expected in July 1978, yields an expected increase of 105%, to $4.1 billion.

In Table 3.7, I repeat the analysis of the cost and schedule slippage of nuclear units under construction (see Table 3.3), updated to the end of 1977. This analysis includes slippage after construction permit receipt: the first estimate for each unit is the initial post-CP estimate, unless there was no such estimate within one year of CP, indicating that the utility accepted the previous estimate as representing conditions at CP issuance. If Millstone 3 experienced throughout its remaining construction the average real cost growth rate this group experienced from CP to 12/77, again with no schedule slippage, the unit would have cost $8.4 billion.[26]

Q: What is the significance of these results for evaluation of NU's prudence in generating planning for Millstone 3?

A: By late 1977, when NU decided to reduce its construction effort and delay the Millstone 3 COD from 1982 to 1986, NU should have foreseen that the cost of Millstone 3 would be

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26. The average cost growth rate of 20%, over 7.84 years, would increase the price by a factor of 4.2 times.

likely to increase very substantially. Continuation of historical experience would have resulted in a final cost of at least $4 billion, and perhaps much more, depending on which trend continued. It would be generous to suggest that NU could have reasonably anticipated limiting the cost increase to only $3.8 billion, the presently estimated cost for the unit.

Q: Do you make any particular assumptions in applying the historical experience to Millstone 3?

A: Yes. Projecting the historical experience would have been appropriate in 1978 if one had assumed that the situation in 1978 and into the future was as unsettled as the previous decade, and that the Millstone 3 estimate was consistent with utility practice, other than the existence of ample float in the critical path for the construction schedule. I believe that a reading of the utility press from that period supports the first assumption (which is not subject to any rigorous test in any case). The second assumption is subject to more empirical tests, if rather rough ones.

The first test of the similarity of the 7/78 Millstone 3 cost estimate to industry norms is an examination of the summaries NU provided of that estimate. The 1978 estimate, for a 1986 COD, included $125 million in contingency, only $25 million more than had been included in the 1977 estimate for the 1982 COD. The 1978 contingency was 6.3% of total project cost, for almost eight years of "exposures to cost increases" (page

5 of the estimate document), as opposed to 8.4% in the 1977 estimate, for a little more than five years of exposure. Contemporaneous cost estimates for Midland, Pilgrim 2, and Seabrook contain contingencies ranging from 5% to 7% of total project cost. All of these estimates were for CODs less remote, and hence less exposed to cost increases, than the May 1986 projection for Millstone 3.[27] Thus, in a period of 100% cost overruns in nuclear construction projects, the 1978 estimate for Millstone 3 included only a tiny contingency, comparable to contingencies in estimates for plants scheduled to be completed much sooner.

The second test of similarity consists of a comparison of estimated costs for plants with similar CODs. That task is particularly difficult for Millstone 3, since its schedule really placed it in a class by itself. Table 3.8 lists the other nuclear units reported to be between 10% and 25% complete, as of 12/77, from **Nuclear News** (2/78). The average of the first units was 18.6% complete (compared to Millstone 3 at 18.3%), and was scheduled for completion in 2/82. Clearly, the previous (3/77) estimate of Millstone 3 completion in May 1982 was consistent with industry practice, while the delay of the COD schedule to May 1986 was extraordinary.

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27. The June 1978 estimate for Midland assumed completion of the two units in 1981 and 1982.

Since the 1978 estimate was based on an unusually long construction schedule, it would be inappropriate to assume that Millstone 3 would repeat industry experience in its myopia factor (which is very sensitive to schedule slippage). The question remains as to whether NU's cost estimate was particularly conservative, given the scheduled in-service date.

Table 3.9 compares the cost estimates for Millstone 3 to those of other units scheduled for completion in 1986. Millstone 3 was estimated to be more expensive than any of these other units. Some of the difference would be explained by the fact that Millstone 3 was a first unit, while each of the other units scheduled for 1986 operation was a second unit, or in the case of Palo Verde 3, even a third unit.[28] Units in multi-unit plants tend to be less expensive, on the average, than single units, and following units tend to be less expensive than initial units. In addition, Cherokee and Yellow Creek were owned by two of the most experienced nuclear utilities, Duke and TVA, respectively, which performed their own engineering and have consistently projected and achieved construction costs below average at their plants. The Millstone 3 cost estimate was 38% higher than the average of Harris 2, Hope Creek 2, and Skagit 2: this was probably only a little bit more than could be

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28. The cost of Harris 2 was based on one quarter of a four-unit plant, which would include large economies of duplication.

explained by the difference in the number of units. Millstone 3 would also be expected to be more expensive than most of the other units, since they were planned for areas with lower labor costs than New England. Overall, the 1978 Millstone 3 cost estimate appears to have been comparable to, or only slightly more conservative than, the industry norm. Accordingly, it would be reasonable to expect Millstone 3 to experience cost ratios and annual cost growth comparable to industry experience.

Q: Was there any more New England experience by 1978?

A: Yes. NU's Millstone 2 entered service in December 1975. Table 3.10 displays the cost estimate history of Millstone 2, which was by far the most expensive nuclear unit in the region up to that time.

Q: Based on the information available through 1977, what do you conclude NU should have known about the likely cost of Millstone 3, when the in-service date was slipped in Ocotber 1977?

A: From its own experience and that of the industry as a whole, NU should have known that its projections of Millstone 3 cost (including the $2 billion estimate in July 1978, for a 1986 COD) were very likely to be substantial undersestimates.

### 3.3 The Implications for Millstone 3 of Nuclear Cost Overruns Through Mid-1980

Q: Did the cost estimates and schedule projections for nuclear plants improve between 1977 and 1980?

A: Not much, if at all. Cost escalation and schedule slippage continued nationwide.

Q: What was the national experience through mid-1980 with cost overruns of completed nuclear plants, from the level of completion then reported for Millstone 3?

A: Table 3.11 repeats the analysis of Table 3.6, for those plants which had entered commercial operation by June 1980. The starting point for each unit is the estimate closest to 33% reported completion, which is approximately the reported status of Millstone 3 through most of 1980. Since the starting point for the cost overrun calculation is later in each unit's construction period, the cost ratios are lower than in Table 3.6, but the myopia factors and annual cost growth are not much different than previously. Of the six new units added to the list from Table 3.6, two showed real cost ratios less than unity: both were second units, with twins whose real cost ratios exceeded unity, and both were completed three or four years after the completion of their twins.[29] Overall, the 1980 data indicate that the situation had not improved significantly since 1977.

It is interesting that only two units reached commercial operation in the last 18 months of the period shown in Table 3.11. This is partially the result of new safety requirements following the TMI accident, but the trend was evident in 1978, as well, when only four units reached commercial operation. Even the fact that only the units (Hatch 2 and Arkansas 2) were in their start-up phase, between operating license and commercial operation, when the TMI accident occurred, is evidence that the number of units nearing completion was shrinking.

By mid-1980, well before the resumption of full construction at Millstone 3, NU should have anticipated that the cost of the unit would rise substantially before completion. If the cost of Millstone 3 increased as much between its July 1980 estimate ($2.6 billion) and its commercial operation date as did the cost of the average unit in Table 3.11, it would have cost $4.8 billion. If the same myopia factor had applied to Millstone 3, it would have cost over $11 billion.

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29. There is some tendency for second units which lag the first unit by more than two years to experience unusually small cost and schedule slippage after the first unit is completed. Hatch 2 is a prime example of this effect, and Cook 2 and Three Mile Island 2 also show the effect clearly, although the effect is not evident for TMI 2 in Table 3.11, presumably because its cost increased so much prior to completion of TMI 1. St. Lucie 2 is perhaps the most celebrated case. I am not sure that NU could have been expected to see this pattern; if it did, the Hatch 2 and Cook 2 experience would have to be discounted as a model for Millstone 3.

Applying only the real cost overrun experience of these 48 units to the Millstone 3, assuming no schedule slippage, would have indicated smaller cost increases. If the real cost increase for Millstone 3 were as large as the historical average, the final cost would have been $4.0 billion. If the cost estimate for Millstone 3 grew at the same real annual rate as the average of the units completed by 1980, its cost would have increased by 5.84 years of 9% growth, or 63%, bringing the final cost to $4.2 billion.

Table 3.12 repeats the slippage calculations of Table 3.7, both for the continuing (1977 to 1980) slippage of the units in Table 3.7 which were still not finished in 1980, and for the total slippage to 1980 of additional units which were not included in Table 3.7 because they received construction permits too late, or because they had no new cost or schedule estimates by the end of 1977. On the average, the cost estimates for this group of units were increasing at 15% annually in nominal terms, and 8% in real terms. If the Millstone 3 real cost estimate escalated as rapidly as the average of this group, it would increase by 57% from July 1980 to May 1986, bringing the total cost to $4.1 billion.

Q: Was the July 1980 estimate based on an unusual schedule, as was the July 1978 schedule?

A: The projection of a May 1986 COD for Millstone 3 in July 1980 was not remarkable, compared to units reported to have reached a similar stage of construction. Table 3.13 compares the schedule projection for Millstone 3 to that of other units which were listed as 25% to 40% complete in June 1980. The average of the first units was 34.2% complete (essentially the same as Millstone 3), and the average expected COD for the group was August 1985. Thus, the schedule estimate for Millstone 3 was somewhat less optimistic than average, but was not an outlier compared to the range of the other estimates. Unless NU had some reason for believing that its unit was much more advanced than those of other utilities with similar reported completion status, or that the schedule slippage problems of the industry were over (a highly dubious proposition by this time), some further slippage in the Millstone 3 schedule should have been anticipated. Extrapolation of historical experience in real cost growth to Millstone 3, without allowing for the effects of schedule slippage, would have been fairly optimistic by this point. Nonetheless, NU has kept Millstone 3 close to its schedule, and it may be reasonable to give NU the benefit of the doubt, by assuming that it could have foreseen these unusually good results.

Table 3.14 compares the July 1980 Millstone 3 cost estimate to those of other units then scheduled for commercial operation in 1986. The average percentage completion was slightly lower than that of Millstone 3, but the average completion date was a couple months later, and the cost estimates were equal to, or larger than, that of Millstone 3. There is no particular evidence in Table 3.14 that the

Millstone 3 schedule or cost estimate was conservative by June 1980.

## 3.4 Nuclear Power Plant Cancellations

Q: In the previous section, you mentioned that many nuclear power plants were canceled during the late 1970's and early 1980's. Please describe the history of these cancellations.

A: Figure 3.1 portrays the annual and cumulative cancellations, through 1983. Figure 3.2 presents the number of new orders, the number of cancellations, and the net change in orders in the same period. With few exceptions, the units canceled prior to 1980 were awaiting construction permits: units with permits were not heavily hit by the wave of cancellations until 1980. Table 3.15 lists the plants canceled in 1977-80, with the construction status of each.

### 3.5 My Previous Projections of Millstone 3 Cost and Schedule

Q: In your testimony in MDPU 84-25, you expressed the opinion that Millstone 3 would probably cost more than $4.5 billion, and would not be likely to enter commercial operation until late in 1987. What bearing do those projections have on this proceeding?

A: My earlier projections, which now appear to be incorrect, illustrate four points. First, anyone estimating the costs of nuclear power plants must expect to be wrong some of the time. While my overall cost and schedule prediction record remains superior to those of most nuclear utilities and A/Es, I was certainly excessively pessimistic with respect to Millstone 3.

Second, the fact that I overestimated the cost and schedule for Millstone 3 indicates just how unusual the 1980, and especially the 1982 and 1984 cost estimates were. Table 3.9 demonstrates that five of the six other units scheduled for 1986 operation in late 1977 have been canceled: Palo Verde 3 has slipped by over a year. Table 3.8 shows that even among the units with reported percentage completion comparable to Millstone 3 in December 1977, two have been canceled, one is suspended (Perry 2, which will probably be canceled), and all the rest have slipped significantly, except for St. Lucie 2.

Table 3.13 shows that, of the ten units reported to be within seven or eight percentage points of Millstone's completion status in 1980, two have been canceled (different ones than in 1977), another is suspended (Perry 2 again), and the schedules for the rest have slipped, in some cases by years. Table 3.14 provides similar information for the units scheduled for commercial operation in 1986, as of June 1980. Of the eleven units, three have been canceled, two are suspended (and likely to be canceled), and only three are still scheduled for 1986 operation.

Tables 3.16 and 3.17 update the analysis to the units for which 1986 operation was projected in 1982 and 1984. Even the 1982 cohort contains at least three units which are unlikely to be completed,[30] compared to just two units which have not yet slipped their scheduled CODs. Of the 1984 cohort, none have been canceled, but eight of the eleven have experienced slippage in scheduled COD's. As it is now March 1986, and none of the units except Palo Verde 2 have operating licenses, many of the CODs schedules for the second and third quarter must be expected to slip further.[31] Millstone 3 was quite unusual in keeping to the same COD schedule since 1978.

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30. In addition to the canceled and suspended units, Bellefonte's completion is higly uncertain.

31. The typical interval from first license to COD has been about 11 months.

This performance is particularly remarkable in that the other four units for which S&W is the A/E -- Shoreham, Nine Mile Point 2, Beaver Valley 2, and River Bend -- are the four most expensive units in the country, in dollars per kilowatt. S&W may have been unlucky in some of the projects it drew: both Shoreham and Nine Mile Point 2 have Mark 2 containments, which had serious design problems, and Shoreham also has problems with evacuation planning (although it was already a very expensive unit before the evacuation problem became critical). On the other hand, some of these units have had advantages, particularly in cost: Shoreham, River Bend, and Nine Mile Point 2 were all partly financed by CWIP in ratebase, and Beaver Valley 2 is a lagging second unit.[32] While Millstone 3 is a fairly expensive plant, it has avoided the extraordinary cost levels of the other S&W units.

Third, NU's forecasting performance at Millstone 3 was superior to industry experience for two reasons. The minor reason is that NU "bit the bullet" earlier than most utilities, and increased its cost estimate more rapidly than usual from 1978 to 1982: the Millstone 3 estimate rose at 15%, as opposed to the 9-10% real rate typical of industry practice. I incorporated into my estimates in MDPU 84-25 all of the explicit cost conservatisms I could identify in NU's documentation of the 1982 estimate, and concluded that

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32. As noted above (page 72), second units which trail the lead unit generally have more stable costs and schedules.

Millstone 3 might be completed for $4.5 billion, as opposed to $5.5 billion for typical industry experience. The major reason for the stability in Millstone 3 cost estimates is that the schedule did not slip, even when apparently comparable units, with similar reported percentage completion and similar COD projections, experienced significant slippage. If Millstone 3 completion had been delayed eighteen months, to the late 1987 date I projected in MDPU 84-25, the combination of inflation and AFUDC (averaging perhaps 9% annually in this period, dominated by AFUDC), would have brought the cost to $4.35 billion, even without any additional scope.

Fourth, the fact that Millstone 3 was able to keep on schedule, while other plants at similar reported percentage completion and with similar schedules were not able to do so, suggests that NU was not publicizing all of the differences between its schedule and those of other plants, or even between its current schedule and earlier NU schedules for Millstone 3 and the other Millstone units. Perhaps NU was intentionally understating its completion percentage, compared to industry practice.[33] More likely, the lengthy delay in construction allowed for an optimization of design and construction sequencing, so that the 34.1% of

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33. NU was certainly overstating inflation rates, and may have included larger contingencies than usual by 1982, as I noted in my 84-25 testimony. The jump in reported completion in December 1982 (to 60.3%, from 47.9% three months earlier) also suggests that earlier reports may have been understated.

construction reported complete in June 1980, for example, was a more useful 34.1% than that reported by other plants in the same period.

NU did not make any obvious unusual claims for its schedule in the 1980-84 period.[34] The reasons for confidence expressed in the revised cost estimate documents were primarily the usual boilerplate seen in cost estimates for other plants, including Seabrook, Midland, WPPSS, and other disasters: a greater fraction of the design was completed, a higher portion of materials had been purchased, a higher percentage of physical construction had been completed, more design requirements had been incorporated.[35] Whether NU never really realized what forecasting advantages it had gained by the construction delay, which was originally attributed to financial constraints, or whether NU avoided

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34. Perhaps it is more accurate to say that I do not see anything unusual in NU's descriptions of the advantages of each succeeding estimate. NU has also declined the opportunity to elaborate on this issue in this case: see IR-AG-8-14.

35. NU's previous assertion that the experience of S&W was a major basis for confidence in the cost and schedule estimates was particularly odd, given S&W's involvement in the previous erroneous estimates, and in the four most expensive nuclear plants in history. On the other hand, NU's assertion that its confidence in the estimates was increased by the proximity of NU headquarters, S&W headquarters, and the construction site, which seemed trivial at the time, may have been an important hint that NU had found it necessary to closely supervise S&W, to avoid the fate of Beaver Valley, or of Nine Mile Point 2. If so, NU may have had reason to believe it could moderate the usual adverse effect of S&W on costs and schedules, to bring construction performance up to industry averages, although this would still imply significant slippage.

criticism of conventional utility estimates (which would include its own earlier estimates and current estimates for other plants, including Seabrook),[36] NU did not publicly differentiate its later estimates from the industry experience, or from its earlier estimates. In any case, if NU had explained why its schedule estimate was <u>really</u> more reliable than industry standards, my cost projections for the unit might have been much closer to NU's.

The bottom line is that NU did a good job of maintaining its projected schedule, after the 1977/78 slippage of the COD. Determining the cause of this performance -- whether it resulted from the ability to sequence work optimally, the ability to control the A/E, or other factors -- or even whether NU could have anticipated its relative successes, is beyond the scope of my analysis. My subsequent analyses will assume that NU could have anticipated its ability to control the Millstone 3 schedule, following the October 1977 slowdown, and that NU thus could have reasonable have expected to complete Millstone 3 for only $3.8 billion.

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36. These flaws were evidently still present in the 1978 and 1980 estimates for Millstone 3, as regards cost estimates, although these errors were moderated by the accuracy of the schedule estimate.

## 4 NU'S ERRORS IN 1978-80: UNDERESTIMATING THE COST OF MILLSTONE 3 POWER, FAILING TO PURSUE MORE PROMISING POWER SUPPLY OPTIONS, AND THUS FAILING TO REDUCE OR TERMINATE ITS PARTICIPATION IN MILLSTONE 3

### 4.1 NU Should Have Expected Millstone 3 Power to be Expensive, Even Compared to Traditional Alternatives

Q: How have you analyzed NU's decisions to proceed with Millstone 3 construction, and to maintain its large ownership share in the unit, in the late 1970s and early 1980s?

A: The first step in this analysis consisted of a retrospective reconstruction of a traditional utility busbar cost comparison of Millstone 3 to the usual alternatives, new coal plants and existing oil plants. I started by estimating the levelized busbar cost of energy from Millstone 3, as it might reasonably have been projected by NU at two points in time: in 1978, shortly after the decision to slow down construction at the unit, conditionally pushing the projected commercial operation date (COD) to May 1986, and in mid-1980, after the importance of the TMI accident was apparent,[37] and prior to

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37. As noted in Sections 2 and 3, the regulatory and cost changes which followed the TMI accident were part of a continuing trend, rather than a major change in the historical pattern. TMI certainly dispelled any reasonable hope that the environment for nuclear construction might improve dramatically in the near future.

resumption of full construction at Millstone 3. I produced two such estimates for each review point. The first estimate, which I call the "optimistic" case, used utility (NU where available, otherwise NEPOOL) cost inputs, except for the construction cost of Millstone 3, for which I use the $3.8 billion figure, which approximates both NU's current estimate and an optimistic expectation for the unit's final cost as early as 1978, as explained in Section 3. The second busbar estimate, which I call the "historical" case, replaces utility estimates for capacity factor and O&M with simple historical averages and trends, as of the date of each review.

Q: How did you determine the historical averages and trends?

A: Appendix D lists, for each nuclear plant in operation for each year from 1968 to 1984, the annual non-fuel O&M expenses, the booked plant cost, and the increase in the plant cost in nominal and constant dollars. Table 4.5 lists the O&M expenses for each single-unit plant over 800 MW, for each full year of operation, in 1983$. These costs were clearly increasing much faster than inflation for most plants. Table 4.5 also displays the annual rate of increase for each plant, through 1977 (the data available in 1978) and through 1979 (the data available in 1980), and calculates the average cost for each year, and the average annual rate of increase. For the retrospective analyses, I projected out these increases at the average historical rate, including inflation. Note that I did not increase the O&M cost to reflect the larger size of Millstone 3, and that the projections for 1986 are much lower than even NU's current projections.

Capital costs for existing plants were also increasing. Table 4.6 lists the average capital additions in 1983$ for single units over 800 MW, for each year 1972-79. I have not included this cost component in the analysis, which thus understates the cost of Millstone 3 power.

Table 4.7 lists the capacity factor for each PWR of more than 300 MW, for each full year of operation through 1981, along with the average capacity factors for all experience, experience in years 1 to 4 (immature years), and experience after year 4 (mature years) as of 1977 and 1979. Since the average size of these units was less than that of Millstone, and since virtually all observers (including NEPOOL) have expected and found that large units have lower capacity factors than small units, even applying these historical capacity factors to Millstone would be optimistic. Therefore, Table 4.8 lists the average capacity factors for units over 800 MW. The historic capacity factors were consistently less than NU's projections for Millstone.[38]

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38. Millstone 2 was immature throughout this period, and performed at a 61% capacity factor, about 5 points better than the average of units over 800 MW. This could have encouraged NU to believe that Millstone 3 would also out-perform the averages, although even Millstone 2 did not measure up to NU's projections. Depending on how NU weighted national experience with Millstone 2 performance, it might

Q: To what did you compare these Millstone 3 busbar cost estimates?

A: I constructed similar retrospective projections of the levelized busbar cost of energy from the conventional sources which were the most obvious competitors to Millstone 3. Again, the estimates were computed for 1978 and 1980, based on utility cost projections from the time period in question. Since NEPOOL and NU were using very different projections for coal plant costs, I calculated busbar costs for both sets of estimates. For oil, I used low-sulfur fuel price projections supplied by NU.

Q: Do you have an opinion as to which of your nuclear cost cases and which of your coal cost cases best represents the results of a careful analysis by a prudent utility in this time period?

A: The historical nuclear case is clearly preferable to the optimistic nuclear case, since the former is based on actual experience available at the time.[39] I was also careful to

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have anticipated performance somewhat better than my "historical" case, but not as good as the capacity factors used in the "NU" case. Millstone 2 has not performed better than the average nuclear plant with regard to O&M costs. Thus, a reasonable range of Millstone 3 busbar cost projections would lie in between the "NU" and "historical" cases I compute in Table 4.1 and 4.3, but closer to the "historical".

39. As noted above, NU might have hoped that the capacity factor performance of Millstone 3 would be somewhat better than

use only simple analyses, rather than the complex multiple regressions used by most analysts. It is quite reasonable to expect major utilities to recognize important trends which affect the economics of their investments (as poor operating performance and rising O&M would affect Millstone 3 economics): it is much harder to determine what functional forms a prudent utility might use in regression analyses of those trends. It is important to recall that even the historical case excludes some categories of nuclear costs, including decommissioning charges and capital additions.

I have used both NU and NEPOOL estimates of coal plant costs, since it is not clear whether one set of estimates would have been clearly preferable to the other. NU was heavily committed to nuclear power -- in the 1970s, it was building Millstone 3, and planning two other nuclear units at Montague -- but had shown no great interest in building a coal plant. NEPOOL, on the other hand, represented both utilities building nuclear plants (including NU), and those proposing to build coal plants (Canal Electric and Central Maine Power both specified sites, and CMP expended significant resources in attempting to secure licenses for its unit). While NEPOOL thus appears to be an appropriate source of estimates, it was very slow to revise projections: the 1980 NEPOOL coal plant cost parameters were mostly from 1976 estimates. The busbar

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average, but there was no historical basis for NU's projections of either capacity factor or O&M.

costs implied by the two sets of estimates were very similar in 1978, although the NU cost assumptions for coal rose considerably by 1980.

Q: What were the results of your retrospective busbar power cost estimates?

A: Table 4.1 presents the results for the 1978 comparisons, and Table 4.3 presents comparable results for 1980. Tables 4.2 and 4.4 present annual values of time series I levelized: fuel, capacity factor, and O&M. Tables 4.1 and 4.3 present estimates of both the net cost of Millstone 3, which subtracts out the sunk cost of Millstone 3 to that time, plus AFUDC through 1986 (to make it fully comparable to the construction cost) and the gross cost, which includes the entire cost of Millstone 3. The net cost is appropriate for cancellation decisions, since the sunk costs could not be avoided by cancellation. For sales of capacity, which would recover most or all of the sunk costs, the entire cost of the unit is relevant.

In 1978, a realistic appraisal of the levelized cost of Millstone 3 power would have been about 11-14 cents/kWh net of sunk costs, or 14-18 cents/kWh total. Coal would have been expected to cost about 9 cents/kWh, and oil also would have an expected levelized cost of about 9 cents/kWh. Even if only the incremental costs of Millstone 3 could be avoided, through cancellation or a sale well below investment to date, coal would have had a strong cost advantage over continued construction of Millstone 3: coal would have been 2.5 to 3.3 cents/kWH, or about 25-40%, less expensive than Millstone 3. If the total cost of Millstone 3 could have been avoided through a sale at full cost, building a coal plant would have appeared to be overwhelmingly preferable to continuing Millstone 3 ownership.

At 1978 projections of oil prices, NU should have expected to be better off burning oil, rather than backing it out with either Millstone 3 or new coal capacity. Neither baseload option would have been expected to be less expensive than oil, even over thirty years, let alone in the shorter term. Coal power was at least close to oil prices, while Millstone 3 would have reasonably been expected to cost much more than oil.

Q: What should have been the response of NU in 1978 to realistic comparisons of the costs of coal, nuclear, and oil power?

A: NU should have recognized that Millstone 3 would not be economic for oil backout, and should have been pursuing other options to provide capacity and reduce costs. So long as conservation, cogeneration, small power, and other alternatives were sufficient to keep reasonably efficient oil as the average marginal fuel,[40] additional central station

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40. Of course, in some hours the marginal fuel could be from a cheaper source than 10000 BTU/kWh 0.5% sulfur oil, such as cogeneration, while in other hours the marginal fuel would be from a more expensive source, such as a gas turbine.

construction simply would not be cost-effective. Of course, oil prices were (and still are) uncertain, and prudent management might well accept small expected-value penalties to replace oil with an energy source having much more certain and less volatile costs. Given the history of nuclear costs, managers should have viewed nuclear power as nearly as risky as oil, and should not have been willing to pay 30% to 100% above the expected cost of oil to exchange the risks of oil dependence for those of nuclear dependence.

Q: How does your analysis change when repeated for 1980?

A: In 1980, the total cost of Millstone 3 power (including a reasonable capital cost estimate) would have risen to 16-19 cents/kWh. Since construction had progressed slightly, the sunk cost of the unit was higher than in 1978, bringing the net cost down to 11-13 cents/kWh. Coal costs were little changed: coal power would have been expected to cost 9-10 cents/kWh for a 1986 in-service date. Oil would have a levelized cost of 25 cents/kWh. The gap between the incremental cost of Millstone 3 and coal had narrowed somewhat (the advantage of the NU coal estimate to the historically-based Millstone 3 estimate had gone from 5.2 cents down to 3), even though the gap between coal and total Millstone 3 cost had widened. Oil cost projections were high enough that one strategy which would have been attractive in 1978, using oil to bridge a gap between the potential availability of Millstone 3 power and the completion of a new coal unit, would have been viable only for very short gaps, or if other power supplies (e.g., cogeneration and conservation) were available to reduce the dependence on oil in the shorter term.

Q: What was the relevance of a hypothetical 1986 coal plant in an analysis of whether to continue to build Millstone 3 in 1978 or 1980? Could a coal plant have been built by 1986?

A: It may not have been possible to complete a coal plant by 1986 based on a 1978 commitment, and it was almost certainly not possible to complete a coal unit in 1986 if the planning were not well under way by 1980. However, as Tables 4.2 and 4.4 demonstrate, NU's 1978 projections of oil prices for the late 1980s were lower than the levelized cost of either Millstone 3 or a coal plant. NU should have felt no urgent need to replace oil with new coal or nuclear capacity, at the costs then projected for the late 1980s. Therefore, whether the oil backout unit entered service in 1986 or in the early 1990s should not have been a particularly important consideration. Even by 1980, the cost of oil projected for the late 1980s was competitive with the full cost of Millstone 3, even though the long-term cost of oil would have appeared to be much higher. Rather than examine mixed cases of oil in the 1980s and coal thereafter, I have simplified the analysis by comparing Millstone 3 to a 1986 coal plant.

Q: What do you conclude from these analyses?

A: Each of these analyses indicates that a realistic Millstone 3 cost estimate would have resulted in the conclusion that Millstone 3 power would be more expensive than power from contemporaneous coal units, based on an analysis performed in either 1978 or 1980, and that Millstone 3 was not even competitive over its lifetime with existing oil plants, given the oil prices projected in 1978. This is true despite the use of the assumptions I cited above, which favor Millstone 3 in the analysis.

Due to the high oil price projections current in 1980, and the inevitable lag if planning for a new coal plant had been started at that time, coal would have been a promising alternative to the incremental cost of Millstone 3, only if there was a reasonable expectation of replacing Millstone 3 for some of the late 1980s and early 1990s with a power source less expensive than oil. If many of the coal plant siting and licensing issues had been resolved before 1980, the plant might have been on line by 1986, or shortly thereafter. Since NU had not pursued the coal option before 1980, a few years of replacement energy would have been needed to bridge the gap between Millstone 3 availability and that of a coal plant: that energy might have come from cogeneration, small power, conservation, or out-of-region purchases. I will discuss the availability of some of these sources in the next section.

## 4.2 NU Failed To Investigate the Most Promising Alternatives to Millstone 3

Q: Given the foreseeable high cost of power from Millstone 3, particularly in the 1978-80 period, did NU respond properly?

A: No. NU did not act in a timely fashion to investigate and facilitate the availability of any of the most promising alternative sources of power.

Q: What options should NU have pursued?

A: NU should have done more to open up both the traditional utility baseload alternative to nuclear power, which was to build a coal-fired plant, and such less usual (but quite attractive) alternatives as conservation, cogeneration and small power.

Q: What actions with respect to coal would have been prudent, considering the foreseeable cost of Millstone 3?

A: As I discussed in Section 2 and 3, NU should have known throughout the course of planning and building Millstone 3 that the cost of the unit was uncertain and subject to major upward revisions. NU's all-nuclear expansion plan (consisting of Millstone 3, Montague 1 and 2, and small pieces of Seabrook, Pilgrim, and other nuclear units) was at best a questionable strategy for a prudent utility, even in the early 1970s, although the difficulty and cost of building nuclear plants would have become clearer as the 1970s wore on. Coal plants had been considered as alternatives to nuclear plants in NU expansion studies since at least 1975 (see Ferland Studies 32-34, which indicate that ten-year lead times for new coal projects were considered feasible for planning purposes). In the nuclear construction environment of the 1970s, even if NU expected nuclear plants to have cost advantages over coal plants, it should have attempted to keep open the coal option, in case the expectations did not materialize. For example, Ferland Study 33 indicates that, in 1975, NU believed that increasing the projected cost of a 1985 nuclear plant by just 5% to 40% would make that unit more expensive than a 1985 coal plant.[41] In an environment of 100% cost increases for nuclear power plants, the 1975 studies should have prompted NU to prepare a coal alternative for Montague, which could have become an alternative to Millstone 3 after October 1977. Nothing I have seen in this case (or elsewhere) suggests that NU made any effort to resolve licensing or siting issues for a specific coal plant, either in its service territory or elsewhere: the coal plants included in NU's expansions studies were always generic units, without site designations.

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41. At the time, the 1985 nuclear plant was assumed to be Montague 1, at $1022/kW. In 1977, it would have been clear that the closest proxy to a 1985 NU nuclear plant would have been Millstone 3: by 1978, the cost of Millstone 3 was estimated to be $1739/kW, 70% over the Montague estimate for 1985.

When it decided to slip the Millstone 3 in-service date, in October 1977, NU should have recognized that its earlier expectations for Millstone 3 were not going to materialize, and that the final cost of Millstone 3 was apt to be well above projections, even corrected for inflation. A prudent utility, in this situation, would have started to line up other alternatives, so that a decision could be made as soon as possible to commit to one of them, if the news for Millstone 3 continued to deteriorate. Even if NU had done nothing earlier, it should have done its best to make coal a real option -- to identify a site, to resolve fuel supply and environmental issues, and to move forward as much of the licensing process as possible -- as soon as Millstone 3 construction was slowed down in 1977.

Had NU acted in this manner, it might have had a real coal-plant alternative to consider when it had to determine whether to resume construction of Millstone 3 in 1980 and 1981.

Q: If NU had acted in the way you suggest in the late 1970s and early 1980s, would there have been any hope that a coal plant could have been on line in the mid- to late-1980s?

A: Yes. Construction would not have been a major impediment to bringing coal capacity on line in the 1980s. Komanoff (1980) reports intervals of four to six years for construction of coal units with scrubbers in the 1970s, from boiler order to COD. Since all the units in his data set were on line by

1977, this information was available at the time NU was making its important decisions regarding Millstone 3. Budwani (1982) found that average construction times from first concrete for small coal plants (under 400 MW) were about 3 years, while the average for units over 800 MW was about 4.5 years. The Somerset coal unit in New York was completed on schedule in 1984, after a construction period of 39 months.

The greater problem would have been siting and licensing. An EBASCO study (Patterson, et al., 1978) estimated that federal and generic state licensing for a coal plant would require 35 to 42 months from the start of site selection to permit issuance. In New England, given greater environmental concerns (Connecticut was especially concerned with air quality) and the probable need to coordinate utilities and regulatory agencies in several states, the process could have taken longer. More troublesome for a utility planner, the length of the licensing period was difficult to predict and control. Thus, it was important that the licensing and siting issues be resolved as early as possible, to allow informed decision-making.

Q: Are you suggesting that NU was imprudent in not abandoning Millstone 3 in October 1977, in favor of a coal plant?

A: No. If NU had been keeping its options open throughout the 1970s, if might have had a much better idea in 1977 of what would be required to get a coal plant built.[42] But even under the best of conditions, NU probably would have been prudent to "prove out" the coal option before it canceled (or sold out of) Millstone 3. Certainly, given the lack of any definite coal contingency plan in 1977, NU could not have been expected to drop Millstone 3, until a clear alternative had been identified. NU's failure, prior to 1977, to prepare alternatives in the event of a major delay or increase in the cost of Millstone 3 was imprudent.

Q: Besides new coal plants and existing oil plants, what other power sources should NU have been comparing to Millstone 3, and preparing to develop in the late 1970s and early 1980s?

A: Once NU recognized the high cost of Millstone 3, its responsibility to provide reliable power supply at the lowest possible cost required that it determine what combination of options would best serve its customers. NU now seems to have made a formal commitment to this approach, which it calls Integrated Demand and Supply Planning (IDSP), and is more generally called least-cost planning. The same questions asked in the IDSP process could and should have been asked in 1977 and 1978: The terminology has changed in the last nine years, but WMECO's franchise responsibility was the same then as it is now. Regardless of whether Millstone 3 appeared to

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42. No major generation facility was apt to be easy to get licensed and built: the relevant question was the relative cost and uncertainty in each option.

be marginally economical or simply uneconomical compared to continued oil consumption or new coal plant construction, or even whether all three of those options were unpleasantly expensive and risky, NU's responsibility was to find the best alternatives to all or part of NU's ownership in Millstone 3, and to all or part of its oil usage.

Other alternatives which should have been considered as early as 1978 included aggressive conservation programs; customer-owned or utility-owned cogeneration (fired by wood, coal, or oil); ownership or purchases from small power producers (including hydro plants, and trash-burning facilities); and purchases from (or co-operative development in) Canada.

Q: Have you been able to determine exactly how large a supply of energy NU should have been able to anticipate from each of these sources in the late 1970s and early 1980s, and at what cost?

A: Not with any great precision. It is difficult to rerun history in this respect. Given more time than is available in this proceeding, it would be possible (if quite complicated) to reconstruct a history of the development of conservation techniques, utility conservation programs, and programs to encourage development of small power producers and cogenerators. I have not been able to conduct an exhaustive survey of the options as known in 1978-80, but I will present examples of the potential for economic power supply alternatives to Millstone 3, which NU should have known were available by 1978. Those examples demonstrate that the potential was not trivial, and that there was ample reason for NU to look to these sources for at least partial relief from the cost burden of Millstone 3.

It is important to recognize that the process of reconstructing NU's past options, and of determining what NU would have found had it looked, is subject to inherent limits, regardless of the availability of time and resources. There is no way to demonstrate conclusively what response NU would have received in 1978, or 1980, in response to a Request for Proposals for cogeneration or conservation services at prices not to exceed 10 cents a kWh, for example. Nor can we determine conclusively what sort of agreement NU might have negotiated with Canadian utilities, or with joint owners in a coal plant, or with environmental regulators. We only know now that NU did not pursue vigorously many of the options which would have looked very promising compared to Millstone 3.

Q: What do we know about the cost and potential for conservation as an alternative to Millstone 3, as of 1978 - 1980?

A: As noted above, I can not reproduce all of the studies NU should have performed in this time period, so I will be able to identify only a portion of the data and technologies which would have been available to NU. A utility would have been able to identify, and quantify, much more conservation potential than I can include in this testimony.

First, it is important to note that conservation as an alternative to plant construction is not a new idea today, and was not a new idea in 1977. As far back as 1972, NU recognized that the need (or at least the timing) of Millstone 3 could be affected by "the degree to which regulatory agencies and others will directly or indirectly influence people's demand for our product" (Ferland Study 18). The study recognized that conservation could be an important factor, and discussed the implications of a 500 MW reduction in load by 1980, two-thirds of NU's Millstone 3 entitlement. NU did not address conservation as a <u>utility</u>-managed supply option at that time, or indeed until about 1981, but that was not because NU did not know that conservation could work.

While NU chose not to pursue conservation as a power supply option, at least one utility made just this choice as early as 1976. The Seattle City Light Department decided in 1976 to turn down the 10% share it had been offered in WPPSS 4 and 5, a total of 225 MW, in favor of a major conservation program, designed to reduce 1990 demand by 15-20% (Henault, 1978). Seattle city Light is a large utility by New England standards: only NU, NEES and BECo have large energy sales.[43]

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43. The Seattle conservation program did not escape national notice. On August 25, 1978, Senator Kennedy praised the program on the floor of the Senate, in which he noted:

> Although not traditionally thought of as a source of power, achieving energy efficiency can frequently result in more available energy and lower cost than any new supply source. . . If every

The New York State Energy Master Plan (New York State Energy Office 1980)[44] found that two of the three least expensive power supply options it addressed were conservation in new homes at $56/kW-year, and existing home conservation at $132/kW-year (Appendix C, page 94). Even if these conservation measures had a load factor of only 40%, they would provide energy at 1.5 to 4 cents/kWh. Conventional generation technologies (oil, coal, and nuclear) were estimated at $200-300/kW-year. The Plan concluded that "conservation is the least expensive, environmentally safest, and most economically beneficial supply option now available to New York" (Page 1).

Federal Energy Administration (1975) discusses a number of utility sponsored conservation programs and provides estimates of the resulting energy savings and costs. In Arkansas Power and Light's program, 35 energy conservative

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> electric utility followed the example of Seattle City Light, . . . we would be well on our way to reducing the need for increased oil imports, prohibitively expensive central powerplants and unproven synthetic fuels.

Senator Kennedy was no more an experienced expert on utility supply planning in 1978 than I was in 1980, or than the Seattle Citizens Overview Committee which developed the City Light conservation program had been in 1976. The potential of conservation was obvious even to newcomers to the field, and should have been clear earlier to such industry participants as NU.

44. The draft plan was published in August 1979, so much of the analysis must have been completed prior to that date.

houses were built which cost no more than a conventional house. Compared to conventional houses, heat loss was reduced by 65% and electricity cost by 37%. Numerous other successful conservation initiatives are discussed including reducing lighting and ventilation levels, retrofitting existing buildings with additional insulation, and conversion from master-metering to individual metering.

Massachusetts Energy Office (1978) concluded that "conservation, at least for the next decade, was the region's best strategy for reducing oil imports, reducing overall energy costs, creating new jobs, and increasing gross regional production" (Page 5). The report also concluded that the combination of conservation and reduced nuclear plant construction could lead to lower electric prices and even greater economic benefits than conservation alone. In the commercial sector, it found that a 20% reduction in energy use was possible with virtually no net investment, while a 30% reduction in the residential sector was very cost-effective. A comprehensive conservation program in all sectors led to a 27% decline in electric demand in the 1974-1985 period (versus a 36% increase in the "business-as-usual" base case).[45]

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45. Decreasing NU's demand by 27% over the 1974-85 time period would have eliminated the need for more energy and capacity than that supplied by Millstone 3.

California Energy Commission (1980) describes two energy scenarios for the 1980-2000 period: Conventional and Alternative Resources. The second scenario includes a variety of measures to encourage conservation and alternative energy in addition to the very substantial measures already in place in the conventional scenario. The Alternative Resources Scenario is found to be preferable with substantial economic and environmental benefits. In the Alternative Resources Scenario, electric demand is reduced 26% by 2000.

Energy System Research Group (1980) developed a similar conservation scenario for New England, in a study for the Congressional General Accounting Office, and estimated its impact on electrical consumption and oil use. "The conservation measures and levels incorporated in the scenario satisfy three criteria. They are technically feasible; their incremental costs to electricity consumers as a group will be less than the costs of additional electricity; and they appear to require the stimulus of additional public action if they are to be implemented" (Page 1). Thus, these conservation measures were in addition to those embodied in the Base Case, which was already lower than the NEPOOL forecast. Also, while the report was directed towards government action, many of the same ends could be achieved by utility actions.

The ESRG conservation scenario for the residential sector included the following elements: Lighting Efficiency

Improvements; Electric Space Heat Regulation; Voltage Regulation; and Standards for Appliance Efficiency, Plumbing Fixture Efficiency, and Building Envelope. The program for the commercial sector also included Building Envelope Standards, Electric Space Heat Regulation, and Voltage Regulation, as well as Passive Solar Energy Requirement in New Construction, HVAC System Equipment Efficiency Regulations and Operations Requirements, and Internal Load Requirements (lighting levels and ventilation rates). The industrial sector program included Cogeneration Regulation and Incentives, Industrial Conservation Program (services, audits, outreach), and Building Envelope Standards.

The effect of the conservation scenario is dramatic. Total energy consumption actually begins to fall in the 1983-1988 period. Only at the end of the study period, 1998, does consumption return to the 1983 level. Relative to the Base Case, utility oil consumption is 28% lower in 1990 and 38% lower in 2000.

It should be emphasized that Energy System Research Group (1980) relied on the existing literature on energy conservation. Defining a conservation scenario was obviously a substantial effort, but not one beyond the resources of a utility of NU's size.

Emshwiller (1980) notes the large variation in the effectiveness of utility conservation programs. Utilities with a serious commitment reported substantial results.

General Public Utilities, in the aftermath of Three Mile Island, planned on reducing demand by 1000 MW over 10 years. TVA had a program to reduce projected 1990 demand by 4000 MW, at a cost of only $200 to $300/kw. TVA had already given out 100,000 interest free loans for home-insulation. Over the next decade, Pacific Gas & Electric's program projected demand reduction of 1400 MW at a cost of $1 billion.

Wright (1981) evaluates the cost of a large number of conservation measures that could be applied in the California residential sector. Measures costing 0-3 cents/kwh save almost 8000 GWH/year, 15% of total residential electric use.

The widely reported Harvard Business School study **Energy Future** identified conservation (within which it included cogeneration) and solar energy as the major alternatives to continued dependence on foreign oil, and concluded that

> conservation energy . . . is no less an energy source than oil, gas, coal, or nuclear. Indeed, in the near term, conservation could do more than any of the conventional sources to help the country deal with the energy problem it has.
>
> If the United States were to make a serious commitment to conservation, it might well consume 30 to 40 percent less energy than it now does, and still enjoy the same or an even higher standard of living. That saving would not hinge on a major technological breakthrough, and it would require only modest adjustments in the way people live. Moreover, the cost of conservation energy is very competitive with other energy sources. The possible energy savings would be the equivalent of the elimination of all imported oil -- and then some. (Stobaugh and Yergin, 1979, pages 136-137)

In my January 1980 testimony in DPU 20055, to which CL&P was a party, I pointed out that nine additional inches of insulation (as opposed to the 6 inch standard NU has used) in existing homes with six inches of insulation would cost just 4.2 to 4.7 cents/kWh saved, and save about 1660 kWh/year for a 1200 square foot ceiling.[46] I also pointed out

- that water heater insulation cost on the order of 0.3 to 1.9 cents/kWh,
- that rate design could have significant effects on conservation (I estimated a long-run decrease in sales of 8% for a 10% increase in tail blocks),
- that conversion of master-metered buildings to individual meters could reduce use 25% to 35%, and
- that conservation voltage reductions appeared to reduce line losses at 0.5 to 5.8 cents/kWh, depending on the study and assumptions.

Most of these results were not dependent on important new information, and would have been available to NU much earlier. In fact, my estimate of 1.9 cents/kWh for water heater insulation costs came from NU's literature.

Q: Was NU actively involved in conservation development in this period?

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46. The cost and effectiveness of building envelope conservation measures varies with climate, so estimates will vary between utilities and within NU's service territory.

A: NU had some limited programs in place earlier than most utilities did. However, these programs were generally quite limited in their scope and efficiency levels. Even while NU was initiating minor conservation programs,[47] it was also promoting electricity use. Excerpts from my testimony in DPU 558, which discusses these issues, are attached as Appendix H of this testimony. That testimony demonstrates that even in 1981, under the original Northeast Utilities Conservation program for the Eighties and Nineties (NUCPEN), NU's direct conservation efforts were minimal:

- WMECO's terms and conditions included provisions which would discourage cogeneration and alternative energy systems, if enforced;

- WMECO was not acting to phase out master-metering (which discourages conservation by tenants), either by tariff provisions or direct incentives;

- NU's target ceiling insulation levels were inadequate;

- the water heater wrap program was designed to reach a fairly small percentage of eligible customers;

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47. I should note that NU's conservation programs, particularly in residential water heating, helped reduce some customers' bills, and made a small contribution to its supply and demand balance. But many opportunities were left unexploited, and conservation was not turned into a major part of NU's power supply planning. It remains to be seen whether NU will pursue conservation more vigorously through the IDSP process, now that Millstone 3 is completed.

- the water heater insulation NU was applying was much thinner than the amount which was economically justified at a 10 cent/kWh cost of power,[48] and provided only about 60% of the economic savings;

- NU had no plans for promoting the installation of heat pumps to replace resistance electric heating, even though it was actively promoting heat pumps in competition with more efficient oil and gas heating systems;

- NU had no plans to finance cogeneration, even though it expressed concern that feasible cogeneration projects would be thwarted by "competing investment opportunities for would-be cogenerators";

- NU had no plans to promote or expedite the vast majority of conservation and solar energy investments (I listed about a dozen such options, as examples);

- NU's electric heating efficiency incentive was limited to increased insulation of ceilings, which its own studies indicated were already relatively well insulated and accounted for only 8% of energy losses in electrically heated homes, and ignored windows, doors, walls, floors, and infiltration;

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48. I had used this as a rough proxy for the value of conservation. The analyses in Section 4 indicate that NU should have anticipated that even the incremental costs of Millstone 3 would exceed 10 cents/kWh.

- NU was actively promoting electric space heating, including resistance heating, despite its inefficiency and high cost; and

- NU was promoting the use of electric cars for fleet applications in its service territory, under the umbrella of its "conservation" program.

It is important to remember that I had relatively little experience in conservation technologies and delivery systems by 1981, so my critique was hardly based on a comprehensive analysis. The problems I identified in NUCPEN should have been obvious to even a casual observer, generally familiar with energy usage issues. NU should have been much more than a casual observer.

NU's comparisons of conservation with completion of Millstone 3 (Ferland Studies 69 and 76) are informative in several ways. Study 69, the first such study, contains the following lessons:

- It does not appear until August 1981, almost four years after the Millstone 3 construction slowdown. By the time NU started to look at conservation alternatives, it was in the process of speeding up construction again.

- The analysis identifies several programs which were very cost-effective, totaling 2052 GWH of annual savings, or about the power output of 410 MW of

Millstone 3 at a 60% capacity factor or 335 MW at NU's assumed 70% capacity factor:

* industrial customer audits at 0.4 cents/kWh,
* water heater wraps at 0.8 cents/kWh,
* pool time clocks at 1.8 cents/kWh,
* exhaust diverters on electric dryers at 2.5 cents/kWh,
* efficient lamps for industrial customers at 2.9 cents/kWh,
* heat pump water heaters at 3.6 cents/kWh,
* commercial audits and conservation investments at 4.7 cents/kWh, and
* efficient incandescent lighting at 6.8 cents/kWh (even assuming that it would cost $40 per household to deliver four $1 bulbs).

- The conservation alternatives included several measures (totaling about 200 GWH annually) which are simply not cost-effective, at least given NU's assumptions of cost and effectiveness: for example, air conditioner rebates cost 17.9 cents/kWh saved, since only a very small improvement in efficiency was assumed (compared to the range of efficiencies available). The study did not explain why these extremely expensive measures were included.[49]

- The remaining energy production from Millstone 3, and about 400 MW of capacity (the study does not indicate how the peak contribution of the measures was determined), would be replaced by cogenerators and small power producers, which were assumed not to provide any savings compared to oil (and presumably to provide no savings compared to new peaking capacity, although the study also does not provide any information on replacement capacity costs).

- Since the "Conservation" alternative actually replaced with conservation only half of energy NU expected to receive from Millstone 3 at maturity, the "Conservation" option is equally an oil option. If the conservation NU identified were all that were available, it could have justified sale of a large share of NU's Millstone 3 capacity (when sales were still possible), even if it were not enough to justify cancellation.

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49. The study does not explain how any of the measures were selected, why other measures are not included, or how the very high cost and low effectiveness of some measures were computed.

- Some highly cost-effective measures, such as upgrading water heater wraps from NU's 2 inches to 6 or 9 inches, were not even discussed, let alone included.[50]

- Except in the residential sector, the programs were defined very vaguely, indicating that even in 1981 NU had not done much to determine the mix of end uses and conservation potential in its non-residential customers. The commercial sector analysis was simply scaled down from a 1980 Pacific Gas & Electric report, the industrial lighting program simply assumed 100 lamps/customer,[51] and the industrial audit program simply assumed 5% savings. No documentation is provided for either of the industrial program assumptions, which appear to be arbitrary round numbers.

- Some of the program elements contained obvious errors, particularly in understatement of potential, indicating that the conservation alternatives were still in very rough form. For example, NU assumed that heat pump water heaters could not be installed in conditioned (that is, heated and cooled) space, even though the heat pump would provide free air conditioning and

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50. See Appendix H for calculations of water heater wrap economics.

51. Analysis and Inference, Inc., a small consulting firm occupying 3100 square feet, has over eighty fluorescent lamps.

dehumidification in the summer, and even in the winter, would provide much of the water heating energy from the space heating system (usually oil or gas) rather than from more expensive electricity. Also, the maximum conservation potential of commercial water heating energy usage was assumed to be only 22%, even though ordinary air-source heat pumps would save about 50% of input energy, and other input measures (heat recovery, ground source heat pumps) could save even more, in addition to end-use reductions (e.g., flow restrictors).

- One of the attached memos is entitled the "Conservation vs. Millstone III Exercise", suggesting that NU was not taking the comparison seriously.

Study 76, even though it was filed in September 1982, identified only 1300 GWH of conservation alternatives (the equivalent of only 212 MW of Millstone 3 at NU's assumed capacity factor), so it was even more clearly an oil-versus-Millstone 3 comparison. This study appears to have problems similar to the earlier one. For example, water heater insulation seems to have disappeared from the analysis entirely.

Only recently, in the IDSP program and the contract with AES, has NU even enunciated a goal of identifying and exploiting all economic conservation in its service territory. Had the IDSP program started in 1977 or 1978, WMECO's customers would be facing a much smaller burden of Millstone 3 costs now, and would be benefiting from much larger investments in energy efficiency.

Q: What do we know about the potential for cogeneration and small power production as an alternative to Millstone 3, as of the 1978 to 1980 period?

A: The Massachusetts Governor's Commission on Cogeneration report (Cogeneration: Its Benefits to New England, October 1978), found a potential of thousands of megawatts of cogeneration in Massachusetts alone. Even backing out only the low utility retail rates with 1-2.3 cent/kWh fuel and O&M, virtually all of the sample sites tested yielded returns in excess of 10%.[52] A very strict economic test was applied to potential sites, which computed the return on investment (ROI) in the facility, compared to then-current utility retail rates in the 3-4 cent/kWh range (and no inflation). The Task Force then assumed that the percentage of sites developed would be twice the difference between the ROI and a 15% threshold. For example, a site with a 30% indicated return would only have a 30% chance of being developed. Even with these constraints, the Task Force estimated that 644 MW of cogeneration would be economic in Massachusetts, and a

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52. Ironically, WMECO's retail rates, the lowest of the major utilities in the state, were low enough to push returns on a few combinations of sites and technologies below the 10% level. From NU's point of view, of course, the appropriate comparison was between cogeneration costs and Millstone 3 costs, not between cogeneration costs and WMECO retail rates.

total of 1683 MW in New England (of which a significant portion would be Connecticut).

Cogeneration would have been a much more promising option, if it were evaluated at the 11 - 18 cent/kWh Millstone 3 costs it could have avoided, and at NU's financing costs. Replacing 1978 retail rates with my estimates of 1978 levelized Millstone 3 costs, and replacing 1978 oil prices with 1978 projections of levelized oil costs, would at least double the difference between operating costs and electricity savings. Doubled operating savings would double the ROI's, to the 30-60% range. Essentially all of the sites examined by the Commission would have been economical compared to Millstone 3, at the 10% to 14% discount rates NU was using in the late 1970s and early 1980s. I cited the Governor's Commission report in my testimony in DPU 20055, and calculated costs of oil backout with cogenerators at 3.8 to 6 cents/kWh for 1985 units.

FEA (1975) discusses the role that utilities can play in establishing facilities to generate electricity from solid wastes. This report describes how utilities can evaluate the potential from this resource and discusses utility involvement in several projects. It notes that utility participation can include ownership and operation of the solid waste processing facility.

Energy System Research Group (1980) evaluated the potential of alternative energy sources in New England for the

1978-2000 period. Cost effectiveness was judged in comparison to the fuel cost of oil generation; no capacity credit for alternatives was assumed. The alternative energy potential for the region, excluding units built, under construction, definitely planned, or included in the Base Case (NEPOOL plans) was as follows:

| | 1990 | 2000 |
|---|---|---|
| Wind | 500 | 2900 |
| Solid Waste | 480 | 850 |
| Tidal Power | 13 | 750 |
| Large Hydro | 195 | 580 |
| Small Hydro | 510 | 510 |
| Wood | 30 | 80 |

Thus, the potential for renewables was over 1700 MW in 1990 and more than 5600 MW in 2000.

California Energy Commission (1979) estimated levelized costs of 10.9 cents/kwh (1985$) for wood-fired generation and 12.79 cents/kwh for wind turbines versus 14.4 cents/kwh for nuclear.

Electrical Week (1980) discusses the California PUC's efforts to encourage cogeneration, including penalizing Pacific Gas & Electric's rate of return for lack of vigor in this area. The article notes that San Diego Gas & Electric owns base loaded cogeneration units which sell steam to participating industries. A spokesman for the PUC stressed that offering full marginal costs encouraged cogeneration, stating "it's amazing how much cogeneration is available once the price is right." This was certainly the experience in Maine several years later.

In New York State Energy Office (1980), the Base Case Energy Master Plan included additions by 1994 of 725 MW of small hydro, 266 MW of solid waste, and 222 MW of cogeneration. 532 MW of this capacity would be in place by 1884 as well as 800 MW of Canadian imports. The Proposed Case, consisting of a variety of legislative and administrative actions, projected additions by 1994 of 1050 MW of small hydro, 558 MW of solid waste, and 559 MW of cogeneration. The Plan estimated the cost of trash burning plants at just $93/kW-year.

California Energy Commission (1980) describes two energy scenarios for the 1980-2000 period: Conventional and Alternative Resources. The second scenario includes a variety of measures to encourage conservation and alternative energy in addition to the very substantial measures already in place in the conventional scenario. The CEC found the Alternative Resources Scenario to be preferable in terms of both economic and environmental benefits. In 1985, the Alternative Resources Scenario projects 3700 MW of cogeneration and 300 MW of wind[53] in addition to the 4900 MW of cogeneration in the Conventional scenario. By 1995, the Alternatives Scenario projected 8600 MW of cogeneration and 2500 MW of wind in addition to the Conventional Scenario's

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53. This is MW of dependable capacity at summer peak. Installed capacity is much higher; at the time of the report, wind was receiving a 25% capacity credit. California utilities collectively are about twice the size of NEPOOL, or about eight times the size of NU.

6700 MW of cogeneration and 600 MW of wind. The difference continues to widen with cogeneration and wind accounting for over 20% of capacity in the Alternatives Scenario versus only 4% in the Conventional Scenario.

Energy Future (Stobaugh and Yergin, 1979) described cogeneration as "industry's North Slope," noted that no major technological breakthrough was required for its development; that the technology was applicable to non-industrial settings, including hospitals and shopping centers; that development was inhibited by utility resistance to interconnection and by high industrial financing costs; and utilities ownership of cogenerators could resolve some of the problems.

Q: Did NU carefully evaluate cogeneration potential in the late 1970s and early 1980s?

A: Not really. The first study of cogeneration potential NU has cited was a Dames & Moore study completed in January 1981. That study had several important flaws:

- It contained no economic analysis, so the results were completely insensitive to retail rates, cogeneration buyback rates, Millstone 3 costs, the availability of NU financing, and so on. Despite the absence of an economic analysis, the study assumed that financial barriers would exist due to customer financing at 30%, rather than NU financing.

- It ignored all non-industrial cogeneration.

- It ignored all cogeneration of heat in forms other than existing steam usage. Other heat uses are absorption chilling (which may be a new heat use, replacing electric chillers and thus further reducing demand), hot water, and hot air or gas (e.g., for drying).

- It assumed that cogeneration could only supply the customer's average steam requirements, which means that a facility which required heat half the time (12 hours/day, or 6 months/year) was assumed to install a cogenerator only half as large as its heat load.

- It assumed that cogeneration potential would only exist at customer premises with electric loads in excess of 1 MW. No justification is offered for this assumption.

- It assumed that only 20% of the calculated potential of 1000 MW would be economic, again without benefit of an economic analysis.

- The study spends a fair amount of time discussing the electricity demand of the cogenerating customer, a topic of virtually no relevance to a utility interested in cogeneration development as a power source.

Despite all of these limitations, the study nonetheless concluded that the cogeneration potential was about 1000 MW, and that "approximately 200 megawatts of cogenerated electric power may be 'economically developable' among Northeast Utilities Connecticut customers. . . The 'actual' cogeneration potential is less than the 'economically developable' potential . . ." (page 2).[54] Dames & Moore also notes that NU had been approached by possible cogenerators with a total potential capacity in excess of 70 MW. None of the documents NU has supplied indicates that it ever attempted to determine whether the 70 MW, the 200 MW, or 1000 MW could be obtained at less than the cost of Millstone 3, or even at less than the cost of oil.[55]

This unduly pessimistic and incomplete study was too little and too late. Given the foreseeable cost of Millstone 3, a thorough examination of NU's cogeneration option, should have commenced in 1977 and 1978. This examination should have included requests of bids on power supply and a general offer to develop viable sites in conjunction with customers.

Q: What should NU have known about cogeneration potential in the 1978-1980 period?

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54. Considering that NU now has agreements for 547 MW of QFs, was negotiating with another 280 MW even prior to the December 1985 CPUCA order raising the contract purchase, and expects to be able to contract for up to 2000 MW, the Dames & Moore study obviously did not involve an exhaustive search for cogeneration potential.

55. See IR-AG-5-23 and 8-27. Also, the Ferland Studies which compare cogeneration alternatives to Millstone 3 (such as #69) include no information on cogeneration costs, even though similar information on conservation costs are included.

A: Had NU analyzed the issue realistically, and with an open mind, it would almost certainly have found that cogeneration was a significant potential source of power at costs well below the cost of Millstone 3.[56]

The technology of cogeneration has not changed radically in the last decade: indeed, many new cogeneration plants are basically similar to those built 50 years ago. Most cogeneration projects use steam turbine designs, which are basically the same as small utility-owned fossil-fired steam plants, except that the steam goes to some end use, rather than to a condenser; gas turbine designs, which are similar to utility gas turbines, except that the exhaust heat is captured; and diesels (or similar engines) which are similar to utility diesels, except that the exhaust heat and the engine coolant heat (which would go to a radiator, if the diesel were in a truck) is captured. The steam plant designs are modernized versions of plants build in the 1940s, or earlier, while the diesels and gas turbine have been available for at least a couple of decades. Some of the facilities now planned for NU's service territories may use improved technologies (such as fluidized beds), which were

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56. It is easy to focus on cogeneration, with its multi-gigawatt potentials, but the same considerations are applicable to other small power producers, which can provide more than a trivial contribution to energy supply. NU currently projects that 220 MW, (about 30% of NU's entitlement in Millstone 3) of renewable-energy small power producers (mostly hydro and refuse-burning) will be developed in its service territory by 1988.

not available a decade ago, but development of equivalent cogeneration capacity at the same facilities might well have been feasible with the traditional generation technologies.

Had NU offered in 1978 to purchase cogenerated energy at prices at, or even well below, the reasonably anticipated cost of Millstone 3, some significant amount[57] of the cogeneration capacity which NU now considers surplus could have started up years earlier, reducing or eliminating NU's dependency on Millstone 3.

Q: How does the lack of FERC rules, and of state rules, pursuant to PURPA Section 210 affect the feasibility of cogeneration development in the late 1970s?

A: Not much. PURPA was enacted in 1978, but the FERC implementing rules were not promulgated until 1980, and the states did not act until later. While PURPA has been important in forcing reluctant utilities to accept power from cogenerators and small power producers, utilities which wished to develop these sources voluntarily would not have been significantly hampered by the lack of PURPA rules.

Any utility could own cogeneration and small power production facilities directly, and include them in rate base in the

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57. Even a couple hundred megawatts could have been significant, if it had allowed NU to sell off a corresponding amount of Millstone 3.

normal manner.[58] A utility may also own a turbine/generator, and purchase steam from the facility which uses the turbine exhaust, or it can just own the turbine, and purchase rotational energy from the heat user. The utility can even lease the turbine, with maintenance, for a nominal sum. If the utility does not want to own and operate the cogenerator or power producer, the arrangement could be structured to transfer virtually all of the financing burden and/or of the risk to the facility owner, without that facility becoming a generator of electricity, subject to utility regulation. In any case, various entities have sold power to utilities for many years prior to PURPA without becoming subject to utility regulation.[59] Thus, NU could have promoted development of small power and cogeneration long before PURPA 210 became effective.

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58. NU owns some small hydro facilities, which would be qualifying facilities under PURPA if they were not utility-owned. Boston Edison operated a cogenerator which provided steam to its steam system for almost fifty years, and Cambridge Electric operates a cogenerator which supplies steam to Harvard.

59. For example, the MDC has sold hydro power to Boston Edison, and Central Maine Power has purchased hydro and cogenerated power from paper mills, both since at least 1972.

### 4.3 NU's Load Forecasts Were Unreliable and Overstated

Q: Did NU's forecasts, as of 1978 or 1980, provide sufficient basis for concluding that it would need Millstone 3 (or equivalent capacity) for reliability purposes in 1986?

A: No. The 1978 forecast (see Ferland Study 48) indicated a need for capacity by 1986, if not before, and the 1979 forecast (see Ferland 63, item 2) indicated a need for some capacity by 1987. The 1980 forecast, on the other hand, projected 21.4% reserves in 1988/89, and almost 19% reserves in 1989/90, even without Millstone 3.[60]

None of these forecasts provided a sound basis for projecting a need for Millstone 3 (or equivalent capacity) in any particular year. I reviewed the 1978 and 1980 NU forecasts: my testimony on those forecasts before the EFSC is attached as Appendix I. I will only summarize the testimony briefly here.

The residential demand model was generally well specified, in that it contained all of the important end uses, and could

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60. Until quite recently, NEPOOL projected requirements of 20% reserves, plus 1% per 1150 MW nuclear unit. Since NU expects to have required reserves slightly smaller than those of the pool (IR-AG-2-12), the 19% reserves would have been adequate with no new nuclear plants, and about 1/2% low if Seabrook 1 were completed.

accommodate such factors as changes in appliance and household size, efficiency improvements, and changes in appliance saturations in new and existing housing. This model could have been the basis for a thorough assessment of residential conservation potential.

The commercial model was much rougher than the residential model, and was riddled with inconsistencies and errors. Rising energy usage was extrapolated from the period of falling prices in the 1960s and early 1970s, into the late 1970s and 1980s. No efficiency improvements were modeled for existing buildings. The electric fraction of energy usage in new buildings was assumed to rise rapidly (although no derivation was provided for this assumption), and even short-term projections of electric penetrations far exceeded recent values. Some of NU's figures could not be derived from the methodologies purported to have created them.

The industrial model was a collection of arbitrary, generally undocumented, and often highly dubious regressions. Price elasticities were low (and in some industrial sectors, non-existent), and long-term elasticities were neglected entirely. Numerous different models were used for different sectors, and NU was not able to explain why any particular SIC code used a particular specification, rather than any of the specifications used for other SICs. In some cases, NU used models with insignificant variables, or which did not have the best statistical results among the possibilities tested: there are many potential reasons for accepting models such as these, but NU could not offer any explanation.

In short, the NU load forecasting models in the 1978-1980 period were good beginnings, but they contained numerous flaws, and in many instances their projections were overstated. The forecasts were not sufficient bases for concluding that NU needed the capacity of Millstone 3.

## 4.4 NU's Decisions

Q: What important decisions did NU make in this period?

A: There were three decisions points I would like to focus on: the 1977 decision to slip the Millstone 3 completion date to 1986; the 1979 decision to withdraw an offer to sell 172.5 MW of Millstone 3, after potential buyers had expressed interest; and the decision to return to a high level of construction activity in 1981.

Q: Did NU act prudently in connection with the 1977 decision to delay Millstone 3?

A: I have not reviewed the decisions to reduce the rate of construction at the plant, and to abandon the 1982 COD target, and I therefore have no opinion on the prudence of <u>those</u> decisions. However, as I have discussed above, NU did not act prudently in four crucial respects, related to the delay decision:

1. Despite ample evidence that there were major difficulties in nuclear construction and cost control, NU had failed to prepare contingency plans for events, such as the 1977 slowdown, which could severely erode the economic position of Millstone 3.

2. NU failed to take actions which could have made feasible subsequent commitment to such power supply alternatives as coal plant construction, cogeneration and small power development, and major conservation programs.

3. NU based its Millstone 3 analyses on cost estimates which it should have known were extremely unlikely to be realized.

4. NU failed to actively seek a market for a substantial portion of its share of Millstone 3 until July 1979, 21 months after the decision to delay. By the time NU finally offered to sell 172.5 MW (about a quarter of its Millstone 3 share), a large amount of PSNH's Seabrook capacity was on the market, complicating the task of selling Millstone 3 shares.

If NU had been energetically pursuing the most attractive alternatives, particularly conservation and cogeneration, it would have been in a much better position to make informed decisions regarding the sale or cancellation of Millstone 3. Had NU started to issue requests for bids, institute programs, and generally prove out the potential for conservation and cogeneration, it would have found out years earlier at least some of what it has learned since: both of these sources offer large supplies of energy at costs well below those of Millstone 3. The "large supplies" might only have been large enough to permit the sale of a couple hundred megawatts of Millstone 3, or they might have allowed cancellation of the plant; in either case, the availability of alternative sources of power supply would have permitted some substantial reduction in the exposure of NU ratepayers to Millstone 3 costs.[61]

The same considerations apply to NU's failure to prepare contingency plans for coal plant construction. Had those plans been ready in 1977, or early 1978, and had some of the siting, licensing, and environmental issues been resolved (or at least been ready for adjudication), NU would have been better able to sell off or cancel Millstone 3. While coal capacity would probably not have been the first choice in power supply options, untile less expensive conservation and cogeneration options were exhausted, its availability would have increased NU's confidence in its ability to cope with less (or no) Millstone 3 capacity.

Q: Was the 1979 decision to withdraw the offer to sell 172.5 MW of Millstone 3 prudent?

A: No. If NU had been planning properly in the mid-1970s and late 1970s, it would have been able to offer this capacity earlier, as I explained above. NU should also have known by

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61. For example, selling 25% of Millstone 3 would have reduced the net loss to WMECO ratepayers by $32 to $106 million, depending on whether Case 1 or Case 3 in Section 6 turns out to be a more accurate reflection of Millstone 3 economics. The savings to other NU customers would be about five times as large as those to WMECO.

1979 that superior alternatives to Millstone 3 were available, especially if the sunk cost of the unit could be recovered through sale. The relatively small amount of Millstone 3 involved in the withdrawn offer could have been replaced several times over by a combination of the following sources:[62]

- a portion of the 400 MW of conservation which NU finally identified in 1981 (Ferland Study 69);
- other conservation measures NU did not include (but which I discuss above);
- the 200 MW of cogeneration Dames and Moore estimated to be "economically developable" in 1981;
- some of the other 800 MW of cogeneration Dames and Moore found feasible;
- other cogeneration Dames and Moore did not consider (as discussed above);
- other small power;
- new coal capacity.

Much of the conservation and cogeneration would have provided power at much lower cost than Millstone 3, and even a new

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62. NU should have anticipated the availability of all of these sources, and could have confirmed their existence in the 1970s, as I demonstrated above, in Section 4.2.

coal plant would have been cheaper than completing Millstone 3. Even if a small portion of the replacement power supply mix were more expensive than Millstone 3, the average cost of the mix could be lower than Millstone 3, if it included the phenomenally cost-effective conservation measures and some of the better cogeneration options.

Q: Was the 1980/81 decision to resume major construction activity at Millstone 3 prudent?

A: That question must be answered in two parts. On the one hand, given the situation in which NU had put itself by early 1981, the decision was probably the only feasible one. There was no longer any significant market for Millstone 3 capacity, so sales were not possible: NU could either cancel the plant or build it. The only alternatives which NU was at all prepared to pursue at that point were existing oil and new coal. Oil would have appeared to be a prohibitively expensive replacement for Millstone 3, at least past the 1980s. Coal power would only have been marginally cheaper than the incremental cost of Millstone 3, given the sunk costs accumulated by 1981, and it was unclear how long it would take to get a coal plant sited, since NU had not developed this option.

On the other hand, NU had erred severely in putting itself in the situation in which it found itself in 1980 and 1981. Had NU developed the markets for conservation and cogeneration, either by the purchase of services or by offering to perform the services itself, it would have known in 1981 that sufficient cost-effective alternatives to Millstone 3 existed, and would have already begun to develop those alternatives.

Consider an automotive analogy. A person who drives down icy roads at high speed, without allowing for road conditions and oncoming traffic, may be generally considered to be imprudent. When an on-coming truck slides into that driver's lane, the best response available to the imprudent driver may be to run off the embankment and into a tree. That bad result is neither the fault of the truck nor of the highway department, since a prudent driver would have responded to the road conditions and would have acted to as not have been at hazard in the first place, by driving more slowly, seeking out a clearer road, or waiting until the highway was sanded. Analogously, by failing to develop its options in the 1970s, NU forced itself into making a no-win decision to restart Millstone 3 construction in 1981.

## 5 ASSESSING THE RELIABILITY BENEFITS OF MILLSTONE 3 TO WMECO RATEPAYERS

Q: You indicated that reliability is one possible justification for constructing generating plants. What determines whether a plant is needed for reliability?

A: Utilities attempt to have sufficient capacity available to provide power whenever customers wish to use it, on-peak and off-peak, throughout the year. Forced outages of generating facilities require that the utility have more capacity than the anticipated demand (a reserve margin) available at all times, and even with a reserve, generating reliability can never be 100% certain. For utilities which are members of power pools (as NU is a member of NEPOOL), the required reserve is determined by the utility's own load and supply characteristics, the load and supply characteristics of the pool, interconnections with other utilities and pools, and the contractual obligations under which the pool's total reserve requirements are allocated to the member utilities.

As a result, the reliability value of Millstone 3 will be determined by three considerations:

1. The accuracy of NU's supply projections.

2. If NU's projections of power supply on its system are correct, the reliability value of Millstone 3 to NU will be determined by the cost of the plants which

otherwise would be required to meet NEPOOL reserve standards.

3. The reliability value of Millstone 3 to the NEPOOL pool as a whole (and thus to the Commonwealth of Massachusetts) will vary from the unit's value to NU.

I will discuss each of these topics in turn. Since NU operates as a single entity within NEPOOL, and since NU asserts that capacity costs are redistributed within NU so that each company pays for a share of capacity determined by its demand, regardless of which subsidiary owns the capacity, I will examine capacity issues entirely at the NU level, without specific reference to WMECO.

Q: What do you conclude from your analysis of the reliability value of Millstone 3?

A: The reliability value of the unit to NU is a tiny fraction of its cost. Until 1992, there would be no need for new capacity to meet NEPOOL requirements, even under NU's load and supply forecast, except to allow the retirement of existing units.[63] After 1992, Millstone 3 would eliminate the need for the construction and/or refurbishment of inexpensive combustion turbines. NU's supply forecast may overstate the (already small) value of Millstone 3. Finally, the reliability value of Millstone 3 to NEPOOL is even smaller than it is to NU.

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63. A small short-term purchase would be required in 1989.

### 5.1 The Value of Millstone 3 to NU

Q: What are the reliability benefits of Millstone 3 to NU?

A: Millstone 3 will contribute to meeting NU's reserve requirements in the NEPOOL power pool. Within the NEPOOL system, each individual utility has a responsibility to maintain a share of the generating capacity required by the pool.[64] The capacity of Millstone 3 is not needed to meet NU's capability responsibilities for at least the rest of the decade, but Millstone 3 will enable (and has already allowed) NU to accelerate the retirement of other units and to defer new investments.

Q: If Millstone 3 is not needed to meet NEPOOL requirements in the short term, what is it worth to NU for reliability purposes?

A: In the short run, Millstone 3 will allow NU to achieve some savings by retiring existing plants. In the longer run, Millstone 3 will allow NU to avoid buying and building new capacity. The minimum fixed cost of enhanced reliability

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64. Unfortunately, the NEPOOL agreement does not reflect well the relative reliability value of various kinds of capacity, which varies with the size, maintenance requirements, and forced outage rates of each unit, so a member utility may meet its capacity requirement without really providing its share of reliability support for the pool as a whole.

from new construction is probably the cost of new combustion turbine (CT) capacity.

At a first approximation, the NEPOOL capability measurement rules insure that a megawatt of any plant is equally valuable to a participant.[65] Thus, we can estimate the value of Millstone 3 for meeting NEPOOL reliability requirements by determining:

1. how many megawatts NU would be short of its NEPOOL obligation without Millstone 3 and without the avoidable retirements in the 1978-87 period, and

2. the cost of retaining, refurbishing and building sufficient capacity to meet the NEPOOL reserve target, without Millstone 3.

The shortfall and the avoided capacity cost are calculated in Tables 5.1 through 5.5.

Q: When would NU have needed to add new capacity to meet NEPOOL requirements, if not for Millstone 3?

A: New capacity would not have been needed until 1992. Table 5.1 shows NU's capacity situation, excluding Millstone 3, given NU projections of summer peak load, required reserves, and retirements. Table 5.1 assumes the addition of some

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65. This approximation somewhat overstates the value of Millstone 3 to NU, since large nuclear units tend to drive up the reserve requirement for the pool, and hence the reserves allocated to each of the members.

hydro units and the Hydro Quebec purchase, which are justified by their fuel savings, regardless of any need for capacity, but no other new additions.[66]

Table 5.2 starts with the capacity shortfall for each year: the shortfall is zero in years with surplus capacity. It then shows the capacity which would be provided by retention -- to their originally scheduled retirement date -- of three steam units (Middletown 1 and Devon 3 and 6) and of seven combustion turbines, which I have called Group 1 (totalling 116 MW).[67] NU now plans to retire all ten units between December 1985 and January 1987.[68] Additional columns show the capacity contributions of refurbishment and fifteen-year life extensions of Group 1 (the seven combustion turbines), of 8 more CTs, retired from 1981 to 1982, which we have

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66. Devon 10 (14 MW) has been included as existing capacity in Table 5.1. According to IR-AG-17-13 (received after the reliability value analysis had been completed), Devon 10 would require repairs close to the cost of the generic $100 per kilowatt refurbishment, in order to return it to service. Thus, Devon 10 should be removed from existing capacity, and added to Group 2 of refurbished CT's. Alternatively, Enfield 10, which is apparently being "retired" by relocation to Devon, could be moved from Group 1 to Group 2.

67. Group 1 includes: Enfield 10, Torrington Terminal 10, Tunnel 10, Franklin Drive 10, Silver Lake 12, Doreen 10 and Woodland Road 10. These units were scheduled for retirement between 1992 and 1994, but for the sake of simplicity have been treated as due for retirement in 1993.

68. This calculation assumes retention of all capacity which was in service in 1984, until its normally scheduled retirement date, with the exception of Devon 4 and 5, which were scheduled for retirement in 1987, anyway.

called Group 2 (totalling 71.5 MW),[69] and the East Springfield CT (13.5 MW), which was sold in 1981.

Column [5] of Table 5.2 then subtracts the total retentions and life extensions from the gross shortfall with NU's present retirement schedule. With those changes in retirements, NU's present capacity would be sufficient until 1992, except for a 38 MW shortfall in 1989.[70]

Q: What is your basis for assuming that these 19 units could have been retained?

A: For the 1986 and 1987 early retirements, NU has provided detailed estimates of the cost of keeping the units on line (IR-AG-2-3). For the earlier retirements, IR-AG-2-5 indicates that the units were retired for a variety of reasons, ranging from the need for major repairs (Silver Lake 10 and 13), to the failure of a transformer (Branford 10). The most common reason for previous CT retirements, however, is that the units were not needed. If NU had not been committed to constructing Millstone 3, and had not made other capacity plans, these units would have been needed, and would have been retained.

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69. Group 2 includes Branford 10, Danielson 1, Thompsonville 1&2, Silver Lake 10, 11 & 13, and Tracey 10.

70. I have assumed that this small shortfall, which would occur while NEPOOL still expects to be in a capacity surplus, could be met by a short-term purchase at the current NEPOOL capacity deficiency charge. If Millstone 3 did not exist, the required reserve would be smaller, and even the 38 MW purchase would not have been necessary.

Q: How did you determine when additional capacity would be required, even with the retention of the existing units?

A: From the capacity shortfall with the life extensions, I calculate the number of megawatts of new CTs which would have to be constructed to meet the capacity target. This calculation is shown in columns [7] and [8] of Table 5.2.

Q: What would it have cost to make up the reserve deficiency without Millstone 3?

A: Table 5.3 displays my calculations of the cost of each of the unit retentions and Table 5.4 calculates the cost of the life extensions through major refurbishment. For each steam plant and the CT scheduled for 1986 and 1987 retirement, I have used the annual costs of keeping the plants in operation through their original retirement dates, as estimated by NU in IR-AG-2-3. For the CTs retired in 1984 and 1985 (Enfield, Tunnel, and Torrington), and for the life extensions, I have extrapolated the costs reported for the four 1986/87 CTs (Franklin Drive, Silver Lake, Doreen and Woodland Road). For the life extensions, I have also added the capital costs of the life extensions (and the resulting property taxes) from NU's assumption of $100/kW in 1983 dollars (AG-2-33, page 1 of 1, dated 1/10/86). The recovery of the capital costs are spread over time as NU distributes the cost recovery for Millstone 3 capital additions with 15-year useful lives.

NU estimates that new combustion turbines would cost about $330/kw in 1984 dollars (IR-AG-2-138, page 3), or only about 11.3% of the cost of Millstone 3. Gas turbines generally have much lower fixed O&M, capital additions, insurance, taxes and retirement costs and can also be brought on line with only a year or two lead time, so they are unlikely to be excess capacity when they are installed.

Table 5.5 calculates the annual carrying costs, taxes and non-fuel O&M for the new CTs which would be required to make up the reserve shortfalls (after retentions and life extensions) indicated in Table 5.2. I have not included the cost of life extensions for the CTs after 25 years, for several reasons. First, the life NU projects for Millstone 3 is highly speculative, as discussed in Section 7. Second, any replacement capacity added in 2017-2020 would be very young at the end of the analysis period, and a credit for its remaining service life would be necessary. Third, NU retired and sold three 1950's vintage CTs[71] in 1981, when they were 27 and 28 years old, and apparently still in good working order: the useful life projection of 25 years seems slightly conservative.

Table 5.6 adds up the cost of the replacement capacity for Millstone 3 which would have been required by NEPOOL reserve targets. I have not included other inexpensive options, such

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71. These were Danielson 1 and Thompsonville 1 & 2

as additions of new economic plants (e.g., cogeneration facilities), which could have negative net reliability costs, once credit is taken for their fuel savings. Table 5.6 also compares my estimate of the reliability benefits of Millstone 3 to that of NU: our figures are very similar for most of this century (there are some timing differences), but NU's projection of avoided cost is consistently higher than mine after 1994, and increases dramatically after 2017.

It is clear from Table 5.6 that most of the cost of Millstone 3 was not required, and would never have been incurred, for system reliability.

Q: Is the capacity of Millstone 3 required to meet NU's reserve target anytime in the 1980's?

A: No. Millstone 3 is only needed for capacity purposes in the 1980's due to the early retirements of the units listed in Table 5.2. Those retirements are planned (or, in the case of East Springfield, Enfield and Group 2, have already occurred) because Millstone 3 is nearing commercial operation. Thus, the net reliability-related benefit of Millstone 3 in the short term is not that it will keep the lights on in Springfield (the smaller existing units would have done a better job of that), nor that it will allow NU to fulfill its obligations to NEPOOL (which the retired plants would have done), but only that it allows the retirement of capacity which costs very little to maintain.

The mere fact that NU chooses to replace one type of plant with another does not imply that the basic function could not have been performed by the original plant, nor that the replacement was necessary. NU could, for example, purchase a fleet of Cadillacs for its meter readers, and sell off its existing cars. It could hardly be argued that the investment in the Cadillacs was required to allow for orderly billing, or that they avoid the cost of taxicabs to transport the meter readers. Even though the Cadillacs perform both those functions (probably quite well), the old fleet served those same ends, at lower costs. The transportation benefit of the Cadillacs is the sale price of the existing cars: the cost of the new fleet above that transportation benefit is either justified by a completely different kind of benefit (e.g., improved labor relations), or not at all.

## 5.2 NU Supply Projections

Is it appropriate to assume that no new generation, other than Millstone 3, the hydro additions and 547 MW of cogenerators will be added in NU's service territory in the rest of the century?

No. NU's supply projections do not include the possibility that large numbers of cogenerators and small power producers will emerge in Massachusetts and Connecticut as a result of the recent rulings on rates and contracts. To the extent that such facilities are developed, the reliability need for Millstone 3 is reduced.

Is there any reason to believe that such capacity will be added?

Yes. NU projects steadily rising avoided energy costs. By the year 2000, NU projects avoided costs of 14.7 cents/kWh, or 6.5 cents/kWh in 1986 dollars, as compared to about 4 cents/kWh projected for 1987 and 1988. These figures are from column [9] in **Table 6.1**. If rates for power purchased under PURPA are based on the same avoided costs NU uses in evaluating the economics of Millstone, the incentives for independent power production will increase substantially in the next couple of decades.[72]

Comparing these avoided costs with NU's fuel cost projections, it is clear that cogeneration would be much more economically viable in the future than at present. The 1987 avoided energy cost is equivalent to 1% sulfur #6 oil at a 10123 BTU/kWh heat rate: a good cogenerator would operate at a heat rate around 5000 BTU/kWh, which leaves a margin of about 1.9 cents per kWh to pay off fixed costs. NU's projection for avoided energy cost in the year 2000 is equivalent to 1% sulfur #6 oil at a heat rate of 11960 BTU/kWh: about 8.6 cents/kWh (or 3.8 cents/kWh in 1986 dollars) would be available to pay for the cogenerator's non-fuel costs. Between 1987 and 2000, the amount available to pay for the non-fuel costs of cogeneration is projected to double in real terms. These results are calculated in Table 5.7.

Q: Does NU now project only 547 MW of cogeneration and small power production?

A: No. IR-AG-8-32 indicates that NU expects that around 2000 MW will be developed.

Q: Does NU present justification for the decline in QF capacity shown in Table 5.1 and on page of Exhibit EJF-I-5?

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72. It is my understanding that the CPUCA has ordered higher rates than these for CL&P purchases from cogenerators.

A: The only rationale given is that QF capacity is removed at the end of the current contract. This is hardly realistic: most of these facilities will be around after the end of the contract period.

## 5.3 The Value of Millstone 3 Capacity to NEPOOL

Q: When would Millstone 3 be required for reliability by NEPOOL?

A: Millstone 3 would not be needed for the next few years to meet NEPOOL's reliability targets. When Millstone 3 enters service, it will to some marginal extent increase the reliability of the NEPOOL generation system. This reliability is expected to be more than adequate for several years to come, into the early 1990's, although there is certainly some benefit from increased reliability in the interim. Once NEPOOL reserve margins shrink to the merely adequate range, the presence of Millstone 3 on the system would allow the deferral of other measures to increase reliability, such as construction of new capacity, purchase of power from outside the region, or continued maintenance of existing capacity.

Q: What is the reliability value of Millstone 3 to NEPOOL?

A: The value of Millstone 3 (or any other large nuclear unit) to NEPOOL is considerably less than its value, under NEPOOL capability responsibility formulas, to the individual NEPOOL members which own that plant. Nuclear plants contribute relatively little to reliability for two reasons. First, due to their large maintenance requirements, nuclear units are often not available when needed.[73] Second, due to the large size of new nuclear units, sufficient reserves must be provided to back up the simultaneous loss of a thousand megawatts or more. As a result, even with the same forced outage rates, large plants require more reserve capacity than small plants.

Analyses performed by NEPOOL indicate that nuclear units only support load of about 50% of their rated capacity, and therefore require an incremental reserve margin of close to 100%. This is demonstrated in Table 5.8. The actual size effect would be even more pronounced, since the reliability of large nuclear units is less than NEPOOL assumed.

Table 5.11 presents my own analysis of the reliability of Millstone 3 and of the reliability alternatives I discussed above. The Table estimates for each type of plant the amount of additional load it allows NEPOOL to support. This additional load, technically called the Effective Load Carrying Capability (ELCC) of the unit, is calculated from the formula developed by Garver (1966). Garver's formula does not recognize any reliability effects of maintenance requirements, and therefore probably overstates the ELCC of nuclear plants, with their large (and inflexible) refueling outages. I have used NU's projection of forced outage rate

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73. For the same reason, forced outage rates, which are included in the NEPOOL responsibility formula, make nuclear units less reliable.

(FOR) for new CTs, and FORs for each existing unit (or plant type) based on recent experience.[74] The historical data is presented in Tables 5.9 and 5.10. Other than the size of the unit and its FOR, Garver's formula requires a measure of system size (which he calls m): I have estimated this parameter as 425 MW for the NEPOOL system, from the NEPLAN report 'Review Of The NEPOOL Reliability Criterion With Respect To The Required Amount Of Installed Generating Capacity' (December, 1984). The result of Table 5.11 is that one megawatt of capacity in the smaller units will replace 1.9 to 2.3 MW of Millstone 3.

The results of Table 5.11 would mean that, in terms of replacing the reliability value of Millstone 3, the extensions and refurbishments would provide roughly twice[75] the extended capacity calculated in Table 5.2. Recognizing the real reliability benefit of these smaller plants, new combustion turbines would not be needed until 1994, and then only an additional 320 MW is required (270 MW in 1994 and 50 MW in 1995). The short-term purchase in 1989 would be totally unnecessary.

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74. For CTs and other units which are on reserve status for many hours of the year, reported FOR's (which compare outage hours to service hours) are not very useful. In these cases, I have calculated FOR as (1-availability).

75. The average of the ELCC ratios for units and groups extended in Table 5.2, is 2.1781

Therefore, Millstone 3 has a much smaller reliability benefit for NEPOOL than it does for NU. The apparent value of the unit to NU is the result of a subsidy from other NEPOOL members, who will have to support higher reserve margins due to Millstone 3.

### 5.4 Summary of Millstone 3 Reliability Benefits

Q: Do the reliability benefits of Millstone 3, as you have estimated them above, justify the cost of Millstone 3?

A: No. Reliability considerations, standing alone, would justify WMECO annual cost recovery for Millstone 3 of less than $1 million through the end of the decade, even based on its inflated value to NU under the NEPOOL agreement.

Q: Does this conclusion indicate that NU has erred in deciding to build Millstone 3, rather than extending the lives of existing plants, and building new CTs?

A: Not necessarily. In the next section, I will consider the fuel savings of Millstone 3. In principle, the lower fuel costs of a new base-load plant can justify its higher cost, compared to existing units or new peakers.

Q: Does your analysis indicate that NU should not retire the plants presently scheduled for retirement?

A: Not necessarily. Now that Millstone 3 has been built, the reliability value of existing units may be surplus to the needs of NU or NEPOOL. However, the units (especially the CTs) represent very inexpensive sources of reliability support, and should not be hastily discarded. Before any irreversible decisions are made regarding the retirement of any of the existing units, NU should be very sure that it will not need the capacity over the next 15-20 years, and should attempt to market this very inexpensive capacity to other utilities. This may not be as important a consideration for NU as for some other utilities, since "retirement" means something different to NU than to other utilities. NU's decisions to "retire" CTs in the past have proven to be reversible, and NU anticipates maintaining most assets of the steam plants it is retiring, for future use as combined cycle facilities.

## 6 THE ECONOMIC BENEFITS OF MILLSTONE 3

Q: You have explained why Millstone 3 will have very limited reliability benefits. What is the unit's major benefit to WMECO and the NEPOOL system?

A: In the light of its much higher cost per kW than other capacity, it is clear that Millstone 3 has been built almost exclusively for fuel displacement purposes. Like all nuclear units, it will provide lower fuel costs than the fossil-fueled plants which dominate NEPOOL's power supply.

Q: Have you analyzed the overall cost-effectiveness of Millstone 3, including its benefits for fuel displacement?

A: I have compared the cost of Millstone 3 under WMECO's phase-in proposal, to the value of power it would displace, under a variety of assumptions regarding Millstone 3 cost and reliability, and regarding the value of the capacity and energy it provides.

Q: How much lower than fossil fuel costs will the fuel cost of Millstone 3 be?

A: Table 6.1 lists, and Figure 6.1 displays, NU projections for Millstone 3 fuel costs and the fuel costs of the fossil (primarily oil-burning) plants it would be backing out, and the differences between those costs. The projected differential starts in 1986 at about 4 cents per kWh, and rises to 15 cents per kWh by 2000, and to 88 cents/kWh in 2024. These savings would be substantial, if they occurred, but they come at the even greater cost of building and operating Millstone 3.

Q: How cost-effective is Millstone 3 under WMECO's current assumptions?

A: WMECO does not present this information in its filing, as it did in Docket 84-25. However, WMECO's responses to information requests indicate that even NU expects that the costs of Millstone 3 will exceed the benefits of the unit for much of its useful life.

Q: How do WMECO's data support the conclusion that Millstone 3 will not pay for itself soon?

A: In Table 6.2, I provide projections of the rate impact of Millstone 3 over its life, based on WMECO assumptions of cost, benefits, useful life, and load growth. Table 6.2 also provides a running simple total of the rate impact, and running discounted totals.[76] The discounted totals are computed at a discount rate of 14.05%, WMECO's estimate of its discount rate.

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76. I refer to these statistics as the "cumulative net cost" and the "discounted net costs", respectively. Discounting is necessary to make the costs and benefits in various years comparable: a dollar in 1995 is worth less than one in 1986.

Even without discounting the cash flow, Millstone 3 would increase rates for WMECO customers in every year through 1996. By 1997, the first year the plant would cost less than it saved, consumers would have paid out over $470 million extra. Discounting the costs and benefit makes the situation much worse: when Millstone 3 reaches its scheduled retirement date, the present value of the rate effects is equivalent to a $129 million loss in 1985. Thus, based on WMECO's own assumptions, Millstone 3 does not have positive present value benefits for its customers. The annual net benefits, the cumulative total, and the discounted totals are plotted in Figure 6.2.

The final column of Table 6.2 computes the value of WMECO's Millstone 3 investment, net of its operating costs. The capital investment in Millstone 3 will be worth something each year, if NU's projections of costs and savings are correct. The net value of Millstone 3 starts at several million dollars annually in the 1980's, and rises to half a billion dollars in each of the last few years of the unit's life. The present value of the investment at 14.05% is $264 million.

Q: Are Table 6.2 and Figure 6.2 entirely the work of WMECO?

A: Almost. The only differences between Table 6.2 and WMECO's response to IR-AG-2-42 and 2-43, is the fact that I have computed annual net benefits, running simple and discounted totals, the value of the capital investment, and present values.

Q: Do any WMECO analyses reach similar conclusions to those you have described above?

A: Yes. IR-COAL-1-12 indicated that the present value of Millstone 3 costs and benefits through 2005 would be a $180 million loss, as compared to the $210 million loss shown in Table 6.2. The same response show that the crossover year (when cumulative net benefits start to become less negative) is 1996, as in Table 6.2. Similarly, IR-COAL-1-11 shows that retail rates would be higher with Millstone 3 than without it, each year through 1997, at the most recent DRI fuel price forecasts, and ignoring capacity costs.[77]

Q: Does Table 6.2 present a reasonable projection of the costs and benefits of Millstone 3?

A: No. WMECO's assumptions are biased in favor of Millstone 3 in several ways:

1. The projection of avoided capacity costs assumes that NU would have taken some inefficient retirèment actions, even in the absence of Millstone 3.

2. WMECO's projections of avoided energy costs are premised on the inefficient and implausible assumption

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77. Table 6.6 shows crossover in 1997 with the new DRI fuel costs and with WMECO's replacement capacity costs.

that, had Millstone 3 not been built, all of its capacity, and much of its energy, would have been replaced by gas turbines.

3. WMECO's assumptions regarding Millstone 3 capacity factors imply considerably better performance than would be indicated by recent experience.

4. WMECO assumes that Millstone 3 non-fuel O&M expenses and capital additions will be considerably lower than would be indicated by recent experience and trends.

5. WMECO assumes that Millstone 3 will experience a very long life, and that current estimates of decommissioning costs will prove correct 40 years in the future.

Q: Have you performed any other total-cost analyses?

A: I have modeled the annual costs of Millstone 3 to ratepayers for several sets of alternative cost and benefit assumptions. The inputs on which these analyses are based are the WMECO projections listed in Table 6.2, which I have labeled Case 1. In the other cases, which are based on the results of my review of NU's projections for Millstone 3 (described in Section 7 of this testimony) and my review of alternative capacity plans (from Section 5), I have adjusted WMECO's projections to reflect more realistic assumptions, or at least assumptions more consistent with experience to date.

Q: What other cases have you analyzed?

A: I have repeated the previous calculations for five other cases:

- Case 2, which uses WMECO's assumptions, except for the substitution of more realistic capacity factors for NU's optimistic capacity factor estimates;

- Case 3, which uses the fuel cost savings calculated in Case 2, and also partially corrects for WMECO's optimism in the cost of running Millstone 3, by replacing WMECO's assumptions regarding certain operating costs with my estimates from Sections 7.2 and 7.3, resulting in annual capital additions about three times as large as WMECO assumes, and station O&M expenses which continue to escalate at something like historical rates;

- Case 4, which estimates more likely benefits for Millstone 3 by replacing NU's avoided capacity costs with my estimates from Section 5;

- Case 5, which replaces the production cost projections used in WMECO's filing with projections based on the latest DRI fuel price forecast;

- Case 6, which replaces the production cost projections used in WMECO's filing with projections based on the fuel price forecasts NU was using in 1978; and

- Case 7, which replaces the production cost projections used in WMECO's filing with projections based on the fuel price forecasts NU was using in 1980.

The results are shown in Tables 6.3 through 6.8, and in Figures 6.3 through 6.8.

It is important to recognize that all of these cases use WMECO's very optimistic assumptions that Millstone 3 will last 39 years, and that the present estimate of the cost of decommissioning will prove correct 40 years hence. The recovery of depreciation and decommissioning costs, even under traditional ratemaking, is determined by the Commission based on projections of conditions far in the future, generally based on utility requests for cost recovery. I expect that WMECO will eventually ask the Commission for higher decommissioning allowances and higher depreciation rates, but I do not know when these requests will occur. Nor am I prepared to project the Commission's response to such requests. Therefore, I have used WMECO's projections of depreciation and decommissioning expenses, which are likely to be the booked expenses for the immediate future, in the absence of any unusual action by the Department.

Also, I have relied on WMECO's production costing runs, which produce avoided energy costs that grow much faster than fuel prices. As discussed above, this inconsistency apparently results from the assumption that much of the replacement energy for Millstone 3 would come from new peaking plants, and that no additional fuel-saving capacity would be added (or even purchased) to back out those turbines, regardless of how high NU's avoided costs rose.

Q: Please describe the results of Case 2.

A: Case 2 is presented in Table 6.3. Due to the lower capacity factors, system savings are lower in every year than they are in Case 1. As a result, net benefits are consistently lower. Net benefits first become positive only one year later than in case 1 (1997, rather than 1996); they are also more negative before that date, and less positive afterwards, compared to the NU case. Since net benefits are consistently lower, so is the cumulative total, which reaches a loss of more than $500 million by the crossover point, and does not reach simple breakeven until 2011, five years later than in Case 1. The discounted net benefits are also more negative, equivalent to a loss of $200 million through 2024. The value of the capital investment is $188 million, 30% lower than in Case 1.

Q: Do the cost-effectiveness results change substantially in Case 3, when the operating costs are adjusted to more realistic values?

A: Yes. This Case presents projections of the benefits of Millstone 3, based on continuation of historical trends in nuclear O&M costs and in capital additions. The effect on Millstone 3 economics of continuation of operating cost trends, combined with the savings estimates of Case 3, is remarkable. Even with rather small increases in cost projections, the benefits of Millstone 3 cover its operating costs only sporadically in the early years of plant life. From 1993 to 2000, savings exceed operating costs, but rising O&M produces negative net operating benefits each year in the next century. The net value of the capital investment would be very slightly negative, if the plant operated until 2024, but continuation of these historical cost trends would result in Millstone 3 being retired earlier, producing slightly positive lifetime operating benefits.

Since the benefits of the plant barely cover its operating costs, they will certainly not cover the capital recovery charges. Net benefits are negative for every year of the projected useful life of Millstone 3. Depending on when the unit is retired, its net present-value burden to WMECO ratepayers would be $350 to $400 million.

Q: What is the effect on Millstone 3 economics of replacing NU's capacity value estimates with yours?

A: Table 6.5 presents the results of Case 4, which is identical to Case 1, except that I have substituted my estimate of the capacity costs avoided by Millstone 3. Since the difference in capacity cost projections is small, so is the difference in rate effects: Case 4 represents an increased net cost to customers of only about $11 million over the life of the unit.

Q: What are the results of changing the system production costs to those based on more recent, or earlier, fuel price projections?

A: Table 6.6 indicates that the general pattern of benefits is changed only slightly by updated fuel cost projections, in Case 6. Compared to Case 1, cross-over is delayed one year, simple breakeven is delayed three years, and Millstone 3 benefits still cover its operating costs in every year. However, since the pattern of lower benefits is so persistent, net benefits and net operating benefits are reduced by about $50 million. Under NU's proposed capital recovery, the ratepayers experience a $180 million loss: the capital investment is worth only $213 million of the $393 million NU wants to charge ratepayers in present-value terms.

Q: Would the economics of Millstone 3 have looked very different during the period construction was slowed down?

A: Table 6.7 shows that the economics of Millstone 3, compared to NU's alternative supply plan proposed in this case, would have appeared much more favorable at the fuel price projections of 1980, in Case 6.[78] Even with NU's proposed phase-in, the costs of Millstone 3 would have exceeded its savings each year from 1987 through 1991, and simple breakeven would not be reached until 1994. But since fuel

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78. Table 6.7 and 6.8 use NU estimates of system production savings from IR-AG-8-26, and NU assumptions for Millstone 3 capacity factors and operating costs.

prices were expected to be rising so rapidly, discounted breakeven would be achieved just one year later, in 1995, and the unit would have cumulative present-value savings of $580 million.

Table 6.8 performs the same calculations for 1978 fuel price projections, Case 7. These results are better than those for Case 1, but not dramatically different. Crossover occurs one year earlier, simple breakeven occurs two years earlier, and the cumulative net cost to ratepayers is reduced to $55 million.

The benefits of both of these Cases are calculated with respect to NU's current expansion plan, which involves extensive reliance on existing oil-fired plants, and the replacement of Millstone 3 with combustion turbines. This alternative expansion plan would not have been pursued if Millstone 3 had been abandoned in the late 1970's or early 1980's, especially if oil prices had followed the 1980 forecasts for long. At higher oil prices, and with longer lead times, NU would have built more new coal plants, converted more existing units to coal, or otherwise reduced its dependency on oil. Therefore, the benefits shown in Tables 6.7 and 6.8 are not really realistic.

Q: Please summarize the results of your cost-benefit analyses for Millstone 3.

A: Table 6.9 compares the costs of power from Millstone 3, and the value of that power, annually and on a levelized basis, for each of the Cases presented above. Many Cases share the same cost or benefit assumptions, reducing the number of columns necessary in Table 6.9. The levelized costs of Millstone 3 range from 13 to 17 cents per kWh, depending on the assumptions, while the benefits vary from 8.5 to 9.8 cents in the contemporaneous cases.[79] In general, the benefits are heavily weighted towards the later years of the unit's life, while WMECO's proposed charges to ratepayers are concentrated in the early years of Millstone 3 operation.

Table 6.10 summarizes some measures of cost-effectiveness for each of the seven Cases: the years of crossover and of simple breakeven, the cumulative net benefit to ratepayers at crossover, and the net present benefit through 2024 (at the 14.05% discount rate). Millstone 3 will never pay for itself at current fuel price projections: even with 1980 oil price projections, the plant would have increased the present value of rates through 1994.

Q: Are the breakeven points applicable to individual customers or only to ratepayers as a whole?

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79. At 1980 fuel price projections, and assuming NU's current expansion plans, Millstone 3 power would have been worth 24 cents/kWh. Of course, at those oil prices, other power supply sources would have been developed to replace Millstone 3, so the system savings comparison would not have been particularly relevant.

A: The dates I calculated may be meaningful for all ratepayers collectively, but not individually. Due to load growth (if WMECO and NU are correct in projecting continued load growth), the later benefits of Millstone 3 will be diluted moré than the early costs, and only customers whose loads grow at the same rate as the system as a whole will break even at these dates. New customers and those with rapidly increasing energy consumption will realize more positive cumulative benefits than I calculated, while customers who conserve in response to the high rates caused by Millstone 3 will be even worse off than the system as a whole. Customers who leave the system before their breakeven date end up with a net loss, regardless of what happens to ratepayers as a group.[80]

Q: Do these results indicate whether Millstone 3 would be a good investment under conventional ratemaking treatment for the customers who pay for its early years?

A: The particular cases I presented above were selected from a wide range of possible outcomes. It is clear from the analysis that Millstone 3 will be very expensive in its early years, as compared to its benefits, and that, under any

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80. The elderly and economically tenuous businesses are particularly likely to pay for Millstone 3 without receiving commensurate benefits. In the case of industrial or commercial customers which are already under financial pressures, the rate increases from Millstone 3 might be the last straw, ensuring that they will not survive to reap whatever benefits the system receives late in the unit's life.

likely projection, Millstone 3 will have negative net benefits for WMECO (or other NU) ratepayers over its life. For some plausible projections of future plant performance, of operating cost levels and trends, and of operating benefits, Millstone 3 would never save money for WMECO's customers, even in a single year.

WMECO's projections represent about the most favorable case which can be made for Millstone 3 economics. Yet even under WMECO's assumptions, ratepayers carry a very heavy burden for a very long time before they start to see any net reward from Millstone 3. A customer with a zero discount rate would be worse off for the first 20 years of Millstone 3 operation (if he or she remained on the system that long): under any plausible discount rate, including that used by NU, Millstone 3 will be highly uneconomic over its entire life. It is hard to say what a comparable "worst case" would look like, but a continuation of historical trends in operating characteristics,[81] combined with a slightly more efficient capacity plan, indicates that Millstone 3 is likely to be a complete economic disaster, under conditions which are much better than the "worst case".

Q: What can be concluded from these analyses?

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81. Recall that my projections incorporate improvements over recent experience: capacity factors are assumed to improve considerably from 1984 levels, only half of the observed deterioration in performance after age 12 is included, and the compound growth in real O&M costs is assumed to become linear.

A: First, even using WMECO's own assumptions and projections, Millstone 3 will not save money for WMECO customers as a whole, even if they were willing to wait forty years. Second, given WMECO's own projections, current customers would be better off if Millstone 3 had never been started, or had been canceled or sold off long ago. Third, if Millstone 3 cost and performance are consistent with past experience and trends, it will continue to be a net loss for all ratepayers, even those who are on the system only late in the plant's life. Fourth, if Millstone 3 benefits exceed its costs for any extended period of time, that period will start well into the next decade, or more likely, the next century.

Q: Are large rate increases such as those required by conventional ratemaking for Millstone 3 a normal and necessary result of commercial operation of large units?

A: No. According to WMECO, each of its previous nuclear units saved more than it cost from its first year of operation (IR-AG-2-1).

## 7 THE COST OF POWER FROM MILLSTONE 3

Q: What cost parameters have you examined for Millstone 3?

A: I have attempted to determine realistic estimates for the capacity factor of Millstone 3 and for the various costs of running the unit, including non-fuel O&M and capital additions. I have also reviewed NU projections for decommissioning costs and for the useful life of Millstone 3. Based upon analyses of historical performance and trends:

1. While NU projects capacity factors beginning at 60% and rising to 70% for Millstone 3, the capacity factors (based on design rating) will more likely average about 56% in the first four years, 61% in the mature years, and 50% after 12 years.

2. Non-fuel O&M has been escalating much faster than general inflation, at about 12-14% in real terms, while NU is projecting essentially no real increases. This trend has persisted for many years and may well continue.

3. If historical rates of additions apply to Millstone 3, the capital cost of the plant will also increase significantly during its lifetime. NU projects that capital costs will increase into the 1990's, and then decrease to nothing by 2006.

4. Decommissioning also must be expected to cost more than NU currently estimates.

5. NU is projecting that Millstone 3 will operate for more than twice as long as any large (that is, over one fifth of the size of Millstone 3) domestic nuclear unit has to date, and nearly twice the median life of the small units commissioned in the early 1960's.

Detailed analyses of these cost components are presented below, including comparisons of my estimates to those of NU.

## 7.1 Capacity Factor

### 7.1.1 Measuring and Comparing Capacity Factors

Q: How can the annual kilowatt-hours output of electricity from each kilowatt of Millstone 3 capacity be estimated?

A: The average output of a nuclear plant is less than its capacity for several reasons, including refueling, other scheduled outages, unscheduled outages, and power reductions. Predictions of annual output are generally based on estimates of capacity factors. Since the capacity factor projections used by NU are rather optimistic, it may be helpful to consider the role of capacity factors in determining the cost of Millstone 3 power, before estimating those factors.[82]

The capacity factor of a plant is the ratio of its average output to its rated capacity. In other words

$$CF = Output/(RC \times hours)$$

where CF = capacity factor, and

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82. This portion of my testimony will also discuss some common errors in utility treatment of nuclear capacity factors, and some of the justifications utilities have offered in previous proceedings for projecting capacity factors which exceed historical experience. Including this material in my direct testimony may simplify surrebuttal on capacity factors, if that is required.

RC = rated capacity.

In this case, it is necessary to estimate Millstone 3's capacity factor, so that annual output, and hence cost per kWh, can be estimated.

On the other hand, an availability factor is the ratio of the number of hours in which some power could be produced to the total number of hours.

The difference between capacity factor and availability factor is illustrated in Figure 7.1. The capacity factor is the ratio of the shaded area in regions A and B to the area of the rectangle, while the availability factor is the sum of the width of regions A, B, and C. Clearly, if the rated capacity is actually the maximum capacity of the unit, the availability factor will always be at least as large as the capacity factor and will generally be larger. Specifically, the availability factor includes the unshaded portion of region B, and all of region C, which are not included in the capacity factor.

Capacity factors are also often compared with equivalent availability factors (EAFs). EAF is a subjective measure, reported by the operating utility and representing only the utility's opinion of what the unit might have done, if not for factors which the utility may wish to consider to be "economic". These "economic" factors include, for example, reductions in output to delay a refueling outage until other nuclear units have completed maintenance or repair procedures. Furthermore, the calculation of EAF assumes that the unit would have run perfectly if not for the "economic" limitation. Utilities frequently assume that new units will have capacity factor similar to historical EAFs, rather than historical CFs. Under the best of conditions, EAF is a performance measure of limited usefulness, due to its subjective nature.

Even if EAF were not such a flawed measure, there is little reason to believe that historical EAFs would provide better (or even as accurate) predictors of Millstone 3 CF than would historical CFs. While utility terminology often suggests that EAFs differ from CFs only because of "load following" and "load leveling", essentially all nuclear units in the US are base-loaded, and the difference between EAF and CF is rarely due to load following, per se.

Perhaps the differences between CF and EAF can best be illustrated by examining the EAFs and CFs reported for existing NEPOOL nuclear units. These units operate under conditions similar to those Millstone 3 will face. The available data for CF and EAF (taken from an EPRI report) are listed in Table 7.1: there are sizable differences between EAF and CF for existing nuclear units in the pool, despite baseload operation and a much less nuclear-rich mix of capacity than will exist with Seabrook and Millstone 3 in service. It is clear from Table 7.1 that EAFs are useless for predicting capacity factors for NEPOOL nuclear units: it appears likely that Millstone 3 will report EAFs higher than its CFs, at least in some years.

Q: What is the appropriate measure of "rated capacity" for determining historical capacity factors to be used in forecasting Millstone 3 power costs?

A: The three most common measures of capacity are

Maximum Dependable Capacity (MDC);

Design Electric Rating (DER); and

Installed or Maximum Generator Nameplate rating (IGN or MGN).

The first two ratings are used by the NRC, and the third by FERC.

The MDC is the utility's statement of the unit's "dependable" capacity (however that is defined) at a particular time. Early in a plant's life, its MDC tends to be low until technical and regulatory constraints are relaxed, as "bugs" are worked out and systems are tested at higher and higher power levels. During this period, the MDC capacity factor will generally be larger than the capacity factor calculated on the basis of DER or MGN, which are fixed at the time the plant is designed and built. Furthermore, many plants' MDCs have never reached their DERs or MGNs.

Humboldt Bay has been retired after fourteen years, and Dresden 1 after 18 years, without getting their MDCs up to their DERs. Connecticut Yankee has not done it in 16 years; nor Big Rock Point in 19 years; nor many other units which have operated for more than a decade, including Dresden units 2 and 3, and Oyster Creek. For only about one nuclear plant in five does MDC equal DER, and in only one case (Pilgrim) does the MDC exceed the DER. Therefore, capacity factors based on MDC will generally continue to be greater than those based on DERs, throughout the unit's life.

The use of MDC capacity factors in forecasting Millstone 3 power cost would present no problem if the MDCs for Millstone 3 were known for each year of its life. Unfortunately, these capacities will not be known until Millstone 3 actually operates and its various problems and limitations appear. All that is known now is an initial estimate of the DER, which is 1055 MW.[83] Since it is impossible to project output without consistent definitions of Capacity Factor and Rated Capacity, only DER and MGN capacity factors are useful for planning purposes. I use DER capacity factors in my analysis.

Actually, DER designations have also changed for some plants. The new, and often lower, DERs will produce different observed capacity factors than the original DERs. For

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83. NU may also have published an estimate of the MGN capacity of the unit, but I have not seen it.

example, Komanoff (1978) reports that Pilgrim's original DER was 670 MW, equal to its current MDC, not the 655 MW value now reported for DER. Therefore, in studying historical capacity factors for forecasting the performance of new reactors, it is appropriate to use the original DER ratings, which would seem to be the capacity measure most consistent with the 1055 MW expectation for Millstone 3. This problem can also be avoided through the use of the MGN ratings, although MGN ratings tend to be nominal, with limited relation to actual capability.

### 7.1.2 Projecting Millstone 3 Capacity Factors

Q: Are NU's projections of Millstone 3 capacity factors appropriate for use in cost-benefit analyses, as in Exhibit EJF-I-5?

A: No. Achievement of the capacity factors NU has projected is highly unlikely, if not completely inconceivable. NU assumes that Millstone 3 will exceed previous performance for similar reactors.

Q: How have you determined the expected capacity factor performance of Millstone 3?

A: I have conducted a series of regression analyses of actual PWR capacity factors, and they are fully explained in Appendix E. The data is listed in Appendix B, and the results of my regressions are given in Table 7.2. Projections for Millstone 3 performance, based on those results, are presented in Table 7.3. As shown in Table 7.2, I incorporated the following variables:

1. an indicator for units of more than 600 MW,

2. unit age, with maturation assumed at 5 years,

3. an indicator of unit age greater than or equal to 12 years,

4. the portion of a refueling or other major outage which occurred in the year, usually taking the values of 0 or 1, and

5. indicators for each year since 1979.

Data were available for 397 full calendar years of operation at all PWRs from 1973 to 1984. A small amount of pre-1973 operating experience could not be used for lack of refueling data.

Equation 1 demonstrates that PWR performance in 1984 was better than in the five previous years, each of which had demonstrated lower performance than the pre-1979 period. The worst performance occurred in 1983 (7.9%). Since no time pattern was evident in the results of Equation 1, I grouped the post-1978 data as a single dummy variable in Equation 2, which shows that performance in 1979 and in the early 1980's has averaged 4.9 percentage points below 1970's performance. In both regressions,

- large PWR's had capacity factors about 12 points lower than small (400-600) units,

- maturation increased capacity factors by about two points annually until age five,

- old units (over age 12) performed about 22% points below mature units in the 5-11 year range,

- refueling decreased capacity factor by about 9%, and

- units with 44" Westinghouse turbines performed almost 5 point below other units.

Table 7.3 provides the projections of Equations 1 and 2 for Millstone 3, under two sets of assumptions: first, that it operates at the levels demonstrated in the pre-1979 period (and 1984), and second, that it operates only as well as the average of PWR performance in the 1979-84 period.[84] Depending on the Equation, and even more on the assumption regarding the relevant period for extrapolation, the mature capacity factor before age 12 ranges from 58% to 64%. The "old age" capacity factor, after year 12, ranges from 47% to 53%, assuming that Millstone 3 will experience only half the degradation experienced to date at other old PWRs.

Q: What capacity factor value should be used in estimating Millstone 3 power cost?

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84. For simplicity, I have treated Millstone 3 as if it were on line for all of 1986. This treatment slightly increases the projected performance in the 1986-1990 period.

A: Many reasonable regression lines can be drawn through any data set. Mature capacity-factor estimates for units like Millstone 3 would seem to lie in the range of 58% to 64% based on regression analyses of the historical record. There is a great deal of variation from the average, however; the regressions typically explain less than a third of the variation in the data, and Easterling (1979) derived 95% prediction intervals of about 8% for years 2 to 10 at 1100 MW PWRs. Actually, the variation would be somewhat larger, due to the greater variation in the first partial year and the first full year.[85]

Predicting the future effects of regulation, of safety issues, and of aging is difficult at best. Projecting Millstone 3 performance based on the variables used in my equations raises such difficult questions as:

- Does a plant's performance really stabilize after year five, and then begin deteriorating after age 12, as represented by AGE5 and AGE_12? What will be the long-term deterioration in capacity factor after age 12?

- Did 1984 mark a recovery from the deterioration in performance seen during the previous five years, will performance continue at average 1980's levels, or will it settle at some intermediate level?

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85. On the other hand, some of the apparent variation may result from the timing of refuelings, which would tend to average out for any individual unit.

For the purposes of this analysis, I have assumed that long-run PWR performance will fall between pre-1979 and post-1979 levels. I have also assumed that only half of the past deterioration in performance by units over age 12 will be observed for Millstone 3.

Thus, I have based my projections on an average of the results of Equations 1 and 2, evaluated at pre-1979 and then average 1980's conditions, and with the AGE_12 variable set equal to zero for units less than 12 years of age, and 0.5 for older units. I have also assumed that Millstone 3 will refuel in every year except the first. Thus, I believe the best current estimates for Millstone 3 are 60%, 53%, 55%, 58% and 60% in years one to five, respectively (averaging 57%), an average of 61% in years six to eleven, and an average of 50% thereafter. This calculation is shown in Column [5] of Table 7.3.

Q: Are NU's projections for Millstone 3 capacity factor reasonable?

A: No. To compare the accuracy of the capacity factors I derived above, and NU's projections, to actual results, I have performed the calculations presented in Table 7.4. For the ten PWRs over 1000 MW which had entered service by 1983, the average capacity factor as of September 1985 was 56.1%. The capacity factor estimates which I derived in Table 7.3 predict an average of 55.4%, while NU would predict an average of 65.8%. Clearly, NU's expectations are highly optimistic. The actual ten-unit average will vary with refueling schedules, and has much less data than I used in my regressions. At the very least, the actual data supports the conclusion that NU's projections significantly overstate the capacity factors of large PWR's. On the other hand, my results closely approximate actual capacity factors, based on average historical conditions.

Q: Have you performed any analyses on the data from these large PWRs, on an annual basis?

A: Yes. Table 7.5 presents the annual capacity factors for the units used in the previous analysis, through December 1984. No other large (over 1000 MW) PWRs had completed a full year of commercial operation as of the end of 1984. I have assumed that the very low capacity factors for Trojan in 1978 and Salem 1 in 1979 are not generated by the same sort of random process which accounts for the other variation in nuclear capacity factor.[86] However, there is no reason to believe that some comparable (if not exactly identical) problem can not occur for Millstone 3. Hence, I delete these two observations from the individual year calculations, and instead reflect the probability of a major problem by computing the average effect. Compared to the results for all the other plants, this event reduced capacity factors by a total of 60.1 percentage points from second year

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86. A previous study by NU (Calderone 1982) identified these outages as deserving special treatment.

performance, in 61 unit-years of experience, for a 1.0% reduction in all capacity factors. The average capacity factor which results from this analysis is about 57% for the first four years, with a mature capacity factor (from year five) of 55%. This analysis indicates that NU's projections for Millstone 3 capacity factor are much higher than the actual performance of large PWRs.

Q: Is it appropriate to include the period since 1979, when the TMI accident and subsequent regulatory actions affected nuclear plant operation, in the analysis of nuclear capacity factors?

A: I believe that it is. Several more major nuclear accidents or near-misses are likely to occur before the scheduled end of Millstone 3 operation. Various recent estimates of major accident probabilities range from 1/200 to 1/1000 per reactor year (See Chernick, et al., 1981; Minarick and Kukielka, 1982). These estimates are based both on the implicit probability assessments of nuclear insurers, who must actually bet their own money on being correct, and on engineering models of actual reactor performance. Thus, major accidents can be expected every two to ten years once 100 reactors are operating. If anything, the 1968-84 period has been relatively favorable for nuclear operations.

## 7.2 Non-Fuel Station O&M

Q: How have you estimated non-fuel O&M expense for Millstone 3?

A: I have examined the available historical data on nuclear O&M for domestic nuclear plants. Appendix D lists the non-fuel O&M for each U.S. nuclear plant for each full operating year from 1968 to the most recent available data. Plants were excluded from the analysis for years in which new nuclear units were added, so each observation represents a full year's O&M for a clearly defined number of units and of megawatts.

Table 7.6 presents the results of five regressions on all of the data in Appendix D for light water reactors, a total of 535 observations. Table 7.7 presents the results of the same five regressions using only the data for plants of more than 300 MW, from Appendix D. All costs are stated in 1983 dollars, deflated at the GNP deflator. A total of 457 observations were available for Table 7.7.

The equations in Table 7.6 indicate that real O&M costs for all plants have increased at about 12% annually, and that the economies-of-scale factor for nuclear O&M is about 0.50, so doubling the size of a plant (in Equations 1 and 2) or of a unit (in Equations 3 - 5) increases the O&M cost by about 40%. Equations 1 and 2 indicate that, once total plant size has been accounted for, the number of units is inconsequential, and the effect on O&M expense is statistically insignificant. Equations 3 and 4 both measure size as MW per unit, and they both find that the effect of adding a second identical unit is about the same as the effect of doubling the size of the first unit: 47% for Equation 3 and 35% for Equation 4.[87] Equation 5 tests for extra costs in the Northeast, which are commonly found in studies of nuclear plant construction and operating costs, but is otherwise identical to Equation 3. Indeed, there is a highly significant differential: Northeast plants cost 32% more to operate than other plants (using the definition of North Atlantic from the Handy-Whitman index). I will use this Equation as the basis of my projection.

The results with the data set which excludes the smaller plants (Table 7.7) are quite similar: the most important difference is that the annual growth rate in large plant O&M is significantly higher than that of the overall data set. This effect would produce much larger O&M projections, if it were extrapolated out into the next century. There is no clear basis for choosing between the two data sets.

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87. The two equations do treat extra units differently after the second: a third unit increases costs by another 35% in Equation 4, but only by 26% in Equation 3. The treatment of additional units in Equation 3 seems more plausible, in that each succeeding unit should be progressively less expensive to run.

Q: What O&M projections would your regression results predict for Millstone 3?

A: Table 7.8 extrapolates the results for Equation 5 for a first unit of 1194 MW MGN,[88] and displays the annual nominal O&M cost implied for Millstone 3 over the period 1986 - 2024, which is NU's projection of the unit's useful life. Results are shown for both datasets. The same Table presents alternative projections from the historical data, assuming that the annual O&M expense increases linearly in real terms, at the real increment projected by Equation 5 between 1986 and 1987. Finally, Table 7.8 compares these results with NU's projections.

Q: Are NU's O&M projections reasonable?

A: Based on the historical data, NU's projections for Millstone 3 O&M are quite optimistic, even in the first few years: the 1987 value of $72 million is about 30% less than the projection from Table 7.8.[89] Since NU assumes that the persistent real escalation in nuclear O&M will abruptly end, even the most favorable projection I present (linear escalation, based on all plants) is twice as large as NU's

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88. In general, MGN ratings average about 4% greater than DER ratings.

89. Since the NU O&M projection is apprently intended to include non-station cost, such as decommissioning and A&G, the discrepency between the station O&M portion of that projection and my historically-based projection is even greater than 30%.

projection by the early 1990's, three times as large by the turn of the century, and five times as large by 2024. Thus, NU's long-term projection of Millstone 3 station O&M costs is inconsistent with historical experience, and is extremely optimistic.

Protracted geometric growth in real O&M cost at historical rates would probably lead to retirement of this plant (and most nuclear plants) fairly early in the century, as it would then be prohibitively expensive to operate (unless the alternatives were even more expensive than NU predicts). High costs of O&M and necessary capital additions were responsible for the retirement (formal or de facto) of Indian Point 1, Humboldt Bay, and Dresden 1, after only 12, 13, and 18 years of operation, respectively. Thus, rising costs caught up to most of the small pre-1965 reactors during the 1970's: only Big Rock Point and Yankee Rowe remain from that cohort. The operator of LaCrosse, a small reactor of 1969 vintage, has announced plans to retire it in the late 1980's.

On the other hand, our experience with nuclear O&M escalation stretches over only 17 years (1968-1984), so projecting continued constant real escalation past the year 2000 (another 16 years into the future) is rather speculative. It is more likely that the actual outcome will fall somewhere around the moderate real growth implied by my linear projections.

### 7.3 Capital Additions

Q: Is NU's estimate of capital additions to Millstone 3 reasonable?

A: No. NU projects annual capital additions (or interim replacements) which are considerably lower than experience would indicate.

Q: How did you estimate capital additions?

A: Appendix D lists annual capital additions for all plants for which cost data was available, from FERC Form 1 and DOE compilations of FERC Form 1 data (now reported on p. 403), through 1984. Each plant is included for all years in which no units were added or deleted, and for which the data were not clearly in error. The available experience totaled 520 plant-years of operation, and the average annual capital addition in the database was $20.7/kW expressed in MGN terms, or about $23.9 million annually for Millstone 3 in 1983 dollars.[90] The capital additions are deflated by the appropriate regional Handy-Whitman index for nuclear construction, which has itself increased at 1.4% above the

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90. The Millstone 3 capacity used in these calculations was 1153 MW, which is the unit's DER. The costs would be about 4% higher if evaluated at the MGN rating.

GNP inflation rate.[91] The July 1984 Handy-Whitman index was estimated by escalating the July 1983 index at the growth rate of the January index from 1983 to 1984.

Capital additions vary with a number of factors, and vary greatly from year to year, complicating statistical analyses. Review of the data indicates that:

- large plants have lower capital additions per kilowatt-year than do small plants,

- multi-unit plants have lower capital additions per kilowatt-year than do single-unit plants,

- Northeastern plants have higher capital additions than those in other parts of the country, and

- capital additions per kilowatt-year have generally been rising over time, despite the greater prevalence of large and multi-unit plants in the later data.

Figure 7.2 and Table 7.10 show the average capital additions for each year since 1972, for all plants, and for large single units. Levels of capital additions for both groups have increased over time, at least since the mid-1970's.[92]

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91. From 1970 to 1983, the GNP deflator rose from 91.45 to 215.63, for an annual rate of 6.8%. In the same period, the July Handy-Whitman nuclear index for Region 1 rose from 81 to 227, an annual increase of 8.2%.

92. The data for large single units in the early 1970's is from a very small sample.

Over the last seven years, the average for all plants was \$27.7/kW-yr: over the last five years, the average has been \$32.3/kW-yr. The rate of capital additions may have stabilized in the 1980's, or it may be increasing at about \$4/kW-$yr^2$. For the large single units, the corresponding averages are \$26.5 and \$28.8/kW-yr, with no clear upward trend since 1980 (other than a jump in 1984). If capital additions continue at \$28/kW-yr in 1983 Handy-Whitman dollars, and if the nuclear Handy-Whitman index continues to run 1.4 points above the GNP deflation (for which I use NU's projections of 5.5% from 1984-1991, and 6% thereafter), the annual capital additions for Millstone 3 would be as shown in Table 7.11, which also shows NU's projections of capital additions.

Some of the trend in the data may result from plant aging, and another portion is undoubtedly related to TMI-inspired regulatory changes, so extrapolating the trend out is somewhat speculative. However, there is some evidence of an overall upward trend in the period 1972-78, as well, so any TMI-related effect constitutes a continuation of the trend, rather than a unique event.

Q: Did you perform a regression analysis on capital additions data?

A: Yes. Appendix F contains a detailed description of the regression analysis and an interpretation of the results. The significance of the resulting regression equations is better than I had expected, and yields reasonable projections, also shown in Table 7.11. The similarity between the two separate methods of projection calculations is encouraging. As a further test of the usefulness of the regression equations, predicted capital additions costs for Millstone 1 and 2 were compared to the actual experience at the two operating units. Table 7.12 shows that the year-to-year residuals do vary a great deal, but on average the overall predictions are accurate.

Q: What are your recommendations with regard to projections of Millstone 3 capital additions?

A: I believe that it is prudent to assume that capital additions at Millstone 3 will continue at recent levels, starting at $42 million in 1987 and rising at 6.5% annually until 1991 and 7% annually thereafter.

By contrast, NU assumes annual capital additions of only $20.06 million from 1987-1992,[93] jumping to $30.09 million from 1993-2000, and actually decreasing to zero by 2006. Considering inflation, NU is projecting falling real capital additions throughout the plant's life: the 50% nominal increase in 1993 simply compensates for inflation from 1987. I see nothing in the historical record to suggest that the

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93. Since my cost data comes primarily from FERC returns, additions in the first partial year of commercial operation (which will be 1986 for Millstone 3) are usually counted as part of the plant construction cost.

need for capital additions is declining over time, or that zero capital additions will be required for the last 20 years of a nuclear unit's life.

## 7.4 Other O&M

Q: What other costs are included in NU's O&M category?

A: NU includes two items which are required by the operation of the plant, but are not generally included in station O&M:

- administrative and general (A&G) expense, and
- decommissioning.

Q: Are these costs projected reasonably?

A: I have not reviewed the basis for the A&G projection. The allowance for decommissioning is discussed in more detail below. Neither of these costs is likely to have any major influence on the overall economics of Millstone 3, at least in the first few years of its life. In the longer term, decommissioning may have a significant effect on costs.

Q: What allowance for decommissioning should be included in the cost of Millstone 3 power?

A: Chernick, <u>et al.</u> (1981) estimated that non-accidental decommissioning of a large reactor will cost about $250 million in 1981 dollars. This is equivalent to about $295 million in 1984 dollars, using the Handy-Whitman deflator. Assuming that the decommissioning fund accumulates uniformly (in constant dollars) over the life of the plant, and that it is invested in risk-free assets (such as Treasury securities) which have historically averaged a real return close to zero, the annual contribution (in 1984 dollars) would be about \$11.8 million per year over a 25 year life, or \$7.4 million annually for a 40 year life. The annual decommissioning charge would have to escalate at the rate of inflation.

Q: How does this compare to NU's assumed decommissioning cost?

A: NU uses a traditional engineering estimate of decommissioning costs for Millstone 3 of \$183.6 million in 1984 dollars. Decommissioning cost estimates have been subject to the same sort of errors and escalation as have estimates of nuclear construction and O&M costs. Experience with decommissioning has been limited to small units with little operating history. It is rather presumptuous to assume that the current engineering cost estimates will prove to be correct 40 years hence.

### 7.5 Millstone 3 Useful Life

Q: Is it reasonable to expect Millstone 3 to operate for 39 years?

A: No. There is simply no basis for this assumption. As I discussed above (page 185), three out of the five small commercial reactors which entered service in the early 1960's were retired by the time they reached age 18. The older and larger of the survivors, Yankee Rowe, has been in service since 1961, and is thus only 25.[94] The first units of more than 300 MW went commercial in January 1968: they have just reached age 18.

NU is projecting that Millstone 3 will survive more than twice as long as has the oldest domestic unit over 300 MW, and over 50% longer than the oldest domestic power reactor of any size. NU expects the unit to operate throughout this unprecedented life, at peak capacity factors, without any major life extension investments,[95] and without any real increases in O&M costs. This expectation contrasts strongly with NU's assumption that fossil-fired plants (which do not

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94. It is also only a 175 MW unit.

95. Indeed, NU's projections of capital additions are lower than actual costs for relatively youthful plants, and NU allows for no capital additions at all for the last 20 years of Millstone 3 life.

share Millstone's exposure to safety issues, structural degradation through irradiation, or radioactive accumulation interference with maintenance) require major investments to operate past 35 years of age, even if they have been operated only sporadically for several years.

While we may all hope that Millstone 3, and other nuclear units, will stay in operation for 40 years or more, at high availability levels and without need for major expenditures to prolong their lives, we must also accept the possibility that they will not survive for more than 25 or 30 years. Early retirement of Millstone 3 would deprive NU's customers of the years in which the plant is projected to be most cost-effective (if it ever pays its way), and leave them (or NU's shareholders) with a large liability for the undepreciated portion of the plant cost, and for the portion of the decommissioning cost not yet covered by the decommissioning fund.

## 8 PHASE-IN OPTIONS

Q: If the Commission does not disallow all or most of the costs WMECO has claimed for Millstone 3 in this case, how should the remaining costs be reflected in rates?

A: I would strongly urge the Commission to phase the costs into rates over an extended period, so that the costs are recovered in a time pattern which reflects the time pattern of benefits from the plant.

Q: Is the WMECO phase-in proposal adequate?

A: No. WMECO's proposal would require three successive annual increases of at least 9%, if the entire expenditure is allowed into rates and Millstone 3 performs as WMECO projects, with correspondingly larger increases if Millstone 3 is more expensive to operate or less reliable. As I showed in Section 6, Millstone 3 would impose large costs on ratepayers in the rest of this century, for benefits to be provided in the next century (if at all), under WMECO's proposed phase-in. The WMECO phase-in does not adequately synchronize costs and benefits over time.

Q: Is it necessary to synchronize the costs and benefits of <u>all</u> utility investments, in the manner you propose for Millstone 3?

A: No, for several reasons. First, it is difficult to define the benefits of any particular investment, except as compared to the cost of operating the rest of the system, without that one investment. Therefore, while the fuel savings of Millstone 3 (or any other generator, or any reasonably small group of generators) can be calculated with reference to the costs of the system without Millstone 3 (or whatever plant is under discussion), the fuel savings of the entire WMECO generation plant is probably undefinable. Second, some plant investments are immediate cost-savers, so the problems of rate shock and intertemporal equity associated with Millstone 3 -- raising rates for customers in the short term, with a promise of long-run savings -- simply do not arise. If the simple, traditional ratemaking approach works for all parties, there is no reason to deal with phase-in issues. Third, many investments involve small costs, so the administrative overhead involved in a phase-in would not be justified, even though the time pattern of costs and benefits is a miniature version of those of Millstone 3. Fourth, some investments (a few generation projects, many transmission projects, and a large proportion of distribution investments) perform functions which simply could not be served otherwise: there is often no basis for comparison of the project's costs and benefits.

Q: What principles might be applied in designing a phase-in for the portion of an expensive new plant which the utility will eventually be allowed to recover from ratepayers?

A: The central goal is the alignment of costs with benefits. There is simply no compelling reason for a new power plant to make customers much worse off in one time period, so that customers in another time period may be much better off. If the plant is beneficial overall, in present value terms, it should be possible to ensure that rates will not be higher (at least on an expected basis) in any year with Millstone 3 than they would have been without the unit. If the allowed cost of the plant exceeds its lifetime benefits, the net burden should be shared fairly over time.

Q: Does the objective of aligning costs and benefits lead to a unique phase-in pattern or mechanism?

A: No. There are many time patterns of costs which might be generally described as "synchronizing" costs and benefits, and for each such pattern, there are several ratemaking mechanisms which would be expected to produce the expected result.

Q: How might the time pattern of the phase-in be varied, within the general objective of matching costs to benefits?

A: The net lifetime difference between costs and benefits (whether that difference is positive or negative) can be distributed in several ways. Rates can be set so that the net cost (or net benefit) per kWh of generation from the plant is constant in nominal terms over the years, or so that it is constant in real (inflation-adjusted) terms over time, or so that the ratio of the net cost to the gross benefits is constant from year to year. In another dimension, the differential between costs and benefits may be levelized per kWh of Millstone 3 generation (which would be expected to rise over the first few years of the unit's life), per kWh of WMECO retail sales (which WMECO projects to rise slowly throughout the life of Millstone 3), or per year. Phase-in structures can also be very detailed, with cost recovery calculated on an annual basis to match benefits, or they can be simplified for administrative convenience and predictability: for example, simplified recovery can be set at 10 cents/kWh over the first five years, or at $15 million annually in 1986, escalating at 6% annually until 1995.[96]

Q: How can the phase-in pattern be modified, to reflect the fact that the costs of Millstone 3 exceed its benefits?

A: To the extent that the Commission assigns to WMECO shareholders some of the costs of planning and building a plant which is not worth what it costs, need for a modification is reduced. If the Commission wishes to allow WMECO to collect more than the plant is worth (and perhaps make the Company entirely whole for its investment), rate recovery may be set above the value of the plants power, so that life-time cost recovery will equal life-time costs.

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96. These approaches can also be combined with other considerations, such as smoothing out annual rate increases over time.

Rates can be set to recover a multiple (say, 110%) of the plant's benefits in each year, or the excess costs can be recovered in some other pattern, such as a levelized or escalating payment.

Q: What kinds of variation in ratemaking mechanisms are appropriate within the general objective of matching costs to benefits?

A: The first type of variation is in the form of the cost recovery, which may take place through base rates, through the fuel adjustment mechanism, or through a separate adjustment. Base rates may be increased to reflect the expected savings of the plant in the rate year (or future test year). Alternatively, fuel cost recovery may be calculated as if Millstone 3 did not exist, which would allow WMECO to keep the actual fuel savings the unit produces. If the automatic adjustment mechanism (which reduces the frequency of base rate cases) is desirable, but the Commission does not wish to interfere with the original purposes of the fuel clause mechanism, a separate adjustment mechanism for Millstone 3 costs may be appropriate.

The second type of variation is in the measure of benefits utilized in the matching process. The benefits may be measured in the short run or the long run. In the short run, the benefits are the fuel costs, the cost of meeting NEPOOL reserve targets, and other costs which would have been experienced in the individual rate year if Millstone 3 suddenly disappeared. Short-run benefits may be estimated in 1986 for the entire life of the plant, or estimated annually for the next year, or determined retrospectively at the end of each year (or other period). In the long run, the benefits of Millstone 3 are the cost of the system adjustments which would have been made in the absence of Millstone 3, perhaps including some of the short-run costs, but also including construction of new plants and implementation of conservation and load-management programs. Long-run benefits can generally be estimated in advance: the real question is when the hypothetical decision to replace Millstone 3 would have been made, which determines when replacement capacity would have been ready, and what mix and timing of investments WMECO would reasonably have pursued.[97]

The third dimension of variation in ratemaking mechanisms concerns the extent to which WMECO's cost recovery is subject to outcomes, rather than projections. At one extreme, cost recovery may be set at the level of projected benefits, regardless of actual Millstone 3 power production, the performance of other WMECO plants, fuel cost differentials, or purchased power availability. A second possibility is to set recovery on a projected cents/kWh basis, so that WMECO's cost recovery is dependent on Millstone 3 power production, but not on fuel or purchased power conditions. Finally, cost

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97. For example, in 1980 the replacement of oil generation with coal seemed far more important (and viable) economically than it does today.

recovery may be tied directly to after-the-fact results, so that WMECO receives only the actual value of Millstone 3 in each year.[98]

Finally, the process of matching costs to benefits may be designed to make WMECO whole for its Millstone 3 investment, regardless of the actual benefits of the unit; to require WMECO to share the burden arising from a limited set of parameters, such as Millstone 3 capacity factor, while immunizing WMECO from all other risks (especially the economic risks of varying fuel prices); or to expose WMECO to a share of the full range of risks associated with Millstone 3.

Q: Would a benefit-matching phase-in have to change if it would impose financial constraints on WMECO, such as triggering bond indenture limits on interest coverage?

A: Financial constraints may prompt the Commission to modify the phase-in, but could hardly invalidate the basic approach. Since a benefit-matching phase-in will generate more cash for WMECO than Millstone 3 did while it was still under

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98. These options tend to interact with the other choices made in setting up the cost-recovery mechanism. For example, it makes little sense to discuss "actual" savings if the measure of benefits is the long-run cost of a hypothetical alternative plant. Similarly, the choice between base-rate and automatic adjustment recovery for Millstone 3 costs is partially dependent on whether the Commission wishes to allow WMECO to recover projected benefits (in which case base rate treatment is appropriate) or whether it prefers to use actual after-the-fact benefits (which would favor an automatic adjustment mechanism, perhaps tied to the fuel clause).

construction, the utility's cash financial condition should improve, rather than deteriorate, once the phase-in takes effect. The Commission may determine that it is in the interests of ratepayers for WMECO to receive even more cash, or for the quality of some of the non-cash earnings to be improved, as by providing a reasonable assurance of later recovery.[99] Either of these actions may be taken as a part of fine-tuning a phase-in, consistent with the basic goals of matching benefits to costs as well as is feasible, and sheltering current customers from large rate increases to pay for a plant which is of little value to them.

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99. I have not examined the financial condition of WMECO, or the cost to ratepayers of various financial constraints, and therefore have not analyzed the financial implications of alternative phase-in treatments.

## 9 RATEMAKING RECOMMENDATIONS

Q: Please summarize the conclusions from your examination of the prudence of, the need for, and the economics of, Millstone 3.

A: My conclusions may be summarized as follows:

1. NU's current estimate of Millstone 3 construction cost could have reasonably been anticipated as early as the time NU decided to slow down construction in 1977.

2. As early as 1977/78, completion of Millstone 3 was not economically competitive with the estimated costs of power from new coal plants, let alone cogeneration, small power production, and conservation.

3. Millstone 3 would not have been required for system reliability in the rest of this decade, and well into the next, but for the retirement of much less expensive capacity.

4. Millstone 3 will have very limited reliability benefits throughout its life.

5. If WMECO recovers the entire cost of Millstone 3 under normal ratemaking treatment, it will not provide an economic benefit to ratepayers, and it will represent a

net loss to WMECO's ratepayers, in 1986 and well beyond the year 2000.[100]

6. Focusing on the present situation, full recovery of Millstone 3 costs would raise rates for the rest of this century (and well into the next), and the present value of the unit's rate effect will be a net cost to ratepayers throughout its life, even under WMECO's assumptions.

7. The economics of Millstone 3 are even worse, if historical patterns in operating cost and reliability continue.

8. The cost burdens for individual customers who pay for the unit's early years will be even more severe than those on the system as a whole.

Under traditional ratemaking, customers would be heavily taxed throughout the rest of this century, and well into the next, to reduce the cost of power to customers in the second and third decades of the twenty-first century, if ever.

Q: What implications do your observations have for ratemaking?

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100. To the extent that the Commission accepts my judgment regarding the prudence of NU's generation planning decisions, or the recommendations of MHB regarding further investigation of construction management, and disallows (or delays action on) a substantial portion of WMECO's investment in Millstone 3, the rate burden will be reduced.

A: There are four major implications. First, since a significant (but difficult to quantify) portion of the excess costs resulted from imprudent actions on the part of NU, the ratepayers should not be charged for the full cost of WMECO's share of Millstone 3.

Second, it is doubtful that the entire cost of Millstone 3 will ever be repaid by its operating savings for customers, and the reliability value of Millstone 3 will never be more than a tiny fraction of its cost. Thus, the portion of the Millstone 3 investment which is useful to the ratepayers, under the Department's definition of useful, is significantly smaller than the entire booked cost.

Third, most of the anticipated value of Millstone 3, either prospectively or retrospectively, result from the expectation that Millstone 3 will provide many kWh annually at a low incremental fuel cost. The Millstone 3 investment which is eventually charged to ratepayers would never have been incurred simply to meet peak demand. Most of the cost of building and running Millstone 3 is related to its energy-serving function, rather than its demand-serving (that is, reliability-related) function. Therefore, most of the cost of the unit should be treated as an energy cost, for both inter-class cost allocations and intra-class rate design. My Institute of Public Utilities paper on the allocation generating plant costs (Chernick and Meyer, 1982), attached as Appendix G to this testimony, discusses this point in greater detail.

Fourth, because the benefits and costs under traditional ratemaking would be so out of line, and would tend to fall on very different groups of ratepayers, the cost of the plant should be recovered in a manner which more closely follows the benefits over time. In other words, a substantial phase-in of plant costs is absolutely necessary to produce any semblance of equity.

## 9.1 The Imprudent Portion of NU's Millstone 3 Investment: Regulatory Treatment and Quantification

Q: How should the Commission treat any Millstone 3 costs which it determines were the result of imprudent behavior on the part of NU or WMECO?

A: The appropriate treatment depends on the nature of the imprudence, but in no case should imprudent utility actions result in higher costs for ratepayers. If the imprudence increased the cost of Millstone 3, the increased costs should be disallowed, and should never be recovered from ratepayers. If the imprudence consisted of choosing to own Millstone 3 capacity, when some other mix of power supply should have been pursued, the cost recovery should not exceed the cost that would have been required by the appropriate and prudent investment.

Q: What actions on the part of NU with respect to Millstone 3 do you consider to have been inappropriate?

A: In 1977 and 1978, NU should have realized that Millstone 3 would be very expensive, and should have taken several actions to reduce its exposure to the costs of that unit. NU should have:

- attempted to sell off a large share of its ownership in the unit,

- tested and established a market for cogeneration and small power production,
- actively sought out and facilitated a major program of conservation investments, to develop (if necessary) all feasible investments which were cost-effective compared to the reasonably foreseeable costs of Millstone 3, and
- supported preliminary planning and siting, to facilitate construction of a coal plant, if and when other options proved to be inadequate.

If the effort to sell down its share was unsuccessful, NU should have been preparing to cancel Millstone 3, and to replace all of the power it would have supplied with more economical sources.

Q: What is the dollar cost of this imprudence?

A: That is very difficult to determine. As I discuss in Section 4, NU should have been soliciting proposals from cogenerators, small power producers, and conservation providers; should have been attempting to sell off ownership shares in Millstone 3; and should have been preparing its own power supply alternatives. The effectiveness of any of these actions would depend on the reception it received from other parties: the cogeneration and small power developers, conservation service providers, and Canadian utilities which could have made available alternative power supplies; environmental and siting regulators, who would be involved in any options to build a coal plant; and other New England utilities, which might have purchased shares in Millstone 3. It is impossible to determine exactly how each of these other parties would have reacted to NU's initiatives, since we can not rerun history by returning to 1978 and taking the actions NU should have taken then.

It is at least possible to determine what NU would have known about the costs and potential for conservation,[101] had it chosen to fully investigate that power supply option. This would be a very demanding task, if it were to involve (for example) compiling a running list of the technologies, studies, projections, and demonstration projects which were available each year from 1976 to 1981, and computing the cost of replacing Millstone 3 with conservation, given the information available to each date. Such a detailed reconstruction of the state of knowledge about conservation possibilities in the late 1970's and the early 1980's is beyond the scope of this testimony, and would not be possible in the time frame available in this proceeding. Section 4.2 provides enough evidence to determine that the identifiable potential was substantial compared to NU's capacity entitlement in Millstone 3.

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101. The same is true to a lesser extent for other power supply options, such as cogeneration, coal, small power, and out-of-region purchases. Those options are more affected by the actions of other parties.

## 9.2 The Useful Portion of NU's Millstone 3 Investment

Q: Please state your understanding of the "used and useful" test which the Commission established in Docket 84-25.

A: The "used and useful" approach which the Commission laid out in that decision defined "useful" for ratemaking purposes as "needed and economically desirable" (84-25, page 41). The Commission then stated that

> [A]t the time the Company seeks to earn a return on Millstone 3, the Department will determine the portion of the plant that is used and useful. . . For the portion of the plant, if any, which is not found to be used and useful . . . the Company may seek recovery of its investment consistent with prior Department treatment of abandoned plant, or, if appropriate, the Department may classify that portion of the investment as plant held for future use. . .

The "treatment of abandoned plant" is a reference to extraordinary losses, which are generally amortized over a (variable) period of years, sometimes with limited interest accrual on the unamortized balance, but without rate base treatment. Plant held for future use generally does not earn either a current return or a deferred return (such as AFUDC). Thus, my understanding is that the Commission has declared that the economic portion of the Millstone 3 investment will be placed in rate base, while the remainder will be treated in a manner which may be far less favorable to WMECO, or alternatively that cost recovery for the remainder of the investment will be delayed until the investment is useful, with no compensation for the delay in recovery.

Q: Is the Commission's general approach a reasonable one for this proceeding?

A: Yes. The Commission correctly identified a problem with traditional approaches to the treatment of costs from canceled and completed plants: canceled plants were subject to a form of penalty, through an amortization of the investment (and perhaps only part of the investment), while completed and operational plant was essentially assured of rate-base treatment. As we have seen, NU proceeded with Millstone 3, and with its large share of Millstone 3, at times when those decisions were at least highly questionable.

Q: How would you suggest the Department determine the portion of Millstone 3 costs which are in excess of the plant's value?

A: I would suggest that the Commission apply the standard long-run avoided cost test. Alternatively, a long-run market test, or a short-run test could be used to determine the used-and-useful portion of Millstone 3.

Q: How would the standard long-run avoided cost test be applied?

A: The standard long-run avoided cost test replaces the unit in question with a hypothetical mix of conventional utility investments. NU's Base Case comparison replaces Millstone 3 with additional oil consumption, the continued use of some older plants, and the construction of new CTs. We do not know what it would cost to replace Millstone 3 with a seri approximation to a least-cost supply mix, including conservation, because NU has only recently started work on an integrated supply planning process.

Over its useful life, the savings in production costs and new investments due to Millstone 3 will be smaller than its costs to ratepayers, even under NU's assumptions. As shown in Table 6.2, the net present value loss to consumers would be $129 million if NU is correct. This $129 million is 33% of the present value of the capital recovery stream WMECO has requested, to recover the $~~380~~ 373 million of NU's ownership share which is allocated to WMECO retail sales through the G&T agreement and the wholesale/retail allocation. Hence, WMECO customers would break even if only $~~255~~ 251 of the $~~380~~ 373 million were allowed. If the G&T agreement did not reassign the majority of the savings to CL&P, this disallowance could be achieved by removing from rate base $~~125~~ 122 million of the $462 million retail WMECO investment (which is much larger than the $~~380~~ 373 million allocated through the G&T). Regardless of how it is treated, $~~125~~ 122 million of the investment in Millstone 3 which is assigned to WMECO retail customers, would not be used and useful.

Table 9.1 lists the net loss implied by each of the contemporary cost-effectiveness cases I ran in Section 6,[102] and computes the portion of the retail WMECO investment in Millstone 3 which is not used and useful. Depending on the Case, the WMECO retail share of NU's investment in Millstone 3 is worth somewhere between nothing and $~~255~~ 251 million: the lowest value results if historical trends in operating parameters continue, while the highest value results from NU's projections.

Q: Which Case do you believe represents the most appropriate estimate of the value of WMECO's Millstone 3 investment?

A: The value of that investment is inherently uncertain. As I discuss below, the Commission can adjust operating cost recovery to conform to the values assumed in setting capital cost recovery in this proceeding, so the cost trends I include in Case 3 need not be included in determining the value of WMECO's investment. Avoided costs are more difficult to constrain in this way: the operation of the fuel clause will tend to give WMECO full fuel cost recovery, regardless of whether Millstone 3 operates as well as NU projects, and the capacity avoided by Millstone 3 will never be built, so there will be no ready opportunity for the Commission to review that cost component. Thus, the Commission should consider carefully both the projected fuel

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102. The Cases which used outdated fuel cost projections are not included.

savings, and the projections of avoided capacity costs, in estimating the useful portion of Millstone 3.

As it happens, there is relatively little dispute regarding the avoided capacity costs. The difference in present value between NU's avoided capacity cost projection (in Case 1) and my projection of the avoided costs (in Case 4) is about ~~less than~~ \$11 million, compared to net costs of \$129 million in the NU Case.[103]

The effects of capacity factors and fuel prices are much more important than those of capacity costs. Case 2 uses all of NU's assumptions, except for projecting Millstone 3 capacity factors at historical levels. That Case indicates that Millstone 3 will cost customers \$205 million more in 1985 present value than it is worth. Case 5 replaces Summer 1985 fuel price forecasts with Winter 1985 forecasts, and projects a net loss of \$180 million. At Winter 1985 fuel price projections, Case 2 would correspond to capacity factors well above historical averages, and about midway between my projections and those of NU. Combining historical capacity factors and current fuel prices would result in much smaller benefits and much larger net losses. If the Commission

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103. In Case 4, I still credit Millstone 3 with replacing an equal number of rated MW, despite the fact that the smaller alternative units are worth much more than Millstone 3, in terms of reliability. If a similar analysis were performed with respect to the benefits of Millstone 3 with respect to NEPOOL, rather than NU, the value of Millstone 3 would be reduced further.

believes that NU is likely to be more successful at operating Millstone 3 than the average historical experience for large PWRs would indicate,[104] and if the Commission is prepared to limit WMECO's recovery of operating costs to the levels projected in this proceeding, Case 2 would be a suitable basis for estimating the useful portion of Millstone 3.

Q: What portion of WMECO's share of Millstone 3 would be useful for each of the contemporaneous cost Cases you examined?

A: Table 9.1 summarizes the results of those Cases, and computes the useful portion of WMECO's allocation of NU's Millstone 3 investment (both in percentage terms, and in millions of dollars) for each Case. Note that the portion of the plant allocated by the G&T agreement is less than WMECO's direct ownership share. Depending on the Case, between one third and the entirety of WMECO's Millstone 3 entitlement is not useful, and therefore would not be in rate base under the ruling in MDPU 84-25.

Q: How would the long-run market test be applied?

A: The long-run market test asks the question:

> Is there an alternative source of power which could replace Millstone 3 at a cost below the cost of full recovery of the Millstone 3 investment?

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104. Since current fuel price projections are lower those used in Case 2, Millstone 3 performance must be correspondingly higher to produce the same benefits.

If such a source exists, its cost can be used as an estimate of the value of Millstone 3, instead of the traditional utility supply mix NU assumes would replace Millstone 3.

Q: Do you have available an estimate of the cost of such an alternative to Millstone 3?

A: I have not been able to fully identify the optimal mix of replacement power for Millstone 3, within the limits imposed by this proceeding. The mix would almost certainly have included large amounts of conservation, cogeneration, and small power. It might also have included a 1986 coal plant, which from the estimates presented in Section 4, would be expected to have cost about 9-10 cents/kWh. The cost of coal power is very similar to the estimates of the value of Millstone 3 power, from Table 6.10, and the cost of the optimal mix would be likely to have been lower.

Q: How would the short-run test be applied?

A: NU has presented the Commission with an estimate of the value of energy in the rate year: Dr. Overcast's testimony sets that figure at about 3.833 cents/kWh at the generation level. This is, in effect, the price NU is willing to pay its customers to conserve electricity.[105] It is difficult to see

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105. The actual rate incentive offered customers is somewhat higher, since they reduce line losses, transmission and distribution investments, and associated maintenance expenses when they conserve electricity. Millstone 3 does not provide comparable benefits.

how NU's own plant can be fairly considered to be more valuable than contemporaneous customer conservation. Marginal cost would be somewhat higher in the absence of Millstone 3: Dr. Overcast estimates that cost at about 4.07 cents/kWh (IR-AG-13-1). The value of Millstone 3 power must lie between the marginal cost before Millstone 3 is added to the system, and the marginal cost after Millstone 3 is added.

Mr. Fox's testimony provides us with a second estimate of the value of Millstone 3 power, in the period 5/1/86 to 4/30/87. For the first year of the unit's operation, the annual avoided cost is 3.7 cents/kWh.[106] Millstone 3 also provides WMECO with annual capacity-related savings (most of which would not be realized until 1987) of about $600,000: these are the costs avoided by retiring Devon 3 and 6, Middletown 1, and the 7 CTs.[107]

Both estimates of the short-term benefits of Millstone 3 will probably exceed the actual benefits, due to the decline in the projected price of oil.

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106. $144,464,000/(8760*741.652*60%)

107. It is not at all clear that retirement of the CTs is in the public interest, and WMECO's cost recovery should not be reduced if it elects to retain some or all of this economical capacity. With the 1150 MW nuclear units and the Hydro Quebec interconnection in operation, New England will need lots of back-up capacity. If the nuclear units have 35% forced outage rates and the HQ purchase is unavailable 5% of the time, all 4300 MW would be expected to be out about two days/year, in addition to the normal level of forced and scheduled outages on the current NEPOOL system.

Q: It appears that you have just cited several different avoided cost figures NU has presented in this case and in connection with other recent issues. What are those estimates, and are they consistent?

A: NU has four kinds of avoided costs. For rate design, which communicates the cost of power supply to consumers and provides their incentives for efficient and frugal energy usage, NU estimates that the avoided cost of electricity is about 4 cents/kWh at the generation level. For QFs, NU believes that the avoided cost of power over thirty years is 8 to 8.5 cents/kWh (IR COAL-1-13). For the Millstone 3 analysis, NU uses fuel and capital costs which have a levelized value of 9.6 cents per kWh. And in Mr. Ferland's testimony, NU rather illogically adds the costs of writing off Millstone 3 to the other costs avoided by Millstone 3, resulting in a total estimate of about 19 cents/kWh avoided.

Q: Why are these values so different?

A: There are three reasons for the differences. First, the time scales are different. The avoided cost for rate design is a short run cost, even though many of the decisions influenced by rate design (e.g., choice of energy sources, level of equipment and appliance efficiencies, building insulation levels, choices between load-reducing and load-shifting investments) have long-run implications, and even though most of the effect of price changes on demand levels is felt <u>after</u>

the year in which the change is made.[108] The avoided cost estimate for QF purposes is based on longer-term costs, up to 30 years. The avoided cost estimates for Millstone 3 are based on even longer-run costs, reaching out nearly forty years.

Second, there are differences in the assumed role of competition, and of NU itself, in determining the various avoided costs. For the Millstone 3 computations, it is assumed that NU would have acted in a very mechanistic and unimaginative manner in the absence of Millstone 3, building CTs, but otherwise not reacting to the change in its supply situation.[109] As a result, the cost of not building Millstone 3 is high. For evaluating QFs, NU recognizes that it has an active role in encouraging (or discouraging) QF development, and further recognizes that competition between QFs can keep down the prices paid for any given amount of generation.

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108. To the extent that NU's approach may be consistent with Department precedent, that precedent is insufficiently clear, and should be refined to specify that rate design should reflect costs in the time period affected by consumer decisions in the rate year. To the extent that NU's approach is required by Department precedent, that precedent is incorrect, inefficient, and inappropriate, and should be reversed in the present case. The Commission's decision in DPU 84-276 appears to definitively acknowledge the necessity for providing long-run price signals for alternatives to utility power supply projects.

109. In some of the alternative cases, NU inexplicably assumes that it would build nothing after 1989 but CTs, which would represent a new low in utility supply planning. NU's hypothetical all-CT supply plan would make absolutely no sense.

Third, NU is engaging in a form of cream-skimming, assigning the most expensive avoided power sources to justify the cost of its own plant, allowing QFs to compete for the less expensive remaining sources, and leaving the cheapest[110] for the ratepayers. The short-run energy costs consist (and will always consist, if NU's current approach is continued) only of those power sources which neither NU nor the QFs can back out.

Fourth, as mentioned above, Mr. Ferland's analysis includes the capital cost of Millstone 3 as one of the costs which Millstone 3 is avoiding. This assumption virtually guarantees that the unit will appear to be economical, since its fuel and capital savings are compared only to its operating costs.[111] The comparison is totally irrelevant, of course, since if Millstone 3 had not been built, or had been sold, its capital cost would have been avoided.

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110. In terms of energy costs, these are the best plants, but they are the hardest to compete with, leaving minimal incentives for conservation.

111. Actually, my Case 3 indicates that the operating benefits may not even cover the operating costs of the unit.

### 9.3 The Treatment of Costs Which are Neither Useful nor Clearly Imprudent

Q: How should the Commission treat the portion of the Millstone 3 investment which is above the level of used-and-useful investment, and which the Commission does not find to be imprudent?

A: The Commission indicated in DPU 84-25 that it would deny recovery for imprudently incurred costs, permit rate base (or similar) recovery of the economic part of investment, and allow recovery of the uneconomic prudent investment as an extraordinary loss over a period of years. This is a generally appropriate and useful ratemaking structure.

The facts I presented in the preceding Sections suggest that NU acted imprudently, and is responsible for some significant fraction of the uneconomic portion of the investment. By the standard established in DPU 84-25,[112] WMECO would be denied recovery of all the costs resulting from the imprudence. Unfortunately, while the imprudent costs are clearly large, they are difficult to quantify precisely. Hence, a slightly different approach to the ratemaking treatment may be warranted.

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112. As I read it, this aspect of the decision simply affirmed the existing prudence standard.

One approach would simply deny WMECO recovery on any of the uneconomical portion of the investment, until WMECO is able to demonstrate that even a prudent utility would have incurred some of these costs. This approach has the disadvantage that NU may resist development of economic power supply options (including conservation), if such development tends to undermine NU's position that the options did not exist in the 1970s, for the purposes of a continuing proceeding on prudence. I would prefer to resolve any ratemaking issues relating to power supply and generation planning decisions resolved in this proceeding, or as soon as feasible.

I would therefore propose the following treatment of Millstone 3 costs: that full recovery (economically equivalent to rate base treatment, from the viewpoint of NU shareholders) be allowed for a portion of the investment which may reasonably be anticipated to be economic, and that the uneconomic remainder of the investment be recovered through amortization over an extended period, with no provision for current or deferred return on the unamortized portion. The extended recovery of the uneconomic investment, without return, would constitute a proxy for disallowance of a large portion of that uneconomic investment, on prudence grounds.

In other words, even if the Commission finds that the evidence presented in Sections 2 through 4 of this testimony establishes that NU's <u>actions</u> were imprudent, and that those actions resulted in unnecessarily expensive power supply, it may not be able to determine exactly what portion of Millstone's cost could have been avoided if NU had acted prudently. In that case, rather than trying to establish a direct dollar value of disallowance for imprudence, the Commission may prefer to penalize the Company by less favorable treatment of the useless investment.

Q: If the Commission takes the latter approach, how would it apply the penalty?

A: In the case of the long-run tests, the Commission could declare the long-term cost effectiveness issue settled in this case, and prescribe an extraordinary loss treatment to be accorded to the non-useful portion. Alternatively, the Commission could leave WMECO with the option of treating all or part of the non-useful investment as plant held for future use, with the option of later applying for either rate base or extraordinary loss treatment. This alternative makes sense primarily if WMECO believes that the Commission's projections of Millstone 3 capacity factors or operating costs are incorrect: WMECO should have the chance to prove that its optimism is justified, by accumulating significant Millstone 3 operating experience. The cost to WMECO of exercising this option is the absence of any recovery on the plant held for future use.

For the short-run test, which only purports to measure the value of Millstone 3 in the rate year, much of the investment in Millstone 3 would be treated as plant held for future use, since the value of the unit's energy is expected to rise over time. At some point in the future, the plant's capacity might also be useful, further increasing the value of Millstone 3. Depending on the Commission's rules for updating the valuation of Millstone 3 power, and NU's projections for the unit's operating characteristics, NU may decide to write off some of the plant immediately, rather than waiting to see how recovery changes over time.

### 9.4 Updating the Cost Recovery

Q: How could future recovery for Millstone 3 be determined?

A: That depends, in part, on the measure of useful investment which the Commission applies. Under the short-run test, the useful investment will have to be determined for each time period. Under the long-run test, the Commission could adjust recovery to reflect Millstone 3 capacity factor performance, Millstone 3 operating costs, and/or avoided costs. However, to provide as much assurance to NU as possible regarding treatment of its investment, and to avoid any incentives for NU to act contrary to the interests of the ratepayers, it is probably best to establish now a schedule (or formula) for capital recovery over time. Variances in capacity factor performance can be dealt with in fuel clause proceedings, variances in O&M expenses can be dealt with in the treatment of those expenses, and changes in avoided cost projections probably should not be reflected at all, once an initial schedule is set.

Q: What parameters might the Commission update over time?

A: There are two broad groups of such parameters: factors internal to Millstone 3 operations and planning (e.g., O&M expenses, capital additions, capacity factors, useful life, projected decommissioning expenses), and those external to

Millstone 3 (e.g., fuel prices, availability of alternative power sources).

The parameters which are directly related to Millstone 3 are all (at least partially) subject to NU's control. There is considerable historical basis for projecting these cost components (except for useful life and decommissioning). NU's projections for all these internal factors are all quite optimistic. Therefore, it is reasonable to hold NU accountable for errors in these projections: certainly, NU should not receive more favorable ratemaking treatment simply for promising good operating results. Hence, I would recommend that the Commission put WMECO on notice that it will have difficulty recovering more in rates for most of these parameters than was assumed in establishing the capital cost recovery mechanism.[113]

The nature of the adjustment mechanism depends on the structure of the cost recovery.

- If a portion of Millstone 3 investment is placed into rate base, with the disallowance calculated as the difference of expected total costs and savings, increases in operating costs (including capital

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113. To the extent that variations are attributable to differences between projected and actual rates of inflation, this rule should be relaxed. Of course, to the extent that actual results are more favorable than the forecast, WMECO should be allowed to keep some of the savings. No hard and fast standards need be established at this time, since WMECO would have to request higher rates in a general rate case.

additions) could be balanced by reductions in rate base. The same result can be achieved with less accounting uncertainty for WMECO, by setting allowed operating cost recovery in future rate cases at the levels projected in this case for the corresponding time period, so that operating costs, as charged to the ratepayers, do not increase over the projections from which the "useful" portion of the investment is calculated. In either case, adjustments should be made for variances in capacity factor from those used in the used-and-useful calculation, either by changing allowed rate base, or by adjustments in fuel cost recovery.

- If total annual cost recovery is fixed in advance, as by setting a schedule of Millstone 3 charges for its entire life, no special mechanism would be required to correct for errors in operating cost projections, since higher operating costs would result in lower contributions to capital cost recovery, and vice versa.

- If recovery is set in cents/kWh generated, the adjustment for capacity factor will also be automatic.

Special considerations govern the treatment of useful life and of decommissioning costs. NU continues to base its projections of costs and benefits on a very optimistic estimate of the useful operating life for Millstone 3, for which there is no historical support. I would therefore recommend that the Commission express its intention to hold

WMECO to its estimate of Millstone 3 lifetime, and thus to not revise depreciation rates upward if NU should determine in the future that the unit is not likely to last as long as it currently projects.[114]

NU's estimates of the cost of decommissioning Millstone 3 are also based on very little experience, and are likely to be understated. However, there is a strong public interest in ensuring the availability of funds for decommissioning. It would be unfortunate if WMECO had any additional incentive to continue underestimating decommissioning costs. Requiring shareholders to bear the costs of increasing the decommissioning fund would create such adverse incentives.[115] Therefore, I would recommend that the Commission allow WMECO to revise its decommissioning cost estimates from time to time, and to increase charges to ratepayers (with Commission approval) as may be necessary to bring the external decommissioning fund to appropriate levels.

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114. It is my understanding that the Commission can not bind future regulators on this point, but it is appropriate to leave a record of the conditions under which the ratemaking which results from this case was allowed.

115. It might be argued that holding shareholders responsible for increases in O&M and capital additions would also create adverse incentives, since NU might be tempted to cut corners on safety concerns. In the long run, utilities which have not taken NRC safety concerns seriously have lost much more from the resultant shutdowns than they could possibly have gained from reduced spending. In any case, the ratemaking treatment of WMECO's share of the unit is unlikely to dominate NU's operating decisions.

Q: Should the Commission provide for updating to reflect changes in the factors external to Millstone 3, especially those which affect the value of the unit's power?

A: I would argue that it should not do so, in most circumstances. Updating is least desirable where it would tend to encourage WMECO and NU to take actions which increase the value of Millstone 3, while increasing total costs to customers. For example, if Millstone 3 cost recovery were tied to short-run avoided cost (as QF cost recovery has been in Massachusetts), NU would be rewarded for actions which increase avoided cost, such as

- reduced availability of base-load plants,
- increased prices for fuel used in marginal plants,
- reduced economy purchases,
- increased heat rates,
- the sale or retirement of economical capacity, and
- increased sales (wholesale or retail), even below cost.

NU would be correspondingly penalized for pursuing policies which achieve the inverse of these outcomes, and for pursuing such other desirable power supplies as conservation and small power. While the Commission might be able to prevent (or charge the shareholders for) some abuses, it will be difficult to detect some kinds of sloppy operations, halfhearted negotiations, and so on. NU's management has demonstrated that it can perform efficiently with the proper incentives; it may not perform so efficiently if it must act contrary to shareholder interests to reduce retail rates. WMECO's ratepayers will be better served if that management is working with the Commission to provide service at the lowest possible cost, rather than at cross purposes.

The adverse incentives can be eliminated by tying cost recovery to measures of value which are beyond NU's control. For example, the value of the Millstone 3 power might be set at the New York Harbor cost of 1% sulfur oil, burned at a 10,000 BTU/kWh heat rate.[116] The result will roughly track NU's short-run marginal cost, but NU can not affect the inputs to such a calculation, and would simply receive an energy credit which varied with world oil price. While this type of cost recovery would not pit NU against its ratepayers, it would still have significant disadvantages.

In my testimony, and the testimony of Susan Geller, on rates for QFs (MDPU 84-276), I discussed some of the problems of purchased power rates which float with avoided costs. To put it simply, risks to the seller are increased, raising the costs of providing the service, while the risks to the

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116. Presumably, this treatment would be coupled with a capacity credit based on the cost of bring new oil-fired capacity on line. The comparison plant could also be a gas-fired combined cycle plant, a coal plant, or a mixture of capacity.

ratepayers is also increased, since the cost of the purchased power will rise exactly when fuel costs are rising. Thus, everybody loses and nobody gains from floating purchased power rates. The same problems arise with floating cost recovery of utility plant.[117]

While floating rates are generally disadvantageous for cost recovery, they can have some benefits, such as encouraging utilities to realistically assess the value of third-party power (since the utility is treated like a third party), and allowing the Commission to avoid projecting fuel prices (a thankless task, if ever there were one). In the long run, I believe that the advantages of floating rates in determining the level of cost recovery are usually outweighed by the problems they create.

Floating rates could be applied in a somewhat different manner for utility cost recovery than they have been for QF ratesetting. The total amount of cost recovery may be fixed independently, and a floating rate calculation may simply determine the rate at which that cost is recovered. So long as the total present-value cost recovery is fixed, most of the problems are ameliorated: investor risks will not be increased significantly, and while rates will still be more sensitive to fuel markets than under fixed recovery

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117. In some respects, value-based pricing treats WMECO (as an owner of Millstone 3) as if it were a third party selling power to WMECO (as a provider of retail service).

schedules, ratepayer exposure will be more limited than under purely floating cost recovery. Volatility in rates could still cause cash flow problems for both the utility and the ratepayers.

Q: What regulatory mechanisms might be employed to accomplish whatever updating the Commission determines is necessary?

A: There are several possible regulatory structures which could be used to update cost recovery as the projected or actual benefits from the plant rise. The Commission could require WMECO to file a new rate case whenever it believes greater recovery is warranted. Alternatively, the Commission could establish a rate rider mechanism, which would allow for revision of rate recovery in a more limited context. This option would be particularly useful if the schedule of cost recovery (annually or per kWh) has been established, so that the proceeding could be limited to accounting issues, the division of costs over kWh sales, and (if relevant) the review of WMECO's projections of operating costs and capacity factor, to determine the level of capital cost recovery.[118]

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118. In either of these formats, the Commission may wish to allow cost recovery on a cents/kWh basis, to reflect the expected value of the plant, but to incorporate those estimated benefits in rates on a projected basis. Some reconciliation mechanism may then be necessary, to discourage NU from overestimating the Millstone 3 capacity factor. The reconciliation might simply consist of reducing the next year's savings projection by the error in the previous year's projection.

As noted previously, I do not believe that it would be appropriate to allow the cost recovery for Millstone 3 to float with short-run benefits. Nonetheless, the Commission may wish to set the initial level of recovery at the value of the short-term benefits, and to initiate a proceeding, without the limitations of the suspension period in the present case, to

- resolve any outstanding prudence issues,
- determine the form of recovery for Millstone 3 costs in excess of the useful investment,
- establish a series of annual avoided-cost values (in cents kWh and dollars per kW-year), or formulae for computing such values, to be used in future Millstone 3 cost-recovery, and
- create a ratemaking mechanism to adjust Millstone 3 cost recovery over time, to reflect the changing avoided-cost values and differences in Millstone 3 performance, without requiring rate-case review.

The major advantage of this approach is that any prudence issues which simply can not be resolved in this case, can be deferred without prejudice.[119]

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119. In the structure I have proposed, recovery of the useless portion of the Millstone 3 investment may be deferred until any outstanding prudence issues are resolved, or the amortization may be initiated, subject to later modification if a portion of the investment is found imprudent.

### 9.5 Phase-in

Q: With the ratemaking approach you discuss above, is there any need for phasing in the rate effects of Millstone 3?

A: Yes, there is. Under either of the long-run tests, the level of cost to be recovered is essentially determined in advance. The pattern of cost recovery over time must also be specified. Even with large disallowances, the normal ratebase treatment of the useful Millstone 3 investment under the long-run standards would result in WMECO's ratepayers paying more than Millstone 3 is worth for some years. If cost recovery is fixed at the 10 cents/kWh level, ratepayers would pay more than the short-run value of the plant each year until 1996, even before including the effect of any extraordinary loss treatment of the non-useful plant. These increases in rates can be mitigated by spreading out recovery of the useful portion of plant cost, the non-useful portion, or both, approximately in proportion to the projected benefits of the plant. One convenient approximation for matching cost recovery to benefits would be to levelize capital cost recovery in real terms, as the Commission has proposed doing for capacity credits in QF rate (84-276, page 62). Similar issues arise for the write-off of extraordinary losses, under any of the usefulness tests, and I would recommend comparable treatment of those costs.

### 9.6 Recommendations

Q: Please describe the ratemaking process you favor, from the range of options you have laid out.

A: I would recommend that the Commission allow WMECO to recover as useful the portion of Millstone 3 costs equivalent to a levelized rate of about 10 cents/kWh, based on the estimated cost of QF purchases avoided, or on NU's projection of the value of Millstone 3 energy and capacity. To split the difference in the parameters in serious dispute between me and NU, I suggest that initial capital recovery be based on the assumptions in my Case 2, which uses my estimates of Millstone 3 capacity factors, and NU's projections of avoided capacity savings, O&M expenses, and capital additions.[120] This level of recovery is equivalent to a present value allowance of $188.0 million for WMECO's retail share (including G&T effects) of carrying charges on the original investment, compared to a present value of $393.2 million for

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120. If NU has underestimated the operating costs, the Commission should be very reluctant to allow WMECO to raise rates to cover higher operating costs, without some very strong showing that the conditions causing the higher costs were unknowable at this time. Since I have predicted much greater operating costs, such a showing would be very difficult. Conversely, if Millstone 3 achieves much better capacity factor performance than I have predicted, WMECO should be free to request more favorable treatment in the future.

full recovery of the investment. This is equivalent to treating as used-and-useful 47.8% of WMECO's share of NU's Millstone 3 ownership, assuming no additional imprudence disallowances.

To mitigate the rate shock and temporal inequities of the useful portion of the plant, I would suggest allowing recovery of these capital costs at a constant real rate. To allow WMECO full recovery of the deferred revenue, with a 9.84% return on the deferrals, the recovery would have to start at $12.8 million in 1986, escalating at 6%. This result is derived in Table 9.2.

The remaining 52.2% of the Millstone 3 investment ($~~198.8~~ 195 million of WMECO's entire retail share of $380.8 million, including G&T effects) is not useful, and will be treated as an extraordinary loss. If the Commission does not impose a separate penalty for planning imprudence, I would recommend that this write-off return much less than present value to the shareholders. It is my understanding that the Commission would usually disallow recovery of equity AFUDC, with recovery of capital spread over 3 to 10 years, depending on the size of the writeoff and other factors. I would strongly urge that this recovery be spread over as long a period as feasible: one solution would be to allow recovery of the entire cost, without any carrying charges, over 15 years, or $13.0 million annually.[121]

Table 9.3 adds up the recovery of useful investment, the recovery of useless investment, and NU's projections of operating costs, and compares the total cost of Millstone 3 under my proposal to the benefits of the plant. Even with an extended phase-in and denial of return on the useless investment, my proposal would result in increased rates through 1994, compared to the case in which Millstone 3 never existed: those increases would be about $20-$25 million in annual revenues for 1986 through 1992, roughly 1/3 to 1/2 as large as the increases under NU's proposal (see Table 6.3). The maximum cumulative burden on the ratepayers is reduced to about a third of that required by NU's proposal, and the lifetime net cost is only about a quarter of that implied by NU's plan. Figure 9.1 shows the rate effects of the recovery of useful costs, of the extraordinary loss, of Millstone 3 fuel and capacity savings, and the net effect on ratepayers, from Table 9.3.

Q: These proposals are based on your capacity factors projections. Have you performed similar analyses for NU's capacity factor projections?

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121. Alternatively, the recovery could be spread over a longer period, using a debt-based return on the unamortized portion (as was done in the Pilgrim 2 recovery cases).

A: Yes. Tables 9.4 and 9.5 repeat the calculations in Table 9.2 and 9.3, but for NU's capacity factor assumptions. Since the projected benefits of the plant are higher with NU's assumptions than with my capacity factors, the fraction of costs recovered in the "useful" column is larger, and the fraction in the "useless" column is smaller. The higher assumed benefits, if they occurred, would also result in a more advantageous outcome for ratepayers: the plant would actually have a (barely) positive present value over its projected lifetime.[122] Figure 9.2 displays the ratemaking results of NU projections of Millstone 3 capacity factor.

The problem with using the NU capacity factor projections is that they are unlikely to be realized. If the Commission allows recovery of Millstone 3 fixed costs based on the assumption that NU's capacity factor projections will be achieved, and the actual benefits of Millstone 3 are those shown in my Case 2,[123] the ratepayers would be worse off by $76 million dollars, in present value terms at 14.05%. If the Commission sets Millstone 3 capital recovery at levels based on my capacity factor projections, it can always give WMECO more favorable treatment as a reward for better

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122. This positive present value, as compared to the negative $129 million value in Table 6.2, results from both the disallowance of return on the useless portion, and the deferral of recovery of the useful portion.

123. See Table 6.3 or 9.3. Since oil price projections are now lower than the fuel prices which underlie Case 2, Millstone 3 would have to perform better than my capacity factor projections to achieve the benefits in Tables 6.3 and 9.3.

performance: applying penalties may be more difficult, and may decrease investor perception of the certainty of cost recovery.

Q: Does this conclude your testimony?

A: Yes.

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COMMONWEALTH OF MASSACHUSETTS
BEFORE THE
DEPARTMENT OF PUBLIC UTILITIES

| | | |
|---|---|---|
| WESTERN MASSACHUSETTS ELECTRIC COMPANY | ) | D.P.U. 85-270 |

TABLES AND FIGURES
FILED WITH TESTIMONY
OF PAUL CHERNICK
ON BEHALF OF THE
ATTORNEY GENERAL

March 19, 1986

TABLE 1.1: Quarterly Data for Millstone 3

| (Quarter) Date of Estimate | Estimated COD | Estimated Cost | Annual Expenditures | (Thousands) Man-hours | Percent Complete | Change in Percent Complete | Increase in Percent Complete | Years Between Estimates |
|---|---|---|---|---|---|---|---|---|
| Dec-73 | | | $10.4 | | | | | |
| Mar-74 | May-79 | $642 | | | 0.0% | 0.0% | 0.0% | 1.246 |
| Jun-74 | May-79 | $642 | | | 0.0% | 0.0% | 0.0% | 0.498 |
| Sep-74 | May-79 | $642 | | | 0.0% | 0.0% | 0.0% | 0.750 |
| Dec-74 | May-79 | $642 | $36.8 | | 0.1% | 0.1% | 0.1% | 0.753 |
| Mar-75 | Nov-79 | $793 | | | 5.8% | 5.8% | 7.8% | 0.747 |
| Jun-75 | Nov-79 | $793 | | | 6.7% | 6.7% | 9.0% | 0.747 |
| Sep-75 | Nov-79 | $793 | | | 7.0% | 6.9% | 9.3% | 0.750 |
| Dec-75 | May-82 | $793 | $117.6 | | 8.0% | 2.2% | 2.9% | 0.753 |
| Mar-76 | May-82 | $793 | | | 8.5% | 1.8% | 2.4% | 0.750 |
| Jun-76 | May-82 | $978 | | | 9.5% | 2.5% | 3.3% | 0.750 |
| Sep-76 | May-82 | $978 | | | 11.0% | 3.0% | 4.0% | 0.753 |
| Dec-76 | May-82 | $978 | $155.0 | | 12.0% | 3.5% | 4.6% | 0.753 |
| Mar-77 | May-82 | $1,173 | | | 12.2% | 2.7% | 3.6% | 0.747 |
| Jun-77 | May-82 | $1,173 | | | 13.5% | 2.5% | 3.3% | 0.747 |
| Sep-77 | May-82 | $1,173 | | | 16.9% | 4.9% | 6.5% | 0.750 |
| Dec-77 | May-86 | $1,173 | $105.4 | | 19.9% | 7.7% | 10.2% | 0.753 |
| Mar-78 | May-86 | $1,173 | | | 20.0% | 6.5% | 8.7% | 0.747 |
| Jun-78 | May-86 | $1,173 | | | 21.5% | 4.6% | 6.2% | 0.747 |
| Sep-78 | May-86 | $1,980 | | | 24.6% | 4.7% | 6.3% | 0.750 |
| Dec-78 | May-86 | $1,980 | $104.1 | | 25.2% | 5.2% | 6.9% | 0.753 |
| Mar-79 | May-86 | $1,980 | | 262 | 25.9% | 4.4% | 5.9% | 0.747 |
| Jun-79 | May-86 | $1,980 | | 295 | 27.1% | 2.5% | 3.3% | 0.747 |
| Sep-79 | May-86 | $1,980 | | 447 | 30.2% | 5.0% | 6.7% | 0.750 |
| Dec-79 | May-86 | $1,980 | $137.3 | 562 | 32.6% | 6.7% | 8.9% | 0.753 |
| Mar-80 | May-86 | $1,980 | | 262 | 33.8% | 6.7% | 8.9% | 0.750 |
| Jun-80 | May-86 | $1,980 | | 230 | 34.5% | 4.3% | 5.7% | 0.750 |
| Sep-80 | May-86 | $1,980 | | 247 | 32.7% | 0.1% | 0.1% | 0.753 |
| Dec-80 | May-86 | $2,573 | $163.9 | 468 | 33.6% | -0.2% | -0.3% | 0.753 |
| Mar-81 | May-86 | $2,573 | | 449 | 35.6% | 1.1% | 1.5% | 0.747 |
| Jun-81 | May-86 | $2,573 | | 696 | 39.0% | 6.3% | 8.4% | 0.747 |
| Sep-81 | May-86 | $2,573 | | 970 | 40.3% | 6.7% | 8.9% | 0.750 |
| Dec-81 | May-86 | $2,577 | $269.2 | 917 | 44.8% | 9.2% | 12.2% | 0.753 |
| Mar-82 | May-86 | $2,577 | | 1169 | 48.7% | 9.7% | 13.0% | 0.747 |
| Jun-82 | May-86 | $2,577 | | 984 | 47.9% | 7.6% | 10.2% | 0.747 |
| Sep-82 | May-86 | $2,577 | | 1741 | 53.2% | 8.4% | 11.2% | 0.750 |
| Dec-82 | May-86 | $3,539 | $461.2 | 1769 | 60.0% | 11.3% | 15.0% | 0.753 |
| Mar-83 | May-86 | $3,539 | | 1798 | 66.3% | 18.4% | 24.6% | 0.747 |
| Jun-83 | May-86 | $3,539 | | 1969 | 72.8% | 19.6% | 26.2% | 0.747 |
| Sep-83 | May-86 | $3,539 | | 1991 | 77.7% | 17.7% | 23.6% | 0.750 |
| Dec-83 | May-86 | $3,539 | $604.9 | 2189 | 81.2% | 14.9% | 19.8% | 0.753 |
| Mar-84 | May-86 | $3,539 | | 1923 | 83.5% | 10.7% | 14.3% | 0.750 |
| Jun-84 | May-86 | $3,539 | | 1887 | 86.5% | 8.8% | 11.7% | 0.750 |
| Sep-84 | May-86 | $3,825 | | 1805 | 89.6% | 8.4% | 11.2% | 0.753 |
| Dec-84 | May-86 | $3,825 | $701.1 | 1556 | 93.2% | 9.7% | 12.9% | 0.753 |
| Mar-85 | May-86 | $3,825 | | 1010 | 94.4% | 7.9% | 10.6% | 0.747 |
| Jun-85 | May-86 | $3,825 | | 2151 | 96.9% | 7.3% | 9.8% | 0.747 |
| Sep-85 | May-86 | $3,825 | | 1197 | 98.5% | 5.3% | 7.1% | 0.750 |
| Dec-85 | May-86 | $3,825 | $707.5 | 614 | 99.5% | 5.1% | 6.8% | 0.753 |

TABLE 1.2: COST AND COD ESTIMATES OF PLANTS UNDER CONSTRUCTION
AS OF JANUARY 1, 1984

| PLANT | (MW) NET CAPACITY | UPDATED COST ESTIMATE | UPDATED COST PER KW | UPDATED COD ESTIMATE | SOURCE | AFUDC % of COST | OPERATING UTILITY | ARCHITECT/ ENGINEER | CONSTRUCTION MANAGER | REACTOR SUPPLR |
|---|---|---|---|---|---|---|---|---|---|---|
| Midland 1 | 1233 | cancelled | infinite | | | 30% | Consumers Pwr | Bechtel | Bechtel | B&W |
| Midland 2 | + | cancelled | infinite | | | | " | " | " | " |
| Zimmer 1 | 810 | cancelled | infinite | | | 35% | Cincinnati G&E | S&L | Kaiser | GE |
| Marble Hill 1 | 2260 | cancelled | infinite | | | 50% | PS of Indiana | S&L | Utility | W |
| Marble Hill 2 | + | cancelled | infinite | | | | " | " | " | " |
| Shoreham | 809 | $4.50 | $5,562 | * | N/* | 35% | LILCo | S&W | Utility | GE |
| Nine Mile Point 2 | 1084 | $5.35 | $4,935 | Oct-86 | T/T | 34% | Niagara Mohawk | S&W | S&W | GE |
| Beaver Valley 2 | 833 | $3.96 | $4,753 | Aug-87 | T/NN | 33% | Duquesne Light | S&W | Utility | W |
| River Bend 1 | 940 | $4.00 | $4,255 | Dec-85 | U/U | 24% | Gulf States | S&W | S&W | GE |
| Seabrook 1 | 1150 | $4.56 | $3,965 | Oct-86 | T/T | 36% | PSNH | UE&C | NH Yankee | W |
| Vogtle 1 | 2200 | $8.40 | $3,818 | Jun-87 | N/T | 34% | Georgia P&L | Util/Bech. | Utility | W |
| Vogtle 2 | + | + | | Sep-88 | +/T | | " | " | " | " |
| Harris 1 | 900 | $3.42 | $3,803 | Sep-86 | T/T | 26% | Carolina P&L | Ebasco | Daniel | W |
| Hope Creek 1 | 1067 | $3.80 | $3,557 | Dec-86 | T/T | 24% | Publ.Serv.E&G | Bechtel | Bechtel | GE |
| Limerick 1 | 2110 | $7.30 | $3,460 | Feb-86 | U/T | 31% | Philadel. Elec. | Bechtel | Bechtel | GE |
| Limerick 2 | + | + | | Jul-90 | +/U | | " | " | " | " |
| Fermi 2 | 1100 | $3.77 | $3,427 | Feb-86 | N/U | 31% | Detroit Ed. | Utility | Daniel | GE |
| Millstone 3 | 1150 | $3.83 | $3,326 | May-86 | T/T | 31% | Northeast Util. | S&W | S&W | W |
| South Texas 1 | 2500 | $8.30 | $3,320 | Jun-87 | U/T | 27% | Houston P&L | Bechtel | Ebasco | W |
| South Texas 2 | + | + | | Jun-89 | +/T | | " | " | " | " |
| Clinton 1 | 950 | $3.15 | $3,314 | Nov-86 | T/T | 25% | Illinois Power | S&L | Baldwin | GE |
| Perry 1 | 1205 | $3.90 | $3,237 | Mar-86 | U/T | 30% | Cleveland Elec. | Gilbert | Utility | GE |
| WNP-2 | 1100 | $3.32 | $3,022 | Dec-84 | U/NRC | - | WPPSS | B&R | Bechtel | GE |
| Grand Gulf 1 | 1250 | $3.50 | $2,800 | Jul-85 | U/NRC | 46% | Middle South | Bechtel | Bechtel | GE |
| Callaway 1 | 1150 | $3.00 | $2,609 | Dec-84 | T/NRC | 37% | Union Electric | Bechtel | Daniel | W |
| Wolf Creek | 1150 | $3.03 | $2,635 | Sep-85 | T/U | 32% | Kansas G&E | Bechtel/S&L | Daniel | W |
| Diablo Canyon 1 | 2190 | $5.56 | $2,538 | May-85 | T/NRC | 34% | Pacific G&E | Utility | Utility | W |
| Diablo Canyon 2 | + | + | | Nov-85 | +/T | | " | " | " | " |
| Palo Verde 1 | 3810 | $9.51 | $2,497 | Dec-85 | U/T | 37% | Arizona PS | Bechtel | Bechtel | CE |
| Palo Verde 2 | + | + | | Apr-86 | +/T | | " | " | " | " |
| Palo Verde 3 | + | + | | Jun-87 | +/T | | " | " | " | " |
| Waterford 3 | 1104 | $2.73 | $2,476 | Sep-85 | T/NRC | 21% | Louisiana P&L | Ebasco | Ebasco | CE |
| Comanche Peak 1 | 2300 | $5.46 | $2,374 | Jun-87 | T/N | 24% | Texas Utils. | Gibbs&Hill | Brwn&Root | W |
| Comanche Peak 2 | + | + | | Dec-87 | +/N | | " | " | " | " |
| Bellefonte 1 | 2426 | $5.66 | $2,333 | Jan-94 | U/T | 40% | TVA | Utility | Utility | B&W |
| Bellefonte 2 | + | + | | Jan-96 | +/T | | " | " | " | " |
| Braidwood 1 | 2240 | $5.01 | $2,237 | May-87 | N/N | 43% | Comm. Ed. | S&L | Utility | W |
| Braidwood 2 | + | + | | Sep-88 | +/N | | " | " | " | " |
| Byron 1 | 2240 | $4.65 | $2,076 | Sep-85 | N/NRC | 39% | Comm. Ed. | S&L | Utility | W |
| Byron 2 | + | + | | May-87 | +/N | | " | " | " | " |
| Susquehanna 2 | 1050 | $2.16 | $2,056 | Feb-85 | T/T | 31% | Pennsylv. P&L | Bechtel | Bechtel | GE |
| San Onofre 2 | 2200 | $4.50 | $2,045 | Aug-83 | T/T | | | | | |
| San Onofre 3 | + | + | | Apr-84 | +/T | 40% | S.Calif.Ed. | Bechtel | Utility | CE |
| Watts Bar 1 | 2354 | $4.10 | $1,742 | Jun-86 | U/U | 33% | TVA | Utility | Utility | W |
| Watts Bar 2 | + | + | | Apr-88 | +/U | | " | " | " | " |
| Catawba 1 | 2290 | $3.90 | $1,703 | Jun-85 | T/NRC | 35% | Duke Power | Utility | Utility | W |
| Catawba 2 | + | + | | Jun-87 | +/T | | Duke Power | Utility | Utility | W |
| Summer 1 | 900 | $1.28 | $1,426 | Jan-84 | T/NRC | 24% | South Carol.E&G | Gilbert | Daniel | W |
| LaSalle 2 | 1078 | $1.16 | $1,074 | Oct-84 | T/NRC | 22% | Comm. Ed. | S&L | Utility | GE |
| McGuire 2 | 1180 | $1.10 | $929 | Mar-84 | T/NRC | 33% | Duke Power | Utility | Utility | W |

Table 1.2 provides an update to the table in "Nuclear Follies," Forbes, James Cook, February 11, 1985, pp. 1, 82-100.

EXPLANATION OF COLUMNS (from left to right):

| | |
|---|---|
| PLANT | The plants listed are the same as those found in the Forbes Table with the addition of:<br>Midland 1 (adding 425 MW capacity, correcting the Forbes' cost per KW)<br>Limerick 2 (1066MW)<br>San Onofre 2 (1100 MW)<br>The plants are sorted by cost per KW with the cancelled plants listed first. |
| NET CAPACITY (MW) | Capacity ratings are the ones used by Forbes<br>(Ratings used by Forbes do not always agree with the NRC Grey and Yellow Book DER)<br>The combined Net Capacity of Bellefonte 1 & 2 was corrected as 2426 MW. |
| COST ESTIMATE<br>COD ESTIMATE<br>SOURCE | The cost estimate and COD were updated using several sources.<br>The updated estimates are referenced in the "Source" column as: source for cost estimate/source for COD estimate<br>U Data Per Telephone (6/85) from Utility<br>T Data from Tennessee Valley Authority, "US Nuclear Plants, Cost Per KW Report," March 1985<br>N Newspaper (Wall Street Journal or New York Times)<br>NRC NRC Grey Book, 12/84<br>* Paul Chernick's current estimate of Utility Cost Forecast |
| OPERATING UTILITY<br>ARCHITECT/ENGINEER<br>CONSTRUCTION MANAGER<br>REACTOR SUPPLIER | Information from the last four columns is from the Forbes article.<br>Only the operating utility is listed; Percent ownership was omitted |

\+ data for second unit combined with data for the first
average excludes San Onofre 2 & 3 as well as the cancelled plants
median excludes San Onofre 2 & 3 and includes cancelled plants

TABLE 1.3: MILLSTONE 3 OFFICIAL COST AND SCHEDULE ESTIMATE HISTORY

| Date of Estimate | In-Service Date | Total Estimated Project Costs ($ Million) |
|---|---|---|
| Jul-71 | Apr-78 | $400 |
| Mar-73 | May-79 | $650 |
| Jan-75 | Nov-79 | $808 |
| Jan-76 | May-82 | $1,010 |
| Mar-77 | May-82 | $1,185 |
| Jul-78 | May-86 | $2,000 |
| Jul-80 | May-86 | $2,600 |
| Aug-82 | May-86 | $3,540 |

Source: Data Request AG-5, 2/21/84, Q-AG-EJF-27, page 2 of 2.

TABLE 3.1: COST AND SCHEDULE OVERRUNS, Non-Turnkey and Non-Demonstration Units, Completed by 12/72

| | ---Actual---- | | ------Initial Estimates----- | | | Years | --Nominal--- | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| Unit Name | Cost | COD | Date of Est. | Cost | COD | to COD | Cost Ratio | Myopia | Duration Ratio | % Comp |
| Nine Mile Point 1** | 162 | Dec-69 | Mar-64 | 68 | Nov-68 | 4.67 | 2.39 | 1.205 | 1.232 | 0.0 |
| Palisades | 147 | Dec-71 | Mar-68 | 89 | May-70 | 2.17 | 1.65 | 1.259 | 1.731 | 31.0 |
| Vermont Yankee | 184 | Nov-72 | Sep-66 | 88 | Oct-70 | 4.08 | 2.10 | 1.199 | 1.510 | 0 |
| Pilgrim 1 | 239 | Dec-72 | Jul-65 | 70 | Jul-71 | 6.00 | 3.42 | 1.227 | 1.236 | |
| Turkey Point 3 | 109 | Dec-72 | Sep-69 | 99 | Jun-71 [1] | 1.75 | 1.10 | 1.055 | 1.861 | 52.2 |
| Maine Yankee*** | 219 | Dec-72 | Sep-67 | 100 | May-72 | 4.67 | 2.19 | 1.183 | 1.125 | |
| Surry 1*** | 247 | Dec-72 | Dec-66 | 130 | Mar-71 | 4.25 | 1.90 | 1.163 | 1.412 | 0.1 |
| AVERAGE | | | | | | 3.94 | 2.11 | 1.184 | 1.444 | |
| NUMBER of DATAPOINTS | | | | | | 7 | 7 | 7 | 7 | |

Notes: [1] From AEC. Month not given, June assumed.
[2] * architect/engineer= Stone & Webster, ** constructor= Stone & Webster,
*** architect/engineer and constructor= Stone & Webster.

TABLE 3.2: COST AND SCHEDULE SLIPPAGE, Completed Turnkey and Demonstration Units, through De

| Unit Name | --Actuals--- Cost | COD | ----First Available--- Estimates Date of Est. | Cost | COD | Est. Years to COD | Cost Ratio | Myopia | Duration Ratio | % Comp |
|---|---|---|---|---|---|---|---|---|---|---|
| Indian Point 1 [1] | 126 | Sep-62 | Jun-60 | 68 | Jan-62 | 1.58 | 1.86 | 1.478 | 1.421 | 78 |
| Humboldt [1] | 24 | Aug-63 | Jun-60 | 3 | Oct-62 | 2.33 | 8.16 | 2.458 | 1.357 | 0.0 |
| Oyster Creek 1 | 90 | Dec-69 | Jun-64 | 59 | Oct-67 | 3.33 | 1.52 | 1.135 | 1.650 | 0.0 |
| Ginna | 83 | Jul-70 | Dec-65 | 64 | Jun-69 | 3.50 | 1.30 | 1.078 | 1.310 | 0.0 |
| Dresden 2 | 83 | Jul-70 | Mar-66 | 79 [2] | Feb-69 | 2.92 | 1.05 | 1.016 | 1.486 | 6.0 |
| Point Beach 1 | 74 | Dec-70 | Jun-66 | 61 | Apr-70 | 3.83 | 1.21 | 1.052 | 1.174 | 0.0 |
| Millstone 1 | 97 | Mar-71 | Dec-65 | 81 [2] | Aug-69 | 3.67 | 1.20 | 1.050 | 1.432 | 0.0 |
| Robinson 2 | 78 | Mar-71 | Jun-66 | 76 | May-70 | 3.92 | 1.02 | 1.006 | 1.213 | 0.0 |
| Monticello | 105 | Jun-71 | Jun-66 | 74 [2] | May-70 | 3.92 | 1.42 | 1.093 | 1.277 | 0.0 |
| Dresden 3 | 104 | Nov-71 | Mar-66 | 81 [2] | Feb-70 | 3.92 | 1.28 | 1.065 | 1.447 | 2.0 |
| Point Beach 2 | 71 | Oct-72 | Mar-67 | 54 | Apr-71 | 4.08 | 1.32 | 1.071 | 1.367 | 0.0 |
| ALL UNITS | | | | | | | | | | |
| AVERAGE | | | | | | 3.36 | 1.94 | 1.227 | 1.376 | |
| # of Datapoints | | | | | | 11 | 11 | 11 | 11 | |
| ALL UNITS EXCEPT Indian Pt 1 & Humboldt | | | | | | | | | | |
| AVERAGE | | | | | | 3.68 | 1.26 | 1.06 | 1.37 | |
| # of Datapoints | | | | | | 9 | 9 | 9 | 9 | |

Notes: [1] Demonstration units
[2] Cost estimate as of 9/66

TABLE 3.3: COST GROWTH IN UNITS PLANNED OR UNDER CONSTRUCTION BY DECEMBER, 1972

| Unit Name | -----Estimates------ Date of Est. | Cost | COD | Years to COD | Years Elapsed | Cost Growth Rate | % Complete | Progress Ratio |
|---|---|---|---|---|---|---|---|---|
| Arkansas 1 | Dec-67 | 132 | Dec-72 | 5.00 | | | 0.0 | |
| | Sep-72 | 185 | Oct-73 | 1.08 | 4.76 | 7.4% | 86.8 | 0.82 |
| Arkansas 2 | Dec-70 | 183 | Oct-75 | 4.83 | | | 0.0 | |
| | Sep-72 | 230 | Oct-76 | 4.08 | 1.75 | 13.9% | 6.9 | 0.43 |
| Duane Arnold | Jun-68 | 103 | Dec-73 | 5.50 | | | 0.0 | |
| | Sep-72 | 192 | Jan-74 | 1.33 | 4.25 | 15.8% | 69.0 | 0.98 |
| Calvert Cliffs 1 | Jun-67 | 118 | Jan-73 | 5.58 | | | 0.0 | |
| | Sep-72 | 250 | Feb-74 | 1.42 | 5.26 | 15.3% | 72.0 | 0.79 |
| Calvert Cliffs 2 | Jun-67 | 105 | Jan-74 | 6.58 | | | 0.0 | |
| | Sep-72 | 204 | Jan-75 | 2.33 | 5.26 | 13.5% | 56.0 | 0.81 |
| Davis-Besse 1 | Dec-68 | 180 | Dec-74 | 6.00 | | | 0.0 | |
| | Dec-72 | 349 | May-75 | 2.42 | 4.00 | 18.0% | 40.0 | 0.90 |
| Farley 1 | Sep-69 | 164 | Apr-75 | 5.58 | | | 0.0 | |
| | Sep-71 | 259 | Apr-75 | 3.58 | 2.00 | 25.7% | 6.0 | 1.00 |
| Farley 2 | Sep-70 | 183 | Apr-77 | 6.58 | | | 0.0 | |
| | Sep-71 | 233 | Apr-77 | 5.58 | 1.00 | 27.3% | 0.0 | 1.00 |
| Hatch 1 | Mar-69 | 151 | Jun-73 | 4.25 | | | 1.5 | |
| | Dec-72 | 282 | Apr-74 | 1.33 | 3.76 | 18.1% | 69.0 | 0.78 |
| Hatch 2 | Jun-70 | 189 | NA | NA | | | NA | |
| | Dec-72 | 330 | Apr-78 | 5.33 | 2.50 | 24.9% | 11.0 | |
| Millstone 2 | Dec-67 | 150 | Apr-74 | 6.33 | | | 0.0 | |
| | Sep-72 | 282 | Apr-74 | 1.58 | 4.76 | 14.2% | 49.0 | 1.00 |
| Oconee 1 | Sep-70 | 109 | Jul-71 | 0.83 | | | 80.0 | |
| | Dec-72 | 137 | Jun-73 | 0.50 | 2.25 | 10.7% | 99.5 | 0.15 |
| Oconee 2 | Sep-70 | 109 | Jul-72 | 1.83 | | | 50.0 | |
| | Sep-71 | 137 | Feb-73 | 1.42 | 1.00 | 25.7% | 71.0 | 0.42 |
| Oconee 3 | Sep-70 | 109 | Jul-73 | 2.83 | | | 25.0 | |
| | Sep-71 | 137 | Nov-73 | 2.17 | 1.00 | 25.7% | 43.0 | 0.67 |
| Peach Bottom 2 | Dec-66 | 138 | NA | NA | | | 0.0 | |
| | Jun-72 | 352 | Sep-73 | 1.25 | 5.50 | 18.5% | 72.0 | |
| Peach Bottom 3 | Dec-66 | 125 | NA | NA | | | NA | |
| | Jun-72 | 316 | Sep-74 | 2.25 | 5.50 | 18.4% | 50.0 | |
| Rancho Seco | Dec-67 | 134 | May-73 | 5.42 | | | 0.0 | |
| | Sep-72 | 300 | Feb-74 | 1.42 | 4.76 | 18.5% | 78.0 | 0.84 |
| San Onofre 2 | Mar-70 | 189 | Jun-76 | 6.25 | | | 0.0 | |
| | Dec-72 | 360 | Oct-78 | 5.84 | 2.76 | 26.3% | 0.0 | 0.15 |
| Trojan | Dec-68 | 196 | Sep-74 | 5.75 | | | 0.0 | |
| | Dec-72 | 284 | Jul-75 | 2.58 | 4.00 | 9.7% | 57.0 | 0.79 |
| Turkey Point 4 | Mar-70 | 80 | NA | NA | | | 66.7 | |
| | Dec-72 | 106 | Jul-73 | 0.58 | 2.76 | 10.7% | 99.0 | |
| Grand Gulf 1 | Jun-72 | 600 | Dec-78 | 6.50 | | | 0.0 | |
| | Dec-72 | 656 | Jun-79 | 6.50 | 0.50 | 19.5% | 0.0 | 0.00 |
| Hope Creek 1 | Mar-70 | 574 | Mar-75 | 5.00 | | | 0.0 | |
| | Dec-72 | 1139 | May-79 | 6.42 | 2.76 | 28.2% | 0.0 | -0.51 |
| Limerick 1 | Mar-70 | 252 | Mar-75 | 5.00 | | | 0.0 | |
| | Dec-72 | 694 | Aug-78 | 5.67 | 2.76 | 44.4% | 1.0 | -0.24 |
| Limerick 2 | Mar-70 | 223 | Mar-77 | 7.00 | | | 0.0 | |
| | Dec-72 | 512 | Jan-80 | 7.08 | 2.76 | 35.2% | 1.0 | -0.03 |
| Midland 1 | Dec-71 | 277 | May-77 | 5.42 | | | 2.0 | |
| | Dec-72 | 383 | Feb-79 | 6.17 | 1.00 | 38.1% | 2.0 | -0.75 |
| Midland 2 | Dec-71 | 277 | May-78 | 6.42 | | | 2.0 | |
| | Dec-72 | 383 | Feb-80 | 7.17 | 1.00 | 38.1% | 2.0 | -0.75 |

| Unit Name | -----Estimates------ Date of Est. | Cost | COD | Years to COD | Years Elapsed | Cost Growth Rate | % Complete | Progress Ratio |
|---|---|---|---|---|---|---|---|---|
| San Onofre 3 | Mar-70 | 189 | Jun-76 | 6.25 | | | 0.0 | |
| | Dec-71 | 409 | NA | NA | 1.75 | 55.3% | 0.0 | |
| Bailly | Mar-67 | 113 | Dec-72 | 5.76 | | | NA | |
| | Jun-72 | 244 | Jun-77 | 5.00 | 5.26 | 15.8% | 0.0 | 0.14 |
| Shearon Harris 3 | Jun-71 | 935 | Mar-77 | 5.75 | | | 0.0 | |
| | Dec-72 | 1095 | Mar-78 | 5.25 | 1.50 | 11.1% | 0.0 | 0.34 |
| Diablo Canyon 1 | Mar-66 | 154 | Mar-72 | 6.01 | | | 0.0 | |
| | Jun-72 | 320 | Mar-75 | 2.75 | 6.26 | 12.4% | 46.5 | 0.52 |
| Diablo Canyon 2 | Dec-68 | 151 | Jul-74 | 5.58 | | | 0.0 | |
| | Jun-72 | 282 | Mar-76 | 3.75 | 3.50 | 19.5% | 9.9 | 0.52 |
| Beaver Valley 2* | Dec-71 | 296 | Mar-78 | 6.25 | | | 0.0 | |
| | Mar-72 | 360 | Mar-78 | 6.00 | 0.25 | 119.3% | 0.0 | 1.00 |
| Bellefonte 1 | Dec-71 | 312 | Jul-77 | 5.59 | | | 0.0 | |
| | Dec-72 | 348 | Sep-79 | 6.75 | 1.00 | 11.3% | 0.0 | -1.16 |
| Bellefonte 2 | Dec-71 | 312 | Jul-77 | 6.75 | | | | |
| | Dec-72 | 348 | Jun-80 | 6.75 | 1.00 | 11.3% | 0.0 | 0.00 |
| Byron 1 | Jun-71 | 400 | Oct-78 | 7.34 | | | 0.0 | |
| | Sep-72 | 464 | May-79 | 6.67 | 1.25 | 12.6% | 0.0 | 0.54 |
| Byron 2 | Jun-71 | 350 | Oct-79 | 8.34 | | | 0.0 | |
| | Jun-72 | 422 | Mar-80 | 7.75 | 1.00 | 20.5% | 0.0 | 0.58 |
| Fermi 2 | Mar-69 | 221 | Feb-74 | 4.93 | | | 0.0 | |
| | Dec-72 | 439 | Aug-76 | 3.67 | 3.76 | 20.0% | 28.5 | 0.33 |
| LaSalle 2 | Jun-70 | 300 | Oct-76 | 6.34 | | | 0.0 | |
| | Sep-72 | 330 | Sep-78 | 6.00 | 2.25 | 4.3% | 0.0 | 0.15 |
| McGuire 2 | Sep-70 | 179 | Nov-76 | 6.17 | | | 0.0 | |
| | Sep-71 | 220 | Mar-77 | 5.50 | 1.00 | 22.9% | 0.0 | 0.67 |
| Nine Mile Point 2*** | Dec-71 | 370 | Jul-78 | 6.59 | | | 0.0 | |
| | Sep-72 | 370 | Nov-78 | 6.17 | 0.75 | 0.0% | 0.0 | 0.55 |
| Shearon Harris 1 | Jun-71 | 234 | Mar-77 | 5.75 | | | 0.0 | |
| | Dec-72 | 274 | Mar-78 | 5.25 | 1.50 | 11.1% | 0.0 | 0.34 |
| Shearon Harris 2 | Jun-71 | 234 | Jun-78 | 5.75 | | | 0.0 | |
| | Dec-72 | 274 | Mar-79 | 5.25 | 1.50 | 11.1% | 0.0 | 0.34 |
| Shoreham * | Mar-67 | 105 | May-73 | 6.17 | | | 0.0 | |
| | Jun-72 | 309 | May-77 | 4.92 | 5.26 | 22.8% | 1.5 | 0.24 |
| Waterford 3 | Sep-70 | 230 | Jan-77 | 6.34 | | | 0.0 | |
| | Sep-72 | 350 | Jan-77 | 4.34 | 2.00 | 23.3% | 0.5 | 1.00 |
| Watts Bar 1 | Dec-71 | 301 | Aug-76 | 4.67 | | | 0.0 | |
| | Dec-72 | 324 | May-77 | 4.42 | 1.00 | 7.6% | 0.0 | 0.25 |
| Watts Bar 2 | Dec-71 | 301 | May-77 | 4.42 | | | | |
| | Dec-72 | 324 | Feb-78 | 4.42 | 1.00 | 7.6% | | 0.00 |
| Zimmer 1 | Dec-69 | 199 | Jan-75 | 5.09 | | | 0.0 | |
| | Dec-72 | 311 | Aug-77 | 4.67 | 3.00 | 16.0% | 1.0 | 0.14 |
| Summer 1 | Mar-71 | 234 | Jan-77 | 5.84 | | | 0.0 | |
| | Sep-72 | 297 | Jan-77 | 4.33 | 1.51 | 17.1% | 0.0 | 1.00 |
| Susquehanna 1 | Jun-69 | 150 | 27560 | 6.00 | | | 0.0 | |
| | Dec-72 | 703 | May-79 | 6.41 | 3.50 | 55.4% | 0.0 | -0.12 |
| Lasalle 1 | Jun-70 | 360 | Oct-75 | 5.33 | | | 0.0 | |
| | Sep-72 | 407 | Dec-77 | 5.25 | 2.25 | 5.6% | 0.0 | 0.04 |
| Sequoyah 2 | Dec-68 | 161 | Oct-73 | 4.83 | | | 0.0 | |
| | Dec-72 | 225 | Dec-75 | 3.00 | 4.00 | 8.7% | NA | 0.46 |
| McGuire 1 | Sep-70 | 179 | Nov-75 | 5.17 | | | 0.0 | |
| | Dec-72 | 220 | Mar-76 | 3.25 | 2.25 | 9.6% | 9.0 | 0.85 |

| Unit Name | -----Estimates------ Date of Est. | Cost | COD | Years to COD | Years Elapsed | Cost Growth Rate | % Complete | Progress Ratio |
|---|---|---|---|---|---|---|---|---|
| Salem 2 | Sep-67 | 128 | May-73 | 5.66 | | | 0.0 | |
| | Dec-72 | 425 | Mar-76 | 3.25 | 5.25 | 25.7% | NA | 0.46 |
| Sequoyah 1 | Sep-68 | 161 | Oct-73 | 5.08 | | | 0.0 | |
| | Dec-72 | 225 | Apr-75 | 2.33 | 4.25 | 8.1% | 45.0 | 0.65 |
| North Anna 2*** | Sep-70 | 184 | Mar-75 | 4.50 | | | NA | |
| | Dec-72 | 227 | Jul-75 | 2.58 | 2.25 | 9.8% | 28.2 | 0.85 |
| Three Mile I. 2 | Aug-69 | 214 | May-74 | 4.75 | | | NA | |
| | Aug-72 | 465 | May-76 | 3.75 | 3.00 | 29.5% | 25.0 | 0.33 |
| Cook 2 | Dec-67 | 235 | Apr-72 | 4.33 | | | NA | |
| | Sep-70 | 339 | Mar-74 | 3.50 | 2.75 | 14.2% | 19.0 | 0.30 |
| North Anna 1*** | Mar-69 | 185 | Mar-74 | 5.00 | | | 0.0 | |
| | Dec-72 | 407 | Dec-74 | 2.00 | 3.76 | 23.4% | 55.0 | 0.80 |
| Salem 1 | Sep-66 | 139 | May-71 | 4.70 | | | 0.0 | |
| | Dec-72 | 425 | Mar-75 | 2.25 | 6.25 | 19.6% | 53.0 | 0.39 |
| Browns Ferry 3 | Mar-68 | 124 | Oct-70 | 2.58 | | | 12.0 | |
| | Sep-72 | 149 | Oct-74 | 2.08 | 4.51 | 4.1% | | 0.11 |
| Crystal River 3 | Mar-67 | 110 | Apr-72 | 5.09 | | | 0.0 | |
| | Dec-72 | 283 | Nov-74 | 1.92 | 5.76 | 17.8% | 63.5 | 0.55 |
| Brunswick 1 | Dec-70 | 194 | Mar-76 | 5.25 | | | 4.0 | |
| | Dec-72 | 214 | Dec-75 | 3.00 | 2.00 | 5.0% | 42.0 | 1.12 |
| WNP 2 | Mar-71 | 187 | Sep-77 | 6.50 | | | 0.0 | |
| | Sep-72 | 374 | Sep-77 | 5.00 | 1.51 | 58.4% | NA | 1.00 |
| AVERAGES | | | | | | | | |
| Simple | | | | | 2.86 | 20.8% | | 0.42 |
| Weighted by Years | | | | | -- | 18.6% | | 0.43 |
| NUMBER OF DATAPOINTS: | | | | | 63 | 63 | | |

NOTES: [1] * architect/engineer=Stone & Webster
** constructor = Stone & Webster
*** architect/engineer and constructor = Stone & Webster

Table 3.4 intentionally omitted.

TABLE 3.5: COST AND SCHEDULE ESTIMATE HISTORIES
of New England Nuclear Units Completed by December, 1972

| Unit Name | Date of Estimate | ----Estimates----- Cost | COD |
|---|---|---|---|
| Connecticut Yankee | 1962 | 86 | 1967 |
| | 1963 | 99 | 1967 |
| | 1967 | 104 | 1967 |
| | Actual | 104 | Jan-68 |
| Millstone 1 | Dec-65 | | Aug-69 |
| | Mar-67 | 81 | Aug-69 |
| | Sep-67 | 84 | Aug-69 |
| | Dec-68 | 90 | Jan-70 |
| | Mar-69 | 90 | Mar-70 |
| | Sep-69 | 92 | Oct-70 |
| | Jun-70 | 92 | Nov-70 |
| | Sep-70 | 92 | Dec-70 |
| | Dec-70 | 92 | Feb-71 |
| | Actual | 97 | Mar-71 |
| Vermont Yankee | Sep-66 | 88 | Oct-70 |
| | Sep-69 | 120 | Jul-71 |
| | Mar-70 | 133 | Jul-71 |
| | Feb-71 | | Oct-71 |
| | Jul-71 | 154 | Mar-72 |
| | Dec-71 | | Sep-72 |
| | Actual | 184 | Nov-72 |
| Pilgrim 1 | Mar-64 | | Oct-71 |
| | Jul-65 | 70 | Jul-71 |
| | Feb-67 | 105 | Jul-71 |
| | Jun-68 | 122 | Sep-71 |
| | Jan-70 | 153 | Sep-71 |
| | Jun-70 | | Dec-71 |
| | Mar-71 | | Nov-71 |
| | Mar-71 | | Apr-72 |
| | Sep-72 | | Nov-72 |
| | Actual | 239 | Dec-72 |
| Maine Yankee*** | Sep-67 | 100 | May-72 |
| | Sep-68 | 131 | May-72 |
| | Mar-70 | 181 | May-72 |
| | Actual | 219 | Dec-72 |

*** architect/engineer and constructor=Stone & Webster

TABLE 3.6: NOMINAL AND REAL COST OVERRUNS AND SCHEDULE SLIPPAGE: Completed Units, with COD up to December, 1977.
From Estimate made at Construction Stage of about 18.3% to Actual Cost and COD

| Unit Name [1] | Actuals Cost | Actuals COD | C.P. issued | Estimate closest to 18.3% Completion: % Complete | Date of Estimate | Estimated Cost | Estimated COD | Years to COD | Nominal: Cost Ratio | Nominal: Myopia Factor | Real: Cost Ratio | Real: Annualized Growth Rate [2] | Actual Duration |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Nine Mile Point 1** | 162 | Dec-69 | Apr-65 | 0.0% | Sep-64 | 68 | Jul-68 | 3.83 | 2.39 | 1.255 | 2.14 | 1.16 | 5.25 |
| Palisades | 147 | Dec-71 | Mar-67 | 31.0% | Mar-68 | 89 | May-70 | 2.17 | 1.65 | 1.260 | 1.46 | 1.11 | 3.75 |
| Pilgrim 1 | 231 | Dec-72 | Aug-68 | 5.0% | Jun-68 | 122 | Sep-71 | 3.25 | 1.89 | 1.216 | 1.72 | 1.13 | 4.50 |
| Surry 1 *** | 247 | Dec-72 | Jun-68 | 15.2% | Dec-68 | 165 | Mar-71 | 2.25 | 1.50 | 1.196 | 1.31 | 1.07 | 4.00 |
| Turkey Point 3 | 109 | Dec-72 | Apr-67 | 52.2% | Sep-69 | 99 | Jun-71 | 1.75 | 1.10 | 1.055 | 0.98 | 0.99 | 3.25 |
| Surry 2*** | 150 | May-73 | Jun-68 | 20.8% | Dec-69 | 138 | Mar-72 | 2.25 | 1.09 | 1.038 | 0.99 | 1.00 | 3.41 |
| Oconee 1 | 156 | Jul-73 | Nov-67 | 24.5% | Sep-69 | 109 | May-72 | 2.66 | 1.13 | 1.046 | 1.31 | 1.07 | 3.83 |
| Indian Point 2 | 206 | Aug-74 | Oct-66 | 19.0% | Jun-67 | 106 | Jun-69 | 2.00 | 1.89 | 1.375 | 1.31 | 1.04 | 7.17 |
| Fort Calhoun 1 | 174 | Sep-73 | Jun-68 | 17.0% | Sep-68 | 92 | May-71 | 2.66 | 1.89 | 1.271 | 1.58 | 1.10 | 5.00 |
| Turkey Point 4 | 123 | Sep-73 | Apr-67 | 52.2% | Sep-69 | 41 | Jun-72 | 2.75 | 3.00 | 1.491 | 2.72 | 1.28 | 4.00 |
| Prairie Isl 1 | 233 | Dec-73 | Jun-68 | 0.5% | Dec-67 | 105 | May-72 | 4.42 | 2.22 | 1.198 | 1.96 | 1.12 | 6.00 |
| Zion 1 | 276 | Dec-73 | Dec-68 | 12.0% | Mar-69 | 205 | Apr-72 | 3.09 | 1.35 | 1.101 | 1.18 | 1.04 | 4.75 |
| Kewaunee | 202 | Jun-74 | Aug-68 | 20.0% | Jun-70 | 123 | Jun-72 | 2.00 | 1.64 | 1.281 | 1.41 | 1.09 | 4.00 |
| Cooper | 246 | Jul-74 | Jun-68 | 9.0% | Mar-68 | 127 | Apr-72 | 4.08 | 1.94 | 1.176 | 1.63 | 1.08 | 6.33 |
| Peach Bottom 2 | 522 | Jul-74 | Jan-68 | 4.4% | Mar-68 | 163 | Mar-71 | 3.00 | 3.20 | 1.474 | 2.48 | 1.15 | 6.33 |
| Browns Ferry 1 | 256 | Aug-74 | May-67 | 8.0% | Sep-67 | 124 | Oct-70 | 3.08 | 2.06 | 1.265 | 1.54 | 1.06 | 6.92 |
| Oconee 2 | 160 | Sep-74 | Nov-67 | 17.7% | Mar-69 | 93 | May-72 | 3.17 | 1.72 | 1.188 | 1.44 | 1.07 | 5.50 |
| Three Mile I. 1 | 398 | Sep-74 | May-68 | 18.0% | Jun-69 | 162 | Sep-71 | 2.25 | 2.46 | 1.491 | 1.95 | 1.14 | 5.25 |
| Zion 2 | 290 | Sep-74 | Dec-68 | 9.0% | Mar-69 | 194 | May-73 | 4.17 | 1.49 | 1.101 | 1.35 | 1.06 | 5.50 |
| Arkansas 1 | 233 | Dec-74 | Dec-68 | 1.0% | Mar-69 | 132 | Dec-72 | 3.75 | 1.77 | 1.163 | 1.51 | 1.07 | 5.75 |
| Oconee 3 | 160 | Dec-74 | Nov-67 | 17.7% | Mar-69 | 93 | Jun-73 | 4.25 | 1.72 | 1.137 | 1.54 | 1.08 | 5.75 |
| Peach Bottom 3 | 220 | Dec-74 | Jan-68 | 13.0% | Mar-70 | 221 | Mar-73 | 3.00 | 1.00 | 0.998 | 0.87 | 0.97 | 4.75 |
| Prairie Isl 2 | 172 | Dec-74 | Jun-68 | 20.0% | Dec-71 | 145 | May-74 | 2.41 | 1.19 | 1.073 | 1.13 | 1.04 | 3.00 |
| Duane Arnold | 202 | Feb-75 | Jun-70 | 10.0% | Dec-70 | 148 | Dec-73 | 3.00 | 1.36 | 1.109 | 1.25 | 1.05 | 4.17 |
| Browns Ferry 2 | 256 | Mar-75 | May-67 | 12.0% | Mar-68 | 124 | Oct-70 | 2.58 | 2.06 | 1.324 | 1.47 | 1.06 | 7.00 |
| Rancho Seco | 344 | Apr-75 | Oct-68 | 0.0% | Dec-67 | 134 | May-73 | 5.42 | 2.56 | 1.190 | 2.21 | 1.11 | 7.33 |
| Calvert Cliffs 1 | 429 | May-75 | Jul-69 | 24.0% | Sep-70 | 170 | Jan-73 | 2.34 | 2.52 | 1.486 | 2.11 | 1.17 | 4.66 |
| Fitzpatrick*** | 419 | Jul-75 | May-70 | 1.0% | Mar-68 | 224 | May-73 | 5.17 | 1.87 | 1.129 | 1.58 | 1.06 | 7.33 |
| Cook 1 | 538 | Aug-75 | Mar-69 | 19.0% | Sep-70 | 339 | Mar-73 | 2.50 | 1.59 | 1.203 | 1.32 | 1.06 | 4.91 |
| Brunswick 2 | 382 | Nov-75 | Feb-70 | 10.0% | Dec-70 | 195 | Mar-74 | 3.25 | 1.96 | 1.230 | 1.72 | 1.12 | 4.92 |
| Hatch 1 | 390 | Dec-75 | Sep-69 | 10.0% | Sep-72 | 184 | Mar-74 | 1.49 | 2.12 | 1.654 | 1.85 | 1.21 | 3.25 |
| Millstone 2 | 418 | Dec-75 | Dec-70 | 24.0% | Sep-71 | 252 | Apr-74 | 2.58 | 1.66 | 1.217 | 1.46 | 1.09 | 4.25 |
| Trojan | 452 | Dec-75 | Feb-71 | 30.0% | Mar-72 | 233 | Sep-74 | 2.50 | 1.94 | 1.303 | 1.76 | 1.16 | 3.75 |
| St. Lucie 1 | 470 | Jun-76 | Jul-70 | 17.0% | Dec-71 | 218 | Jun-74 | 2.50 | 2.16 | 1.360 | 1.85 | 1.15 | 4.50 |
| Indian Point 3 | 570 | Aug-76 | Aug-69 | 14.7% | Jun-69 | 156 | Apr-72 | 2.83 | 3.65 | 1.580 | 2.61 | 1.14 | 7.21 |
| Beaver Valley 1*** | 599 | Oct-76 | Jun-70 | 23.0% | Sep-70 | 219 | Jun-73 | 2.75 | 2.73 | 1.442 | 2.12 | 1.13 | 6.08 |
| Browns Ferry 3 | 301 | Mar-77 | Jul-68 | 12.0% | Mar-68 | 124 | Oct-70 | 2.58 | 2.43 | 1.409 | 1.48 | 1.04 | 9.00 |
| Brunswick 1 | 318 | Mar-77 | Feb-70 | 17.0% | Jun-71 | 182 | Mar-75 | 3.75 | 1.75 | 1.161 | 1.50 | 1.07 | 5.75 |
| Crystal River 3 | 366 | Mar-77 | Sep-68 | 2.0% | Jun-69 | 148 | Apr-72 | 2.83 | 2.47 | 1.376 | 1.69 | 1.07 | 7.75 |
| Calvert Cliffs 2 | 335 | Apr-77 | Jul-69 | 21.0% | Sep-70 | 128 | Jan-74 | 3.33 | 2.62 | 1.335 | 2.04 | 1.11 | 6.58 |
| Salem 1 | 850 | Jun-77 | Sep-68 | 20.0% | Mar-70 | 237 | Dec-72 | 2.75 | 3.59 | 1.590 | 2.54 | 1.14 | 7.25 |
| Farley 1 | 727 | Dec-77 | Aug-72 | 6.0% | Sep-71 | 259 | Apr-75 | 3.58 | 2.81 | 1.334 | 2.29 | 1.14 | 6.25 |
| AVERAGE | | | | 15.7% | | | | | 2.03 | 1.27 | 1.68 | 1.10 | |
| NUMBER OF DATAPOINTS: | | | | 42 | | | | | 42 | 42 | 42 | 42 | |

Notes: 1. Excluded are: turnkey and demonstration plants because their cost is not meaningful in this context, and two early New England plants, Maine Yankee and Vermont Yankee, for which the data is very incomplete.
2. Real Cost Ratio = Actual cost deflated at 8% to Estimated COD / Estimated Cost
3. * architect= Stone & Webster, ** constructor = Stone & Webster,
*** architect/engineer and constructor = Stone & Webster.

Table 3.6 Results Applied to Northeast Utilities Estimate

NU COST AND SCHEDULE ESTIMATE OF: Jul-78

| | | |
|---|---|---|
| - Cost: | $2,000 | Million |
| - COD: | May-86 | |
| - Duration: | 7.84 | |

| Projection Method | Cost Multiplier | Cost | Averages |
|---|---|---|---|
| 1. Nominal Cost Ratio | 2.03 | $4,054 | |
| 2. Nominal Myopia Factor | 6.46 | $12,912 | $8,483 |
| 3. Real Cost Ratio | 1.68 | $3,350 | |
| 4. Annual Growth Rate | 2.05 | $4,090 | $3,720 |
| | | | ------- |
| | | | $6,101 |

Notes: 1. Cost Multiplier = Average Nominal Cost Ratio
2. Cost Multiplier = Average Nominal Myopia Factor raised to NU Duration.
3. Cost Multiplier = Average Real Cost Ratio
4. Cost Multiplier = Annual Growth Rate raised to NU Duration.

Source: Data Req. AG-5, 2/21/84, Q-AG-EJF-27, p.2 of 2

| Unit Name | C.P. Issuance | Cost & Schedule Estimates Date [1] | Cost | COD | Years to Go | Years between Estimates | Cost Ratio | Years between CODs | Reduction Years To Go | COST GROWTH RATE Nominal | Real | Progress Rate | Percent Complete |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Arkansas 2 | Dec-72 | Jun-73 | 275 | Oct-76 | 3.33 | | | | | | | | 13.6% |
| Arkansas 2 | | Dec-75 | 393 | Mar-78 | 2.25 | 2.50 | 1.43 | 1.41 | 1.09 | 15% | 10% | 43% | 56.4% |
| Bailly Nuclear 1 | May-74 | Sep-74 | 447 | Jun-77 | 2.75 | | | | | | | | 0.5% |
| Bailly Nuclear 1 | | Dec-77 | 705 | Jun-84 | 6.50 | 3.25 | 1.58 | 7.00 | -3.75 | 15% | -3% | -115% | 0.5% |
| Beaver Valley 2* | May-74 | Sep-74 | 685 | Jun-81 | 6.75 | | | | | | | | 0.1% |
| Beaver Valley 2 | | Dec-77 | 942 | May-82 | 4.41 | 3.25 | 1.38 | 0.91 | 2.34 | 10% | 8% | 72% | 15.0% |
| Bellefonte 1 | Dec-74 | Mar-75 | 482 | Jun-80 | 5.26 | | | | | | | | 3.0% |
| Bellefonte 1 | | Dec-77 | 632 | Jun-80 | 2.50 | 2.75 | 1.31 | 0.00 | 2.76 | 10% | 10% | 100% | 52.0% |
| Bellefonte 2 | Dec-74 | Mar-75 | 482 | Mar-81 | 6.01 | | | | | | | | 0.0% |
| Bellefonte 2 | | Dec-77 | 632 | Mar-81 | 3.25 | 2.75 | 1.31 | 0.00 | 2.76 | 10% | 10% | 100% | 37.0% |
| Braidwood 1 | Dec-75 | Mar-76 | 716 | Oct-81 | 5.59 | | | | | | | | 1.0% |
| Braidwood 1 | | Sep-77 | 829 | Oct-81 | 4.08 | 1.50 | 1.16 | 0.00 | 1.51 | 10% | 10% | 100% | 21.0% |
| Braidwood 2 | Dec-75 | Mar-76 | 485 | Oct-82 | 6.59 | | | | | | | | 1.0% |
| Braidwood 2 | | Sep-77 | 519 | Oct-82 | 5.08 | 1.50 | 1.07 | 0.00 | 1.51 | 5% | 5% | 100% | 18.0% |
| Browns Ferry 3 | Jul-68 | Jun-69 | 149 | Oct-72 | 1.33 | | | | | | | | 26.0% |
| Browns Ferry 3 | | Jun-75 | 246 | Feb-85 | 9.66 | 6.00 | 1.65 | 12.33 | -8.33 | 9% | -7% | -139% | NA |
| Brunswick 1 | Feb-70 | Dec-70 | 194 | Mar-76 | 5.25 | | | | | | | | 4.0% |
| Brunswick 1 | | Dec-75 | 281 | Jun-76 | 0.50 | 5.00 | 1.45 | 0.25 | 4.75 | 8% | 7% | 95% | 1.0% |
| Byron 1 | Dec-75 | Mar-76 | 663 | Oct-80 | 4.59 | | | | | | | | 6.0% |
| Byron 1 | | Dec-77 | 862 | Sep-81 | 3.75 | 1.75 | 1.30 | 0.92 | 0.84 | 16% | 12% | 48% | 33.0% |
| Byron 2 | Dec-75 | Mar-76 | 487 | Oct-82 | 6.59 | | | | | | | | 6.0% |
| Byron 2 | | Sep-77 | 538 | Oct-82 | 5.08 | 1.50 | 1.10 | 0.00 | 1.51 | 7% | 7% | 100% | 23.0% |
| Callaway 1 | Apr-76 | Dec-76 | 1088 | Jun-82 | 5.50 | | | | | | | | 2.7% |
| Callaway 1 | | Dec-77 | 1122 | Oct-82 | 4.83 | 1.00 | 1.03 | 0.33 | 0.67 | 3% | 1% | 67% | 11.2% |
| Callaway 2 | Apr-76 | Dec-76 | 1297 | Apr-87 | 10.33 | | | | | | | | 0.4% |
| Callaway 2 | | Dec-77 | 1288 | Apr-87 | 9.33 | 1.00 | 0.99 | 0.00 | 1.00 | -1% | -1% | 100% | 0.4% |
| Calvert Cliffs 2 | Jul-69 | Mar-69 | 105 | Jan-74 | 4.84 | | | | | | | | 2.0% |
| Calvert Cliffs 2 | | Dec-75 | 259 | Jan-77 | 1.09 | 6.75 | 2.47 | 3.00 | 3.75 | 14% | 10% | 56% | 0.9% |
| Catawba 1 | Aug-75 | Dec-74 | 542 | Jan-81 | | | | | | | | | 0.7% |
| Catawba 1 | | Mar-77 | 649 | Jul-81 | 4.33 | 2.25 | 1.20 | 0.50 | -4.33 | 8% | 7% | -193% | 11.5% |
| Catawba 2 | Aug-75 | Dec-74 | 542 | Jan-82 | 7.09 | | | | | | | | 0.0% |
| Catawba 2 | | Mar-77 | 649 | Jan-83 | 5.84 | 2.25 | 1.20 | 1.00 | 1.25 | 8% | 5% | 56% | 11.5% |
| Clinton 1 | Feb-76 | Sep-76 | 825 | Jun-81 | 4.75 | | | | | | | | 6.0% |
| Clinton 1 | | Dec-77 | 1051 | Dec-81 | 4.00 | 1.25 | 1.27 | 0.50 | 0.75 | 21% | 18% | 60% | 20.0% |
| Clinton 2 | Feb-76 | Sep-76 | 699 | Jun-84 | 7.75 | | | | | | | | 0.0% |
| Clinton 2 | | Dec-77 | 1059 | Jun-88 | 10.50 | 1.25 | 1.52 | 4.00 | -2.75 | 39% | 9% | -220% | 0.0% |

| Unit Name | C.P. Issuance | Cost & Schedule Estimates Date [1] | Cost | COD | Years to Go | Years between Estimates | Cost Ratio | Years between CODs | Years Reduction To Go | COST GROWTH RATE Nominal | Real | Progress Rate | Percent Complete |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Comanche Peak 1 | Dec-74 | Mar-74 | 355 | Jan-80 | 5.84 | | | | | | | | 0.0% |
| Comanche Peak 1 | | Jun-77 | 850 | Jan-81 | 3.59 | 3.25 | 2.39 | 1.00 | 2.25 | 31% | 28% | 69% | 39.0% |
| Comanche Peak 2 | Dec-74 | Mar-74 | 355 | Jan-82 | 7.84 | | | | | | | | 0.0% |
| Comanche Peak 2 | | Jun-77 | 850 | Jan-83 | 5.59 | 3.25 | 2.39 | 1.00 | 2.26 | 31% | 28% | 69% | 9.7% |
| Cook 2 | Mar-69 | Jun-69 | 235 | Sep-72 | 3.25 | | | | | | | | 1.0% |
| Cook 2 | | Dec-76 | 437 | 28656 | 1.50 | 7.50 | 1.86 | 5.75 | 1.75 | 9% | 2% | 23% | 82.4% |
| Crystal River 3 | Sep-68 | Jun-69 | 148 | Apr-72 | 2.83 | | | | | | | | 2.0% |
| Crystal River 3 | | Jun-75 | 420 | Sep-76 | 1.25 | 6.00 | 2.84 | 4.42 | 1.58 | 19% | 12% | 26% | 95.0% |
| Davis-Besse 1 | Mar-71 | Sep-70 | 266 | Dec-74 | 4.25 | | | | | | | | 2.0% |
| Davis-Besse 1 | | Dec-75 | 533 | Mar-77 | 1.25 | 5.25 | 2.00 | 2.25 | 3.00 | 14% | 10% | 57% | 95.0% |
| Diablo Canyon 1 | Apr-68 | Dec-68 | 154 | Jan-73 | 4.09 | | | | | | | | 0.0% |
| Diablo Canyon 1 | | Sep-77 | 672 | Jun-78 | 0.75 | 8.75 | 4.36 | 5.41 | 3.34 | 18% | 13% | 38% | 99.2% |
| Diablo Canyon 2 | Dec-70 | Mar-71 | 185 | May-75 | 4.17 | | | | | | | | 0.0% |
| Diablo Canyon 2 | | Sep-77 | 548 | Jun-78 | 0.75 | 6.51 | 2.96 | 3.09 | 3.42 | 18% | 14% | 53% | 90.9% |
| Farley 1 | Feb-71 | Sep-71 | 259 | Apr-75 | 3.58 | | | | | | | | 6.0% |
| Farley 1 | | Jun-76 | 614 | Jun-77 | 1.00 | 4.75 | 2.37 | 2.17 | 2.58 | 20% | 16% | 54% | 91.0% |
| Farley 2 | Aug-72 | Mar-73 | 268 | Apr-77 | 4.08 | | | | | | | | 5.3% |
| Farley 2 | | Jun-77 | 689 | Apr-80 | 2.83 | 4.25 | 2.57 | 3.00 | 1.25 | 25% | 18% | 29% | 45.0% |
| Fermi 2 | Sep-72 | Dec-72 | 439 | Aug-76 | 3.67 | | | | | | | | 28.5% |
| Fermi 2 | | Mar-77 | 882 | Dec-80 | 3.75 | 4.25 | 2.01 | 4.33 | -0.09 | 18% | 9% | -2% | 46.0% |
| Forked River 1 | Jul-73 | Mar-75 | 694 | May-82 | 7.17 | | | | | | | | 0.5% |
| Forked River 1 | | Dec-76 | 894 | May-83 | 6.41 | 1.75 | 1.29 | 1.00 | 0.76 | 16% | 11% | 43% | 0.5% |
| Grand Gulf 1 | Sep-74 | Sep-75 | 689 | Sep-79 | 4.00 | | | | | | | | 11.0% |
| Grand Gulf 1 | | Dec-77 | 1174 | Apr-81 | 3.33 | 2.25 | 1.70 | 1.58 | 0.67 | 27% | 20% | 30% | 57.9% |
| Grand Gulf 2 | Sep-74 | Sep-75 | 699 | Sep-83 | 8.00 | | | | | | | | 1.6% |
| Grand Gulf 2 | | Dec-77 | 954 | Jan-84 | 6.08 | 2.25 | 1.36 | 0.33 | 1.92 | 15% | 14% | 85% | 2.4% |
| Hartsville A-1 | May-77 | Jun-77 | 602 | Jun-83 | 6.00 | | | | | | | | 3.0% |
| Hartsville A-1 | | Sep-77 | 854 | Jun-83 | 5.75 | 0.25 | 1.42 | 0.00 | 0.26 | 301% | 301% | 102% | 5.0% |
| Hartsville A-2 | May-77 | Jun-77 | 602 | Jun-84 | 7.01 | | | | | | | | 1.0% |
| Hartsville A-2 | | Sep-77 | 854 | Jun-84 | 6.75 | 0.25 | 1.42 | 0.00 | 0.26 | 301% | 301% | 102% | 2.0% |
| Hartsville B-1 | May-77 | Jun-77 | 602 | Dec-83 | 6.50 | | | | | | | | NA |
| Hartsville B-1 | | Sep-77 | 854 | Dec-83 | 6.25 | 0.25 | 1.42 | 0.00 | 0.26 | 301% | 301% | 102% | 3.0% |
| Hartsville B-2 | May-77 | Jun-77 | 602 | Dec-84 | 7.51 | | | | | | | | NA |
| Hartsville B-2 | | Sep-77 | 854 | Dec-84 | 7.25 | 0.25 | 1.42 | 0.00 | 0.26 | 301% | 301% | 102% | NA |
| Hatch 2 | Dec-72 | Dec-72 | 330 | Apr-78 | 5.33 | | | | | | | | 11.0% |

| Unit Name | C.P. Issuance | Date [1] | Cost | COD | Years to Go | Years between Estimates | Cost Ratio | Years Reduction between CODs | Years To Go | COST GROWTH RATE Nominal | Real | Progress Rate | Percent Complete |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Hatch 2 | | Jun-76 | 512 | Apr-79 | 2.83 | 3.50 | 1.55 | 1.00 | 2.50 | 13% | 11% | 71% | 57.0% |
| Hope Creek 1 | Nov-74 | Mar-75 | 1972 | Dec-82 | 7.75 | | | | | | | | 0.0% |
| Hope Creek 1 | | Sep-76 | 2580 | May-84 | 7.66 | 1.51 | 1.31 | 1.42 | 0.09 | 20% | 11% | 6% | 2.0% |
| Lasalle 1 | Sep-73 | Sep-73 | 430 | Dec-78 | 5.25 | | | | | | | | 0.0% |
| Lasalle 1 | | Sep-77 | 675 | Sep-79 | 2.00 | 4.00 | 1.57 | 0.75 | 3.25 | 12% | 10% | 81% | 55.0% |
| LaSalle 2 | Sep-73 | Sep-74 | 343 | Oct-79 | 5.08 | | | | | | | | 3.0% |
| LaSalle 2 | | Sep-77 | 513 | Sep-80 | 3.00 | 3.00 | 1.50 | 0.92 | 2.08 | 14% | 12% | 69% | 45.0% |
| Limerick 1 | Jun-74 | Sep-74 | 1212 | Apr-81 | 6.58 | | | | | | | | 2.0% |
| Limerick 1 | | Jun-77 | 1635 | Apr-83 | 5.83 | 2.75 | 1.35 | 2.00 | 0.75 | 12% | 5% | 27% | 32.0% |
| Limerick 2 | Jun-74 | Dec-74 | 539 | Jul-82 | 7.58 | | | | | | | | 8.0% |
| Limerick 2 | | Jun-77 | 949 | Apr-85 | 7.83 | 2.50 | 1.76 | 2.75 | -0.25 | 25% | 15% | -10% | 22.0% |
| McGuire 1 | Feb-73 | Sep-73 | 220 | Nov-76 | 3.17 | | | | | | | | 22.2% |
| McGuire 1 | | Sep-77 | 466 | Jul-79 | 1.83 | 4.00 | 2.12 | 2.66 | 1.34 | 21% | 15% | 33% | 86.0% |
| McGuire 2 | Feb-73 | Sep-73 | 220 | Sep-77 | 4.00 | | | | | | | | 16.4% |
| McGuire 2 | | Sep-77 | 466 | Mar-81 | 3.50 | 4.00 | 2.12 | 3.50 | 0.51 | 21% | 13% | 13% | 54.0% |
| Midland 1 | Dec-72 | Jun-73 | 385 | Mar-80 | 6.75 | | | | | | | | 2.0% |
| Midland 1 | | Jun-76 | 700 | Mar-82 | 5.75 | 3.00 | 1.82 | 2.00 | 1.00 | 22% | 16% | 33% | 13.0% |
| Midland 2 | Dec-72 | Dec-72 | 383 | Feb-80 | 7.17 | | | | | | | | 2.0% |
| Midland 2 | | Jun-76 | 700 | Mar-81 | 4.75 | 3.50 | 1.83 | 1.08 | 2.42 | 19% | 16% | 69% | 16.0% |
| Nine Mile Point 2* | Jun-74 | Mar-75 | 749 | Oct-82 | 7.59 | | | | | | | | 1.0% |
| Nine Mile Point 2 | | Dec-77 | 1505 | Oct-83 | 5.83 | 2.75 | 2.01 | 1.00 | 1.76 | 29% | 25% | 64% | 17.5% |
| North Anna 1*** | Feb-71 | Jun-71 | 308 | Mar-74 | 2.75 | | | | | | | | 29.0% |
| North Anna 1 | | Mar-76 | 567 | Apr-77 | 1.08 | 4.75 | 1.84 | 3.09 | 1.66 | 14% | 8% | 35% | 88.8% |
| North Anna 2*** | Feb-71 | Sep-71 | 191 | Jun-75 | 3.75 | | | | | | | | 7.8% |
| North Anna 2 | | Sep-77 | 426 | Mar-79 | 1.49 | 6.00 | 2.23 | 3.75 | 2.25 | 14% | 9% | 38% | 86.6% |
| North Anna 3*** | Jul-74 | Dec-74 | 432 | Jun-80 | 5.50 | | | | | | | | 3.6% |
| North Anna 3 | | Dec-77 | 818 | Oct-83 | 5.83 | 3.00 | 1.89 | 3.33 | -0.33 | 24% | 14% | -11% | 7.0% |
| North Anna 4*** | Jul-74 | Sep-74 | 281 | Dec-79 | 5.25 | | | | | | | | 1.7% |
| North Anna 4 | | Dec-77 | 568 | Sep-84 | 6.75 | 3.25 | 2.02 | 4.75 | -1.50 | 24% | 11% | -46% | 3.7% |
| Palo Verde 1 | May-76 | Dec-75 | 975 | May-82 | 6.42 | | | | | | | | 0.0% |
| Palo Verde 1 | | Dec-77 | 989 | May-82 | 4.41 | 2.00 | 1.01 | 0.00 | 2.00 | 1% | 1% | 100% | 21.9% |
| Salem 1 | Sep-68 | Dec-67 | 152 | Mar-72 | 4.25 | | | | | | | | 0.0% |
| Salem 1 | | Mar-75 | 678 | Sep-76 | 5.75 | 7.25 | 4.46 | 4.50 | -1.50 | 23% | 17% | -21% | 90.5% |
| Salem 2 | Sep-68 | Dec-67 | 128 | Mar-73 | 5.25 | | | | | | | | 0.0% |
| Salem 2 | | Sep-74 | 496 | May-79 | 4.66 | 6.75 | 3.88 | 6.17 | 0.59 | 22% | 14% | 9% | 48.5% |

| Unit Name | C.P. Issuance | Date [1] | Cost | COD | Years to Go | Years between Estimates | Cost Ratio | Years between CODs | Reduction Years To Go | COST GROWTH RATE Nominal | Real | Progress Rate | Percent Complete |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Cost & Schedule Estimates | | | | | | | | | | | |
| San Onofre 2 | Oct-73 | Mar-74 | 655 | Jun-79 | 5.25 | | | | | | | | 0.0% |
| San Onofre 2 | | Jun-77 | 1320 | Oct-81 | 4.33 | 3.25 | 2.02 | 2.34 | 0.92 | 24% | 17% | 28% | 44.0% |
| San Onofre 3 | Oct-73 | Mar-74 | 655 | Jun-80 | 6.25 | | | | | | | | 0.0% |
| San Onofre 3 | | Jun-77 | 1080 | Jan-83 | 5.59 | 3.25 | 1.65 | 2.58 | 0.66 | 17% | 10% | 20% | 30.0% |
| Seabrook 1 | Jul-76 | Dec-76 | 684 | Nov-81 | 4.92 | | | | | | | | 1.0% |
| Seabrook 1 | | Dec-77 | 1375 | Dec-82 | 5.00 | 1.00 | 2.01 | 1.08 | -0.08 | 101% | 85% | -8% | 8.0% |
| Seabrook 2 | Jul-76 | Dec-76 | 684 | Nov-83 | 6.92 | | | | | | | | 1.0% |
| Seabrook 2 | | Dec-77 | 825 | Dec-84 | 7.00 | 1.00 | 1.21 | 1.08 | -0.08 | 21% | 11% | -8% | 1.0% |
| Sequoyah 1 | May-70 | Jun-70 | 187 | Apr-74 | 3.83 | | | | | | | | 5.0% |
| Sequoyah 1 | | Mar-77 | 475 | Sep-78 | 1.50 | 6.75 | 2.54 | 4.42 | 2.33 | 15% | 9% | 35% | 75.0% |
| Sequoyah 2 | May-70 | Sep-70 | 187 | Dec-74 | 4.25 | | | | | | | | NA |
| Sequoyah 2 | | Mar-77 | 475 | May-79 | 2.17 | 6.50 | 2.54 | 4.41 | 2.08 | 15% | 10% | 32% | 65.0% |
| Shoreham * | Apr-73 | Dec-73 | 461 | Jul-77 | 5.92 | | | | | | | | 6.0% |
| Shoreham | | Sep-77 | 1188 | Sep-80 | 3.00 | 3.75 | 2.58 | 3.17 | 2.92 | 29% | 21% | 78% | 62.0% |
| St. Lucie 2 | Nov-72 | Dec-72 | 360 | Oct-78 | 5.83 | | | | | | | | 0.0% |
| St. Lucie 2 | | Jun-77 | 850 | May-83 | 5.91 | 4.50 | 2.36 | 4.58 | -0.08 | 21% | 12% | -2% | 1.0% |
| Summer 1 | Mar-73 | Jun-73 | 297 | Jan-78 | 4.59 | | | | | | | | 0.1% |
| Summer 1 | | Dec-76 | 635 | May-80 | 3.41 | 3.50 | 2.14 | 2.33 | 1.17 | 24% | 18% | 33% | 42.5% |
| Surry 3* | Dec-74 | Mar-75 | 728 | May-83 | 8.17 | | | | | | | | 0.0% |
| Surry 3 | | Jun-76 | 1074 | Apr-86 | 9.83 | 1.25 | 1.48 | 2.92 | -1.66 | 36% | 14% | -132% | 0.0% |
| Surry 4* | Dec-74 | Mar-75 | 506 | May-84 | 9.18 | | | | | | | | 0.0% |
| Surry 4 | | Jun-76 | 765 | Apr-87 | 10.83 | 1.25 | 1.51 | 2.92 | -1.66 | 39% | 16% | -132% | 0.0% |
| Susquehanna 1 | Nov-73 | Sep-74 | 810 | Nov-80 | 6.17 | | | | | | | | 4.0% |
| Susquehanna 1 | | Mar-77 | 1097 | Nov-80 | 3.67 | 2.50 | 1.35 | 0.00 | 2.50 | 13% | 13% | 100% | 44.0% |
| Susquehanna 2 | Nov-73 | Mar-74 | 575 | Jun-81 | 7.25 | | | | | | | | 1.0% |
| Susquehanna 2 | | Sep-77 | 710 | May-82 | 4.66 | 3.50 | 1.23 | 0.91 | 2.59 | 6% | 4% | 74% | 35.9% |
| Three Mile I. 2 | Nov-69 | Sep-70 | 285 | May-74 | 3.66 | | | | | | | | NA |
| Three Mile I. 2 | | Aug-76 | 637 | May-78 | 1.75 | 5.92 | 2.24 | 4.00 | 1.92 | 15% | 9% | 32% | 81.0% |
| Vogtle 1 | Jun-74 | Jun-74 | 629 | Apr-80 | 5.83 | | | | | | | | 0.0% |
| Vogtle 1 | | Dec-77 | 1537 | Nov-84 | 6.92 | 3.50 | 2.44 | 4.59 | -1.08 | 29% | 17% | -31% | 5.0% |
| Vogtle 2 | Jun-74 | Jun-74 | 534 | Apr-81 | 6.83 | | | | | | | | 0.0% |
| Vogtle 2 | | Dec-77 | 1075 | Nov-85 | 7.92 | 3.50 | 2.01 | 4.59 | -1.08 | 22% | 10% | -31% | 3.0% |
| Waterford 3 | Nov-74 | Dec-74 | 710 | Jun-80 | 5.50 | | | | | | | | 1.0% |
| Waterford 3 | | Sep-76 | 815 | Apr-81 | 4.58 | 1.75 | 1.15 | 0.83 | 0.92 | 8% | 4% | 53% | 15.0% |
| Watts Bar 1 | Jan-73 | Jun-73 | 324 | Mar-78 | 4.75 | | | | | | | | 2.0% |
| Watts Bar 1 | | Dec-77 | 520 | Dec-79 | 2.00 | 4.50 | 1.61 | 1.75 | 2.75 | 11% | 8% | 61% | 76.0% |

| Unit Name | C.P. Issuance | Cost & Schedule Estimates Date [1] | Cost | COD | Years to Go | Years between Estimates | Cost Ratio | Years between CODs | Years Reduction To Go | COST GROWTH RATE Nominal | Real | Progress Rate | Percent Complete |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Watts Bar 2 | Jan-73 | Jun-73 | 324 | Dec-78 | 5.50 | | | | | | | | NA |
| Watts Bar 2 | | Sep-77 | 520 | Mar-80 | 2.50 | 4.25 | 1.61 | 1.25 | 3.01 | 12% | 9% | 71% | 55.0% |
| WNP 1 | Dec-75 | Jun-76 | 1147 | Mar-81 | 4.75 | | | | | | | | 1.2% |
| | | Sep-77 | 1087 | Dec-82 | 5.25 | 1.25 | 0.95 | 1.75 | -0.50 | -4% | -14% | -40% | 5.8% |
| WNP 2 | Mar-73 | Sep-73 | 472 | Sep-77 | 4.00 | | | | | | | | 2.0% |
| WNP 2 | | Mar-77 | 905 | Sep-80 | 3.50 | 3.50 | 1.92 | 3.00 | 0.50 | 20% | 13% | 14% | 39.6% |
| Zimmer 1 | Oct-72 | Dec-72 | 311 | Aug-77 | 4.67 | | | | | | | | 1.0% |
| Zimmer 1 | | Sep-77 | 531 | Jul-79 | 1.83 | 4.75 | 1.71 | 1.91 | 2.84 | 12% | 9% | 60% | 77.2% |
| | | | | | AVERAGE: | 3.34 | 1.82 | 2.30 | 0.91 | 0.33 | 0.27 | 0.28 | |
| | | | | | EXPERIENCE WEIGHTED AVERAGE: | | 1.36 | | | 0.25 | 0.20 | 0.23 | |

Notes: 1. The first estimate shown is within a year after Construction Permit Issuance or if unavailable, within a year before CPIS.
The second estimate shown is the last estimate before December, 1977.

* Architect/Engineer = Stone & Webster, ** Constructor= Stone & Webster,
*** Architect/Engineer and Constructor= Stone & Webster.

TABLE 3.8: UNITS BETWEEN 10% AND 25% COMPLETE IN DECEMBER, 1977

| Unit Name | Size (MW) | % Complete at 12/77 | Estimated COD [2] | Actual or Current Est. COD |
|---|---|---|---|---|
| Millstone 3*** | 1153 | 12.5% [1] | May-86 + | May-86 |
| Midland 2 | 811 | 25.0% | Mar-81 + | Cancelled |
| Catawba 1 | 1145 | 19.0% | Jul-81 + | Jun-85 |
| Braidwood 1 | 1120 | 24.0% | Oct-81 + | Oct-86 |
| Clinton 1 | 950 | 23.0% | Dec-81 + | Jul-86 |
| Perry 1 | 1205 | 13.8% | Dec-81 + | Jun-86 |
| Midland 1 | 460 | 25.0% | Mar-82 | Cancelled |
| Beaver Valley 2*** | 852 | 12.0% | May-82 + | Aug-87 |
| Braidwood 2 | 1120 | 20.0% | Oct-82 | Dec-87 |
| Callaway 1 | 1150 | 10.1% | Oct-82 + | Apr-85 |
| Catawba 2 | 1145 | 19.0% | Jan-83 | Jun-87 |
| Comanche Peak 2 | 1150 | 11.0% | Jan-83 | Dec-87 |
| St. Lucie 2 | 802 | 22.0% | May-83 + | Aug-83 |
| Perry 2 | 1205 | 13.8% | Jun-83 | Suspended |
| Limerick 2 | 1055 | 20.0% | Apr-85 | Oct-90 |
| AVERAGES | | | | |
| All Units | 1012 | 18.4% | Aug-82 | |
| First Units | 1004 | 18.6% | Feb-82 [3] | |

Source: Nuclear News, February, 1978 ; EIA-254 Quarterly Reports for Estimated Cost; Current Status from February 1986 Nuclear News and from utilities.

Notes: 1. Nuclear News reports an outdated statistic for the % construction completed.
2. + indicates first units.
3. Averages exclude Millstone 3.
4. * Architect/Engineer= Stone & Webster,
** Constructor = Stone & Webster,
*** Architect/Engineer and constructor = Stone & Webster

TABLE 3.9: DECEMBER 1977: ESTIMATED COST FOR UNITS WITH COD PROJECTED FOR 1986

| Unit Name | Size (MW) | % complete [1] | | Estimated COD [2] | Estimated Cost $ Millions [3] | Estimated Cost $/KW | Next Reported Change Date | New Cost $ Million | New Cost $/KW | Actual or Current Est. COD |
|---|---|---|---|---|---|---|---|---|---|---|
| Millstone 3*** | 1153 | 12.5% | CP | May-86 | $1,173 | $1,017 | Sep-78 | $1,980 | $1,717 | May-86 |
| Shearon Harris 2 | 900 | 2.0% | LWA | Mar-86 | $1,039 | $1,154 | Dec-79 | $1,208 | $1,342 | Cancelled |
| Yellow Creek 2 | 1285 | 0.0% | | Mar-86 | $1,048 | $815 | Sep-78 | $1,172 | $912 | Cancelled |
| Hope Creek 2 | 1067 | 5.0% | CP | May-86 | $1,290 | $1,209 | Jun-78 | $1,445 | $1,354 | Cancelled |
| Palo Verde 3 | 1270 | 1.0% | CP | May-86 | $950 | $748 | Mar-78 | $834 | $657 | Aug-87 |
| Cherokee 2 | 1280 | 0.0% | CP | Jul-86 | $1,007 | $787 | Mar-78 | $1,176 | $919 | Cancelled |
| Skagit 2 | 1288 | 0.0% | | Aug-86 | $870 | $675 | Mar-78 | $1,324 | $1,028 | Cancelled |
| AVERAGES | | | | | | | | | | |
| All Units | 1182 | 1.3% | | May-86 | $1,034 | $898 | Aug-78 | $1,193 | $1,035 [4] | |

Source: Nuclear News, February, 1978 and 1986; EIA-254 Quarterly Reports for Estimated Cost; NRC Summary Information Report, 1985.

Notes: [1] Nuclear News reports an outdated statistic for the M3 % construction completed. CP indicates units with construction permits. LWA indicates units with with limited work authorizations.

[2] No month was indicated in the COD for NEP-1 or Jamesport 2. June was assumed.

[3] Yellow Creek 2 and Hope Creek 2 costs= unit 1+2 cost/2. Shearon Harris cost=unit 1+2+3+4 cost/4.

[4] Averages exclude Millstone 3.

[5] *** architect/engineer and constructor= Stone & Webster.

TABLE 3.10: MILLSTONE 2 COST ESTIMATE HISTORY

| Unit Name | Date of Estimate | ----Estimates---- Cost | COD |
|---|---|---|---|
| Millstone 2 | Dec-67 | 150 | Apr-74 |
| | Mar-68 | 146 | Apr-74 |
| | Dec-68 | 179 | Apr-74 |
| | Dec-69 | 183 | Apr-74 |
| | Dec-70 | 239 | Apr-74 |
| | Sep-71 | 252 | Apr-74 |
| | Sep-72 | 282 | Apr-74 |
| | Mar-73 | 341 | Dec-74 |
| | Dec-73 | 380 | May-75 |
| | Sep-74 | 399 | Aug-75 |
| | Jun-75 | 399 | Oct-75 |
| | Sep-75 | 416 | Nov-75 |
| | Dec-75 | 416 | Dec-75 |
| | Actual | 426 | Dec-75 |

TABLE 3.11: NOMINAL AND REAL COST OVERRUNS AND SCHEDULE SLIPPAGE: Completed Units, with COD up to June, 1980
From Estimate made at Construction Stage of about 33% to Actual Cost and COD

| Unit Name | Actuals Cost | Actuals COD | C.P. issued | Estimate closest to 33% Completion: % Complete | Date of Estimate | Estimated Cost | Estimated COD | Years to COD | -- Nominal -- Cost Ratio | Myopia Factor | Real Cost Ratio | Real Annualized Growth Rate --[2]- | Actual Duration |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Nine Mile Point 1** | 162 | Dec-69 | Apr-65 | 34.0% | Jun-66 | 88 | Nov-68 | 2.42 | 1.84 | 1.288 | 1.70 | 1.16 | 3.50 |
| Palisades | 147 | Dec-71 | Mar-67 | 31.0% | Mar-68 | 89 | May-70 | 2.17 | 1.65 | 1.260 | 1.46 | 1.11 | 3.75 |
| Pilgrim 1 | 231 | Dec-72 | Aug-68 | 60.0% | Jan-70 | 153 | Sep-71 | 1.66 | 1.51 | 1.281 | 1.37 | 1.11 | 2.92 |
| Surry 1*** | 247 | Dec-72 | Jun-68 | 33.7% | Jun-69 | 165 | Apr-71 | 1.83 | 1.50 | 1.246 | 1.31 | 1.08 | 3.50 |
| Turkey Point 3 | 109 | Dec-72 | Apr-67 | 52.0% | Sep-69 | 99 | Jun-71 | 1.75 | 1.10 | 1.055 | 0.98 | 0.99 | 3.25 |
| Surry 2*** | 150 | May-73 | Jun-68 | 37.4% | Sep-70 | 138 | May-72 | 1.66 | 1.09 | 1.051 | 1.01 | 1.00 | 2.66 |
| Oconee 1 | 156 | Jul-73 | Nov-67 | 24.5% | Sep-69 | 109 | May-71 | 1.66 | 1.43 | 1.239 | 1.21 | 1.05 | 3.83 |
| Indian Point 2 | 206 | Aug-74 | Oct-66 | 56.0% | Sep-68 | 106 | Apr-70 | 1.58 | 1.94 | 1.523 | 1.39 | 1.06 | 5.91 |
| Fort Calhoun 1 | 174 | Sep-73 | Jun-68 | 30.0% | Sep-69 | 92 | Sep-71 | 2.00 | 1.89 | 1.376 | 1.62 | 1.13 | 4.00 |
| Turkey Point 4 | 123 | Sep-73 | Apr-67 | 52.6% | Sep-69 | 41 | Jun-72 | 2.75 | 3.00 | 1.491 | 2.72 | 1.28 | 4.00 |
| Prairie Isl 1 | 233 | Dec-73 | Jun-68 | 37.0% | Sep-70 | 148 | Oct-72 | 2.08 | 1.58 | 1.244 | 1.44 | 1.12 | 3.25 |
| Zion 1 | 276 | Dec-73 | Dec-68 | 43.0% | Jun-70 | 232 | Apr-72 | 1.83 | 1.19 | 1.099 | 1.05 | 1.01 | 3.50 |
| Kewaunee | 202 | Jun-74 | Aug-68 | 28.0% | Sep-70 | 123 | Sep-72 | 2.00 | 1.64 | 1.281 | 1.44 | 1.10 | 3.75 |
| Cooper | 246 | Jul-74 | Jun-68 | 42.0% | Dec-70 | 207 | Apr-73 | 2.33 | 1.19 | 1.077 | 1.08 | 1.02 | 3.58 |
| Peach Bottom 2 | 522 | Jul-74 | Jan-68 | 35.0% | Sep-69 | 206 | Mar-72 | 2.50 | 2.53 | 1.451 | 2.12 | 1.17 | 4.83 |
| Browns Ferry 1 | 256 | Aug-74 | May-67 | 31.0% | Sep-69 | 149 | Oct-71 | 2.08 | 1.72 | 1.297 | 1.38 | 1.07 | 4.91 |
| Oconee 2 | 160 | Sep-74 | Nov-67 | 24.5% | Jun-69 | 109 | May-72 | 2.92 | 1.47 | 1.142 | 1.23 | 1.04 | 5.25 |
| Three Mile I. 1 | 398 | Sep-74 | May-68 | 37.5% | Mar-70 | 184 | May-72 | 2.17 | 2.16 | 1.427 | 1.81 | 1.14 | 4.50 |
| Zion 2 | 290 | Sep-74 | Dec-68 | 36.0% | Jun-70 | 213 | May-73 | 2.92 | 1.36 | 1.112 | 1.23 | 1.05 | 4.25 |
| Arkansas 1 | 233 | Dec-74 | Dec-68 | 16.0% | Mar-72 | 175 | Sep-73 | 1.50 | 1.33 | 1.210 | 1.21 | 1.07 | 2.75 |
| Oconee 3 | 160 | Dec-74 | Nov-67 | 25.0% | Sep-70 | 109 | Jul-73 | 2.83 | 1.47 | 1.146 | 1.32 | 1.07 | 4.25 |
| Peach Bottom 3 | 220 | Dec-74 | Jan-68 | 30.0% | Dec-70 | 221 | Oct-73 | 2.83 | 1.00 | 0.998 | 0.91 | 0.98 | 4.00 |
| Prairie Isl 2 | 172 | Dec-74 | Jun-68 | 35.0% | Sep-72 | 160 | Oct-74 | 2.08 | 1.08 | 1.035 | 1.06 | 1.03 | 2.25 |
| Duane Arnold | 202 | Feb-75 | Jun-70 | 10.0% | Dec-70 | 148 | Dec-73 | 3.00 | 1.36 | 1.109 | 1.25 | 1.05 | 4.17 |
| Browns Ferry 2 | 256 | Mar-75 | May-67 | 31.0% | Sep-69 | 149 | Oct-71 | 2.08 | 1.72 | 1.297 | 1.32 | 1.05 | 5.49 |
| Rancho Seco | 344 | Apr-75 | Oct-68 | 43.0% | Jun-71 | 215 | May-73 | 1.92 | 1.60 | 1.277 | 1.38 | 1.09 | 3.83 |
| Calvert Cliffs 1 | 429 | May-75 | Jul-69 | 24.0% | Sep-70 | 170 | Jan-73 | 2.34 | 2.52 | 1.486 | 2.11 | 1.17 | 4.66 |
| Fitzpatrick*** | 419 | Jul-75 | May-70 | 71.0% | Jun-72 | 301 | Oct-73 | 1.33 | 1.39 | 1.282 | 1.22 | 1.07 | 3.08 |
| Cook 1 | 538 | Aug-75 | Mar-69 | 40.0% | Jun-71 | 356 | Mar-73 | 1.75 | 1.51 | 1.266 | 1.25 | 1.06 | 4.17 |
| Brunswick 2 | 382 | Nov-75 | Feb-70 | 46.0% | Dec-71 | 210 | Mar-74 | 2.25 | 1.82 | 1.305 | 1.60 | 1.13 | 3.92 |
| Hatch 1 | 390 | Dec-75 | Sep-69 | 10.0% | Sep-70 | 184 | Apr-73 | 2.58 | 2.12 | 1.338 | 1.73 | 1.11 | 5.25 |
| Millstone 2 | 418 | Dec-75 | Dec-70 | 24.0% | Sep-71 | 252 | Apr-74 | 2.58 | 1.66 | 1.217 | 1.46 | 1.09 | 4.25 |
| Trojan | 452 | Dec-75 | Feb-71 | 30.0% | Mar-72 | 233 | Sep-74 | 2.50 | 1.94 | 1.303 | 1.76 | 1.16 | 3.75 |
| St. Lucie 1 | 470 | Jun-76 | Jul-70 | 25.0% | Jun-72 | 269 | May-75 | 2.91 | 1.75 | 1.211 | 1.61 | 1.13 | 4.00 |
| Indian Point 3 | 570 | Aug-76 | Aug-69 | 23.0% | Sep-69 | 156 | May-73 | 3.66 | 3.65 | 1.424 | 2.84 | 1.16 | 6.96 |
| Beaver Valley 1*** | 599 | Oct-76 | Jun-70 | 35.0% | Mar-72 | 309 | Oct-74 | 2.58 | 1.94 | 1.292 | 1.66 | 1.12 | 4.59 |
| Browns Ferry 3 | 301 | Mar-77 | Jul-68 | 31.0% | Jun-69 | 149 | Oct-71 | 2.33 | 2.02 | 1.352 | 1.33 | 1.04 | 7.75 |
| Brunswick 1 | 318 | Mar-77 | Feb-70 | 30.0% | Dec-71 | 181 | Mar-75 | 3.25 | 1.76 | 1.190 | 1.51 | 1.08 | 5.25 |
| Crystal River 3 | 366 | Mar-77 | Sep-68 | 37.0% | Sep-71 | 190 | Sep-73 | 2.00 | 1.93 | 1.388 | 1.47 | 1.07 | 5.50 |
| Calvert Cliffs 2 | 335 | Apr-77 | Jul-69 | 21.0% | Sep-70 | 128 | Jan-74 | 3.33 | 2.62 | 1.335 | 2.04 | 1.11 | 6.58 |
| Salem 1 | 850 | Jun-77 | Sep-68 | 33.0% | Dec-70 | 237 | Apr-73 | 2.33 | 3.59 | 1.729 | 2.60 | 1.16 | 6.50 |
| Farley 1 | 727 | Dec-77 | Aug-72 | 35.5% | Mar-73 | 294 | Apr-75 | 2.08 | 2.47 | 1.545 | 2.01 | 1.16 | 4.75 |
| North Anna 1*** | 782 | Jun-78 | Feb-71 | 33.0% | Sep-71 | 310 | Jun-74 | 2.75 | 2.52 | 1.400 | 1.85 | 1.10 | 6.75 |
| Cook 2 | 444 | Jul-78 | Mar-69 | 19.0% | Sep-70 | 339 | Mar-74 | 3.50 | 1.31 | 1.080 | 0.94 | 0.99 | 7.83 |
| Davis-Besse 1 | 635 | Jul-78 | Mar-71 | 40.0% | Dec-72 | 349 | May-75 | 2.41 | 1.82 | 1.282 | 1.43 | 1.07 | 5.58 |
| Three Mile I. 2 | 715 | Dec-78 | Nov-69 | 37.5% | Mar-70 | 184 | May-72 | 2.17 | 3.88 | 1.870 | 2.35 | 1.10 | 8.72 |
| Hatch 2 | 509 | Sep-79 | Dec-72 | 32.0% | Sep-75 | 513 | Apr-79 | 3.58 | 0.99 | 0.998 | 0.96 | 0.99 | 4.00 |
| Arkansas 2 | 640 | Mar-80 | Dec-72 | 33.5% | Jun-74 | 318 | Feb-77 | 2.67 | 2.01 | 1.299 | 1.59 | 1.08 | 5.75 |
| AVERAGE | | | | 33.9% | | | | | 1.85 | 1.28 | 1.53 | 1.09 | |
| NUMBER OF DATAPOINTS: | | | | 48 | | | | | 48 | 48 | 48 | 48 | |

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Notes, Table 3.11: 2. See table 3.6
* A/E = S&W, ** Constr. = S&W, *** A/E and Constr. = S&W.

Table 3.11 Results Applied to Northeast Utilities Estimate

NU COST AND SCHEDULE ESTIMATE OF: Jul-80
- Cost: $2,600 Million
- COD: May-86
- Duration: 5.84

| Projection Method | Cost Multiplier | Cost | Averages |
|---|---|---|---|
| 1. Nominal Cost Ratio | 1.85 | $4,798 | |
| 2. Nominal Myopia Factor | 4.29 | $11,151 | $7,975 |
| 3. Real Cost Ratio | 1.53 | $3,971 | |
| 4. Annual Growth Rate | 1.63 | $4,235 | $4,103 |
| | | | ------- |
| | | | $6,039 |

Notes: 1. Cost Multiplier = Average Nominal Cost Ratio
2. Cost Multiplier = Average Nominal Myopia Factor raised to NU Duration.
3. Cost Multiplier = Average Real Cost Ratio
4. Cost Multiplier = Annual Growth Rate raised to NU Duration.

Source: Data Req. AG-5, 2/21/84, Q-AG-EJF-27, p.2 of 2

| Unit Name | Cost & Schedule Estimates | | | | Years between Estimates | Cost Ratio | Years between CODs | Reduction Years To Go | COST GROWTH RATE | | Progress Rate | Percent Complete |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Date | Cost | COD | YrstoGo | | | | | Nominal | Real | | |
| Farley 2 | Jun-77 | 689 | Apr-80 | 2.83 | | | | | | | | 45.0% |
| Farley 2 | Sep-79 | 684 | Sep-80 | 1.00 | 2.25 | 0.99 | 0.42 | 1.83 | 0% | -2% | 81% | 83.7% |
| Lasalle 1 | Sep-77 | 675 | Sep-79 | 2.00 | | | | | | | | 55.0% |
| Lasalle 1 | Dec-79 | 1003 | Dec-80 | 1.00 | 2.25 | 1.49 | 1.25 | 1.00 | 19% | 14% | 44% | 93.0% |
| McGuire 1 | Sep-77 | 466 | Jul-79 | 1.83 | | | | | | | | 86.0% |
| McGuire 1 | Dec-78 | 549 | Feb-80 | 1.17 | 1.25 | 1.18 | 0.59 | 0.66 | 14% | 10% | 53% | 96.0% |
| North Anna 2*** | Sep-77 | 426 | Mar-79 | 1.49 | | | | | | | | 86.6% |
| North Anna 2 | Mar-78 | 467 | Mar-79 | 1.00 | 0.50 | 1.10 | 0.00 | 0.50 | 20% | 20% | 100% | 90.4% |
| Salem 2 | Sep-74 | 496 | May-79 | 4.66 | | | | | | | | 48.1% |
| Salem 2 | Mar-78 | 619 | May-79 | 1.17 | 3.50 | 1.25 | 0.00 | 3.50 | 7% | 7% | 100% | 90.6% |
| San Onofre 2 | Jun-77 | 1320 | Oct-81 | 4.33 | | | | | | | | 44.0% |
| San Onofre 2 | Mar-80 | 1824 | Dec-81 | 1.75 | 2.75 | 1.38 | 0.17 | 2.58 | 12% | 12% | 94% | 86.0% |
| Sequoyah 1 | Mar-77 | 475 | Sep-78 | 1.50 | | | | | | | | 75.0% |
| Sequoyah 1 | Jun-79 | 632 | Jun-80 | 1.00 | 2.25 | 1.33 | 1.75 | 0.50 | 14% | 7% | 22% | 98.0% |
| Sequoyah 2 | Mar-77 | 475 | May-79 | 2.17 | | | | | | | | 65.0% |
| Sequoyah 2 | Sep-79 | 442 | Jun-81 | 1.75 | 2.50 | 0.93 | 2.09 | 0.42 | -3% | -9% | 17% | 84.0% |
| St. Lucie 2 | Jun-77 | 850 | May-83 | 5.91 | | | | | | | | 1.0% |
| St. Lucie 2 | Dec-78 | 919 | May-83 | 4.41 | 1.50 | 1.08 | 0.00 | 1.50 | 5% | 5% | 100% | 16.8% |
| Summer 1 | Dec-76 | 635 | May-80 | 3.41 | | | | | | | | 42.5% |
| Summer 1 | Mar-80 | 827 | Jun-81 | 1.25 | 3.25 | 1.30 | 1.08 | 2.16 | 8% | 6% | 67% | 94.8% |
| Susquehanna 1 | Mar-77 | 1097 | Nov-80 | 3.67 | | | | | | | | 44.0% |
| Susquehanna 1 | Sep-79 | 1607 | Jan-82 | 2.34 | 2.50 | 1.46 | 1.17 | 1.34 | 16% | 12% | 53% | 70.0% |
| Bailly Nuclear 1 | Dec-77 | 705 | Jun-84 | 6.50 | | | | | | | | 0.5% |
| Bailly Nuclear 1 | Sep-79 | 1100 | Jun-87 | 7.75 | 1.75 | 1.56 | 3.00 | -1.25 | 29% | 13% | -71% | 0.5% |
| Cherokee 1 | Dec-77 | 336 | Jan-85 | 7.09 | | | | | | | | 1.0% |
| Cherokee 1 | Mar-80 | 402 | Jan-90 | 9.84 | 2.25 | 1.20 | 5.00 | -2.75 | 8% | -9% | -122% | 15.0% |
| Cherokee 2 | Dec-77 | 336 | Jan-87 | 9.08 | | | | | | | | 1.0% |
| Cherokee 2 | Mar-80 | 402 | Jan-92 | 11.84 | 2.25 | 1.20 | 5.00 | -2.75 | 8% | -9% | -122% | 1.0% |
| Cherokee 3 | Mar-77 | 336 | Jan-89 | 11.84 | | | | | | | | 0.5% |
| Cherokee 3 | Mar-80 | 402 | Jan-94 | 13.84 | 3.00 | 1.20 | 5.00 | -2.00 | 6% | -7% | -67% | 1.0% |
| Forked River 1 | Dec-76 | 894 | May-83 | 6.41 | | | | | | | | 0.5% |
| Forked River 1 | Dec-78 | 1150 | Dec-83 | 5.00 | 2.00 | 1.29 | 0.59 | 1.41 | 13% | 11% | 71% | 4.1% |
| Hartsville B-1 | Sep-77 | 854 | Dec-83 | 6.25 | | | | | | | | 3.0% |
| Hartsville B-1 | Sep-79 | 1418 | Jun-89 | 9.75 | 2.00 | 1.66 | 5.50 | -3.50 | 29% | 4% | -175% | 15.0% |
| Hartsville B-2 | Sep-77 | 854 | Dec-84 | 7.25 | | | | | | | | NA |
| Hartsville B-2 | Sep-79 | 1418 | Jun-90 | 10.75 | 2.00 | 1.66 | 5.50 | -3.50 | 29% | 4% | -175% | 5.0% |

| Unit Name | Cost & Schedule Estimates | | | | Years between Estimates | Cost Ratio | Years between CODs | Reduction Years To Go | COST GROWTH RATE | | Progress Rate | Percent Complete |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Date | Cost | COD | YrstoGo | | | | | Nominal | Real | | |
| North Anna 3*** | Dec-77 | 818 | Oct-83 | 5.83 | | | | | | | | 7.0% |
| North Anna 3 | Sep-79 | 1428 | Apr-86 | 6.58 | 1.75 | 1.75 | 2.50 | -0.75 | 38% | 23% | -43% | 7.0% |
| North Anna 4*** | Dec-77 | 568 | Sep-84 | 6.75 | | | | | | | | 3.7% |
| North Anna 4 | Sep-79 | 956 | Apr-87 | 7.58 | 1.75 | 1.68 | 2.58 | -0.83 | 35% | 20% | -47% | 3.7% |
| Phipps Bend 1 | Dec-77 | 876 | Aug-84 | 6.67 | | | | | | | | 0.0% |
| Phipps Bend 1 | Sep-79 | 1440 | Mar-87 | 7.50 | 1.75 | 1.64 | 2.58 | -0.83 | 33% | 19% | -47% | 7.0% |
| Phipps Bend 2 | Dec-77 | 876 | Aug-85 | 7.67 | | | | | | | | 0.0% |
| Phipps Bend 2 | Jun-80 | 1440 | May-94 | 13.91 | 2.50 | 1.64 | 8.75 | -6.25 | 22% | -7% | -250% | 4.0% |
| Shearon Harris 3 | Dec-77 | 1039 | Mar-90 | 12.25 | | | | | | | | 0.5% |
| Shearon Harris 3 | Jun-80 | 1208 | Mar-94 | 13.75 | 2.50 | 1.16 | 4.00 | -1.50 | 6% | -6% | -60% | 0.5% |
| Shearon Harris 4 | Dec-77 | 1039 | Mar-88 | 10.25 | | | | | | | | 0.5% |
| Shearon Harris 4 | Jun-80 | 1208 | Mar-92 | 11.75 | 2.50 | 1.16 | 4.00 | -1.50 | 6% | -6% | -60% | 0.5% |
| WNP 4 | Dec-77 | 1232 | Jun-84 | 6.50 | | | | | | | | 2.8% |
| WNP 4 | Mar-80 | 3086 | Jun-86 | 6.25 | 2.25 | 2.50 | 2.00 | 0.25 | 50% | 41% | 11% | 14.5% |
| WNP 5 | Dec-77 | 1470 | Jul-85 | 7.58 | | | | | | | | 0.0% |
| WNP 5 | Jun-80 | 3705 | Jun-87 | 7.00 | 2.50 | 2.52 | 1.92 | 0.58 | 45% | 36% | 23% | 6.7% |
| Callaway 2 | Dec-77 | 1288 | Apr-87 | 9.33 | | | | | | | | 0.4% |
| Callaway 2 | Jun-80 | 1609 | Apr-87 | 6.83 | 2.50 | 1.25 | 0.00 | 2.50 | 9% | 9% | 100% | 0.7% |
| Callaway 1 | Dec-77 | 1122 | Oct-82 | 4.83 | | | | | | | | 11.2% |
| Callaway 1 | Mar-80 | 1261 | Oct-82 | 2.58 | 2.25 | 1.12 | 0.00 | 2.25 | 5% | 5% | 100% | 64.0% |
| Grand Gulf 1 | Dec-77 | 1174 | Apr-81 | 3.33 | | | | | | | | 57.9% |
| Grand Gulf 1 | Dec-79 | 1203 | Apr-82 | 2.33 | 2.00 | 1.02 | 1.00 | 1.00 | 1% | -3% | 50% | 80.0% |
| Grand Gulf 2 | Dec-77 | 954 | Jan-84 | 6.08 | | | | | | | | 2.4% |
| Grand Gulf 2 | Jun-80 | 878 | Apr-86 | 5.83 | 2.50 | 0.92 | 2.25 | 0.25 | -3% | -10% | 10% | 23.0% |
| Hope Creek 1 | Sep-76 | 2580 | May-84 | 7.66 | | | | | | | | 2.0% |
| Hope Creek 1 | Jun-80 | 4310 | Dec-86 | 6.50 | 3.75 | 1.67 | 2.58 | 1.16 | 15% | 9% | 31% | 23.5% |
| Limerick 1 | Jun-77 | 1635 | Apr-83 | 5.83 | | | | | | | | 32.0% |
| Limerick 1 | Jun-79 | 1695 | Apr-83 | 3.83 | 2.00 | 1.04 | 0.00 | 2.00 | 2% | 2% | 100% | 52.0% |
| Limerick 2 | Jun-77 | 949 | Apr-85 | 7.83 | | | | | | | | 22.0% |
| Limerick 2 | Jun-79 | 909 | Apr-85 | 5.83 | 2.00 | 0.96 | 0.00 | 2.00 | -2% | -2% | 100% | 35.0% |
| Midland 1 | Jun-76 | 700 | Mar-82 | 5.75 | | | | | | | | 13.0% |
| Midland 1 | May-80 | 1550 | Mar-85 | 4.83 | 3.92 | 2.21 | 3.00 | 0.91 | 23% | 15% | 23% | 13.0% |
| Midland 2 | Jun-76 | 700 | Mar-81 | 4.75 | | | | | | | | 16.0% |
| Midland 2 | May-80 | 1550 | Sep-84 | 4.34 | 3.92 | 2.21 | 3.50 | 0.41 | 23% | 14% | 10% | 16.0% |

| Unit Name | Cost & Schedule Estimates Date | Cost | COD | YrstoGo | Years between Estimates | Cost Ratio | Years between CODs | Reduction Years To Go | COST GROWTH RATE Nominal | Real | Progress Rate | Percent Complete |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Palo Verde 1 | Dec-77 | 989 | May-82 | 4.41 | | | | | | | | 21.9% |
| Palo Verde 1 | Jun-80 | 1429 | May-83 | 2.91 | 2.50 | 1.44 | 1.00 | 1.50 | 16% | 12% | 60% | 68.3% |
| Palo Verde 2 | Dec-75 | 845 | May-84 | 8.42 | | | | | | | | 0.0% |
| Palo Verde 2 | Jun-80 | 820 | May-84 | 3.92 | 4.50 | 0.97 | 0.00 | 4.50 | -1% | -1% | 100% | 37.7% |
| Palo Verde 3 | Dec-76 | 950 | Jun-86 | 9.50 | | | | | | | | 0.0% |
| Palo Verde 3 | Jun-80 | 1125 | Jun-86 | 6.00 | 3.50 | 1.18 | 0.00 | 3.50 | 5% | 5% | 100% | 10.8% |
| San Onofre 3 | Jun-77 | 1080 | Jan-83 | 5.59 | | | | | | | | 30.0% |
| San Onofre 3 | Mar-80 | 1216 | Jan-83 | 2.84 | 2.75 | 1.13 | 0.00 | 2.75 | 4% | 4% | 100% | 60.0% |
| South Texas 1 | Sep-75 | 676 | Oct-80 | 5.08 | | | | | | | | 0.0% |
| South Texas 1 | Sep-79 | 1208 | Feb-84 | 4.42 | 4.00 | 1.79 | 3.33 | 0.67 | 16% | 8% | 17% | 48.3% |
| South Texas 2 | Sep-75 | 676 | Mar-82 | 6.50 | | | | | | | | 0.0% |
| South Texas 2 | Sep-79 | 1208 | Feb-86 | 6.42 | 4.00 | 1.79 | 3.92 | 0.08 | 16% | 7% | 2% | 15.0% |
| Susquehanna 2 | Sep-77 | 710 | May-82 | 4.66 | | | | | | | | 35.9% |
| Susquehanna 2 | Jun-80 | 1082 | Aug-82 | 2.17 | 2.75 | 1.52 | 0.25 | 2.50 | 17% | 16% | 91% | 53.0% |
| Vogtle 1 | Dec-77 | 1537 | Nov-84 | 6.92 | | | | | | | | 5.0% |
| Vogtle 1 | Jun-80 | 1746 | May-85 | 4.91 | 2.50 | 1.14 | 0.50 | 2.00 | 5% | 4% | 80% | 10.0% |
| Vogtle 2 | Dec-77 | 1075 | Nov-85 | 7.92 | | | | | | | | 3.0% |
| Vogtle 2 | Jun-80 | 988 | Nov-87 | 7.42 | 2.50 | 0.92 | 2.00 | 0.50 | -3% | -9% | 20% | 4.0% |
| WNP 1 | Sep-77 | 1087 | Dec-82 | 5.25 | | | | | | | | 5.8% |
| WNP 1 | Jun-80 | 2498 | Jun-85 | 5.00 | 2.75 | 2.30 | 2.50 | 0.25 | 35% | 26% | 9% | 41.1% |
| WNP 2 | Mar-77 | 905 | Sep-80 | 3.50 | | | | | | | | 39.6% |
| WNP 2 | Jun-80 | 2392 | Jan-83 | 2.58 | 3.25 | 2.64 | 2.33 | 0.92 | 35% | 28% | 28% | 85.2% |
| Wolf Creek | Mar-77 | 1029 | Apr-83 | 6.08 | | | | | | | | 1.0% |
| Wolf Creek | Dec-79 | 1296 | Apr-83 | 3.33 | 2.75 | 1.26 | 0.00 | 2.75 | 9% | 9% | 100% | 47.9% |
| Beaver Valley 2* | Dec-77 | 942 | May-82 | 4.41 | | | | | | | | 15.0% |
| Beaver Valley 2 | Dec-79 | 2024 | May-86 | 6.41 | 2.00 | 2.15 | 4.00 | -2.00 | 47% | 26% | -100% | 35.2% |
| Bellefonte 1 | Dec-77 | 632 | Jun-80 | 2.50 | | | | | | | | 52.0% |
| Bellefonte 1 | Sep-79 | 1001 | Sep-83 | 4.00 | 1.75 | 1.58 | 3.25 | -1.50 | 30% | 13% | -86% | 69.0% |
| Bellefonte 2 | Dec-77 | 632 | Mar-81 | 3.25 | | | | | | | | 37.0% |
| Bellefonte 2 | Sep-79 | 1001 | Jun-84 | 4.75 | 1.75 | 1.58 | 3.25 | -1.50 | 30% | 13% | -86% | 48.0% |
| Braidwood 1 | Sep-77 | 829 | Oct-81 | 4.08 | | | | | | | | 21.0% |
| Braidwood 1 | Jun-80 | 1585 | Oct-85 | 5.33 | 2.75 | 1.91 | 4.00 | -1.25 | 27% | 13% | -46% | 56.0% |
| Braidwood 2 | Sep-77 | 519 | Oct-82 | 5.08 | | | | | | | | 18.0% |
| Braidwood 2 | Jun-80 | 1011 | Oct-86 | 6.33 | 2.75 | 1.95 | 4.00 | -1.25 | 27% | 14% | -46% | 44.0% |
| Byron 1 | Dec-77 | 862 | Sep-81 | 3.75 | | | | | | | | 33.0% |
| Byron 1 | Jun-80 | 1483 | Oct-83 | 3.33 | 2.50 | 1.72 | 2.08 | 0.42 | 24% | 17% | 17% | 69.0% |

| Unit Name | Cost & Schedule Estimates Date | Cost | COD | YrstoGo | Years between Estimates | Cost Ratio | Years between CODs | Reduction Years To Go | COST GROWTH RATE Nominal | Real | Progress Rate | Percent Complete |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Byron 2 | Sep-77 | 538 | Oct-82 | 5.08 | | | | | | | | 23.0% |
| Byron 2 | Jun-80 | 922 | Oct-84 | 4.33 | 2.75 | 1.71 | 2.00 | 0.75 | 22% | 15% | 27% | 55.0% |
| Catawba 1 | Mar-77 | 649 | Jul-81 | 4.33 | | | | | | | | 11.5% |
| Catawba 1 | Jun-80 | 754 | Mar-84 | 3.75 | 3.25 | 1.16 | 2.67 | 0.59 | 5% | -2% | 18% | 73.0% |
| Clinton 1 | Dec-77 | 1051 | Dec-81 | 4.00 | | | | | | | | 20.0% |
| Clinton 1 | Mar-80 | 1397 | Dec-82 | 2.75 | 2.25 | 1.33 | 1.00 | 1.25 | 13% | 10% | 56% | 66.0% |
| Comanche Peak 1 | Jun-77 | 850 | Jan-81 | 3.59 | | | | | | | | 39.0% |
| Comanche Peak 1 | Mar-79 | 850 | Jun-81 | 2.25 | 1.75 | 1.00 | 0.41 | 1.33 | 0% | -2% | 76% | 68.8% |
| Comanche Peak 2 | Jun-77 | 850 | Jan-83 | 5.59 | | | | | | | | 9.7% |
| Comanche Peak 2 | Mar-79 | 850 | Jun-83 | 4.25 | 1.75 | 1.00 | 0.41 | 1.33 | 0% | -2% | 76% | 26.4% |
| Diablo Canyon 1 | Sep-77 | 672 | Jun-78 | 0.75 | | | | | | | | 99.2% |
| Diablo Canyon 1 | Mar-80 | 880 | Jun-81 | 1.25 | 2.50 | 1.31 | 3.00 | -0.50 | 11% | 2% | -20% | 99.2% |
| Diablo Canyon 2 | Sep-77 | 548 | Jun-78 | 0.75 | | | | | | | | 90.9% |
| Diablo Canyon 2 | Dec-79 | 721 | Jun-81 | 1.50 | 2.25 | 1.32 | 3.00 | -0.75 | 13% | 2% | -33% | 97.9% |
| Fermi 2 | Mar-77 | 882 | Dec-80 | 3.75 | | | | | | | | 46.0% |
| Fermi 2 | Jun-80 | 1283 | Mar-82 | 1.75 | 3.25 | 1.45 | 1.25 | 2.01 | 12% | 9% | 62% | 79.4% |
| Hartsville A-1 | Sep-77 | 854 | Jun-83 | 5.75 | | | | | | | | 5.0% |
| Hartsville A-1 | Sep-79 | 1418 | Jul-86 | 6.83 | 2.00 | 1.66 | 3.08 | -1.08 | 29% | 14% | -54% | 21.0% |
| Hartsville A-2 | Sep-77 | 854 | Jun-84 | 6.75 | | | | | | | | 2.0% |
| Hartsville A-2 | Sep-79 | 1418 | Jul-87 | 7.83 | 2.00 | 1.66 | 3.08 | -1.08 | 29% | 14% | -54% | 8.0% |
| LaSalle 2 | Sep-77 | 513 | Sep-80 | 3.00 | | | | | | | | 45.0% |
| LaSalle 2 | Jun-80 | 786 | Jun-82 | 2.00 | 2.75 | 1.53 | 1.75 | 1.00 | 17% | 11% | 36% | 78.0% |
| Marble Hill 1 | Dec-77 | 511 | Sep-82 | 4.75 | | | | | | | | NA |
| Marble Hill 1 | Jun-80 | 2001 | Dec-86 | 6.50 | 2.50 | 3.92 | 4.25 | -1.75 | 73% | 51% | -70% | 20.0% |
| Marble Hill 2 | Dec-77 | 353 | Jun-84 | 6.50 | | | | | | | | 0.4% |
| Marble Hill 2 | Jun-80 | 1383 | Dec-87 | 7.50 | 2.50 | 3.92 | 3.50 | -1.00 | 73% | 55% | -40% | 9.0% |
| McGuire 2 | Sep-77 | 466 | Mar-81 | 3.50 | | | | | | | | 54.0% |
| McGuire 2 | Jun-80 | 635 | Sep-82 | 2.25 | 2.75 | 1.36 | 1.50 | 1.25 | 12% | 7% | 45% | 83.0% |
| Nine Mile Point 2*** | Dec-77 | 1505 | Oct-83 | 5.83 | | | | | | | | 17.5% |
| Nine Mile Point 2 | Jun-80 | 1953 | Oct-84 | 4.33 | 2.50 | 1.30 | 1.00 | 1.50 | 11% | 8% | 60% | 37.7% |
| Perry 1 | Sep-77 | 988 | Dec-81 | 4.25 | | | | | | | | 13.3% |
| Perry 1 | Jun-80 | 1701 | May-84 | 3.92 | 2.75 | 1.72 | 2.41 | 0.33 | 22% | 14% | 12% | 59.4% |
| Perry 2 | Sep-77 | 1123 | Jun-83 | 5.75 | | | | | | | | 6.3% |
| Perry 2 | Jun-80 | 2157 | May-88 | 7.92 | 2.75 | 1.92 | 4.92 | -2.17 | 27% | 10% | -79% | 46.5% |

| Unit Name | Cost & Schedule Estimates: Date | Cost | COD | YrstoGo | Years between Estimates | Cost Ratio | Years between CODs | Reduction Years To Go | COST GROWTH RATE: Nominal | Real | Progress Rate | Percent Complete |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| River Bend 1*** | Dec-77 | 1172 | Sep-83 | 5.75 | | | | | | | | 5.0% |
| River Bend 1 | Mar-80 | 1679 | Apr-84 | 4.08 | 2.25 | 1.43 | 0.58 | 1.66 | 17% | 15% | 74% | 11.9% |
| Seabrook 1 | Dec-77 | 1375 | Dec-82 | 5.00 | | | | | | | | 8.0% |
| Seabrook 1 | Jun-80 | 1493 | Apr-83 | 2.83 | 2.50 | 1.09 | 0.33 | 2.17 | 3% | 2% | 87% | 39.7% |
| Seabrook 2 | Dec-77 | 825 | Dec-84 | 7.00 | | | | | | | | 1.0% |
| Seabrook 2 | Jun-80 | 1558 | Feb-85 | 4.67 | 2.50 | 1.89 | 0.17 | 2.33 | 29% | 28% | 93% | 7.6% |
| Shearon Harris 1 | Dec-77 | 1039 | Mar-84 | 6.25 | | | | | | | | 1.7% |
| Shearon Harris 1 | Jun-80 | 1208 | Mar-85 | 4.75 | 2.50 | 1.16 | 1.00 | 1.50 | 6% | 3% | 60% | 32.8% |
| Shearon Harris 2 | Dec-77 | 1039 | Mar-86 | 8.25 | | | | | | | | 1.7% |
| Shearon Harris 2 | Jun-80 | 1208 | Mar-88 | 7.75 | 2.50 | 1.16 | 2.00 | 0.50 | 6% | 0% | 20% | 3.7% |
| Shoreham * | Sep-77 | 1188 | Sep-80 | 3.00 | | | | | | | | 62.0% |
| Shoreham | Jun-80 | 1213 | Feb-83 | 2.67 | 2.75 | 1.02 | 2.42 | 0.33 | 1% | -6% | 12% | 85.5% |
| St. Lucie 2 | Jun-77 | 850 | May-83 | 5.91 | | | | | | | | 1.0% |
| St. Lucie 2 | Jun-80 | 1100 | May-83 | 2.91 | 3.00 | 1.29 | 0.00 | 3.00 | 9% | 9% | 100% | 45.1% |
| Waterford 3 | Sep-76 | 815 | Apr-81 | 4.58 | | | | | | | | 15.0% |
| Waterford 3 | Sep-79 | 1229 | Feb-82 | 2.42 | 3.00 | 1.51 | 0.84 | 2.16 | 15% | 12% | 72% | 69.5% |
| Watts Bar 1 | Dec-77 | 520 | Dec-79 | 2.00 | | | | | | | | 76.0% |
| Watts Bar 1 | Jun-80 | 720 | May-82 | 1.91 | 2.50 | 1.38 | 2.41 | 0.08 | 14% | 6% | 3% | 87.0% |
| Watts Bar 2 | Sep-77 | 520 | Mar-80 | 2.50 | | | | | | | | NA |
| Watts Bar 2 | Jun-80 | 720 | Feb-83 | 2.67 | 2.75 | 1.38 | 2.92 | -0.17 | 13% | 4% | -6% | 72.0% |
| WNP 3 | Mar-77 | 1482 | May-83 | 6.17 | | | | | | | | 0.0% |
| WNP 3 | Sep-79 | 2256 | Dec-84 | 5.25 | 2.50 | 1.52 | 1.59 | 0.91 | 18% | 13% | 37% | 16.6% |
| Yellow Creek 1 | Sep-77 | 1048 | Mar-85 | 7.50 | | | | | | | | 0.0% |
| Yellow Creek 2 | Sep-79 | 1445 | Apr-88 | 8.58 | 2.00 | 1.38 | 3.09 | -1.09 | 17% | 4% | -54% | 2.0% |
| Zimmer 1 | Sep-77 | 531 | Jul-79 | 1.83 | | | | | | | | 77.2% |
| Zimmer 1 | Jun-80 | 1027 | Apr-82 | 1.83 | 2.75 | 1.93 | 2.75 | 0.00 | 27% | 18% | 0% | 93.8% |
| AVERAGES: | | | | | 2.52 | 1.52 | 2.10 | 0.42 | 17% | 9% | 13% | |
| EXPERIENCE WEIGHTED AVERAGE: | | | | | | 1.36 | | | 15% | 8% | 12% | |

Notes: 1. The first estimate shown is last estimate available before December, 1977 (see Table 3.7).
The second estimate shown is last estimate available before June, 1980.

* Architect/Engineer = Stone & Webster, ** Constructor= Stone & Webster,
*** Architect/Engineer and Constructor= Stone & Webster.
Midland estimates from Consumers Power Review of Bechtel Forecast.

Table 3.13: UNITS BETWEEN 25% AND 40% COMPLETE
AS OF JUNE 1980

| Unit Name | Size (MW) | % complete at 6/80 | Estimated COD ---[1]--- | Estimated Cost as of 12/80 ($ Million) | Current Estimate or Actual Cost ($ Million) | COD |
|---|---|---|---|---|---|---|
| Millstone 3*** | 1153 | 33.0% | May-86 + | $2,573 | $3,800 | May-86 |
| Seabrook 1 | 1150 | 37.0% | Dec-83 + | $1,493 | $4,500 | Oct-86 |
| S. Texas Project 1 | 1250 | 40.0% | Apr-84 + | $1,208 | $4,150 | Dec-87 |
| Palo Verde 2 | 1270 | 35.5% | May-84 | $948 | $3,166 | Aug-86 |
| Shearon Harris 1 | 900 | 31.0% | Mar-85 + | $3,258 | $3,400 | Late 1986 |
| Beaver Valley 2*** | 833 | 38.0% | May-86 + | $2,203 | $3,500 | Aug-87 |
| Marble Hill 1 | 1130 | 27.7% | Jun-86 + [2] | $2,001 | Cancelled | |
| Nine Mile Point 2*** | 1080 | 37.0% | Jul-86 + | $3,612 | $5,400 | Oct-86 |
| Hartsville A1 | 1233 | 29.0% | Jul-86 + | $5,673 | Cancelled | |
| Limerick 2 | 1055 | 36.0% | Apr-87 | $1,581 | $3,600 | 1990 |
| Perry 2 | 1205 | 35.9% | May-88 | $2,157 | Suspended | |
| AVERAGES | | | | | | |
| ALL UNITS | 1111 | 34.7% | Dec-85 | | | |
| FIRST UNITS | 1587 | 34.2% | Aug-85 [3] | | | |

Source: Nuclear News, August, 1980 and February, 1986; EIA-254 Quarterly Reports for Estimated Costs.

[1] + indicates first units.
[2] No month was indicated for Marble Hill's COD. June was assumed.
[3] Averages exclude Millstone 3.
[4] * architect/engineer= Stone & Webster,
** constructor= Stone & Webster,
*** architect/engineer and constructor= Stone & Webster.
[5] Current estimate of costs for S. Texas Project 1 and Limerick 2 =(unit 1 + unit 2)/2. Current estimate of costs for Palo Verde 2=(unit 1 + unit 2 + unit 3)/3.

TABLE 3.14: JUNE, 1980: ESTIMATED COST FOR
UNITS WITH COD PROJECTED FOR 1986

| | |------------ | ----as of June, 1980 | ----------- | ----------- | -----------\| | --Next Reported Change--\| | | Actual or |
|---|---|---|---|---|---|---|---|---|---|
| | | | Estimated | Estimated Cost | | | ----New Cost---- | | Current |
| Unit Name | Size (MW) | % compl | COD | $ Million | $/kw | Date | $ Million | $/KW | Est. COD |
| ---------------- | ---------- | ---------- | -[1]--- | ----[4]----- | ------ | ---- | --------- | ---- | ------- |
| Millstone 3*** | 1153 | 33.0% | May-86 + | $1,980 | $1,717 | Dec-80 | $2,573 | $2,232 | May-86 |
| S. Texas Project 2 | 1250 | 9.0% | Apr-86 | $1,208 | $966 | Dec-81 | $1,717 | $1,374 | Jun-89 |
| Beaver Valley 2*** | 833 | 38.0% | May-86 + | $2,024 | $2,430 | Sep-80 | $2,203 | $2,645 | Aug-87 |
| Palo Verde 3 | 1270 | 9.7% | May-86 | $1,088 | $857 | Sep-80 | $1,212 | $954 | Aug-87 |
| Marble Hill 1 | 1130 | 27.7% | Jun-86 + [2] | $2,001 | $1,771 | Sep-81 | $2,504 | $2,216 | Cancelled |
| WNP-3 | 1240 | 23.4% | Jun-86 | $2,993 | $2,414 | Sep-80 | $2,900 | $2,339 | Suspended |
| WNP-4 | 1250 | 16.9% | Jun-86 | $3,086 | $2,469 | Jun-81 | $4,251 | $3,401 | Cancelled |
| Hartsville A1 | 1233 | 29.0% | Jul-86 + | $1,418 | $1,150 | Mar-81 | $1,973 | $1,600 | Cancelled |
| Grand Gulf 2 | 1250 | 22.8% | Sep-86 [3] | $878 | $702 | | | | Suspended |
| Braidwood 2 | 1120 | 43.0% | Oct-86 | $1,011 | $903 | Dec-80 | $1,014 | $905 | Dec-87 |
| Nine Mile Point 2*** | 1080 | 37.0% | Oct-86 + | $3,612 | $3,344 | Mar-81 | $3,727 | $3,451 | Oct-86 |
| Hope Creek 1 | 1070 | 24.0% | Dec-86 + | $4,310 | $4,028 | Sep-80 | $4,595 | $4,294 | Sep-86 |
| AVERAGES | | | | | | | | | |
| ALL UNITS | 1157 | 25.5% | Jul-86 | $2,148 | $1,912 | Feb-81 | $2,610 | $2,318 | |
| FIRST UNITS | 1069 | 31.1% | Aug-86 | $2,041 | $2,545 | Feb-81 | $3,000 | $2,841 [5] | |

Source: Nuclear News, August, 1980 and February,1986; EIA-254 Quarterly Reports for Estimated Costs.

Notes: [1] + indicates first units.
[2] No month was indicated for Marble Hill's COD. June was assumed.
[3] Hartsville A1 estimated cost=cost of unit 1+2+3+4 cost/4.
[4] The EIA-254 Report for Grand Gulf 2's COD varies from the Nuclear News Report by more than 6 months. No cost estimates were available for Grand Gulf 2 after 6/80.
[5] Averages exclude Millstone 3.
[6] * architect/engineer= Stone & Webster, constructor= Stone & Webster, architect/engineer and constructor= Stone & Webster.

| Unit Name | Year of Cancellation | Construction Status | % Complete |
|---|---|---|---|
| Alan Barton 1 | 1977 | order | |
| Alan Barton 2 | | order | |
| Douglas Point 1 | | order | |
| Ft. Calhoun 2 | | order | |
| South Dade 1 | | order | |
| South Dade 2 | | order | |
| Surry 3* | | cp | 0% |
| Surry 4* | | cp | 0% |
| Sears Island*** | | order | |
| Atlantic 1 | 1978 | order | |
| Atlantic 2 | | order | |
| Blue Hills 1 | | order | |
| Blue Hills 2 | | order | |
| Haven 2*** | | order | |
| Islote | | order | |
| S.R. 1 | | order | |
| S.R. 2 | | order | |
| Sundesert 1*** | | order | |
| Sundesert 2*** | | order | |
| PSE&G Co. unit 1 | | order | |
| PSE&G Co. unit 2 | | order | |
| Wm. H. Zimmer 2 | | order | |
| Greene County*** | 1979 | order | |
| NEP-1 | | order | |
| NEP-2 | | order | |
| Palo Verde 4 | | order | |
| Palo Verde 5 | | order | |
| Tyrone 1 | | cp | 0% |
| Davis Besse 2 | 1980 | limited work authority | 0% |
| Davis Besse 3 | | limited work authority | 0% |
| Erie 1 | | order | |
| Erie 2 | | order | |
| Forked River 1 | | cp | 5% |
| Greenwood 2 | | order | |
| Greenwood 3 | | order | |
| Haven 1*** | | order | |
| Jamesport 1* | | cp | 0% |
| Jamesport 2* | | cp | 0% |
| Montague 1*** | | order | |
| Montague 2*** | | order | |
| New Haven 1 | | order | |
| New Haven 2 | | order | |
| North Anna 4*** | | cp | 4% |
| Sterling | | cp | 0% |

Source: Atomic Industrial Forum, "Background Info", January, 1984.

NOTES: [1] * architect/engineer= Stone & Webster,
** constructor= Stone & Webster, architect/engineer and
constructor= Stone & Webster.

TABLE 3.16: UNITS SCHEDULED FOR 1986 OPERATION,
AS OF JUNE, 1982

| Unit Name | Size (MW) | % complete at 8/82 | Estimated COD -[1]-[2]- | Actual or Current Est. COD |
|---|---|---|---|---|
| Millstone 3*** | 1153 | 45.0% | May-86 + | May-86 |
| | | | | |
| Beaver Valley 2*** | 833 | 53.3% | May-86 | Aug-87 |
| Nine Mile Point 2*** | 1080 | 44.0% | Oct-86 | Oct-86 |
| Seabrook 2 | 1150 | 20.0% | May-86 | Suspended |
| Hope Creek 1 | 1070 | 50.0% | Dec-86 + | Sep-86 |
| Braidwood 2 | 1120 | 48.0% | Oct-86 | Dec-87 |
| Marble Hill 1 | 1130 | 35.0% | Jun-86 + | Cancelled |
| Bellefonte 1 | 1213 | 79.0% | Nov-86 + | 1995 |
| Palo Verde 3 | 1270 | 39.1% | May-86 | Aug-87 |
| S. Texas 1 | 1250 | 60.0% | Jun-86 + | Dec-87 |
| WNP 3 | 1240 | 53.8% | Dec-86 | Suspended |
| | | | | |
| AVERAGES | | | | |
| All Units | 1136 | 48.2% | Aug-86 | |
| First Units | 1166 | 56.0% | Sep-86 [3] | |

Source: Nuclear News, August,1982 and February, 1986.

Notes: [1] No month was reported for the CODs of Marble Hill 1 and South Texas Project 1. June was assumed.
[2] + indicates first units.
[3] Averages exclude Millstone 3.
[4] * architect/engineer=Stone & Webster,
** constructor=Stone & Webster
***architect/engineer and constructor=Stone & Webster.

TABLE 3.17: UNITS SCHEDULED FOR 1986 OPERATION,
AS OF JUNE, 1984

| Unit Name | Size (MW) | % complete at 6/84 | Estimated COD -[1]-[2]- | Actual or Current Est. COD |
|---|---|---|---|---|
| Millstone 3*** | 1153 | 86.0% | May-86 + | May-86 |
| Beaver Valley 2*** | 833 | 78.5% | Oct-86 | Aug-87 |
| Nine Mile Point 2*** | 1085 | 75.5% | Oct-86 | Oct-86 |
| Seabrook 1 | 1150 | 75.0% | Feb-86 + | Oct-86 |
| Hope Creek 1 | 1070 | 85.6% | Dec-86 + | Sep-86 |
| Byron 2 | 1120 | 67.0% | Feb-86 | Oct-86 |
| Braidwood 1 | 1120 | 73.0% | Feb-86 + | Oct-86 |
| Clinton 1 | 933 | 84.7% | Nov-86 + | Jul-86 |
| Shearon Harris 1 | 900 | 86.0% | Mar-86 + | Late 1986 |
| Watts Bar 2 | 1177 | 61.0% | Oct-86 | Apr-88 |
| Palo Verde 2 | 1270 | 99.3% | Jun-86 | Aug-86 |
| Comanche Peak 2 | 1150 | 65.0% | Jun-86 | Dec-87 |
| AVERAGES | | | | |
| All Units | 1073 | 77.3% | Jul-86 | |
| First Units | 1035 | 80.9% | Jun-86 [3] | |

Source: Nuclear News, August,1982 and February, 1986.

Notes: [1] No month was reported for the CODs of Comanche Peak 2 and Palo Verde 2. June was assumed.
[2] + indicates first units.
[3] Averages exclude Millstone 3.
[4] * architect/engineer=Stone & Webster,
** constructor=Stone & Webster
***architect/engineer and constructor=Stone & Webster.

TABLE 4.1: BUSBAR COST COMPARISON IN 1978.

| | | MILLSTONE 3 | | | | COAL | | OIL |
|---|---|---|---|---|---|---|---|---|
| 1. | Case | NU | NU | Historical | Historical | NEPOOL | NU | |
| 2. | Cost | Incremental | Total | Incremental | Total | | | |
| 3. | Construction Cost Estimate ($M) | $3,800 | | $3,800 | | $827 | $1,020 | - |
| 4. | Sunk Cost: $541 Million with AFUDC, to 5/86 at: 8.0% | $1,002 | | $1,002 | | $0 | $0 | - |
| 5. | Net Investment ($M) | $2,798 | $3,800 | $2,798 | $3,800 | $827 | $1,020 | - |
| 6. | Levelized Carrying Charges ($M) | 21% | 21% | 21% | 21% | 21% | 21% | - |
| 7. | Annual Carrying Cost ($M) | $588 | $798 | $588 | $798 | $174 | $214 | - |
| 8. | O&M, ($M) | $47 | $47 | $121 | $121 | $54 | $33 | - |
| 9. | Annual Cost ($M) | $635 | $845 | $708 | $919 | $227 | $247 | |
| 10. | Unit Size (MW) | 1150 | 1150 | 1150 | 1150 | 800 | 800 | - |
| 11. | Annual Cost, $/KW | $552 | $735 | $616 | $799 | $284 | $308 | |
| 12. | Capacity Factor | 66.9% | 66.9% | 57.8% | 57.8% | 70.7% | 74.0% | - |
| 13. | Non-Fuel Cost, cents/kwh | 9.4 | 12.5 | 12.2 | 15.8 | 4.6 | 4.8 | |
| 14. | Fuel Cost, cents/kwh | 1.97 | 1.97 | 1.97 | 1.97 | 4.22 | 4.11 | 8.85 |
| 15. | Total Cost, cents/kwh | 11.4 | 14.5 | 14.1 | 17.8 | 8.8 | 8.9 | 8.8 |

Notes:
3. NEPOOL coal data from NEPLAN, 1977 revised forecast, escalated to 1986$.;
NU coal data from Data Request 1/28/86, Q-AG 8-24,. p. 2 of 2.
- Capital Costs in 1986: 1275 $/KW. Unit Size 800 MW.
4. Millstone 3 Cumulative Total in 1978 from: IR AG 6 QAG-6-30, page 2 of 2.
5. (3) - (4)
6. Millstone 3 and Coal: NEPLAN, 1977 revised forecast. Based on Cost of Money: 12%.
7. (5) * (6)
8., 12., 13. Millstone 3: see Table 4.2, levelized values.
9. (7) + (8)
11. (9) * 1000 / (10)
13. (11) * 100 / (12) * 8760
14. Levelized fuel costs from Table 4.2.
15. (13) + (14)

TABLE 4.2: LEVELIZED COST PROJECTIONS IN 1978.

| Year | MILLSTONE 3 | MILLSTONE 3 NU | | MILLSTONE 3 Historical | | COAL NEPOOL | | | COAL NU | | | OIL |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Fuel cts/kwh [1] | CF [1] | O&M $Mill [1a] | CF [4] | O&M $Mill [2] | CF [3] | O&M $Mill [3] | Fuel cts/kwh [3] | CF [5] | O&M $Mill [5] | Fuel cts/kwh [5] | Fuel cts/kwh [1] |
| 1986 | 1.18 | 60% | $26.9 | 54.1% | $26.86 | 53% | $31.8 | 2.50 | 74% | $18.5 | 2.37 | 4.98 |
| 1987 | 2.07 | 63% | $28.6 | 54.1% | $32.8 | 62% | $33.8 | 2.65 | 74% | $19.7 | 2.51 | 5.3 |
| 1988 | 2.07 | 65% | $30.4 | 54.1% | $39.5 | 66% | $35.8 | 2.81 | 74% | $21.0 | 2.67 | 5.6 |
| 1989 | 2.07 | 65% | $32.4 | 54.1% | $46.7 | 72% | $37.9 | 2.98 | 74% | $22.3 | 2.84 | 6.0 |
| 1990 | 2.07 | 65% | $34.4 | 60.0% | $54.8 | 72% | $40.2 | 3.16 | 74% | $23.7 | 3.02 | 6.4 |
| 1991 | 2.07 | 68% | $36.6 | 60.0% | $63.6 | 76% | $42.6 | 3.35 | 74% | $25.2 | 3.21 | 6.8 |
| 1992 | 2.07 | 70% | $39.0 | 60.0% | $73.2 | 76% | $45.2 | 3.55 | 74% | $26.9 | 3.41 | 7.3 |
| 1993 | 2.07 | 70% | $41.5 | 60.0% | $83.8 | 76% | $47.9 | 3.76 | 74% | $28.6 | 3.62 | 7.7 |
| 1994 | 2.07 | 70% | $44.1 | 60.0% | $95.4 | 76% | $50.8 | 3.99 | 74% | $30.4 | 3.85 | 8.2 |
| 1995 | 2.07 | 70% | $47.0 | 60.0% | $108.1 | 76% | $53.8 | 4.23 | 74% | $32.4 | 4.09 | 8.8 |
| 1996 | 2.07 | 70% | $50.0 | 60.0% | $122.0 | 76% | $57.0 | 4.48 | 74% | $34.4 | 4.35 | 9.3 |
| 1997 | 2.07 | 70% | $53.2 | 60.0% | $137.2 | 76% | $60.4 | 4.75 | 74% | $36.6 | 4.62 | 10.0 |
| 1998 | 2.07 | 70% | $56.6 | 60.0% | $153.7 | 76% | $64.1 | 5.04 | 74% | $39.0 | 4.91 | 10.6 |
| 1999 | 2.07 | 70% | $60.2 | 60.0% | $171.7 | 76% | $67.9 | 5.34 | 74% | $41.5 | 5.22 | 11.3 |
| 2000 | 2.07 | 70% | $64.0 | 60.0% | $191.4 | 76% | $72.0 | 5.66 | 74% | $44.1 | 5.55 | 12.0 |
| 2001 | 2.07 | 70% | $68.1 | 60.0% | $212.7 | 76% | $76.3 | 6.00 | 74% | $46.9 | 5.90 | 12.8 |
| 2002 | 2.07 | 70% | $72.5 | 60.0% | $236.0 | 76% | $80.9 | 6.36 | 74% | $49.9 | 6.27 | 13.6 |
| 2003 | 2.07 | 70% | $77.1 | 60.0% | $261.3 | 76% | $85.7 | 6.74 | 74% | $53.1 | 6.66 | 14.5 |
| 2004 | 2.07 | 70% | $82.1 | 60.0% | $288.7 | 76% | $90.9 | 7.14 | 74% | $56.5 | 7.08 | 15.5 |
| 2005 | 2.07 | 70% | $87.3 | 60.0% | $318.5 | 76% | $96.3 | 7.57 | 74% | $60.2 | 7.53 | 16.5 |
| 2006 | 2.07 | 70% | $92.9 | 60.0% | $350.9 | 76% | $102.1 | 8.03 | 74% | $64.0 | 8.00 | 17.5 |
| 2007 | 2.07 | 70% | $98.8 | 60.0% | $385.9 | 76% | $108.2 | 8.51 | 74% | $68.1 | 8.51 | 18.7 |
| 2008 | 2.07 | 70% | $105.2 | 60.0% | $424.0 | 76% | $114.7 | 9.02 | 74% | $72.5 | 9.04 | 19.9 |
| 2009 | 2.07 | 70% | $111.9 | 60.0% | $465.2 | 76% | $121.6 | 9.56 | 74% | $77.1 | 9.61 | 21.2 |
| 2010 | 2.07 | 70% | $119.1 | 60.0% | $509.8 | 76% | $128.9 | 10.13 | 74% | $82.0 | 10.22 | 22.6 |
| 2011 | 2.07 | 70% | $126.7 | 60.0% | $558.1 | 76% | $136.7 | 10.74 | 74% | $87.3 | 10.86 | 24.0 |
| 2012 | 2.07 | 70% | $134.8 | 60.0% | $610.4 | 76% | $144.9 | 11.38 | 74% | $92.9 | 11.55 | 25.6 |
| 2013 | 2.07 | 70% | $143.4 | 60.0% | $666.9 | 76% | $153.6 | 12.07 | 74% | $98.8 | 12.28 | 27.3 |
| 2014 | 2.07 | 70% | $152.6 | 60.0% | $728.0 | 76% | $162.8 | 12.79 | 74% | $105.2 | 13.05 | 29.0 |
| 2015 | 2.07 | 70% | $162.4 | 60.0% | $794.0 | 76% | $172.5 | 13.56 | 74% | $111.9 | 13.87 | 30.9 |
| 2016 | 2.07 | 70% | $172.8 | 60.0% | $865.4 | 76% | $182.9 | 14.37 | 74% | $119.0 | 14.75 | 32.9 |
| LEVELIZED at Cost of Money [1] 12.00% | 1.97 | 66.9% | $47.2 | 57.8% | $121 | 70.7% | $53.7 | 4.22 | 74.0% | $32.5 | 4.11 | 8.8 |

[1] 'The Economics Of And Need For Millstone 3 With Revised Estimate', October 1978:

- Capacity Factor, page 1. Assumes operation begins May 1, 1986.
- Nuclear Fuel, page 2: 1986 ISD assumptions: 11.8 Mills/KWh in 1st year, 20.7 Mills/KWh 30 yr levelized (1987-2016)
- Oil, page 2. (Booz,Allen estimates): 498 cents/MBTU, escalating at 6.5%. We assume 10,000 BTU/kwh.

[1a] - O&M from Data Request 1/28/86, AG-8-24, p. 2 of 2.: $23.36/kw-yr, escalated at 6.4%

[3] From NEPLAN and GTF Revised Forecast, 1977. All escalation at 6%.

[2] See Table 4.5: Average O&M in 1977 (1986$) increased at average linear least squares growth, in 1986$, and inflated at 6%

[4] Simple average of historical capacity factors in 1977, from Table 4.6(b).

Continued Notes Table 4.2:

[5] NU coal estimates and assumptions used in 1977 from Data Request Q-AG 8-24, page 1 of 2.

- Capacity Factor: 74%
- Fixed O&M 23.14 $/kw-yr, escalated at 6.4%.
  Variable O&M: 2.1 Mills/kwh, escalated at 6.4% is added to fuel.
- Fuel: 222 cts/MBTU, Heat Rate 9713 BTU/kwh, escalated at 4.9%. Variable O&M added.
- Cost of Money: 12%

TABLE 4.3: BUSBAR COST COMPARISON IN 1980

| | | MILLSTONE 3 | | | | COAL | | OIL |
|---|---|---|---|---|---|---|---|---|
| 1. | Case | NU | NU | Historical | Historical | NEPOOL | NU | |
| 2. | Cost | Incremental | Total | Incremental | Total | | | |
| 3. | Construction Cost Estimate ($M) | $3,800 | | $3,800 | | $827 | $953 | - |
| 4. | Sunk Cost: $763 Million with AFUDC, to 5/86 at: 8.0% | $1,413 | | $1,413 | | $0 | $0 | - |
| 5. | Net Investment ($M) | $2,387 | $3,800 | $2,387 | $3,800 | $827 | $953 | - |
| 6. | Levelized Carrying Charges | 23% | 23% | 23% | 23% | 23% | 23% | - |
| 7. | Annual Carrying Cost ($M) | $549 | $874 | $549 | $874 | $190 | $219 | - |
| 8. | O&M, ($M) | $75 | $75 | $104 | $104 | $51 | $59 | - |
| 9. | Annual Cost, ($M) | $624 | $949 | $653 | $978 | $241 | $278 | - |
| 10. | Unit Size (MW) | 1150 | 1150 | 1150 | 1150 | 800 | 862.5 | - |
| 11. | Annual Cost, $/KW | $543 | $826 | $567 | $850 | $301 | $322 | - |
| 12. | Capacity Factor | 66.4% | 66.4% | 56.1% | 56.1% | 70.1% | 66.9% | - |
| 13. | Non-Fuel Cost, cents/kwh | 9.34 | 14.20 | 11.54 | 17.29 | 4.91 | 5.49 | |
| 14. | Fuel Cost, cents/kwh | 1.63 | 1.63 | 1.63 | 1.63 | 3.99 | 4.70 | 25.4 |
| 15. | Total Cost, cents/kwh | 11.0 | 15.8 | 13.2 | 18.9 | 8.9 | 10.2 | 25.4 |

Notes:

3. Millstone 3: see text. Coal: NEPLAN, 1977 revised forecast, escalated to 1986$. NU Coal Projection from 'Options to Reduce NU Oil Dependence By 1990 [..]' BEC-173, Study #62.' The 1990 construction cost is deflated at 10.5% to 1986 'General Plant' escalation in 1980, from Q-AG-8-25 p. 3 of 3.
4. Cumulative Total in 1979 plus one half of 1980 expenditures, from: IR AG 6 QAG-6-30, page 2 of 2.
5. (3) - (4)
6. Millstone 3 and Coal: NEPLAN, 1977 revised forecast, increased by 4 percentage points.
7. (5) * (6)
8., 12., 13. Millstone 3: see Table 4.4, levelized values. Coal, NEPOOL: 1977 revised forecast and NEPOOL 1979 maintenance requirements.
9. (7) + (8)
10. NU Coal Unit Size from study #62 (see note [1]).
11. (9) * 1000 / (10)
13. (11) * 100 / (12) * 8760
14. Levelized fuel costs from Table 4.4.
15. (13) + (14)

TABLE 4.4: LEVELIZED COST PROJECTIONS IN 1980.

| | MILLSTONE 3 | MILLSTONE 3 NU | | MILLSTONE 3 Historical | | COAL NEPOOL | | | COAL NU | | | OIL |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Year | Fuel cts/kwh [1] | CF [1] | O&M $Mill [1] | CF [4] | O&M $Mill [3] | CF [2] | O&M $Mill [2] | Fuel cts/kwh [2] | CF [5] | O&M $Mill [5] | Fuel cts/kwh [5] | Fuel cts/kwh [1] |
| 1986 | 1.03 | 60.0% | $41.4 | 56.0% | $37.36 | 53% | $31.8 | 2.50 | 60% | $34 | 3.3 | 11.91 |
| 1987 | 0.94 | 63.0% | $44.5 | 56.0% | $41.9 | 62% | $33.8 | 2.65 | 65% | $36 | 3.4 | 13.0 |
| 1988 | 0.96 | 65.0% | $47.8 | 56.0% | $47.1 | 66% | $35.8 | 2.81 | 65% | $39 | 3.6 | 14.1 |
| 1989 | 1.06 | 65.0% | $51.3 | 56.0% | $52.8 | 72% | $37.9 | 2.98 | 65% | $41 | 3.7 | 15.4 |
| 1990 | 1.16 | 65.0% | $55.1 | 56.2% | $59.1 | 72% | $40.2 | 3.16 | 65% | $44 | 3.9 | 16.8 |
| 1991 | 1.25 | 65.0% | $59.2 | 56.2% | $66.2 | 76% | $42.6 | 3.35 | 70% | $48 | 4.0 | 18.3 |
| 1992 | 1.36 | 70.0% | $63.6 | 56.2% | $74.1 | 76% | $45.2 | 3.55 | 70% | $53 | 4.2 | 19.9 |
| 1993 | 1.48 | 70.0% | $68.3 | 56.2% | $82.8 | 76% | $47.9 | 3.76 | 70% | $58 | 4.5 | 21.7 |
| 1994 | 1.64 | 70.0% | $73.4 | 56.2% | $92.4 | 76% | $50.8 | 3.99 | 70% | $58 | 4.7 | 23.7 |
| 1995 | 1.79 | 70.0% | $78.8 | 56.2% | $103.0 | 76% | $53.8 | 4.23 | 70% | $63 | 4.9 | 25.8 |
| 1996 | 1.95 | 70.0% | $84.7 | 56.2% | $114.6 | 76% | $57.0 | 4.48 | 70% | $69 | 5.2 | 28.1 |
| 1997 | 2.10 | 70.0% | $91.0 | 56.2% | $127.4 | 76% | $60.4 | 4.75 | 70% | $69 | 5.4 | 30.7 |
| 1998 | 2.23 | 70.0% | $97.7 | 56.2% | $141.5 | 76% | $64.1 | 5.04 | 70% | $74 | 5.7 | 33.4 |
| 1999 | 2.35 | 70.0% | $105.0 | 56.2% | $157.0 | 76% | $67.9 | 5.34 | 70% | $79 | 6.0 | 36.4 |
| 2000 | 2.50 | 70.0% | $112.8 | 56.2% | $173.9 | 76% | $72.0 | 5.66 | 70% | $85 | 6.3 | 39.7 |
| 2001 | 2.66 | 70.0% | $121.1 | 56.2% | $192.4 | 76% | $76.3 | 6.00 | 70% | $90 | 6.7 | 43.3 |
| 2002 | 2.84 | 70.0% | $130.1 | 56.2% | $212.7 | 76% | $80.9 | 6.36 | 70% | $96 | 7.0 | 47.1 |
| 2003 | 3.02 | 70.0% | $139.8 | 56.2% | $234.8 | 76% | $85.7 | 6.74 | 70% | $103 | 7.4 | 51.4 |
| 2004 | 3.22 | 70.0% | $150.2 | 56.2% | $259.0 | 76% | $90.9 | 7.14 | 70% | $110 | 7.8 | 56.0 |
| 2005 | 3.43 | 70.0% | $161.3 | 56.2% | $285.4 | 76% | $96.3 | 7.57 | 70% | $117 | 8.3 | 61.0 |
| 2006 | 3.65 | 70.0% | $173.3 | 56.2% | $314.1 | 76% | $102.1 | 8.03 | 70% | $125 | 8.7 | 66.5 |
| 2007 | 3.88 | 70.0% | $186.1 | 56.2% | $345.3 | 76% | $108.2 | 8.51 | 70% | $133 | 9.2 | 72.5 |
| 2008 | 4.14 | 70.0% | $199.9 | 56.2% | $379.4 | 76% | $114.7 | 9.02 | 70% | $142 | 9.7 | 79.0 |
| 2009 | 4.41 | 70.0% | $214.8 | 56.2% | $416.4 | 76% | $121.6 | 9.56 | 70% | $152 | 10.2 | 86.1 |
| 2010 | 4.69 | 70.0% | $230.7 | 56.2% | $456.6 | 76% | $128.9 | 10.13 | 70% | $162 | 10.8 | 93.8 |
| 2011 | 5.00 | 70.0% | $247.8 | 56.2% | $500.2 | 76% | $136.7 | 10.74 | 70% | $173 | 11.4 | 102.2 |
| 2012 | 5.32 | 70.0% | $266.2 | 56.2% | $547.6 | 76% | $144.9 | 11.38 | 70% | $185 | 12.0 | 111.4 |
| 2013 | 5.67 | 70.0% | $286.0 | 56.2% | $599.1 | 76% | $153.6 | 12.07 | 70% | $197 | 12.7 | 121.4 |
| 2014 | 6.04 | 70.0% | $307.2 | 56.2% | $654.8 | 76% | $162.8 | 12.79 | 70% | $210 | 13.4 | 132.3 |
| 2015 | 6.43 | 70.0% | $330.0 | 56.2% | $715.2 | 76% | $172.5 | 13.56 | 70% | $224 | 14.1 | 144.2 |
| 2016 | 6.85 | 70.0% | $354.4 | 56.2% | $780.7 | 76% | $182.9 | 14.37 | 70% | $239 | 14.9 | 157.1 |
| LEVELIZED at Cost of Money: 14.00% [*] | 1.63 | 66.4% | $75.4 | 56.12% | $103.5 | 70% | $50.8 | 3.99 | 67% | $58.6 | 4.70 | 25.42 |

Notes: [1] Briefing Document, 'Millstone 3 Reduced Ownership Study, 1986 to 2000', March, 1980. [jec-c17-E].
We carried study assumptions out to the year 2016
- Nuclear Fuel, page 19. Projections for 1986 through 2000, We assumed escalation at 6.5% thereafter.
- Capacity Factor, page 3. Assumes Operation May 31, 1986.
- O&M, page 2. $36 $/KW-yr in 1986, escalating at 7.2% Assumes 1150 MW-yrs.
- Oil, .5% Sulphur Fuel, page 2. 1986: 1190.74 cts/MBTU. Assumes 10,000 BTU/kWh Heat Rate, escalating at 8.98

Continued Notes Table 4.4:

[2] NEPOOL 1977 Revised Forecast.

[3] See Table 4.5: Average linear cost (squares) growth as of 1980, in 1986 dollars.

[4] See Table 4.6(b): Simple average of historical capacity factors in 1979, for units of 800 MW or greater.

[5] Coal data from: 'Options to Reduce NorthEast Utilities Oil Dependence By 1990 [..]' [BEC-173, Study #62].
- Fuel Costs for coal plants with ISD in 1990, deflated at ratio of cts/MBTU fuel costs for years 1986 - 1989. Escalated at 5.5% after 2000.
- O&M for ISD in 1990, deflated 1990-1986 and escalated 1999-2016 at average annual growth rate of O&M given.

TABLE 4.5: ANNUAL NUCLEAR O&M EXPENSES, 1972-1977, 1972-1979, in 1983 dollars ($1000)
SINGLE UNITS OF 800 MW OR GREATER

| Plant: | 1972 | 1973 | 1974 | 1975 | 1976 | 1977 | Linear Cost (Least Squares) Growth to 1977 --[1]--- | 1978 | 1979 | Linear Cost (Least Square Growth to 1979 --[1]--- |
|---|---|---|---|---|---|---|---|---|---|---|
| Arkansas 1 | | | | $12,042 | $9,787 | $12,883 | $421 | $17,358 | $24,935 | $3,336 |
| Beaver Valley | | | | | * | 22590 | | 32470 | 30185 | 3797 |
| Cook 1 | | | | * | 11467 | 15394 | 3928 | | | |
| Cooper | | | * | 12644 | 16615 | 15711 | 1534 | 11891 | 13483 | -305 |
| Crystal River | | | | | | * | | 22351 | 31614 | 9263 |
| Davis-Besse | | | | | | * | | 20180 | 13920 | -6259 |
| Farley 1 | | | | | | * | | 17475 | 29708 | 12232 |
| Fitzpatrick | | | | * | 17411 | 26728 | 9317 | 27265 | 33115 | 4765 |
| Hatch 1 | | | | | 9547 | 15066 | 5519 | 17563 | 17887 | 2752 |
| Indian Point 2 [1] | | | | | | | | 40324 | 43014 | 2690 |
| Indian Point 3 | | | | | * | 19457 | | 33382 | 38061 | 9302 |
| Maine Yankee | | 8214 | 9790 | 10787 | 8561 | 12943 | 823 | 15486 | 13139 | 1011 |
| Millstone 1 | 16532 | 15547 | 18353 | 20654 | 22846 | 19431 | 1105 | 23547 | 30386 | 1695 |
| Millstone 2 | | | | * | 17783 | 26719 | 8935 | 31907 | 28899 | 3853 |
| Palisades | 1622 | 6435 | 22039 | 16436 | 16024 | 10100 | 1873 | 22036 | 34714 | 3255 |
| Rancho Seco | | | | * | 11704 | 21526 | 9822 | 16941 | 18079 | 1454 |
| Salem 1 | | | | | | * | | 31940 | 56013 | 24072 |
| St. Lucie | | | | | * | 11575 | | 22639 | 18964 | -3695 |
| Three Mile Island 1 | | | * | 24354 | 29029 | 20430 | -1962 | 25705 | 15604 | -2082 |
| Trojan | | | | | * | 20954 | | 21766 | 22344 | 695 |

| | | 1977: O&M Expense | Linear Increase | 1979: O&M Expense | Linear Increase |
|---|---|---|---|---|---|
| - Averages, in 1983 dollars | | $18,101 | $3,756 | $27,056 | $3,781 |
| - Averages converted back to current dollars (1977$,1979$ resp.) | | $11,772 | $2,443 | $20,533 | $2,869 |
| - Inflated to 1986 at | 6.0% | $19,889 | $4,127 | $30,873 | $4,314 |
| - Projected 1986 O&M Expense (as of 1977, 1979 resp.) (for Tables 4.2 and 4.4) | | $26,861 | | $37,360 | |

Notes: * Partial years' O&M not included.
[1] Linear Cost Squares Growth when more than 2 observations available.

TABLE 4.6: NUCLEAR CAPITAL ADDITIONS

| | Year | Averages by Year (in $/kw-yr): All plants | Single units, > 800 MW |
|---|---|---|---|
| All years before and including: | 1972 | $1.43 | |
| | 1973 | $10.87 | $38.90 |
| | 1974 | $11.07 | $26.82 |
| | 1975 | $8.71 | $19.72 |
| | 1976 | $15.07 | $2.98 |
| | 1977 | $19.91 | $12.78 |
| | 1978 | $17.77 | $25.94 |
| | 1979 | $14.82 | $16.75 |
| | 1980 | $27.73 | $27.97 |
| | 1981 | $31.66 | $28.33 |
| | 1982 | $29.06 | $24.80 |
| | 1983 | $29.78 | $26.42 |
| | 1984 | $42.88 | $34.45 |
| Overall Average: | | $20.74 | $23.37 |
| (# of obs.) | | 520 | 127 |
| 1978-84 Average: | | $27.69 | $26.49 |
| (# of obs.) | | 314 | 97 |
| 1980-84 Average: | | $32.29 | $28.80 |
| (# of obs.) | | 224 | 67 |

OM8AVGS/17-Mar-86

TABLE 4.7: ANNUAL PWR CAPACITY FACTORS, 1968-81 (%)

| Plant | DER | 1968 | 1969 | 1970 | 1971 | 1972 | 1973 | 1974 | 1975 | 1976 | 1977 | 1978 | 1979 | 1980 | 1981 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| San Onofre 1 | 450 | 31.9% | 66.1% | 77.6% | 83.8% | 71.1% | 57.5% | 79.8% | 82.3% | 62.6% | 59.2% | 68.0% | 85.1% | 20.7% | 19.8% |
| Conn Yankee | 575 | 59.3% | 72.2% | 70.2% | 83.1% | 85.1% | 48.1% | 86.4% | 81.8% | 79.7% | 79.7% | 93.5% | 81.7% | 70.5% | 80.7% |
| Ginna | 490 | | | | 63.0% | 54.7% | 79.1% | 48.9% | 70.8% | 47.9% | 70.5% | 75.0% | 69.0% | 71.9% | 77.4% |
| Point Beach 1 | 497 | | | | 75.2% | 67.0% | 63.0% | 72.2% | 67.1% | 78.0% | 84.7% | 87.2% | 70.2% | 56.7% | 60.1% |
| Robinson 2 | 707 | | | | | 77.8% | 60.8% | 77.7% | 67.3% | 78.5% | 68.3% | 64.3% | 64.7% | 51.7% | 56.6% |
| Palisades | 821 | | | | | 24.5% | 33.5% | 1.1% | 33.8% | 39.5% | 70.7% | 36.5% | 47.7% | 33.0% | 48.2% |
| Point Beach 2 | 497 | | | | | | 69.0% | 73.0% | 85.9% | 86.2% | 83.2% | 88.6% | 85.1% | 82.2% | 85.4% |
| Surry 1 | 823 | | | | | | 48.0% | 46.0% | 54.3% | 60.8% | 69.7% | 65.2% | 31.3% | 34.2% | 33.0% |
| Turkey Point 3 | 745 | | | | | | 51.0% | 55.5% | 67.0% | 66.0% | 68.5% | 69.0% | 44.1% | 67.0% | 14.0% |
| Maine Yankee | 790 | | | | | | | 51.6% | 65.1% | 85.4% | 74.3% | 77.4% | 65.6% | 63.5% | 75.3% |
| Surry 2 | 823 | | | | | | | 36.5% | 70.1% | 46.2% | 61.8% | 74.5% | 8.5% | 31.0% | 71.4% |
| Oconee 1 | 886 | | | | | | | 51.5% | 68.1% | 51.3% | 50.8% | 65.1% | 64.4% | 65.7% | 38.6% |
| Indian Point 2 | 873 | | | | | | | 43.5% | 63.9% | 29.6% | 68.1% | 57.1% | 62.8% | 55.6% | 39.9% |
| Turkey Point 4 | 745 | | | | | | | 65.8% | 61.1% | 57.6% | 56.2% | 58.0% | 58.9% | 58.9% | 69.0% |
| Fort Calhoun | 457 | | | | | | | 60.3% | 52.0% | 54.7% | 74.8% | 71.2% | 91.6% | 50.1% | 53.7% |
| Prairie Island 1 | 530 | | | | | | | 30.9% | 79.6% | 70.2% | 80.0% | 82.1% | 62.7% | 66.7% | 82.7% |
| Zion 1 | 1050 | | | | | | | 37.8%. | 53.4% | 51.6% | 54.7% | 73.6% | 60.2% | 70.6% | 67.3% |
| Kewaunee | 560 | | | | | | | | 68.1% | 68.8% | 72.3% | 79.3% | 70.1% | 73.8% | 76.8% |
| Oconee 2 | 886 | | | | | | | | 64.0% | 54.3% | 49.3% | 61.7% | 76.9% | 49.8% | 66.9% |
| TMI 1 | 819 | | | | | | | | 77.2% | 60.3% | 76.1% | 79.1% | | | |
| Zion 2 | 1050 | | | | | | | | 52.5% | 50.3% | 68.2% | 73.2% | 51.8% | 57.2% | 57.2% |
| Oconee 3 | 986 | | | | | | | | 58.3% | 54.9% | 60.7% | 70.2% | 37.7% | 60.2% | 72.6% |
| Arkansas 1 | 850 | | | | | | | | 65.5% | 52.1% | 68.5% | 70.5% | 44.6% | 50.7% | 65.8% |
| Prairie Island 2 | 530 | | | | | | | | 68.4% | 57.2% | 83.6% | 84.5% | 90.3% | 74.5% | 66.6% |
| Rancho Seco | 913 | | | | | | | | | 27.5% | 73.5% | 62.4% | 71.4% | 55.1% | 32.9% |
| Calvert Cliffs 1 | 845 | | | | | | | | | 84.9% | 66.0% | 63.2% | 56.7% | 61.1% | 82.5% |
| Cook 1 | 1090 | | | | | | | | | 71.1% | 50.1% | 65.8% | 59.3% | 67.5% | 71.0% |
| Millstone 2 | 828 | | | | | | | | | 62.4% | 59.9% | 62.0% | 60.2% | 67.1% | 84.0% |
| Trojan | 1130 | | | | | | | | | | 65.6% | 16.8% | 53.2% | 61.2% | 64.9% |
| Indian Point 3 | 873 | | | | | | | | | | 72.2% | 71.4% | 62.7% | 40.0% | 39.7% |
| Beaver Valley 1 | 852 | | | | | | | | | | 39.8% | 33.2% | 23.8% | 4.0% | 62.5% |
| St. Lucie 1 | 802 | | | | | | | | | | 76.1% | 71.2% | 69.5% | 73.8% | 70.4% |
| Crystal River 3 | 825 | | | | | | | | | | | 35.9% | 52.1% | 46.3% | 56.5% |
| Calvert Cliffs 2 | 845 | | | | | | | | | | | 70.6% | 74.2% | 86.4% | 73.2% |
| Salem 1 | 1090 | | | | | | | | | | | 47.4% | 21.4% | 59.4% | 64.8% |
| Davis-Besse 1 | 906 | | | | | | | | | | | 32.9% | 39.4% | 26.3% | 55.0% |
| Farley 1 | 829 | | | | | | | | | | | 81.5% | 24.0% | 63.2% | 36.0% |
| Cook 2 | 1100 | | | | | | | | | | | | 61.8% | 69.3% | 66.3% |
| North Anna 1 | 907 | | | | | | | | | | | | 52.7% | 70.7% | 58.4% |
| Arkansas 2 | 912 | | | | | | | | | | | | | | 54.1% |
| North Anna 2 | 907 | | | | | | | | | | | | | | 71.1% |
| Farley 2 | 829 | | | | | | | | | | | | | | 72.9% |

| AVERAGES THROUGH: | 1977 | 1979 |
|---|---|---|
| Cumulative | 62.8% | 62.5% |
| Immature Years (1-4) | 60.8% | 60.0% |
| Mature Years (5+) | 70.8% | 67.7% |

TABLE 4.8: ANNUAL PWR CAPACITY FACTORS, 1968-81 (%) UNITS 800 MW +

| Plant | DER | 1972 | 1973 | 1974 | 1975 | 1976 | 1977 | 1978 | 1979 | 1980 | 1981 | 1982 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Palisades | 821 | 24.5% | 33.5% | 1.1% | 33.8% | 39.5% | 70.7% | 36.5% | 47.7% | 33.0% | 48.2% | 46.5% |
| Surry 1 | 823 | | 48.0% | 46.0% | 54.3% | 60.8% | 69.7% | 65.2% | 31.3% | 34.2% | 33.0% | 76.1% |
| Maine Yankee | 825 | | | 51.6% | 65.1% | 85.4% | 74.3% | 77.4% | 65.6% | 63.5% | 75.3% | 65.4% |
| Surry 2 | 823 | | | 36.5% | 70.1% | 46.2% | 61.8% | 74.5% | 8.5% | 31.0% | 71.4% | 76.2% |
| Oconee 1 | 886 | | | 51.5% | 68.1% | 51.3% | 50.8% | 65.1% | 64.4% | 65.7% | 38.6% | 66.4% |
| Indian Point 2 | 873 | | | 43.5% | 63.9% | 29.6% | 68.1% | 57.1% | 62.8% | 55.6% | 39.9% | 58.1% |
| Zion 1 | 1050 | | | 37.8% | 53.4% | 51.6% | 54.7% | 73.6% | 60.2% | 70.6% | 67.3% | 51.0% |
| Oconee 2 | 886 | | | | 64.0% | 54.3% | 49.3% | 61.7% | 76.9% | 49.8% | 66.9% | 44.3% |
| TMI 1 | 819 | | | | 77.2% | 60.3% | 76.1% | 79.1% | | | | |
| Zion 2 | 1050 | | | | 52.5% | 50.3% | 68.2% | 73.2% | 51.8% | 57.2% | 57.2% | 56.1% |
| Oconee 3 | 986 | | | | 58.3% | 54.9% | 60.7% | 70.2% | 37.7% | 60.2% | 72.6% | 24.5% |
| Arkansas 1 | 850 | | | | 65.5% | 52.1% | 68.5% | 70.5% | 44.6% | 50.7% | 65.8% | 50.0% |
| Rancho Seco | 913 | | | | | 27.5% | 73.5% | 62.4% | 71.4% | 55.1% | 32.9% | 42.1% |
| Calvert Cliffs 1 | 845 | | | | | 84.9% | 66.0% | 63.2% | 56.7% | 61.1% | 82.5% | 72.4% |
| Cook 1 | 1090 | | | | | 71.1% | 50.1% | 65.8% | 59.3% | 67.5% | 71.0% | 56.1% |
| Millstone 2 | 828 | | | | | 62.4% | 59.9% | 62.0% | 60.2% | 67.1% | 84.0% | 69.1% |
| Trojan | 1130 | | | | | | 65.6% | 16.8% | 53.2% | 61.2% | 64.9% | 48.5% |
| Indian Point 3 | 873 | | | | | | 72.2% | 71.4% | 62.7% | 40.0% | 39.7% | 18.8% |
| Beaver Valley 1 | 852 | | | | | | 39.8% | 33.2% | 23.8% | 4.0% | 62.5% | 36.0% |
| St. Lucie 1 | 802 | | | | | | 76.1% | 71.2% | 69.5% | 73.8% | 70.4% | 96.6% |
| Crystal River 3 | 825 | | | | | | | 35.9% | 52.1% | 46.3% | 56.5% | 68.0% |
| Calvert Cliffs 2 | 845 | | | | | | | 70.6% | 74.2% | 86.4% | 73.2% | 67.6% |
| Salem 1 | 1090 | | | | | | | 47.4% | 21.4% | 59.4% | 64.8% | 42.9% |
| Davis-Besse 1 | 906 | | | | | | | 32.9% | 39.4% | 26.3% | 55.0% | 40.5% |
| Farley 1 | 829 | | | | | | | 81.5% | 24.0% | 63.2% | 36.0% | 71.8% |
| Cook 2 | 1100 | | | | | | | | 61.8% | 69.3% | 66.3% | 72.6% |
| North Anna 1 | 907 | | | | | | | | 52.7% | 70.7% | 58.4% | 30.2% |
| Arkansas 2 | 912 | | | | | | | | | | 54.1% | 47.7% |
| North Anna 2 | 907 | | | | | | | | | | 71.1% | 50.9% |
| Farley 2 | 829 | | | | | | | | | | 72.9% | 50.9% |

| | 1977 | 1979 |
|---|---|---|
| AVERAGES THROUGH: | ==== | ==== |
| Cumulative | 56.2% | 56.1% |
| Immature Years (1-4) | 56.0% | 56.0% |
| Mature Years (5+) | 60.0% | 56.2% |
| MILLSTONE 2 AVERAGES | 61.1% | 61.1% |

Table 5.1
Northeast Utilities
Summer Capabilities and Peak Loads
NU Assumptions: No Nuclear Units

| | 1986 | 1987 | 1988 | 1989 | 1990 | 1991 | 1992 | 1993 | 1994 | 1995 | 1996 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| CAPACITY | ---- | ---- | ---- | ---- | ---- | ---- | ---- | ---- | ---- | ---- | ---- |
| 1. Existing Capacity (MW) | 5866.4 | 5596.9 | 5596.9 | 5596.9 | 5596.9 | 5596.9 | 5596.9 | 5596.9 | 5596.9 | 5596.9 | 5596.9 |
| 2. Changes in Capacity [1] | | | | 36.8 | 376.8 | 376.8 | 376.8 | 376.8 | 376.8 | 376.8 | 376.8 |
| 3. Retirements | | | | | | | | | | | |
| a. Devon 4&5 | | 98 | 98 | 98 | 98 | 98 | 98 | 98 | 98 | 98 | 98 |
| b. Devon 3&6 | | 136 | 136 | 136 | 136 | 136 | 136 | 136 | 136 | 136 | 136 |
| c. Middletown 1 | | 67 | 67 | 67 | 67 | 67 | 67 | 67 | 67 | 67 | 67 |
| d. 6 CT's | | 98.8 | 98.8 | 98.8 | 98.8 | 98.8 | 98.8 | 98.8 | 98.8 | 98.8 | 98.8 |
| e. Enfield 10 | 17.2 | 17.2 | 17.2 | 17.2 | 17.2 | 17.2 | 17.2 | 17.2 | 17.2 | 17.2 | 17.2 |
| f. W. Springfield 1&3 | | | | | | | 102 | 102 | 102 | 102 | 102 |
| 4. QF's | 44 | 190 | 346 | 407 | 547 | 547 | 527 | 527 | 524 | 503 | 402 |
| 5. Total Capacity [2] | 5893.2 | 5369.9 | 5525.9 | 5623.7 | 6103.7 | 6103.7 | 5981.7 | 5981.7 | 5978.7 | 5957.7 | 5856.7 |
| DEMAND | | | | | | | | | | | |
| 6. Peak Load Forecast | 4499 | 4616 | 4746 | 4897 | 5024 | 5152 | 5277 | 5438 | 5565 | 5689 | 5752 |
| 7. Annual Load Reduction | 16 | 27 | 36 | 44 | 63 | 75 | 89 | 101 | 112 | 120 | 143 |
| 8. Net Load [3] | 4483 | 4589 | 4710 | 4853 | 4961 | 5077 | 5188 | 5337 | 5453 | 5569 | 5609 |
| 9. Available Reserves (MW) [4] | 1410.2 | 780.9 | 815.9 | 770.7 | 1142.7 | 1026.7 | 793.7 | 644.7 | 525.7 | 388.7 | 247.7 |
| 10. Required Reserve | 22.5% | 22.5% | 23.5% | 23.5% | 22.5% | 22.5% | 22.5% | 22.5% | 22.5% | 22.5% | 22.5% |
| Required Capacity | 5491.7 | 5621.5 | 5816.9 | 5993.5 | 6077.2 | 6219.3 | 6355.3 | 6537.8 | 6679.9 | 6822.0 | 6871.0 |
| SHORTFALL AND SURPLUS | | | | | | | | | | | |
| 11. Shortfall (MW) [5] | 0.0 | 251.6 | 291.0 | 369.8 | 0.0 | 115.6 | 373.6 | 556.1 | 701.2 | 864.3 | 1014.3 |
| 12. Surplus (MW) [6] | 401.5 | 0.0 | 0.0 | 0.0 | 26.5 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |

Sources: EJF-I-5, page 8, 19 and 21.
Power Facilities Forecast, Vol. 2, April, 1985.

Notes: [1] 36.8 MW from Hydro in 1989.
340 MW from HQ2 in 1990.
[2] Total Capacity = 1+2-3+4.
[3] Net Load = 6-7.
[4] Available reserves = 2-3.
[5] Shortfall = 9-(8*10).
[6] Surplus = 9-(8*10).

TABLE 5.2: CALCULATION OF CAPACITY ALTERNATIVES TO MILLSTONE 3, All Capacity in Rated Megawatts

| in Year | Shortfall [1] | Continued Operation With Existing Units (Limited Capital Additions) [2]: Group 1 | M 1 | Devon 3&6 | ES 10 | Life Extension Capacity (With Major Refurbishment) [3]: Group 1 | (2nd) Group 1 | Group 2 & ES 10 | (2nd) Group 2 & ES 10 | Total Extended Capacity [4] | Shortfall after Extension [5] | Shortterm Purchases [6] | New CTs Needed to Replace Millstone 3 [7] | Cumulative New CTs Added [8] |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1986 | 0 | 17.2 | | | 13.5 | | | | | 31 | 0 | 0 | 0 | 0 |
| 1987 | 252 | 116.0 | 66.8 | 136 | 13.5 | | | | | 332 | 0 | 0 | 0 | 0 |
| 1988 | 291 | 116.0 | 66.8 | 136 | 13.5 | | | | | 332 | 0 | 0 | 0 | 0 |
| 1989 | 370 | 116.0 | 66.8 | 136 | 13.5 | | | | | 332 | 38 | 38 | 0 | 0 |
| 1990 | 0 | 116.0 | 66.8 | 136 | 13.5 | | | | | 332 | 0 | 0 | 0 | 0 |
| 1991 | 116 | 116.0 | 66.8 | 136 | 13.5 | | | | | 332 | 0 | 0 | 0 | 0 |
| 1992 | 374 | 116.0 | 66.8 | | 13.5 | | | 71.5 | | 268 | 106 | 0 | 106 | 106 |
| 1993 | 556 | 116.0 | 66.8 | | | | | 85 | | 268 | 288 | 0 | 183 | 288 |
| 1994 | 701 | | | | | 116 | | 85 | | 201 | 500 | 0 | 212 | 500 |
| 1995 | 751 | | | | | 116 | | 85 | | 201 | 550 | 0 | 50 | 550 |
| 1996 | 751 | | | | | 116 | | 85 | | 201 | 550 | 0 | 0 | 550 |
| 1997 | 751 | | | | | 116 | | 85 | | 201 | 550 | 0 | 0 | 550 |
| 1998 | 751 | | | | | 116 | | 85 | | 201 | 550 | 0 | 0 | 550 |
| 1999 | 751 | | | | | 116 | | 85 | | 201 | 550 | 0 | 0 | 550 |
| 2000 | 751 | | | | | 116 | | 85 | | 201 | 550 | 0 | 0 | 550 |
| 2001 | 751 | | | | | 116 | | 85 | | 201 | 550 | 0 | 0 | 550 |
| 2002 | 751 | | | | | 116 | | 85 | | 201 | 550 | 0 | 0 | 550 |
| 2003 | 751 | | | | | 116 | | 85 | | 201 | 550 | 0 | 0 | 550 |
| 2004 | 751 | | | | | 116 | | 85 | | 201 | 550 | 0 | 0 | 550 |
| 2005 | 751 | | | | | 116 | | 85 | | 201 | 550 | 0 | 0 | 550 |
| 2006 | 751 | | | | | 116 | | 85 | | 201 | 550 | 0 | 0 | 550 |
| 2007 | 751 | | | | | 116 | | 13.5 | 71.5 | 201 | 550 | 0 | 0 | 550 |
| 2008 | 751 | | | | | 116 | | | 85 | 201 | 550 | 0 | 0 | 550 |
| 2009 | 751 | | | | | | 116 | | 85 | 201 | 550 | 0 | 0 | 550 |
| 2010 | 751 | | | | | | 116 | | 85 | 201 | 550 | 0 | 0 | 550 |
| 2011 | 751 | | | | | | 116 | | 85 | 201 | 550 | 0 | 0 | 550 |
| 2012 | 751 | | | | | | 116 | | 85 | 201 | 550 | 0 | 0 | 550 |
| 2013 | 751 | | | | | | 116 | | 85 | 201 | 550 | 0 | 0 | 550 |
| 2014 | 751 | | | | | | 116 | | 85 | 201 | 550 | 0 | 0 | 550 |
| 2015 | 751 | | | | | | 116 | | 85 | 201 | 550 | 0 | 0 | 550 |
| 2016 | 751 | | | | | | 116 | | 85 | 201 | 550 | 0 | 0 | 550 |
| 2017 | 751 | | | | | | 116 | | 85 | 201 | 550 | 0 | 0 | 550 |
| 2018 | 751 | | | | | | 116 | | 85 | 201 | 550 | 0 | 0 | 550 |
| 2019 | 751 | | | | | | 116 | | 85 | 201 | 550 | 0 | 0 | 550 |
| 2020 | 751 | | | | | | 116 | | 85 | 201 | 550 | 0 | 0 | 550 |
| 2021 | 751 | | | | | | 116 | | 85 | 201 | 550 | 0 | 0 | 550 |
| 2022 | 751 | | | | | | 116 | | 85 | 201 | 550 | 0 | 0 | 550 |
| 2023 | 751 | | | | | | 116 | | 85 | 201 | 550 | 0 | 0 | 550 |
| 2024 | 751 | | | | | | 116 | | 85 | 201 | 550 | 0 | 0 | 550 |

Notes: [1] Shortfall is taken from Table 5.1, capped at NU's entitlement in Millstone 3: 751.4274 MW.

[2] Group 1 consists of 7 combustion turbines, including Enfield 10, Torrington Terminal 10, Tunnel 10, Franklin Drive 10, Silver Lake 12, Doreen 10, and Woodland Road 10. Enfield 10 could be on line in 1986. M1 = Middletown 1 and ES 10= East Springfield 10.

[3] Group 2 consists of 8 combustion turbines, including Branford 10, Danielson 1, Thompsonville 1&2, Tracey 10, and Silver Lake 10, 11, and 13.

TABLE 5.3: COST OF RETAINING OLD CAPACITY, 1986-2024

| | Life Extension Carrying Cost [1] | | | | | | | | Total Cost |
|---|---|---|---|---|---|---|---|---|---|
| | Middletown 1 | | Devon 3&6 | | Group 1 | | E. Springfield 10 | | of Life |
| Size | 66.8 MW | | 136 MW | | 116 | | 13.5 | | Extensions |
| | $ Million | $/kW-yr | $ Million | $/kW-yr | $ Million [2] | $/kW-yr | $ Million [3] | $/KW-yr | $ Million |
| Year | | | | | | | | | |
| 1986 | | | | | $0.08 | $0.70 | $0.06 | $4.71 | $0.14 |
| 1987 | $0.66 | $9.84 | $2.58 | $18.97 | $0.58 | $5.02 | $0.07 | $5.02 | $3.89 |
| 1988 | $0.69 | $10.36 | $2.48 | $18.24 | $0.84 | $7.27 | $0.10 | $7.27 | $4.11 |
| 1989 | $1.63 | $24.40 | ($1.36) | ($9.99) | $1.13 | $9.74 | $0.13 | $9.74 | $1.53 |
| 1990 | $0.76 | $11.39 | $7.84 | $57.64 | ($0.19) | ($1.68) | $0.19 | $13.85 | $8.59 |
| 1991 | $0.63 | $9.45 | $2.51 | $18.48 | $0.53 | $4.57 | $0.12 | $9.22 | $3.80 |
| 1992 | $0.66 | $9.81 | $1.38 | $10.13 | $0.40 | $3.48 | $0.05 | $3.48 | $2.48 |
| 1993 | $0.68 | $10.19 | | | $0.32 | $2.73 | | | $1.00 |
| 1994 | | | | | $0.32 | $2.78 | | | $0.32 |
| 1995 | | | | | $0.00 | $0.00 | | | $0.00 |
| 1996 | | | | | | | | | $0.00 |
| 1997 | | | | | | | | | $0.00 |
| 1998 | | | | | | | | | $0.00 |
| 1999 | | | | | | | | | $0.00 |
| 2000 | | | | | | | | | $0.00 |
| 2001 | | | | | | | | | $0.00 |
| 2002 | | | | | | | | | $0.00 |
| 2003 | | | | | | | | | $0.00 |
| 2004 | | | | | | | | | $0.00 |
| 2005 | | | | | | | | | $0.00 |
| 2006 | | | | | | | | | $0.00 |
| 2007 | | | | | | | | | $0.00 |
| 2008 | | | | | | | | | $0.00 |
| 2009 | | | | | | | | | $0.00 |
| 2010 | | | | | | | | | $0.00 |
| 2011 | | | | | | | | | $0.00 |
| 2012 | | | | | | | | | $0.00 |
| 2013 | | | | | | | | | $0.00 |
| 2014 | | | | | | | | | $0.00 |
| 2015 | | | | | | | | | $0.00 |
| 2016 | | | | | | | | | $0.00 |
| 2017 | | | | | | | | | $0.00 |
| 2018 | | | | | | | | | $0.00 |
| 2019 | | | | | | | | | $0.00 |
| 2020 | | | | | | | | | $0.00 |
| 2021 | | | | | | | | | $0.00 |
| 2022 | | | | | | | | | $0.00 |
| 2023 | | | | | | | | | $0.00 |
| 2024 | | | | | | | | | $0.00 |

NOTES:[1] Life extension cost includes O&M cost, property tax, and the cost of capital additions.East Springfield and Group 1 costs were projected according to MW size from the sum of costs for Woodland Road, Silver Lake, Doreen, and Franklin Drive. From Exhibit 1, AG-2,Q-2-3, January 10, 1986, pages 11,12,13,15,16,17,and 18.

[2] 1986 cost for Enfield 10 (17.2 MW), scaled down and deflated from total cost at 6.5%

[3] No transmission costs are calculated in the life extension cost for East Springfield 10. 1986 cost deflated from 1987 cost at 6.5%

Table 5.4: COST OF REFURBISHING RETIRED CAPACITY

Life Extension Cost with Major Refurbishment [1]

| | Group 1 | | Group 1 | | Group 2 and ES 10 | | Group 2 and ES 10(2nd) | | |
|---|---|---|---|---|---|---|---|---|---|
| Size | 116 | | 116 | | 71.5 | 13.5 | 71.5 | 13.5 | Total Cost |
| Capital Cost [2] | $22.0 | | $52.8 | | $12.08 | $2.42 | $28.95 | $5.79 | Life Extensions |
| | $ Million | $/KW-yr | $ Million | $/KW-yr | $ Million | $/KW-yr | $ Million | $/KW-yr | $ Million |
| Year | | | | | | | | | |
| 1986 | | | | | | | | | $0.00 |
| 1987 | | | | | | | | | $0.00 |
| 1988 | | | | | | | | | $0.00 |
| 1989 | | | | | | | | | $0.00 |
| 1990 | | | | | | | | | $0.00 |
| 1991 | | | | | | | | | $0.00 |
| 1992 | | | | | $3.5 | $48.4 | | | $3.46 |
| 1993 | | | | | $3.9 | $46.3 | | | $3.94 |
| 1994 | $6.3 | $54.2 | | | $3.7 | $43.6 | | | $9.99 |
| 1995 | $5.9 | $50.8 | | | $3.4 | $39.8 | | | $9.28 |
| 1996 | $5.5 | $47.8 | | | $3.3 | $38.3 | | | $8.80 |
| 1997 | $5.0 | $43.4 | | | $3.1 | $36.1 | | | $8.10 |
| 1998 | $4.9 | $42.3 | | | $2.9 | $33.6 | | | $7.76 |
| 1999 | $4.6 | $39.5 | | | $2.7 | $31.2 | | | $7.24 |
| 2000 | $4.3 | $36.8 | | | $2.4 | $28.7 | | | $6.71 |
| 2001 | $4.0 | $34.1 | | | $2.2 | $26.3 | | | $6.19 |
| 2002 | $3.6 | $31.3 | | | $2.1 | $25.1 | | | $5.77 |
| 2003 | $3.3 | $28.7 | | | $2.0 | $24.0 | | | $5.37 |
| 2004 | $3.2 | $27.6 | | | $1.9 | $22.8 | | | $5.14 |
| 2005 | $3.1 | $26.3 | | | $1.8 | $21.7 | | | $4.89 |
| 2006 | $2.9 | $25.0 | | | $1.7 | $20.6 | | | $4.65 |
| 2007 | $2.8 | $23.7 | | | $0.3 | $21.3 | $8.3 | $115.5 | $11.30 |
| 2008 | $2.1 | $17.9 | | | | | $9.4 | $110.6 | $11.47 |
| 2009 | | | $15.0 | $129.6 | | | $8.8 | $103.9 | $23.86 |
| 2010 | | | $14.1 | $121.6 | | | $8.1 | $94.9 | $22.17 |
| 2011 | | | $13.3 | $114.3 | | | $7.8 | $91.4 | $21.03 |
| 2012 | | | $12.0 | $103.7 | | | $7.3 | $86.1 | $19.35 |
| 2013 | | | $11.7 | $101.1 | | | $6.8 | $80.3 | $18.55 |
| 2014 | | | $11.0 | $94.6 | | | $6.3 | $74.4 | $17.30 |
| 2015 | | | $10.2 | $88.1 | | | $5.8 | $68.5 | $16.04 |
| 2016 | | | $9.5 | $81.6 | | | $5.3 | $62.9 | $14.81 |
| 2017 | | | $8.7 | $75.0 | | | $5.1 | $60.0 | $13.80 |
| 2018 | | | $8.0 | $68.8 | | | $4.9 | $57.3 | $12.85 |
| 2019 | | | $7.7 | $66.2 | | | $4.6 | $54.5 | $12.31 |
| 2020 | | | $7.3 | $63.1 | | | $4.4 | $51.8 | $11.73 |
| 2021 | | | $7.0 | $60.0 | | | $4.2 | $49.2 | $11.14 |
| 2022 | | | $6.6 | $57.1 | | | $2.0 | $150.3 | $8.65 |
| 2023 | | | $6.3 | $54.1 | | | $1.7 | $122.8 | $7.94 |
| 2024 | | | $2.4 | $20.9 | | | $1.7 | $127.7 | $4.15 |

NOTES: [1] Life extension cost with major refurbishment includes O&M cost, property tax, and capital cost. O&M cost and property tax were taken from Exhibit 1, AG-2, Q-2-3, January 10, 1986, pages 11 and 15. O&M cost was then escalated at 6.5% (AG-2-, Q-AG-2-32, page 4). Property tax was increased by 1% of the additional capital cost.

[2] Capital cost=$100/kw in 1983 and was inflated at 6%. % carrying charge rate was taken from the testimony of H. E. Overcast, December, 1985, Table B-4, page 1.

TABLE 5.5: COST OF NEW COMBUSTION TURBINE CAPACITY AVOIDED BY Millstone 3

| Year Added: | 1989 | 1990 | 1991 | 1992 | 1993 | 1994 | 1995 | 1996 | 1997 | Total Annual Property Taxes [5] | Total CT Capacity Added to Date MW [2] | O&M $/kW [3] | Total O&M ($Mill) | Total Cost of new CTs ($Mill) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Cost/kW [1]: | $461 | $491 | $523 | $526 | $568 | $614 | $663 | $716 | $773 | | | | | |
| MW Added: | 0 | 0 | 0 | 106 | 183 | 212 | 50 | 0 | 0 | | | | | |
| Total ($M): | $0 | $0 | $0 | $56 | $104 | $130 | $33 | $0 | $0 | | | | | |
| Added Taxes: | $0.0 | $0.0 | $0.0 | $0.6 | $1.0 | $1.3 | $0.3 | $0.0 | $0.0 | | | | | |
| in Year | ANNUAL CARRYING CHARGES ON TOTAL COST ($MILLION) [4] | | | | | | | | | | | | | |
| 1989 | $0.0 | | | | | | | | | $0.0 | 0 | $0.68 | $0.00 | $0.00 |
| 1990 | $0.0 | $0.0 | | | | | | | | $0.0 | 0 | $0.72 | $0.00 | $0.00 |
| 1991 | $0.0 | $0.0 | $0.0 | | | | | | | $0.0 | 0 | $0.76 | $0.00 | $0.00 |
| 1992 | $0.0 | $0.0 | $0.0 | $15.1 | | | | | | $0.6 | 106 | $0.81 | $0.09 | $15.71 |
| 1993 | $0.0 | $0.0 | $0.0 | $14.4 | $28.1 | | | | | $1.6 | 288 | $0.86 | $0.25 | $44.29 |
| 1994 | $0.0 | $0.0 | $0.0 | $13.4 | $26.8 | $35.2 | | | | $2.9 | 500 | $0.91 | $0.45 | $78.72 |
| 1995 | $0.0 | $0.0 | $0.0 | $12.5 | $24.9 | $33.6 | $9.0 | | | $3.2 | 550 | $0.96 | $0.53 | $83.77 |
| 1996 | $0.0 | $0.0 | $0.0 | $11.7 | $23.3 | $31.3 | $8.6 | $0.0 | | $3.2 | 550 | $1.02 | $0.56 | $78.59 |
| 1997 | $0.0 | $0.0 | $0.0 | $10.9 | $21.8 | $29.2 | $8.0 | $0.0 | $0.0 | $3.2 | 550 | $1.09 | $0.60 | $73.67 |
| 1998 | $0.0 | $0.0 | $0.0 | $10.1 | $20.3 | $27.3 | $7.5 | $0.0 | $0.0 | $3.2 | 550 | $1.16 | $0.64 | $69.04 |
| 1999 | $0.0 | $0.0 | $0.0 | $9.4 | $18.8 | $25.5 | $7.0 | $0.0 | $0.0 | $3.2 | 550 | $1.24 | $0.68 | $64.53 |
| 2000 | $0.0 | $0.0 | $0.0 | $8.6 | $17.4 | $23.6 | $6.5 | $0.0 | $0.0 | $3.2 | 550 | $1.32 | $0.73 | $60.11 |
| 2001 | $0.0 | $0.0 | $0.0 | $7.9 | $16.0 | $21.9 | $6.0 | $0.0 | $0.0 | $3.2 | 550 | $1.41 | $0.78 | $55.81 |
| 2002 | $0.0 | $0.0 | $0.0 | $7.1 | $14.7 | $20.1 | $5.6 | $0.0 | $0.0 | $3.2 | 550 | $1.50 | $0.83 | $51.55 |
| 2003 | $0.0 | $0.0 | $0.0 | $6.8 | $13.3 | $18.4 | $5.2 | $0.0 | $0.0 | $3.2 | 550 | $1.60 | $0.88 | $47.74 |
| 2004 | $0.0 | $0.0 | $0.0 | $6.5 | $12.7 | $16.6 | $4.7 | $0.0 | $0.0 | $3.2 | 550 | $1.70 | $0.94 | $44.78 |
| 2005 | $0.0 | $0.0 | $0.0 | $6.3 | $12.2 | $16.0 | $4.3 | $0.0 | $0.0 | $3.2 | 550 | $1.81 | $1.00 | $42.89 |
| 2006 | $0.0 | $0.0 | $0.0 | $6.0 | $11.6 | $15.3 | $4.1 | $0.0 | $0.0 | $3.2 | 550 | $1.93 | $1.06 | $41.27 |
| 2007 | $0.0 | $0.0 | $0.0 | $5.7 | $11.1 | $14.6 | $3.9 | $0.0 | $0.0 | $3.2 | 550 | $2.06 | $1.13 | $39.66 |
| 2008 | $0.0 | $0.0 | $0.0 | $5.4 | $10.6 | $13.9 | $3.7 | $0.0 | $0.0 | $3.2 | 550 | $2.19 | $1.21 | $38.05 |
| 2009 | $0.0 | $0.0 | $0.0 | $5.1 | $10.0 | $13.3 | $3.6 | $0.0 | $0.0 | $3.2 | 550 | $2.33 | $1.28 | $36.45 |
| 2010 | $0.0 | $0.0 | $0.0 | $4.8 | $9.5 | $12.6 | $3.4 | $0.0 | $0.0 | $3.2 | 550 | $2.48 | $1.37 | $34.85 |
| 2011 | $0.0 | $0.0 | $0.0 | $4.5 | $8.9 | $11.9 | $3.2 | $0.0 | $0.0 | $3.2 | 550 | $2.64 | $1.45 | $33.26 |
| 2012 | $0.0 | $0.0 | $0.0 | $4.2 | $8.4 | $11.2 | $3.0 | $0.0 | $0.0 | $3.2 | 550 | $2.81 | $1.55 | $31.67 |
| 2013 | $0.0 | $0.0 | $0.0 | $3.9 | $7.9 | $10.5 | $2.9 | $0.0 | $0.0 | $3.2 | 550 | $2.99 | $1.65 | $30.09 |
| 2014 | $0.0 | $0.0 | $0.0 | $3.6 | $7.3 | $9.9 | $2.7 | $0.0 | $0.0 | $3.2 | 550 | $3.18 | $1.75 | $28.51 |
| 2015 | | $0.0 | $0.0 | $3.4 | $6.8 | $9.2 | $2.5 | $0.0 | $0.0 | $3.2 | 550 | $3.39 | $1.87 | $26.94 |
| 2016 | | | $0.0 | $3.1 | $6.2 | $8.5 | $2.4 | $0.0 | $0.0 | $3.2 | 550 | $3.61 | $1.99 | $25.38 |
| 2017 | | | | $0.0 | $5.7 | $7.8 | $2.2 | $0.0 | $0.0 | $3.2 | 550 | $3.84 | $2.11 | $21.06 |
| 2018 | | | | | $0.0 | $7.2 | $2.0 | $0.0 | $0.0 | $3.2 | 550 | $4.09 | $2.25 | $14.64 |
| 2019 | | | | | | $0.0 | $1.8 | $0.0 | $0.0 | $3.2 | 550 | $4.36 | $2.40 | $7.46 |
| 2020 | | | | | | | $0.0 | $0.0 | $0.0 | $3.2 | 550 | $4.64 | $2.55 | $5.78 |
| 2021 | | | | | | | | $0.0 | $0.0 | $3.2 | 550 | $4.92 | $2.71 | $5.94 |
| 2022 | | | | | | | | | $0.0 | $3.2 | 550 | $5.21 | $2.87 | $6.10 |
| 2023 | | | | | | | | | | $3.2 | 550 | $5.53 | $3.04 | $6.27 |
| 2024 | | | | | | | | | | $3.2 | 550 | $5.86 | $3.22 | $6.45 |

Notes:

1. Testimony of H. E. Overcast, December 1985, Table B-4, page 1. 1996 Total ($716 $/kW) esc. and defl. at 6%.
2. Assumes CTs continue to operate to end of Millstone 3 projected life.
3. Fixed O&M Expenses from Overcast, Table B-4. p.1 of 1, years 1990-95 deflated at 6%, 2021-24 escalated at 6%).
4. CT annual cost (capital cost) expensed over 25 years using "% Carrying Charge Rate" from testimony of H. E. Overcast, December 1985, Table B-4, page 1.
5. Total Annual Taxes are sum of additional taxes per year as 1.0% of Capital Addition.

TABLE 5.6: TOTAL COST OF CAPACITY AVOIDED BY MILLSTONE 3 ($Million)

| | | | | | TOTAL AVOIDED CAPACITY COST | | | | |
|---|---|---|---|---|---|---|---|---|---|
| Year | Shortterm Purchases | Life Extensions | Refurbished Capacity | New CTs | NU SHARE | WMECO SHARE | WMECO RETAIL PORTION | NU Projection of Avoided Capacity Costs WMECo Retail | Difference (NU-PLC) |
| | [1] | [2] | [3] | [4] | [5] | [6] | [7] | [8] | [9] |
| 1986 | $0.00 | $0.14 | $0.00 | $0.00 | $0.14 | $0.02 | $0.02 | $0.0 | ($0.0) |
| 1987 | $0.00 | $3.89 | $0.00 | $0.00 | $3.89 | $0.59 | $0.57 | $1.1 | $0.5 |
| 1988 | $0.00 | $4.11 | $0.00 | $0.00 | $4.11 | $0.63 | $0.61 | $0.5 | ($0.1) |
| 1989 | $0.83 | $1.53 | $0.00 | $0.00 | $2.36 | $0.36 | $0.35 | $0.8 | $0.5 |
| 1990 | $0.00 | $8.59 | $0.00 | $0.00 | $8.59 | $1.31 | $1.26 | $0.5 | ($0.8) |
| 1991 | $0.00 | $3.80 | $0.00 | $0.00 | $3.80 | $0.58 | $0.56 | $0.4 | ($0.2) |
| 1992 | $0.00 | $2.48 | $3.46 | $15.71 | $21.66 | $3.31 | $3.19 | $0.3 | ($2.9) |
| 1993 | $0.00 | $1.00 | $3.94 | $44.29 | $49.23 | $7.53 | $7.25 | $5.2 | ($2.0) |
| 1994 | $0.00 | $0.32 | $9.99 | $78.72 | $89.03 | $13.62 | $13.10 | $10.2 | ($2.9) |
| 1995 | $0.00 | $0.00 | $9.28 | $83.77 | $93.04 | $14.24 | $13.70 | $15.1 | $1.4 |
| 1996 | $0.00 | $0.00 | $8.80 | $78.59 | $87.39 | $13.37 | $12.86 | $17.2 | $4.3 |
| 1997 | $0.00 | $0.00 | $8.10 | $73.67 | $81.76 | $12.51 | $12.04 | $19.4 | $7.4 |
| 1998 | $0.00 | $0.00 | $7.76 | $69.04 | $76.80 | $11.75 | $11.30 | $18.1 | $6.8 |
| 1999 | $0.00 | $0.00 | $7.24 | $64.53 | $71.76 | $10.98 | $10.56 | $18.3 | $7.7 |
| 2000 | $0.00 | $0.00 | $6.71 | $60.11 | $66.82 | $10.22 | $9.84 | $17.0 | $7.2 |
| 2001 | $0.00 | $0.00 | $6.19 | $55.81 | $62.01 | $9.49 | $9.13 | $15.8 | $6.7 |
| 2002 | $0.00 | $0.00 | $5.77 | $51.55 | $57.32 | $8.77 | $8.44 | $14.6 | $6.2 |
| 2003 | $0.00 | $0.00 | $5.37 | $47.74 | $53.11 | $8.13 | $7.82 | $13.4 | $5.6 |
| 2004 | $0.00 | $0.00 | $5.14 | $44.78 | $49.92 | $7.64 | $7.35 | $12.4 | $5.1 |
| 2005 | $0.00 | $0.00 | $4.89 | $42.89 | $47.79 | $7.31 | $7.03 | $11.6 | $4.6 |
| 2006 | $0.00 | $0.00 | $4.65 | $41.27 | $45.92 | $7.03 | $6.76 | $10.9 | $4.1 |
| 2007 | $0.00 | $0.00 | $11.30 | $39.66 | $50.96 | $7.80 | $7.50 | $10.4 | $2.9 |
| 2008 | $0.00 | $0.00 | $11.47 | $38.05 | $49.52 | $7.58 | $7.29 | $9.9 | $2.6 |
| 2009 | $0.00 | $0.00 | $23.86 | $36.45 | $60.31 | $9.23 | $8.88 | $9.4 | $0.5 |
| 2010 | $0.00 | $0.00 | $22.17 | $34.85 | $57.02 | $8.72 | $8.39 | $9.0 | $0.6 |
| 2011 | $0.00 | $0.00 | $21.03 | $33.26 | $54.28 | $8.31 | $7.99 | $8.5 | $0.5 |
| 2012 | $0.00 | $0.00 | $19.35 | $31.67 | $51.02 | $7.81 | $7.51 | $8.2 | $0.7 |
| 2013 | $0.00 | $0.00 | $18.55 | $30.09 | $48.64 | $7.44 | $7.16 | $7.7 | $0.5 |
| 2014 | $0.00 | $0.00 | $17.30 | $28.51 | $45.81 | $7.01 | $6.74 | $7.3 | $0.6 |
| 2015 | $0.00 | $0.00 | $16.04 | $26.94 | $42.99 | $6.58 | $6.33 | $6.8 | $0.5 |
| 2016 | $0.00 | $0.00 | $14.81 | $25.38 | $40.20 | $6.15 | $5.92 | $6.5 | $0.6 |
| 2017 | $0.00 | $0.00 | $13.80 | $21.06 | $34.86 | $5.33 | $5.13 | $6.0 | $0.9 |
| 2018 | $0.00 | $0.00 | $12.85 | $14.64 | $27.49 | $4.21 | $4.05 | $31.4 | $27.4 |
| 2019 | $0.00 | $0.00 | $12.31 | $7.46 | $19.77 | $3.02 | $2.91 | $57.6 | $54.7 |
| 2020 | $0.00 | $0.00 | $11.73 | $5.78 | $17.51 | $2.68 | $2.58 | $83.8 | $81.2 |
| 2021 | $0.00 | $0.00 | $11.14 | $5.94 | $17.08 | $2.61 | $2.51 | $94.5 | $92.0 |
| 2022 | $0.00 | $0.00 | $8.65 | $6.10 | $14.75 | $2.26 | $2.17 | $105.5 | $103.3 |
| 2023 | $0.00 | $0.00 | $7.94 | $6.27 | $14.21 | $2.17 | $2.09 | $98.9 | $96.8 |
| 2024 | $0.00 | $0.00 | $4.15 | $6.45 | $10.60 | $1.62 | $1.56 | $99.0 | $97.4 |

NOTES: [1] See Table 5.1. Shortterm Purchases at $22/kw.
[2] See Table 5.3.
[3] See Table 5.4.
[4] See Table 5.5.
[5] Total=1+2+3+4
[8] Data Request AG-2 42, total minus System Production Costs.

Table 5.7: WMECo FUEL AND AVOIDED COST PROJECTIONS

| Year | 1%S Fuel Oil DRI Price Forecast $/BBl. | $/MMBTU | WMECo Avoided System Production Cost $/MWH | Heat Rate At Which Oil Price = Avoided Cost BTU/kWh | Avoided Cost - Cogenerator Fuel at 5000 BTU/KWH current $/MWH | constant 1986$/MWH |
|---|---|---|---|---|---|---|
| | [1] | [2] | [3] | [4] | [5] | [6] |
| 1986 | $25.41 | $4.09 | $49.01 | 11,997 | $29 | $29 |
| 1987 | $24.93 | $4.01 | $40.57 | 10,123 | $21 | $19 |
| 1988 | $25.58 | $4.11 | $39.79 | 9,675 | $19 | $17 |
| 1989 | $26.78 | $4.31 | $44.41 | 10,316 | $23 | $19 |
| 1990 | $28.21 | $4.54 | $42.44 | 9,357 | $20 | $16 |
| 1991 | $30.13 | $4.84 | $49.01 | 10,118 | $25 | $19 |
| 1992 | $32.52 | $5.23 | $54.56 | 10,435 | $28 | $20 |
| 1993 | $35.39 | $5.69 | $59.50 | 10,458 | $31 | $21 |
| 1994 | $38.74 | $6.23 | $63.32 | 10,166 | $32 | $20 |
| 1995 | $42.56 | $6.84 | $79.15 | 11,567 | $45 | $27 |
| 1996 | $47.44 | $7.63 | $90.74 | 11,897 | $53 | $29 |
| 1997 | $53.27 | $8.56 | $103.04 | 12,031 | $60 | $32 |
| 1998 | $60.06 | $9.66 | $114.34 | 11,842 | $66 | $33 |
| 1999 | $67.81 | $10.90 | $130.31 | 11,953 | $76 | $36 |
| 2000 | $76.52 | $12.30 | $147.13 | 11,960 | $86 | $38 |
| 2001 | $85.12 | $13.68 | $153.49 | 11,216 | $85 | $35 |
| 2002 | $93.73 | $15.07 | $153.35 | 10,177 | $78 | $31 |
| 2003 | $102.34 | $16.45 | $172.29 | 10,471 | $90 | $33 |
| 2004 | $110.95 | $17.84 | $191.37 | 10,729 | $102 | $36 |
| 2005 | $119.55 | $19.22 | $210.88 | 10,972 | $115 | $38 |
| 2006 | $130.08 | $20.91 | $233.63 | 11,171 | $129 | $40 |
| 2007 | $141.55 | $22.76 | $261.33 | 11,484 | $148 | $43 |
| 2008 | $153.99 | $24.76 | $286.21 | 11,561 | $162 | $45 |
| 2009 | $164.77 | $26.49 | $309.11 | 11,669 | $177 | $46 |
| 2010 | $176.30 | $28.34 | $314.90 | 11,110 | $173 | $43 |
| 2011 | $188.65 | $30.33 | $337.94 | 11,142 | $186 | $43 |
| 2012 | $201.85 | $32.45 | $366.63 | 11,298 | $204 | $45 |
| 2013 | $215.98 | $34.72 | $379.07 | 10,917 | $205 | $43 |
| 2014 | $231.10 | $37.15 | $409.03 | 11,009 | $223 | $44 |
| 2015 | $247.28 | $39.75 | $441.40 | 11,103 | $243 | $45 |
| 2016 | $264.58 | $42.54 | $476.31 | 11,197 | $264 | $46 |
| 2017 | $283.11 | $45.52 | $513.90 | 11,291 | $286 | $47 |
| 2018 | $302.92 | $48.70 | $554.47 | 11,385 | $311 | $48 |
| 2019 | $324.13 | $52.11 | $598.14 | 11,478 | $338 | $49 |
| 2020 | $346.82 | $55.76 | $645.35 | 11,574 | $367 | $51 |
| 2021 | $371.09 | $59.66 | $697.64 | 11,693 | $399 | $52 |
| 2022 | $397.07 | $63.84 | $752.48 | 11,787 | $433 | $53 |
| 2023 | $424.87 | $68.31 | $813.12 | 11,904 | $472 | $55 |
| 2024 | $454.61 | $73.09 | $877.14 | 12,001 | $512 | $56 |

NOTES: [1] From AG-2, 1/10/86, Q-2-3, page 52. Escalated from 7% after 2009.
[2] [1] divided by 6.22.
[3] Column 9 from Table 6.1.
[4] ([3]*1,000,000)/([2]*1,000).
[5] [3]-([2]*5,000 BTU/KWH)
[6] Deflated at 6%.

TABLE 5.8: NEPOOL NUCLEAR DATA

(A) OBJECTIVE CAPABILITY (MW) WITH NEW NUCLEAR UNITS

Number of New Nuclear Units

| Year | 0 | 1 | 2 | 3 | 4 | 5 |
|---|---|---|---|---|---|---|
| 81/82 | 21880 | 22445 | | | | |
| 82/83 | 23127 | 23526 | 23924 | 24323 | | |
| 83/84 | | 24626 | 25047 | 25468 | 25889 | |
| 84/85 | | | 26035 | 26480 | 26925 | 27370 |

Source: 8/12/76 NEPOOL Executive Committee Minutes.

(B) DERIVATION OF NUCLEAR FIRM LOAD CARRYING CAPACITY

| Year | Increase In Reserve Per Nuclear Unit (MW) | Nuclear Reduction In Other Capacity Req. (MW) | Firm Load Carried (MW) | Ratio of Firm Load to Nuclear Capacity |
|---|---|---|---|---|
| | [1] | [2] | [3] | [4] |
| 81/82 | 565 | 585 | 504.3 | 0.44 |
| 82/83 | 398.7 | 751.3 | 647.7 | 0.56 |
| 83/84 | 421 | 729 | 628.4 | 0.55 |
| 84/85 | 445 | 705 | 607.8 | 0.53 |
| Average | | | | 0.52 |

Notes: 1. Calculated from data in part (A) above.

2. 1150-[1].

3. [2]/1.16; 16% reserves required for 1981/82 and 82/83 with no new nuclear capacity, from 6/24/76 NEPOOL Executive Committee minutes.

4. [3]/1150.

TABLE 5.9: Availablity Factors, NU Fossil Units, 1971-84

| Plant | 1971 | 1972 | 1973 | 1974 | 1975 | 1976 | 1977 | 1978 | 1979 | 1980 | 1981 | | 1983 | 1984 | AVERAGE |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Devon 3 | 85.8% | 92.0% | 61.8% | 95.5% | 93.5% | 92.0% | 81.4% | 93.8% | 81.5% | 92.5% | 87.4% | 92.5% | 95.3% | 90.7% | 88.3% |
| Devon 4 | 89.8% | 94.2% | 95.0% | 87.2% | 96.2% | 96.5% | 93.2% | 89.1% | 99.9% | 94.9% | 96.5% | 89.7% | 95.6% | 95.2% | 93.8% |
| Devon 5 | 92.3% | 93.7% | 93.1% | 81.8% | 96.9% | 96.3% | 99.5% | 98.3% | 69.5% | 94.7% | 92.7% | 95.1% | 93.8% | 88.8% | 91.9% |
| Devon 6 | 94.1% | 97.4% | 67.1% | 90.8% | 92.1% | 96.4% | 83.2% | 92.6% | 85.9% | 83.9% | 94.1% | 93.4% | 87.6% | 91.2% | 89.3% |
| Devon 7 | 74.6% | 72.0% | 92.5% | 78.4% | 91.8% | 83.2% | 87.1% | 83.3% | 92.2% | 95.4% | 74.3% | 89.6% | 91.6% | 91.8% | 85.6% |
| Devon 8 | 92.2% | 83.0% | 94.5% | 85.4% | 60.7% | 90.7% | 94.8% | 81.2% | 94.5% | 75.9% | 82.1% | 92.5% | 92.4% | 74.7% | 85.3% |
| Middletown 1 | 95.3% | 93.5% | 96.7% | 98.9% | 95.7% | 99.1% | 83.7% | 100.0% | 100.0% | 93.7% | 92.3% | 91.3% | 93.0% | 94.1% | 94.8% |
| Middletown 2 | 89.2% | 97.4% | 88.0% | 97.0% | 94.3% | 87.8% | 96.6% | 91.3% | 95.5% | 84.0% | 96.1% | 80.6% | 95.5% | 88.9% | 91.6% |
| Middletown 3 | 85.2% | 91.5% | 91.1% | 88.7% | 82.9% | 91.0% | 90.1% | 92.8% | 66.1% | 91.4% | 88.2% | 85.7% | 88.1% | 91.1% | 87.4% |
| Montville 5 | 92.3% | 88.1% | 91.1% | 90.2% | 80.8% | 85.0% | 91.1% | 55.6% | 77.2% | 87.6% | 87.8% | 89.3% | 84.8% | 81.5% | 84.5% |
| Norwalk Harbor 1 | 74.6% | 82.5% | 87.1% | 90.0% | 78.4% | 93.8% | 93.2% | 97.1% | 79.1% | 97.4% | 94.6% | 93.6% | 84.7% | 91.2% | 88.4% |
| Norwalk Harbor 2 | 92.0% | 84.6% | 91.1% | 93.4% | 96.2% | 84.0% | 93.4% | 92.5% | 97.4% | 93.4% | 82.0% | 95.0% | 93.7% | 94.2% | 91.6% |
| W. Springfield 1 | 92.1% | 98.6% | 98.2% | 91.5% | 97.4% | 98.6% | 96.3% | 90.6% | 95.7% | 94.5% | 95.3% | 88.8% | 95.8% | 95.6% | 94.9% |
| W. Springfield 2 | 93.4% | 98.1% | 97.8% | 96.3% | 92.7% | 96.3% | 96.1% | 96.0% | 89.3% | 95.6% | 95.7% | 94.5% | 90.0% | 95.6% | 94.8% |
| W. Springfield 3 | 90.7% | 98.4% | 91.6% | 97.0% | 96.5% | 94.8% | 77.0% | 95.2% | 95.1% | 94.5% | 81.2% | 92.8% | 86.1% | 93.4% | 91.7% |
| Combustion Turbines | | | | | | | | | | | | | | | |
| Branford 10 [1] | 78.6% | 97.0% | 72.2% | 98.4% | 95.8% | 97.7% | 95.8% | 94.7% | 91.1% | 86.5% | 81.8% | 72.7% | 0.0% | | 81.7% |
| Cos Cob 10 | 94.1% | 96.8% | 59.7% | 92.3% | 94.3% | 95.5% | 93.3% | 95.5% | 94.8% | 97.3% | 95.5% | 92.6% | 86.8% | 98.2% | 91.9% |
| Cos Cob 11 | 98.1% | 92.3% | 80.6% | 90.0% | 96.0% | 91.2% | 90.5% | 83.1% | 97.4% | 97.2% | 96.5% | 95.0% | 97.2% | 99.1% | 93.2% |
| Cos Cob 12 | 70.7% | 96.4% | 80.3% | 82.1% | 94.0% | 95.9% | 98.9% | 91.9% | 94.0% | 98.5% | 88.8% | 91.6% | 8.6% | 7.8% | 78.5% |
| Devon 10 | 97.9% | 97.0% | 94.8% | 96.6% | 95.7% | 96.0% | 98.4% | 92.9% | 98.9% | 86.5% | 94.6% | 98.2% | 98.2% | 57.6% | 93.1% |
| Doreen 10 | 98.8% | 98.0% | 95.9% | 96.1% | 82.1% | 99.5% | 97.4% | 98.7% | 95.7% | 97.2% | 97.9% | 98.8% | 99.5% | 98.7% | 96.7% |
| Enfield 10 | 97.5% | 93.9% | 97.5% | 90.7% | 80.3% | 98.3% | 99.0% | 98.8% | 97.7% | 96.3% | 98.7% | 98.5% | 99.0% | 94.7% | 95.8% |
| E. Springfield 10 | 92.6% | 99.2% | 95.6% | 97.5% | 97.3% | 98.8% | 98.5% | 98.5% | 98.7% | | | | | | 97.4% |
| Franklin Drive 19 | 93.1% | 99.4% | 99.0% | 96.0% | 96.1% | 99.0% | 97.3% | 98.0% | 97.7% | 98.0% | 97.8% | 96.0% | 97.1% | 97.6% | 97.3% |
| Middletown 10 | 90.7% | 73.3% | 97.7% | 92.4% | 93.8% | 74.9% | 99.9% | 98.6% | 97.8% | 8.6% | 0.0% | 0.0% | 25.0% | 98.1% | 67.9% |
| Norwalk Harbor 10 | 36.7% | 93.0% | 87.0% | 94.4% | 60.0% | 11.8% | 94.0% | 99.5% | 98.9% | 98.5% | 98.7% | 98.8% | 5.3% | 81.1% | 75.6% |
| Silver Lake 10 | 94.0% | 98.7% | 97.3% | 98.6% | 90.9% | 60.9% | 100.0% | 99.6% | 99.3% | 100.0% | 99.3% | 89.6% | | | 94.0% |
| Silver Lake 11 [2] | 94.9% | 99.5% | 96.7% | 94.5% | 96.7% | 98.8% | 34.5% | | | | | | | | 87.9% |
| Silver Lake 12 | 90.3% | 92.8% | 94.6% | 49.5% | 90.4% | 99.7% | 83.7% | 99.9% | 99.5% | 100.0% | 99.3% | 96.7% | 90.0% | 81.8% | 90.6% |
| Silver Lake 13 | 98.3% | 99.1% | 95.4% | 94.2% | 72.7% | 99.9% | 99.8% | 97.9% | 99.9% | 99.8% | 99.1% | 96.9% | | | 96.1% |
| South Meadow 11 | 85.5% | 68.9% | 90.2% | 96.2% | 99.3% | 96.4% | 90.4% | 98.6% | 91.4% | 82.6% | 94.8% | 55.3% | 0.0% | 54.5% | 78.9% |
| South Meadow 12 | 81.5% | 96.7% | 94.1% | 97.3% | 95.6% | 98.4% | 96.6% | 99.8% | 98.7% | 99.3% | 98.9% | 88.8% | 97.0% | 96.6% | 95.7% |
| South Meadow 13 | 96.3% | 80.3% | 95.7% | 98.3% | 98.5% | 98.9% | 95.8% | 99.6% | 99.1% | 99.9% | 95.8% | 94.0% | 96.8% | 98.6% | 96.3% |
| South Meadow 14 | 93.0% | 94.4% | 78.4% | 97.8% | 99.8% | 99.0% | 95.8% | 98.7% | 98.7% | 99.1% | 99.8% | 97.2% | 97.3% | 96.5% | 96.1% |
| Torrington 10 | 97.6% | 98.3% | 76.5% | 97.0% | 95.2% | 96.0% | 98.3% | 98.2% | 95.5% | 98.3% | 89.3% | 78.8% | 0.0% | 73.7% | 85.2% |
| Tracey 10 | 98.3% | 97.4% | 96.5% | 90.2% | 93.9% | 98.1% | 100.0% | 90.1% | 98.5% | | | | | | 95.9% |
| Tunnel 10 | 97.6% | 97.0% | 97.7% | 93.9% | 97.7% | 95.3% | 98.6% | 98.8% | 98.4% | 97.6% | 93.2% | 98.7% | 99.6% | 76.8% | 95.8% |
| Woodland Road 10 | 76.7% | 82.4% | 98.4% | 93.1% | 92.6% | 98.4% | 98.7% | 98.8% | 98.5% | 98.0% | 99.1% | 98.6% | 56.5% | 52.8% | 88.8% |
| W. Springfield 10 | 67.0% | 99.0% | 75.5% | 99.7% | 95.7% | 98.8% | 98.8% | 96.8% | 98.4% | 93.7% | 98.6% | 97.0% | 98.4% | 98.1% | 94.0% |
| [3] AVERAGES: | 88.3% | 93.4% | 89.5% | 92.8% | 91.9% | 91.6% | 93.9% | 96.8% | 97.3% | 92.0% | 91.3% | 87.3% | 65.9% | 81.2% | 90.2% |

Notes: 1. Retired July 1984.
2. Silver Lake 11 did not generate in 1978 and 1979.
3. Averages are for combustion turbines only.

Sources: NU, Vol.2 Power Facilities Forecast. April, 1981.
NU, Vol.2 Power Facilities Forecast. April, 1985.
WMEC, Performance Program Proposal. February, 1982.
WMEC, Performance Program Proposal. March, 1984.

TABLE 5.10: Equivalent Availability Factors, Selected NU Steam

| | 1979 | 1980 | 1981 | 1982 | 1983 | Average |
|---|---|---|---|---|---|---|
| Devon 3 | 81.1% | 92.2% | 86.8% | 91.9% | 94.7% | 89.3% |
| Devon 6 | 85.0% | 82.1% | 92.9% | 89.2% | 85.9% | 87.0% |
| Middletown 1 | 99.8% | 93.2% | 92.1% | 91.2% | 93.0% | 93.9% |

Differences, AF-EAF
-------------------

| | 1979 | 1980 | 1981 | 1982 | 1983 | Average |
|---|---|---|---|---|---|---|
| Devon 3 | 0.4% | 0.3% | 0.6% | 0.6% | 0.6% | 0.5% |
| Devon 6 | 0.9% | 1.8% | 1.2% | 4.2% | 1.7% | 2.0% |
| Middletown 1 | 0.2% | 0.5% | 0.2% | 0.1% | 0.0% | 0.2% |

Sources: WMEC, Performance Program Proposal. February, 1982.
WMEC, Performance Program Proposal. March, 1984.

TABLE 5.11: EFFECTIVE LOAD CARRYING CAPABILITY

| | INPUTS: Rated MW | m | EFOR [1] | AVE MW | ELCC | ELCC/MW | ELCC/ AVE MW | Ratio of ELCC/MW to M3 ELCC/MW | Millstone 3 MW Replaced On ELCC Basis [6 |
|---|---|---|---|---|---|---|---|---|---|
| Millstone 3 | 1153 | 425 | 20.0% [2] | 922.40 | 583.98 | 50.6% | 63.3% | | |
| | 1153 | 425 | 25.0% | 864.75 | 512.03 | 44.4% | 59.2% | | |
| | 1153 | 425 | 27.5% | 835.93 | 480.17 | 41.6% | 57.4% | 1.000 | 1153.00 |
| | 1153 | 425 | 30.0% | 807.10 | 450.52 | 39.1% | 55.8% | | |
| | 1153 | 425 | 35.0% [3] | 749.45 | 396.80 | 34.4% | 52.9% | | |
| Typical Existing Combustion Group 1 | 116 | 425 | 9.8% [4] | 104.63 | 103.13 | 88.9% | 98.6% | 2.135 | 247.63 [7] |
| Turbine Group 2 | 85 | 425 | 9.8% | 76.67 | 75.88 | 89.3% | 99.0% | 2.144 | 182.20 [8] |
| New Combustion Turbines | 100 | 425 | 10.0% [5] | 90.00 | 88.87 | 88.9% | 98.7% | 2.134 | 213.41 |
| E. Springfield 10 | 13.5 | 425 | 4.2% | 12.93 | 12.92 | 95.7% | 99.9% | 2.299 | 31.03 |
| Devon 3 | 68 | 425 | 11.7% | 60.04 | 59.46 | 87.4% | 99.0% | 2.100 | 142.78 |
| Devon 6 | 68 | 425 | 10.7% | 60.72 | 60.18 | 88.5% | 99.1% | 2.125 | 144.51 |
| Devon 4 | 50 | 425 | 6.2% | 46.90 | 46.72 | 93.4% | 99.6% | 2.244 | 112.19 |
| Devon 5 | 48 | 425 | 8.1% | 44.11 | 43.90 | 91.5% | 99.5% | 2.196 | 105.42 |
| W. Springfield 1 | 51 | 425 | 5.1% | 48.40 | 48.25 | 94.6% | 99.7% | 2.272 | 115.85 |
| W. Springfield 2 | 51 | 425 | 5.2% | 48.35 | 48.19 | 94.5% | 99.7% | 2.269 | 115.72 |
| Middletown 1 | 66.8 | 425 | 5.2% | 63.33 | 63.06 | 94.4% | 99.6% | 2.267 | 151.41 |

Notes:

1. From Table 5.9 and 5.10: Overall average. Assumes FOR = 1 - EAF.
2. Consistent with NU Capacity Factor projection.
3. Consistent with my Capacity Factor projection.
4. EFOR for existing combustion turbines = 1 - the average of the EAF of all combustion turbines listed in Appendix E.
5. From NEPLAN and GTF, Summary of Generation Task Force Long-Range Study Assumptions. November, 1983.
6. Ratio of ELCC/MW to M3 ELCC/MW multiplied by the rated MW.
7. For 116 rated MW in 7 CTs(Group 1).
8. For 85 rated MW in 8 CTs(Group 2).
9. Average Ratio for Group 1, Group 2, East Springfield 10, Devon 3 & 6 and Middleton 1 = 2.1781

TABLE 6.1: WMECO RETAIL PORTION OF PROJECTED MILLSTONE 3 TOTAL COST OF AVOIDED ENERGY

| | MILLSTONE 3 | | | WMECO RETAIL PORTION | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | MILLSTONE 3 FUEL SAVINGS ADVANTAGE | | Avoided Energy Cost |
| Year | Capacity Factor | Capacity Rating MW | Generation MWH | Generation MWH | Fuel Cost $Million | Fuel Cost $/MWH | $Million | $/MWH | $/MWH |
| ---- | ---[1]--- | ---[2]--- | ---[3]--- | ---[4]--- | ---[5]--- | ---[6]--- | ---[7]--- | ---[8]--- | --[9]-- |
| 1986 | 60% | 1138 | 3,506,861 | 350,937 | $5 | $14.2 | $12.2 | $34.76 | $49.01 |
| 1987 | 63% | 1138 | 6,280,394 | 628,489 | $7 | $11.1 | $18.5 | $29.44 | $40.57 |
| 1988 | 65% | 1138 | 6,479,772 | 648,441 | $7 | $10.8 | $18.8 | $28.99 | $39.79 |
| 1989 | 65% | 1138 | 6,479,772 | 648,441 | $6 | $9.3 | $22.8 | $35.16 | $44.41 |
| 1990 | 65% | 1146 | 6,522,477 | 652,715 | $6 | $9.2 | $21.7 | $33.25 | $42.44 |
| 1991 | 65% | 1153 | 6,565,182 | 656,988 | $6 | $9.1 | $26.2 | $39.88 | $49.01 |
| 1992 | 70% | 1153 | 7,070,196 | 707,526 | $6 | $8.5 | $32.6 | $46.08 | $54.56 |
| 1993 | 70% | 1153 | 7,070,196 | 707,526 | $5 | $7.1 | $37.1 | $52.44 | $59.50 |
| 1994 | 70% | 1153 | 7,070,196 | 707,526 | $5 | $7.1 | $39.8 | $56.25 | $63.32 |
| 1995 | 70% | 1153 | 7,070,196 | 707,526 | $5 | $7.1 | $51.0 | $72.08 | $79.15 |
| 1996 | 70% | 1153 | 7,070,196 | 707,526 | $6 | $8.5 | $58.2 | $82.26 | $90.74 |
| 1997 | 70% | 1153 | 7,070,196 | 707,526 | $6 | $8.5 | $66.9 | $94.55 | $103.04 |
| 1998 | 70% | 1153 | 7,070,196 | 707,526 | $6 | $8.5 | $74.9 | $105.86 | $114.34 |
| 1999 | 70% | 1153 | 7,070,196 | 707,526 | $7 | $9.9 | $85.2 | $120.42 | $130.31 |
| 2000 | 70% | 1153 | 7,070,196 | 707,526 | $7 | $9.9 | $97.1 | $137.24 | $147.13 |
| 2001 | 70% | 1153 | 7,070,196 | 707,526 | $7 | $9.9 | $101.6 | $143.60 | $153.49 |
| 2002 | 70% | 1153 | 7,070,196 | 707,526 | $8 | $11.3 | $100.5 | $142.04 | $153.35 |
| 2003 | 70% | 1153 | 7,070,196 | 707,526 | $8 | $11.3 | $113.9 | $160.98 | $172.29 |
| 2004 | 70% | 1153 | 7,070,196 | 707,526 | $9 | $12.7 | $126.4 | $178.65 | $191.37 |
| 2005 | 70% | 1153 | 7,070,196 | 707,526 | $9 | $12.7 | $140.2 | $198.16 | $210.88 |
| 2006 | 70% | 1153 | 7,070,196 | 707,526 | $10 | $14.1 | $155.3 | $219.50 | $233.63 |
| 2007 | 70% | 1153 | 7,070,196 | 707,526 | $11 | $15.5 | $173.9 | $245.79 | $261.33 |
| 2008 | 70% | 1153 | 7,070,196 | 707,526 | $11 | $15.5 | $191.5 | $270.66 | $286.21 |
| 2009 | 70% | 1153 | 7,070,196 | 707,526 | $12 | $17.0 | $206.7 | $292.14 | $309.11 |
| 2010 | 70% | 1153 | 7,070,196 | 707,526 | $13 | $18.4 | $209.8 | $296.53 | $314.90 |
| 2011 | 70% | 1153 | 7,070,196 | 707,526 | $13 | $18.4 | $226.1 | $319.56 | $337.94 |
| 2012 | 70% | 1153 | 7,070,196 | 707,526 | $14 | $19.8 | $245.4 | $346.84 | $366.63 |
| 2013 | 70% | 1153 | 7,070,196 | 707,526 | $15 | $21.2 | $253.2 | $357.87 | $379.07 |
| 2014 | 70% | 1153 | 7,070,196 | 707,526 | $16 | $22.6 | $273.4 | $386.42 | $409.03 |
| 2015 | 70% | 1153 | 7,070,196 | 707,526 | $17 | $24.0 | $295.3 | $417.37 | $441.40 |
| 2016 | 70% | 1153 | 7,070,196 | 707,526 | $18 | $25.4 | $319.0 | $450.87 | $476.31 |
| 2017 | 70% | 1153 | 7,070,196 | 707,526 | $19 | $26.9 | $344.6 | $487.05 | $513.90 |
| 2018 | 70% | 1153 | 7,070,196 | 707,526 | $20 | $28.3 | $372.3 | $526.20 | $554.47 |
| 2019 | 70% | 1153 | 7,070,196 | 707,526 | $21 | $29.7 | $402.2 | $568.46 | $598.14 |
| 2020 | 70% | 1153 | 7,070,196 | 707,526 | $22 | $31.1 | $434.6 | $614.25 | $645.35 |
| 2021 | 70% | 1153 | 7,070,196 | 707,526 | $24 | $33.9 | $469.6 | $663.72 | $697.64 |
| 2022 | 70% | 1153 | 7,070,196 | 707,526 | $25 | $35.3 | $507.4 | $717.15 | $752.48 |
| 2023 | 70% | 1153 | 7,070,196 | 707,526 | $27 | $38.2 | $548.3 | $774.95 | $813.12 |
| 2024 | 70% | 1153 | 7,070,196 | 707,526 | $28 | $39.6 | $592.6 | $837.57 | $877.14 |

Notes:
1. Testimony of E.J.Ferland, Vol. 1 Ratemaking Analysis of Millstone 3, Exhibit EJF-1-5, p. 16 of 26.
2. *Testimony of E.J.Ferland, Vol. 1 Ratemaking Analysis of Millstone 3, Exhibit* EJF-1-5, p. 16 of 26. Rating for 1990 is average of 1138 and 1153.
3. [3] = [1] * [2] * 8760, except in 1986: [2] * [1] * 8760 * (1 - 151/365).
4. WMECO Retail Portion = 65.1715% * 15.96% * 96.21% of Millstone 3 Generation.
5. Data Request AG-2, January 10, 1986, Q-AG 2-43, p. 2 of 2.
6. [6] = [5] * 1000000 / [4]
7. Data Request AG-2, January 10, 1986. Q-AG 2-42, page 2 of 4.
8. [8] = [7] * 1000000 / [4]
9. [8]+[6]

TABLE 6.2: MILLSTONE 3 RATE IMPACT - CASE I
UMECO ASSUMPTIONS
UMECO RETAIL PORTION, $MILLION

| Year | O&M Cost | Carrying Charges | Capital Additions | Property Tax | Total Costs | Total Benefits | Net Benefits | Cumulative Total | Net Benefits Discounted at 14.05% | Benefits minus Operating Costs |
|---|---|---|---|---|---|---|---|---|---|---|
| ---- | -[1]- | -[2]-- | --[3]--- | --[4]-- | -[5]-- | --[6]--- | --[7]--- | ---[8]--- | ----[9]------ | ----[10]---- |
| 1986 | $5 | $24 | $0 | $2 | $31 | $12.2 | ($18.8) | ($18.8) | ($16.5) | $5.2 |
| 1987 | $7 | $53 | $0 | $3 | $63 | $19.6 | ($43.4) | ($62.2) | ($49.8) | $9.6 |
| 1988 | $9 | $77 | $1 | $3 | $90 | $19.3 | ($70.7) | ($132.9) | ($97.5) | $6.3 |
| 1989 | $9 | $83 | $2 | $3 | $97 | $23.6 | ($73.4) | ($206.3) | ($140.9) | $9.6 |
| 1990 | $9 | $78 | $2 | $3 | $92 | $22.2 | ($69.8) | ($276.1) | ($177.1) | $8.2 |
| 1991 | $10 | $73 | $2 | $3 | $88 | $26.6 | ($61.4) | ($337.5) | ($205.0) | $11.6 |
| 1992 | $11 | $71 | $3 | $4 | $89 | $32.9 | ($56.1) | ($393.6) | ($227.3) | $14.9 |
| 1993 | $12 | $65 | $3 | $4 | $84 | $42.3 | ($41.7) | ($435.3) | ($241.9) | $23.3 |
| 1994 | $12 | $64 | $3 | $4 | $83 | $50.0 | ($33.0) | ($468.3) | ($252.0) | $31.0 |
| 1995 | $13 | $52 | $4 | $5 | $74 | $66.1 | ($7.9) | ($476.2) | ($254.1) | $44.1 |
| 1996 | $14 | $47 | $4 | $5 | $70 | $75.4 | $5.4 | ($470.8) | ($252.8) | $52.4 |
| 1997 | $15 | $46 | $5 | $5 | $71 | $86.3 | $15.3 | ($455.5) | ($249.7) | $61.3 |
| 1998 | $16 | $45 | $5 | $6 | $72 | $93.0 | $21.0 | ($434.5) | ($245.9) | $66.0 |
| 1999 | $17 | $43 | $6 | $6 | $72 | $103.5 | $31.5 | ($403.0) | ($240.9) | $74.5 |
| 2000 | $18 | $40 | $6 | $7 | $71 | $114.1 | $43.1 | ($359.9) | ($234.9) | $83.1 |
| 2001 | $19 | $40 | $6 | $8 | $73 | $117.4 | $44.4 | ($315.5) | ($229.5) | $84.4 |
| 2002 | $20 | $38 | $7 | $8 | $73 | $115.1 | $42.1 | ($273.4) | ($225.0) | $80.1 |
| 2003 | $22 | $38 | $7 | $9 | $76 | $127.3 | $51.3 | ($222.1) | ($220.1) | $89.3 |
| 2004 | $23 | $35 | $7 | $10 | $75 | $138.8 | $63.8 | ($158.3) | ($214.9) | $98.8 |
| 2005 | $25 | $35 | $6 | $11 | $77 | $151.8 | $74.8 | ($83.5) | ($209.5) | $109.8 |
| 2006 | $26 | $34 | $6 | $12 | $78 | $166.2 | $88.2 | $4.7 | ($203.9) | $122.2 |
| 2007 | $29 | $34 | $6 | $14 | $83 | $184.3 | $101.3 | $106.0 | ($198.3) | $135.3 |
| 2008 | $30 | $32 | $5 | $15 | $82 | $201.4 | $119.4 | $225.4 | ($192.5) | $151.4 |
| 2009 | $32 | $30 | $5 | $17 | $84 | $216.1 | $132.1 | $357.5 | ($186.9) | $162.1 |
| 2010 | $34 | $29 | $5 | $19 | $87 | $218.8 | $131.8 | $489.3 | ($181.9) | $160.8 |
| 2011 | $36 | $28 | $4 | $24 | $92 | $234.6 | $142.6 | $631.9 | ($177.3) | $170.6 |
| 2012 | $38 | $27 | $4 | $25 | $94 | $253.6 | $159.6 | $791.5 | ($172.7) | $186.6 |
| 2013 | $41 | $27 | $4 | $28 | $100 | $260.9 | $160.9 | $952.4 | ($168.6) | $187.9 |
| 2014 | $43 | $25 | $4 | $31 | $103 | $280.7 | $177.7 | $1,130.1 | ($164.7) | $202.7 |
| 2015 | $46 | $25 | $3 | $34 | $108 | $302.1 | $194.1 | $1,324.2 | ($160.9) | $219.1 |
| 2016 | $49 | $23 | $3 | $37 | $112 | $325.5 | $213.5 | $1,537.7 | ($157.3) | $236.5 |
| 2017 | $52 | $22 | $3 | $40 | $117 | $350.6 | $233.6 | $1,771.3 | ($153.8) | $255.6 |
| 2018 | $56 | $21 | $3 | $43 | $123 | $403.7 | $280.7 | $2,052.0 | ($150.2) | $301.7 |
| 2019 | $59 | $19 | $3 | $47 | $128 | $459.8 | $331.8 | $2,383.8 | ($146.4) | $350.8 |
| 2020 | $63 | $19 | $2 | $51 | $135 | $518.4 | $383.4 | $2,767.2 | ($142.5) | $402.4 |
| 2021 | $67 | $19 | $2 | $56 | $144 | $564.1 | $420.1 | $3,187.3 | ($138.8) | $439.1 |
| 2022 | $72 | $16 | $2 | $60 | $150 | $612.9 | $462.9 | $3,650.2 | ($135.3) | $478.9 |
| 2023 | $77 | $16 | $2 | $65 | $160 | $647.2 | $487.2 | $4,137.4 | ($132.0) | $503.2 |
| 2024 | $82 | $15 | $2 | $71 | $170 | $691.6 | $521.6 | $4,659.0 | ($128.9) | $536.6 |
| NPV at 14.05% | $89.1 | $393.2 | $17.9 | $37.8 | $538.0 | $409.1 | ($128.9) | | | $264.3 |

Notes: 1.- 4. From Data Request AG-2, 1/10/86, Q-AG-2-43, p. 2 of 2.
5. Total Costs = [1] + [2] + [3] + [4].
6. Total Benefits = Early Retirements + Property Tax + Gas Turbine O&M + Gas Turbine Carrying Charges + System Production Costs. From Q-AG 2-42, 1/10/86, page 2 of 4.
7. Net Benefits = Total Benefits - Total Cost.
10. Operating Costs = O&M Cost + Capital Additions + Property Tax.

TABLE 6.3: MILLSTONE 3 RATE IMPACT - CASE II
WMECO ASSUMPTIONS, EXCEPT PLC CAPACITY FACTOR (IN NET BENEFITS)
WMECO RETAIL PORTION, $MILLION

| Year | Total Costs | Total Benefits | Net Benefits | Cumulative Total | Net Benefits Discounted at 14.05% | Benefits minus Operating Costs |
|---|---|---|---|---|---|---|
| ---- | -[1]- | --[2]--- | --[3]--- | ---[4]---- | -----[5]----- | ---[6]---- |
| 1986 | $31 | $12.1 | ($18.9) | ($18.9) | ($16.5) | $5.13 |
| 1987 | $63 | $16.6 | ($46.4) | ($65.2) | ($52.2) | $6.63 |
| 1988 | $90 | $16.5 | ($73.5) | ($138.8) | ($101.8) | $3.47 |
| 1989 | $97 | $21.0 | ($76.0) | ($214.8) | ($146.7) | $6.97 |
| 1990 | $92 | $20.5 | ($71.5) | ($286.3) | ($183.8) | $6.47 |
| 1991 | $88 | $25.0 | ($63.0) | ($349.4) | ($212.4) | $9.98 |
| 1992 | $89 | $28.7 | ($60.3) | ($409.7) | ($236.4) | $10.69 |
| 1993 | $84 | $37.5 | ($46.5) | ($456.1) | ($252.7) | $18.51 |
| 1994 | $83 | $44.9 | ($38.1) | ($494.3) | ($264.3) | $25.87 |
| 1995 | $74 | $59.5 | ($14.5) | ($508.8) | ($268.2) | $37.52 |
| 1996 | $70 | $67.9 | ($2.1) | ($510.9) | ($268.7) | $44.89 |
| 1997 | $71 | $77.7 | $6.7 | ($504.2) | ($267.4) | $52.67 |
| 1998 | $72 | $83.3 | $11.3 | ($492.9) | ($265.3) | $56.34 |
| 1999 | $72 | $79.2 | $7.2 | ($485.7) | ($264.2) | $50.17 |
| 2000 | $71 | $86.4 | $15.4 | ($470.3) | ($262.0) | $55.37 |
| 2001 | $73 | $88.4 | $15.4 | ($454.9) | ($260.1) | $55.39 |
| 2002 | $73 | $86.4 | $13.4 | ($441.5) | ($258.7) | $51.40 |
| 2003 | $76 | $94.8 | $18.8 | ($422.8) | ($257.0) | $56.77 |
| 2004 | $75 | $102.7 | $27.7 | ($395.1) | ($254.7) | $62.70 |
| 2005 | $77 | $111.8 | $34.8 | ($360.3) | ($252.2) | $69.76 |
| 2006 | $78 | $121.9 | $43.9 | ($316.4) | ($249.4) | $77.85 |
| 2007 | $83 | $134.6 | $51.6 | ($264.9) | ($246.5) | $85.64 |
| 2008 | $82 | $146.7 | $64.7 | ($200.1) | ($243.4) | $96.71 |
| 2009 | $84 | $157.1 | $73.1 | ($127.0) | ($240.3) | $103.07 |
| 2010 | $87 | $158.9 | $71.9 | ($55.1) | ($237.6) | $100.89 |
| 2011 | $92 | $170.0 | $78.0 | $22.9 | ($235.0) | $106.03 |
| 2012 | $94 | $183.5 | $89.5 | $112.4 | ($232.5) | $116.52 |
| 2013 | $100 | $188.6 | $88.6 | $201.0 | ($230.2) | $115.59 |
| 2014 | $103 | $202.6 | $99.6 | $300.6 | ($228.0) | $124.62 |
| 2015 | $108 | $217.8 | $109.8 | $410.4 | ($225.9) | $134.77 |
| 2016 | $112 | $234.4 | $122.4 | $532.8 | ($223.8) | $145.40 |
| 2017 | $117 | $252.2 | $135.2 | $668.0 | ($221.8) | $157.19 |
| 2018 | $123 | $297.4 | $174.4 | $842.4 | ($219.5) | $195.38 |
| 2019 | $128 | $344.9 | $216.9 | $1,059.3 | ($217.0) | $235.94 |
| 2020 | $135 | $394.3 | $259.3 | $1,318.6 | ($214.4) | $278.29 |
| 2021 | $144 | $430.0 | $286.0 | $1,604.6 | ($211.9) | $305.00 |
| 2022 | $150 | $468.0 | $318.0 | $1,922.6 | ($209.5) | $334.00 |
| 2023 | $160 | $490.6 | $330.6 | $2,253.2 | ($207.2) | $346.62 |
| 2024 | $170 | $522.4 | $352.4 | $2,605.6 | ($205.1) | $367.37 |
| NPV at 14.05% | $538.0 | $332.8 | ($205.1) | | | $188.0 |

Notes:

1. Total Cost = O&M + Carrying Charges + Capital Additions + Property Tax. From Q-AG-2-43, 1/10/86, p. 2 of 2.
2. Total Benefits = Early Retirements + Gas Turbine Property Tax + Gas Turbine O&M + Gas Turbine Carrying Charges + System Production Costs. System Production Costs were calculated using PLC capacity factors. From Q-AG 2-42, 1/10/86, page 2 of 4.
6. Operating Costs = O&M + Capital Additions + Property Tax.

TABLE 6.4: MILLSTONE 3 RATE IMPACT - CASE III
HISTORICAL PROJECTIONS

| Year<br>---- | Station O&M<br>-[1]- | Other O&M<br>-[2]- | Capital Additions<br>---[3]--- | Carrying Charges<br>--[4]-- | Total Cost<br>--[5]-- | PLC Total Benefits<br>--[6]-- | Net Benefits<br>---[7]--- | Cumulative Total<br>--[8]-- | Net Benefits Discounted at 14.05%<br>---[9]--- | Benefits minus Operating Costs<br>---[10]--- |
|---|---|---|---|---|---|---|---|---|---|---|
| 1986 | $8.9 | $5.1 | $0.0 | $24.0 | $38.0 | $12.1 | ($25.9) | ($25.9) | ($22.7) | ($1.9) |
| 1987 | $10.5 | $6.2 | $0.8 | $53.0 | $70.4 | $16.6 | ($53.8) | ($79.7) | ($64.1) | ($0.8) |
| 1988 | $12.3 | $6.4 | $1.5 | $77.0 | $97.2 | $16.5 | ($80.7) | ($160.4) | ($118.5) | ($3.7) |
| 1989 | $14.2 | $6.6 | $2.3 | $83.0 | $106.1 | $21.0 | ($85.1) | ($245.5) | ($168.8) | ($2.1) |
| 1990 | $16.3 | $6.8 | $3.1 | $78.0 | $104.2 | $20.5 | ($83.8) | ($329.3) | ($212.2) | ($5.8) |
| 1991 | $18.6 | $7.3 | $3.9 | $73.0 | $102.8 | $25.0 | ($77.8) | ($407.1) | ($247.6) | ($4.8) |
| 1992 | $21.2 | $8.6 | $4.8 | $71.0 | $105.5 | $28.7 | ($76.8) | ($484.0) | ($278.2) | ($5.8) |
| 1993 | $24.0 | $8.9 | $5.7 | $65.0 | $103.6 | $37.5 | ($66.1) | ($550.1) | ($301.3) | ($1.1) |
| 1994 | $27.1 | $9.3 | $6.6 | $64.0 | $107.0 | $44.9 | ($62.1) | ($612.2) | ($320.3) | $1.9 |
| 1995 | $30.5 | $10.7 | $7.5 | $52.0 | $100.7 | $59.5 | ($41.2) | ($653.4) | ($331.4) | $10.8 |
| 1996 | $34.2 | $11.2 | $8.5 | $47.0 | $100.9 | $67.9 | ($33.0) | ($686.4) | ($339.1) | $14.0 |
| 1997 | $38.2 | $11.7 | $9.6 | $46.0 | $105.4 | $77.7 | ($27.7) | ($714.1) | ($344.9) | $18.3 |
| 1998 | $42.6 | $13.2 | $10.7 | $45.0 | $111.4 | $83.3 | ($28.1) | ($742.2) | ($349.9) | $16.9 |
| 1999 | $47.4 | $13.7 | $11.9 | $43.0 | $116.0 | $79.2 | ($36.8) | ($779.0) | ($355.8) | $6.2 |
| 2000 | $52.5 | $15.4 | $13.2 | $40.0 | $121.1 | $86.4 | ($34.7) | ($813.7) | ($360.6) | $5.3 |
| 2001 | $58.2 | $17.0 | $14.5 | $40.0 | $129.7 | $88.4 | ($41.3) | ($855.1) | ($365.7) | ($1.3) |
| 2002 | $64.3 | $17.7 | $16.0 | $38.0 | $136.0 | $86.4 | ($49.6) | ($904.7) | ($371.0) | ($11.6) |
| 2003 | $71.0 | $19.5 | $17.6 | $38.0 | $146.0 | $94.8 | ($51.2) | ($955.9) | ($375.8) | ($13.2) |
| 2004 | $78.2 | $21.3 | $19.3 | $35.0 | $153.7 | $102.7 | ($51.0) | ($1,007.0) | ($380.0) | ($16.0) |
| 2005 | $86.0 | $23.2 | $21.1 | $35.0 | $165.3 | $111.8 | ($53.5) | ($1,060.5) | ($383.8) | ($18.5) |
| 2006 | $94.5 | $25.1 | $23.0 | $34.0 | $176.7 | $121.9 | ($54.8) | ($1,115.3) | ($387.3) | ($20.8) |
| 2007 | $103.7 | $28.1 | $25.1 | $34.0 | $191.0 | $134.6 | ($56.3) | ($1,171.7) | ($390.4) | ($22.3) |
| 2008 | $113.7 | $30.2 | $27.4 | $32.0 | $203.3 | $146.7 | ($56.6) | ($1,228.3) | ($393.2) | ($24.6) |
| 2009 | $124.5 | $33.4 | $29.8 | $30.0 | $217.7 | $157.1 | ($60.7) | ($1,288.9) | ($395.8) | ($30.7) |
| 2010 | $136.2 | $36.7 | $32.4 | $29.0 | $234.3 | $158.9 | ($75.4) | ($1,364.3) | ($398.6) | ($46.4) |
| 2011 | $148.8 | $43.1 | $35.3 | $28.0 | $255.2 | $170.0 | ($85.2) | ($1,449.5) | ($401.4) | ($57.2) |
| 2012 | $162.5 | $45.6 | $38.4 | $27.0 | $273.4 | $183.5 | ($89.9) | ($1,539.4) | ($404.0) | ($62.9) |
| 2013 | $177.2 | $50.2 | $41.7 | $27.0 | $296.2 | $188.6 | ($107.6) | ($1,647.0) | ($406.7) | ($80.6) |
| 2014 | $193.2 | $54.9 | $45.4 | $25.0 | $318.5 | $202.6 | ($115.9) | ($1,762.9) | ($409.2) | ($90.9) |
| 2015 | $210.4 | $59.8 | $49.5 | $25.0 | $344.7 | $217.8 | ($126.9) | ($1,889.9) | ($411.7) | ($101.9) |
| 2016 | $229.0 | $64.8 | $52.0 | $23.0 | $368.8 | $234.4 | ($134.4) | ($2,024.3) | ($414.0) | ($111.4) |
| 2017 | $249.1 | $70.0 | $55.6 | $22.0 | $396.7 | $252.2 | ($144.5) | ($2,168.8) | ($416.1) | ($122.5) |
| 2018 | $270.7 | $75.4 | $60.6 | $21.0 | $427.7 | $297.4 | ($130.3) | ($2,299.2) | ($417.8) | ($109.3) |
| 2019 | $294.1 | $81.9 | $67.4 | $19.0 | $462.4 | $344.9 | ($117.4) | ($2,416.6) | ($419.2) | ($98.4) |
| 2020 | $319.3 | $88.6 | $76.6 | $19.0 | $503.5 | $394.3 | ($109.2) | ($2,525.8) | ($420.3) | ($90.2) |
| 2021 | $346.4 | $96.6 | $89.6 | $19.0 | $551.6 | $430.0 | ($121.6) | ($2,647.5) | ($421.3) | ($102.6) |
| 2022 | $375.7 | $103.8 | $109.1 | $16.0 | $604.5 | $468.0 | ($136.5) | ($2,784.0) | ($422.4) | ($120.5) |
| 2023 | $407.2 | $112.2 | $141.2 | $16.0 | $676.6 | $490.6 | ($186.0) | ($2,970.0) | ($423.7) | ($170.0) |
| 2024 | $441.1 | $121.9 | $211.5 | $15.0 | $789.6 | $522.4 | ($267.2) | ($3,237.2) | ($425.2) | ($252.2) |
| NPV at 14.0 | $233.5 | $79.4 | $52.0 | $393.2 | $758.1 | $332.8 | ($425.2) | | | ($32.1) |

Notes:

1. From Table 7.8, Column 9. Adjusted to WMECo's retail portion.
2. Other O&M = A&G + Property Taxes + Decommissioning Costs. A&G from Bernard Fox Testimony, Exh. BMF-2, 12/85, p. 2 of 3. Adjusted to WMECo's retail portion. Escalated at 8% after 1990. Decommissioning Costs from NU Schedule C-3.38. Escalated at 7% after 1986. From Data Request Q-AG-2-32, p. 3 of 4. Property taxes from Q-AG-2-43, 1/10/86, p. 2 of 2.
3. From Table 7.11, Column [3] and Appendix K.
4. From Data Request AG-2, 1/10/86, Q-AG 2-43, page 2 of 2.
5. [1] + [2] + [3] + [4].
6. See Table 6.3, Column 2.
7. [6]-[5].

TABLE 6.5: MILLSTONE 3 RATE IMPACT: CASE IV

WMECO ASSUMPTIONS, COSTS BASED ON NU ASSUMPTIONS FOR MILLSTONE 3, BENEFITS INCLUDE OUR CALCULATION OF AVOIDED CAPACITY COST, WMECO PORTION, $ MILLION

| Year | Total Costs | Total Benefits | Net Benefits | Net Cumulative Total | Net Benefits Discounted at 14.05% | Benefits minus Operating Costs |
|---|---|---|---|---|---|---|
| ---- | -[1]- | --[2]-- | ---[3]--- | ---[4]---- | ----[5]----- | --[6]--- |
| 1986 | $31.0 | $12.2 | ($18.8) | ($18.8) | ($16.5) | $5.2 |
| 1987 | $63.0 | $19.1 | ($43.9) | ($62.7) | ($50.2) | $9.1 |
| 1988 | $90.0 | $19.4 | ($70.6) | ($133.3) | ($97.8) | $6.4 |
| 1989 | $97.0 | $23.1 | ($73.9) | ($207.2) | ($141.5) | $9.1 |
| 1990 | $92.0 | $23.0 | ($69.0) | ($276.2) | ($177.2) | $9.0 |
| 1991 | $88.0 | $26.8 | ($61.2) | ($337.4) | ($205.1) | $11.8 |
| 1992 | $89.0 | $35.9 | ($53.1) | ($390.6) | ($226.2) | $17.9 |
| 1993 | $84.0 | $44.6 | ($39.4) | ($430.0) | ($240.0) | $25.6 |
| 1994 | $83.0 | $53.2 | ($29.8) | ($459.8) | ($249.2) | $34.2 |
| 1995 | $74.0 | $65.0 | ($9.0) | ($468.8) | ($251.6) | $43.0 |
| 1996 | $70.0 | $71.3 | $1.3 | ($467.5) | ($251.3) | $48.3 |
| 1997 | $71.0 | $79.2 | $8.2 | ($459.3) | ($249.6) | $54.2 |
| 1998 | $72.0 | $86.4 | $14.4 | ($444.8) | ($247.0) | $59.4 |
| 1999 | $72.0 | $96.0 | $24.0 | ($420.9) | ($243.1) | $67.0 |
| 2000 | $71.0 | $107.1 | $36.1 | ($384.7) | ($238.1) | $76.1 |
| 2001 | $73.0 | $110.9 | $37.9 | ($346.8) | ($233.5) | $77.9 |
| 2002 | $73.0 | $109.1 | $36.1 | ($310.7) | ($229.6) | $74.1 |
| 2003 | $76.0 | $121.9 | $45.9 | ($264.8) | ($225.3) | $83.9 |
| 2004 | $75.0 | $133.9 | $58.9 | ($205.9) | ($220.5) | $93.9 |
| 2005 | $77.0 | $147.4 | $70.4 | ($135.5) | ($215.4) | $105.4 |
| 2006 | $78.0 | $162.2 | $84.2 | ($51.3) | ($210.1) | $118.2 |
| 2007 | $83.0 | $181.5 | $98.5 | $47.2 | ($204.6) | $132.5 |
| 2008 | $82.0 | $198.9 | $116.9 | $164.1 | ($198.9) | $148.9 |
| 2009 | $84.0 | $215.7 | $131.7 | $295.8 | ($193.3) | $161.7 |
| 2010 | $87.0 | $218.3 | $131.3 | $427.1 | ($188.4) | $160.3 |
| 2011 | $92.0 | $234.2 | $142.2 | $569.3 | ($183.7) | $170.2 |
| 2012 | $94.0 | $253.0 | $159.0 | $728.4 | ($179.2) | $186.0 |
| 2013 | $100.0 | $260.5 | $160.5 | $888.8 | ($175.1) | $187.5 |
| 2014 | $103.0 | $280.2 | $177.2 | $1,066.1 | ($171.2) | $202.2 |
| 2015 | $108.0 | $301.7 | $193.7 | $1,259.8 | ($167.5) | $218.7 |
| 2016 | $112.0 | $325.0 | $213.0 | $1,472.8 | ($163.8) | $236.0 |
| 2017 | $117.0 | $349.8 | $232.8 | $1,705.6 | ($160.4) | $254.8 |
| 2018 | $123.0 | $376.4 | $253.4 | $1,958.9 | ($157.1) | $274.4 |
| 2019 | $128.0 | $405.1 | $277.1 | $2,236.1 | ($153.9) | $296.1 |
| 2020 | $135.0 | $437.2 | $302.2 | $2,538.3 | ($150.9) | $321.2 |
| 2021 | $144.0 | $472.1 | $328.1 | $2,866.4 | ($148.0) | $347.1 |
| 2022 | $150.0 | $509.6 | $359.6 | $3,226.0 | ($145.2) | $375.6 |
| 2023 | $160.0 | $550.4 | $390.4 | $3,616.4 | ($142.6) | $406.4 |
| 2024 | $170.0 | $594.2 | $424.2 | $4,040.5 | ($140.0) | $439.2 |
| NPV at 14.05% | $538.0 | $397.9 | ($140.0) | | | $253.1 |

NOTES: [1] Total Costs= O&M Cost+Carrying Charges+Capital Additions +Property Tax. Taken from Q-AG-2-43, 1/10/86, page 2 of 2.

[2] Total Benefits= NU System Production Cost+PLC Avoided Capacity Cost from Table 5.6, Column 7.

[3] Net Benefits=Total Benefits-TotalCosts.

[6] Operating Costs=O&M Cost+Capital Cost+Property Tax.

TABLE 6.6: MILLSTONE 3 RATE IMPACT - CASE V
WMECO ASSUMPTIONS, PRODUCTION COST BASED ON DRI, LATE 1985 FUEL PRICE PROJECTIONS
WMECO RETAIL PORTION, $ MILLION

| Year | Total Costs | Total Benefits | Net Benefits | Cumulative Total | Net Benefits Discounted at 14.05% | Benefits minus Operating Costs |
|---|---|---|---|---|---|---|
| ---- | -[1]- | --[2]--- | --[3]--- | ---[4]--- | ---[5]----- | --[6]--- |
| 1986 | $31.0 | $11.2 | ($19.8) | ($19.8) | ($17.4) | $4.2 |
| 1987 | $63.0 | $16.8 | ($46.2) | ($66.0) | ($52.9) | $6.8 |
| 1988 | $90.0 | $16.3 | ($73.7) | ($139.7) | ($102.6) | $3.3 |
| 1989 | $97.0 | $20.0 | ($77.0) | ($216.7) | ($148.1) | $6.0 |
| 1990 | $92.0 | $18.6 | ($73.4) | ($290.1) | ($186.1) | $4.6 |
| 1991 | $88.0 | $22.0 | ($66.0) | ($356.1) | ($216.1) | $7.0 |
| 1992 | $89.0 | $26.8 | ($62.2) | ($418.3) | ($240.9) | $8.8 |
| 1993 | $84.0 | $34.9 | ($49.1) | ($467.4) | ($258.0) | $15.9 |
| 1994 | $83.0 | $41.9 | ($41.1) | ($508.6) | ($270.6) | $22.9 |
| 1995 | $74.0 | $55.5 | ($18.5) | ($527.1) | ($275.6) | $33.5 |
| 1996 | $70.0 | $63.1 | ($6.9) | ($534.0) | ($277.2) | $40.1 |
| 1997 | $71.0 | $71.6 | $0.6 | ($533.3) | ($277.1) | $46.6 |
| 1998 | $72.0 | $78.2 | $6.2 | ($527.2) | ($276.0) | $51.2 |
| 1999 | $72.0 | $89.1 | $17.1 | ($510.1) | ($273.3) | $60.1 |
| 2000 | $71.0 | $98.9 | $27.9 | ($482.2) | ($269.4) | $67.9 |
| 2001 | $73.0 | $103.3 | $30.3 | ($451.8) | ($265.7) | $70.3 |
| 2002 | $73.0 | $103.6 | $30.6 | ($421.2) | ($262.4) | $68.6 |
| 2003 | $76.0 | $114.7 | $38.7 | ($382.5) | ($258.8) | $76.7 |
| 2004 | $75.0 | $125.7 | $50.7 | ($331.8) | ($254.6) | $85.7 |
| 2005 | $77.0 | $138.0 | $61.0 | ($270.9) | ($250.2) | $96.0 |
| 2006 | $78.0 | $151.8 | $73.8 | ($197.1) | ($245.6) | $107.8 |
| 2007 | $83.0 | $168.9 | $85.9 | ($111.1) | ($240.8) | $119.9 |
| 2008 | $82.0 | $185.4 | $103.4 | ($7.8) | ($235.8) | $135.4 |
| 2009 | $84.0 | $198.6 | $114.6 | $106.9 | ($230.9) | $144.6 |
| 2010 | $87.0 | $202.9 | $115.9 | $222.8 | ($226.5) | $144.9 |
| 2011 | $92.0 | $216.4 | $124.4 | $347.2 | ($222.5) | $152.4 |
| 2012 | $94.0 | $233.4 | $139.4 | $486.5 | ($218.5) | $166.4 |
| 2013 | $100.0 | $237.5 | $137.5 | $624.0 | ($215.0) | $164.5 |
| 2014 | $103.0 | $255.5 | $152.5 | $776.5 | ($211.6) | $177.5 |
| 2015 | $108.0 | $274.9 | $166.9 | $943.4 | ($208.4) | $191.9 |
| 2016 | $112.0 | $295.6 | $183.6 | $1,127.0 | ($205.3) | $206.6 |
| 2017 | $117.0 | $318.9 | $201.9 | $1,328.9 | ($202.3) | $223.9 |
| 2018 | $123.0 | $369.4 | $246.4 | $1,575.3 | ($199.1) | $267.4 |
| 2019 | $128.0 | $422.8 | $294.8 | $1,870.1 | ($195.7) | $313.8 |
| 2020 | $135.0 | $478.4 | $343.4 | $2,213.5 | ($192.2) | $362.4 |
| 2021 | $144.0 | $520.9 | $376.9 | $2,590.4 | ($188.9) | $395.9 |
| 2022 | $150.0 | $566.3 | $416.3 | $3,006.8 | ($185.7) | $432.3 |
| 2023 | $160.0 | $596.9 | $436.9 | $3,443.7 | ($182.7) | $452.9 |
| 2024 | $170.0 | $637.3 | $467.3 | $3,911.0 | ($180.0) | $482.3 |
| NPV at 14.05 | $538.0 | $358.0 | ($180.0) | | | $213.2 |

NOTES: 1. Total Costs = O&M + Carrying Charges + Capital Additions + Property Tax. From Q-AG-2-43, 1/10/86, page 2 of 2.

2. Total Benefits = Early Retirements + Gas Turbine Property Tax + Gas Turbine O&M + Gas Turbine Carrying Charges + System Production Costs. System Production Costs were calculated using the DRI oil price projections from December, 1985 and coal price projections from September 1985. From AG-8,1/31/86, Q-AG 8-26, page 2.

6. Operating Costs = O&M + Capital Cost + Property Tax.

TABLE 6.7: MILLSTONE 3 RATE IMPACT - CASE VI
WMECO ASSUMPTIONS, PRODUCTION COSTS BASED ON DRI 1980 FUEL PRICE PROJECTIONS
WMECO RETAIL PORTION, $ MILLION

| Year<br>---- | Total Costs<br>--[1]- | Total Benefits<br>--[2]--- | Net Benefits<br>--[3]--- | Cumulative Total<br>----[4]--- | Net Benefits Discounted at 14.05%<br>----[5]----- | Benefits minus Operating Costs<br>--[6]--- |
|---|---|---|---|---|---|---|
| 1986 | $31.0 | $33.6 | $2.6 | $2.6 | $2.3 | $26.6 |
| 1987 | $63.0 | $56.2 | ($6.8) | ($4.2) | ($2.9) | $46.2 |
| 1988 | $90.0 | $57.8 | ($32.2) | ($36.4) | ($24.6) | $44.8 |
| 1989 | $97.0 | $65.5 | ($31.5) | ($67.9) | ($43.3) | $51.5 |
| 1990 | $92.0 | $68.0 | ($24.0) | ($91.9) | ($55.7) | $54.0 |
| 1991 | $88.0 | $82.6 | ($5.4) | ($97.3) | ($58.2) | $67.6 |
| 1992 | $89.0 | $103.1 | $14.1 | ($83.2) | ($52.6) | $85.1 |
| 1993 | $84.0 | $118.6 | $34.6 | ($48.6) | ($40.5) | $99.6 |
| 1994 | $83.0 | $132.3 | $49.3 | $0.6 | ($25.4) | $113.3 |
| 1995 | $74.0 | $169.8 | $95.8 | $96.4 | $0.4 | $147.8 |
| 1996 | $70.0 | $189.9 | $119.9 | $216.3 | $28.6 | $166.9 |
| 1997 | $71.0 | $217.1 | $146.1 | $362.4 | $58.7 | $192.1 |
| 1998 | $72.0 | $236.9 | $164.9 | $527.3 | $88.6 | $209.9 |
| 1999 | $72.0 | $259.0 | $187.0 | $714.3 | $118.3 | $230.0 |
| 2000 | $71.0 | $277.4 | $206.4 | $920.7 | $147.0 | $246.4 |
| 2001 | $73.0 | $275.1 | $202.1 | $1,122.8 | $171.7 | $242.1 |
| 2002 | $73.0 | $286.6 | $213.6 | $1,336.4 | $194.5 | $251.6 |
| 2003 | $76.0 | $319.0 | $243.0 | $1,579.4 | $217.3 | $281.0 |
| 2004 | $75.0 | $370.8 | $295.8 | $1,875.2 | $241.7 | $330.8 |
| 2005 | $77.0 | $410.1 | $333.1 | $2,208.4 | $265.7 | $368.1 |
| 2006 | $78.0 | $453.7 | $375.7 | $2,584.0 | $289.4 | $409.7 |
| 2007 | $83.0 | $480.1 | $397.1 | $2,981.2 | $311.5 | $431.1 |
| 2008 | $82.0 | $542.7 | $460.7 | $3,441.9 | $333.9 | $492.7 |
| 2009 | $84.0 | $566.8 | $482.8 | $3,924.7 | $354.4 | $512.8 |
| 2010 | $87.0 | $631.7 | $544.7 | $4,469.3 | $374.8 | $573.7 |
| 2011 | $92.0 | $621.0 | $529.0 | $4,998.3 | $392.1 | $557.0 |
| 2012 | $94.0 | $697.4 | $603.4 | $5,601.7 | $409.5 | $630.4 |
| 2013 | $100.0 | $746.5 | $646.5 | $6,248.3 | $425.8 | $673.5 |
| 2014 | $103.0 | $814.9 | $711.9 | $6,960.2 | $441.5 | $736.9 |
| 2015 | $108.0 | $889.6 | $781.6 | $7,741.8 | $456.6 | $806.6 |
| 2016 | $112.0 | $971.5 | $859.5 | $8,601.3 | $471.2 | $882.5 |
| 2017 | $117.0 | $1,060.7 | $943.7 | $9,545.0 | $485.3 | $965.7 |
| 2018 | $123.0 | $1,184.3 | $1,061.3 | $10,606.3 | $499.1 | $1,082.3 |
| 2019 | $128.0 | $1,317.7 | $1,189.7 | $11,796.0 | $512.8 | $1,208.7 |
| 2020 | $135.0 | $1,461.1 | $1,326.1 | $13,122.1 | $526.1 | $1,345.1 |
| 2021 | $144.0 | $1,599.9 | $1,455.9 | $14,578.0 | $538.9 | $1,474.9 |
| 2022 | $150.0 | $1,750.8 | $1,600.8 | $16,178.8 | $551.2 | $1,616.8 |
| 2023 | $160.0 | $2,897.2 | $2,737.2 | $18,916.0 | $569.8 | $2,753.2 |
| 2024 | $170.0 | $2,064.4 | $1,894.4 | $20,810.3 | $581.0 | $1,909.4 |
| NPV at 14.05% | $538.0 | $1,119.0 | $581.0 | | | $974.2 |

Notes:
1. Total Costs = O&M Cost + Carrying Charges + Capital Additions + Property Tax. From Q-AG-2-43, 1/10/86, page 2 of 2.
2. Total Benefits = Early Retirements + Gas Turbine Property Tax + Gas Turbine O&M + Gas Turbine Carrying Charges + System Production Costs. System Production Costs were calculated using the DRI fuel price projections from February, 1980. From AG-8,1/31/86, Q-AG-8-26, p. 2
3. Net Benefits = Total Benefits - Total Costs.
6. Operating Costs = O&M Cost + Capital Cost + Property Tax.

TABLE 6.8: MILLSTONE 3 RATE IMPACT - CASE VII
WMECO ASSUMPTIONS, PRODUCTION COSTS BASED ON 1977 and 1978 FUEL PRICE PROJECTIONS
WMECO PORTION, $ MILLION

| Year | Total Costs | Total Benefits | Net Benefits | Cumulative Total | Net Benefits Discounted at 14.05% | Benefits minus Operating Costs |
|---|---|---|---|---|---|---|
| ---- | -[1]-- | --[2]--- | --[3]--- | ---[4]---- | ---[5]---- | --[6]-- |
| 1986 | $31.0 | $12.7 | ($18.3) | ($18.3) | ($16.1) | $5.7 |
| 1987 | $63.0 | $22.6 | ($40.4) | ($58.7) | ($47.1) | $12.6 |
| 1988 | $90.0 | $24.1 | ($65.9) | ($124.6) | ($91.5) | $11.1 |
| 1989 | $97.0 | $30.2 | ($66.8) | ($191.4) | ($131.0) | $16.2 |
| 1990 | $92.0 | $29.8 | ($62.2) | ($253.6) | ($163.3) | $15.8 |
| 1991 | $88.0 | $36.2 | ($51.8) | ($305.5) | ($186.8) | $21.2 |
| 1992 | $89.0 | $44.8 | ($44.2) | ($349.7) | ($204.4) | $26.8 |
| 1993 | $84.0 | $55.9 | ($28.1) | ($377.7) | ($214.2) | $36.9 |
| 1994 | $83.0 | $64.1 | ($18.9) | ($396.7) | ($220.0) | $45.1 |
| 1995 | $74.0 | $82.6 | $8.6 | ($388.0) | ($217.7) | $60.6 |
| 1996 | $70.0 | $99.7 | $29.7 | ($358.3) | ($210.7) | $76.7 |
| 1997 | $71.0 | $102.9 | $31.9 | ($326.4) | ($204.1) | $77.9 |
| 1998 | $72.0 | $108.6 | $36.6 | ($289.8) | ($197.5) | $81.6 |
| 1999 | $72.0 | $117.7 | $45.7 | ($244.1) | ($190.2) | $88.7 |
| 2000 | $71.0 | $126.3 | $55.3 | ($188.8) | ($182.5) | $95.3 |
| 2001 | $73.0 | $127.7 | $54.7 | ($134.1) | ($175.9) | $94.7 |
| 2002 | $73.0 | $122.0 | $49.0 | ($85.1) | ($170.6) | $87.0 |
| 2003 | $76.0 | $134.5 | $58.5 | ($26.6) | ($165.1) | $96.5 |
| 2004 | $75.0 | $147.1 | $72.1 | $45.5 | ($159.2) | $107.1 |
| 2005 | $77.0 | $162.4 | $85.4 | $130.9 | ($153.0) | $120.4 |
| 2006 | $78.0 | $97.4 | $19.4 | $150.4 | ($151.8) | $53.4 |
| 2007 | $83.0 | $197.5 | $114.5 | $264.9 | ($145.5) | $148.5 |
| 2008 | $82.0 | $215.5 | $133.5 | $398.4 | ($139.0) | $165.5 |
| 2009 | $84.0 | $234.9 | $150.9 | $549.3 | ($132.5) | $180.9 |
| 2010 | $87.0 | $239.1 | $152.1 | $701.4 | ($126.9) | $181.1 |
| 2011 | $92.0 | $266.3 | $174.3 | $875.7 | ($121.1) | $202.3 |
| 2012 | $94.0 | $294.6 | $200.6 | $1,076.3 | ($115.4) | $227.6 |
| 2013 | $100.0 | $297.3 | $197.3 | $1,273.6 | ($110.4) | $224.3 |
| 2014 | $103.0 | $327.0 | $224.0 | $1,497.6 | ($105.5) | $249.0 |
| 2015 | $108.0 | $359.9 | $251.9 | $1,749.5 | ($100.6) | $276.9 |
| 2016 | $112.0 | $396.4 | $284.4 | $2,033.9 | ($95.8) | $307.4 |
| 2017 | $117.0 | $436.5 | $319.5 | $2,353.4 | ($91.0) | $341.5 |
| 2018 | $123.0 | $507.1 | $384.1 | $2,737.5 | ($86.0) | $405.1 |
| 2019 | $128.0 | $582.8 | $454.8 | $3,192.4 | ($80.8) | $473.8 |
| 2020 | $135.0 | $663.9 | $528.9 | $3,721.3 | ($75.5) | $547.9 |
| 2021 | $144.0 | $735.3 | $591.3 | $4,312.5 | ($70.3) | $610.3 |
| 2022 | $150.0 | $823.3 | $673.3 | $4,985.8 | ($65.1) | $689.3 |
| 2023 | $160.0 | $880.8 | $720.8 | $5,706.6 | ($60.2) | $736.8 |
| 2024 | $170.0 | $962.7 | $792.7 | $6,499.3 | ($55.5) | $807.7 |
| NPV at 14.05 | $538.0 | $482.5 | ($55.5) | | | $337.7 |

Notes:
1. Total Costs = O&M + Carrying Charges + Capital Additions + Property Tax. From Q-AG-2-43, 1/10/86, page 2 of 2.
2. Total Benefits = Early Retirements + Gas Turbine Property Tax + Gas Turbine O&M + Gas Turbine Carrying Charges + System Production Costs. System Production Cost were calculated using the DRI oil price projections from November, 1978 and coal price projections from July, 1977. From AG-8,1/31/86, Q-AG 8-26, page 2 of 3.
6. Operating Costs = O&M + Capital Cost + Property Tax.

TABLE 6.9: SUMMARY OF CASES

| Case | | I | II | III | IV | V | VI | VII |
|---|---|---|---|---|---|---|---|---|
| | | WMECO | WMECO and PLC Capacity Factor | Historical | Avoided Capacity Cost | DRI 12/85 | DRI 1980 | DRI 1977/78 |
| Table | | 6.2 | 6.3 | 6.4 | 6.5 | 6.6 | 6.7 | 6.8 |
| Crossover Year | | 1996 | 1997 | NEVER | 1996 | 1997 | 1992 | 1995 |
| Breakeven Year | | 2006 | 2011 | NEVER | 2007 | 2009 | 1994 | 2004 |
| Discounted Breakeven Year | at 14.05% | NEVER | NEVER | NEVER | NEVER | NEVER | 1995 | NEVER |
| Cumulative Savings at Crossover($million) | | ($471) | ($504) | | ($468) | ($533) | ($83) | ($388) |
| Terminal Discounted Savings($million) | at 14.05% | ($129) | ($205) | ($425) | ($140) | ($180) | $581 | ($56) |

Table 6.10: SUMMARY OF CASES: VALUE OF MILLSTONE 3, WMECO RETAIL PORTION. CTS/KWH

| | Total Cost of Millstone 3 Power | | | Total Benefits of Millstone 3 Power | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| Case: | I, IV - VII | II | III | I | II & III | IV | V | VI | VII |
| Year | [1] | [2] | [3] | [4] | [5] | [6] | [7] | [8] | [9] |
| 1986 | 10.3 | 10.3 | 12.3 | 4.9 | 4.9 | 4.9 | 4.6 | 11.0 | 5.0 |
| 1987 | 11.1 | 13.1 | 12.3 | 4.2 | 4.3 | 4.1 | 3.8 | 10.1 | 4.7 |
| 1988 | 15.0 | 17.4 | 16.1 | 4.1 | 4.1 | 4.1 | 3.6 | 10.0 | 4.8 |
| 1989 | 15.9 | 17.8 | 17.3 | 4.6 | 4.6 | 4.5 | 4.0 | 11.0 | 5.6 |
| 1990 | 15.0 | 16.2 | 16.9 | 4.3 | 4.3 | 4.4 | 3.8 | 11.3 | 5.5 |
| 1991 | 14.3 | 15.2 | 16.6 | 5.0 | 5.0 | 5.0 | 4.3 | 13.5 | 6.4 |
| 1992 | 13.4 | 15.3 | 15.8 | 5.5 | 5.5 | 5.9 | 4.6 | 15.4 | 7.2 |
| 1993 | 12.6 | 14.3 | 15.3 | 6.7 | 6.8 | 7.0 | 5.6 | 17.5 | 8.6 |
| 1994 | 12.4 | 14.2 | 15.8 | 7.8 | 8.0 | 8.2 | 6.6 | 19.4 | 9.8 |
| 1995 | 11.2 | 12.7 | 14.9 | 10.0 | 10.4 | 9.9 | 8.5 | 24.7 | 12.4 |
| 1996 | 10.7 | 12.2 | 15.1 | 11.5 | 11.9 | 10.9 | 9.8 | 27.7 | 14.9 |
| 1997 | 10.9 | 12.4 | 15.7 | 13.0 | 13.5 | 12.0 | 11.0 | 31.5 | 15.4 |
| 1998 | 11.0 | 12.5 | 16.6 | 14.0 | 14.4 | 13.1 | 11.9 | 34.3 | 16.2 |
| 1999 | 11.2 | 15.2 | 17.4 | 15.6 | 16.7 | 14.6 | 13.6 | 37.6 | 17.6 |
| 2000 | 11.0 | 15.0 | 18.1 | 17.1 | 18.1 | 16.1 | 15.0 | 40.2 | 18.8 |
| 2001 | 11.3 | 15.4 | 19.3 | 17.6 | 18.5 | 16.7 | 15.6 | 39.9 | 19.0 |
| 2002 | 11.4 | 15.6 | 20.4 | 17.4 | 18.2 | 16.6 | 15.8 | 41.6 | 18.4 |
| 2003 | 11.9 | 16.2 | 21.8 | 19.1 | 19.9 | 18.4 | 17.3 | 46.2 | 20.1 |
| 2004 | 11.9 | 16.1 | 23.0 | 20.9 | 21.6 | 20.2 | 19.0 | 53.7 | 22.1 |
| 2005 | 12.2 | 16.5 | 24.6 | 22.7 | 23.4 | 22.1 | 20.8 | 59.2 | 24.2 |
| 2006 | 12.4 | 16.8 | 26.4 | 24.9 | 25.5 | 24.3 | 22.9 | 65.5 | 15.2 |
| 2007 | 13.3 | 18.0 | 28.5 | 27.6 | 28.2 | 27.2 | 25.4 | 69.4 | 29.5 |
| 2008 | 13.1 | 17.8 | 30.3 | 30.0 | 30.6 | 29.7 | 27.8 | 78.3 | 32.0 |
| 2009 | 13.6 | 18.3 | 32.5 | 32.2 | 32.8 | 32.2 | 29.8 | 81.8 | 34.9 |
| 2010 | 14.1 | 19.0 | 35.0 | 32.8 | 33.3 | 32.7 | 30.5 | 91.1 | 35.6 |
| 2011 | 14.8 | 20.0 | 37.9 | 35.0 | 35.5 | 34.9 | 32.4 | 89.6 | 39.5 |
| 2012 | 15.3 | 20.6 | 40.6 | 37.8 | 38.3 | 37.7 | 35.0 | 100.5 | 43.6 |
| 2013 | 16.3 | 21.9 | 44.0 | 39.0 | 39.4 | 38.9 | 35.7 | 107.6 | 44.1 |
| 2014 | 16.8 | 22.6 | 47.3 | 41.9 | 42.3 | 41.9 | 38.4 | 117.4 | 48.5 |
| 2015 | 17.7 | 23.8 | 51.1 | 45.1 | 45.5 | 45.0 | 41.3 | 128.1 | 53.3 |
| 2016 | 18.4 | 24.7 | 54.7 | 48.5 | 48.9 | 48.5 | 44.3 | 139.8 | 58.6 |
| 2017 | 19.2 | 25.8 | 58.8 | 52.2 | 52.6 | 52.1 | 47.8 | 152.6 | 64.4 |
| 2018 | 20.2 | 27.2 | 63.3 | 59.9 | 61.7 | 56.0 | 55.0 | 170.2 | 74.5 |
| 2019 | 21.1 | 28.3 | 68.3 | 68.0 | 71.2 | 60.2 | 62.7 | 189.2 | 85.3 |
| 2020 | 22.2 | 29.8 | 74.3 | 76.4 | 81.1 | 64.9 | 70.7 | 209.6 | 96.9 |
| 2021 | 23.7 | 31.9 | 81.4 | 83.1 | 88.5 | 70.1 | 77.0 | 229.5 | 107.3 |
| 2022 | 24.7 | 33.2 | 89.0 | 90.2 | 96.1 | 75.6 | 83.6 | 251.0 | 119.9 |
| 2023 | 26.4 | 35.5 | 99.4 | 95.3 | 100.9 | 81.6 | 88.2 | 413.3 | 128.3 |
| 2024 | 28.0 | 37.6 | 115.6 | 101.7 | 107.3 | 87.9 | 94.0 | 295.7 | 140.0 |
| NPV at: 14.05% | 90.9 | 105.3 | 123.3 | 67.8 | 69.5 | 66.2 | 60.3 | 172.6 | 78.5 |
| Levelized at: 14.05% | 12.8 | 14.9 | 17.4 | 9.6 | 9.8 | 9.4 | 8.5 | 24.4 | 11.1 |

Notes:

1. From Tables 6.2, 6.5, 6.6, 6.7, and 6.8.
2. From Table 6.3
3. From Table 6.4.
4. From Table 6.2.
5. From Table 6.3 and 6.4.
6. From Table 6.5.
7. From Table 6.6.
8. From Table 6.7.
9. From Table 6.8.

TABLE 7.1: COMPARISON OF EQUIVALENT AVAILABILITY FACTORS TO CAPACITY FACTORS
NEPOOL NUCLEAR UNITS

| Year | Connecticut Yankee * EAF | CF | EAF-CF | Maine Yankee EAF | CF | EAF-CF | Vermont Yankee EAF | CF | EAF-CF |
|---|---|---|---|---|---|---|---|---|---|
| 1968 | 73.8 | 73.8 | 0.0 | | | | | | |
| 1969 | 84.5 | 76.1 | 8.4 | | | | | | |
| 1970 | 70.4 | 70.2 | 0.2 | | | | | | |
| 1971 | 84.1 | 83.1 | 1.0 | | | | | | |
| 1972 | 85.4 | 85.1 | 0.3 | | | | 44.3 | 44.3 | 0.0 |
| 1973 | 48.2 | 48.2 | 0.0 | 48.4 | 48.4 | 0.0 | 40.3 | 40.3 | 0.0 |
| 1974 | 86.4 | 86.4 | 0.0 | 51.7 | 51.7 | 0.0 | 55.1 | 55.1 | 0.0 |
| 1975 | 82.3 | 81.9 | 0.4 | 65.1 | 65.1 | 0.0 | 79.1 | 79.1 | 0.0 |
| 1976 | 79.8 | 79.8 | 0.0 | 85.4 | 85.4 | 0.0 | 72.7 | 72.2 | 0.5 |
| 1977 | 79.8 | 79.7 | 0.1 | 76.6 | 74.3 | 2.3 | 80.8 | 78.6 | 2.2 |
| 1978 | 93.5 | 93.5 | 0.0 | 75.8 | 75.4 | 0.4 | 72.3 | 72.0 | 0.3 |
| 1979 | 81.8 | 81.8 | 0.0 | 64.7 | 62.8 | 1.9 | 77.8 | 76.6 | 1.2 |
| 1980 | 70.6 | 70.6 | 0.0 | 61.9 | 60.8 | 1.1 | 67.5 | 66.0 | 1.5 |
| 1981 | 83.6 | 79.7 | 3.9 | 72.2 | 72.1 | 0.1 | 79.5 | 79.3 | 0.2 |
| 1982 | 89.0 | 89.0 | 0.0 | 63.8 | 62.6 | 1.2 | 92.8 | 92.7 | 0.1 |
| 1983 | 74.4 | 74.1 | 0.3 | | | | | | |

| Year | Pilgrim 1 * EAF | CF | EAF-CF | Millstone 1 * EAF | CF | EAF-CF | Millstone 2 * EAF | CF | EAF-CF |
|---|---|---|---|---|---|---|---|---|---|
| 1968 | | | | | | | | | |
| 1969 | | | | | | | | | |
| 1970 | | | | | | | | | |
| 1971 | | | | 70.4 | 70.4 | 0.0 | | | |
| 1972 | | | | 54.6 | 54.6 | 0.0 | | | |
| 1973 | 69.6 | 69.6 | 0.0 | 32.5 | 32.5 | 0.0 | | | |
| 1974 | 33.7 | 33.7 | 0.0 | 62.3 | 62.3 | 0.0 | | | |
| 1975 | 44.2 | 44.2 | 0.0 | 67.4 | 67.4 | 0.0 | | | |
| 1976 | 41.2 | 41.2 | 0.0 | 64.8 | 64.8 | 0.0 | 62.3 | 62.3 | 0.0 |
| 1977 | 45.3 | 45.3 | 0.0 | 83.4 | 83.4 | 0.0 | 59.8 | 59.8 | 0.0 |
| 1978 | 74.8 | 74.8 | 0.0 | 80.9 | 80.5 | 0.4 | 62.0 | 62.0 | 0.0 |
| 1979 | 83.0 | 82.8 | 0.2 | 73.4 | 73.1 | 0.3 | 58.4 | 58.5 | -0.1 |
| 1980 | 52.0 | 51.9 | 0.1 | 59.1 | 58.6 | 0.5 | 63.9 | 63.9 | 0.0 |
| 1981 | 59.0 | 58.7 | 0.3 | 44.0 | 43.6 | 0.4 | 80.5 | 79.9 | 0.6 |
| 1982 | 57.5 | 56.0 | 1.5 | 70.5 | 70.5 | 0.0 | 65.7 | 65.7 | 0.0 |
| 1983 | 82.2 | 80.3 | 1.9 | 92.7 | 92.6 | 0.1 | 32.7 | 32.2 | 0.5 |

Source: Electric Power Research Institute, Nuclear Unit Operating Experience: 1980-1982 Update; April 1984, Appendix F (EPRI NP-3480)

* 1981-1983 data from utilities' Performance Program filings.

TABLE 7.2: PWR CAPACITY FACTOR REGRESSIONS

| | Equation 1 | | Equation 2 | |
|---|---|---|---|---|
| | Coef | t-stat | Coef | t-stat |
| CONSTANT | 73.05% | 22.0 | 72.84% | 22.0 |
| MW600 [1] | -12.11% | -4.9 | -11.86% | -4.8 |
| AGE5 [2] | 2.29% | 3.3 | 2.33% | 3.4 |
| AGE_12 [3] | -22.31% | -5.1 | -21.54% | -5.0 |
| OUT [4] | -9.07% | -4.4 | -9.11% | -4.4 |
| W44 [5] | -4.71% | -2.4 | -4.79% | -2.4 |
| YEAR INDICATORS [6] | | | | |
| 1979 | -6.05% | -1.9 | --- | --- |
| 1980 | -6.90% | -2.1 | --- | --- |
| 1981 | -2.78% | -0.9 | --- | --- |
| 1982 | -5.61% | -1.0 | --- | --- |
| 1983 | -7.90% | -2.4 | --- | --- |
| 1984 | 0.03% | 0.0 | --- | --- |
| post-1978 [7] | --- | --- | -4.90% | -2.3 |
| ADJUSTED R-SQ | | 0.204 | | 0.201 |
| F STATISTIC | | 10.2 | | 17.5 |
| OBSERVATIONS [8] | | 396 | | 396 |

Notes: [1] MW600 = 1, if Design Electrical Rating (DER) > 600 MW; 0 otherwise.
[2] AGE5 = minimum of AGE (years from COD to middle of current year), and 5.
[3] AGE_12 = 1, if AGE >= 12; 0 otherwise.
[4] OUT = number of refuelings in year, including other single outages lasting more than 3 months (OUT usually equals 0 or 1).
[5] W44 = 1, if unit contains Westinghouse 44" turbine; 0 otherwise.
[6] Indicator = 1 in this year; 0 otherwise.
[7] AFT78 = 1, if 1979 or later; 0 otherwise.
[8] Full calendar years of PWR operation, 1963-84.

TABLE 7.3: PWR CAPACITY FACTOR PROJECTIONS FOR MILLSTONE 3

| | | | | Equation 1 | | Equation 2 | | |
|---|---|---|---|---|---|---|---|---|
| YEAR | Value of REFUEL | Value of AGES | Value of AGE_12 | Pre-1979 Conds. | Avg. 1979-84 Conds. | Pre-1979 Conds. | Avg. 1979-84 Conds. | Average of four cases |
| | | | | [1] | [2] | [3] | [4] | [5] |
| 1986 | 0 | 0.5 | 0 | 62.08% | 57.21% | 62.14% | 57.24% | 59.67% |
| 1987 | 1 | 1.5 | 0 | 55.30% | 50.44% | 55.36% | 50.46% | 52.89% |
| 1988 | 1 | 2.5 | 0 | 57.59% | 52.73% | 57.69% | 52.79% | 55.20% |
| 1989 | 1 | 3.5 | 0 | 59.89% | 55.02% | 60.02% | 55.11% | 57.51% |
| 1990 | 1 | 4.5 | 0 | 62.18% | 57.31% | 62.35% | 57.44% | 59.82% |
| 1991-1997 | 1 | 5 | 0 | 63.32% | 58.46% | 63.51% | 58.61% | 60.97% |
| 1998-2025 [6] | 1 | 5 | 0.5 | 52.17% | 47.30% | 52.74% | 47.83% | 50.01% |

General note:

All coefficients are from equations in Table 7.2. Calculated for a 1153 MW unit with a General Electric turbine, and a COD of 5/31/86.

Column notes:

[1] Assumes pre-1979 conditions exist in the projection years; therefore, all year indicators are set equal to 0.

[2] Adjusts the projected capacity factor by the average of the coefficients for all of the year indicators.

[3] Assumes pre-1979 conditions exist in the projection years; therefore, AFT78 variable is set equal to 0.

[4] Adjusts the projected capacity factor by the coefficient of the AFT78 variable.

[5] Average of columns [1] through [4].

[6] Assumes Millstone 3 will experience half of the observed decline in capacity factor after age 12 (i.e. AGE_12 = 0.5.)

TABLE 7.4: COMPARISON OF CAPACITY FACTOR PREDICTIONS

| Capacity Factor Predictions | Calendar Years of Experience | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | 1 -[1]- | 2 | 3 | 4 | 5 | 6 | 7-11 | 12 + |
| PLC [2] | 59.7% | 52.9% | 55.2% | 57.5% | 59.8% | 61.0% | 61.0% | 50.0% |
| NU [3] | 59.2% | 62.2% | 64.2% | 64.2% | 64.6% | 65.0% | 70.0% | 70.0% |

As of: 30-Sep-85

| | COD | | Unit Years of Experience in each Calendar Year | | | | | | | Predicted Capacity Factors | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | | | | Actual [4] | NU | PLC [5] |
| Salem 1 | 30-Jun | 77 | 0.51 | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 | 2.76 | 49.7% | 65.7% | 54.0% |
| Zion 1 | 31-Dec | 73 | 0.00 | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 | 6.77 | 55.8% | 67.5% | 54.7% |
| Zion 2 | 17-Sep | 74 | 0.29 | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 | 5.75 | 60.3% | 67.0% | 54.6% |
| Cook 1 | 27-Aug | 75 | 0.35 | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 | 4.76 | 59.5% | 66.7% | 59.1% |
| Cook 2 | 01-Jul | 78 | 0.50 | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 | 1.75 | 62.7% | 65.1% | 58.3% |
| Trojan | 20-May | 76 | 0.62 | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 | 3.76 | 50.9% | 66.1% | 58.9% |
| Sequoyah 1 | 01-Jul | 81 | 0.50 | 1.00 | 1.00 | 1.00 | 0.75 | | | 58.3% | 63.2% | 51.8% |
| Sequoyah 2 | 01-Jun | 82 | 0.59 | 1.00 | 1.00 | 0.75 | | | | 67.5% | 62.7% | 51.1% |
| McGuire 1 | 01-Dec | 81 | 0.08 | 1.00 | 1.00 | 1.00 | 0.75 | | | 50.4% | 63.6% | 51.5% |
| Salem 2 | 13-Oct | 81 | 0.22 | 1.00 | 1.00 | 1.00 | 0.75 | | | 43.2% | 63.5% | 51.6% |
| Average [6] | | | | | | | | | | 56.1% | 65.8% | 55.4% |

Notes:
[1] First partial year.
[2] Projections from column [5] of Table 7.3.
[3] Projections from Exhibit EJF-I-5, page 16 of 26. Capacity factors are adjusted to account for the fact that NU is projecting capacity factors based on 1130 MW capacity rating rather than the full 1153 MW, until the middle of 1990.
[4] Cumulative Net Elec. Energy/Report Period Hours/DER; From NRC Gray Book, Sept. 30, 1985.
[5] Salem 1 and 2, Zion 1 and 2, Sequoyah 1 and 2, and McGuire 1 have Westinghouse 44" turbines. Therefore, the value of the W44 coefficient is added to the projected capacity factor for these plants.
[6] Weighted by experience.

TABLE 7.5: HISTORICAL CAPACITY FACTORS (DER), UNITS SIMILAR TO MILLSTONE 3

| UNIT | DER NET [1] | first year | CAPACITY FACTOR BY CALENDAR YEAR [2] 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| ZION 1 | 1050 | 74 | 37.8% | 53.4% | 51.6% | 54.7% | 73.6% | 60.2% | 70.6% | 67.3% | 51.0% | 43.7% | 61.7% |
| ZION 2 | 1050 | 75 | 52.5% | 50.3% | 68.2% | 73.2% | 51.8% | 57.2% | 57.2% | 56.1% | 67.2% | 64.9% | |
| COOK 1 | 1090 | 76 | 71.1% | 50.1% | 65.8% | 59.3% | 67.5% | 71.0% | 56.1% | 55.4% | 78.9% | | |
| TROJAN | 1130 | 77 | 65.6% | 16.8% | 53.2% | 61.2% | 64.9% | 48.5% | 41.2% | 47.7% | | | |
| SALEM 1 | 1090 | 78 | 47.4% | 21.4% | 59.4% | 64.8% | 42.9% | 56.3% | 22.2% | | | | |
| COOK 2 | 1100 | 79 | 61.8% | 69.3% | 66.3% | 72.6% | 72.8% | 55.5% | | | | | |
| SEQUOYAH 1 | 1148 | 82 | 48.8% | 73.0% | 60.5% | | | | | | | | |
| SALEM 2 | 1115 | 82 | 81.3% | 7.5% | 32.7% | | | | | | | | |
| MCGUIRE 1 | 1180 | 82 | 41.6% | 44.8% | 61.9% | | | | | | | | |
| SEQUOYAH 2 | 1148 | 83 | 66.5% | 63.5% | | | | | | | | | |
| AVERAGES: | | | | | | | | | | | | | |
| ALL UNITS [3] | 1106 | | 57.4% | 51.5% | 58.3% | 64.3% | 62.2% | 58.1% | 49.5% | 56.6% | 65.7% | 54.3% | 61.7% |
| FIRST SIX [3] | 1085 | | 56.0% | 55.8% | 60.7% | 64.3% | 62.2% | 58.1% | 49.5% | 56.6% | 65.7% | 54.3% | 61.7% |
| ADJUSTMENT FOR DEVIATIONS AT SALEM 1 AND TROJAN | | | | | | | | | | | | | |
| ALL UNITS: | | | | | | | | | | | | | |
| Salem/Trojan deviation [4] | | | | 60.1% | | | | | | | | | |
| unit-years [5] | | | | 61 | | | | | | | | | |
| deviation/unit-year | | | | 1.0% | | | | | | | | | |
| ADJUSTED AVERAGE (all units) [5] | | | 56.5% | 48.2% | 57.3% | 63.3% | 61.2% | 57.1% | 48.5% | 55.6% | 64.7% | 53.3% | 60.7% |
| all years | | | 56.4% | | | | | | | | | | |
| >5 years | | | 55.7% | | | | | | | | | | |
| FIRST SIX UNITS: | | | | | | | | | | | | | |
| Salem/Trojan deviation [6] | | | | 73.3% | | | | | | | | | |
| unit-years [5] | | | | 49 | | | | | | | | | |
| deviation/unit-year | | | | 1.5% | | | | | | | | | |
| ADJUSTED AVERAGE (first six) [7] | | | 54.5% | 54.3% | 59.3% | 62.8% | 60.7% | 56.6% | 48.0% | 55.1% | 64.2% | 52.8% | 60.2% |
| all years | | | 57.2% | | | | | | | | | | |
| >5 years | | | 55.2% | | | | | | | | | | |

Notes:
1. Original reported value.
2. Computed from NRC-reported net output and original DER; Grey Book, 1/85.
3. Values for year 2 for Trojan and Salem 1 are excluded from averages.
4. 2*51.5% - 16.8% - 21.4%.
5. Excludes Salem 1 and Trojan second years.
6. 2*55.8% - 16.8% - 21.4%.
7. Simple averages minus Salem/Trojan deviation per unit/year.

TABLE 7.6: RESULTS OF REGRESSIONS ON O&M DATA (All plants in dataset)

| | Equation 1 | | Equation 2 | | Equation 3 | | Equation 4 | | Equation 5 | |
|---|---|---|---|---|---|---|---|---|---|---|
| | Coef | t-stat | Coef | t-stat | Coef | t-stat | Coef | t-stat | Coef | t-stat |
| CONSTANT | -2.12 | -7.94 | -2.13 | -8.15 | -2.12 | -7.94 | -2.50 | -9.60 | -2.19 | -8.77 |
| ln(MW) [2] | 0.53 | 21.15 | 0.52 | 21.17 | -- | -- | -- | -- | -- | -- |
| ln(UNITS) | 0.03 | 0.56 | -- | -- | 0.56 | 12.27 | -- | -- | 0.70 | 15.34 |
| YEAR [3] | 0.11 | 28.62 | 0.11 | 28.66 | 0.11 | 28.62 | 0.11 | 28.87 | 0.11 | 31.24 |
| UNITS | -- | -- | 0.03 | 0.96 | -- | -- | 0.35 | 12.53 | -- | -- |
| ln(MW/unit) | -- | -- | -- | -- | 0.53 | 21.15 | 0.53 | 21.36 | 0.48 | 20.23 |
| NE [4] | -- | -- | -- | -- | -- | -- | -- | -- | 0.28 | 8.78 |
| Adjusted R-sq. | | 0.85 | | 0.85 | | 0.85 | | 0.85 | | 0.87 |
| F statistic | | 1032.2 | | 1033.5 | | 1032.2 | | 1043.9 | | 904.3 |

Notes: [1] The dependent variable in each equation is ln(non-fuel O&M in 1983$)

[2] MW = number of MegaWatts in Maximum Generator Nameplate (MGN).

[3] YEAR = Calendar Year - 1900; e.g., 1985 = 85.

[4] NE is a dummy variable which measures whether the plant is located in the Northeast Region (defined as Handy Whitman's North Atlantic Region), where Millstone 3 is located. NE = 1 if located in Northeast Region, 0 if elsewhere.

TABLE 7.7: RESULTS OF REGRESSIONS ON O&M DATA (All plants > 300 MW)

| | Equation 1 | | Equation 2 | | Equation 3 | | Equation 4 | | Equation 5 | |
|---|---|---|---|---|---|---|---|---|---|---|
| | Coef | t-stat | Coef | t-stat | Coef | t-stat | Coef | t-stat | Coef | t-stat |
| CONSTANT | -4.38 | -9.43 | -4.16 | -9.77 | -4.38 | -9.43 | -4.81 | -10.57 | -4.46 | -10.30 |
| ln(MW) [2] | 0.62 | 10.13 | 0.58 | 9.85 | -- | -- | -- | -- | -- | -- |
| ln(UNITS) | -0.07 | -0.85 | -- | -- | 0.55 | 12.93 | -- | -- | 0.67 | 15.88 |
| YEAR [3] | 0.13 | 28.31 | 0.13 | 28.36 | 0.13 | 28.31 | 0.13 | 28.67 | 0.13 | 30.73 |
| UNITS | -- | -- | 0.00 | -0.09 | -- | -- | 0.35 | 13.31 | -- | -- |
| ln(MW/unit) | -- | -- | -- | -- | 0.62 | 10.13 | 0.63 | 10.33 | 0.59 | 10.34 |
| NE [4] | -- | -- | -- | -- | -- | -- | -- | -- | 0.26 | 8.31 |
| Adjusted R-sq. | | 0.77 | | 0.77 | | 0.77 | | 0.78 | | 0.80 |
| F statistic | | 519.4 | | 518.3 | | 519.4 | | 530.0 | | 465.4 |

Notes: [1] The dependent variable in each equation is ln(non-fuel O&M in 1983$)

[2] MW = number of MegaWatts in Maximum Generator Nameplate (MGN).

[3] YEAR = Calendar Year - 1900; e.g., 1985 = 85.

[4] NE is a dummy variable which measures whether the plant is located in the Northeast Region (defined as Handy Whitman's North Atlantic Region), where Millstone 3 is located. NE = 1 if located in Northeast Region, 0 if elsewhere.

TABLE 7.8: PROJECTIONS OF ANNUAL NON-FUEL O&M EXPENSE FOR MILLSTONE 3 ($ million)

| Year | NU Projections | From Equation #5 (Table 7.7) [A] | | | | From Equation #5 (Table 7.6) [B] | | | |
|---|---|---|---|---|---|---|---|---|---|
| | | Compund real growth | | Linear real growth | | Compund real growth | | Linear real growth | |
| | nominal | 1983$ | nominal | 1983$ | nominal | 1983$ | nominal | 1983$ | nominal |
| | [1] | [2] | [3] | [4] | [5] | [6] | [7] | [8] | [9] |
| 1986 | $47 | $89 | $105 | $89 | $105 | $76 | $89 | $76 | $89 |
| 1987 | $72 | $102 | $127 | $102 | $127 | $85 | $105 | $85 | $105 |
| 1988 | $87 | $117 | $152 | $115 | $150 | $95 | $124 | $94 | $123 |
| 1989 | $90 | $133 | $184 | $128 | $176 | $106 | $146 | $103 | $142 |
| 1990 | $87 | $152 | $221 | $140 | $204 | $119 | $173 | $112 | $163 |
| 1991 | $102 | $174 | $266 | $153 | $235 | $133 | $204 | $121 | $186 |
| 1992 | $109 | $198 | $322 | $166 | $269 | $149 | $243 | $130 | $212 |
| 1993 | $116 | $226 | $390 | $178 | $307 | $167 | $288 | $139 | $240 |
| 1994 | $124 | $258 | $472 | $191 | $349 | $187 | $342 | $148 | $271 |
| 1995 | $132 | $295 | $571 | $204 | $395 | $209 | $406 | $157 | $305 |
| 1996 | $140 | $337 | $692 | $216 | $444 | $234 | $481 | $166 | $341 |
| 1997 | $149 | $384 | $837 | $229 | $498 | $262 | $571 | $175 | $382 |
| 1998 | $159 | $439 | $1,013 | $242 | $558 | $294 | $678 | $184 | $425 |
| 1999 | $169 | $501 | $1,226 | $254 | $622 | $329 | $805 | $193 | $473 |
| 2000 | $180 | $572 | $1,483 | $267 | $692 | $368 | $955 | $203 | $525 |
| 2001 | $192 | $653 | $1,795 | $280 | $769 | $413 | $1,134 | $212 | $581 |
| 2002 | $205 | $746 | $2,173 | $292 | $852 | $462 | $1,346 | $221 | $643 |
| 2003 | $218 | $851 | $2,629 | $305 | $942 | $517 | $1,597 | $230 | $709 |
| 2004 | $232 | $972 | $3,182 | $318 | $1,040 | $579 | $1,896 | $239 | $781 |
| 2005 | $247 | $1,110 | $3,851 | $330 | $1,146 | $648 | $2,250 | $248 | $860 |
| 2006 | $263 | $1,267 | $4,661 | $343 | $1,262 | $726 | $2,670 | $257 | $945 |
| 2007 | $280 | $1,447 | $5,640 | $356 | $1,387 | $813 | $3,169 | $266 | $1,037 |
| 2008 | $298 | $1,652 | $6,826 | $368 | $1,523 | $910 | $3,761 | $275 | $1,136 |
| 2009 | $318 | $1,886 | $8,261 | $381 | $1,670 | $1,019 | $4,464 | $284 | $1,244 |
| 2010 | $338 | $2,153 | $9,997 | $394 | $1,829 | $1,141 | $5,298 | $293 | $1,361 |
| 2011 | $360 | $2,458 | $12,099 | $407 | $2,001 | $1,278 | $6,289 | $302 | $1,487 |
| 2012 | $384 | $2,806 | $14,642 | $419 | $2,187 | $1,431 | $7,464 | $311 | $1,624 |
| 2013 | $409 | $3,204 | $17,720 | $432 | $2,388 | $1,602 | $8,858 | $320 | $1,771 |
| 2014 | $435 | $3,658 | $21,444 | $445 | $2,606 | $1,793 | $10,514 | $329 | $1,931 |
| 2015 | $464 | $4,177 | $25,952 | $457 | $2,841 | $2,008 | $12,478 | $338 | $2,103 |
| 2016 | $494 | $4,768 | $31,408 | $470 | $3,095 | $2,248 | $14,810 | $347 | $2,288 |
| 2017 | $526 | $5,444 | $38,010 | $483 | $3,369 | $2,518 | $17,578 | $357 | $2,489 |
| 2018 | $560 | $6,215 | $45,999 | $495 | $3,665 | $2,819 | $20,862 | $366 | $2,705 |
| 2019 | $597 | $7,096 | $55,669 | $508 | $3,985 | $3,156 | $24,761 | $375 | $2,939 |
| 2020 | $635 | $8,102 | $67,371 | $521 | $4,329 | $3,534 | $29,388 | $384 | $3,190 |
| 2021 | $677 | $9,250 | $81,532 | $533 | $4,701 | $3,957 | $34,879 | $393 | $3,462 |
| 2022 | $721 | $10,561 | $98,671 | $546 | $5,101 | $4,431 | $41,397 | $402 | $3,754 |
| 2023 | $767 | $12,057 | $119,412 | $559 | $5,533 | $4,961 | $49,132 | $411 | $4,069 |
| 2024 | $817 | $13,766 | $144,514 | $571 | $5,998 | $5,555 | $58,313 | $420 | $4,408 |

Notes: [1] From: Exhibit EJF-I-5, Page 16 of 26.
[2],[6] MW = 1194, UNITS = 1, NE = 1.
[3],[5],[7],[9] Assume 5.5% inflation for 1984 - 1991, and 6.0% thereafter (IR-AG-32, Table I).
[4],[8] From 1988 on, projections increase by the amount of the difference between the 1986 and 1987 projections.
[A] Regressions originally performed on data from all plants > 300 MW.
[B] Regressions originally performed on data from all plants in database.

TABLE 7.9: COMPARISON OF O&M PROJECTIONS WITH EXPERIENCE OF MILLSTONE 1 AND 2

| | Millstone 1 | | | Millstone 2 | | |
|---|---|---|---|---|---|---|
| | Actual | Projected | Residual | Actual | Projected | Residual |
| 1972 | $17 | $12 | $5 | | | |
| 1973 | $16 | $13 | $2 | | | |
| 1974 | $18 | $15 | $4 | | | |
| 1975 | $21 | $16 | $4 | | | |
| 1976 | $23 | $18 | $4 | $18 | $21 | ($4) |
| 1977 | $19 | $21 | ($1) | $27 | $24 | $3 |
| 1978 | $24 | $23 | $1 | $32 | $27 | $5 |
| 1979 | $30 | $26 | $5 | $29 | $30 | ($1) |
| 1980 | $30 | $29 | $1 | $36 | $34 | $3 |
| 1981 | $37 | $32 | $4 | $32 | $38 | ($6) |
| 1982 | $35 | $36 | ($1) | $47 | $42 | $5 |
| 1983 | $44 | $41 | $3 | $56 | $47 | $9 |
| 1984 | $36 | $45 | ($10) | $48 | $53 | ($5) |
| | Average (1972-84) | | $2 | | | |
| | Average (1976-84) | | $1 | Average (1976-84) | | $1 |

Notes: Projections are based on Equation #5, Table 7.6.
See Appendix D for actual O&M data.
Residual = Actual - Projected.

TABLE 7.10: NUCLEAR CAPITAL ADDITIONS

| | Year | Averages by Year (in $/kw-yr) All plants | Single units, > 800 MW |
|---|---|---|---|
| All years before and including: | 1972 | $1.43 | |
| | 1973 | $10.87 | $38.90 |
| | 1974 | $11.07 | $26.82 |
| | 1975 | $8.71 | $19.72 |
| | 1976 | $15.07 | $2.98 |
| | 1977 | $19.91 | $12.78 |
| | 1978 | $17.77 | $25.94 |
| | 1979 | $14.82 | $16.75 |
| | 1980 | $27.73 | $27.97 |
| | 1981 | $31.66 | $28.33 |
| | 1982 | $29.06 | $24.80 |
| | 1983 | $29.78 | $26.42 |
| | 1984 | $42.88 | $34.45 |
| Overall Average: | | $20.74 | $23.37 |
| (# of obs.) | | 520 | 127 |
| 1978-84 Average: | | $27.69 | $26.49 |
| (# of obs.) | | 314 | 97 |
| 1980-84 Average: | | $32.29 | $28.80 |
| (# of obs.) | | 224 | 67 |

TABLE 7.11: PROJECTIONS OF CAPITAL ADDITIONS COSTS FOR MILLSTONE 3 ($million)

| Year | NU Capital Additions Budget [1] | Extrapolation of Recent Historical Average [2] | Projections from Regression Analysis [3] |
|---|---|---|---|
| Capital Additions for the Plant in 1983 $: | | $32.28 | $32.74 |
| 1986 | $10.03 | $36.65 | $37.17 |
| 1987 | $20.06 | $39.04 | $39.58 |
| 1988 | $20.06 | $41.57 | $42.16 |
| 1989 | $20.06 | $44.28 | $44.90 |
| 1990 | $20.06 | $47.15 | $47.82 |
| 1991 | $20.06 | $50.46 | $51.16 |
| 1992 | $20.06 | $53.99 | $54.74 |
| 1993 | $30.09 | $57.77 | $58.58 |
| 1994 | $30.09 | $61.81 | $62.68 |
| 1995 | $30.09 | $66.14 | $67.06 |
| 1996 | $30.09 | $70.77 | $71.76 |
| 1997 | $30.09 | $75.72 | $76.78 |
| 1998 | $30.09 | $81.02 | $82.16 |
| 1999 | $30.09 | $86.69 | $87.91 |
| 2000 | $30.09 | $92.76 | $94.06 |
| 2001 | $20.06 | $99.25 | $100.65 |
| 2002 | $20.06 | $106.20 | $107.69 |
| 2003 | $20.06 | $113.64 | $115.23 |
| 2004 | $10.03 | $121.59 | $123.30 |
| 2005 | $10.03 | $130.10 | $131.93 |
| 2006 | $0.00 | $139.21 | $141.16 |
| 2007 | $0.00 | $148.95 | $151.04 |
| 2008 | $0.00 | $159.38 | $161.62 |
| 2009 | $0.00 | $170.54 | $172.93 |
| 2010 | $0.00 | $182.47 | $185.03 |
| 2011 | $0.00 | $195.25 | $197.99 |
| 2012 | $0.00 | $208.91 | $211.85 |
| 2013 | $0.00 | $223.54 | $226.67 |
| 2014 | $0.00 | $239.19 | $242.54 |
| 2015 | $0.00 | $255.93 | $259.52 |
| 2016 | $0.00 | $273.84 | $277.69 |
| 2017 | $0.00 | $293.01 | $297.12 |
| 2018 | $0.00 | $313.52 | $317.92 |
| 2019 | $0.00 | $335.47 | $340.18 |
| 2020 | $0.00 | $358.95 | $363.99 |
| 2021 | $0.00 | $384.08 | $389.47 |
| 2022 | $0.00 | $410.97 | $416.73 |
| 2023 | $0.00 | $439.73 | $445.90 |
| 2024 | $0.00 | $470.51 | $477.12 |

NOTES: [1] From Data Request AG-2, Q-AG 2-31, Page 2 of 2; Millstone 3 Projected Capital Additions.

[2] $28/kW in 1983$, multiplied by 1153 MW MGN. Escalated to 1985 dollars using the Handy-Whitman cost index. Escalated from 1986-91 by 6.5% and by 7% therafter (Q-AG 2-138, page 3 of 10).

[3] Projections from regression analysis on capital additions, which is fully described in Appendix F. Escalated in the same way as Column 2.

TABLE 7.12: COMPARISON OF CAPITAL ADDITIONS PROJECTIONS WITH EXPERIENCE OF MILLSTONE 1 AND 2

| | Millstone 1 | | | Millstone 2 | | |
|---|---|---|---|---|---|---|
| | Actual | Projected | Residual | Actual | Projected | Residual |
| 1972 | $1 | $25 | ($24) | | | |
| 1973 | $3 | $25 | ($22) | | | |
| 1974 | ($0) | $25 | ($25) | | | |
| 1975 | $1 | $25 | ($24) | | | |
| 1976 | $43 | $25 | $18 | $13 | $29 | ($16) |
| 1977 | $4 | $25 | ($21) | $35 | $29 | $6 |
| 1978 | $18 | $25 | ($7) | $22 | $29 | ($7) |
| 1979 | $18 | $25 | ($7) | $1 | $29 | ($28) |
| 1980 | $18 | $25 | ($7) | $16 | $29 | ($13) |
| 1981 | $91 | $25 | $66 | $20 | $29 | ($8) |
| 1982 | $30 | $25 | $5 | $35 | $29 | $6 |
| 1983 | $7 | $25 | ($18) | $29 | $29 | $0 |
| 1984 | $17 | $25 | ($8) | $8 | $29 | ($21) |
| | Average (1972-84) | | ($6) | | | |
| | Average (1976-84) | | $2 | Average (1976-84) | | ($9) |

Notes: Projections are based on regression analysis described in Appendix ??.
See Appendix B for actual Capital Additions data.
Residual = Actual - Projected.

Table 9.1: USEFUL AND USELESS WMECo RETAIL PORTIONS OF MILLSTONE 3 ($Million)

| | | | | | |
|---|---|---|---|---|---|
| 1. Case | I | II | III | IV | V |
| 2. Description | NU | Historical Capacity Factor | Historical Operating Cost & Capacity Factor | PLC Avoided Capacity Cost | Current DRI Fuel |
| 3. Present Value of Useful Investment | $264.3 | $188.0 | ($32.1) | $253.1 | 213.2 |
| 4. Percent of Investment which is Useful | 67.22% | 47.81% | -8.16% | 64.37% | 54.22% |
| 5. Useful Portion of WMECo Allocation of Total NU Investment | $251.13 | $178.63 | ($30.50)* | $240.49 | $202.58 |
| 6. Useless Portion of WMECo Allocation | $122.48 | $194.98 | $404.11 | $133.12 | $171.03 |

Notes:
* No part of the investment is useful; the useless portion is greater than the investment itself.
3. Present Value of "Benefits minus Operating Costs", Tables 6.2 - 6.6.
4. [3] / Present Value of full recovery of NU's investment.($393.2)
5. [4] * 15.3% * 98.10% * NU share of Total Investment ($2489.2)
6. (1 - [4]) * 15.3% * 98.10% * $2489.2

TABLE 9.2: DERIVATION OF COST RECOVERY, USEFUL PLANT, PLC CAPACITY FACTOR (Case II)

| Year | NU Carrying Charges Full Recovery | NU Carrying Charges 47.81% Recovery | Carrying Charges Real-levelized at 6% Inflation | Deferrals This Year | Carrying Charges | Cumulative Deferrals |
|---|---|---|---|---|---|---|
| ---- | --[1]--- | --[2]--- | -----[3]------- | --[4]--- | --[5]-- | --------- |
| 1986 | $24.0 | $11.5 | $12.8 | ($1.3) | $0.0 | ($1.3) |
| 1987 | $53.0 | $25.3 | $13.6 | $11.8 | ($0.1) | $10.3 |
| 1988 | $77.0 | $36.8 | $14.4 | $22.4 | $1.0 | $33.8 |
| 1989 | $83.0 | $39.7 | $15.2 | $24.4 | $3.3 | $61.6 |
| 1990 | $78.0 | $37.3 | $16.2 | $21.1 | $6.1 | $88.8 |
| 1991 | $73.0 | $34.9 | $17.1 | $17.8 | $8.7 | $115.3 |
| 1992 | $71.0 | $33.9 | $18.1 | $15.8 | $11.3 | $142.4 |
| 1993 | $65.0 | $31.1 | $19.2 | $11.8 | $14.0 | $168.3 |
| 1994 | $64.0 | $30.6 | $20.4 | $10.2 | $16.6 | $195.1 |
| 1995 | $52.0 | $24.9 | $21.6 | $3.2 | $19.2 | $217.5 |
| 1996 | $47.0 | $22.5 | $22.9 | ($0.4) | $21.4 | $238.5 |
| 1997 | $46.0 | $22.0 | $24.3 | ($2.3) | $23.5 | $259.6 |
| 1998 | $45.0 | $21.5 | $25.7 | ($4.2) | $25.5 | $281.0 |
| 1999 | $43.0 | $20.6 | $27.3 | ($6.7) | $27.6 | $301.9 |
| 2000 | $40.0 | $19.1 | $28.9 | ($9.8) | $29.7 | $321.8 |
| 2001 | $40.0 | $19.1 | $30.7 | ($11.5) | $31.7 | $341.9 |
| 2002 | $38.0 | $18.2 | $32.5 | ($14.3) | $33.6 | $361.2 |
| 2003 | $38.0 | $18.2 | $34.4 | ($16.3) | $35.5 | $380.5 |
| 2004 | $35.0 | $16.7 | $36.5 | ($19.8) | $37.4 | $398.1 |
| 2005 | $35.0 | $16.7 | $38.7 | ($22.0) | $39.2 | $415.3 |
| 2006 | $34.0 | $16.3 | $41.0 | ($24.8) | $40.9 | $431.4 |
| 2007 | $34.0 | $16.3 | $43.5 | ($27.2) | $42.5 | $446.7 |
| 2008 | $32.0 | $15.3 | $46.1 | ($30.8) | $44.0 | $459.8 |
| 2009 | $30.0 | $14.3 | $48.9 | ($34.5) | $45.2 | $470.5 |
| 2010 | $29.0 | $13.9 | $51.8 | ($37.9) | $46.3 | $478.9 |
| 2011 | $28.0 | $13.4 | $54.9 | ($41.5) | $47.1 | $484.5 |
| 2012 | $27.0 | $12.9 | $58.2 | ($45.3) | $47.7 | $486.9 |
| 2013 | $27.0 | $12.9 | $61.7 | ($48.8) | $47.9 | $486.0 |
| 2014 | $25.0 | $12.0 | $65.4 | ($53.4) | $47.8 | $480.4 |
| 2015 | $25.0 | $12.0 | $69.3 | ($57.4) | $47.3 | $470.3 |
| 2016 | $23.0 | $11.0 | $73.5 | ($62.5) | $46.3 | $454.1 |
| 2017 | $22.0 | $10.5 | $77.9 | ($67.4) | $44.7 | $431.4 |
| 2018 | $21.0 | $10.0 | $82.6 | ($72.5) | $42.5 | $401.4 |
| 2019 | $19.0 | $9.1 | $87.5 | ($78.4) | $39.5 | $362.4 |
| 2020 | $19.0 | $9.1 | $92.8 | ($83.7) | $35.7 | $314.4 |
| 2021 | $19.0 | $9.1 | $98.3 | ($89.2) | $30.9 | $256.1 |
| 2022 | $16.0 | $7.7 | $104.2 | ($96.6) | $25.2 | $184.7 |
| 2023 | $16.0 | $7.7 | $110.5 | ($102.8) | $18.2 | $100.1 |
| 2024 | $15.0 | $7.2 | $117.1 | ($109.9) | $9.8 | $0.0 |
| NPV at 9.84%: | | $250.0 | $250.0 | | | |
| NPV of $1 in 1986, escalated at 6% to 2024: | | $19.5 | $12.8 | | | |

Notes:
1. From Table 6.2, Column [2].
2. [1] x Percent Useful Investment (See Table 9.1).
3. The NPV of Column [2] at 9.84% was divided by the NPV (at 9.84%) of $1 escalated at 6% from 1986 to 2024. This quotient was then escalated at 6% from 1986.
4. [2]-[3].
5. 9.84% * Cumulative Deferrals from previous year.

TABLE 9.3: RECOMMENDED CAPITAL COST RECOVERY, NU OPERATING COST ASSUMPTIONS, PLC CAPACITY FACTORS (Case II)

| Year | UMECo Projection Operating Costs | Recovery of Useful Costs | Recovery of Useless Investment | Total Costs | Total Benefits | Net Benefits | Cumulative Total | Net Benefits Discounted At 14.05% |
|---|---|---|---|---|---|---|---|---|
| ---- | -----[1]------ | ---[2]--- | ---[3]----- | -[4]- | --[5]--- | ---[6]-- | ---[7]---- | ----[8]----- |
| 1986 | $7.0 | $12.8 | $13.0 | $32.8 | $12.1 | ($20.7) | ($20.7) | ($18.1) |
| 1987 | $10.0 | $13.6 | $13.0 | $36.6 | $16.6 | ($19.9) | ($40.6) | ($33.4) |
| 1988 | $13.0 | $14.4 | $13.0 | $40.4 | $16.5 | ($23.9) | ($64.5) | ($49.5) |
| 1989 | $14.0 | $15.2 | $13.0 | $42.2 | $21.0 | ($21.3) | ($85.8) | ($62.1) |
| 1990 | $14.0 | $16.2 | $13.0 | $43.1 | $20.5 | ($22.7) | ($108.4) | ($73.9) |
| 1991 | $15.0 | $17.1 | $13.0 | $45.1 | $25.0 | ($20.1) | ($128.6) | ($83.0) |
| 1992 | $18.0 | $18.1 | $13.0 | $49.1 | $28.7 | ($20.5) | ($149.0) | ($91.2) |
| 1993 | $19.0 | $19.2 | $13.0 | $51.2 | $37.5 | ($13.7) | ($162.8) | ($96.0) |
| 1994 | $19.0 | $20.4 | $13.0 | $52.4 | $44.9 | ($7.5) | ($170.3) | ($98.3) |
| 1995 | $22.0 | $21.6 | $13.0 | $56.6 | $59.5 | $2.9 | ($167.4) | ($97.5) |
| 1996 | $23.0 | $22.9 | $13.0 | $58.9 | $67.9 | $9.0 | ($158.4) | ($95.4) |
| 1997 | $25.0 | $24.3 | $13.0 | $62.3 | $77.7 | $15.4 | ($143.0) | ($92.2) |
| 1998 | $27.0 | $25.7 | $13.0 | $65.7 | $83.3 | $17.6 | ($125.4) | ($89.0) |
| 1999 | $29.0 | $27.3 | $13.0 | $69.3 | $79.2 | $9.9 | ($115.5) | ($87.4) |
| 2000 | $31.0 | $28.9 | $13.0 | $72.9 | $86.4 | $13.4 | ($102.1) | ($85.6) |
| 2001 | $33.0 | $30.7 | | $63.7 | $88.4 | $24.7 | ($77.3) | ($82.6) |
| 2002 | $35.0 | $32.5 | | $67.5 | $86.4 | $18.9 | ($58.4) | ($80.5) |
| 2003 | $38.0 | $34.4 | | $72.4 | $94.8 | $22.3 | ($36.1) | ($78.4) |
| 2004 | $40.0 | $36.5 | | $76.5 | $102.7 | $26.2 | ($9.9) | ($76.3) |
| 2005 | $42.0 | $38.7 | | $80.7 | $111.8 | $31.1 | $21.1 | ($74.0) |
| 2006 | $44.0 | $41.0 | | $85.0 | $121.9 | $36.8 | $58.0 | ($71.7) |
| 2007 | $49.0 | $43.5 | | $92.5 | $134.6 | $42.1 | $100.1 | ($69.4) |
| 2008 | $50.0 | $46.1 | | $96.1 | $146.7 | $50.6 | $150.7 | ($66.9) |
| 2009 | $54.0 | $48.9 | | $102.9 | $157.1 | $54.2 | $204.9 | ($64.6) |
| 2010 | $58.0 | $51.8 | | $109.8 | $158.9 | $49.1 | $254.0 | ($62.8) |
| 2011 | $64.0 | $54.9 | | $118.9 | $170.0 | $51.1 | $305.1 | ($61.1) |
| 2012 | $67.0 | $58.2 | | $125.2 | $183.5 | $58.3 | $363.5 | ($59.4) |
| 2013 | $73.0 | $61.7 | | $134.7 | $188.6 | $53.9 | $417.4 | ($58.1) |
| 2014 | $78.0 | $65.4 | | $143.4 | $202.6 | $59.2 | $476.6 | ($56.7) |
| 2015 | $83.0 | $69.3 | | $152.3 | $217.8 | $65.5 | $542.0 | ($55.5) |
| 2016 | $89.0 | $73.5 | | $162.5 | $234.4 | $71.9 | $614.0 | ($54.3) |
| 2017 | $95.0 | $77.9 | | $172.9 | $252.2 | $79.3 | $693.3 | ($53.1) |
| 2018 | $102.0 | $82.6 | | $184.6 | $297.4 | $112.8 | $806.1 | ($51.6) |
| 2019 | $109.0 | $87.5 | | $196.5 | $344.9 | $148.4 | $954.5 | ($49.9) |
| 2020 | $116.0 | $92.8 | | $208.8 | $394.3 | $185.5 | $1,140.1 | ($48.0) |
| 2021 | $125.0 | $98.3 | | $223.3 | $430.0 | $206.7 | $1,346.7 | ($46.2) |
| 2022 | $134.0 | $104.2 | | $238.2 | $468.0 | $229.8 | $1,576.5 | ($44.5) |
| 2023 | $144.0 | $110.5 | | $254.5 | $490.6 | $236.1 | $1,812.6 | ($42.9) |
| 2024 | $155.0 | $117.1 | | $272.1 | $522.4 | $250.3 | $2,062.9 | ($41.4) |

NOTES:
1. O&M Costs + Capital Additions + Property Taxes.
2. From Table 9.2, Column [3].
3. See Table 9.1. Useless Portion divided over 15 years.
4. [1] + [2] + [3].
5. From Table 6.3, Column 2.

TABLE 9.4: DERIVATION OF COST RECOVERY, USEFUL PLANT, NU ASSUMPTIONS (Case I)

| Year | NU Carrying Charges Full Recovery | NU Carrying Charges 67.2% Recovery | Carrying Charges Real-levelized at 6% Inflation | Deferrals This Year | Carrying Charges | Cumulative Deferrals |
|---|---|---|---|---|---|---|
| ---- | --[1]--- | --[2]--- | -----[3]------- | --[4]--- | --[5]-- | ---[6]--- |
| 1986 | $24.0 | $16.1 | $18.0 | ($1.9) | $0.0 | ($1.9) |
| 1987 | $53.0 | $35.6 | $19.1 | $16.6 | ($0.2) | $14.5 |
| 1988 | $77.0 | $51.8 | $20.2 | $31.5 | $1.4 | $47.5 |
| 1989 | $83.0 | $55.8 | $21.4 | $34.4 | $4.7 | $86.5 |
| 1990 | $78.0 | $52.4 | $22.7 | $29.7 | $8.5 | $124.8 |
| 1991 | $73.0 | $49.1 | $24.1 | $25.0 | $12.3 | $162.1 |
| 1992 | $71.0 | $47.7 | $25.5 | $22.2 | $15.9 | $200.2 |
| 1993 | $65.0 | $43.7 | $27.0 | $16.6 | $19.7 | $236.6 |
| 1994 | $64.0 | $43.0 | $28.7 | $14.4 | $23.3 | $274.2 |
| 1995 | $52.0 | $35.0 | $30.4 | $4.6 | $27.0 | $305.8 |
| 1996 | $47.0 | $31.6 | $32.2 | ($0.6) | $30.1 | $335.2 |
| 1997 | $46.0 | $30.9 | $34.1 | ($3.2) | $33.0 | $365.0 |
| 1998 | $45.0 | $30.2 | $36.2 | ($5.9) | $35.9 | $395.0 |
| 1999 | $43.0 | $28.9 | $38.4 | ($9.5) | $38.9 | $424.4 |
| 2000 | $40.0 | $26.9 | $40.7 | ($13.8) | $41.8 | $452.4 |
| 2001 | $40.0 | $26.9 | $43.1 | ($16.2) | $44.5 | $480.7 |
| 2002 | $38.0 | $25.5 | $45.7 | ($20.1) | $47.3 | $507.8 |
| 2003 | $38.0 | $25.5 | $48.4 | ($22.9) | $50.0 | $534.9 |
| 2004 | $35.0 | $23.5 | $51.3 | ($27.8) | $52.6 | $559.7 |
| 2005 | $35.0 | $23.5 | $54.4 | ($30.9) | $55.1 | $583.9 |
| 2006 | $34.0 | $22.9 | $57.7 | ($34.8) | $57.5 | $606.5 |
| 2007 | $34.0 | $22.9 | $61.1 | ($38.3) | $59.7 | $627.9 |
| 2008 | $32.0 | $21.5 | $64.8 | ($43.3) | $61.8 | $646.4 |
| 2009 | $30.0 | $20.2 | $68.7 | ($48.5) | $63.6 | $661.5 |
| 2010 | $29.0 | $19.5 | $72.8 | ($53.3) | $65.1 | $673.3 |
| 2011 | $28.0 | $18.8 | $77.2 | ($58.4) | $66.2 | $681.2 |
| 2012 | $27.0 | $18.1 | $81.8 | ($63.7) | $67.0 | $684.5 |
| 2013 | $27.0 | $18.1 | $86.7 | ($68.6) | $67.4 | $683.3 |
| 2014 | $25.0 | $16.8 | $91.9 | ($75.1) | $67.2 | $675.4 |
| 2015 | $25.0 | $16.8 | $97.5 | ($80.6) | $66.5 | $661.2 |
| 2016 | $23.0 | $15.5 | $103.3 | ($87.8) | $65.1 | $638.4 |
| 2017 | $22.0 | $14.8 | $109.5 | ($94.7) | $62.8 | $606.5 |
| 2018 | $21.0 | $14.1 | $116.1 | ($101.9) | $59.7 | $564.3 |
| 2019 | $19.0 | $12.8 | $123.0 | ($110.3) | $55.5 | $509.5 |
| 2020 | $19.0 | $12.8 | $130.4 | ($117.6) | $50.1 | $442.0 |
| 2021 | $19.0 | $12.8 | $138.2 | ($125.5) | $43.5 | $360.1 |
| 2022 | $16.0 | $10.8 | $146.5 | ($135.8) | $35.4 | $259.7 |
| 2023 | $16.0 | $10.8 | $155.3 | ($144.6) | $25.6 | $140.7 |
| 2024 | $15.0 | $10.1 | $164.6 | ($154.6) | $13.8 | $0.0 |
| NPV at 9.84%: | | $351.5 | $351.5 | | | |
| NPV of $1 in 1986, escalated at 6% to 2024: | | $19.5 | $18.0 | | | |

Notes:
1. From Table 6.2, Column [2].
2. [1] x Percent Useful Investment (See Table 9.1).
3. The NPV of Column [2] at 9.84% was divided by the NPV (at 9.84%) of $1 inflated at 6% from 1986 to 2024. This quotient was then escalated at 6% from 1986.
4. [2]-[3].
5. 9.84% * Cumulative Deferrals from previous year.

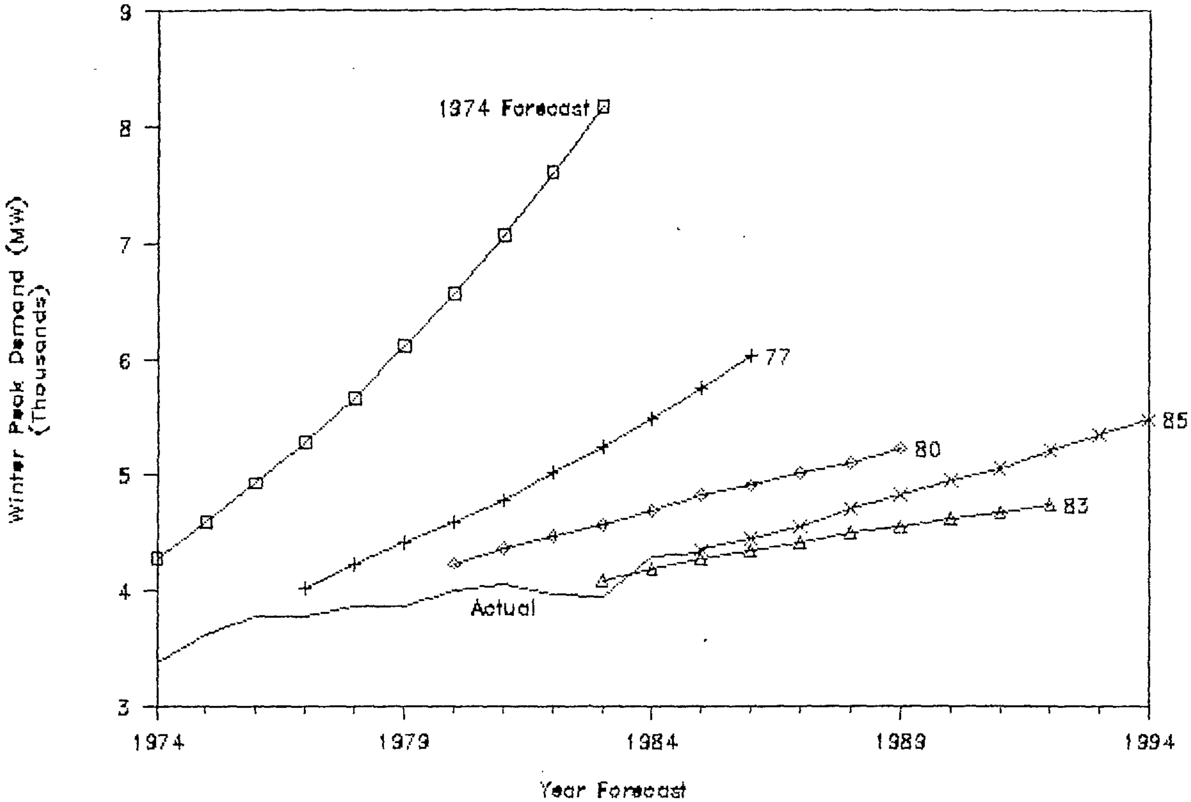
TABLE 9.5: RECOMMENDED CAPITAL COST RECOVERY, NU ASSUMPTIONS (Case I)

| Year | WMECo Projection Operating Costs ------[1]------- | Recovery of Useful Costs ---[2]---- | Recovery of Useless Investment ---[3]---- | Total Costs -[4]-- | Total Benefits ---[5]--- | Net Benefits ---[6]-- | Cumulative Total ---[7]---- | Net Benefits Discounted At 14.05% ---[8]------ |
|---|---|---|---|---|---|---|---|---|
| 1986 | $7.0 | $18.0 | $8.2 | $33.2 | $12.2 | ($21.0) | ($21.0) | ($18.4) |
| 1987 | $10.0 | $19.1 | $8.2 | $37.2 | $19.6 | ($17.6) | ($38.6) | ($31.9) |
| 1988 | $13.0 | $20.2 | $8.2 | $41.4 | $19.3 | ($22.1) | ($60.7) | ($46.8) |
| 1989 | $14.0 | $21.4 | $8.2 | $43.6 | $23.6 | ($20.0) | ($80.6) | ($58.6) |
| 1990 | $14.0 | $22.7 | $8.2 | $44.9 | $22.2 | ($22.7) | ($103.3) | ($70.4) |
| 1991 | $15.0 | $24.1 | $8.2 | $47.2 | $26.6 | ($20.6) | ($123.9) | ($79.7) |
| 1992 | $18.0 | $25.5 | $8.2 | $51.7 | $32.9 | ($18.8) | ($142.7) | ($87.2) |
| 1993 | $19.0 | $27.0 | $8.2 | $54.2 | $42.3 | ($11.9) | ($154.6) | ($91.4) |
| 1994 | $19.0 | $28.7 | $8.2 | $55.8 | $50.0 | ($5.8) | ($160.5) | ($93.2) |
| 1995 | $22.0 | $30.4 | $8.2 | $60.6 | $66.1 | $5.5 | ($154.9) | ($91.7) |
| 1996 | $23.0 | $32.2 | $8.2 | $63.4 | $75.4 | $12.0 | ($142.9) | ($88.8) |
| 1997 | $25.0 | $34.1 | $8.2 | $67.3 | $86.3 | $19.0 | ($123.9) | ($84.9) |
| 1998 | $27.0 | $36.2 | $8.2 | $71.4 | $93.0 | $21.6 | ($102.2) | ($81.0) |
| 1999 | $29.0 | $38.4 | $8.2 | $75.5 | $103.5 | $28.0 | ($74.3) | ($76.6) |
| 2000 | $31.0 | $40.7 | $8.2 | $79.8 | $114.1 | $34.3 | ($40.0) | ($71.8) |
| 2001 | $33.0 | $43.1 | | $76.1 | $117.4 | $41.3 | $1.3 | ($66.8) |
| 2002 | $35.0 | $45.7 | | $80.7 | $115.1 | $34.4 | $35.7 | ($63.1) |
| 2003 | $38.0 | $48.4 | | $86.4 | $127.3 | $40.9 | $76.6 | ($59.2) |
| 2004 | $40.0 | $51.3 | | $91.3 | $138.8 | $47.5 | $124.0 | ($55.3) |
| 2005 | $42.0 | $54.4 | | $96.4 | $151.8 | $55.4 | $179.4 | ($51.3) |
| 2006 | $44.0 | $57.7 | | $101.7 | $166.2 | $64.5 | $243.9 | ($47.3) |
| 2007 | $49.0 | $61.1 | | $110.1 | $184.3 | $74.2 | $318.1 | ($43.1) |
| 2008 | $50.0 | $64.8 | | $114.8 | $201.4 | $86.6 | $404.7 | ($38.9) |
| 2009 | $54.0 | $68.7 | | $122.7 | $216.1 | $93.4 | $498.1 | ($35.0) |
| 2010 | $58.0 | $72.8 | | $130.8 | $218.8 | $88.0 | $586.1 | ($31.7) |
| 2011 | $64.0 | $77.2 | | $141.2 | $234.6 | $93.4 | $679.5 | ($28.6) |
| 2012 | $67.0 | $81.8 | | $148.8 | $253.6 | $104.8 | $784.3 | ($25.6) |
| 2013 | $73.0 | $86.7 | | $159.7 | $260.9 | $101.2 | $885.4 | ($23.0) |
| 2014 | $78.0 | $91.9 | | $169.9 | $280.7 | $110.8 | $996.2 | ($20.6) |
| 2015 | $83.0 | $97.5 | | $180.5 | $302.1 | $121.6 | $1,117.9 | ($18.2) |
| 2016 | $89.0 | $103.3 | | $192.3 | $325.5 | $133.2 | $1,251.1 | ($16.0) |
| 2017 | $95.0 | $109.5 | | $204.5 | $350.6 | $146.1 | $1,397.2 | ($13.8) |
| 2018 | $102.0 | $116.1 | | $218.1 | $403.7 | $185.6 | $1,582.8 | ($11.4) |
| 2019 | $109.0 | $123.0 | | $232.0 | $459.8 | $227.8 | $1,810.6 | ($8.8) |
| 2020 | $116.0 | $130.4 | | $246.4 | $518.4 | $272.0 | $2,082.6 | ($6.0) |
| 2021 | $125.0 | $138.2 | | $263.2 | $564.1 | $300.9 | $2,383.4 | ($3.4) |
| 2022 | $134.0 | $146.5 | | $280.5 | $612.9 | $332.4 | $2,715.8 | ($0.8) |
| 2023 | $144.0 | $155.3 | | $299.3 | $647.2 | $347.9 | $3,063.7 | $1.5 |
| 2024 | $155.0 | $164.6 | | $319.6 | $691.6 | $372.0 | $3,435.6 | $3.7 |

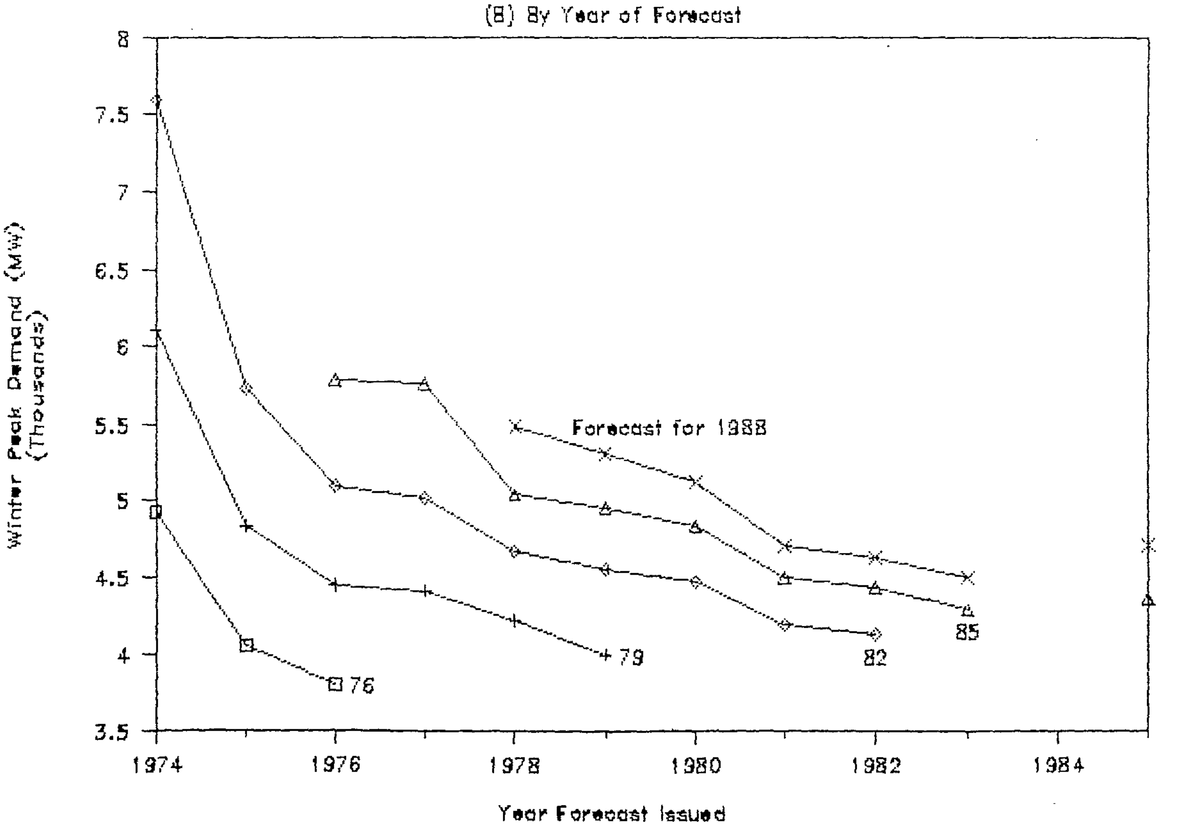
Notes:
1. O&M Costs + Capital Additions + Property Taxes.
2. From Table 9.4, Column [3].
3. See Table 9.1. Useless Portion (Case I) divided over 15 years.
4. [1] + [2] + [3].
5. From Table 6.2, Column 2.

# Figure 1.1: NU FORECAST HISTORY

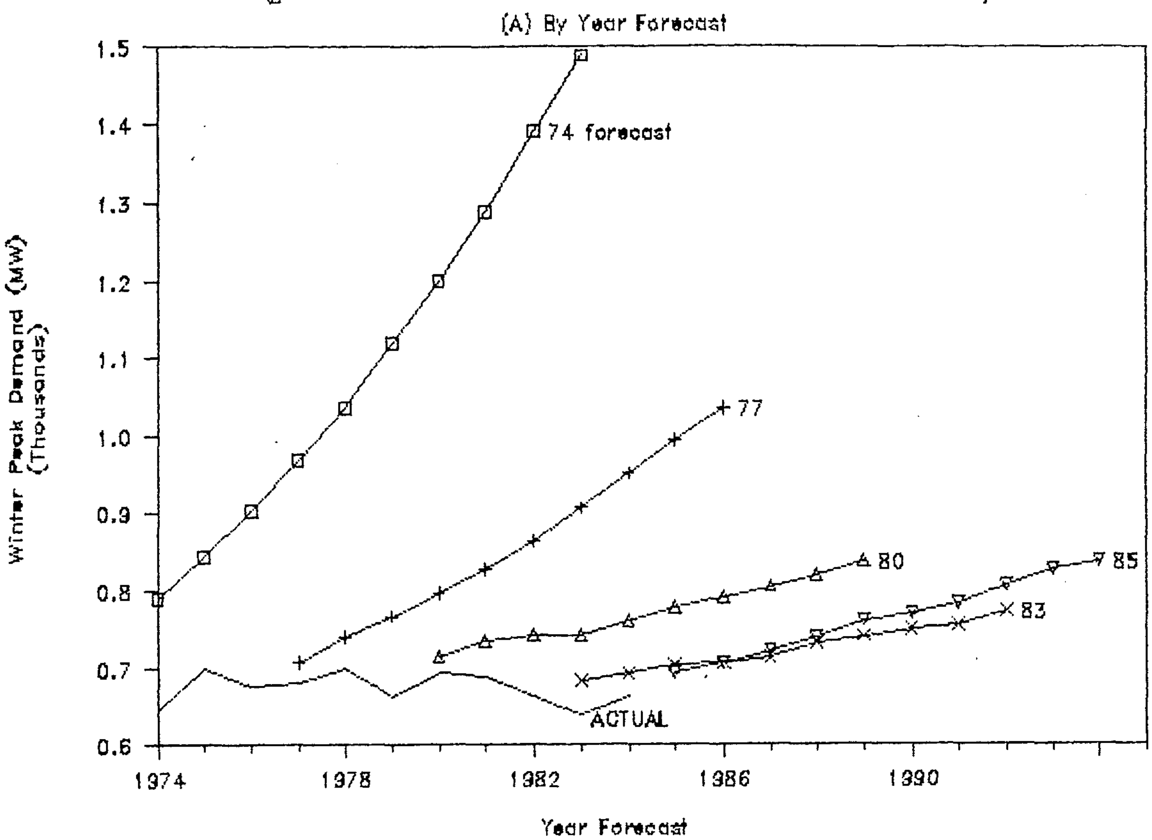
(A) By Year Forecast




(B) By Year of Forecast



# Figure 1.2: WMECO Forecast History



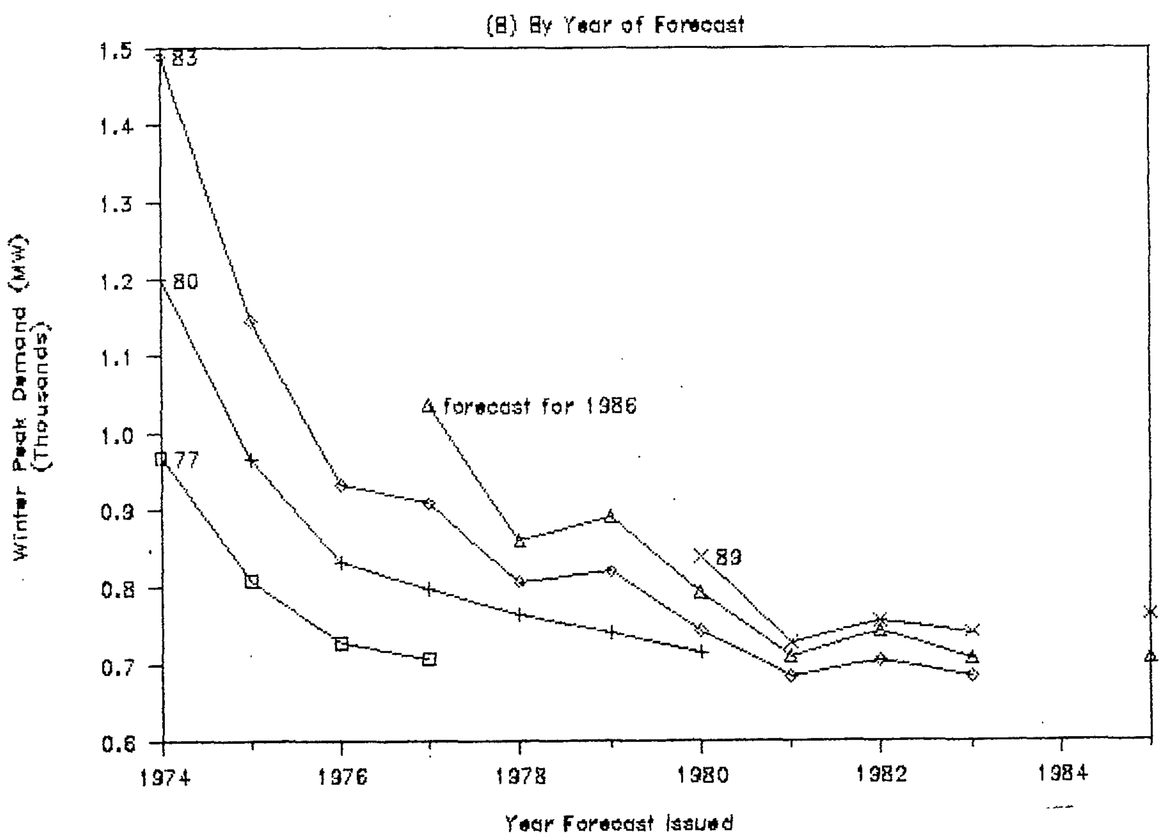
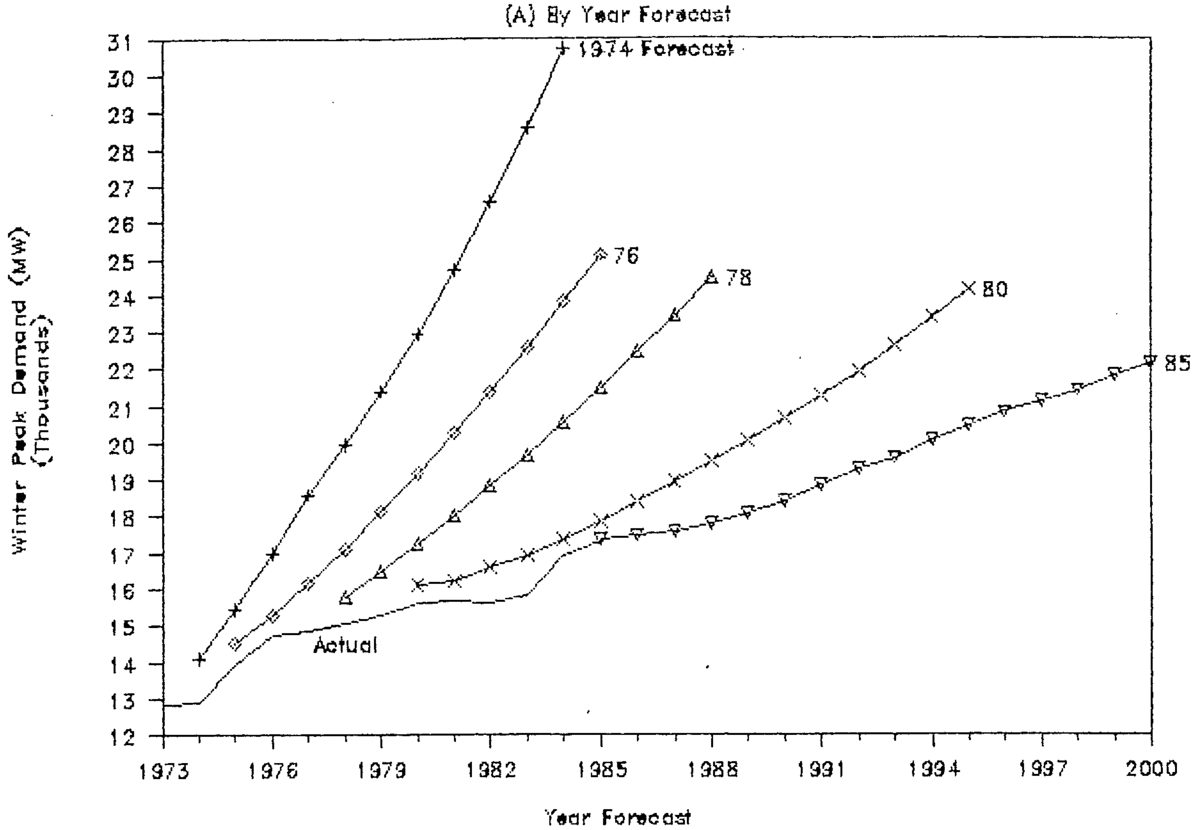
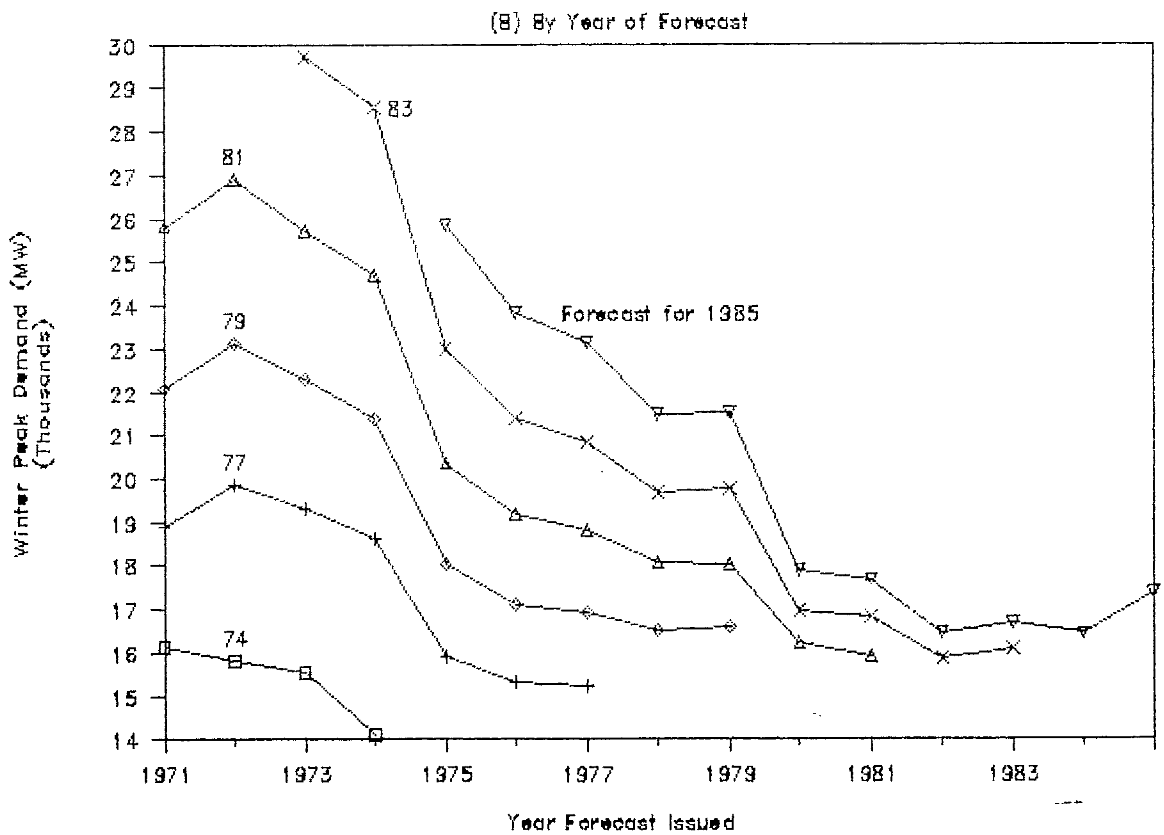
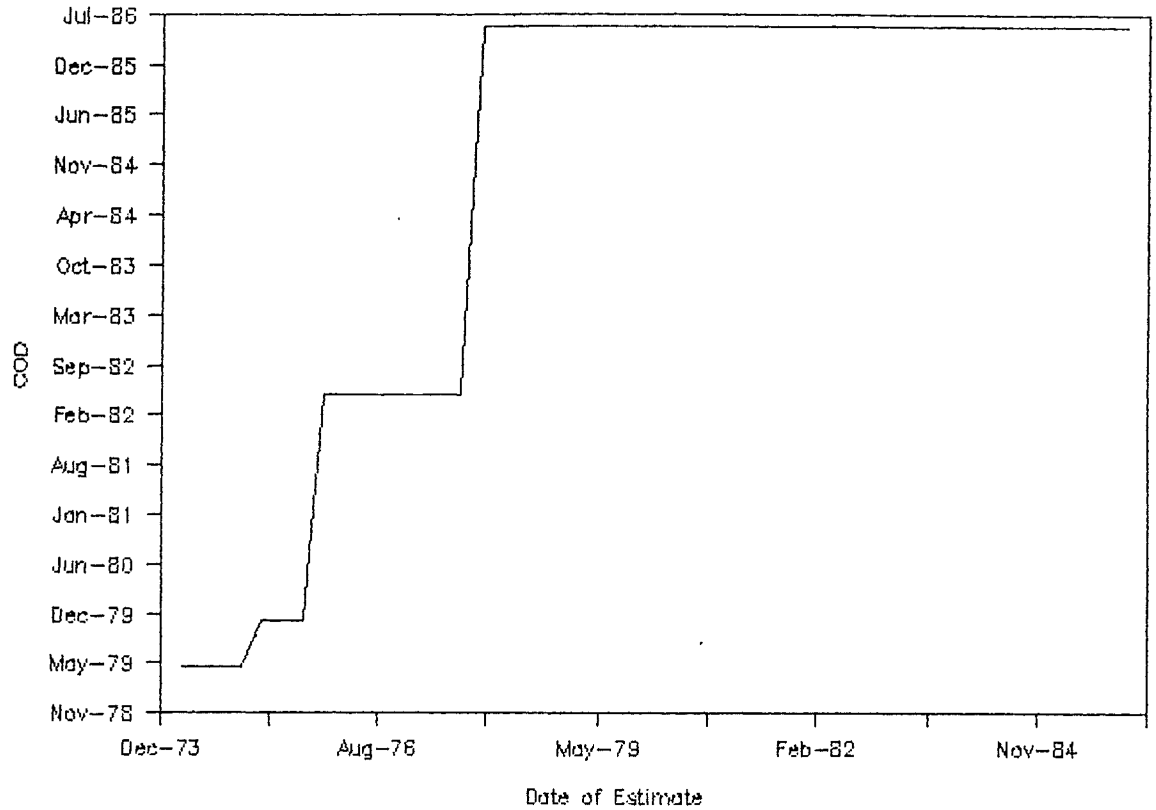



Figure 1.3: NEPOOL Forecast History

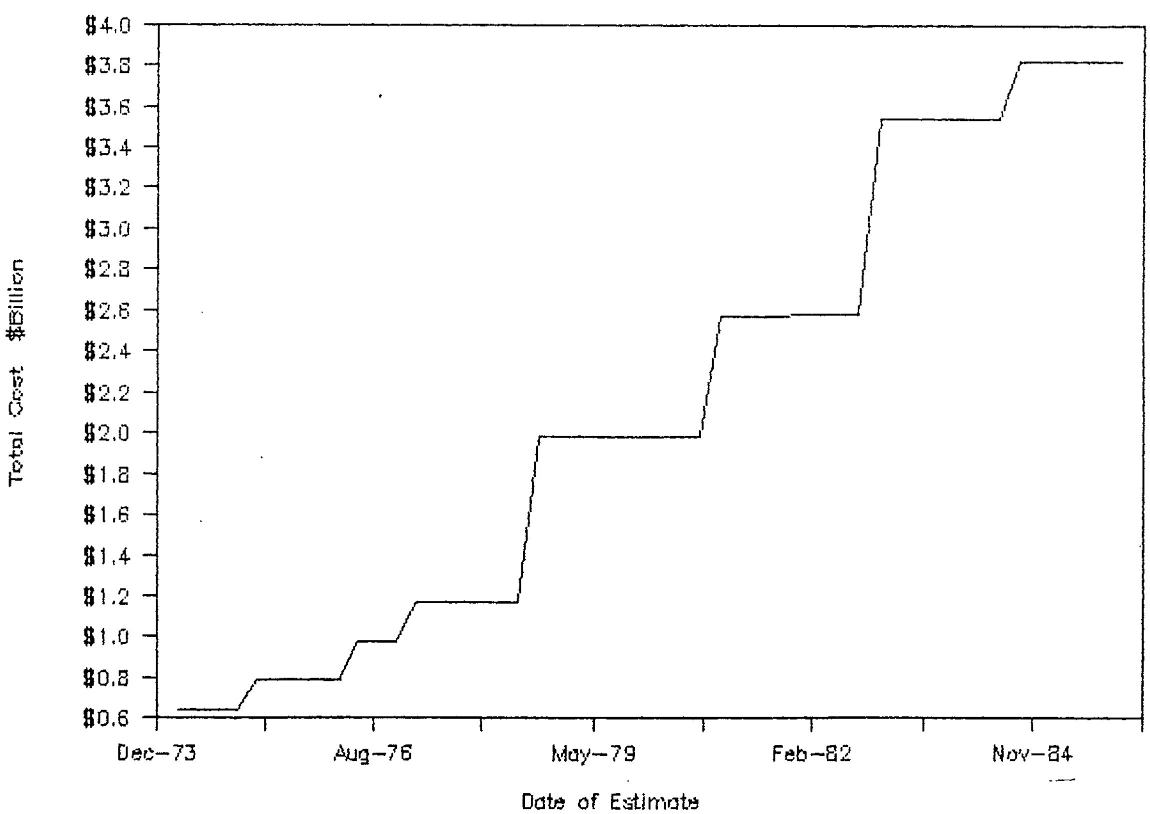


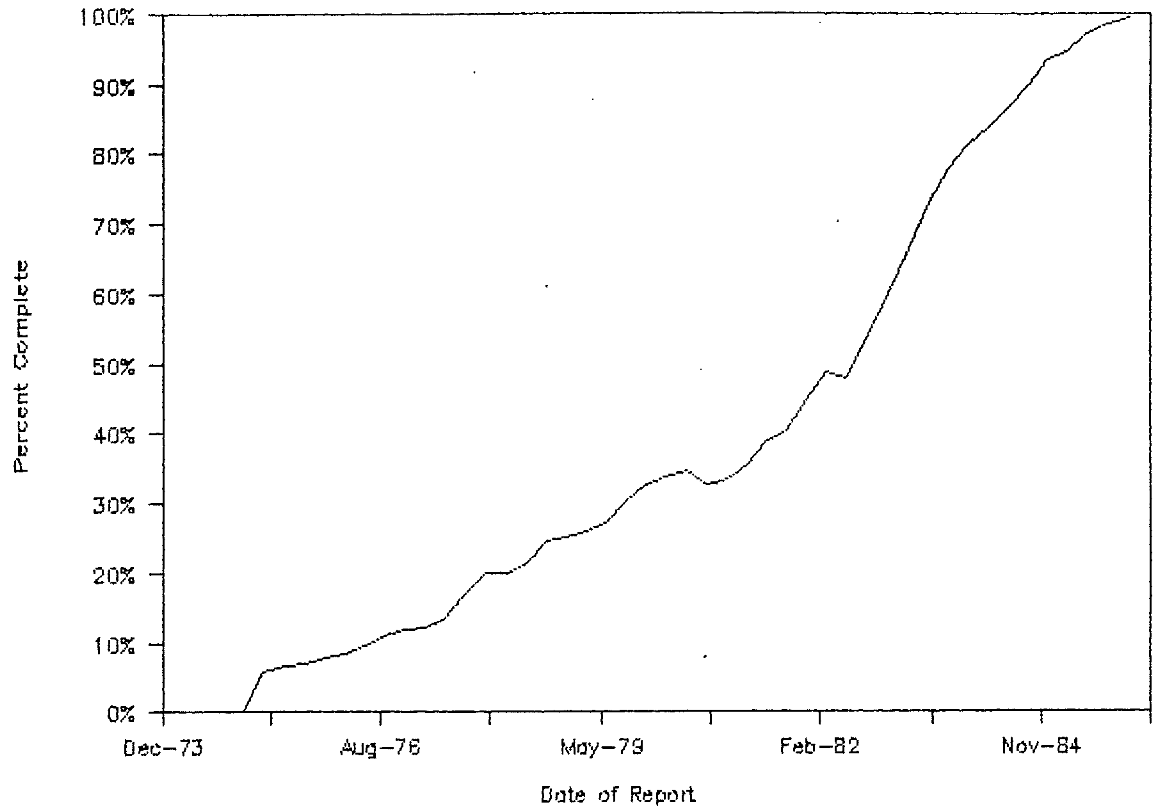
# Figure 1.4: Millstone 3 COD Estimates




# Figure 1.5: Millstone 3 Cost Estimates

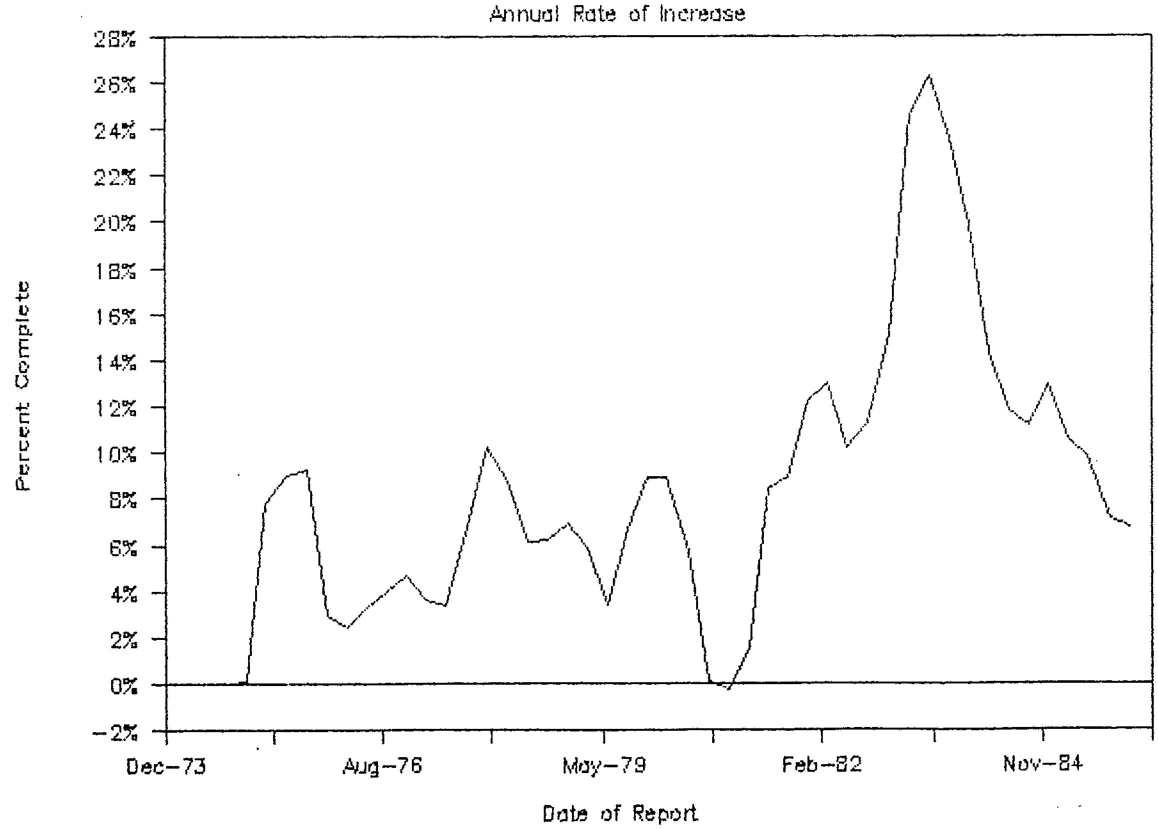


## Figure 1.6: Millstone 3 % Complete

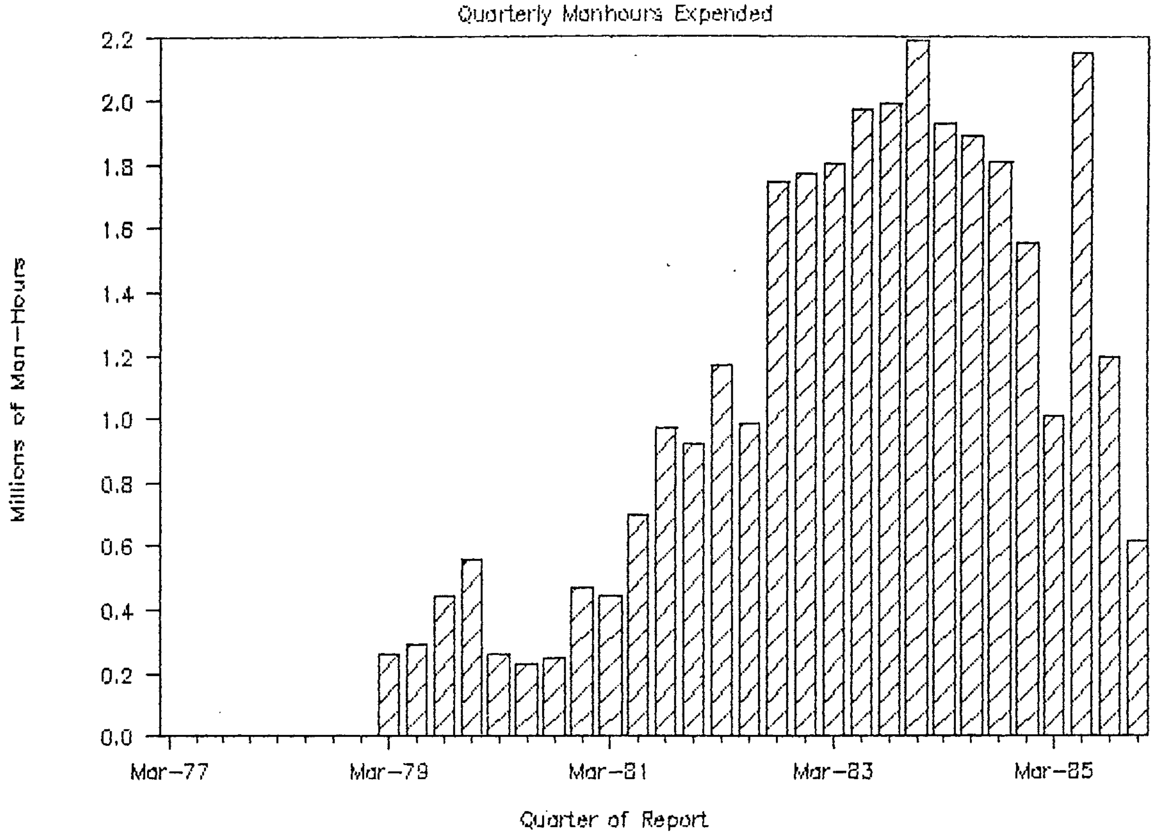



## Figure 1.7: Millstone 3 Construction

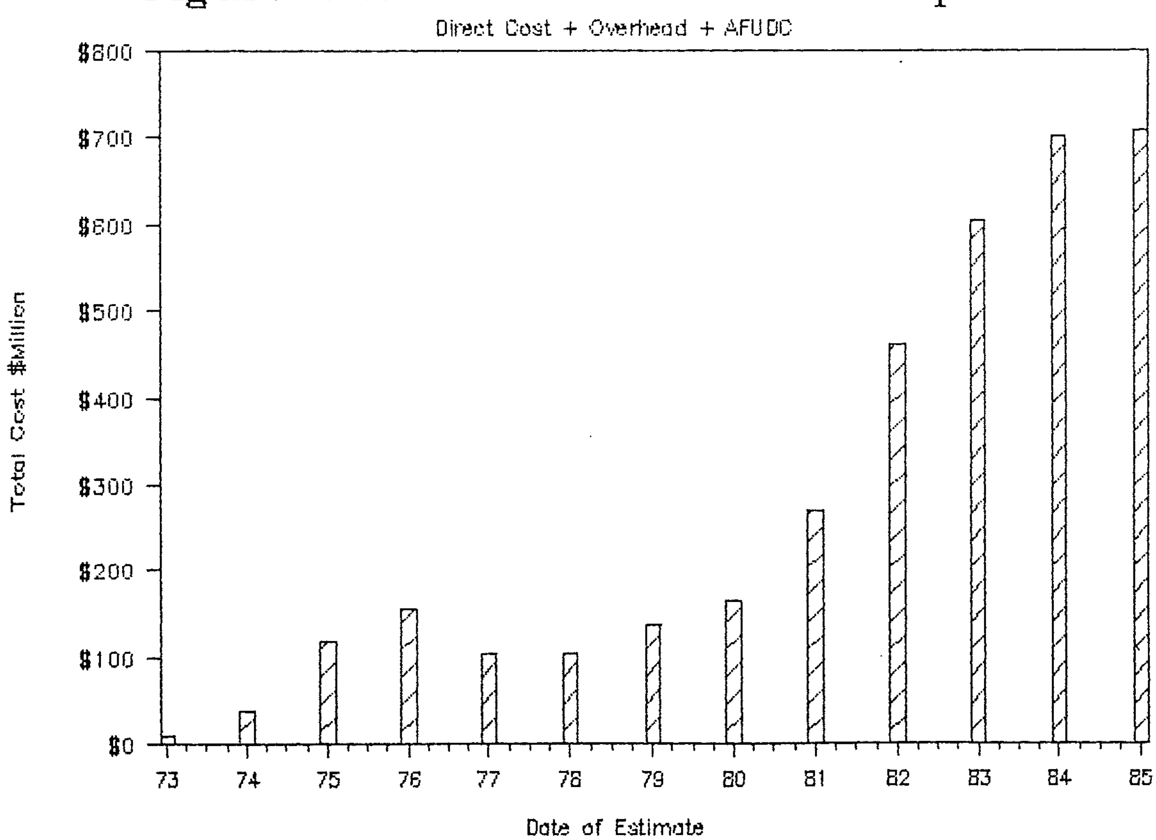
Annual Rate of Increase



## Figure 1.8: Millstone 3 Man-hours

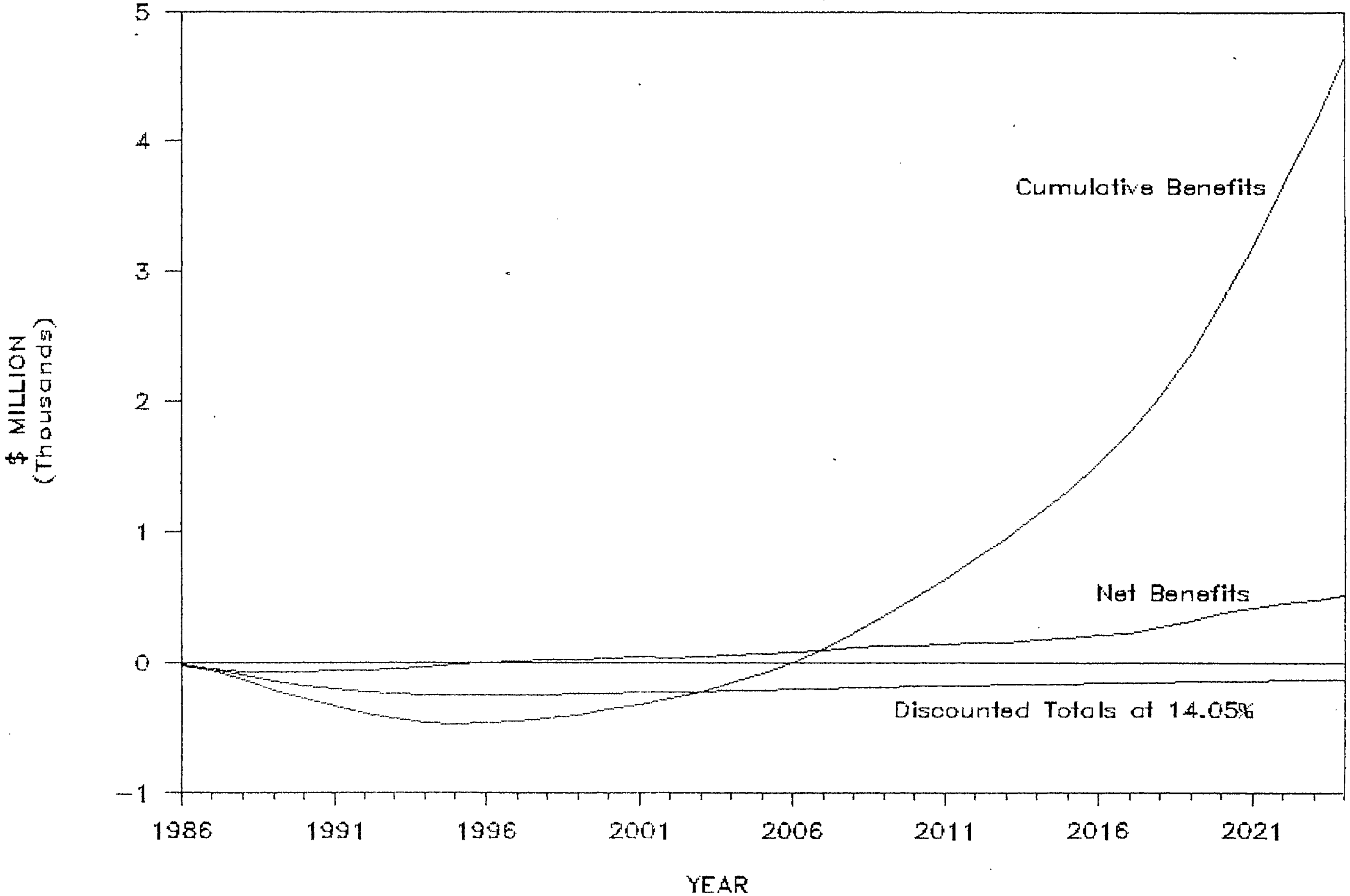



## Figure 1.9: Millstone 3 Annual Expenses



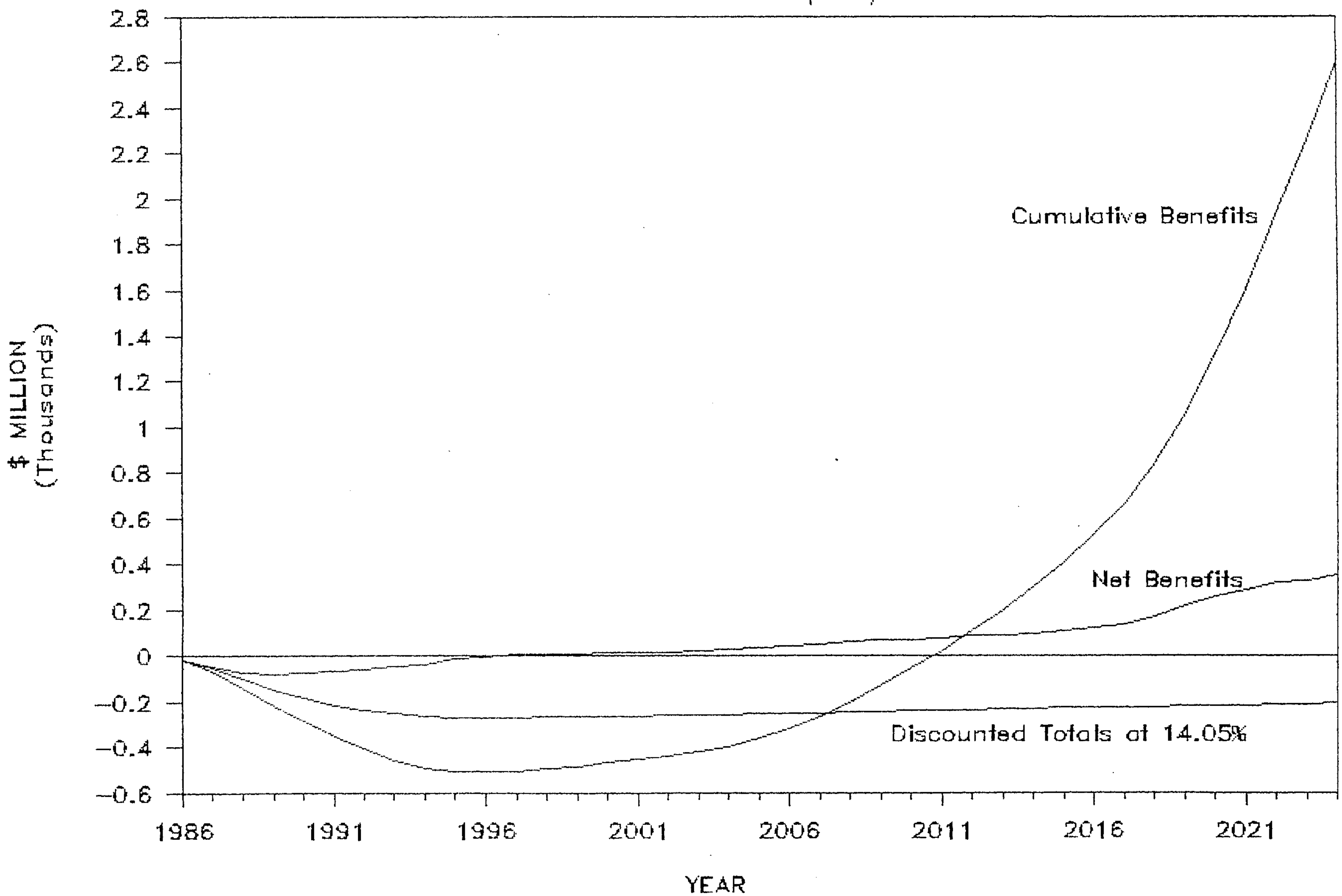
# FIGURE 6.1: MILLSTONE 3 RATE IMPACT

Case I: WMECo Assumptions

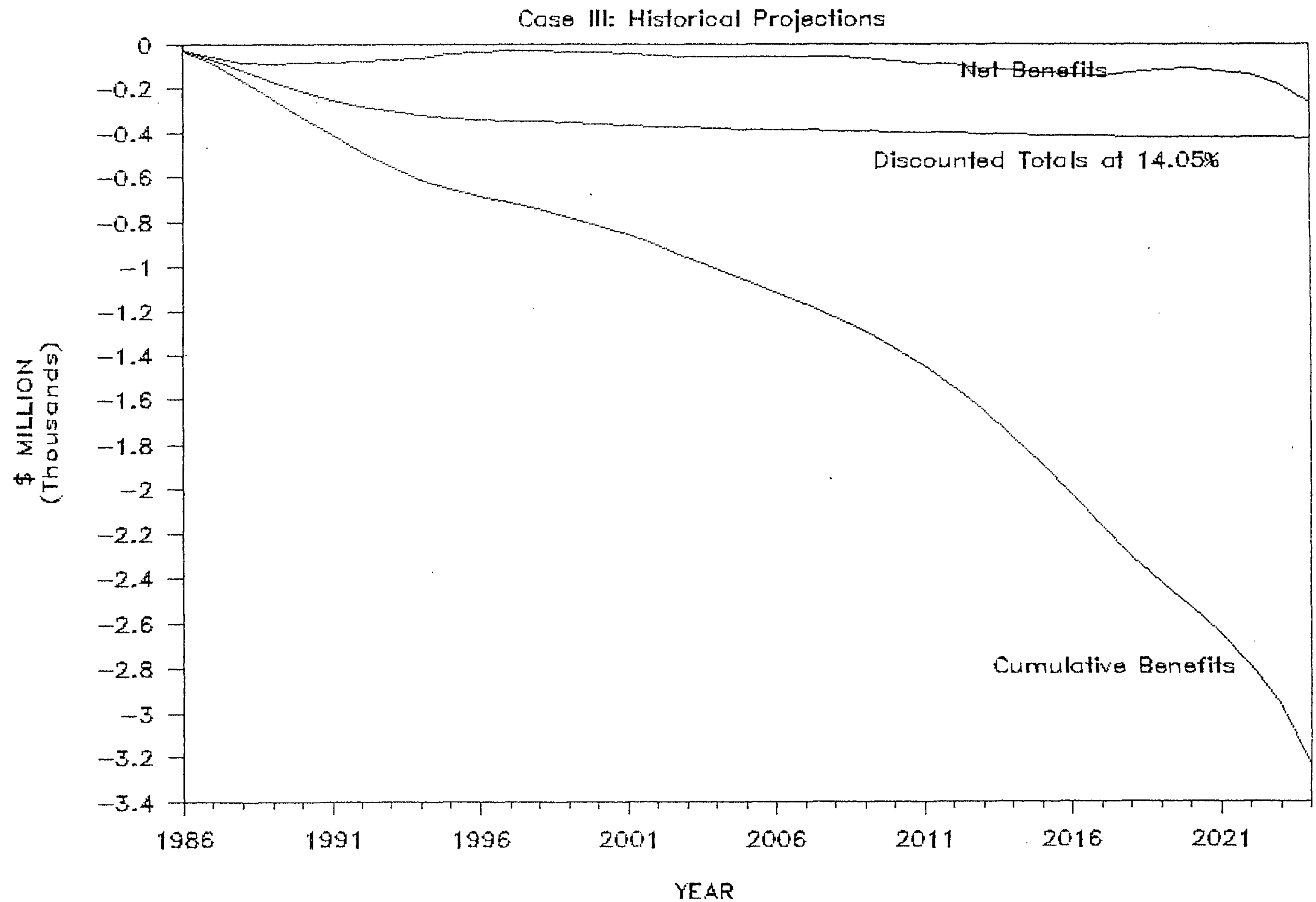


# FIGURE 6.2: MILLSTONE 3 RATE IMPACT

Case II: WMECo and PLC Capacity Factor

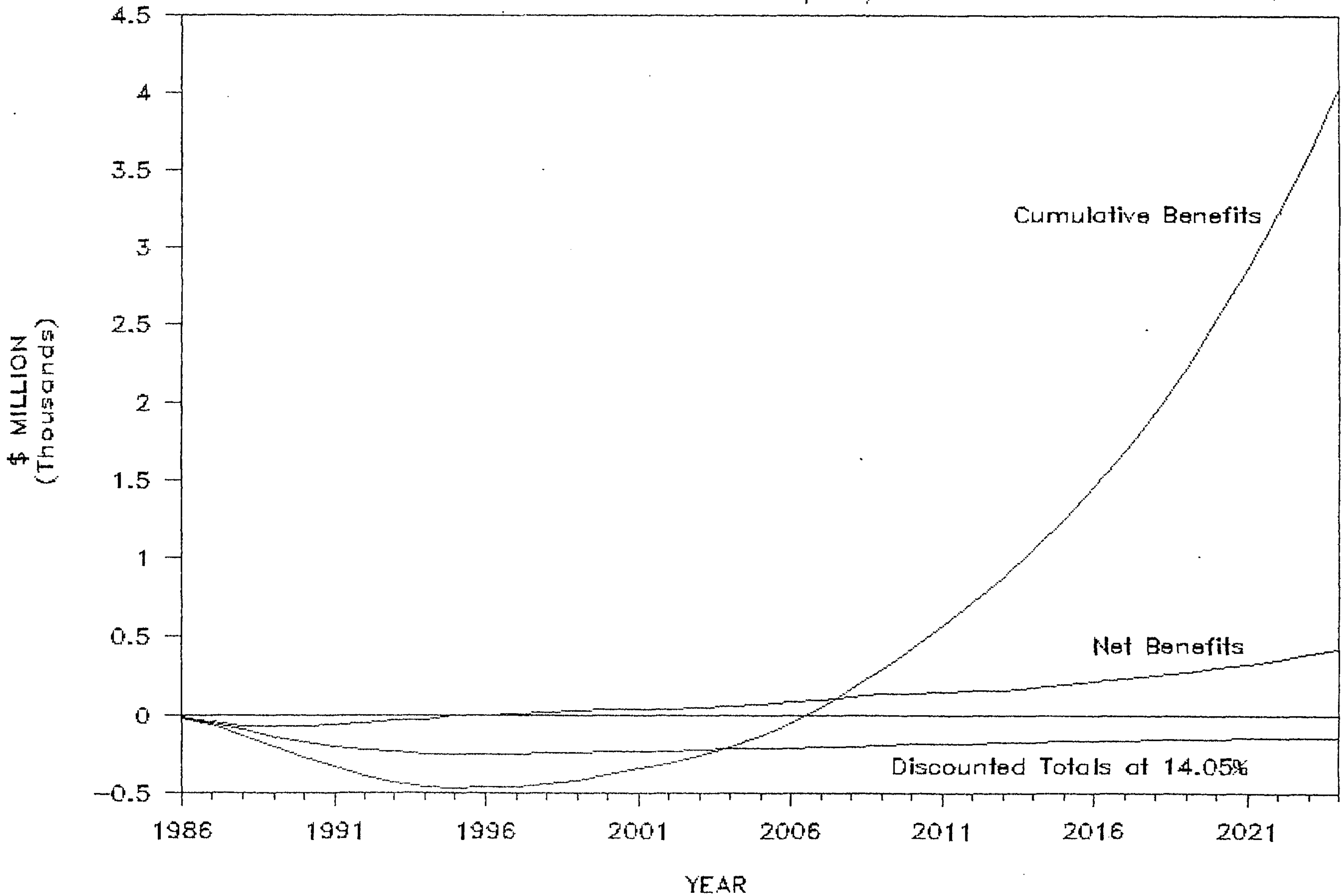


# FIGURE 6.3: MILLSTONE 3 RATE IMPACT



# FIGURE 6.4: MILLSTONE 3 RATE IMPACT

Case IV: PLC Avoided Capacity Cost



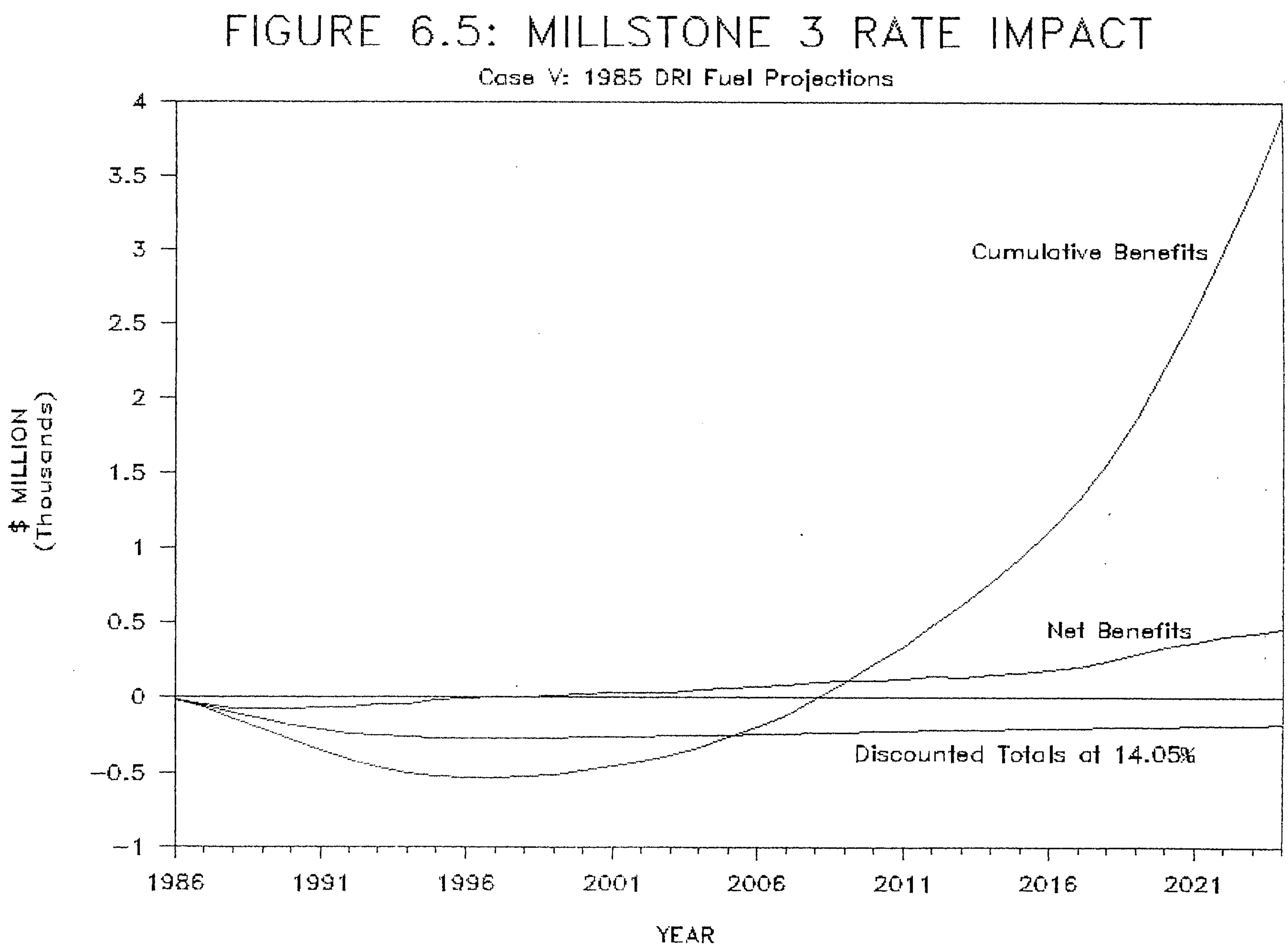
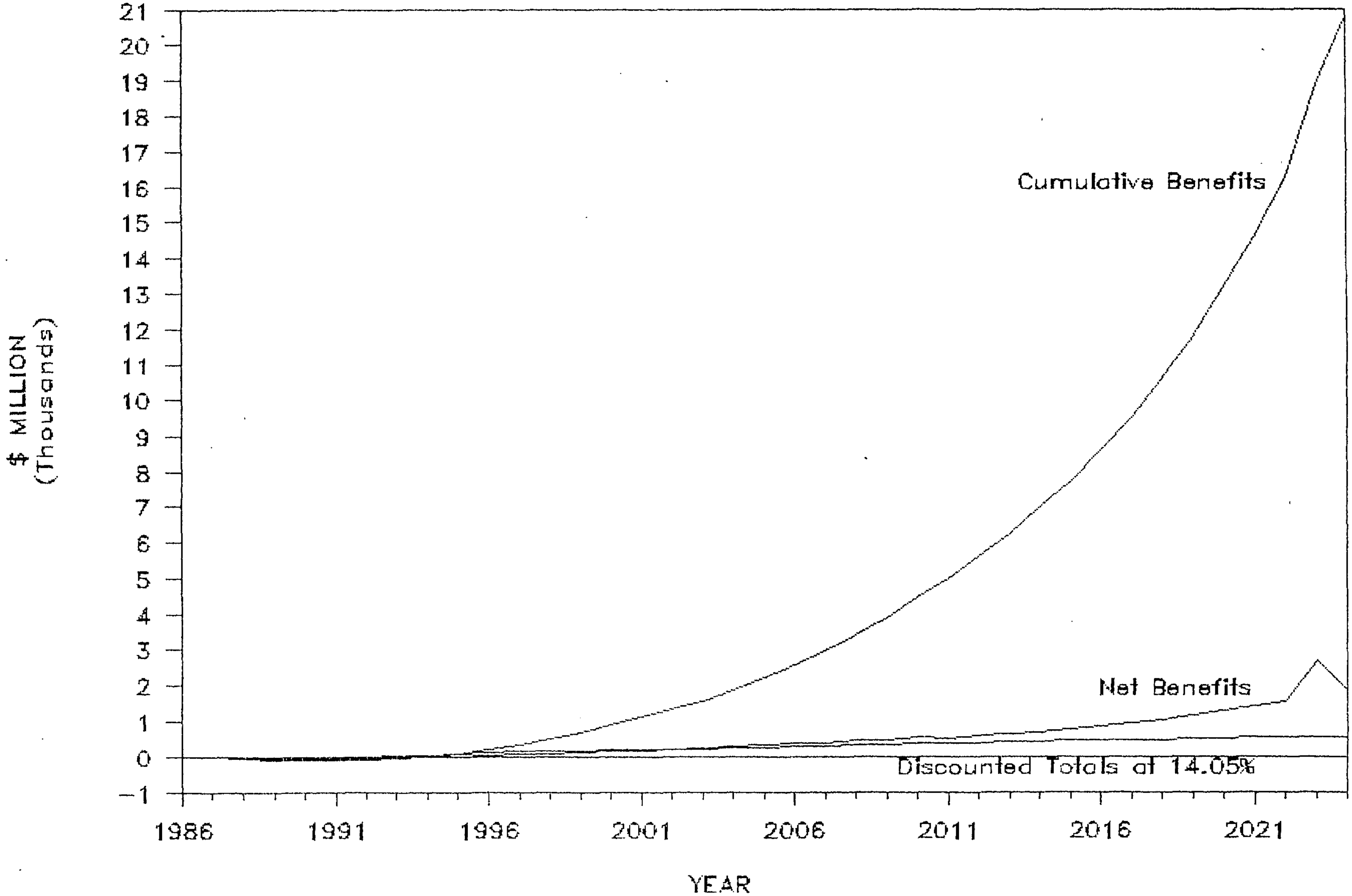


FIGURE 6.5: MILLSTONE 3 RATE IMPACT
Case V: 1985 DRI Fuel Projections
$ MILLION
(Thousands)
4
3.5
3
2.5
2
1.5
1
0.5
0
−0.5
−1
Cumulative Benefits
Net Benefits
Discounted Totals at 14.05%
1986
1991
1996
2001
2006
2011
2016
2021
YEAR

# FIGURE 6.6: MILLSTONE 3 RATE IMPACT

Case VI: 1980 DRI Fuel Projections



# FIGURE 6.7: MILLSTONE 3 RATE IMPACT

Case VI: 1977/78 DRI Fuel Projections

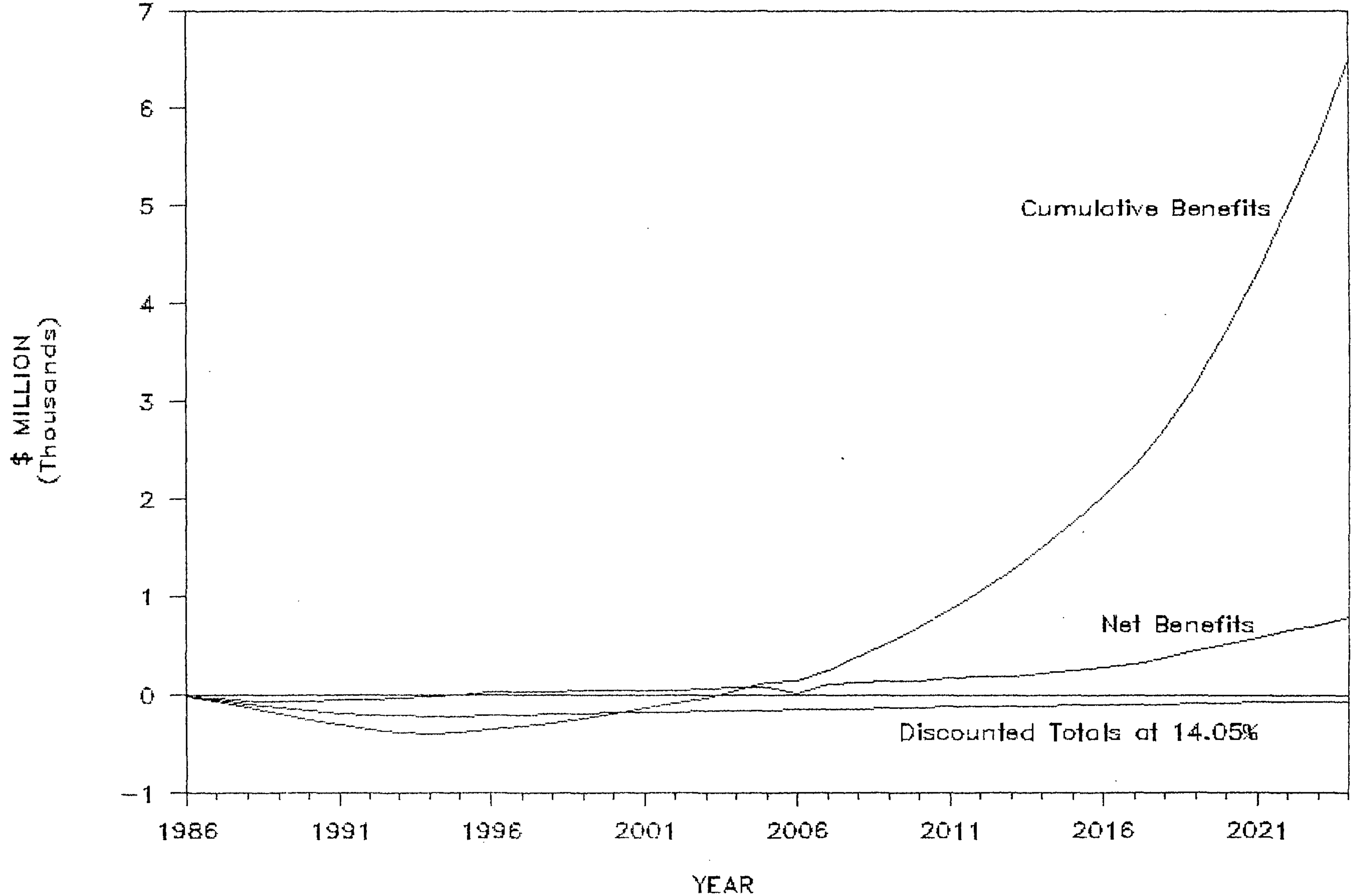


FIGURE 7.1: DIAGRAMMATIC DESCRIPTION OF AVAILABILITY FACTOR AND CAPACITY FACTOR

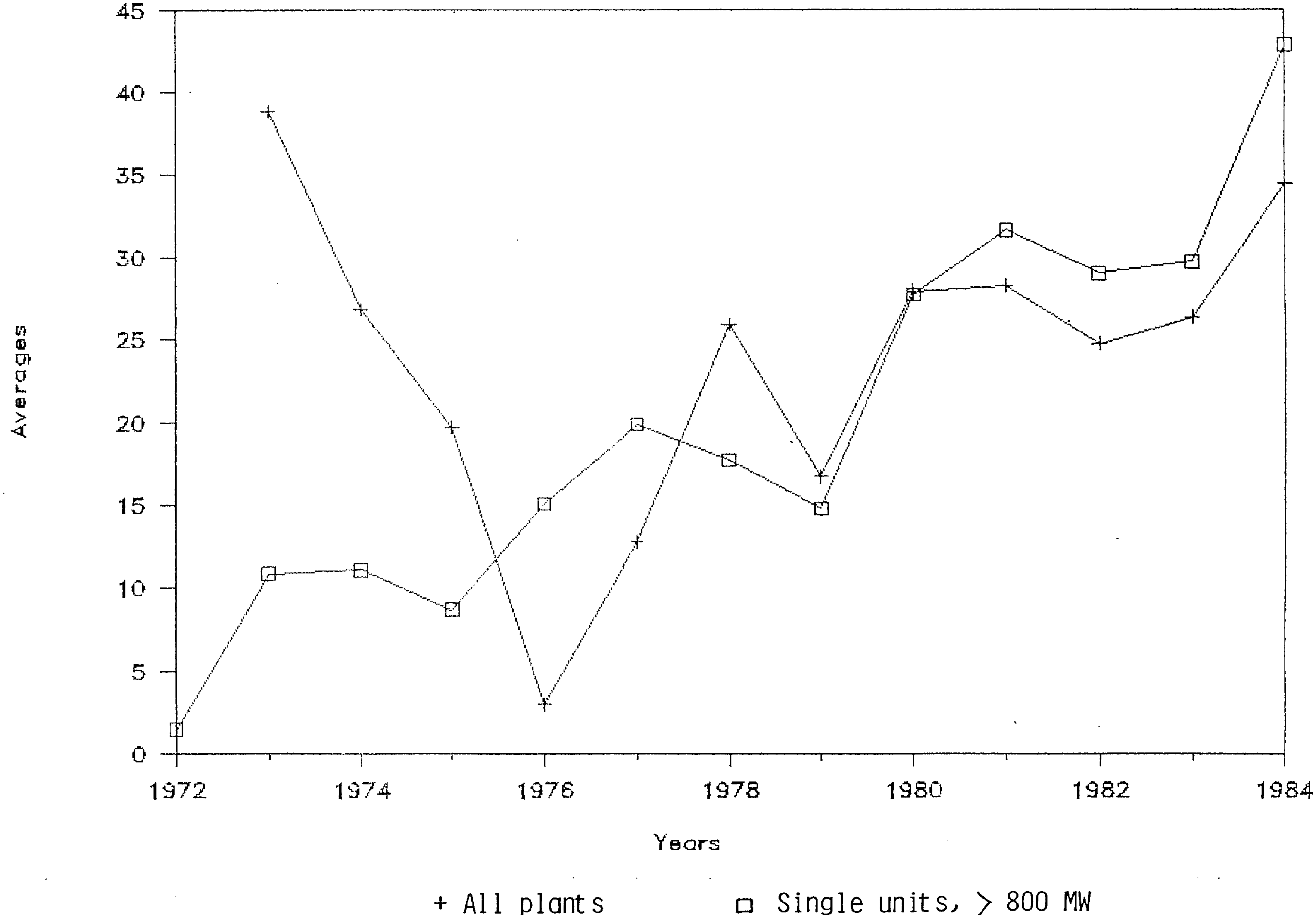
```
Region:              A                   B                  C           D
                |                     | Unit operates at  | Unit not opera-| Unit is |
                | Unit operates at    | less than full    | ting, though   |   not   |
                | full rated capacity | rated capacity    | it could be    |operable |
          100    ______________________________________________________________________|
                | \\\\\\\\\\\\\\\\\\\\|\                  |                |         |
                | \\\\\\\\\\\\\\\\\\\\|\\                 |                |         |
                | \\\\\\\\\\\\\\\\\\\\|\\                 |                |         |
                | \\\\\\\\\\\\\\\\\\\\|\\\                |                |         |
                | \\\\\\\\\\\\\\\\\\\\|\\\\               |                |         |
                | \\\\\\\\\\\\\\\\\\\\|\\\\               |                |         |
                | \\\\\\\\\\\\\\\\\\\\|\\\\\              |                |         |
                | \\\\\\\\\\\\\\\\\\\\|\\\\\\             |                |         |
   OUTPUT       | \\\\\\\\\\\\\\\\\\\\|\\\\\\\            |                |         |
    as %        | \\\\\\\\\\\\\\\\\\\\|\\\\\\\\           |                |         |
  of rated      | \\\\\\\\\\\\\\\\\\\\|\\\\\\\\           |                |         |
  capacity      | \\\\\\\\\\\\\\\\\\\\|\\\\\\\\\          |                |         |
                | \\\\\\\\\\\\\\\\\\\\|\\\\\\\\\\         |                |         |
                | \\\\\\\\\\\\\\\\\\\\|\\\\\\\\\\\        |                |         |
                | \\\\\\\\\\\\\\\\\\\\|\\\\\\\\\\\        |                |         |
                | \\\\\\\\\\\\\\\\\\\\|\\\\\\\\\\\\       |                |         |
                | \\\\\\\\\\\\\\\\\\\\|\\\\\\\\\\\\\      |                |         |
                | \\\\\\\\\\\\\\\\\\\\|\\\\\\\\\\\\\\     |                |         |
                | \\\\\\\\\\\\\\\\\\\\|\\\\\\\\\\\\\\\    |                |         |
                | \\\\\\\\\\\\\\\\\\\\|\\\\\\\\\\\\\\\\\  |                |         |
                | \\\\\\\\\\\\\\\\\\\\|\\\\\\\\\\\\\\\\\\\|                |         |
            0    ----------------------------------------------------------------------|
                0                                                                     100
                                 % of HOURS in period
```

1. CAPACITY FACTOR = AVERAGE OUTPUT / RATED CAPACITY
   (Shaded Area / Area of Rectangle)

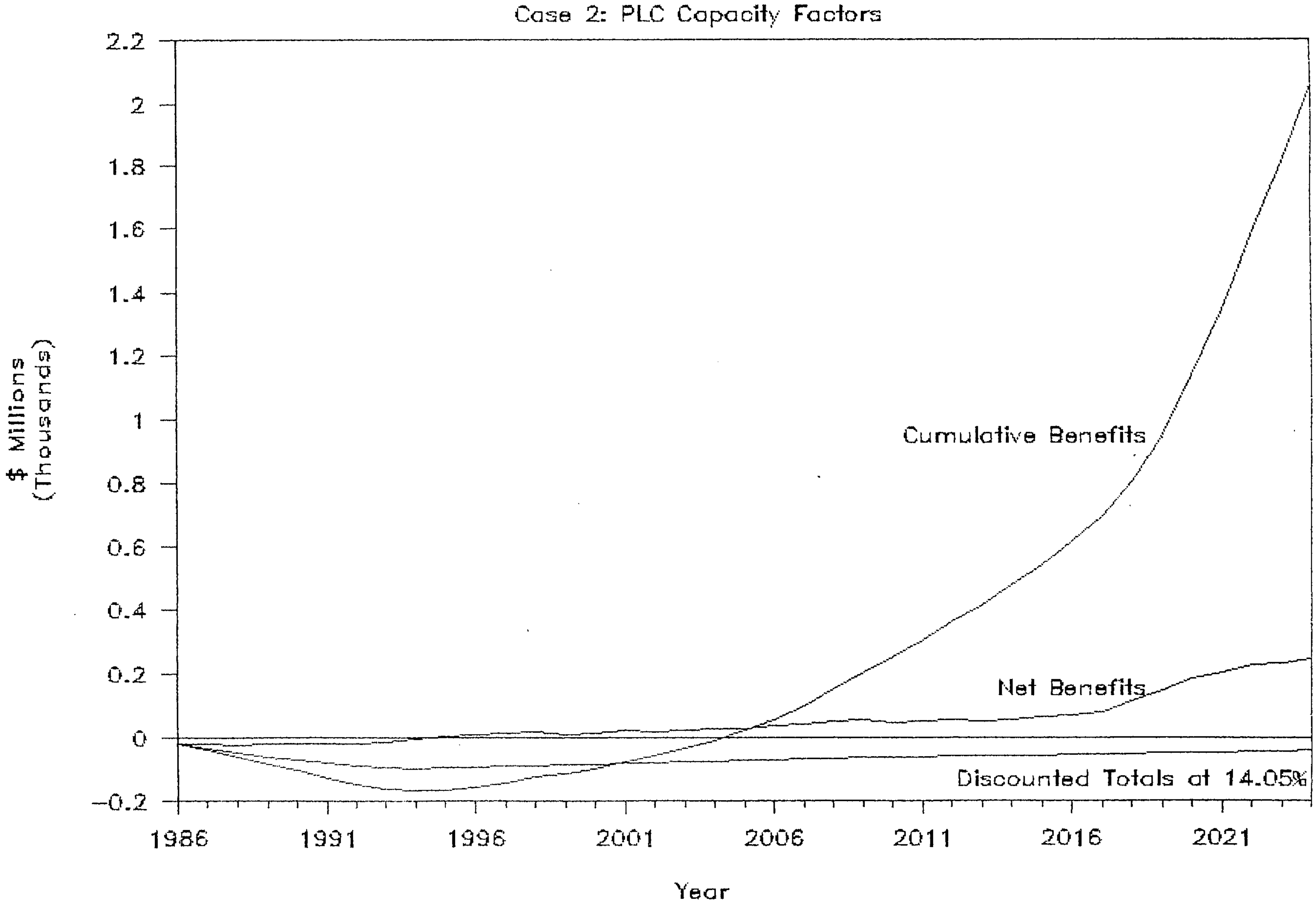
2. AVAILABILITY FACTOR = POSSIBLE HOURS OF PRODUCTION / TOTAL HOURS
   (Sum of widths A,B,C & D)

# FIGURE 7.2: CAPITAL ADDITIONS

(yearly avgs. in 1983 $/MW-yr)



# FIGURE 9.1: RECOMMENDED COST RECOVERY



# FIGURE 9.2: RECOMMENDED COST RECOVERY