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THE STATE OF MAINE
BEFORE THE PUBLIC UTILITIES COMMISSION

RE: INVESTIGATION OF SEABROOK INVOLVEMENT BY MAINE UTILITIES	DOCKET No. 84-113 Phase 2

TESTIMONY OF PAUL CHERNICK
ON BEHALF OF THE
MAINE PUBLIC UTILITIES COMMISSION STAFF

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TESTIMONY OF PAUL CHERNICK

ON BEHALF OF THE MAINE PUBLIC UTILITIES COMMISSION

1 - INTRODUCTION AND QUALIFICATIONS

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

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

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

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

I was a Utility Analyst for the Massachusetts Attorney General for over three years, and was involved in numerous aspects of utility rate design, costing, load forecasting, and evaluation of power supply options. My work has considered, among other things, the need for new power supply investments, and the likely costs of those investments, particularly in nuclear power, and the availability and cost of alternatives to proposed supply sources.

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 thirty-five times on utility issues before this Commission 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 Commisssion, the Pennsylvania Public Utilities 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 New England utility load forecasts, and predicted that growth rates would be lower than the utilities expected. Many of my criticisms have been incorporated in subsequent forecasts, and load growth has almost universally been lower than the utility forecast. For example, in DPU 19494, I reviewed the 1978 Central Maine Power load forecast and identified several aspects of that forecast which were inconsistent with the historical record, or otherwise projected load growth without sufficient support.

In DPU 19494 and NRC 50-471, I reviewed the NEPOOL forecast, both for the 1978 edition (which was the last version to be compiled as the sum of the utilities' own forecasts) and the

1979 edition (the first of the new end-use forecasts by state). I identified many overstatements and other errors in both versions. The 1978 version predicted a winter peak in 1983/84 of 19670 MW (compared to 15019 MW in 1977/78), and a ten-year growth rate of 4.5%; corresponding figures from the 1979 forecast were 19755 MW and 3.8% growth. Actual 1983/84 winter peak was 15949 MW, and the 1984 NEPOOL forecast predicts 2.0% annual growth in the long term. The history of NEPOOL load forecasts is presented in Figure 1.2.

Among the utility forecasts underlying the 1978 NEPOOL forecast, one of the largest contributors to predicted growth was the forecast of Public Service of New Hampshire (PSNH). In my review in DPU 19494, I identified this forecast as being outstanding for the unreasonable methodologies and implausible assumptions it incorporated. The history of PSNH load forecasts is presented in Figure 1.3.

My analyses of other utility forecasts, including Northeast Utilities, Boston Edison, and various smaller utilities, have been similarly confirmed by the low load growth over the past few years, and by repeated downward revisions in utility forecasts.

My projections of nuclear power costs have been somewhat more recent, but utility projections have already confirmed my analyses. For example, in the Pilgrim 2 construction permit proceeding (NRC 50-471), Boston Edison was projecting a cost of $1.895 billion. With techniques similar to those used in this testimony, I projected a cost between $3.40 and $4.93 billion in my testimony of June, 1979. Boston Edison's final cost estimate (issued when Pilgrim 2 was canceled in September 1981) stood at $4.0 billion. Figure 1.4 compares my Pilgrim 2 estimates to those of BECo.

In MDPU 20055, PSNH projected in-service dates for Seabrook of about 4/83 and 2/85, at a total cost of $2.8 billion. My testimony of January, 1980 predicted in-service dates of 10/85 and 10/87, with a cost around $5.3-$5.8 billion on PSNH's schedule or $7.8 billion on a more realistic schedule. At the time I filed my testimony in NHPUC DE 81-312 (October 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. Within two months of my filing, PSNH had revised its estimates to values of 12/84, 7/87, and $5.2 billion. On March 1, 1984, PSNH released a new cost estimate of $9 billion, with in-service dates of 7/86 and 12/90. In June 1983, I updated my analysis for CPUCA 83-03-01, and estimated a total cost of $10.3 billion, with COD's of 11/86 and 3/91.[1] Thus, PSNH's estimates of Seabrook in-service dates and costs have increased by a factor of more than three since the filing of DPU 20055, and are now relatively close to my projections. Figure 1.5 compares the history of PSNH cost estimates for Seabrook to my estimates, and Table 1.1 lists PSNH's projections of Seabrook cost and schedule.

Critiquing and improving on utility load forecasts and nuclear power cost projections has not been very difficult over the last few years. Many other analysts have also noticed that various of these utility projections were inconsistent with reality.

Q: What is the subject of your testimony?

A: I have been asked to review the information available to Central Maine Power (CMP), Maine Public Service (MPS) and Bangor Hydro-Electric (BHE) in connection with their various decisions to initiate and continue their involvement in the second unit of the Seabrook nuclear power plant construction project. I have specifically been asked to determine what a responsible and prudent utility would have known at critical points in the project, and to describe responsible responses to the information which was available at those times.

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1. Those results were averages, which included methodologies which I knew to be biased on the low side. The methods used in this testimony produced COD estimates of 10/87 and 6/94.

Q: How is your testimony structured?

A: The second section of my testimony will discuss the state of the nuclear power industry in 1972, when Central Maine Power (CMP) signed the Seabrook 2 Joint Ownership Agreement, and describe some of the facts of which CMP was, or should have been, aware at that time. I will then consider, in section 3, the changes in circumstances between 1972 and 1976, when Seabrook received its construction permit, and identify some of the concerns with which the Seabrook 2 participants should have been dealing, and of which MPS and BHE should have been aware in 1977 and 1978 when they were in the process of buying Seabrook shares from NU. The fourth portion of this testimony will consider the state of the industry, Seabrook 2, and the participants in December, 1978, following the first major financial crisis of the joint owners, after the construction suspension and restart. This point in time was also significant, as it marked the conclusion of the process of the initial MPS and BHE purchases of Seabrook shares, and the beginning of the process of all three utilities increasing their participation through purchases from PSNH and (in the case of CMP) from UI. In the fifth section, I will review the same issues as of mid-1980, after the accident at Three Mile Island and near the end of the BHE and MPS purchase processes. Section six brings the analysis up to December, 1982, at the time Seabrook's total cost jumped from $3.56 billion to $5.12 billion. Section seven repeats contemporaneous cost-benefit analyses for realistic Seabrook costs, and Section eight considers the financial consequences of building Seabrook 2. Section nine briefly reviews the quality of the utilities' load forecasts in the 1970's, to determine the appropriate role of those forecasts in the Seabrook purchase decisions. Finally, in my conclusions, I will summarize and interpret the results of the previous sections, describe the actions which prudent utilities would have taken at various points in time, and suggest ratemaking treatment of the Seabrook 2 investments, in light of the facts I present.

2 - THE NUCLEAR INDUSTRY IN 1972

Q: Why is the status of the commercial nuclear power industry in 1972 pertinent to this proceeding?

A: It was in 1972 that CMP decided to sign the Seabrook 2 Joint Ownership agreement, obligating CMP to pay 2.55% of project costs.

Q: When it entered into the ownership agreement, were there any particular considerations of which CMP should have been aware?

A: Yes. Any utility with large enough a staff to keep up with the general industry literature,[2] should have been aware of four ~~two~~ 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,

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2. Examples of this literature would include **Electrical World** and **Power Engineering** magazines. All three utilities considered in this testimony pass this test.

3. Nuclear plant consruction 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 this statement?

A: I have two sources. First, there is the data itself. Table 2.1 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.[3] For each of these ~~six~~ seven units, Table 2.1 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.

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3. 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.

Most of my 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). 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.[4] Final cost and commercial operation date (COD) information, for example, is generally from reports to the FPC and the FERC, and the operation date information may therefore differ 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,

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

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

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

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. I am not suggesting that the Maine utilities should have performed exactly the same summary calculations that I present in this testimony, but I am suggesting that they should have examined the uncertainties and contingencies involved in nuclear investments,[5] 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 the utilities' prudence as if they had these calculations before them, since they should have been familiar with the data and should have noted (formally or informally, rigorously or intuitively) the same patterns and relationships I present.

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5. As I will show below, the utility industry literature provided ample notice that nuclear plant construction was not "business as usual."

Q: What do these results imply for Seabrook 2?

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 Seabrook 2 ($486 million and a COD of 11/81, or 9.76 years from the 2/72 estimate date), to produce revised or corrected estimates.[6] Multiplying $486 million by the average cost ratio of 2.11 produces a corrected cost estimate of $1023 million. However, the estimated duration for Seabrook 2 was somewhat longer than for the units in Table 2.1, so applying the average myopia factor of 18.4% for 9.76 years would produce a cost ratio of 5.22, and a Seabrook 2 cost of $2535 million. Finally, multiplying the estimated Seabrook 2 duration ratio by the average duration ratio of 1.444 produces a corrected duration estimate of 14.09 years, and a COD of 3/86. Thus, if the factors which had caused other nuclear power plant estimates to be incorrect also operated for Seabrook 2, it would be considerably more expensive and time-consuming to construct than was implied by the official projections from PSNH and the architect/engineer (A/E), United Engineers and Constructors (UE&C).

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

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6. The same adjustment technique can be applied to Seabrook 1 as well.

1972?

A: Yes. Table 2.2 repeats the duration analysis in Table 2.1, 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.

Tables 2.3 and 2.4 list 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 Seabrook 2 if these trends had extended to its cost and schedule evolution, we may divide the projection of 9.76 years by the experience-weighted[7] average progress ratio of 45%, to yield a corrected duration of 21.7 years (indicating that Seabrook 2 would have been completed in 10/93) and increased the cost estimate of $486 million by 21.7 years of cost growth at 18.6% annually, for a final cost of $19.8 billion.

Q: Do you mean that a prudent utility would have expected Seabrook 2 to be completed in the 1990's at a cost of $20 billion?

A: No. I would have expected a prudent utility to know that _if recent experience continued_, Seabrook 2 would not be completed, and might well be cancelled after considerable investment had been made in it. That prudent utility would also have known that, even if the historical experience moderated considerably, Seabrook 2 would take a long time to build and would be very expensive, and that completion of the unit at anything like PSNH's cost estimate would require a radical change in the nuclear constructin environment.

Q: What significance do these results have for Central Maine Power's decision to enter into the Seabrook 2 joint ownership agreement?

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

A: They indicate that both CMP and PSNH knew, or should have known, while CMP was deciding to join in constructing Seabrook 2, that construction cost and duration estimates for other nuclear units had been significantly understated, and thus that the cost and schedule estimates for Seabrook 2 were likely to be less reliable than estimates for other (non-nuclear) utility projects.[8] Both utilities should also have been aware that continuation of these trends would have resulted in a very expensive plant, or in one which was simply impossible to complete. As it happens, both of these events occurred.

Q: Are there any particular reasons to believe that CMP and PSNH 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 2.5.[9] 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. These units are in the

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8. These conclusions, and my subsequent conclusions regarding knowledge of the problems of the nuclear industry, generally apply to BHE and MPS as well, but are less relevant to this time frame, since they did not buy into Seabrook until much more bad news was available.

9. Yankee Rowe is omitted for lack of data.

figurative back yard of both utilities, and the various utilities have varying interests in the Yankees: PSNH owns 5% of Connecticut Yankee, 4% of Vermont Yankee and 5% of Maine Yankee; CMP is the lead utility at Maine Yankee (owning 38%), and is also a participant in the Vermont (4%) and Connecticut (6%) Yankee plants; BHE owns 7% of Maine Yankee; and MPS owns 5% of Maine Yankee. In addition, Yankee Atomic had a role in the construction management for all the Yankee plants, as well as for Seabrook.

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 Seabrook 2.

Q: What was the second source of your belief that CMP and PSNH should have known in 1972 that nuclear cost and schedule estimates were likely to be unreliable and understated?

A: 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 technologywhich 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.[10]
>
> 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

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

$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 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 suprise to the FPC staff, which accompanied each announcement with its judgement that growth in nuclear capacity was inevitable and desirable.

Q: How should these facts have affected the behavior of PSNH and CMP in 1972?

A: PSNH should have realized that its cost estimates, which were methodologically similar to earlier, understated estimates, were also subject to significant overruns. As the lead utility in Seabrook 2, PSNH had a moral, and perhaps a legal, responsibility to inform its potential partners of the risks they were undertaking, and to clearly identify its cost estimate as a routine nuclear plant cost estimate, subject to all the problems of that genre.[11] Similar obligations may extend to UE&C and Yankee Atomic.

Furthermore, it is increasingly 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 MAC, in testimony filed by Central Maine Power and Maine Public Service in their current rate cases, summarize this practice:

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11. Examples of these problems would include the exclusion of many potential costs, the failure to incorporate sufficient contingency for current and future regulatory changes, and the absence of an allowance for the problems of building a plant whose design is still changing.

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

UI has also recognized this problem, as demonstrated by the testimony of its President and other officials before the CPUCA 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: Should CMP have been aware of the same considerations?

A: Assuming even the most cursory familiarity with industry publications and experience, CMP also should have been aware of the previous problems in the nuclear industry. CMP has not offered any evidence to suggest that CMP ever critically reviewed any estimate it received from PSNH, at least until 1980,[12] in the light of industry (or New England) experience. If this was due to vigorous PSNH representations, CMP may have been an excessively credulous victim. If CMP's confidence in the cost and schedule estimates were entirely due to CMP's failure to credit current experience, CMP would appear to have been acting in an imprudent and irresponsible manner.

By the time it signed the participation agreement, CMP should

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12. Even this "review" consisted only of the suggestion that the then-current cost estimate might be subjected to a modest 25% increase. It was late 1983 before CMP commissioned an independent review of Seabrook costs (NERA, 1984).

have been in a position to extract from PSNH either more realistic estimate ranges, or the information necessary to estimate a reasonable CMP contingency. Its apparent failure to do so also appears to be imprudent, unless PSNH's behavior was such as to transfer the responsibility to PSNH. For example, if PSNH assured CMP that the estimate actually included a 100% contingency, while it only included a 3% contingency, CMP may argue that it attempted to act in a responsible manner, but was defrauded by PSNH (and perhaps UE&C as well) to secure CMP's participation in the project. If, on the other hand, CMP's reliance on the PSNH/UE&C estimates resulted entirely from the absence of any active inquiry by CMP, that reliance must be considered negligent. In any case, the division of responsibility between the utilities and contractors may be settled elsewhere and should not affect the utilities' rates.

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

A: Because I spotted these problems in 1979, under circumstances much less favorable than those of CMP's staff.[13] My initial observations were based on only a couple of cost estimate histories, and I had no access to the utility literature or other utiltiies, but a pattern of substantial cost overruns

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13. The staffs of BHE and MPS were similarly better situated than I was when I observed these phenomena.

quickly became obvious. The calculation of cost ratios, myopia factors, and duration ratios were simple ways of quantifying very important phenomena, requiring no strong assumptions or complex calculations. I can not imagine why any utility with an established power-supply planning process would not have noticed the same problems.

Q: Is it your opinion that CMP's decision to sign the joint ownership agreement was imprudent?

A: Not necessarily. It was certainly imprudent for any utility to sign such an agreement and then fail to monitor (and critically assess) developments for most of the next decade, as CMP appears to have done. It is possible that participating in Seabrook in itself, coupled with a commitment to due diligence in the future, may have been a reasonable decision at the time.

Q: Considering the problems you have described, how could such a commitment be 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: Quebec was an inconceivably distant power source and New England hydro potential seemed trivial compared to the perceived need although a very good utility would have foreseen some fo 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 or participation in the large plants then in planning, in favor of smaller alternatives. Thus, it is hard to say that CMP erred in signing the Seabrook Joint Ownership Agreement, or similar agreements for other nuclear plants in the same period, without allowing a certain amount of hindsight to influence our judgement.

Another issue specifically facing the utilities buying into Seabrook was the linkage between the two units at the plant. The first unit may have looked particularly attractive, in the capacity-short early 1970's.[14] Since utilities could not purchase capacity in one without buying into the other, the risks of Seabrook 2 might have seemed worthwhile.

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: There are two central points which can be drawn from the facts I laid out. First, as discussed previously, CMP's failure to acknowledge the weakness of the Seabrook cost and schedule estimates can only be attributed to irresponsible and/or incompetent behavior on the part of either CMP or PSNH.[15] Second, even if CMP somehow believed that PSNH's projections were the best available estimates, it should at least have recognized that the projections were subject to tremendous uncertainty. <u>At a minimum</u>, choosing to participate in Seabrook created a responsiblity for CMP to monitor the progress of the project, and of its cost estimates, and to be prepared to react appropriately if the historical trends continued or accelerated. The same can be said, even more emphatically, of PSNH's responsibility as the sponsor of the project.

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14. Whether it should have looked attractive or not is another issue.

15. Again, the same considerations may apply to UE&C and Yankee.

Q: Given the nature of the joint owners' agreement, was there any advantage for any of the joint owners in monitoring Seabrook 2 cost estimates? Did any of the joint owners other than PSNH have any control over the project?

A: Despite their lack of formal control, it is clear that joint owners can have significant influence over the fate of a nuclear unit. This influence is seen most clearly in the case of Seabrook 2 itself, in the effect of the 1983/84 opposition by United Illuminating, Connecticut Light and Power, Central Maine Power itself, and other utilities. Another visible example is Dayton Power and Light's opposition to the completion of the Zimmer nuclear plant. The public opposition to (or even doubt of) pursuing Unit 2 by one of the Seabrook joint owners might well have led to the cancelation or mothballing of the unit much earlier, and hence saved all the owners millions of dollars.

In particular, intervention in the regulatory proceedings (particularly those of the NRC, the NHPUC, and other state utility regulators) by a joint owner which believed (or suspected) that construction was impossible, or excessively expensive, would have made it very difficult for those agencies to continue to support the plant. The same could be said for the filing of a lawsuit, even if it eventually proved to be unsuccessful. PSNH presumably would have been aware of this possibility,[16] and would almost certainly have cooperated with CMP's efforts to review the cost estimates, rather than face a public confrontation. Perhaps most importantly, had CMP been monitoring actively the quality and reliability of the cost and schedule estimates, it might have spared itself the error of buying additional ownership in Seabrook in 1980. Even before that time, CMP had a great deal of power, and even the facts of 1972 should have alerted CMP to the possibility that it would have to exercise that power.

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16. If one believes that PSNH really was not aware of the state of the nuclear industry throughout the 1970's, it may be conceivable that it would not have spotted its significant liabilities in the event of a public disagreement with a joint owner. If this were the case, CMP could have pointed out PSNH's vulnerability.

3 - NUCLEAR PROBLEMS IN THE MID-1970's

Q: You have described the problems of the nuclear industry in the early 1970's. How had the situation changed by the end of 1976?

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, Seabrook actually received its construction permit in July 1976.[17]

Q: Which utilities, in addition to CMP, should particularly have been aware of nuclear power experience between 1972 and 1976?

A: Both MPS and BHE made commitments to Seabrook in 1977 and officially joined the Seabrook participants in 1978, by buying 1.46% and .37%, respectively, from Northeast Utilities (NU). Both of these utilities should have been aware of the recent history of nuclear projects before buying into

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17. That permit was suspended or otherwise under a cloud from late 1976 to August 1978.

Seabrook. (CMP attempted to acquire 2.6% of Seabrook from UI and NU in 1976, but did not renew its offer when the original transfers were terminated.)

Q: Please describe the continuing problems of the nuclear industry.

A: Table 3.1 updates to the end of 1976 the previous analyses (Tables 2.1 and 2.2) of cost and schedule slippage in completed nuclear units. By this time, Seabrook 2 had received a construction permit (CP), so the summary statistics are computed from the estimate at the time of the CP, to the actual cost (or completion date). In determining which estimate corresponds to the CP, I used the first post-CP estimate, if there was a new estimate within a year after the CP, and otherwise the last pre-CP estimate.[18] On this basis, the average cost ratio[19] is 2.05, the average myopia factor is 22.8%, and the average duration ratio is 1.624. The cost results are not very different than those in the previous analysis, through 1972, but the duration ratio is somewhat worse than the 1972 result. If the Seabrook 2 cost and schedule changed as much during construction as did those of the 49 units in Table 3.1, it would have cost $2.1

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18. If the utility did not find it necessary to release a new estimate for more than a year after the CP, it must have been fairly content with the prior estimate.

19. Turnkey plants are excluded from the cost analysis.

to $4.2 billion, and entered service in 3/88.

In Table 3.2, I repeat the analysis of the cost and schedule slippage of nuclear units under construction (see Table 2.4), updated to the end of 1976. This analysis only includes slippage after construction permit receipt: the first estimate is defined as in Table 3.1. If Seabrook 2 experienced throughout its construction the average progress ratio and cost growth rate this group had from CP to 12/76, construction would have required 19 years,[20] to sometime near the end of the century, and the unit would have cost $18 billion.[21] These results indicate that Seabrook 2 could not both have repeated this experience and have been completed. Even with much improvement over the historical average, Seabrook 2 would have been a disaster.

Q: Do you make any particular assumptions in applying the historical experience to Seabroook 2?

A: Yes. Projecting the historical experience would have been appropriate in 1976 if one had assumed that the situation in 1976 and into the future was as unsettled as the previous decade, and that the Seabrook 2 estimate was consistent with

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20. This is PSNH's estimate of 6.92 years, divided by the progress ratio of 36.3%.

21. The average cost growth rate of 16.4%, over 19 years, would increase the price by a factor of almost 18 times.

utility practice. 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 more empirical. Table 3.3 lists the other second units with CP's or Limited Work Authorizations (LWA's), but still less than 10% complete, as of 12/76, from **Nuclear News** (2/77). The average of these 33 plants was 2.0% complete (compared to Seabrook 2 at 1.0%), and was scheduled for completion in 11/82. Second units were scheduled for somewhat later operation; thus, the schedule estimate for Seabrook 2 was consistent with industry practice.

Q: Was there any more New England experience by 1976?

A: Yes. Millstone 2 entered service in December 1975. Table 3.4 displays the cost estimate history of Millstone 2, which was by far the most expensive nuclear unit in the region. While none of the Maine utilties has any direct interest in Millstone 2, it would be particularly difficult for any New England utility not to be aware of the history of this relatively local unit.

Q: Were there any particular reasons for other New England utilities to take note of the cost and schedule overruns for Millstone 2?

A: Yes. Previous capacity additions were almost always welcome for reliability purposes, and most additions also reduced costs when they entered service or soon thereafter. Public agencies were primarily concerned with the adequacy of power supply, and the only capacity problem was a potential shortage. The situation was rather different for Millstone 2, which caused considerable consternation when it was completed. The unit was unnecessary and had expensive excess capacity at the time it entered service. As I will discuss below, the radical reduction in load growth following the oil price increases of 1973-74 had left New England utilities (including NU, the sole owner of Millstone 2) with enormous reserve margins. The construction cost of the plant was so high that even post-embargo oil prices did not make it cost-effective in the short run, and there was initially concern that it might not be cheaper than oil over its life as a whole.[22] The Massachusetts Attorney General opposed (unsuccessfully) the inclusion of Millstone 2 in the rate base of Western Massachusetts Electric Company (WMECo) on the grounds that the unit's capacity was surplus to the utility's needs.

Q: Does the size of MPS, BHE, and their professional staffs have any bearing on their responsibility to understand, review, or monitor the Seabrook cost projections?

A: Not in any way relevant to this case. It is clear that both

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22. This problem was solved by the Iranian revolution in 1979.

utilities had access to enough information to raise serious questions about the quality of the cost esitmates it was receiving from PSNH. There is no evidence to suggest that either MPS or BHE then attempted to set up any sort of monitoring process, either individually, jointly, or in conjunction with other small utilities, to assure that it would be prepared to respond if the historic pattern continued.

Q: What sort of monitoring might MPS or BHE have conducted?

A: While I would not want to prescribe any particular approach, they might have collected some of the articles I have quoted, identified and confirmed the trends and problems addressed in those articles, and then pressed PSNH for some explanation as to how the Seabrook estimates corrected for and incorporated those problems. They might also have talked directly to some of the analysts with concerns about nuclear costs, both inside and outside the industry.

Q: In the previous section, you contrasted the resources available to you when you first identifed the patterns in cost estimates to the resources available to CMP in 1972. How do the resources of the MPS and BHE Staffs in the mid-1970's compare to yours in the late 1970's?

A: While these utilities are much smaller than CMP, their opportunities for addressing these issues were still much greater than mine.

Q: Did the electric utility literature continue to note the persistence of these problems?

A: Yes. 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)

Seabrook 2 would have been one of the "new plants in the past three years that estimated commercial operation in six to eight years", with more aggressive schedules than "The great bulk 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 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)

Some other examples from the nuclear literature of this period would 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)

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)

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 serivce is slightly over nine years. (Brandfon 1976)

> 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, [and even assuming nuclear costs of only $883/kw in 1985, compared to PSNH's estimate of $1007/kw for Seabrook 2 in 1983] 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)

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. The 1976 survey was published in January of 1977. 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.

Q: Did the series of FPC reviews continue?

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 proceeeding 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 reeexamined 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 commmercial 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.

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 <u>last</u> year was the end of the trend, and that <u>next</u> 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 mid-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.[23] In addition, the

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23. Many authors also continued to express suprise at the size of the increases, even after the pattern had persisted for a

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 and subsequent dramatic rise in oil prices had several important effects. On the one hand, it improved the relative economics of any 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 (Those of CMP, NEPOOL and PSNH are illustrated in Figures 1.1, 1.2, and 1.3., and CMP, MPS and BHE forecasts are discussed further in Section 9.) had two effects. First, the reduced need for power plants made it harder to justify building any new

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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.

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?

A: The reduction in load growth was largely due to conservation, of course: this demonstrated that continual increases in electricity consumption were not inevitable. In particular, it became clear 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. For the most part, those programs did not get off the ground 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: How did the first oil price shock induce financial stress for utilities constructing nuclear power plants?

A: As I noted above, reduced load growth resulted in lower sales and lower earnings than the utilities would have expected. At the same time, the higher cost of oil, and subsequent inflation throughout the economy, greatly increased the utilities' expenses. The pinch between rising costs and falling sales expectations limited the ability of many utilities to finance the construction programs they had planned in more affluent years. In the next section, I discuss how this problem caught up with PSNH, UI, and NU in the 1977-78 period, but both UI and NU were trying to trim their construction programs by 1976; Section 8 considers financial issues in more detail.

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

4 - FINANCIAL CRUNCH: 1977 AND 1978

Q: Did the situation of the nuclear industry, the Seabrook project, and Unit 2 in particular, improve in the first two years following Seabrook's receipt of a construction permit?

A: No. Cost escalation and schedule slippage continued nationwide, Seabrook's construction was interrupted by unresolved environmental issues, and some of the major owners reached the limits of their ability to finance the plant.

Q: What was the national experience with cost overruns and schedule slippage in 1977 and 1978?

A: Table 4.1 continues the analysis of Table 3.1, for those plants which entered commercial operation in 1977 and 1978. On the whole, these two years were even worse for cost overruns by completed plants than was the previous decade. Applying the experience of these 10 units to the current estimate for Seabrook 2 (which was only 2.8% complete) would produce a corrected cost estimate of $3.5 - 6.2 billion, and a commercial operation date of December 1991. Including the experience of the units completed by 1976 would moderate this somewhat, producing an estimated completion date of 6/89 and a cost estimate of $2.8 - 4.9 billion. These costs are equivalent to increases of 115-375% over PSNH's $1.3 billion estimate of January 1979, as contrasted with the 20-40% cost increases CMP contemplated in its analyses in MPUC U3238. Clearly, Seabrook 2 would have been a major nuclear success story if its cost had increased only 20-40% more.

Table 4.2 repeats the slippage calculations of Table 3.2, both for the continuing (1976 to 1978) slippage of the units in Table 3.2 which were still not finished in 1978, and for the total slippage to 1978 of some 26 additional units which were not included in Table 3.2 because they received construction permits too late, or because they had no new cost or schedule estimates by the end of 1976. On the average, the cost estimate for this group of units was increasing at 17.9% annually, and they were making only 41.4% of the scheduled progress towards completion: for each year that went by, they were getting only 5 months closer to completion. If Seabrook 2 progressed as slowly, and if its cost escalated as rapidly as the average of this group, then it would require 14.7 more years (to 9/93) and would cost $14.7 billion to complete, again indicating that it could not repeat this average experience and be completed.

Table 4.3 compares the schedule projection for Seabrook 2 to that of other units which held construction permits, and which were listed as less than 10% complete in December

1978. The average of these plants was 3.6% complete (compared to Seabrook 2 at 2.0%), and was scheduled for completion in 12/85. Second units (averaging 3.4% complete) were scheduled for somewhat later operation, with an average 2/86 COD. Thus, the schedule estimate for Seabrook 2 was somewhat more optimistic than average, but was not out of line with a few of the other estimates, and extrapolation of historical experience to Seabrook 2 was only mildly optimistic.

Q: Did observers within the nuclear industry continue to report the problems you described in previous sections?

A: Yes. Again, the A/E's identified the past pattern, although they were loath to admit that their current efforts were subject to the same problems:

> 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 betweeen 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)

From Burns and Roe came the observations that:

> 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 cancelled, and the Nuclear Regulatory Commission has imposed a temporary moratorium on the licensing of nuclear power plants.

The authors 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)

F. C. 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 unrealistic utility attitudes) 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 oepration 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.

Florida Power and Light became a bit more colorful in its description of the problems which resulted in the cancelation 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)

Electrical World continued its increasingly gloomy reviews:

> 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" [sic] 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")

Q: Did the Federal Power Commission surveys continue?

A: Yes. The language of the prose summaries in the **Steam Plant**

Book, now published by the Federal Energy Regulatory Commission (FERC), was becoming quite repetitive:

> 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.

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.

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 judgement 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: 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. These efforts indicated that it was possible to foster conservation, and establish 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 cancelation in 1978. The Wisconsin PSC undertook similar reviews of the need for planned facilities in that state, and concluded that further nuclear investments were inappropriate, which finally resulted in the cancelation of three nuclear units in that state.[24] More careful regulatory oversight was clearly emerging by 1978.

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

A: Yes. As shown in Table 1.1, the Seabrook cost estimate increased twice between the end of 1976 and the beginning of 1979, for a total increase of 29.5%, or 13.2% annually. Meanwhile, the in-service dates for the two units had slipped by an average of 16 months in a period of 25 months, and the scheduled COD for Unit 2 remained over 6 years in the future.[25] As demonstrated by Figures 1.2 and 1.3, the load forecasts for the lead participant and for the region were falling rapidly, slightly eroding the economic value of the plant, and more significantly eroding the financial strength of the owners and potential owners.

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24. 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.

25. BHE

Q: What special problems afflicted the Seabrook project in this period?

A: Two problems which were particularly vexing for the Seabrook project were the continued regulatory problems which flowed from PSNH's decision to start construction before final approvals of the cooling system[26] were in hand. The construction permit was suspended from 1/24/77 to 7/26/77, and again from 7/21/78 to 8/10/78, as a result; the permit was under a cloud for most of this two-year period, including at least one interval in which PSNH curtailed construction in anticipation of permit suspension. In addition, Seabrook was the target of some of the strongest and most militant environmental opposition of any domestic nuclear plant. While this opposition, culminating in an occupation of the site in April, 1977 by over 1400 demonstrators, probably had little or no direct effect on the construction schedule or cost of the plant, it certainly insured an exceptional level of public scrutiny of the safety and financial decisions involving the plant.

Q: How did the problems of Seabrook and the nuclear industry affect the Seabrook owners?

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26. If the cooling tunnels were ultimately rejected in favor of cooling towers, the environmental superiority of the site was open to question and rehearing; all investment at the Seabrook site was at risk so long as those approvals remained conditional.

A: There were several effects of both the general and the specific problems of Seabrook. The combination of rising prices, falling load growth, heightened regulatory scrutiny, and increased plant construction costs combined to force Northeast Utilities (NU) and United Illuminating (UI) to offer part or all of their Seabrook shares for sale. NU offered all of its 12% share in 1976, and UI offered half of its 20% share on January 26, 1979. This was UI's second attempt to sell part of its share; the first attempt, in 1976, floundered due to the permit suspensions. PSNH had been able to maintain its 50% ownership only because of the inclusion of construction work in progress (CWIP) in its ratebase. Legislation to bar CWIP was passed by the New Hampshire legislature and vetoed by Governor Thomson. The election in 1978 of Governor Gallen, who ran on a no-CWIP platform, forced PSNH to solicit interest in a portion of its entitlement early in December, 1978.

PSNH's financial condition in this period was so shaky that the NRC, in order to uphold the ASLB finding that PSNH was financially qualified to build Seabrook, was forced to restate the financial qualification standard. Previously, that standard had required "reasonable assurance" of financing; the Seabrook decision changed this to a standard which only required a "reasonable financing plan", without any assurance that the plan could be achieved. This revision attracted much notice in the utility industry, and was clear evidence that PSNH, for a nuclear lead participant, was unusually vulnerable to financial difficulties.

The Maine utilities were familiar with PSNH's financial problems, as was anyone who was involved in New England utility matters in this period. Mr. Lee's testimony in this docket (p. 13) discusses BHE's knowledge of PSNH's condition, while CMP's understanding of the financial situations of PSNH and UI was laid out in more detail by Mr. Webb in U3238 (Tr. 1135-1138 and P-25 to p. 31), where he referred to PSNH "immediate needs" for cash as being "critical", attributed the unprecedented discounting of Seabrook share to PSNH's "desperate" straits, noted that investors did not know if PSNH "was going to be able to continue ... to pay interest", and described UI's circumstances as "dire". Mr. Kelly of CMP also described some problems of PSNH and Seabrook, and expressed skepticism that Seabrook 2 could even meet a completion date tow years later than the official estimate:

> Q: Now I understand that you're not interested in increasing your ownership in Seabrook, Pilgrim or Millstone.
>
> A: That is correct.
>
> Q: But can you rank them for me in terms of which ones would you most likely invest in if you had to?
>
> A: Reluctantly I would probably lean towards Millstone III.

Q: And why?

A: Because I believe that that project will be completed sooner and it is at an existing site with two other units. They do not apparently have anywheres near as severe regulatory problems as Seabrook has and obviously Pilgrim has.

Q: The capital cost of that plant is higher than Seabrook.

A: It is slighlty higher, yes, but it's better to get a plant in service than to - Seabrook could be considerably higher if it goes to the 1990 time frame - much higher than Millstone III.

Q: And with your 85-87 date for Seabrook you show a capital cost of $17.43 per KW and for Millstone coming on in 86 you show $23.74.

A: That's correct.

Q: So it's a plant coming on sooner, yet it costs more.

A: I don't believe that they're going to make that date. I'm saying if you ask me if I had my preference, I believe where Millstone III is substantially constructed, is being built by a utility that is three times as large as Publice Service Company of New Hampshire and I think the risks are considerably - are less in that unit. I say are considerably - they are less in that unit in my opinion.

Q: That's the first time I've heard that one. The larger the utility that's building it the lower the risk?

A: The larger the utility the more, generally speaking, financial ability they might have. They have a lot of experience with nuclear, much more than Public Service of New Hampshire, for example. They have two operating units and they ran Connecticut Yankeee very successfully. I'm not saying New Hampshire is not a good utility. Don't get me wrong. But they have more experience - a larger utility.

Q: Was PSNH's difficulty in financing its principal nuclear construction program in this period unique?

A: No, it was not even unusual, except in degree. Delays in the in-service dates of nuclear plants, suspension of construction, and even cancelations, were often attributed to the financial condition of the constructing utility. Close to home, Northeast Utilities (NU) decided in 1977 to stretch out construction of Millstone 3, moving the scheduled in-service date back from 1982 to 1986, due to the unit's strain on NU's finances. Seabrook was also the major item in the construction program which was stressing UI's finances. As I discuss in my testimony in 84-120, the ability of Boston Edison (BECo) to finance its 59% share of Pilgrim 2 was also doubted by many observers, including the NRC staff, BECo employees, and CMP employees. As I will show in Section 8, PSNH's nuclear commitment (primarily to Seabrook) was much larger, in proportion to the size of the utility, than NU's nuclear commitment (primarily to Millstone 3), BECo's commitment (to Pilgrim 2), or UI's commitment (mostly Seabrook). Therefore, it should hardly have suprised any of the Seabrook owners that PSNH's ability to finance Seabrook was contingent on favorable, and even exceptional, ratemaking treatment. If that favorable treatment was withdrawn, or threatened, PSNH was sure to have difficulty financing its share of Seabrook.

Q: How did the Maine utilities react to the information available at the end of this time period?

A: Despite all the warning signs, BHE committed itself to purchase 1.8% of Seabrook from PSNH, and CMP committed to 1% from PSNH and 2.5% from UI. Neither of these utiltiies appears to have attempted to link its purchase to any measures which would have increased the likelihood of completion of Unit 1, such as abandonment of Unit 2.

5 - MID-1980: TMI, DPU 20055

Q: What is the significance of the June 1980 date for the Maine utilities' participation in the Seabrook project?

A: This date is near the middle of the transfer process of Seabrook shares from PSNH to BHE and CMP. It also followed closely yet another upward revision in Seabrook cost estimates, with accompanying delays in the completion schedule. This was also over a year after the Three Mile Island (TMI) accident, giving the participants in Seabrook and other plants time to absorb the results of that event.

Q: What important developments occurred for Seabrook 2 and the Maine utilities' participation, in the period from late 1978 to the summer of 1980?

A: Four groups of events took place. First, PSNH received some important warnings regarding its nuclear construction program, including information about the costs and schedule of the Seabrook units. Second, PSNH's attempt to reduce its commitment to Seabrook was not wholly successful, due to saturation of the market for nuclear plant shares, and particularly Seabrook shares, among New England utilities, with a situation of scarcity changing to a situation of surplus. Third, the TMI accident further accelerated the ongoing changes in nuclear regulation. Fourth, the general deterioration in the economics of nuclear power continued, accompanied by a virtual torrent of plant cancelations.

Q: What warning signals regarding its Seabrook investment were presented to PSNH in this same period?

A: There were several such signals. PSNH was a party to Massachusetts DPU 19494, in which I pointed out some of the errors in its load forecast: PSNH's forecast was remarkable for its overstatement of demand, even in an era of universally optimistic utility load projections. In the second phase of MDPU 19494, and again in NRC 50-471 and DPU 20055, 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. Figure 1.2 demonstrates that our overall criticism was well taken, and that the NEPOOL forecast has indeed declined continually both before and since our review. MDPU 19484 also highlighted the enormous cost overruns at Pilgrim 1.

PSNH 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 considerably more limited, I was able to present cost estimate histories for six completed units[27] 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 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 PSNH 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 by the end of that case.[28]

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27. The utilities, including PSNH, refused to provide further cost estimate histories, even for Maine and Vermont Yankee. Had PSNH cooperated in gathering and examining this data, rather than proclaiming its unavailability and irrelevance, perhaps Unit 2 would have been suspended or cancelled in 1980, leaving all the participants less exposed to the current Seabrook debacle: this case might involve the writeoff of 4.38% of a \$200 million investment, rather than a 9.68% share of an \$800 million unit.

28. 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 4 of this testimony. Unfortunately, the utilities, including PSNH, took to heart the optimistic projections of these studies and ignored the dismal recitations of the industry's past and current problems.

Most importantly, however, PSNH itself recognized that it could not afford more than 25% of Seabrook if it retained its shares of Pilgrim 2 and Millstone 3, or 28% if it sold off its shares of those other units. PSNH actually tried to sell its Seabrook share down to 20%, and to sell all of the other units. There was no market at all for Pilgrim capacity, the Millstone 3 shares moved very slowly (about a quarter of PSNH's share was sold in 1982), and by the end of 1980 there were commitments for sales only sufficient to bring PSNH down to 35% of Seabrook. Therefore, even by PSNH's calculations, it was overextended by some 40%; at realistic cost estimates, the financial burden would have been even greater.

Q: Did Seabrook suffer any other problems in this period?

A: Yes. There was a 45 day carpenters' strike in 1979, and persistent problems with shortages of particular skilled trades. Due to PSNH's financial condition, the construction workforce was cut approximately in half in March 1980; this condition was to continue until the summer of 1981. In the third quarter of 1980 (just after the end of this review period), the project suffered a nine-week strike by iron workers.

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 cancelations, 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.

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: Did the cost estimates and schedule projections for nuclear plants improve between 1976 and 1980?

A: No. Table 5.1 presents summaries of the cost and schedule histories of plants which entered service between January 1979 and June 1980. This Table is comparable to Tables 2.1, 2.2, 3.1, and 4.1. The calculated summary statistics indicate a slight improvement compared to the previous decade, but this is eclipsed by the fact that only two units reached commercial operation in this 18 month period. This is partially the result of new safety requirements following the TMI accident, but the trend was evident in 1978, as well, when only three units reached commercial operation. Even the fact that only the two units listed in Table 5.1 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. Considering that the apparent improvement in the ratios was really due entirely to an exceptional performance by Hatch 2,[29] while Arkansas 2 cost experience was as bad as average, and its schedule slippage was worse, the 1980 data indicate that the situation had not improved, and in fact had deteriorated considerably. Applying the cumulative results through 6/80 to the 4/80 estimate for Seabrook 2 would predict a cost of $3.47 to $4.51 billion dollars, and an in-service date of 7/88, while the results for Hatch 2 and Arkansas 2 alone would project a cost of $3 - 3.7 billion and an in-service date of 3/88.

Table 5.2 updates the slippage analysis from Table 4.2. The cost and schedule estimates as of both 12/78 and 6/80 are listed, along with the percentage increase in the cost estimate, and the months of slippage in the in-service date. The schedule for the average of these 77 units had slipped

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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 one good example of this effect; St. Lucie 2 is another celebrated case. I am not sure that the Maine utilities' could have been expected to see this pattern; if it did, the Hatch 2 experience would have to be discounted as a model for Seabrook 2, at least until Seabrook 1 entered service.

slightly faster than the time between the estimates, producing negative progress, and the average cost estimate had increased about 18% annually. Unless the schedule performance improved, the average plant would never be completed (and in fact, many of the units with negative progress in Table 5.2 have since been canceled.)

If Seabrook 2 were as fortunate in its schedule as the average <u>completed</u> plant (from Table 5.1) through June 1980, so it entered commercial operation in 7/88, and its cost only increased by 17.7% annually, it still would have cost $6 billion; the later its completion, the worse this result was likely to be. As we will see, even PSNH's ability to complete the unit on PSNH's schedule and at PSNH's cost projection was highly questionable; on either a financial or an economic basis, it was only reasonable to expect that a continuation of recent trends would have been fatal to Unit 2, probably also to the plant, and possibly to the utility as well.

Table 5.3 compares the schedule projection for Seabrook 2 to that of other units which held construction permits, and which were listed as less than 10% complete in December 1980 (since I have not been able to find the same data tabulated for 6/80). The average of the eight units with COD schedules was 4% complete (compared to Seabrook 2 at 7.7%), and was scheduled for completion in January 1990. None of the units was scheduled for operation until 20 months after the scheduled Seabrook COD; even WPPSS 4 (listed as 15% complete) was scheduled for 2/87 COD. Thus, the schedule estimate for Seabrook 2 was highly optimistic, compared to the industry average, and greater overruns than average would be expected.

Q: Please describe the history of cancelations of ordered reactors within the US nuclear industry.

A: Figure 5.1 portrays the annual and cumulative cancelations, through 1983. Figure 5.2 presents the number of new orders, the number of cancelations, and the net change in orders in the same period. While some of the canceled units had construction permits, units awaiting permits were more heavily hit by the wave of cancelations. Table 5.4 lists the plants canceled in 1977-80, with the construction status of each.

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.[30] 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 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.

Mr. Kelly described the effects of the Three Mile Island accident on Seabrook as

> We don't know the problems at Three Mile Island. That's the risk situation and we don't know what might happen to Seabrook. There might be another $200,000,000 required to make that plant meet the new criteria--or it might be 500--or it might be nothing--to meet the criteria the NRC might or might not come up with. We don't know, in our opinion, what's going to come out of the Three Mile Island situation as far as nuclear.

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30. The NRC was less willing to address the difficult, "generic" issues which might bring into question the viability of the industry.

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)

Q: Was CMP aware of the problems of Seabrook, PSNH, and the industry in this time period?

A: CMP was certainly aware of industry problems, including the financial problems at Millstone 3, the effects of Three Mile Island on regulatory and investor confidence in nuclear investments, the upward trend in cost estimates, the continuing slippage in schedules, and the difficulty in licensing new plants. CMP was also aware that PSNH and Seabrook had problems. Specifically referring to Seabrook, but discussing nuclear issues in general, Mr. Kelly observed that

> There is a certain amount of risk involved in the nuclear capacity and I believe the last two or three months have borne that out very clearly. . . [Seabrook would be cheaper in terms of KW cost than the anticipated cost of Sears Island] [u]nder the current cost that they estimate, assuming they're accurate . . . Not knowing what's going to happen out of the NRC after the latest events, there are some people . . . that say it will be more expensive than coal, but I don't know. (ibid, page 184).

This is, of course, the fundamental problem with nuclear power: the plants are generally economical at their projected costs, but the projections have little chance of becoming reality. Furthermore, Mr. Kelly did not expect the uncertainties and problems surrounding nuclear power development to be resolved soon:

> Q: Okay. So right now you're generally pretty lukewarm to any nuclear. Is that right?
>
> A: That is correct. That's exactly correct.
>
> Q: But that could change momentarily, say within weeks?
>
> A: No, sir. I doubt if it'll change within weeks. I suspect it'll take years before they get straightened out. With Three Mile Island it'll probably take a year --

His rebuttal testimony discussed these issues further:

> Q: Mr. Kelly, are you aware of the original and current schedules for the Seabrook, Pilgrim, Millstone and Montague nuclear plants which are suggested in the ADL optimistic nuclear options?
>
> A: Yes, I am. The original in-service dates for Seabrook 1 and 2 was 1979 and 1981 and the current dates are 1983 and 1985. The original in-service date for Pilgrim 2 was 1978 and the current date is 1985. The original in-service date for Millstone 3 was 1979 and the present date is 1986. The original in-service dates for Montague 1 and 2 were 1981 and 1983 and are now some time in the early 1990's. This constitutes a four year delay for Seabrook; a seven year delay for Pilgrim 2; a seven year delay for Millstone 3 and an estimated ten year delay for the Montague Station.
>
> Q: What have been the primary causes of these delays?
>
> A: Nuclear plant delays in New England have in generaly been based on a decline in load growth, financial problems, and regulatory and licensing delays. While there is some reason to believe that the load growth rates have stabilized, there is

> little, in my opinion, to justify the belief that financial problems or licensing and regulatory delays are going to be significantly reduced in the short term especially in regard to nuclear plants. Mr. Monty has more to say on this point.
>
> Q: Do you believe Mr. Heuchling's assumed nuclear delays are reasonable?
>
> A: Mr. Heuchling's assumed nuclear delays are consistent with the past history of delay and from that point of view they are not unreasonable. However, Mr. Heuchling's major theme is that nuclear delays are controlled primarily by reduced load growth in New England. While Mr. Heuchling's testimony is unclear on this point he may also be suggesting that with higher load growth in New England more nuclear plants could be brought on line. If this is an underlying assumption by Mr. Heuchling, he would necessarily be ignoring the huge impact regulatory and licensing delays have had on nuclear plants in New England and nation-wide. With the Three Mile Island incident fresh in the mind of the public and government and Central Maine's own experience with Maine Yankee, I see little reason to assume that the impact of regulatory delays will be removed ro reduced with regard to nuclear power. My primary concern is with the situation where load growth is higher than Mr. Talbot has assumed for New England and Maine and that nuclear plants will not be able to be built on a schedule to meet that load growth because of financial and regulatory problems.

Indeed, Mr. Monty did have more to say on the subject:

> . . . I would consider the Company's . . . probability of getting 459 megawatts from a 1992 nuclear plant to be no greater than 25% . . . I base this judgment primarily on the current public attitude toward nuclear power prevailing since the Three Mile Island incident and the construction delays and regulatory difficulties encountered in the construction of nuclear plants even prior to the Three Mile Island incident . . . [B]ased on these same considerations, I view the probability that nuclear plant construction will proceed on schedule in New England to be no greater than 50% . . . (Rebuttal, page 13)

Mr. Monty also offered his opinions that "indefinite postponement of nuclear construction in New England", "an extraordinary escalation of nuclear costs", and "a failure of the regulatory process such that power plant construction in New England falls behind the actual load growth",

> all four of these conditions have a high probability of occurrence. First, the postponement of nuclear power plant construction in New England rather than being a matter of judgement, is a matter of history. There is not a single nuclear plant proposed for New England which has not been significantly delayed. The Sears Island Nuclear Plant was cancelled because of regulatory requirements; the two Montague units have been indefinitely postponed because the Massachusetts Energy Facilities Siting Council has refused to hold the required siting hearings. The two Charlestown units do not have a site. As a result of court action the constructing utility has been unable to buy the Charlestown site from the General Services Administration. The Pilgrim No. 2 unit still does not have a construction permit although the project started eight years ago and has been almost continuously in the courts and before regulatory bodies for the entire period. The Nuclear Regulatory Commission recently announced a moratorium on new permits and there are currently several bills before Congress calling for a moratorium on nuclear power plant construction. The Millstone No. 3 plant is currently being constructed on a delayed schedule becasue of the inability of the principal owner to finance a normal construction schedule. This plant which was originally scheduled for completion in 1979 is now scheduled to be finished in 1986. The two Seabrook units are currently being built following two halts to plant construction caused by controversies over the cooling water system and the appropriateness of the plant site. Most recently the plant has been rescued from a third construction halt by the purchase of part of the ownership interest of Public Service Company of New Hampshire by utilties in the other New England states. I have also included Exhibit Monty-6 which shows nuclear plant deferrals and cancellations in 1977 and 1978. In 1977 there were six reactors cancelled, totalling 6,384 MW and in 1978 there were twelve reactors cancelled, totalling 12,433 MW. This data and exhibit were taken from the Atomic Industrial

> Forum, Inc. publication INFO dated December 31, 1978. All in all, the construction outlook for all nuclear power plants is highly questionable at the present time.
>
> Second, nuclear power plant costs have already undergone an extraordinary escalation. A 800 megawatt nuclear plant such as Maine Yankee which was completed in 1972 at a cost of less than $300 a kilowatt. A 1200 megawatt plant scheduled for completion in 1987 will probably cost about $1700 a kilowatt. This increase represents almost 500% cost escalation in 15 years, an escalation appreciably higher than expected for the cost of living index. Much, if not most of the increase has resulted from added requirements imposed by the Nuclear Regulatory Commission. In light of the Three Mile Island incident it is certainly reasonable to assume the Nuclear Regulatory Commission requirements and the attendant added costs will increase the extraordinary escalatin of nuclear costs. . .
>
> Finally, the failure of the regulatory process in allowing nuclear plant construction to progress pm schedule is a fully demonstrated fact of history. Not a single New England nuclear plant has been built on schedule since Maine Yankee was completed in 1972. Every nuclear plant currently in process in New England has been delayed in some manner by the regulatory process as I have already discussed. To assume that substantial further delay will not be encountered in my opinion is to engage in wishful thinking. In light of delays of the plants now contemplated, there should be little confidence that future delays will not be beyond the time the plants are needed to meet actual load growth. Regulatory issues such as nuclear safety and construction work in progress are highly emotionally matters as evidenced by the public mood in the aftermath of the Three Mile Island incident and by the recent New Hampshire gubernatorial election, where "construction work in progress" was a major campaign issue. Public pressures are very likely in the future to delay the completion of nuclear plants beyond the dates when they are required to meet actual load growth.(ibid)

This was a fairly scathing denunciation of nuclear power, and certainly indicates that CMP was not blind to the problems of the technology.[31]

Mr. Webb's rebuttal in that proceeding also discussed the regulatory, financial, and risk problems of nuclear power:

> It is a generally accepted theory that due to the regulatory process governing rates of electric utilities, period of extended "heavy" financing are also period of financing deterioration. It is further generally true that weaker credits must pay more for borrowed funds. Therefore, if we assume that the "optimistic nuclear option" significantly increases CMP's external capital requirements during the 1979-1983 period, it is also reasonable to assume that CMP's overall cost of capital will tend to be greater than it otherwise would have been. . .
>
> General federal government and regulatory ambivalence toward the nuclear industry coupled with the Three Mile Island incident and the shutdown of various nuclear plants has created an attitude of uncertainty in the marketplace is presently demanding a premium for investing in nuclear-related utilties. CMP Exhibit No. Webb-1 shows that for the period since the accident at Three Mile Island through May 21, 1979, the New York Stock Exchange Utility Index declined 3.8%, while utilities with significant current or future nuclear generation declined 6.7%. During this same period Central Maine Power Company stock declined 10.5%. How long this "nuclear premium" will be reflected in the marketplace is difficult to say, but the financial risks associated with nuclear generation, which have been highlighted since the Three Mile Island incident and subsequent shutdowns, are obviously weighting heavily on the minds of investors and may well indicate a slow return to the point where no "market premium" is

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31. Mr. Monty's list also included an endorsement of the NEPOOL forecast, indicating that his perceptions were not infallible. However, that endorsement consisted only of the claims that the NEPOOL staff was professional and that its model was large, new, and "state of the art"; compared to his specific arguments on other topics, this is close to damning by faint praise.

associated with nuclear intensive companies . . .

The "optimistic nuclear option" in general assumes there is no additional business of financial risk associated with basing the energy future of this state and the financial well-being of the owners of Central Maine Power Company totally on the future of nuclear generation. In my opinion, that is not reasonable, especially when we face the unanswered questions of spent fuel disposal, decommissioning costs and methodology, regulatory delay and social and political opposition. Although I believe that nuclear power is essential to the energy future of this country, I also believe that any decision regarding a major new commitment to nuclear at this point in time must consider the potential financial impact of these many risks.

6 - THE EARLY 1980's

Q: Did the patterns and trends you identified in earlier sections continue from June 1980 to the end of 1982?

A: Yes. The pattern of cancelations is shown in Figures 5.1 and 5.2. The problems of the nuclear industry were widespread; utilities with nuclear construction programs became particularly suspect in the investment community. The cost overruns and schedule slippage continued.

Q: What was the cost and schedule experience for units entering service in this period?

A: Only seven units went commercial in these 30 months: one in 1980, four in 1981, and two in 1982. The average cost and schedule experience of these units was worse than that of the previous decade, and six of the seven units had higher duration ratios and myopia factors than the historical average, as shown in Table 6.1. The one exception was LaSalle 1, a Commonwealth Edison unit, which beat the averages by small margins. If the Seabrook 2 cost estimate of 12/82 were subject to the average myopia and duration ratios that these seven units had experienced, it would have been completed in 5/94 and cost between $10.8 and $12.4 billion.

Q: How does this differ from the results of continuing the average experience of all the units which entered service by 1982?

A: Applying the 26% myopia and the 1.79 duration ratio to PSNH's estimate of a 4.58 year duration and a cost of $2.7 billion would result in a cost of $6.5 to $7.8 billion, and a COD of 2/91.

Q: What was the experience of units under construction in this period?

A: This data is displayed in Table 6.2, which shows an average progress ratio of 33.9% and an average annual cost increase of 25.3%. If this performance were duplicated by Seabrook 2 during the remainder of its construction period, it would be completed in 6/96 at a cost of some $57 billion. As in the previous Section, a continuation of the cost trends for units under construction would preclude completion of Seabrook 2.

Q: Was the Seabrook 2 estimate consistent with the general industry cost and schedule projection methodologies?

A: Not quite. In 12/82, Seabrook 2 was reported to be 16.9% complete: virtually all plants listed as less than 20% complete had been canceled or indefinitely deferred by this point. Table 6.3 lists the units less than 30% complete as of 12/82. The five other units with scheduled COD's and less than 30% complete averaged 18% completion, and a scheduled in-service date of 12/88. Of these units, the one closest to Seabrook 2's COD schedule was Limerick 2, which was 30% complete, and was still scheduled for operation five months after Seabrook 2. Other units scheduled for completion in 1987, comparable to the Seabrook 2 schedule, were listed as up to 62% complete. Therefore, it is likely that PSNH's schedule for Unit 2 (and thus at least part of the cost projection) was very optimistic at that point, even by industry standards. As a result, simply using historical experience with utility cost estimates would have been optimistic: since the Seabrook 2 schedule was especially aggressive, it was also likely to slip more than the average.

Q: What was the status of the units which were cancelled in this period?

A: Table 6.4 displays this data. The high rate of cancellations shown in Table 5.4 continued, with units holding construction permits becoming an ever larger portion of the cancelations. Of the six units with permits canceled in 1979 and 1980, four were killed by state actions, and a fifth was owned by General Public Utilities (GPU), which also owned Three Mile Island, and which had neither the cash nor the inclination to attempt to continue construction of another nuclear plant in the aftermath of the TMI accident. None of the canceled plants in 1979/80 had been listed as more than 5% complete.

In contrast, 1981 and 1982 saw the cancelation of fourteen units with construction permits, most of which were canceled because the utility determined either that the unit was uneconomic or that the unit could not be financed. When four of the units were canceled, they were reported to be more complete than Seabrook 2 was at the end of 1982, and four more were over 5% complete.

Q: Was there any more bad news for Seabrook in this period?

A: Yes. Perhaps the worst news was that the market for Seabrook shares, and indeed for any nuclear plant under construction, had finally dried up completely. PSNH was unable to reduce its ownership share below the 35% level, and UI was left with 17.5%. Thus, PSNH had about a third more plant to finance than it had told its commission it could afford,[32] and UI had 75% more than it wanted.[33]

In January 1982, the NHPUC ordered PSNH to reduce its ownership share of Seabrook from 35% to 28%, indicated that it would attempt to block further work on Unit 2 if PSNH's bonds were downgraded again, and offered PSNH the option of

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32. It is not clear whether the 25% or the 28% target was more applicable, since Pilgrim 2 was canceled, rather than sold, and only part of the Millstone share had been sold.

33. NU was also unable to find a buyer for the remainder of its entitlement in Seabrook, but its financial exposure was less extreme than that of UI or especially PSNH.

canceling Seabrook 2 to alleviate its financinal problems. In July 1982, following the next reduction in bond ratings, the NHPUC attempted to force PSNH to suspend construction of Unit 2 until it could either reduce its share of the plant to 28%, complete Unit 1, or receive some equivalent financial assistance from the Joint Owners. The PUC recognized that PSNH's finances were critically stressed by the attempt to build two units simultaneously, and acted to protect the utility from itself. PSNH appealed the PUC's order; CMP and MPS, along with other Joint Owners, joined in the appeal in support of PSNH. It is difficult to understand why these Maine utilities supported PSNH's efforts to destroy itself; on the face of it, this action was totally imprudent. If the Maine utilities had any role in the proceeding, it should have been in support of the NHPUC. As it turned out, the NH Supreme Court's suspension and eventually overruling of the PUC's order was predicated on the statutory limits of the PUC's powers, rather than on the merits of the case. Nonetheless, the opposition of even a single joint owner to continued expenditures on the plant might have forced PSNH to comply with the spirit of the PUC order.

In February 1982, the NRC staff produced a list of expected 1982 cancelations, which included Seabrook 2. While this study was primarily intended as a summary of current expectations, and did not include any new financial or economic analysis, it clearly identified Seabrook 2 as among the most likely candidates for prompt cancelation.

In November 1982, the MPUC found that Seabrook was likely to cost over $8 billion, as compared to PSNH's estimate of $5.24 billion in December. I have not found any indication that any of the Maine utilities re-evaluated the cost-effectiveness of Seabrook 2 at the PUC's cost estimate.

7 - ECONOMIC ANALYSIS

Q: How have you investigated the economic desirability of Seabrook 2?

A: I have compared the cost of energy from Seabrook 2 to the cost of energy from new coal plants, and from existing oil plants, using my estimates of Seabrook cost and NEPOOL estimates (NEPLAN 1976) for most other inputs. This analysis as of 1976 is presented in Table 7.1. Since the Maine utilities have not provided their own analyses for most of the Seabrook planning and construction period (and apparently did not perform any analyses), these NEPOOL reports are my best estimates of the Maine utilities' assumptions at this time. In fact, CMP relied on these studies in later analyses, and these coal plant costs were similar to CMP's estimates of Sears Island costs. Many of the assumptions are highly favorable to nuclear power, including

- the absence of decommissioning charges
- the absence of capital additions
- the lack of any real escalation (that is, above the level of inflation) in nuclear O&M expenses
- the use of a very high nuclear capacity factor.

In addition, the Seabrook cost estimate used in Table 7.1 is the average of the results for completed units in Table 3.1, rather than the more pessimistic results for the units under construction in Table 3.2. Even in Table 3.1, the myopia results, which recognize the construction stage (and expected remaining duration) of the plant, are more pessimistic than the results from the historic cost ratios, which neglect the long expected construction period for Seabrook 2.[34]

Tables 7.2 to 7.4 update this analysis to 1978, 1980, and 1982, respectively. NEPLAN revised its maintenance assumptions in 1979 (NEPOOL Planning Committee, 1979), and revised most of its assumptions in 1982 (NEPLAN 1982). Table 7.2 and 7.3 compare the cost of Seabrook 2 power to the cost of energy from existing oil plants, as estimated by CMP in January 1979 and February 1980, and provided in the restrospective analyses of Exhibits Webb-15, Webb-17 and Webb-18 in 82-266.[35] Table 7.4 uses actual Wyman 4 oil prices in 1982, and NEPLAN inflation rates. These tables contain the same sources of nuclear optimism as Table 7.1, and the 1980 and 1982 analyses also do not correct for the highly aggressive nature of the Seabrook 2 cost estimates at

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34. The Tables subtract out the sunk cost of Seabrook 2 at each point in time, which is appropriate for utilities which already owned Seabrook shares. For new purchases, the entire cost is relevant.

35. CMP has not provided comparable information for 1976.

those times.

Q: Was there evidence by 1976 to suggest that these assumptions were optimistic?

A: Yes. Table 7.5 lists the annual non-fuel O&M expenses for all nuclear plants in operation for each year from 1968 to 1981. Table 7.6 provides the booked plant cost for each plant for each year in the same period, along with the increase in the cost in nominal and constant dollars. O&M expenses were clearly increasing much faster than inflation, and capital costs for existing plants were also increasing. Table 7.7 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 1975, 1977, 1979, and 1981, corresponding to the data available in 1976, 1978, 1980, and 1982, respectively. Since the average size of these units was less than that of Seabrook, 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 Seabrook would be optimistic. Nonetheless, the historic capacity factors were consistently less than NEPLAN and Maine utilities' projections for Seabrook. Column B of Tables 7.1 through 7.4 demonstrates the effect of using cumulative average PWR capacity factors instead of NEPLAN's baseless assumptions.

CMP was aware of the cost increases in operating plants, as Mr. Kelly noted in U3238 (Tr. 229-230).

Q: The--so I would assume with respect to--using Seabrook as an example--if Seabrook were actually operating, if it were licensed completely by the Nuclear Regulatory Commission and operating, you would view it differently than you would today?

A: We would look at it slightly different on that one criteria, but, as you know, the other major critia I mentioned was risk, and that obviously would have some bearing.

Q: If I understand it, the risk you were talking about was the risk that the plant won't be operating when you want it to be operating.

A: The risk is the nuclear risk in general, the risk of probable increased costs of those plants which we see about in the papers all the time.

Q: Here, though, we're talking about--the assumption now is that Seabrook's operating already, so I would assume you already know what the costs are.

A: Yes, but the back-fit costs to keep some of these nuclear plants to meet the criteria, if they change the criteria at the NRC--which is conceivable; I guess everybody would have to agree to that--the costs could continue to go up. We would look at it if it was operating.

Q: How do these results compare to the results of Mr. Webb's retrospective analyses of Pilgrim 2 costs in Exhibits Webb-15, 17 and 18 in PUC 82-266?

A: Tables 7.8 and 7.9 repeat these analyses, but increase the fixed charges by the ratio of the average projection of Seabrook 2 cost from historical experience (from Tables 7.2 and 7.3) to BECo's cost estimate for Pilgrim used in Mr. Webb's exhibits. These Tables also start in the year indicated as the first year of Seabrook 2 operation in Table 7.2 and 7.3, and compute a cumulative discounted difference at the discount rates derived in those Tables. Even using CMP's capacity factors, Table 7.8 indicates that a realistic review of the dependability of BECo's cost estimate would have indicated that Seabrook 2 would be much more expensive than oil. Table 7.9 indicates that by 1980, CMP's assumptions would indicate that power from Seabrook 2 would pay off against oil in several years, if construction of Unit 2 were still possible. Seabrook 2 looks better in Table 7.9 because PSNH's official estimate was extremely optimistic, and I have not corrected for that source of error. Furthermore, both the nuclear and oil cost projections in this Table are so high that it is difficult to believe th other, less expensive options were not available.

Figure 7.1 reproduces Exhibit Webb-15, but adds a realistic Seabrook busbar cost, derived by multiplying BECo's capital cost recovery (in mills/kwh) for Pilgrim by the ratio of my realistic cost estimate for Seabrook 2 ($3122 million) to BECo's estimate used in preparing the Webb-15 ($1521 million). The cost advantage of the BECo estimate over coal is obliterated by an increase of this magnitude and would have been eliminated by a cost increase as small as 75%. Therefore, Exhibit Webb-15 demonstrates that Seabrook 2 power was virtually certain to cost more than power from BECo's hypothetical coal plant.

Figure 7.2 reproduces a similar analysis by BHE, from the July 1977 Base Load Capacity Expansion study (Exhibit Lee-7). The capital cost of the BHE nuclear option (apparently the NEPCo units at $910/KW or $1.05 billion each) is increased to reflect my 12/76 corrected cost estimate for Seabrook 2 ($3.122 billion).

Q: Were these the only comparisons that the utilities should have conducted at the time?

A: No. Once Seabrook 2 was found to be uneconomical compared to continued oil consumption or new coal plant construction, it still remained to be determined whether the coal and oil options were the best choices. Other alternatives which should have been considered as early as 1976 included aggressive conservation programs, coal conversions of existing capacity in Maine and elsewhere in New England (the Maine utilities might, for example, have offered to purchase BECo's efficient Edgar station and converted it to coal, rather than allowing BECo to dismantle it), customer-owned or utility-owned cogeneration (fired by wood, coal, or oil), small hydro plants, trash-burning facilities, and purchases from (or co-operative development in) Canada. It is my understanding that CMP never studied most of these options seriously during the period of its Pilgrim investment, and those which it did pursue only entered its supply plans rather late in the 1970's or in the early 1980's, and were not generally seriously compared to nuclear expansion. For example, in commissioning a study of cogeneration potential by C. T. Main, CMP basically assumed the results of the study (U3238 Tr. Q-22 to Q-25). Had CMP analyzed the issue without prior biases, it would almost certainly have found that cogeneration is not "too small, too costly, or too geographically diffuse" to justify significant development, and much of the cogeneration capacity now in the pipeline could have started up years earlier. The same is true, of course, of other small power producers.

Q: What do you conclude from these analyses?

A: Each of these analyses indicates that the use of a realistic Seabrook 2 cost estimate, combined with standard NEPOOL assumptions, would have resulted in the conclusion that Seabrook 2 power would be more expensive than power from new coal units, for any analysis performed from 1976 to 1982, and that Seabrook 2 was not competitive with existing oil plants in most of this period. This is true despite the use of the optimistic nuclear assumptions I cited above.

Q: Why do your conclusions regarding the economic desirability of Seabrook 2 differ so much from those of Dr. Perl?

A: There are several reasons. The most important include:

- Dr. Perl assumes throughout that Unit 2 was financially feasible, which was in doubt by 1976. Among other things, this assumes that Unit 1 rate shock (or ratemaking to avoid that shock) would not endanger the financing of Unit 2.

- Dr. Perl assumes that nuclear, coal, and oil were the only available choices. This is clearly contrary to fact, as Hydro Quebec, Maine's small power producer programs, and California's conservation programs have demonstrated.

- Dr. Perl uses very low discount rates, which are calculated from an incorrect method. Even if it were correct, it would not have been reasonable to expect the utilites to use the discount rate methodology which Dr. Perl prefers.

- Dr. Perl's nuclear cost estimation methodology has some fundamental technical shortcomings, and it is not a method which the utilities could reasonably have been expected to employ, especially in the early- to mid-1970's.

- Most importantly, Dr. Perl assumes that it was prudent to continually expect nuclear construction and operating costs to stop increasing.

Q: You discuss financial feasibility and other power supply options elsewhere in your testimony. What is wrong with Dr. Perl's discount rate methodology?

A: Dr. Perl uses the after-tax cost of money (ATCOM) as a discount rate, which is the average cost of capital to the company, minus the tax credit due to the deductibility of the interest on debt. Using the average cost of capital is erroneous, since the discount rate used should reflect the degree of risk involved in the projected stream of costs and benefits. As CMP noted many times in U3238, nuclear is a very risky investment, riskier than coal plant construction, and almost certainly riskier than any other major activity of the Maine utilities, and should therefore be assigned a higher discount rate. Dr. Perl is actually discounting customer costs, rather than utility costs, and should therefore use approximations of customer discount rates, rather than utility discount rates. However, I would not expect a utility in the mid-1970's or early 1980's to recognize these relative fine points in economic evaluation. Thus, I accept as reasonable the past use of discount rates based on average utility costs of capital, despite the fact that it is not quite correct. My disagreement with Dr. Perl centers on his use of the ATCOM, rather than the full cost of capital.

Dr. Perl believes that the present value of an expenditure is the same, regardless of whether the cost is expensed or capitalized, so long as the discount rate is return net of the debt tax shield, and thus that he has constructed his analysis so that consumers will be indifferent between expensing and capitalizing costs. The "after tax cost of money" Dr. Perl defines is only relevant to the company if (a) revenues do not vary with financial structure (which is true for most corporations, but not for utilities), or if (b) there is no taxable return on the investment (neither a delayed return, such as AFUDC, nor an immediate return, such as rate base treatment). If the return on investment is to be covered by increased revenues, taxes must be <u>added</u> to the cost of money, not subtracted, to establish a discount rate at which the consumers would be indifferent between expensing and capitalizing expenditures. Under traditional rate-base treatment, the utility is paid a cash return on its investment, and it must therefore pay additional taxes if it capitalizes, rather than expenses, its expenditures. Hence, the discount rate at which the consumers are indifferent between expensing and capitalizing is the overall rate of return, plus income taxes. Only if the capitalized investment yields neither a current return nor a future return will the net-of-tax rate be the discount rate at which ratepayers are indifferent between expensing and capitalizing the cost.

Q: Does Dr. Perl offer any support for his claim that this ATCOM method is correct?

A: Yes. In response to 33 Staff 19, he offers some calculations which purport to show that the ATCOM produces the same present value of rates, regardless of the time period of the recovery of costs. In this response, he has made the counterfactual assumptions that (a) the tax life of Seabrook 2 is one year and (b) the flow-through method of tax accounting is used. As a result, he implicitly assumes that the government makes a $500 (for the $1000 dollars of plant cost in his example) loan to the ratepayers for the duration of the cost recovery.

The more realistic example in Table R-1 in my rebuttal testimony in Phase 1 found that the rate of indifference was the average cost of capital, plus taxes on equity. Recognition of tax credits and accelerated depreciation would bring the break-even discount rate down towards the average cost of capital.

Q: What rates were utilities using for this type of analysis in this time period?

A: NEPOOL studies appear to use the overall cost off capital. I am not aware of any utility analyses in the 1976-1982 time period which used the ATCOM as a discount rate.

Q: What are the problems with Dr. Perl's technical approach to nuclear cost estimation?

A: A: There are three generic problems with the approach to nuclear cost projections, which are intrinsic to any regression analysis across plants. First, the data on construction costs are not well suited to comparison between plants, since the cost of each plant will depend on the amount of escalation included (and hence on the amount of work performed in each year), the utility's AFUDC rates, and whether CWIP was included in rate base (and if so, how much and for how long). Correcting for differences in prevailing prices, financing costs, and accounting practices, to produce comparable cost figures for individual plants, requires tremendous amounts of data, or some strong assumptions. The same is true for such other site-specific and company-specific factors as labor-management relations, and the accounting treatment of nuclear-related overhead.

Second, there is an intrinsic selectivity bias in this technique: the successful plants are included in the data base, while the canceled or delayed plants are not. This problem is particularly severe for later cohorts, for which only a few exceptional plants have entered service (and the data base).[36] Treating these exceptions as if they were typical of their cohorts understates the time-related cost trend.

Third, the results of these projections are very sensitive to the functional forms and independent variables chosen, especially where it is necessary to project the effects of variables well beyond the range of the historic data. For example, the continual increase in plant cost with time can be modeled as a function of construction permit (CP) issuance date, commercial operation date (COD), the average of the CP and COD dates, the number (or MW) of plants in service (or under construction) at the CP or COD, the cumulative operating experience in plant-years (or MW-years) at the CP or COD, the number of NRC regulations issued during

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36. The same may be true for large plants, which are concentrated in the later cohorts.

construction,[37] and so forth.[38] Each of those variables may be transposed as a logarithm, an exponential, a reciprocal, a power or root, and more. Each variation may produce a different projection for a particular unit, especially for one near or beyond the end of the data set, such as Seabrook.

It also would have been impossible for the utilities to have performed most of the analyses which Dr. Perl suggests they might have performed, since he uses data through 1982 to estimate construction and operating costs as early as 1973. Even assuming that the utilities could have done these analyses with data that did not yet exist, I do not believe that it is reasonable to expect that they would have done so, and it is not at all clear what they would have concluded had they used Dr. Perl's techniques with the data then available and their own choices of specifications.

Q: What does Dr. Perl assume regarding the adverse trends in nuclear construction and operating costs?

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37. "Regulation" may be defined in several ways, to include regulatory guides, bulletins, and so on, and the number of the applicable document can be measured as an average number issued per year of construction, total issued during construction, total issued at CP or COD, etc.

38. Since Dr. Perl chooses to assume in each year that there will be no more bad news, this is not as important an issue as it is for more realistic analysts, such as Komanoff and ESRG, who attempt to forecast future regulatory effects.

A: He assumes that in each year it was prudent and correct to ignore past experience and to assume that future costs will not increase from current levels. This is his most serious error, by far. The data and industry quotes which I present, and the regression results which Dr. Perl presents, all indicate clearly that the cost of building and operating nuclear units was rising steadily throughout the 1970's (and even before), and there was much evidence that the trend was continuing and even accelerating at many times. Dr. Perl has made many incorrect projections of nuclear plant costs, going back to at least 1978, although he has often warned his readers that his conclusions were based on the assumption that nuclear cost escalation (or at least the worst of it) was over. I do not believe that utilities which based investments on Dr. Perl's admittedly optimistic projections were prudent at the time, and I disagree strongly with Dr. Perl's suggestion that retrospective prudence determination should accept utility errors based on the naive assumption that nothing else can go wrong with nuclear power.

8 - FINANCIAL ANALYSIS

Q: What is the difference between economic feasibility and financial feasibility?

A: Economic feasibility is desirability of the plant from a cost-benefit perspective, in terms of its costs compared to alternative sources of power. Financial feasibility is the ability "to get from here to there", to actually pay for the investment. The previous section presents a very strong case that Seabrook 2 was not economically feasible as far back as 1976. But even if the plant were economically feasible, compared to a hypothetical (and worse-case) alternative of burning oil over the life of the unit, it could not be built if it were financially infeasible. This is the situation that Seabrook is in now: neither unit is likely to be economically feasible, but we will never know, since unit 2 has become financially infeasible and unit 1 is likely to follow soon.

Q: How did the relative size of PSNH's proposed nuclear construction program compare to those of other New England utilities?

A: Table 8.1 compares the 1972/73 commitment (in MW's and in projected dollar costs) by NU, UI, and BECo in nuclear plants planned for operation in the late 1970's and early 1980's (Seabrook, Millstone 3, and Pilgrim 2) to PSNH's commitment. The table also lists various measures of the size of the utilities, such as peak demand, sales, revenues, and net plant in service, and the ratios of the size measures to their nuclear commitments. The relative burden on PSNH would have been much heavier than those on any of the other utilities by all of these measures. While I have not performed this tabulation for all the major New England utilities, I believe that the results would be the same if any of the other utilities were used instead. Thus, it could have been anticipated in 1972 that, if any major New England utility were stressed by its nuclear construction program, PSNH would be the most likely candidate. It could also be determined that PSNH was undertaking a much larger commitment to a single plant, in proportion to its size, than any other major utility in the region.

Q: Did this relationship persist throughout the period of Seabrook 2 construction?

A: Yes. Tables 8.2 through 8.5 update this analysis to 1976, 1978, 1980, and 1982, respectively. Since UI originally attempted to sell Seabrook shares in 1976 to alleviate its financial problems, and renewed its attempt in 1978, and since NU deferred construction of Millstone 3 in 1977, and offered its share of Pilgrim and Seabrook for sale in 1976 for similar reasons, these utilities were financial canaries for the other New England utilities. By 1978, it was well known that BECo was having difficulty financing Pilgrim 2 without CWIP in ratebase.[39] In 1976, and thereafter, PSNH was more exposed than any of these utilities, whose nuclear investments were already causing considerable difficulty. Thus, the financial problems for PSNH's commitment to Seabrook 2 should have been evident as early as 1977, when NU slowed down construction of Millstone 3, and certainly by 1980.

Q: Did the financial analyses of the Maine utilities support similar conclusions?

A: Yes. From CMP's viewpoint, it is particularly significant that BECo was carrying a greater nuclear commitment than CMP found prudent for itself. Tables 8.3 through 8.5 include financial data for CMP, at the nuclear investment levels which CMP found excessive in Mr. Monty's testimony in the second round of U3238 (filed 8/22/80): 280 MW of Seabrook, 28 MW of Millstone 3, and 33 MW of Pilgrim 2. Mr. Monty described this case as "deleterious", producing "significantly higher risk" for CMP and creating serious effects on CMP's financial status, at least without CWIP in ratebase (which PSNH lost early in 1979). Assuming that this

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39. See Staff Exhibit 57, PUC 82-266, quoted at the end of Section 4 of my testimony in 82-266.

unacceptable burden was also recognizable in 1978, CMP's internal analysis provides a benchmark for the nuclear burden on PSNH. In 1978, PSNH was carrying larger proportional nuclear costs than CMP's unacceptable case, and the situation deteriorated further in later years. Thus, the financial problems for PSNH's commitment to Seabrook should have been evident to CMP as early as 1978.

In addition, MPS was aware that its Seabrook burden was excessive without CWIP or some other exceptional ratemaking (Bustard testimony, pages 12-13). Tables 8.3 to 8.5 demonstrate that PSNH was more heavily burdened by Seabrook than was MPS.

Q: Were these problems evident to the utilities involved in the Seabrook project?

A: Yes. For example, the MMWEC Prospectus dated 9/13/78 noted that

> The construction and operation of Seabrook Nos. 1 and 2 will be dependent upon the financial ability of all owners, particularly PSNH as the sponsoring utility, to provide the necessary funds to pay the costs of construction and operation. No assurance can be given that the joint owners will continue to be able to provide their share of construction funds as needed. . .
>
> PSNH has stated that its ability to provide adequate funds for its construction program will depend on, among other things, its ability to borrow funds, to raise equity capital, and to generate funds from operations. PSNH has indicated that it plans to acquire a major portion of the

> required funds from external sources and that this external financing represents a major undertaking for it. In this connection, PSNH has stated that, among other factors, it must obtain adequate and timely rate relief. (page 26)

The financial capability of PSNH was also an issue in DPU 20055.

Q: What would Tables 8.1 through 8.5 look like if realistic cost estimates for Seabrook 1 and 2 were substituted for PSNH's estimates?

A: The cost of Seabrook, and hence the cost burden for PSNH would increase dramatically. Considering that PSNH's burden was already much heavier than that of utilities which were admittedly over-extended, even at their own cost estimates,[40] for most of these years, observers familiar with the data I present in Sections 2 to 6 should have known that PSNH's investment in Seabrook was ambitious in 1972, risky in 1976, impossible after the election of 1978 (and the attendent loss of CWIP), and self-destructive thereafter. Whatever was true of the risks of PSNH's involvement in Seabrook was also true for participation by other parties who were, as MMWEC noted, dependent on PSNH's ability to finance its share of the plant. As I note above, the Maine utilities should have been

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40. Perhaps one of the reasons that NU, UI, and other utilities limited, or attempted to limit, their nuclear exposure to the extent that they did, was the realization that the cost estimates used in their financial projections were optimistic, and that the actual results were almost certain to be worse.

familiar with the history of the nuclear industry, and should have anticipated just such cost escalation as has actually occurred, and should have recognized that the chances of completing Seabrook, and particularly of completing Seabrook 2, were slim.

Q: What has actually occurred, in terms of the effects of Seabrook construction on the participants?

A: Most of the major participants in Seabrook have been subjected to greater financial stress than they would have voluntarily undertaken. The best known examples of this distress are PSNH, which has eliminated common and preferred dividends, and UI, which has reduced common dividends, but Central Maine Power and several of the smaller utilities (including MPS) also consider themselves to be in difficult, if not impossible, financial situations, and have taken such unusual steps as cutting dividends. The largest New England utilities are in somewhat better shape: NEES because of its relatively small share of Seabrook and Millstone, as well as FERC regulation, BECo because of the cancelation of Pilgrim 2, and NU because of the delay in Millstone 3 construction, and exceptional rate relief. NU's situation may change if the cost of Millstone 3 continues to rise.

9 - LOAD FORECASTING

Q: What relevence do the forecasts of the Maine utilities and of NEPOOL have to the prudence of the Maine utilities' investments in Seabrook 2, and of the prudence of CMP's investment in Pilgrim 2?

A: The forecasts should not have had much of an influence on these decisions, and they should not therefore be of much concern in this proceeding, or in 84-120.

Q: Why should the forecasts have had little influence on the utilities' decisions with regard to nuclear purchases and construction?

A: Most of the cost of nuclear investments can not be justified, and would not be necessary, simply to meet peak demand (or more accurately, to provide reliable service). There are always less expensive approaches to covering load growth: expansion of capacity at existing hydro sites, construction of combustion turbines and diesels, load management, or even construction of new (or renovation of old) fossil steam plants. Nuclear plants, especially large ones like Seabrook and Pilgrim, are too large and too unreliable to contribute much to the load carrying capacity of the system, and could be replaced by a much smaller set of peakers (perhaps 50% to

60%) without decreasing the reliability of the system. Peakers, such as cumbustion turbines, if brought on line in the 1980's, would probably cost no more than 10% of the cost of contemporaneous nuclear units.

Q: Why would any utility ever have planned a nuclear unit, if not to meet peak?

A: Nuclear, and all other base load capacity, is constructed to provide more economical power than would be available from capacity which is less expensive to construct. Coal and nuclear plants are less expensive to operate[41] than oil-fired steam plants, especially thermal peaking units. When Seabrook and Pilgrim were undertaken, the utilities expected that their total costs would be less than those of new fossil plants. After 1974, the utilities generally expected that the nuclear units would be less expensive than just the fuel cost at existing oil plants. Therefore, any valid rationale for buying or continuing to own nuclear generation could not have been a need for capacity (since less expensive options were available), and must have been an economic comparison, such as those presented in Section 7 of this testimony and in Section 6 of my testimony in 84-120. If the nuclear units were cheap enough, they would have been desirable at zero load growth and 100% reserve margins, while if they were

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41. Nuclear non-fuel O&M expenses are escalating rapidly, so this statement may not be true in 10 or 15 years.

expensive enough, they would not have been desirable at 7% load growth rates.

Q: Why then do you discuss load forecasts?

A: The Maine utilities have offered their own and NEPOOL's load forecasts from the 1970's as partial justification for their decisions to purchase Seabrook (and for CMP, Pilgrim 2) shares. As I explained above, the connection between "needing" some capacity and purchasing nuclear capacity is extremely tenuous, even if the "need" is accepted. Nonetheless, to the extent that load growth results in greater use of existing high-fuel cost generation, and to the extent that it requires the addition of some new capacity (however inexpensive) to maintain reliability, it increases the economic justification of baseload capacity. In addition, both MPS and BHE seem to believe that their load growth threatened to leave them scrambling for capacity in a tight market (because the NEPOOL forecast consistently overstated growth in the region, the tightness of future markets was always overstated), with only limited options for adding new capacity on their own systems. Therefore, it seems appropriate to at least quickly review the utility forecasts in this period.

9.1 - The Load Forecasts of MPS

Q: Please describe the load forecasts of MPS in the late 1970's.

A: Table 9.1 lists MPS's load forecasts and actual peak loads for the 1970's and 1980's, and Figure 9.1 graphs the patterns of changes in MPS' projections.

Q: How sophisticated were the forecasts on which MPS relied in making its decision to purchase a portion of Seabrook?

A: From the documents provided by MPS, it appears that the forecasts were based on little more than trending and judgement. There is no explicit treatment of conservation, including price effects, nor is there any explicit consideration of any other economic measure, such as personal income, value added, gross national product, or employment, to name a few which might be used.

Q: Given the size of MPS, what other techniques were applicable?

A: The were at least two other approaches available to MPS. One was to rely on economic projections for its service territory and for the products produced there, modified by price elasticities, foreseeable conservation effects, and so on. Unlike many utilities with loads in its range, MPS serves a geographically large and contiguous area, and its load is less apt to be affected by which side of the town line major industrial and commercial customers decide to locate on. However, MPS is still rather small and not well diversified, so even fairly sophisticated forecasts can easily be greatly in error, due to unforeseen events in particular industries or firms. Therefore, the second approach, of a regional or diversified forecast, might also have been appealing to MPS. The logical region for forecasting would have been Maine; alternatively, MPS might have joined with other small New England utilities in a collective forecast. Such cooperative efforts spread out the costs of developing reasonable models, take advantage of the law of averages (the average of several partially independent random variables will be more stable than the individual variables), and allow for sharing the risks of over- and under-capacity. If the second strategy did not work out, the first approach (which may be simply stated as "model well") could still have improved MPS' forecasting considerably.

Q: How much reliance should MPS have placed on its forecasts?

A: Very little. The methodology was not much better than speculation, and the results should have been treated accordingly.

9.2 - The Load Forecasts of BHE

Q: Please describe the load forecasts of BHE in the late 1970's.

A: Table 9.2 lists BHE's load forecasts and actual peak loads for the 1970's and 1980's, and Figure 9.2 graphs the patterns of changes in BHE' projections.

Q: How sophisticated were the forecasts on which BHE relied in making its decision to purchase a portion of Seabrook?

A: They were based on a much better structured forecasting model than those of MPS, if it is proper to refer to MPS having had a model at all. The 1976 forecast (Exhibit Lee-6) was fairly sophisticated for a utility of BHE's size, and considered a number of causal factors, although appliance and equipment stocks and efficiencies were not dealt with directly, and the industrial forecast depends on customer short-term projections and trending, rather than macro-economic forces (such as national paper production projections). The major failing in this forecast, however, is its decision to discount recent experience: growth trends are based on the 1966-75 experience, and were therefore over-stated for the post-embargo world of high, rising, and uncertain energy prices. Considering that government energy use per capita had been falling since 1970, projecting that measure to suddenly increase was unjustified. Similarly, it defied reason to assume that space heating penetration would double and that these new customers would use as much energy as previous customers. Price elasticities and the delayed effects of the oil price increase of 1974 were not addressed explicitly.

Q: Did the 1978 forecast (Exhibit Lee-10) represent a significant improvement?

A: The model structure is much more complex, and allows for the inclusion of many more relevant factors, including appliance and equipment efficiencies and a host of economic considerations. This was again a good modeling effort for its time, and for the size of the utility. Unfortunately, the BHE model was an adaptation of the NEPOOL/Battelle model, which was seriously flawed. Battelle's contributions to this model included numerous logical and practical errors, particularly in the economic-demographic module, and many of the assumptions about conservation understated the likely effects. A detailed critique of the NEPOOL model, from my 1979 testimony before the NRC, is attached as Appendix D to this testimony, so I will not repeat the recitation of the problems discussed there. Since my critique, NEPOOL has apparently abandoned or modified many of the features to which I objected: unfortunately, NEPOOL has not (so far as I know) released a definitive description of its model since the version I reviewed.

Q: Should BHE have recognized the shortcomings in the NEPOOL model?

A: I think that it should have at least noted that the long-run elasticities used by NEPOOL were much lower than those indicated by many independent studies, and that the short-run elasticities were very high (at least given the values asssumed for the long run). The combination of these assumptions resulted in the conclusion that most of the adaptation to the 1974 price increases had already occurred by 1978, while in fact, there were major adjustments in appliances, equipment, lighting, and thermal efficiency still to be completed.

Q: Was reliance on these forecasts for power supply planning purposes prudent?

A: Preparation of the forecasts, as part of a continuing process of refining and improving BHE's forecasting ability, was certainly prudent. BHE should only have used the results for high-growth sensitivity cases (if it used them at all), sincee they were clearly overstated.

9.3 - The Load Forecasts of CMP

Q: Please describe the load forecasts of CMP in the late 1970's.

A: Table 9.3 lists CMP's load forecasts and actual peak loads for the 1970's and 1980's, and Figure 9.3 graphs the patterns of changes in CMP' projections.

Q: How sophisticated were the forecasts on which CMP relied in making its decision to purchase a portion of Seabrook?

A: Contemporaneous reviews of these forecasts are available, so we can evaluate them without the benefit of hindsight. CMP's forecast of late 1977, which became part of the NEPOOL 1978 forecast, was one of the utility forecasts I reviewed in MDPU 19494, in early 1979. That review is reproduced as Appendix C to this testimony. The methodology at that time consisted mostly of time trends, with large (and sometimes unprecedented) increases in energy intensity projected in virtually every sector. The approach was a little more detailed than BHE's 1976 forecast, but the projections appear to have been quite arbitrary, and the overall result was disappointing for a utility of CMP's size.

The next CMP forecast, from Fall 1978, was reviewed extensively in U3238, by A.D. Little for the Commission Staff, by the Office of Energry Resources and its consultant, and ultimately by the Commission. I will not attempt to repeat that level of review, but will simply note a few of the forecast's salient characteristics. CMP relied on some of the weakest portions of the NEPOOL model to project the economic and demographic parameters which drive consumption in the various sectors. Price elasticities were neglected entirely. Other conservation effects were reflected to a modest extent in the residential sector (appliance efficiencies were only assumed to improve by the proposed FEA standards and no changes in usage patterns were assumed) and were not explicitly addressed elsewhere. The Commission's decision in U3238 addresses many of the other problems in CMP's forecast, and I generally agree with the Commission's conclusions.

Q: What reliance should CMP have placed on its forecasts in determining whether to purchase more Seabrook capacity and whether to support continued construction of Unit 2?

A: Like BHE, CMP could only conclude that its forecasts represented a "high growth" scenario that was unlikely to occur. Such a scenario might be useful for sensitivity analysis, but not as a most likely or best estimate. Indeed, as the Commission noted

> . . . the projection of future power demand cannot be viewed by this Commisssion as simply a process of predicting a predetermined, or wholly extrinsically determined, outcome. The policy and rate decisions of this Commission and of the Company can influeence thae growth in both energy

> consumption and peak demand. Obviously, these matters are by no means entirely within the control of the petitioner and this agency, but future growth can be managed and limited to some extent. (U3238, page 45)

Thus, the CMP forecast results might define the maximum growth case for which the company should prepare contingency conservation plans.[42] In any case, CMP should have known that its forecasts were overstated, and should not have relied on them as the basis for decisions to buy or continue with Seabrook.

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42. By 1980, CMP recognized that lower growth was beneficial for the utility: unfortunately, it had already increased its Seabrook commitment in the anticipation (or hope) of higher growth.

9.4 - The Load Forecasts of NEPOOL

Q: How are the NEPOOL load forecast relevant to this proceeding?

A: For all of the utilities, the level of their concern about the future availiability of capacity should have depended to some extent on the NEPOOL load and capacity situation. So long as NEPOOL has large reserve margins, there are opportunities for the purchase of capacity entitlements or firm power from other utilities, and supply deficits on any particular system would be less threatening. This is particularly true for MPS, due to its small size (a modest excess of capacity on the BECo or NU systems, for example, would accomodate several years of MPS load growth), and for BHE, due both to its size and to its reliance on purchased power throughout the 1970's.

Q: How reliable were the NEPOOL forecasts in this period?

A: Through 1978, the NEPOOL forecast was simply the sum of the utility forecasts, adjusted for diversity and 345 kV losses. All the Maine utilities should have been aware that their own forecasts were overstated in the post-embargo period, and should have anticipated that other utilities' forecasts (and hence the NEPOOL projection) were similar optimistic. Unfortunately, even CMP apparently had not reviewed the forecasts of other NEPOOL members (U3238 Tr. 293-294), so it might not have realized just how badly overstated the forecasts of some members (such as PSNH) were.

In 1979, NEPOOL introduced its own forecasting model. As I noted previously, and as discussed in Appendix D, this model contained many errors and overstatements of demand, many of which should have been obvious to anyone familiar with load forecasting.

Q: How should the utilities have used the NEPOOL forecasts in this period?

A: They should have treated the NEPOOL forecasts much as they should have treated their own forecasts: as overestimates of the likely need for power, and thus underestimates of the amount of power available from existing and committed plants, after taking into account such adjustments as the cancelation of all nuclear plants without construction permits and the indefinite suspension of Seabrook.

10 - CONCLUSIONS AND RECOMMENDATIONS

Q: Please summarize the conclusions of the previous sections.

A: We may conclude that

- Nuclear cost estimates have never been reliable, either before or after the issuance of a construction permit.
- Nuclear power plants have consistently failed to meet their construction schedules.
- Seabrook, and particularly the second unit, had problems at least equal to those of the industry as a whole.
- Seabrook 2 could not have been built for any of the cost estimates PSNH produced, or been completed on the PSNH schedules, and these facts should have been apparent to PSNH and most of the joint owners.
- It was foreseeable throughout the Seabrook 2 construction period that the unit would impose tremendous financial strain on PSNH and other joint owners, and in fact it has.
- Seabrook 2 was not cost-competitive with new coal construction as far back as 1976.

- Had Seabrook 2 been completed, it would have operated at much lower capacity factors than assumed in the utility cost-benefit analyses.

Thus, the termination of construction at Seabrook 2 was inevitable, desirable, and long past due when it finally occurred. Utilities have never known the scope of nuclear projects until they are completed, or actually until they are retired. This fact was clear to me in 1979, and it should have been clear much earlier to PSNH (which had access to data I have only recently seen, and probably much which I still have not seen); and it should have been clear to the Maine utilities, as well.

Q: What are your conclusions regarding the prudence of the major decisions to participate in, and attempt to construct, Seabrook 2?

A: Reviewing the preceding information and analysis, I conclude that a reasonable observer, with access to the information reasonably available to the Maine utilities would have concluded:

1. As a general matter, participating in a nuclear power plant construction program may well have been prudent in 1972, so long as it was accompanied by a commitment to continued monitoring of developments in the industry and in the particular project, and with the knowledge

that nuclear cost projections were highly unreliable.

2. Continuing direct expenditures on Seabrook 2 past 1976 was extremely questionable. Other than minimal investment necessary to allow the tie-in of Unit 2 to the common facilities, no further expenditures should have been undertaken without a thorough and candid assessment of the costs, benefits, and risks of continued expenditures. Such an analysis might well have indicated that cancelation of the plant was economically and financially justified. If the unit were not canceled as a result of the analysis, further construction should at least have been deferred until the completion of Unit 1, at which time the cost and schedule for Unit 2 could have been determined with greater accuracy, and the owners might actually have been able to afford to build the second unit. In any case, in the absence of further study and justification, continued avoidable investments in Seabrook 2 were indefensible, after 1976.

3. By the end of 1978, the accumulation of bad news had progressed to the point that cancelation was very likely to be preferred in any honest appraisal of the Seabrook 2 project. Even so, there were limited costs involved in maintaining the option to resume Seabrook 2 construction in the mid-1980's, when Seabrook 1 was

likely to be complete, and it is possible that a prudent assessment would have found that preservation of Unit 2 assets remained viable.

4. Completion of Seabrook 2 was probably impossible, and certainly undesirable, by the middle of 1980, given the financial condition of the owners, and the rapidly rising cost of nuclear plants. As soon after the Three Mile Island accident as the participants' reaction time would allow (certainly by early in 1980), cancelation (or at least mothballing) of Unit 2 was absolutely and certainly required.

5. By the end of 1982, it may already have been too late to save either unit at Seabrook. However, prompt cancelation of the second unit would have improved the financial condition of those utilities who were allowed to recover part of the cost, and reduced the exposure for all the participants. No other course of action could have been defensible by that point.

Q: How would these conclusions have affected the behavior of the Maine utilities and PSNH, had they been acting prudently?

A: In 1972, and throughout the early 1970's, all utilities with nuclear investments should have been monitoring the evolution of the numerous problems of the nuclear industry. By 1976, PSNH, CMP, and probably MPS should have been carefully and critically re-examining the economics, and the financial viability, of the project, with the knowledge that the cost and schedule estimates prepared by UE&C and PSNH were almost certain to be over-optimistic. If PSNH were not willing to undertake such studies, CMP should have performed them on its own, or with other joint owners, or attempted to force PSNH to take the problems seriously. MPS and BHE should have refused to buy into the plant in the absence of such analysis. Had those studies been performed, the plant would probably have been mothballed; at the very least, the rate of expenditures would have been reduced to the absolute minimum level which would have preserved the investment to that date, and allowed later restart.

By 1978, CMP, BHE, and MPS should have been publicly opposing continuation of Seabrook 2, if PSNH had not halted cash expenditures or actually canceled the unit. PSNH should have been carefully considering any additional expenditures, and should almost certainly have stopped direct construction by that time.

By early 1980, Seabrook 2 should have been canceled and all three Maine utilities should have been advocating cancelation. CMP and BHE should have refused to complete their purchase of further Seabrook shares from PSNH until

Seabrook 2 construction had stopped, and should not have purchased the valueless Seabrook 2 assets.

Q: If PSNH had acted as you suggest they should have, would even PSNH and its customers be better off today than they are?

A: Yes. The losses suffered by both PSNH's ratepayers and its shareholders would have been limited. Had PSNH not wasted its limited resources on Unit 2, the first unit at Seabrook might still be under full construction, with a reasonable chance of completion in the middle of this decade. In addition, the several other New England utilities (and their customers) which are joint owners in the Seabrook project would be better off today, due to the smaller direct loss on Seabrook 2, and to the improved construction conditions for Unit 1.

Q: How would you recommend that this Commission treat the Maine utilities' investment in Seabrook 2 for ratemaking purposes?

A: I would recommend that the Commission disallow all costs beyond mid-1980, including the entire cost of the increase in the CMP and BHE shares of the second unit. This is based on my conclusion that an honest appraisal of the project at that date would probably have recommended cancelation at this date. Since the Maine utilities did not conduct any such inquiry (nor attempt to force PSNH to conduct one), their investment beyond that date appears to be totally due to their imprudence.

My other recommendations are more limited or conditional. First, I believe that the Commission should determine whether it wishes to disallow costs after the time at which the utilities' behavior became imprudent, or only at the time when prudent behavior would have resulted in a different substantive outcome. This is equivalent to the question of whether a driver is imprudent as soon as he falls asleep behind the wheel, or whether that behavior only becomes imprudent when the car hits someone. If the Commission chooses the first standard, then none of the Seabrook 2 investments should be recovered from ratepayers.

Second, if the Commission does allow recovery of any costs prior to mid-1980, that recovery should not include any direct costs for 1977 through mid-1980, since the second unit should not have been under active construction at that time. It is my understanding that all common costs are now assigned (or will be reassigned) to Unit 1, presumably including the common costs which were necessary to keep the Unit 2 option open.

Third, if the Commission wishes to allow partial recovery of any costs, to reflect the uncertainty which remains about the appropriate course of action for a responsible utility at any particular point, I suggest that the Commission review the evidence and allow a fraction of the disputed costs, proportional to the Commission's assessment of the probability that an unbiased review by a prudent utility at that particular time would have resulted in the expenditure in question. For example, if the Commission agrees with me that CMP did not perform the analyses it should have in 1976, but believes that there was a 50% chance that a prudent appraisal would have recommended continued investment in Unit 2 at that time, it might allow CMP to collect half of the direct costs for 1977 and 1978. The corresponding percentages would be lower for the MPS and BHE purchases of Seabrook in 1977-78: new investment should have been conditional on a higher level of confidence then continued ownership.

Finally, the Commission must determine whether any of the purchases of Seabrook shares, after CMP's initial commitment in the early 1970's, were prudent. I believe that I have demonstrated that the status of the nuclear industry, and of Seabrook, rendered imprudent all the purchases from 1977 onwards. However, this is a somewhat finer judgment than my major conclusion, that all post-1980 expenditures (and all post-1976 directs) were imprudent.

Q: Do you have any opinion as to whether the Maine utilities, PSNH or UE&C should bear the portion of the costs which are not recovered from the Maine utilities' ratepayers?

A: Not really. As I noted above, this question hinges on the nature of PSNH's representations and responsibilities to the Maine utilities, and the relationship between PSNH and UE&C. I do not believe that this potential dispute between the utilities and their contractors should in any way affect the Commission's decision in this proceeding, however, since the only issue here is whether the Maine utilities' customers should be paying these costs.

Q: Does this conclude your testimony?

A: Yes.

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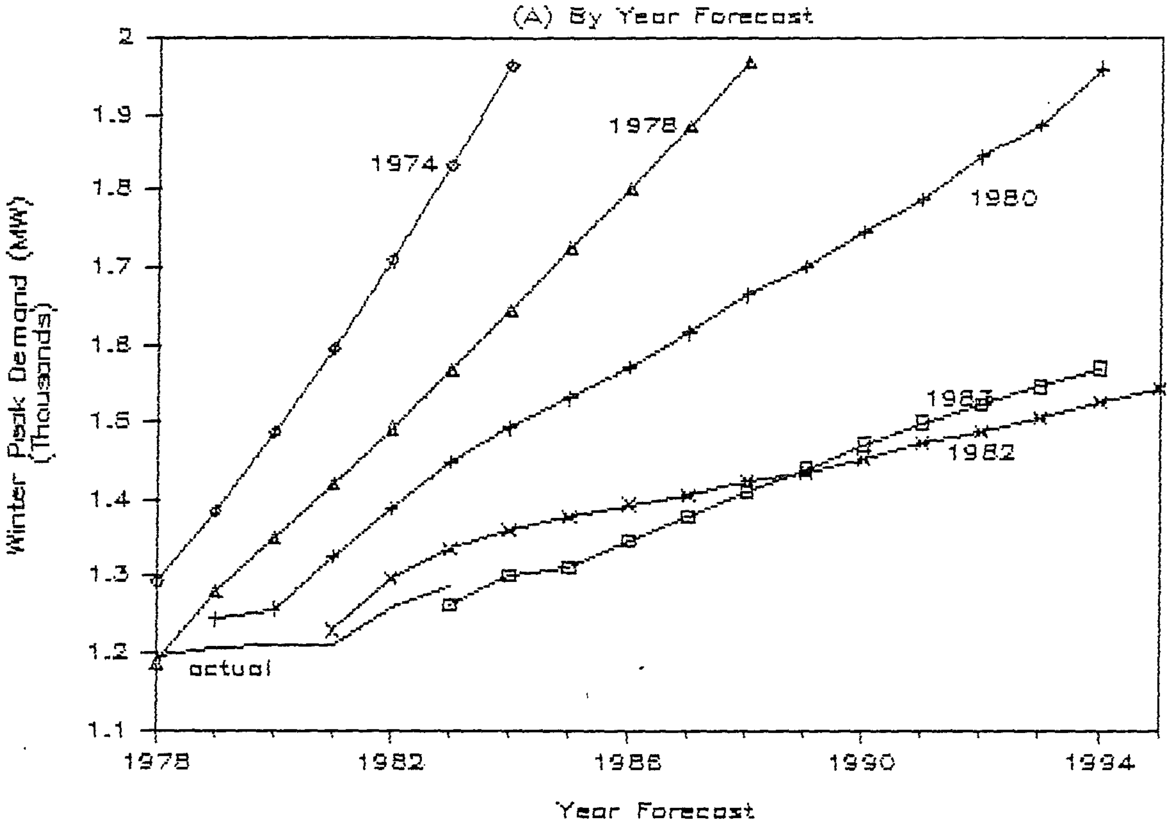
TABLE 1.1: PILGRIM 2 COST AND SCHEDULE ESTIMATES

Estimate Date	Cost Estimate ($ million)	Commercial Operation Date	Projected CP Issue Date
Feb-72	402	Nov-78	Jan-74
Apr-73	655	Aug-80	Aug-75
Mar-75	1221	Oct-82	Oct-76
Oct-76	1396	Mar-84	Jul-77
May-78	1895	Jun-85	Mar-79
Mar-79	1895	Dec-85	Mar-79
May-80	3220	May-89	Jul-79
Jun-80	3515	Mar-90	?
Sep-81	3975	Mar-90	?

Sources: Montaup Electric Company, Docket No. ER81-749-000 and ER82-325-000, Exh. (MEC-701)
Start of Construction from: EIA-254 Progress Reports

Figure 1.1: CMP Forecast History



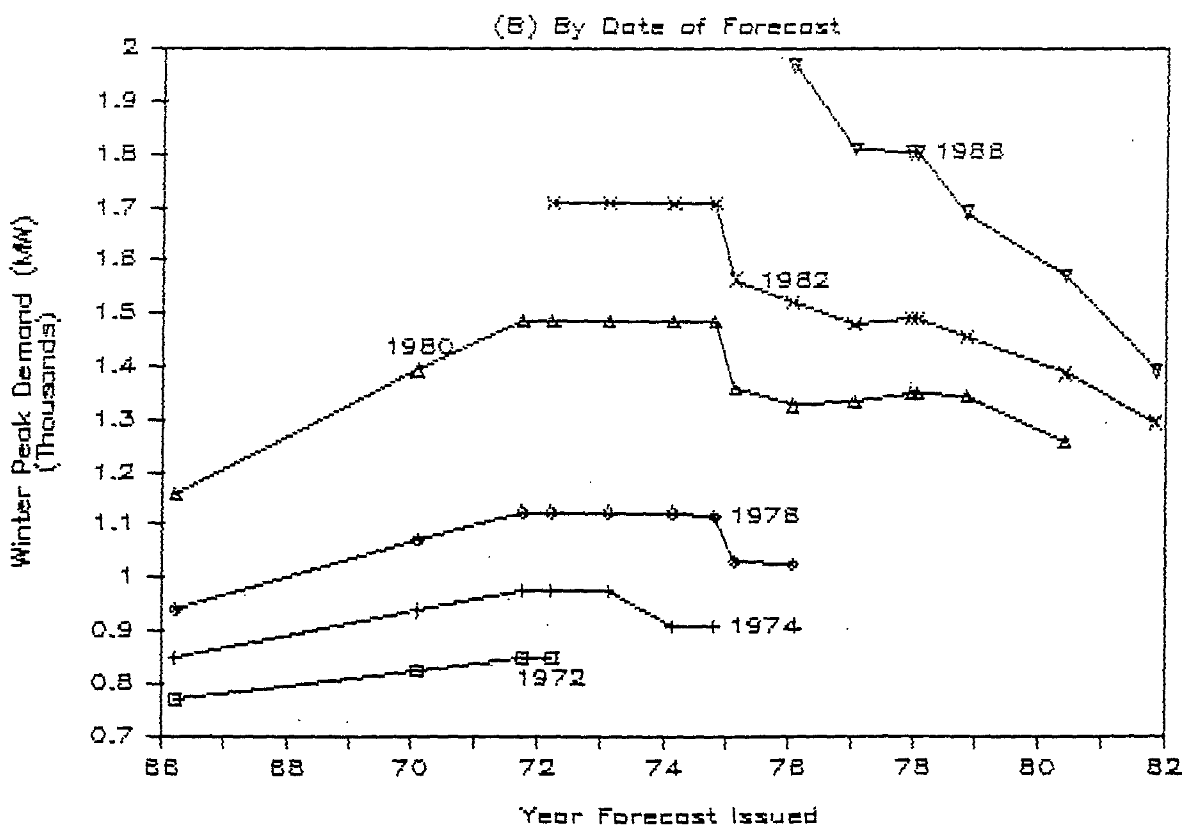


Figure 1.2: NEPOOL Forecast History

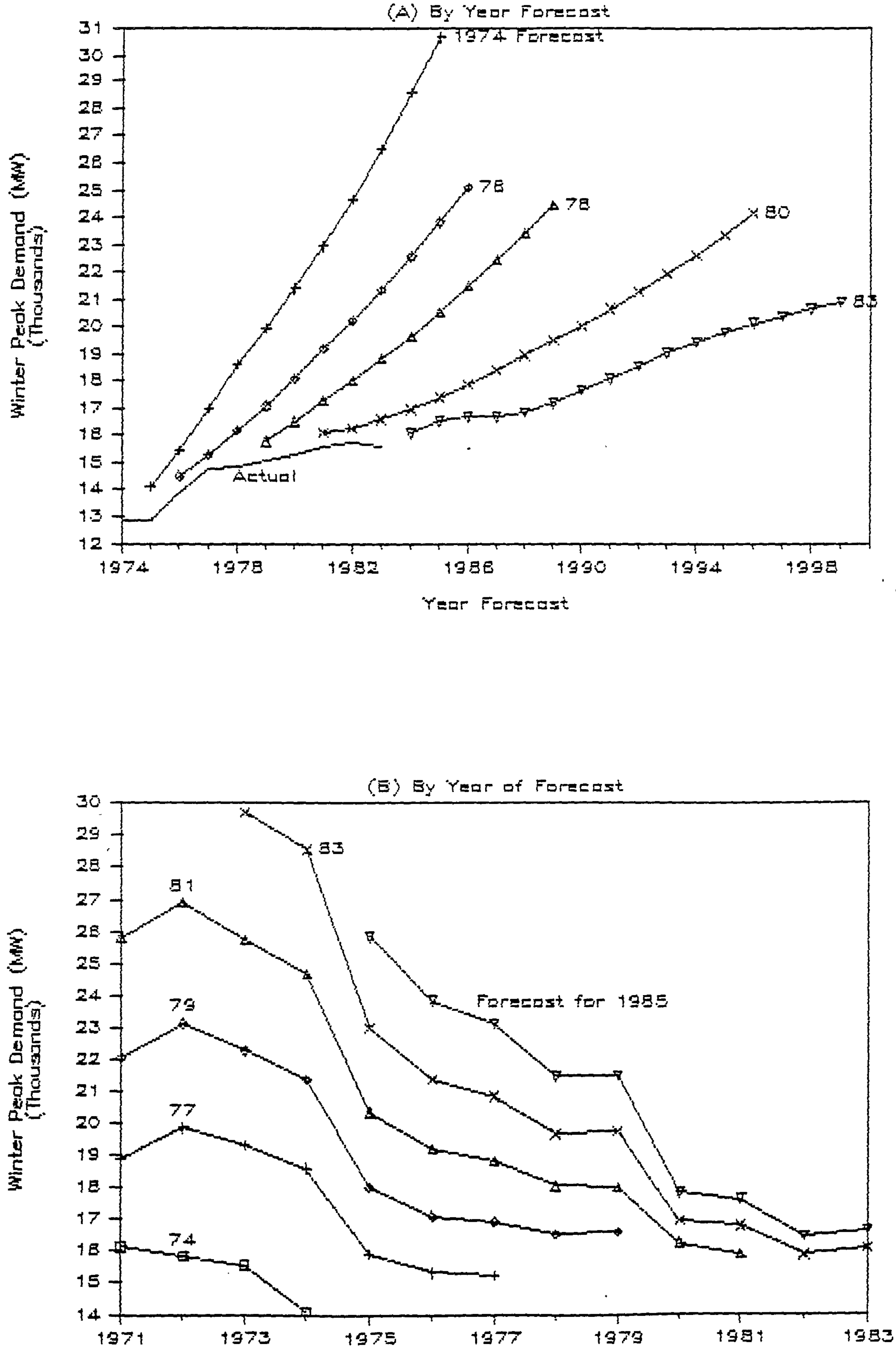


Figure 1.3: PSNH Forecast History

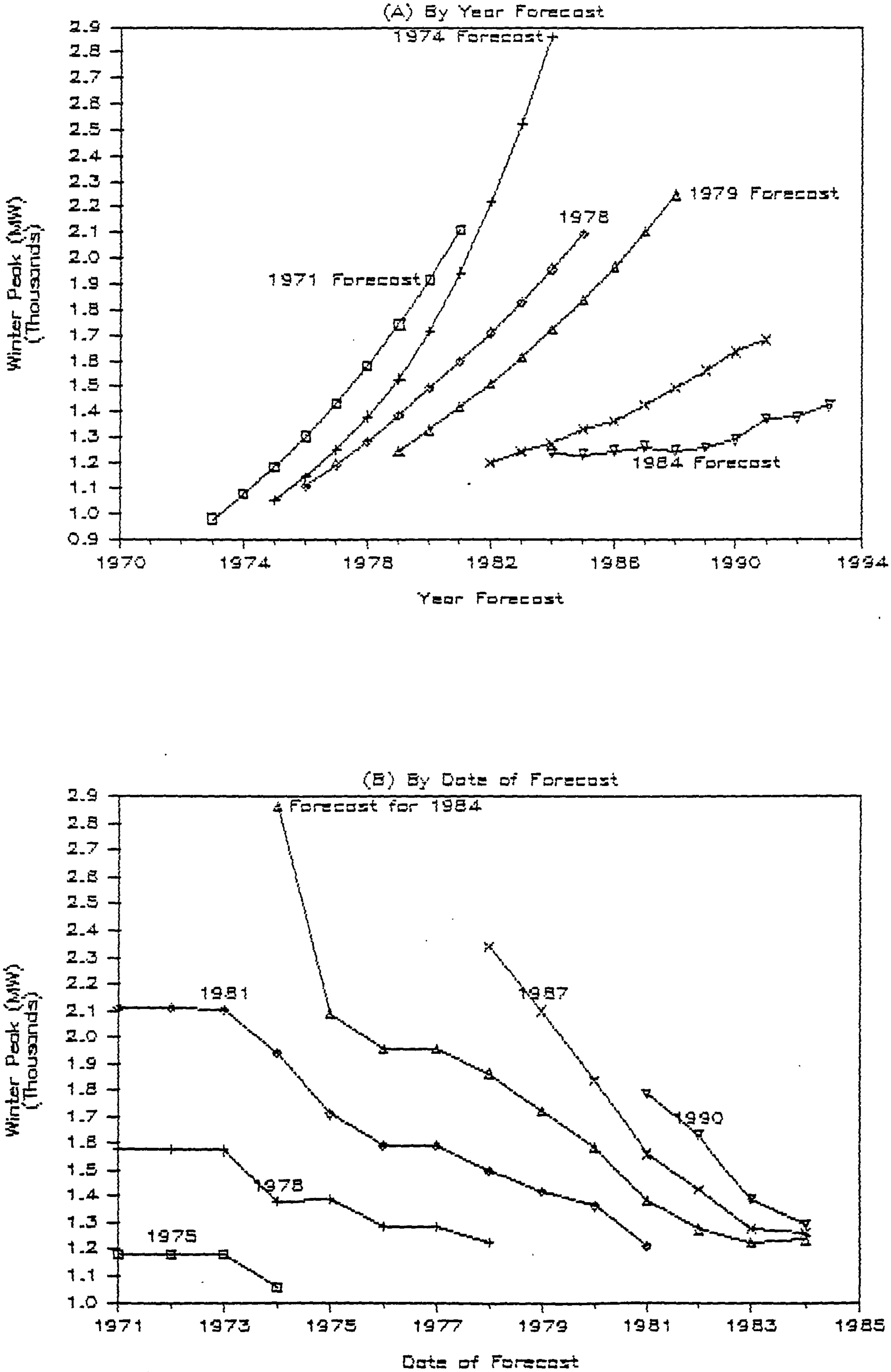


Figure 1.4: Pilgrim 2 Cost Estimates

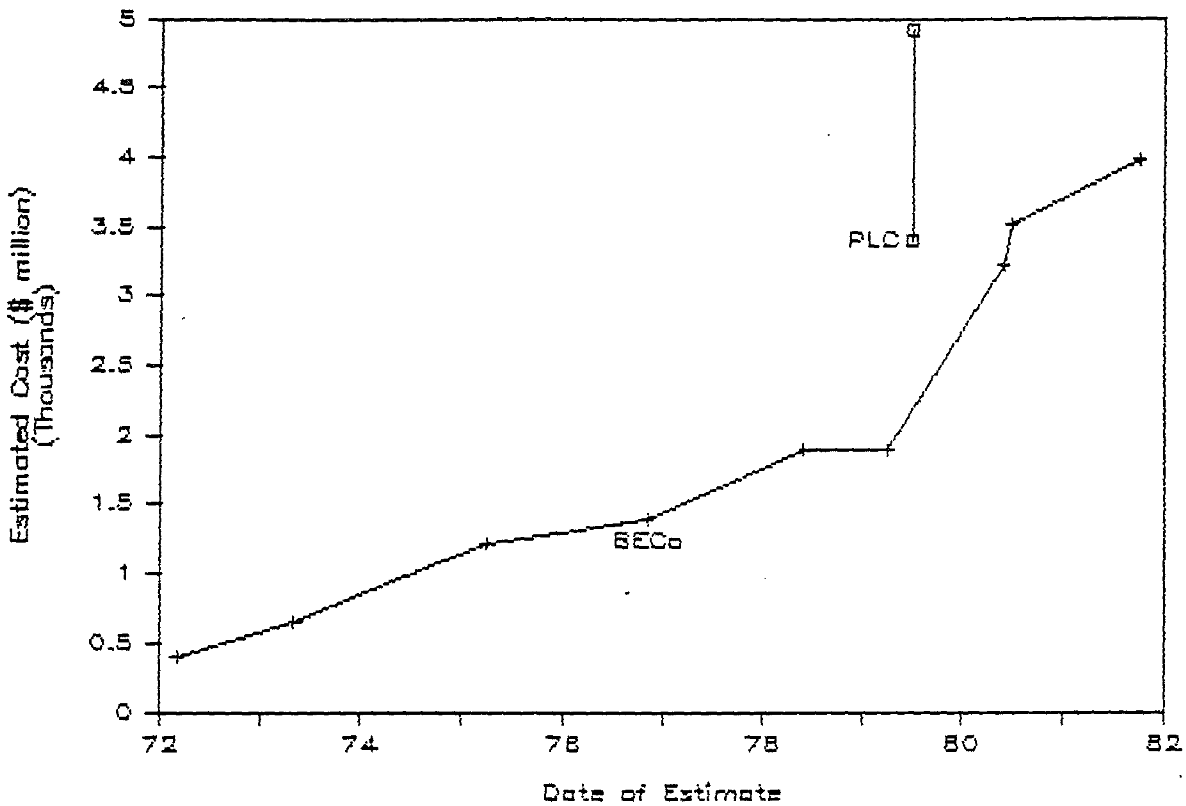


TABLE 2.1: COMPLETED NON-TURNKEY NUCLEAR UNITS, with COD before December, 1972

Unit Name	--Actual--- Cost	COD	------Estimates----- Date of Est.	Cost	COD	Years to COD	--Nominal--- 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.

TABLE 2.2: COMPLETED TURNKEY AND DEMONSTRATION UNITS, with COD before 12/1972

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
* Constructor=UE&C

TABLE 2.3: 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
Arkansas 1	Dec-67	132	Dec-72	5.00			0.0
	Sep-72	185	Oct-73	1.08	4.76	7.4%	86.8
Arkansas 2	Dec-70	183	Oct-75	4.83			0.0
	Sep-72	230	Oct-76	4.08	1.75	13.9%	6.9
Duane Arnold	Jun-68	103	Dec-73	5.50			0.0
	Sep-72	192	Jan-74	1.33	4.25	15.8%	69.0
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
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
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
Farley 1	Sep-69	164	Apr-75	5.58			0.0
	Sep-71	259	Apr-75	3.58	2.00	25.7%	6.0
Farley 2	Sep-70	183	Apr-77	6.58			0.0
	Sep-71	233	Apr-77	5.58	1.00	27.3%	0.0
Hatch 1	Mar-69	151	Jun-73	4.25			1.5
	Dec-72	282	Apr-74	1.33	3.76	18.1%	69.0
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
Oconee 1	Sep-70	109	Jul-71	0.83			80.0
	Dec-72	137	Jun-73	0.50	2.25	10.7%	99.5
Oconee 2	Sep-70	109	Jul-72	1.83			50.0
	Sep-71	137	Feb-73	1.42	1.00	25.7%	71.0
Oconee 3	Sep-70	109	Jul-73	2.83			25.0
	Sep-71	137	Nov-73	2.17	1.00	25.7%	43.0
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
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
Trojan	Dec-68	196	Sep-74	5.75			0.0
	Dec-72	284	Jul-75	2.58	4.00	9.7%	57.0
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
	Dec-72	656	Jun-79	6.50	0.50	19.5%	0
Hope Creek 1	Mar-70	574	Mar-75	5.00			0
	Dec-72	1139	May-79	6.42	2.76	28.2%	0
Limerick 1	Mar-70	252	Mar-75	5.00			0
	Dec-72	694	Aug-78	5.67	2.76	44.4%	1
Limerick 2	Mar-70	223	Mar-77	7.00			0
	Dec-72	512	Jan-80	7.08	2.76	35.2%	1
Midland 1	Dec-71	277	May-77	5.42			2
	Dec-72	383	Feb-79	6.17	1.00	38.1%	2
Midland 2	Dec-71	277	May-78	6.42			2
	Dec-72	383	Feb-80	7.17	1.00	38.1%	2

TABLE 2.3: 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
Salem 2 *	Sep-67	128	May-73	5.66			0.0
	Dec-72	425	Mar-76	3.25	5.25	25.7%	NA
Sequoyah 1	Sep-68	161	Oct-73	5.08			0.0
	Dec-72	225	Apr-75	2.33	4.25	8.1%	45.0
North Anna 2	Sep-70	184	Mar-75	4.50			NA
	Dec-72	227	Jul-75	2.58	2.25	9.8%	28.2
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
Cook 2	Dec-67	235	Apr-72	4.33			NA
	Sep-70	339	Mar-74	3.50	2.75	14.2%	19.0
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
Salem 1 *	Sep-66	139	May-71	4.70			0.0
	Dec-72	425	Mar-75	2.25	6.25	19.6%	53.0
Browns Ferry 3	Mar-68	124	Oct-70	2.58			12.0
	Sep-72	149	Oct-74	2.08	4.51	4.1%	
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
Brunswick 1 **	Dec-70	194	Mar-76	5.25			4.0
	Dec-72	214	Dec-75	3.00	2.00	5.0%	42.0
WNP 2	Mar-71	187	Sep-77	6.50			0
	Sep-72	374	Sep-77	5.00	1.51	58.4%	NA
AVERAGES							
Simple					2.86	20.8%	
Weighted by Years					--	18.6%	
NUMBER OF DATAPOINTS:					63	63	

Notes: * Constructor=UE&C
** Architect/Engineer=UE&C

TABLE 2.4: SCHEDULE SLIPPAGE IN UNITS PLANNED OR UNDER CONSTRUCTION BY DECEMBER, 1972

Unit Name	Date of Estimate	Estimated Cost	Estimated COD	Years to COD	Years Elapsed	Progress Ratio	% Complete
Arkansas 1	Dec-67	132	Dec-72	5.01			0.0
	Sep-72	185	Oct-73	1.08	4.76	82.5%	86.8
Arkansas 2	Dec-70	183	Oct-75	4.84			0.0
	Sep-72	230	Oct-76	4.08	1.75	42.8%	6.9
Duane Arnold	Jun-68	103	Dec-73	5.50			0.0
	Sep-72	192	Jan-74	1.33	4.25	98.0%	69.0
Calvert Cliffs 1	Jun-67	118	Jan-73	5.59			0.0
	Sep-72	250	Feb-74	1.42	5.26	79.4%	72.0
Calvert Cliffs 2	Jun-67	105	Jan-74	6.59			0.0
	Sep-72	204	Jan-75	2.33	5.26	81.0%	56.0
Davis-Besse 1	Dec-68	180	Dec-74	6.00			0.0
	Dec-72	349	May-75	2.41	4.00	89.7%	40.0
Farley 1	Sep-69	164	Apr-75	5.58			0.0
	Sep-71	259	Apr-75	3.58	2.00	100.0%	6.0
Farley 2	Sep-70	183	Apr-77	6.59			0.0
	Sep-71	233	Apr-77	5.59	1.00	100.0%	0.0
Hatch 1	Jun-68	NA	Jun-73	5.00			0.0
	Dec-72	282	Apr-74	1.33	4.50	81.5%	69.0
Millstone 2	Dec-67	150	Apr-74	6.34			0.0
	Sep-72	282	Apr-74	1.58	4.76	100.0%	49.0
Oconee 1	Sep-70	109	Jul-71	0.83			80.0
	Dec-72	137	Jun-73	0.50	2.25	14.7%	99.5
Oconee 2	Sep-70	109	Jul-72	1.83			50.0
	Sep-71	137	Feb-73	1.42	1.00	41.1%	71.0
Oconee 3	Sep-70	109	Jul-73	2.83			25.0
	Sep-71	137	Nov-73	2.17	1.00	66.3%	43.0
Peach Bottom 2	Mar-68	163	Mar-71	3.00			4.4
	Jun-72	352	Sep-73	1.25	4.25	41.1%	72.0
Peach Bottom 3	Mar-68	145	Jan-73	4.84			1.6
	Jun-72	316	Sep-74	2.25	4.25	60.8%	50.0
Rancho Seco	Dec-67	134	May-73	5.42			0.0
	Sep-72	300	Feb-74	1.42	4.76	84.1%	78.0
Trojan	Dec-68	196	Sep-74	5.75			0.0
	Dec-72	284	Jul-75	2.58	4.00	79.3%	57.0
Turkey Point 4	Sep-71	96	Jul-72	0.83			75.5
	Dec-72	106	Jul-73	0.58	1.25	20.1%	99.0
Grand Gulf 1	Jun-72	600	Dec-78	6.50			0
	Dec-72	656	Jun-79	6.50	0.50	0.5%	0
Hope Creek 1	Mar-70	574	Mar-75	5.00			0
	Dec-72	1139	May-79	6.42	2.76	-51.3%	0
Limerick 1	Mar-70	252	Mar-75	5.00			0
	Dec-72	694	Aug-78	5.67	2.76	-24.2%	1
Limerick 2	Mar-70	223	Mar-77	7.01			0
	Dec-72	512	Jan-80	7.09	2.76	-3.0%	1
Midland 1	Jun-68	NA	Feb-74	5.67			0
	Dec-72	383	Feb-79	6.17	4.50	-11.1%	2
Midland 2	Mar-68	NA	Feb-75	6.93			0
	Dec-72	383	Feb-80	7.17	4.76	-5.2%	2
San Onofre 3	Mar-70	189	Jun-76	6.26			0
	Sep-72	NA	Apr-79	6.58	2.51	-13.0%	
Vogtle 1	Sep-71	NA	Apr-78	6.59			0
	[illegible]	[illegible]	[illegible]	[illegible]	1.25	-60.0%	0

TABLE 2.4: SCHEDULE SLIPPAGE IN UNITS PLANNED OR UNDER CONSTRUCTION BY DECEMBER, 1972

Unit Name	Date of Estimate	Estimated Cost	Estimated COD	Years to COD	Years Elapsed	Progress Ratio	% Complete
Vogtle 2	Sep-71	NA	Apr-79	7.59			0
	Dec-72	NA	Apr-81	8.34	1.25	-60.0%	0
Bailly	Mar-67	113	Dec-72	5.76			NA
	Jun-72	244	Jun-77	5.00	5.26	14.4%	0
Shearon Harris 3	Jun-71	935	Mar-77	5.75			0
	Dec-72	1095	Mar-78	5.25	1.50	33.5%	0
WNP 2	Mar-71	187	Sep-77	6.51			0
	Sep-72	374	Sep-77	5.00	1.51	100.0%	NA
Summer 1	Mar-71	234	Jan-77	5.84			0.0
	Sep-72	297	Jan-77	4.34	1.51	100.0%	0.0
San Onofre 2	Mar-70	189	Jun-76	6.26			0.0
	Dec-72	360	Oct-78	5.84	2.76	15.3%	0
Susquehanna 1	Jun-69	150	27560	6.00			0.0
	Dec-72	703	May-79	6.42	3.50	-11.8%	0.0
Lasalle 1	Jun-70	360	Oct-75	5.34			0.0
	Sep-72	407	Dec-77	5.25	2.25	3.8%	0.0
Sequoyah 2	Dec-68	161	Oct-73	4.84			0.0
	Dec-72	225	Dec-75	3.00	4.00	45.9%	NA
McGuire 1	Sep-70	179	Nov-75	5.17			0.0
	Dec-72	220	Mar-76	3.25	2.25	85.3%	9.0
Salem 2 *	Sep-67	128	May-73	5.67			0.0
	Dec-72	425	Mar-76	3.25	5.25	46.0%	NA
Sequoyah 1	Sep-68	161	Oct-73	5.08			0.0
	Dec-72	225	Apr-75	2.33	4.25	64.8%	45.0
North Anna 2	Sep-70	184	Mar-75	4.50			NA
	Dec-72	227	Jul-75	2.58	2.25	85.2%	28.2
Hatch 2	Jun-70	189	Apr-76	5.88			NA
	Dec-72	330	Apr-78	5.33	2.50	21.8%	11.0
Three Mile I. 2 *	Aug-69	214	May-74	4.75			NA
	Aug-72	465	May-76	3.75	3.00	33.3%	25.0
Cook 2	Dec-67	235	Apr-72	4.34			NA
	Sep-70	339	Mar-74	3.50	2.75	30.4%	19.0
North Anna 1	Mar-69	185	Mar-74	5.00			0.0
	Dec-72	407	Dec-74	2.00	3.76	79.9%	55.0
Salem 1 *	Sep-66	139	May-71	4.71			0.0
	Dec-72	425	Mar-75	2.25	6.25	39.3%	53.0
Browns Ferry 3	Mar-68	124	Oct-70	2.59			12.0
	Sep-72	149	Oct-74	2.08	4.51	11.2%	
Crystal River 3	Mar-67	110	Apr-72	5.09			0.0
	Dec-72	283	Nov-74	1.92	5.76	55.1%	63.5
Brunswick 1 **	Dec-70	194	Mar-76	5.25			4.0
	Dec-72	214	Dec-75	3.00	2.00	112.4%	42.0
Diablo Canyon 1	Mar-66	154	Mar-72	6.01			0
	Jun-72	320	Mar-75	2.75	6.26	52.1%	46.5
Diablo Canyon 2	Dec-68	151	Jul-74	5.58			0
	Jun-72	282	Mar-76	3.75	3.50	52.3%	9.9
Beaver Valley 2	Dec-71	296	Mar-78	6.25			0
	Mar-72	360	Mar-78	6.00	0.25	100.0%	0
Bellefonte 1	Dec-70	NA	Jul-77	6.59			0
	Dec-72	348	Sep-79	6.75	2.00	-8.3%	0
Bellefonte 2	Dec-70	NA	Apr-78	7.34			0
	Dec-72	348	Jun-80	7.50	2.00	-8.3%	0

TABLE 2.4: SCHEDULE SLIPPAGE IN UNITS PLANNED OR UNDER CONSTRUCTION BY DECEMBER, 1972

Unit Name	Date of Estimate	Estimated Cost	Estimated COD	Years to COD	Years Elapsed	Progress Ratio	% Complete
Byron 1	Jun-71	400	Oct-78	7.34			0
	Sep-72	464	May-79	6.67	1.25	53.7%	0
Byron 2	Jun-71	350	Oct-79	8.34			0
	Jun-72	422	Mar-80	7.75	1.00	58.5%	0
Fermi 2	Mar-69	221	Feb-74	4.93			0
	Dec-72	439	Aug-76	3.67	3.76	33.5%	28.5
LaSalle 2	Jun-70	300	Oct-76	6.34			0
	Sep-72	330	Sep-78	6.00	2.25	14.9%	0
McGuire 2	Sep-70	179	Nov-76	6.17			0
	Sep-71	220	Mar-77	5.50	1.00	67.1%	0
Nine Mile Point 2	Dec-71	370	Jul-78	6.59			0
	Sep-72	370	Nov-78	6.17	0.75	55.3%	0
Shearon Harris 1	Jun-71	234	Mar-77	5.75			0
	Dec-72	274	Mar-78	5.25	1.50	33.5%	0
Shearon Harris 2	Jun-71	234	Jun-78	7.01			0
	Dec-72	274	Mar-79	6.25	1.50	50.3%	0
Shoreham	Mar-67	105	May-73	6.17			0
	Jun-72	309	May-77	4.92	5.26	23.9%	1.5
Waterford 3	Sep-70	230	Jan-77	6.34			0
	Sep-72	350	Jan-77	4.34	2.00	100.0%	0.5
Watts Bar 1	Dec-70	NA	Aug-76	5.67			0
	Dec-72	324	May-77	4.42	2.00	62.7%	0
Watts Bar 2	Dec-70	NA	May-77	6.42			NA
	Dec-72	324	Feb-78	5.17	2.00	62.2%	
Zimmer 1	Dec-69	199	Jan-75	5.09			0
	Dec-72	311	Aug-77	4.67	3.00	14.0%	1

	Years Elapsed	Progress Ratio
AVERAGES:		
Simple:	2.95	43.4%
Weighted by Years:	--	45.0%
NUMBER OF DATAPOINTS:	65	65

Notes: * Constructor=UE&C
** Architect/Engineer=UE&C

TABLE 2.5: COST AND SCHEDULE ESTIMATE HISTORIES of New England Nuclear Units to 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

TABLE 3.1: COST AND SCHEDULE SLIPPAGE: Completed Plants, with COD up to 12/76

	Actuals				Estimated		Est.	---Nominal---			
Unit Name	Cost	COD	C.P. issued	Date of Estimate	Cost	COD	Years to COD	Cost Ratio	Myopia Factor	Duration Ratio	% Comp
Nine Mile Point 1	162	Dec-69	Apr-65	Sep-64	68	Jul-68	3.83	2.39	1.255	1.37	0.0
Oyster Creek 1	90	Dec-69	Dec-64	Sep-65		Nov-67	2.17			1.96	18.0
Dresden 2 *	83	Jul-70	Jan-66	Mar-66		Feb-69	2.92			1.48	6.0
Ginna	83	Jul-70	Apr-66	Mar-66		Jun-69	3.25			1.33	0.0
Point Beach 1	74	Dec-70	Jul-67	Sep-66		Apr-70	3.58			1.19	0.0
Millstone 1	97	Mar-71	May-66	Mar-67		Aug-69	2.42			1.65	21.7
Robinson 2	78	Mar-71	Apr-67	Jun-66		May-70	3.92			1.21	0.0
Monticello	105	Jun-71	Jun-67	Jun-66		May-70	3.92			1.28	0.0
Dresden 3	104	Nov-71	Oct-66	Mar-66		Feb-70	3.92			1.45	2.0
Palisades	147	Dec-71	Mar-67	Mar-68	89	May-70	2.17	1.65	1.260	1.73	31.0
Point Beach 2	71	Oct-72	Jul-68	Mar-67		Apr-71	4.08			1.37	0.0
Vermont Yankee	172	Nov-72	Dec-67	Sep-66	88	Oct-70	4.08	1.95	1.178	1.51	0.0
Maine Yankee	219	Dec-72	Oct-68	Sep-68	131	May-72	3.66	1.67	1.151	1.16	
Pilgrim 1	231	Dec-72	Aug-68	Jun-68	122	Sep-71	3.25	1.89	1.216	1.39	
Surry 1	247	Dec-72	Jun-68	Dec-68	165	Mar-71	2.25	1.50	1.196	1.78	15.2
Turkey Point 3 [1]	109	Dec-72	Apr-67	Sep-69	99	Jun-71	1.75	1.10	1.055	1.86	52.2
Quad Cities 1 *	100	Feb-73	Feb-67	Sep-67		Mar-70	2.50			2.17	26.0
Quad Cities 2 *	100	Mar-73	Feb-67	Sep-67		Mar-71	3.50			1.57	16.0
Surry 2	150	May-73	Jun-68	Dec-68	123	Mar-72	3.25	1.22	1.063	1.36	6.3
Oconee 1	156	Jul-73	Nov-67	Sep-67	93	May-71	3.66	1.68	1.152	1.59	1.0
Indian Point 2 **	206	Aug-73	Oct-66	Jun-66		Jun-69	3.00			2.39	7.0
Fort Calhoun 1	174	Sep-73	Jun-68	Sep-68	92	May-71	2.66	1.89	1.271	1.88	17.0
Turkey Point 4 [1]	123	Sep-73	Apr-67	Sep-69	41	Jun-72	2.75	3.00	1.491	1.46	52.2
Prairie Isl 1	233	Dec-73	Jun-68	Dec-67	105	May-72	4.42	2.22	1.198	1.36	0.5
Zion 1	276	Dec-73	Dec-68	Mar-69	205	Apr-72	3.09	1.35	1.101	1.54	12.0
Kewaunee	202	Jun-74	Aug-68	Mar-69	109	Jun-72	3.25	1.85	1.209	1.61	3.5
Cooper	246	Jul-74	Jun-68	Mar-68	127	Apr-72	4.08	1.94	1.176	1.55	0.9
Peach Bottom 2	522	Jul-74	Jan-68	Mar-68	163	Mar-71	3.00	3.20	1.474	2.11	4.4
Browns Ferry 1	256	Aug-74	May-67	Sep-67	124	Oct-70	3.08	2.06	1.264	2.24	8.0
Oconee 2	160	Sep-74	Nov-67	Dec-67	88	May-72	4.42	1.83	1.146	1.53	0.0
Three Mile I. 1 *	398	Sep-74	May-68	Dec-68	150	Sep-71	2.75	2.65	1.426	2.09	9.0
Zion 2	290	Sep-74	Dec-68	Mar-69	194	May-73	4.17	1.49	1.101	1.32	9.0
Arkansas 1	233	Dec-74	Dec-68	Mar-69	138	Dec-72	3.75	1.69	1.150	1.53	1.0
Oconee 3	160	Dec-74	Nov-67	Dec-67	93	Jun-73	5.50	1.73	1.105	1.27	2.0
Peach Bottom 3	220	Dec-74	Jan-68	Mar-68	145	Jan-73	4.84	1.52	1.090	1.40	1.6
Prairie Isl 2	172	Dec-74	Jun-68	Dec-67	80	May-74	6.41	2.16	1.127	1.09	0.5
Duane Arnold	202	Feb-75	Jun-70	Dec-70	148	Dec-73	3.00	1.36	1.109	1.39	10.0
Browns Ferry 2	256	Mar-75	May-67	Mar-67	117	Feb-70	2.92	2.18	1.306	2.74	3.0
Rancho Seco	344	Apr-75	Oct-68	Dec-67	134	May-73	5.42	2.56	1.190	1.35	0.0
Calvert Cliffs 1	429	May-75	Jul-69	Mar-69	124	Jan-73	3.84	3.46	1.382	1.61	3.0
Fitzpatrick	419	Jul-75	May-70	Mar-68	224	May-73	5.17	1.87	1.129	1.42	1.0
Cook 1	538	Aug-75	Mar-69	Jun-69	235	Sep-72	3.25	2.29	1.290	1.90	1.0
Brunswick 2 **	382	Nov-75	Feb-70	Dec-70	195	Mar-74	3.25	1.96	1.230	1.51	10.0
Hatch 1	390	Dec-75	Sep-69	Mar-70	185	Jun-73	3.25	2.11	1.258	1.77	5.0
Millstone 2	418	Dec-75	Dec-70	Dec-70	239	Apr-74	3.33	1.75	1.183	1.50	10.0
Trojan	452	Dec-75	Feb-71	Mar-71	228	Sep-74	3.50	1.98	1.216	1.36	3.6
St. Lucie 1	470	Jun-76	Jul-70	Dec-70	200	Jun-74	3.50	2.35	1.277	1.57	9.0
Indian Point 3	570	Aug-76	Aug-69	Sep-69	156	Jul-72	2.83	3.65	1.580	2.46	NA
Beaver Valley 1	599	Oct-76	Jun-70	Sep-70	219	Jun-73	2.75	2.73	1.442	2.21	5.0

TABLE 3.1: COST AND SCHEDULE SLIPPAGE: Completed Plants, with COD up to 12/76

Unit Name	Actuals Cost	Actuals COD	C.P. issued	Date of Estimate	Estimated Cost	Estimated COD	Est. Years to COD	---Nominal--- Cost Ratio	---Nominal--- Myopia Factor	Duration Ratio	% Comp
AVERAGE (THROUGH 12/76):								2.05	1.228	1.624	
NUMBER OF DATAPOINTS:								37	37	49	

[1] First estimate available after receipt of Construction Permit

* Constructor=UE&C ** Architect/Engineer=UE&C

TABLE 3.2: UNITS UNDER CONSTRUCTION, up to December, 1976.

Unit Name	C.P. issued	Date of Estimate	Estimated Cost	Estimated COD	Est. Years to COD	Years Elapsed	Cost Growth Rate	Progress Rate	% Comp
Diablo Canyon 1	Apr-68	Dec-68	154	Jan-73	4.09				0
		Sep-76	530	Jun-77	0.75	7.76	17.3%	43.1%	98.5
Browns Ferry 3	Jul-68	Jun-69	149	Oct-72	1.33				26.0
		Jun-75	246	Jun-76	1.00	6.00	8.7%	5.5%	
Salem 1 *	Sep-68	Dec-67	152	Mar-72	4.25				0.0
		Mar-75	678	Sep-76	1.51	7.25	22.9%	37.8%	90.5
Salem 2 *	Sep-68	Dec-67	128	Mar-73	5.25				0.0
		Sep-74	496	May-79	4.66	6.76	22.2%	8.7%	48.1
Crystal River 3	Sep-68	Jun-69	148	Apr-72	2.83				2.0
		Jun-75	420	Sep-76	1.25	6.00	19.0%	26.3%	95.0
Cook 2	Mar-69	Jun-69	235	Sep-72	3.25				1.0
		Dec-76	437	Jun-78	1.50	7.51	8.6%	23.4%	82.4
Calvert Cliffs 2	Jul-69	Mar-69	105	Jan-74	4.84				2.0
		Dec-75	251	Jan-77	1.09	6.76	13.8%	55.5%	92.1
Three Mile I. 2 *	Nov-69	Sep-70	285	May-74	3.66				NA
		Aug-76	637	May-78	1.75	5.92	14.6%	32.4%	81.0
Brunswick 1 **	Feb-70	Dec-70	194	Mar-76	5.25				4.0
		Dec-75	329	Mar-77	1.25	5.00	11.1%	80.0%	86.0
Sequoyah 1	May-70	Jun-70	187	Apr-74	3.83				5.0
		Sep-76	475	May-78	1.66	6.26	16.1%	34.7%	80.0
Sequoyah 2	May-70	Sep-70	187	Dec-74	4.25				NA
		Jun-76	364	Jan-79	2.58	5.75	12.3%	28.9%	NA
Diablo Canyon 2	Dec-70	Mar-71	185	May-75	4.17				0
		Jun-76	425	Jun-77	1.00	5.26	17.1%	60.3%	79
North Anna 1	Feb-71	Jun-71	308	Mar-74	2.75				29.0
		Mar-76	567	Apr-77	1.08	4.75	13.7%	35.0%	88.8
North Anna 2	Feb-71	Sep-71	191	Jun-75	3.75				7.8
		Dec-76	381	Aug-78	1.66	5.25	14.0%	39.6%	76.3
Farley 1	Feb-71	Sep-71	259	Apr-75	3.58				6.0
		Jun-76	614	Jun-77	1.00	4.75	19.9%	54.3%	91.0
Davis-Besse 1	Mar-71	Sep-70	266	Dec-74	4.25				2.0
		Dec-75	533	Mar-77	1.25	5.25	14.1%	57.1%	95.0
Farley 2	Aug-72	Mar-73	268	Apr-77	4.08				5.3
		Dec-76	572	Apr-79	2.33	3.76	22.4%	46.7%	42.0
Fermi 2	Sep-72	Dec-72	439	Aug-76	3.67				28.5
		Jun-75	899	Sep-80	5.26	2.50	33.2%	-63.6%	45
Zimmer 1	Oct-72	Dec-72	311	Aug-77	4.67				1
		Sep-76	531	Jan-79	2.33	3.75	15.3%	62.2%	58.1
Arkansas 2	Dec-72	Jun-73	275	Oct-76	3.33				13.6
		Dec-75	393	Mar-78	2.25	2.50	15.3%	43.5%	56.4
Hatch 2	Dec-72	Dec-72	330	Apr-78	5.33				11.0
		Jun-76	512	Apr-79	2.83	3.50	13.4%	71.4%	57.0
Midland 1	Dec-72	Jun-73	385	Mar-80	6.75				2
		Jun-76	700	Mar-82	5.75	3.00	22.0%	33.3%	13
Midland 2	Dec-72	Dec-72	383	Feb-80	7.17				2
		Jun-76	700	Mar-81	4.75	3.50	18.8%	69.0%	16
Watts Bar 1	Jan-73	Jun-73	324	Mar-78	4.75				2
		Sep-76	475	Jun-79	2.75	3.25	12.5%	61.5%	51
Watts Bar 2	Jan-73	Jun-73	324	Dec-78	5.50				NA
		Sep-76	475	Mar-80	3.50	3.25	12.5%	61.6%	
McGuire 1	Feb-73	Sep-73	220	Nov-76	3.17				22.2
		Dec-76	384	Feb-79	2.17	3.25	18.7%	30.7%	81.2

TABLE 3.2: UNITS UNDER CONSTRUCTION, up to December, 1976.

Unit Name	C.P. issued	Date of Estimate	Estimated Cost	Estimated COD	Est. Years to COD	Years Elapsed	Cost Growth Rate	Progress Rate	% Comp
McGuire 2	Feb-73	Sep-73	220	Sep-77	4.00				16.4
		Dec-76	384	Feb-80	3.17	3.25	18.7%	25.6%	55.6
Summer 1	Mar-73	Jun-73	297	Jan-78	4.59				0.1
		Dec-76	635	May-80	3.41	3.50	24.2%	33.4%	42.5
WNP 2	Mar-73	Sep-73	472	Sep-77	4.00				2
		Dec-76	901	Sep-80	3.75	3.25	22.0%	7.7%	35.8
Forked River 1	Jul-73	Mar-75	694	May-82	7.17				0.5
		Dec-76	894	May-83	6.42	1.76	15.5%	43.1%	0.5
Lasalle 1	Sep-73	Sep-73	430	Dec-78	5.25				0.0
		Dec-76	585	Sep-79	2.75	3.25	9.9%	76.9%	45.0
LaSalle 2	Sep-73	Sep-74	343	Oct-79	5.08				3
		Dec-76	400	Sep-80	3.75	2.25	7.1%	59.1%	37
San Onofre 2	Oct-73	Mar-74	655	Jun-79	5.25				0.0
		Jun-76	1210	Oct-81	5.33	2.25	31.3%	-3.6%	23.0
San Onofre 3	Oct-73	Mar-74	655	Jun-80	6.25				0
		Dec-76	996	Jan-83	6.08	2.76	16.4%	6.0%	20
Susquehanna 1	Nov-73	Sep-74	810	Nov-80	6.17				4.0
		Dec-76	1032	Nov-80	3.92	2.25	11.3%	99.9%	39.6
Susquehanna 2	Nov-73	Mar-74	575	Jun-81	7.25				1
		Sep-76	706	May-82	5.67	2.51	8.5%	63.2%	21.2
Bailly Nuclear 1	May-74	Sep-74	447	Jun-77	2.75				0.5
		Dec-76	674	Nov-82	5.92	2.25	20.0%	-140.8%	0.5
Beaver Valley 2	May-74	Sep-74	685	Jun-81	6.75				0.05
		Sep-76	922	May-82	5.67	2.00	16.0%	54.3%	0.5
Limerick 1	Jun-74	Sep-74	1212	Apr-81	6.58				2
		Jun-76	1212	Apr-83	6.83	1.75	0.0%	-14.3%	28.6
Limerick 2	Jun-74	Dec-74	539	Jul-82	7.58				8
		Jun-76	539	Apr-85	8.83	1.50	0.0%	-83.3%	15.3
Nine Mile Point 2	Jun-74	Mar-75	749	Oct-82	7.59				1
		Jun-76	793	Oct-82	6.34	1.25	4.7%	100.0%	1.4
North Anna 3	Jul-74	Dec-74	432	Jun-80	5.50				3.6
		Mar-76	653	Apr-81	5.09	1.25	39.2%	33.3%	6.9
North Anna 4	Jul-74	Sep-74	281	Dec-79	5.25				1.7
		Mar-76	423	Nov-81	5.67	1.50	31.4%	-28.2%	1.6
Millstone 3	Aug-74	Mar-75	793	Nov-79	4.67				5.8
		Jun-76	998	May-82	5.92	1.25	20.1%	-99.1%	9.9
Grand Gulf 1	Sep-74	Sep-75	689	Sep-79	4.00				11
		Sep-76	935	Jun-80	3.75	1.00	35.6%	24.9%	32.5
Grand Gulf 2	Sep-74	Sep-75	699	Sep-83	8.00				1.6
		Sep-76	775	Sep-83	7.00	1.00	10.8%	99.7%	6.5
Hope Creek 1	Nov-74	Mar-75	1972	Dec-82	7.75				0
		Sep-76	2580	May-84	7.67	1.51	19.5%	5.5%	2
Waterford 3	Nov-74	Dec-74	710	Jun-80	5.50				1
		Sep-76	815	Apr-81	4.58	1.75	8.2%	52.5%	15
Bellefonte 1	Dec-74	Mar-75	482	Jun-80	5.26				3
		Sep-76	587	Jun-80	3.75	1.51	13.9%	100.0%	24
Bellefonte 2	Dec-74	Mar-75	482	Mar-81	6.01				0
		Sep-76	587	Mar-81	3.75	1.51	13.9%	149.6%	
Comanche Peak 1	Dec-74	Mar-74	355	Jan-80	5.84				0
		Dec-76	690	Jan-80	3.08	2.76	27.3%	100.0%	40
Comanche Peak 2	Dec-74	Mar-74	355	Jan-82	7.84				0
		Dec-76	690	Jan-82	5.09	2.76	27.3%	100.0%	17

TABLE 3.2: UNITS UNDER CONSTRUCTION, up to December, 1976.

Unit Name	C.P. issued	Date of Estimate	Estimated Cost	Estimated COD	Est. Years to COD	Years Elapsed	Cost Growth Rate	Progress Rate	% Comp
Surry 3	Dec-74	Mar-75	728	May-83	8.17				0
		Jun-76	1074	Apr-86	9.84	1.25	36.3%	-132.8%	0
Surry 4	Dec-74	Mar-75	506	May-84	9.18				0
		Jun-76	765	Apr-87	10.84	1.25	39.0%	-132.5%	0
Catawba 2	Aug-75	Dec-74	542	Jan-82	7.09				0
		Dec-76	542	Jun-83	6.50	2.00	0.0%	29.4%	9.5
WNP 1 **	Dec-75	Jun-76	1147	Mar-81	4.75				1.2
		Dec-76	1057	Sep-81	4.75	0.50	-15.0%	0.0%	1.8
Braidwood 1	Dec-75	Mar-76	716	Oct-81	5.59				1
		Sep-76	718	Oct-81	5.08	0.50	0.6%	100.0%	6
Braidwood 2	Dec-75	Mar-76	485	Oct-82	6.59				1
		Sep-76	486	Oct-82	6.08	0.50	0.4%	100.0%	4
Byron 1	Dec-75	Mar-76	663	Oct-80	4.59				6
		Dec-76	664	Mar-81	4.25	0.75	0.2%	45.1%	14
Byron 2	Dec-75	Mar-76	487	Oct-82	6.59				6
		Sep-76	489	Oct-82	6.08	0.50	0.8%	100.0%	9

	Years Elapsed	Cost Growth Rate	Progress Rate
AVERAGES:			
Simple	3.16	15.7%	33.6%
Weighted by years	-	16.4%	36.3%
NUMBER OF DATAPOINTS:	60	60	60

*Constructor=UE&C
**Architect/Engineer=UE&C

TABLE 3.3: UNITS WITH CONSTRUCTION PERMIT OR LIMITED WORK AUTHORIZATION IN DECEMBER, 1976 (PERCENT COMPLETE <= 10%).

Unit Name	cp/lwa issue date	% complete at 12/76	Estimated COD
Forked River 1	cp: Jul-73	0.0%	May-82
Vogtle 1	cp: Jun-74	0.0%	Apr-83
Vogtle 2	cp: Jun-74	0.0%	Apr-84 ++
Surry 4	cp: Dec-74	0.0%	Apr-87 ++
Surry 3	cp: Dec-74	0.0%	Apr-86
Perry 1	lwa: Oct-75	0.0%	Jun-81
Perry 2	lwa: Oct-75	0.0%	Jun-83 ++
Clinton 2	cp: Feb-76	0.0%	Jun-83 ++
Palo Verde 3	cp: May-76	0.0%	May-86 ++
Bailly 1	cp: May-74	0.5%	Oct-82
WPPSS 4	lwa: Aug-75	0.5%	Mar-83 ++
South Texas 2	cp: Dec-75	0.5%	Mar-82 ++
Callaway 2	cp: Apr-76	0.5%	Apr-81 ++
Beaver Valley 2	cp: May-74	1.0%	May-82 ++
Hope Creek 1	cp: Nov-74	1.0%	May-84
Hope Creek 2	cp: Nov-74	1.0%	May-86 ++
Palo Verde 2	cp: May-76	1.0%	May-84 ++
River Bend 1	lwa: Sep-75	1.5%	Oct-81
River Bend 2	lwa: Sep-75	1.5%	Oct-83 ++
WPPSS 1	cp: Dec-75	1.5%	Sep-81
North Anna 4	cp: Jul-74	2.0%	Nov-81 ++
Grand Gulf 2	cp: Sep-74	2.0%	Jan-85 ++
Callaway 1	cp: Apr-76	2.0%	Oct-81
Comanche Peak 2	cp: Dec-74	2.5%	Jan-82 ++
South Texas 1	cp: Dec-75	2.5%	Oct-80
Nine Mile Point 2	cp: Jun-74	4.0%	Oct-82
North Anna 3	cp: Jul-74	4.0%	Apr-81
Catawba 1	cp: Aug-75	5.0%	Jan-81
Catawba 2	cp: Aug-75	5.0%	Jan-83 ++
Palo Verde 1	cp: May-76	5.0%	May-82
Braidwood 1	cp: Dec-75	7.0%	Oct-79
Braidwood 2	cp: Dec-75	7.0%	Oct-80 ++
Clinton 1	cp: Feb-76	8.0%	Jun-80
AVERAGES			
All Units	May-75	2.0%	Nov-82
Second Units	Jun-75	1.4%	Aug-83

Source: Nuclear News, February 1977
Notes: ++ = Second Units, other than Seabrook 2

TABLE 3.4: 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 4.1: COST AND SCHEDULE SLIPPAGE: Completed Plants, with COD in 1977 and 1978

	Actuals		C.P.	Date of	Estimated		Est.	---Nominal---		Duration	%
Unit Name	Cost	COD	issued	Estimate	Cost	COD	Years to COD	Cost Ratio	Myopia Factor	Ratio	Comp
Browns Ferry 3	301	Mar-77	Jul-68	Jun-69	149	Oct-72	3.34	2.02	1.234	2.32	26.0
Brunswick 1 *	318	Mar-77	Feb-70	Dec-70	194	Mar-76	5.25	1.64	1.099	1.19	4.0
Crystal River 3	366	Mar-77	Sep-68	Jun-69	148	Apr-72	2.83	2.47	1.376	2.73	2.0
Calvert Cliffs 2	335	Apr-77	Jul-69	Mar-69	105	Jan-74	4.84	3.19	1.271	1.67	2.0
Salem 1 *	850	Jun-77	Sep-68	Dec-67	152	Mar-72	4.25	5.59	1.500	2.24	0.0
Davis-Besse 1	588	Nov-77	Mar-71	Sep-70	266	Dec-74	4.25	2.21	1.205	1.69	2.0
Farley 1	727	Dec-77	Feb-71	Sep-71	259	Apr-75	3.58	2.81	1.334	1.75	6.0
North Anna 1	782	Jun-78	Feb-71	Jun-71	308	Mar-74	2.75	2.54	1.403	2.55	29.0
Cook 2	444	Jul-78	Mar-69	Jun-69	235	Sep-72	3.25	1.89	1.216	2.79	1.0
Three Mile I. 2 *	715	Dec-78	Nov-69	Sep-70	285	May-74	3.66	2.51	1.286	2.24	NA
AVERAGE (1969 - 1978)								2.19	1.242	1.707	
NUMBER OF DATAPOINTS:								47	47	59	
AVERAGE (1977 and 1978)								2.69	1.293	2.117	
NUMBER OF DATAPOINTS:								10	10	10	

* Constructor=UE&C

TABLE 4.2: UNITS UNDER CONSTRUCTION, in December, 1978.

Unit Name	C.P. issued	Date of Estimate	Estimated Cost	COD	Est. Years to COD	Years Elapsed	Cost Growth Rate	Progress Rate	% Comp
Diablo Canyon 1	Apr-68	Sep-76	530	Jun-77	0.75				98.5
		Jun-78	672	Jun-79	1.00	1.75	14.5%	-14.4%	99.2
Salem 2 *	Sep-68	Sep-74	496	May-79	4.66				48.1
		Mar-78	619	May-79	1.17	3.50	6.5%	99.9%	90.6
Sequoyah 1	May-70	Sep-76	475	May-78	1.66				80.0
		Sep-78	632	Oct-79	1.08	2.00	15.4%	29.0%	92.0
Sequoyah 2	May-70	Jun-76	364	Jan-79	2.58				NA
		Sep-78	632	Jun-80	1.75	2.25	27.8%	37.1%	78.0
Diablo Canyon 2	Dec-70	Jun-76	425	Jun-77	1.00				79
		Dec-78	548	Jun-80	1.50	2.50	10.7%	-20.0%	96.9
North Anna 2	Feb-71	Dec-76	381	Aug-78	1.66				76.3
		Mar-78	467	Mar-79	1.00	1.25	17.7%	53.4%	90.4
Farley 2	Aug-72	Dec-76	572	Apr-79	2.33				42.0
		Sep-78	652	Apr-80	1.58	1.75	7.8%	42.7%	72.4
Fermi 2	Sep-72	Jun-75	899	Sep-80	5.26				
		Mar-77	882	Dec-80	3.76	1.75	-1.1%	85.8%	
Zimmer 1	Oct-72	Sep-76	531	Jan-79	2.33				58.1
		Mar-78	664	Jan-80	1.84	1.50	16.1%	33.2%	81.3
Watts Bar 1	Jan-73	Sep-76	475	Jun-79	2.75				51
		Dec-78	617	Jun-80	1.50	2.25	12.3%	55.4%	87
Watts Bar 2	Jan-73	Sep-76	475	Mar-80	3.50				
		Dec-78	617	Mar-81	2.25	2.25	12.3%	55.5%	68
McGuire 1	Feb-73	Dec-76	384	Feb-79	2.17				81.2
		Dec-78	549	Feb-80	1.17	2.00	19.6%	50.0%	96.0
McGuire 2	Feb-73	Dec-76	384	Feb-80	3.17				55.6
		Mar-78	549	Mar-81	3.00	1.25	33.2%	13.4%	51
Summer 1	Mar-73	Dec-76	635	May-80	3.41				42.5
		Sep-78	675	Dec-80	2.25	1.75	3.6%	66.5%	77.0
WNP 2	Mar-73	Dec-76	901	Sep-80	3.75				35.8
		Mar-78	1001	Sep-80	2.50	1.25	8.8%	100.3%	60.7
Forked River 1	Jul-73	Dec-76	894	May-83	6.42				0.5
		Dec-78	1150	Dec-83	5.00	2.00	13.4%	70.7%	4.1
Lasalle 1	Sep-73	Dec-76	585	Sep-79	2.75				45.0
		Sep-77	675	Sep-79	2.00	0.75	21.0%	99.9%	55.0
LaSalle 2	Sep-73	Dec-76	400	Sep-80	3.75				37
		Dec-78	580	Sep-80	1.75	2.00	20.4%	100.0%	59
San Onofre 2	Oct-73	Jun-76	1210	Oct-81	5.33				23.0
		Jun-77	1320	Oct-81	4.33	1.00	9.1%	99.9%	44.0
San Onofre 3	Oct-73	Dec-76	996	Jan-83	6.08				20
		Jun-77	1080	Jan-83	5.58	0.50	17.6%	100.3%	30
Susquehanna 1	Nov-73	Dec-76	1032	Nov-80	3.92				39.6
		Sep-78	1293	Feb-81	2.42	1.75	13.8%	85.5%	76.1
Susquehanna 2	Nov-73	Sep-76	706	May-82	5.67				21.2
		Sep-78	787	May-82	3.67	2.00	5.6%	100.0%	51.7
Beaver Valley 2	May-74	Sep-76	922	May-82	5.67				0.5
		Sep-78	1415	May-84	5.67	2.00	23.9%	-0.1%	26
Bailly Nuclear 1	May-74	Dec-76	674	Nov-82	5.92				0.5
		Dec-78	850	Dec-84	6.01	2.00	12.3%	-4.2%	0.5
Limerick 1	Jun-74	Jun-76	1212	Apr-83	6.83				28.6
		Jun-77	1635	Apr-83	5.83	1.00	34.9%	100.0%	32
Limerick 2	Jun-74	Jun-76	539	Apr-85	8.83				15.3
		Jun-77	949	Apr-85	7.83	1.00	76.1%	100.0%	22

TABLE 4.2: UNITS UNDER CONSTRUCTION, in December, 1978.

Unit Name	C.P. issued	Date of Estimate	Estimated Cost	Estimated COD	Est. Years to COD	Years Elapsed	Cost Growth Rate	Progress Rate	% Comp
Vogtle 1	Jun-74	Jun-74	629	Apr-80	5.83				0
		Sep-78	1586	Nov-84	6.17	4.25	24.3%	-8.0%	5
Vogtle 2	Jun-74	Jun-74	534	Apr-81	6.83				0
		Dec-78	1297	Nov-87	8.92	4.50	21.8%	-46.3%	3
Nine Mile Point 2	Jun-74	Jun-76	793	Oct-82	6.34				1.4
		Dec-78	1954	Oct-84	5.84	2.50	43.4%	19.9%	24.1
North Anna 3	Jul-74	Mar-76	653	Apr-81	5.09				6.9
		Mar-78	1012	Oct-83	5.59	2.00	24.5%	-25.1%	7
North Anna 4	Jul-74	Mar-76	423	Nov-81	5.67				1.6
		Mar-78	660	Sep-84	6.51	2.00	24.9%	-41.8%	3.7
Millstone 3	Aug-74	Jun-76	998	May-82	5.92				9.9
		Sep-78	1980	May-86	7.67	2.25	35.6%	-77.7%	24.5
Grand Gulf 1	Sep-74	Sep-76	935	Jun-80	3.75				32.5
		Dec-77	1174	Apr-81	3.33	1.25	20.0%	33.4%	57.9
Grand Gulf 2	Sep-74	Sep-76	775	Sep-83	7.00				6.5
		Dec-77	954	Jan-84	6.08	1.25	18.1%	73.4%	2.4
Hope Creek 1	Nov-74	Sep-76	2580	May-84	7.67				2
		Jun-78	2890	May-84	5.92	1.75	6.7%	100.1%	8.5
Waterford 3	Nov-74	Sep-76	815	Apr-81	4.58				15
		Sep-78	1110	Oct-81	3.08	2.00	16.7%	74.9%	48.8
Bellefonte 1	Dec-74	Sep-76	587	Jun-80	3.75				24
		Sep-78	792	Sep-81	3.00	2.00	16.2%	37.4%	60
Bellefonte 2	Dec-74	Sep-76	587	Mar-81	3.75				
		Sep-78	792	Jun-82	3.75	2.00	16.2%	0.0%	42
Comanche Peak 1	Dec-74	Dec-76	690	Jan-80	3.08				40
		Jun-77	850	Jan-81	3.59	0.50	51.9%	-101.1%	39
Comanche Peak 2	Dec-74	Dec-76	690	Jan-82	5.09				17
		Jun-77	850	Jan-83	5.59	0.50	51.9%	-100.5%	9.67
Catawba 1	Aug-75	Dec-74	542	Jan-81	6.09				0.7
		Mar-78	673	Jul-81	3.34	3.25	6.9%	84.7%	28
Catawba 2	Aug-75	Dec-76	542	Jun-83	6.50				9.5
		Mar-78	673	Jan-83	4.84	1.25	19.0%	133.2%	22
WNP 1	Dec-75	Dec-76	1057	Sep-81	4.75				1.8
		Mar-78	1164	Dec-82	4.75	1.25	8.0%	0.0%	9.3
Braidwood 1	Dec-75	Sep-76	718	Oct-81	5.08				6
		Dec-78	902	Oct-81	2.84	2.25	10.7%	100.0%	45
Braidwood 2	Dec-75	Sep-76	486	Oct-82	6.08				4
		Dec-78	601	Oct-82	3.84	2.25	9.9%	100.0%	36
Byron 1	Dec-75	Dec-76	664	Mar-81	4.25				14
		Dec-78	984	Sep-81	2.75	2.00	21.7%	74.8%	52
Byron 2	Dec-75	Sep-76	489	Oct-82	6.08				9
		Dec-78	624	Oct-82	3.84	2.25	11.4%	100.0%	42
Clinton 1	Feb-76	Sep-76	825	Jun-81	4.75				6
		Dec-78	1297	Dec-82	4.00	2.25	22.3%	33.3%	36
Clinton 2	Feb-76	Sep-76	699	Jun-84	7.75				0
		Dec-77	1059	Jun-88	10.51	1.25	39.4%	-220.4%	0
Callaway 1	Apr-76	Dec-76	1088	Jun-82	5.50				2.7
		Dec-77	1122	Oct-82	4.83	1.00	3.1%	66.7%	11.2
Callaway 2	Apr-76	Dec-76	1297	Apr-87	10.33				0.4
		Sep-78	1306	Apr-87	8.58	1.75	0.4%	100.0%	0.4
Palo Verde 1	May-76	Dec-75	975	May-82	6.42				0
		Sep-78	760	May-82	3.67	2.75	-8.7%	99.9%	28.5

TABLE 4.2: UNITS UNDER CONSTRUCTION, in December, 1978.

Unit Name	C.P. issued	Date of Estimate	Estimated Cost	Estimated COD	Est. Years to COD	Years Elapsed	Cost Growth Rate	Progress Rate	% Comp
Palo Verde 2	May-76	Dec-75	845	May-84	8.42				0
		Sep-78	598	May-84	5.67	2.75	-11.8%	99.9%	7.8
Palo Verde 3	May-76	Mar-76	950	Jun-86	9.50				0
		Sep-78	702	Jun-86	7.75	2.50	-11.4%	69.9%	0.5
Seabrook 1 * **	Jul-76	Dec-76	684	Nov-81	4.92				1
		Jun-78	1340	Dec-82	4.50	1.50	56.6%	27.8%	13
Seabrook 2 * **	Jul-76	Dec-76	684	Nov-83	6.92				1
		Mar-78	980	Dec-84	6.76	1.25	33.4%	13.0%	2
River Bend 1	Mar-77	Dec-77	1172	Sep-83	5.75				5
		Jun-78	1172	Sep-84	6.26	0.50	0.0%	-101.1%	5
St. Lucie 2	May-77	Jun-77	850	May-83	5.91				1
		Dec-78	919	May-83	4.41	1.50	5.3%	99.9%	16.8
Hartsville A-1	May-77	Jun-77	602	Jun-83	6.00				3
		Sep-78	853	Jun-83	4.75	1.25	32.1%	100.0%	13
Hartsville A-2	May-77	Jun-77	602	Jun-84	7.01				1
		Sep-78	853	Jun-84	5.75	1.25	32.1%	100.0%	
Hartsville B-1	May-77	Jun-77	602	Dec-83	6.50				NA
		Sep-77	854	Dec-83	6.25	0.25	300.2%	100.0%	
Hartsville B-2	May-77	Jun-77	602	Dec-84	7.51				NA
		Sep-77	854	Dec-84	7.25	0.25	300.2%	100.0%	
Perry 1	May-77	Sep-77	988	Dec-81	4.25				13.3
		Dec-78	1159	May-83	4.42	1.25	13.6%	-13.2%	33.2
Perry 2	May-77	Sep-77	1123	Jun-83	5.75				6.3
		Sep-78	1318	May-85	6.67	1.00	17.4%	-91.8%	20.2
St. Lucie 2	May-77	Jun-77	850	May-83	5.92				1
		Dec-78	919	May-83	4.42	1.50	5.3%	100.0%	16.8
Cherokee 1	Dec-77	Dec-77	336	Jan-85	7.09				1
		Mar-78	392	Jan-85	6.84	0.25	87.6%	100.0%	1
Cherokee 2	Dec-77	Dec-77	336	Jan-87	9.09				1
		Mar-78	392	Jan-87	8.84	0.25	87.6%	100.0%	2
Cherokee 3	Dec-77	Mar-77	336	Jan-89	11.85				0.5
		Mar-78	392	Jan-89	10.85	1.00	16.8%	100.0%	1
Shoreham	Jan-78	Sep-78	1293	Sep-80	2.00				75
		Dec-78	1337	Dec-80	2.00	0.25	14.4%	0.0%	78
WNP 4	Feb-78	Mar-78	1610	Jun-84	6.26				3.2
		Sep-78	1982	Jun-85	6.75	0.50	51.0%	-98.4%	7.6
AVERAGES									
Simple:						1.66	28.6%	42.2%	
Weighted by years:						--	17.9%	41.4%	
NUMBER OF DATAPOINTS:						70	70	70	

* Constructor=UE&C

** Architect/Engineer=UE&C

TABLE 4.3: UNITS WITH CONSTRUCTION PERMIT OR LIMITED WORK AUTHORIZATION IN DECEMBER, 1978 (PERCENT COMPLETE <= 10%).

Unit Name	cp/lwa issue date		% complete at 12/76	Estimated COD
Seabrook 2	cp:	Jul-76	2.0%	Dec-84
Davis-Besse 2	lwa:	Dec-75	0.0%	Jun-88
Davis-Besse 3	lwa:	Dec-75	0.0%	Jun-90 ++
Clinton 2	cp:	Feb-76	0.0%	Jun-88 ++
Tyrone 1	cp:	Dec-77	0.0%	Jun-86
Black Fox 1	lwa:	Jul-78	0.0%	Apr-84
Black Fox 2	lwa:	Jul-78	0.0%	Apr-86 ++
Jamesport 1	cp:	Jan-79	0.0%	Jun-88
Jamesport 2	cp:	Jan-79	0.0%	Jun-90 ++
WPPSS 5	cp:	May-78	0.3%	Jul-85 ++
Callaway 2	cp:	Apr-76	0.5%	Apr-87 ++
Palo Verde 3	cp:	May-76	0.5%	May-86
Shearon Harris 2	cp:	Jan-78	0.5%	Mar-86 ++
Shearon Harris 3	cp:	Jan-78	0.5%	Mar-90
Phipps Bend 2	cp:	Jan-78	0.5%	Aug-85 ++
Shearon Harris 4	cp:	Jan-78	0.5%	Mar-88
Bailly 1	cp:	May-74	1.0%	Jun-84
Yellow Creek 2	cp:	Nov-78	1.0%	May-86 ++
Forked River 1	cp:	Jul-73	2.0%	Dec-83
Phipps Bend 1	cp:	Jan-78	3.0%	Aug-84
WPPSS 3	cp:	Apr-78	3.0%	Jan-84
Yellow Creek 1	cp:	Nov-78	3.0%	May-85
North Anna 4	cp:	Jul-74	3.7%	May-84 ++
Cherokee 1	cp:	Dec-77	4.0%	Jan-85
Cherokee 2	cp:	Dec-77	4.0%	Jan-87 ++
Cherokee 3	cp:	Dec-77	4.0%	Jan-89
Marble Hill 2	cp:	Apr-78	4.0%	Jun-84 ++
Vogtle 2	cp:	Jun-74	5.0%	Nov-87 ++
River Bend 1	cp:	Sep-75	5.0%	Oct-84
River Bend 2	cp:	Sep-75	5.0%	indef.
Hartsville A-2	cp:	May-77	6.0%	Jun-84 ++
Hartsville B-2	cp:	May-77	5.0%	Dec-84 ++
North Anna 3	cp:	Jul-74	7.0%	Apr-83
Grand Gulf 2	cp:	Sep-74	7.0%	Jan-84 ++
WPPSS 4	cp:	Feb-78	8.0%	Mar-83 ++
South Texas 2	cp:	Dec-75	9.0%	Apr-83 ++
Hope Creek 2	cp:	Jun-74	10.0%	Sep-86 ++
Vogtle 1	cp:	Jun-74	10.0%	Nov-84
Hope Creek 1	cp:	Nov-74	10.0%	Sep-84
Seabrook 1	cp:	Jul-76	10.0%	Dec-82
Shearon Harris 1	cp:	Jan-78	10.0%	Mar-84
AVERAGES				
All Units		Nov-76	3.6%	Dec-85
Second Units		Dec-76	3.4%	Feb-86

Source: Nuclear News, February 1979
Notes: ++ = Second Units, other than Seabrook 2

TABLE 5.1: COST AND SHEDULE SLIPPAGE, Completed Plants, with COD in 1979 and first half of 1980

Unit Name	Actuals Cost	Actuals COD	C.P. issued	Date of Estimate	Estimated Cost	Estimated COD	Est. Years to COD	---Nominal--- Cost Ratio	---Nominal--- Myopia Factor	Duration Ratio	% Comp
Hatch 2	509	Sep-79	Dec-72	Dec-72	330	Apr-78	5.33	1.54	1.085	1.27	11.0
Arkansas 2	640	Mar-80	Dec-72	Jun-73	275	Oct-76	3.33	2.33	1.288	2.02	13.6
AVERAGE (1969 - 6/1980)								2.18	1.24	1.71	
NUMBER OF DATAPOINTS:								49	49	61	
AVERAGE (1979 - 6/1980)								1.93	1.19	1.64	
NUMBER OF DATAPOINTS:								2	2	2	

TABLE 5.2: UNITS UNDER CONSTRUCTION in June, 1980.

Unit Name	C.P. issued	Date of Estimate	Estimated Cost	Estimated COD	Est. Years to COD	Years Elapsed	Cost Growth Rate	Progress Rate	% Comp
Diablo Canyon 1	Apr-68	Jun-78	672	Jun-79	1.00				99.2
		Mar-80	880	Jun-81	1.25	1.75	16.7%	-14.4%	99.2
Sequoyah 1	May-70	Sep-78	632	Oct-79	1.08				92.0
		Jun-79	632	Jun-80	1.00	0.75	0.0%	10.6%	98.0
Sequoyah 2	May-70	Sep-78	632	Jun-80	1.75				78.0
		Sep-79	442	Jun-81	1.75	1.00	-30.1%	0.0%	84.0
Diablo Canyon 2	Dec-70	Dec-78	548	Jun-80	1.50				96.9
		Dec-79	721	Jun-81	1.50	1.00	31.6%	0.0%	97.9
Farley 2	Aug-72	Sep-78	652	Apr-80	1.58				72.4
		Sep-79	684	Sep-80	1.00	1.00	4.9%	58.0%	83.7
Fermi 2	Sep-72	Jun-75	899	Sep-80	5.26				45
		Jun-80	1283	Mar-82	1.75	5.01	7.4%	70.1%	79.4
Zimmer 1	Oct-72	Mar-78	664	Jan-80	1.84				81.3
		Jun-80	1027	Apr-82	1.83	2.25	21.3%	0.2%	93.8
Watts Bar 1	Jan-73	Dec-78	617	Jun-80	1.50				87
		Jun-80	720	May-82	1.92	1.50	10.8%	-27.6%	87
Watts Bar 2	Jan-73	Dec-78	617	Mar-81	2.25				68
		Jun-80	720	Feb-83	2.67	1.50	10.8%	-28.1%	72
McGuire 2	Feb-73	Mar-78	549	Mar-81	3.00				51
		Jun-80	635	Sep-82	2.25	2.25	6.7%	33.3%	83
Summer 1	Mar-73	Sep-78	675	Dec-80	2.25				77.0
		Mar-80	827	Jun-81	1.25	1.50	14.5%	66.7%	94.8
WNP 2	Mar-73	Mar-78	1001	Sep-80	2.50				60.7
		Jun-80	2392	Jan-83	2.58	2.25	47.2%	-3.7%	85.2
Lasalle 1	Sep-73	Sep-77	675	Sep-79	2.00				55.0
		Jun-80	1107	Jun-81	1.00	2.75	19.7%	36.3%	98.0
LaSalle 2	Sep-73	Dec-78	580	Sep-80	1.75				59
		Jun-80	786	Jun-82	2.00	1.50	22.4%	-16.4%	78
San Onofre 2	Oct-73	Jun-77	1320	Oct-81	4.33				44.0
		Mar-80	1824	Dec-81	1.75	2.75	12.5%	93.9%	86.0
San Onofre 3	Oct-73	Jun-77	1080	Jan-83	5.58				30
		Mar-80	1216	Jan-83	2.83	2.75	4.4%	100.0%	60
Susquehanna 1	Nov-73	Sep-78	1293	Feb-81	2.42				76.1
		Sep-79	1607	Jan-82	2.34	1.00	24.3%	8.5%	70.0
Susquehanna 2	Nov-73	Sep-78	787	May-82	3.67				51.7
		Jun-80	1082	Aug-82	2.17	1.75	19.9%	85.7%	53
Beaver Valley 2	May-74	Sep-78	1415	May-84	5.67				26
		Dec-79	2024	May-86	6.42	1.25	33.2%	-60.1%	35.2
Bailly Nuclear 1	May-74	Dec-78	850	Dec-84	6.01				0.5
		Sep-79	1100	Jun-87	7.75	0.75	41.0%	-232.8%	0.5
Limerick 1	Jun-74	Jun-77	1635	Apr-83	5.83				32
		Jun-79	1695	Apr-83	3.83	2.00	1.8%	100.0%	52
Limerick 2	Jun-74	Jun-77	949	Apr-85	7.83				22
		Jun-79	909	Apr-85	5.83	2.00	-2.1%	100.0%	35
Vogtle 1	Jun-74	Dec-77	1537	Nov-84	6.92				5
		Jun-80	1746	May-85	4.92	2.50	5.2%	80.0%	10
Vogtle 2	Jun-74	Dec-78	1297	Nov-87	8.92				3
		Jun-80	988	Nov-87	7.42	1.50	-16.6%	99.9%	4
Nine Mile Point 2	Jun-74	Dec-78	1954	Oct-84	5.84				24.1
		Jun-80	1953	Oct-84	4.34	1.50	.0%	100.0%	37.7
North Anna 3	Jul-74	Mar-78	1012	Oct-83	5.59				7
		Sep-79	1428	Apr-86	6.59	1.50	25.7%	-66.3%	7

TABLE 5.2: UNITS UNDER CONSTRUCTION in June, 1980.

Unit Name	C.P. issued	Date of Estimate	Estimated Cost	Estimated COD	Est. Years to COD	Years Elapsed	Cost Growth Rate	Progress Rate	% Comp
River Bend 1	Mar-77	Jun-78	1172	Sep-84	6.26				5
		Mar-80	1679	Apr-84	4.09	1.75	22.8%	123.9%	11.9
St. Lucie 2	May-77	Dec-78	919	May-83	4.41				16.8
		Jun-80	1100	May-83	2.91	1.50	12.7%	99.9%	45.1
Wolf Creek	May-77	Mar-77	1029	Apr-83	6.08				1
		Dec-79	1296	Apr-83	3.33	2.75	8.7%	99.9%	47.9
Hartsville A-1	May-77	Sep-78	853	Jun-83	4.75				13
		Sep-79	1418	Jul-86	6.84	1.00	66.3%	-208.5%	21
Hartsville A-2	May-77	Sep-78	853	Jun-84	5.75				
		Sep-79	1418	Jul-87	7.84	1.00	66.3%	-208.2%	8
Perry 1	May-77	Dec-78	1159	May-83	4.42				33.2
		Jun-80	1701	May-84	3.92	1.50	29.1%	33.2%	59.4
Perry 2	May-77	Sep-78	1318	May-85	6.67				20.2
		Jun-80	2157	May-88	7.92	1.75	32.5%	-71.5%	46.5
St. Lucie 2	May-77	Dec-78	919	May-83	4.42				16.8
		Jun-80	1100	May-83	2.92	1.50	12.7%	100.0%	45.1
Hartsville B-1	May-77	Sep-77	854	Dec-83	6.25				NA
		Sep-79	1418	Jun-89	9.76	2.00	28.9%	-175.2%	15
Hartsville B-2	May-77	Sep-77	854	Dec-84	7.25				NA
		Sep-79	1418	Jun-90	10.76	2.00	28.9%	-175.1%	5
Cherokee 1	Dec-77	Mar-78	392	Jan-85	6.84				1
		Mar-80	402	Jan-90	9.84	2.00	1.3%	-149.8%	15
Cherokee 2	Dec-77	Mar-78	392	Jan-87	8.84				2
		Mar-80	402	Jan-92	11.84	2.00	1.3%	-149.8%	1
Cherokee 3	Dec-77	Mar-78	392	Jan-89	10.85				1
		Mar-80	402	Jan-94	13.85	2.00	1.3%	-149.8%	1
Shearon Harris 1	Jan-78	Dec-77	1039	Mar-84	6.25				1.7
		Jun-80	1208	Mar-85	4.75	2.50	6.2%	60.0%	32.8
Shearon Harris 2	Jan-78	Dec-77	1039	Mar-86	6.25				1.7
		Jun-80	1208	Mar-88	4.75	2.50	6.2%	60.0%	3.7
Shoreham	Jan-78	Dec-78	1337	Dec-80	2.00				78
		Jun-80	1213	Feb-83	2.67	1.50	-6.3%	-44.5%	85.5
Shearon Harris 3	Jan-78	Dec-77	1039	Mar-90	12.25				0.5
		Jun-80	1208	Mar-94	13.76	2.50	6.2%	-60.0%	0.5
Shearon Harris 4	Jan-78	Dec-77	1039	Mar-88	10.25				0.5
		Jun-80	1208	Mar-92	11.76	2.50	6.2%	-60.0%	0.5
Phipps Bend 1	Jan-78	Sep-78	872	Aug-84	5.92				1
		Sep-79	1440	Mar-87	7.50	1.00	65.1%	-158.1%	7
Phipps Bend 2	Jan-78	Sep-78	872	Aug-85	6.92				0
		Jun-80	1440	May-94	13.92	1.75	33.2%	-400.0%	4
WNP 4	Feb-78	Sep-78	1982	Jun-85	6.75				7.6
		Mar-80	3086	Jun-86	6.25	1.50	34.4%	33.3%	14.5
Marble Hill 1	Apr-78	Jun-78	511	Oct-82	4.34				8
		Jun-80	2001	Dec-86	6.50	2.00	97.7%	-108.2%	20
Marble Hill 2	Apr-78	Mar-79	818	Jan-84	4.84				5.2
		Jun-80	1383	Dec-87	7.50	1.25	52.0%	-212.2%	9
WNP 3	Apr-78	Mar-79	1948	Dec-84	5.76				11.2
		Sep-79	2256	Dec-84	5.25	0.50	33.8%	100.0%	16.6
WNP 5	Apr-78	Mar-79	2224	Jun-86	7.26				1.8
		Jun-80	3705	Jun-87	7.00	1.25	50.2%	20.3%	6.7

TABLE 5.2: UNITS UNDER CONSTRUCTION in June, 1980.

Unit Name	C.P. issued	Date of Estimate	Estimated Cost	Estimated COD	Est. Years to COD	Years Elapsed	Cost Growth Rate	Progress Rate	% Comp
	AVERAGES								
	Simple:					1.83	19.7%	-10.5%	
	Weighted by years:					-	17.7%	-0.9%	
	NUMBER OF DATAPOINTS:					77	77	77	

* Constructor=UE&C
** Architect/Engineer=UE&C

TABLE 5.3: UNITS WITH CONSTRUCTION PERMIT OR LIMITED WORK AUTHORIZATION IN DECEMBER, 1980 (PERCENT COMPLETE <= 15%).

Unit Name	cp/lwa issue date	% complete at 12/76	Estimated COD
Seabrook 2	cp: Jul-76	7.7%	Jun-85
River Bend 2	cp: Sep-75	0.0%	indef.
Clinton 2	cp: Feb-76	0.0%	indef.
Cherokee 2	cp: Dec-77	0.0%	Jan-93
Cherokee 3	cp: Dec-77	0.0%	indef.
Callaway 2	cp: Apr-76	0.5%	indef. [1]
Shearon Harris 3	cp: Jan-78	0.5%	Mar-94
Shearon Harris 4	cp: Jan-78	0.5%	Mar-92
Bailly 1	cp: May-74	1.0%	indef. [1]
Shearon Harris 2	cp: Jan-78	3.0%	Mar-88
Yellow Creek 2	cp: Nov-78	3.0%	indef.
Vogtle 2	cp: Jun-74	4.4%	Jun-88
Phipps Bend 2	cp: Jan-78	5.0%	indef.
Hartsville B-2	cp: May-77	7.0%	indef.
North Anna 3	cp: Jul-74	8.8%	Jun-89
WPPSS 5	cp: Apr-78	9.0%	Sep-87
Marble Hill 2	cp: Apr-78	11.0%	indef. [1]
WPPSS 4	cp: Feb-78	15.0%	Feb-87
AVERAGES	Feb-77	4.0%	Jan-90

Source: Nuclear News, February, 1981
Notes: [1] Nuclear Industry, January, 1981.

TABLE 5.4: PLANT CANCELATIONS: 1977-1980

Unit Name	Year of Cancelation	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 auth.	0%
Davis-Besse 3		limited work auth.	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.

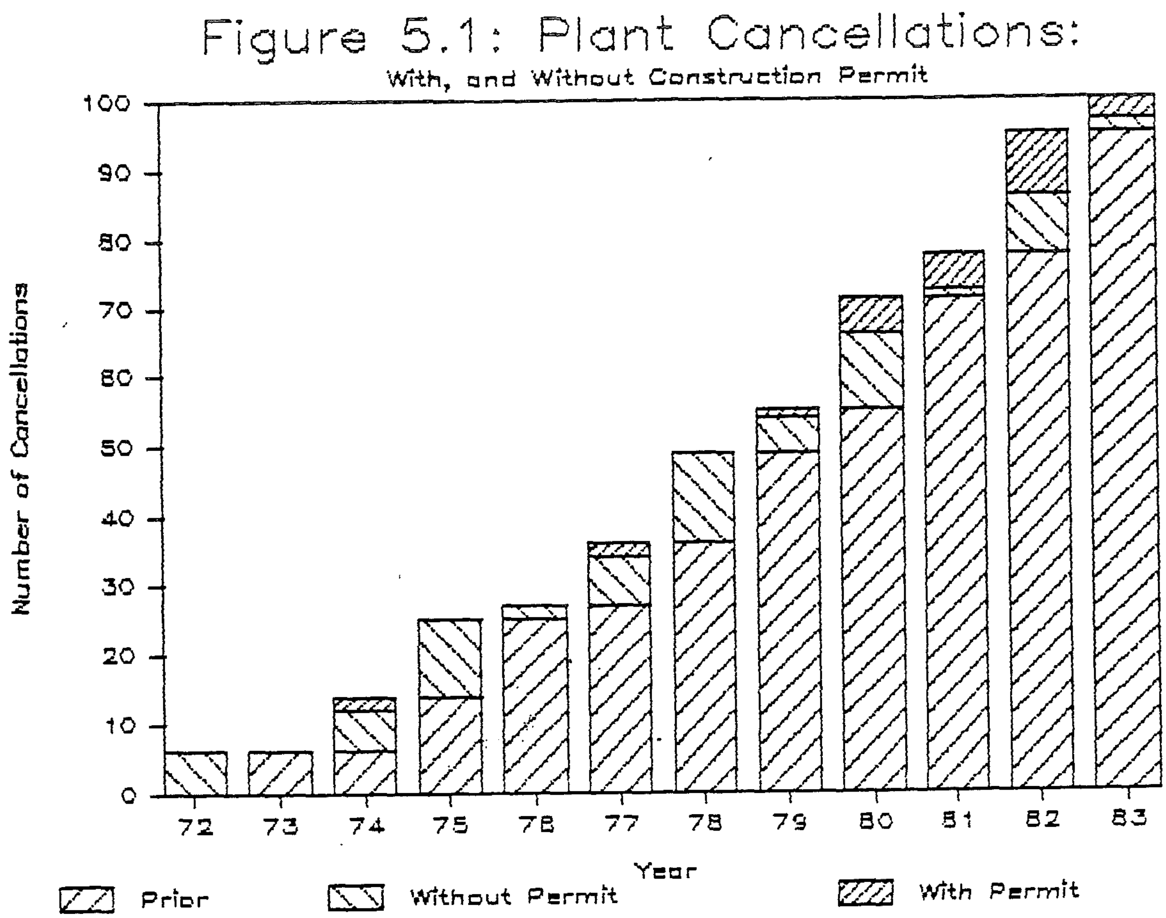


Figure 5.1: Plant Cancellations:
With, and Without Construction Permit
Number of Cancellations
100
90
80
70
60
50
40
30
20
10
0
72
73
74
75
76
77
78
79
80
81
82
83
Year
Prior
Without Permit
With Permit

Figure 5.2: NET NUCLEAR ORDERS

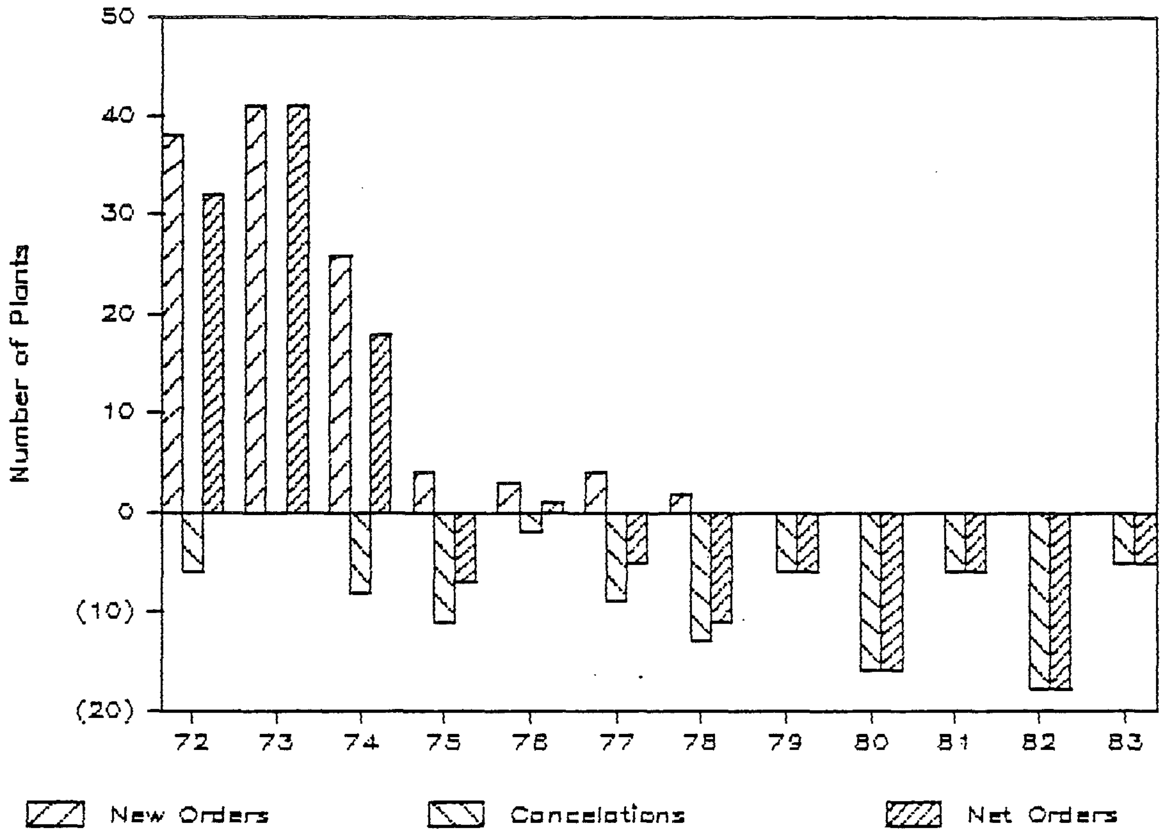


TABLE 6.1: COST AND SHEDULE SLIPPAGE, Completed Plants, with COD between July, 1980 and Dec. 1982

Unit Name	Actuals Cost	Actuals COD	C.P. issued	Date of Estimate	Estimated Cost	Estimated COD	Est. Years to COD	---Nominal--- Cost Ratio	---Nominal--- Myopia Factor	Duration Ratio	% Comp
North Anna 2	532	Dec-80	Feb-71	Sep-71	191	Jun-75	3.75	2.79	1.314	2.47	7.8
Farley 2	781	Jul-81	Aug-72	Mar-73	268	Apr-77	4.08	2.91	1.299	2.04	5.3
Sequoyah 1	984	Jul-81	May-70	Jun-70	187	Apr-74	3.83	5.27	1.543	2.89	5.0
Salem 2 *	820	Oct-81	Sep-68	Dec-67	128	Mar-73	5.25	6.41	1.425	2.64	0.0
McGuire 1	906	Dec-81	Feb-73	Sep-73	220	Nov-76	3.17	4.12	1.563	2.60	22.2
Sequoyah 2	623	Jun-82	May-70	Jun-70	187	Apr-74	3.83	3.34	1.370	3.13	5.0
Lasalle 1	1336	Oct-82	Sep-73	Sep-73	430	Dec-78	5.25	3.11	1.241	1.73	0.0
AVERAGE (1969 - 12/1982)								2.40	1.26	1.79	
NUMBER OF DATAPOINTS:								56	56	68	
AVERAGE (7/1980 - 12/1982)								3.99	1.39	2.50	
NUMBER OF DATAPOINTS:								7	7	7	

* Constructor=UE&C

TABLE 6.2: UNITS UNDER CONSTRUCTION, in December 1982

Unit Name	C.P. issued	Date of Estimate	Estimated Cost	Estimated COD	Est. Years to COD	Years Elapsed	Cost Growth Rate	Progress Rate	% Comp
Diablo Canyon 1	Apr-68	Mar-80	880	Jun-81	1.25				99.2
		Mar-82	1378	Jun-83	1.25	2.00	25.1%	0.0%	99.8
Sequoyah 2	May-70	Sep-79	442	Jun-81	1.75				84.0
		Dec-80	1094	Jul-82	1.58	1.25	106.2%	13.6%	96.0
Diablo Canyon 2	Dec-70	Dec-79	721	Jun-81	1.50				97.9
		Dec-82	1126	Jun-84	1.50	3.00	16.0%	0.0%	95
Fermi 2	Sep-72	Jun-80	1283	Mar-82	1.75				79.4
		Sep-82	2346	Nov-83	1.17	2.25	30.7%	25.8%	92
Zimmer 1	Oct-72	Jun-80	1027	Apr-82	1.83				93.8
		Sep-82	1667	Jan-84	1.33	2.25	24.0%	22.1%	98.26
Midland 1	Dec-72	Jun-76	700	Mar-82	5.75				13
		Mar-82	1695	Jul-84	2.33	5.75	16.6%	59.4%	74
Midland 2	Dec-72	Jun-76	700	Mar-81	4.75				16
		Sep-82	1695	Dec-83	1.25	6.25	15.2%	56.0%	84
Watts Bar 1	Jan-73	Jun-80	720	May-82	1.92				87
		Sep-82	1697	Nov-84	2.17	2.25	46.4%	-11.3%	87
Watts Bar 2	Jan-73	Jun-80	720	Feb-83	2.67				72
		Sep-82	1697	Dec-85	3.25	2.25	46.4%	-25.8%	54
McGuire 2	Feb-73	Jun-80	635	Sep-82	2.25				83
		Dec-82	1069	Mar-84	1.25	2.50	23.1%	40.1%	98
Summer 1	Mar-73	Mar-80	827	Jun-81	1.25				94.8
		Dec-82	1313	Oct-83	0.79	2.80	18.0%	16.5%	
WNP 2	Mar-73	Jun-80	2392	Jan-83	2.58				85.2
		Jun-81	2784	Feb-84	2.67	1.00	16.4%	-8.3%	85.9
Lasalle 1	Sep-73	Jun-80	1107	Jun-81	1.00				98.0
		Dec-80	1184	Apr-82	1.33	0.50	14.4%	-66.1%	99.0
LaSalle 2	Sep-73	Jun-80	786	Jun-82	2.00				78
		Dec-81	1027	Oct-83	1.83	1.50	19.5%	11.1%	84
San Onofre 2	Oct-73	Mar-80	1824	Dec-81	1.75				86.0
		Dec-82	2502	Oct-83	0.79	2.80	12.0%	34.4%	
San Onofre 3	Oct-73	Mar-80	1216	Jan-83	2.83				60
		Dec-82	1668	May-83	0.42	2.75	12.2%	87.8%	97
Susquehanna 1	Nov-73	Sep-79	1607	Jan-82	2.34				70.0
		Dec-82	2252	May-83	0.37	3.30	10.8%	59.6%	92.0
Susquehanna 2	Nov-73	Jun-80	1082	Aug-82	2.17				53
		Jun-82	1598	Nov-84	2.42	2.00	21.5%	-12.5%	68
Beaver Valley 2	May-74	Dec-79	2024	May-86	6.42				35.2
		Dec-82	3076	May-86	3.42	3.00	15.0%	100.0%	58.1
Bailly Nuclear 1	May-74	Sep-79	1100	Jun-87	7.75				0.5
		Jun-81	1815	Jun-89	8.01	1.75	33.1%	-14.4%	0.5
Limerick 1	Jun-74	Jun-79	1695	Apr-83	3.83				52
		Dec-82	2657	Apr-85	2.33	3.50	13.7%	42.8%	83.1
Limerick 2	Jun-74	Jun-79	909	Apr-85	5.83				35
		Dec-82	3126	Oct-88	5.83	3.50	42.3%	0.0%	30
Vogtle 1	Jun-74	Jun-80	1746	May-85	4.92				10
		Dec-82	3722	Mar-87	4.25	2.50	35.3%	26.7%	45
Vogtle 2	Jun-74	Jun-80	988	Nov-87	7.42				4
		Dec-82	1476	Sep-88	5.75	2.50	17.4%	66.6%	15
Nine Mile Point 2	Jun-74	Jun-80	1953	Oct-84	4.34				37.7
		Dec-82	4174	Oct-86	3.84	2.50	35.5%	20.0%	56.7
North Anna 3	Jul-74	Sep-79	1428	Apr-86	6.59				7
		Dec-82	4053	Oct-89	6.84	3.25	37.8%	-7.8%	8

TABLE 6.2: UNITS UNDER CONSTRUCTION, in December 1982

Unit Name	C.P. issued	Date of Estimate	Estimated Cost	Estimated COD	Est. Years to COD	Years Elapsed	Cost Growth Rate	Progress Rate	% Comp
Millstone 3	Aug-74	Sep-78	1980	May-86	7.67				24.5
		Dec-82	3539	May-86	3.42	4.25	14.6%	100.0%	60.3
Grand Gulf 1	Sep-74	Dec-79	1203	Apr-82	2.33				80
		Sep-82	2859	Dec-83	1.25	2.75	36.9%	39.3%	99
Hope Creek 1	Nov-74	Jun-80	4310	Dec-86	6.50				23.5
		Dec-82	3780	Dec-86	4.00	2.50	-5.1%	99.9%	60.6
Waterford 3	Nov-74	Sep-79	1229	Feb-82	2.42				69.5
		Sep-82	2057	Jan-84	1.33	3.00	18.7%	36.2%	93.9
Bellefonte 1	Dec-74	Sep-79	1001	Sep-83	4.00				69
		Sep-82	2214	Nov-86	4.17	3.00	30.3%	-5.6%	81
Bellefonte 2	Dec-74	Sep-79	1001	Jun-84	4.75				48
		Sep-82	2214	Nov-87	5.17	3.00	30.3%	-13.9%	60
Comanche Peak 1	Dec-74	Mar-79	850	Jun-81	2.25				68.8
		Jun-82	1720	Jun-84	2.00	3.25	24.2%	7.7%	91
Comanche Peak 2	Dec-74	Mar-79	850	Jun-83	4.25				26.4
		Jun-82	1720	Jun-85	3.00	3.25	24.2%	38.5%	55
Catawba 1	Aug-75	Jun-80	754	Mar-84	3.75				73
		Dec-82	1800	Jun-85	2.50	2.50	41.6%	49.9%	92
Catawba 2	Aug-75	Jun-80	754	Sep-85	5.25				15
		Dec-82	2100	Jun-87	4.50	2.50	50.6%	30.1%	47
South Texas 1	Dec-75	Sep-79	1208	Feb-84	4.42				48.3
		Dec-81	1786	Feb-84	2.17	2.25	19.0%	99.9%	50
South Texas 2	Dec-75	Sep-79	1208	Feb-86	6.42				15
		Dec-81	1717	Feb-86	4.17	2.25	16.9%	99.9%	18
WNP 1 **	Dec-75	Jun-80	2498	Jun-85	5.00				41.1
		Jun-81	3460	Jun-86	5.00	1.00	38.5%	0.0%	51
Braidwood 1	Dec-75	Jun-80	1585	Oct-85	5.34				56
		Dec-81	1635	Oct-85	3.84	1.50	2.1%	100.0%	61
Braidwood 2	Dec-75	Jun-80	1011	Oct-86	6.34				44
		Dec-81	1076	Oct-86	4.84	1.50	4.2%	100.0%	48
Byron 1	Dec-75	Jun-80	1483	Oct-83	3.33				69
		Dec-81	1635	Feb-84	2.17	1.50	6.7%	77.6%	79
Byron 2	Dec-75	Jun-80	922	Oct-84	4.34				55
		Dec-81	1093	Feb-85	3.17	1.50	12.0%	77.6%	63
Clinton 1	Feb-76	Mar-80	1397	Dec-82	2.75				66
		Jun-82	1819	Sep-84	2.25	2.25	12.4%	22.1%	83
Clinton 2	Feb-76	Dec-77	1059	Jun-88	10.51				0
		Mar-82	2181	Jun-88	6.26	4.25	18.5%	100.0%	3
Callaway 1	Apr-76	Mar-80	1261	Oct-82	2.58				64
		Dec-82	2850	Jun-85	2.50	2.75	34.5%	3.0%	86
Callaway 2	Apr-76	Jun-80	1609	Jun-88	8.00				0.7
		Mar-81	1688	Apr-90	9.08	0.75	6.6%	-144.8%	0.7
Palo Verde 1	May-76	Jun-80	1429	May-83	2.92				68.3
		Mar-82	1670	May-83	1.17	1.75	9.3%	100.1%	96.5
Palo Verde 2	May-76	Jun-80	820	May-84	3.92				37.7
		Mar-82	1136	May-84	2.17	1.75	20.5%	100.1%	82.6
Palo Verde 3	May-76	Jun-80	1125	Jun-86	6.00				10.8
		Dec-82	2474	May-86	3.42	2.50	37.0%	103.3%	52.5
Seabrook 1 * **	Jul-76	Jun-80	1493	Apr-83	2.83				39.7
		Dec-81	1735	Feb-84	2.17	1.50	10.5%	44.2%	54
Seabrook 2 * **	Jul-76	Jun-80	1558	Feb-85	4.67				7.55
		Dec-81	[illegible]	May-86	4.42	1.50	11.1%	17.2%	9.2

TABLE 6.2: UNITS UNDER CONSTRUCTION, in December 1982

Unit Name	C.P. issued	Date of Estimate	Estimated Cost	Estimated COD	Est. Years to COD	Years Elapsed	Cost Growth Rate	Progress Rate	% Comp
River Bend 1	Mar-77	Mar-80	1679	Apr-84	4.09				11.9
		Sep-82	2474	Dec-85	3.25	2.50	16.7%	33.4%	51.6
Wolf Creek	May-77	Dec-79	1296	Apr-83	3.33				47.9
		Dec-82	2420	Apr-85	2.33	3.00	23.1%	33.3%	83.3
Hartsville A-1	May-77	Sep-79	1418	Jul-86	6.84				21
		Sep-81	3368	Apr-91	9.59	2.00	54.0%	-137.3%	35
Hartsville A-2	May-77	Sep-79	1418	Jul-87	7.84				8
		Sep-81	3368	Apr-92	10.59	2.00	54.0%	-137.5%	27
Perry 1	May-77	Jun-80	1701	May-84	3.92				59.4
		Sep-81	1884	May-84	2.67	1.25	8.5%	100.0%	78.8
Perry 2	May-77	Jun-80	2157	May-88	7.92				46.5
		Jun-81	1808	May-88	6.92	1.00	-16.2%	100.0%	52.3
St. Lucie 2	May-77	Jun-80	1100	May-83	2.92				45.1
		Sep-82	1420	May-83	0.66	2.25	12.0%	100.0%	89.7
Cherokee 1	Dec-77	Mar-80	402	Jan-90	9.84				15
		Sep-80	729	Jan-90	9.34	0.50	224.8%	100.0%	17
Cherokee 2	Dec-77	Mar-80	402	Jan-92	11.84				1
		Sep-80	729	Jan-93	12.34	0.50	224.8%	-98.9%	1
Cherokee 3	Dec-77	Mar-80	402	Jan-94	13.85				1
		Sep-80	729	Jan-95	14.34	0.50	224.8%	-98.4%	1
Shearon Harris 1	Jan-78	Jun-80	1208	Mar-85	4.75				32.8
		Dec-82	2586	Mar-86	3.25	2.50	35.6%	60.0%	76
Shearon Harris 2	Jan-78	Jun-80	1208	Mar-88	4.75				3.7
		Dec-82	2023	Mar-90	7.25	2.50	22.9%	-100.0%	4
Shoreham	Jan-78	Jun-80	1213	Feb-83	2.67				85.5
		Dec-82	3150	Dec-83	1.00	2.50	46.4%	66.8%	95.6
Phipps Bend 1	Jan-78	Sep-79	1440	Mar-87	7.50				7
		Mar-81	2685	Feb-89	7.93	1.50	51.5%	-28.5%	27
WNP 4	Feb-78	Mar-80	3086	Jun-86	6.25				14.5
		Jun-81	4251	Jun-87	6.00	1.25	29.1%	20.1%	26.5
Marble Hill 1	Apr-78	Jun-80	2001	Dec-86	6.50				20
		Sep-82	2725	Dec-86	4.25	2.25	14.7%	100.0%	42.9
Marble Hill 2	Apr-78	Jun-80	1383	Dec-87	7.50				9
		Dec-82	2260	Jun-88	5.50	2.50	21.7%	80.0%	27.3
WNP 3	Apr-78	Sep-79	2256	Dec-84	5.25				16.6
		Jun-81	3809	Dec-86	5.50	1.75	34.9%	-14.2%	32
WNP 5	Apr-78	Jun-80	3705	Jun-87	7.00				6.7
		Jun-81	4845	Dec-87	6.50	1.00	30.8%	49.9%	14.3
Yellow Creek 1	Nov-78	Sep-79	1445	Nov-85	6.17				7
		Sep-82	1938	Oct-90	8.09	3.00	10.3%	-63.8%	33
Yellow Creek 2	Nov-78	Sep-79	1445	Apr-88	8.59				2
		Sep-81	1938	Apr-88	6.59	2.00	15.8%	100.0%	
AVERAGES:									
Simple						2.30	32.5%	28.5%	
Weighted by years							25.3%	33.9%	
NUMBER OF DATAPOINTS:						73	73	73	

* Constructor=UE&C

** Architect/Engineer=UE&C

TABLE 6.3: UNITS WITH CONSTRUCTION PERMIT OR LIMITED WORK AUTHORIZATION IN DECEMBER, 1982 (PERCENT COMPLETE <= 30%).

Unit Name	cp/lwa	issue date	% complete at 12/76	Estimated COD
Seabrook 2	cp:	Jul-67	13.0%	Mar-87
River Bend 2	cp:	Sep-75	0.0%	indef.
Clinton 2	cp:	Feb-76	0.0%	indef.
Yellow Creek 2	cp:	Nov-78	3.0%	indef.
Shearon Harris 2	cp:	Jan-78	4.0%	Mar-90
Vogtle 2	cp:	Jun-74	14.0%	Sep-88
South Texas 2	cp:	Dec-75	16.0%	Jun-89
Cherokee 1	cp:	Dec-77	18.0%	indef.
Grand Gulf 2	cp:	Sep-74	25.0%	indef.
Marble Hill 2	cp:	Apr-78	26.0%	Jun-88
Limerick 2	cp:	Jun-75	30.0%	Oct-87
AVERAGES				
All Units		Jul-76	13.6%	
Units With Schedule		Jun-76	18.0%	Dec-88

Source: Nuclear News, February 1983

TABLE 6.4: PLANT CANCELATIONS: 1981-1982

Unit Name	Year of Cancelation	Construction Status	% Complete
Bailly Nuclear 1	1981	cp	1.0%
Callaway 2		cp	1.0%
Shearon Harris 3		cp	1.0%
Shearon Harris 4		cp	1.0%
Hope Creek 2		cp	19.0%
Pilgrim 2		order	
Allens Creek 1	1982	order	
Black Fox 1		lwa	<1%
Black Fox 2		lwa	<1%
Cherokee 2		cp	0.0%
Cherokee 3		cp	0.0%
Hartsville B-1		cp	17.0%
Hartsville B-2		cp	7.0%
North Anna 3		cp	7.0%
Pebble Springs 1		order	
Pebble Springs 2		order	
Perkins 1		order	
Perkins 2		order	
Perkins 3		order	
Phipps Bend 1		cp	27.0%
Phipps Bend 2		cp	5.0%
Vandalia		order	
WPPSS 4		cp	23.0%
WPPSS 5		cp	16.0%

Source: Atomic Industrial Forum, "Background Info", January, 1984.

TABLE 7.1: BUSBAR COST COMPARISON, 1976

	Seabrook 2		Coal	Oil
	A	B	C	D
Based on PSNH Cost Estimate of:	Dec-76	Dec-76		
PLC Revised Cost Estimate:	$3,122 [1]	$3,122	$950 [2]	
PLC Revised COD Estimate:	Mar-88 [3]	Mar-88	Mar-88 [4]	
In-core Fuel	$218 [5]	$218		
Total Investment	$3,340	$3,340		
Sunk Cost $22 plus AFUDC to COD	$65	$65		
Net Investment	$3,275	$3,275	$950	
Levelized Carrying Charges:	18.7% [6]	18.7%	18.7%	
Annual Cost:	$612	$612	$178	
O&M:	$47 [7]	$47	$65 [7]	
Capacity Factor:	73.2% [5]	68.3% [8]	73.2% [5]	
Non-fuel cents/kwh:	8.94	9.58	4.74	
Fuel:	1.60 [9]	1.60	5.14 [10]	7.28 [10]
Total cents/kwh:	10.54	11.18	9.88	

Notes: [1] Average of Table 3.1 results for Seabrook 2.

[6] Bond rate = average of Aaa and Baa.
Cost of money = bond rate + 1.6% = discount rate, from NEPLAN (1976)
= 10.7%
Carrying Charge = cost of money + 8%, from NEPLAN (1976)
= 18.7%

[10] Coal price 1980 = 1.76 cents/kwh, from NEPLAN (1976) fuel costs at 9800 BTU/kwh.
Oil Price 1980 = $2.5 /MMBTU, 1980$, assumes 10,000 BTU/kwh, NEPOOL (1977).

* All other notes are listed after Tables 7.1 - 7.4.
All dollar costs are in $ million for the unit.
Inflation = 6.2% Fuel Inflation= 6.2%
Inflation, 1980 to COD, with 30 year levelization
= 2.913 Fuel Inflation= 2.913

TABLE 7.2: BUSBAR COST COMPARISON, 1978

	Seabrook 2		Coal	Oil
	A	B	C	D
Based on PSNH Cost Estimate of:	Jan-79	Jan-79		
PLC Revised Cost Estimate:	$4,355 [1]	$4,355	$1,105 [2]	
PLC Revised COD Estimate:	Sep-90 [3]	Sep-90	Sep-90 [4]	
In-core Fuel	$253 [5]	$253		
Total Investment	$4,608	$4,608	$1,105	
Sunk Cost $87 with AFUDC to COD	$266	$266		
Net Investment	$4,342	$4,342		
Levelized Carrying Charges:	18.7% [6]	18.7%	18.7%	
Annual Cost:	$812	$812	$207	
O&M:	$55 [7]	$55	$76 [7]	
Capacity Factor:	73.2% [5]	67.3% [8]	73.2% [5]	
Non-fuel cents/kwh:	11.76	12.79	5.51	
Fuel:	1.86 [9]	1.86	5.97 [10]	8.47 [10]
Total cents/kwh:	13.62	14.65	11.48	8.47

Notes: [1] Average of myopia and cost ratio results for Seabrook 2 in Table 4.1, for all units through 1978, and all units in 1977 and 1978; total of four results.

[6] Bond rate = average of Aaa and Baa.
Cost of money = bond rate + 1.6% = discount rate, from NEPLAN (1976).
= 10.7%
Carrying charge = cost of money + 8%, from NEPLAN (1976).
= 18.7%

[10] Coal price 1980 = 1.76 cents/kwh, from NEPLAN (1976) fuel costs at 9800 BTU/kwh.
Oil price 1980 = 2.50 ,from Exh. Webb-17, PUC 82-266, 3.59 cents in 1986, deflated at 6.2% to 1980.

* All other notes are listed after Tables 7.1 - 7.4.
Inflation = 6.2% fuel = 6.2% oil = 6.2%
Inflation, 1980 to COD, with 30 year levelization
= 3.384 = 3.384 = 3.384

TABLE 7.3: BUSBAR COST COMPARISON, 1980

	Seabrook 2		Coal	Oil
	A	B	C	D
Based on PSNH Cost Estimate of:	Apr-80	Apr-80		
PLC Revised Cost Estimate:	$3,987 [1]	$3,987	$970 [2]	
PLC Revised COD Estimate:	Jul-88 [3]	Jul-88	Jul-88 [4]	
In-core Fuel	$199 [5]	$199		
Total Investment	$4,186	$4,186		
Sunk Cost $247 plus AFUDC to COD	$511	$511		
Net Investment	$3,676	$3,676	$970	
Levelized Carrying Charges:	22.4% [6]	22.4%	22.4%	
Annual Cost:	$823	$823	$217	
O&M:	$43 [7]	$43	$60 [7]	
Capacity Factor:	70.1% [11]	64.4% [8]	67.1% [5]	
Non-fuel cents/kwh:	12.26	13.35	5.89	
Fuel:	1.47 [9]	1.47	4.71 [10]	28.29
Total cents/kwh:	13.73	14.82	10.60	28.29

Notes: [1] Average of myopia and cost ratio results for Seabrook 2, from Table 5.1, and all experience through 1980; two results.

[6] Bond rate = average of Aaa and Baa.
Cost of money = bond rate + 1.6% = discount rate, from NEPLAN (1976).
= 14.4%
Carrying charge = cost of money + 8%, from NEPLAN (1976).
= 22.4%

[10] Coal price 1980 = 1.76 cents/kwh, from NEPLAN (1976).
Oil price 1980 = 5.44 , from Exh. Webb-18, PUC 82-266, 11.66 cents in 1988, deflated by 10% to 1980.

[11] Forced outage rates from NEPLAN (1976), maintenance from NEPOOL (1979).

* All other notes are listed after Tables 7.1 - 7.4.
Inflation = 6.2% fuel inf. 6.2% oil inf. 10.0%
Inflation, 1980 to COD, with 30 year levelization
= 2.667 2.667 5.201

TABLE 7.4: BUSBAR COST COMPARISON, 1982

	Seabrook 2		Coal	Oil
	A	B	C	D
Based on PSNH Cost Estimate of:	Dec-82	Dec-82		
PLC Revised Cost Estimate:	$9,378 [1]	$9,378	$2,187 [2]	
PLC Revised COD Estimate:	Oct-92 [3]	Oct-92	Oct-92 [4]	
In-core Fuel				
Sunk Cost $508 plus AFUDC to COD	$1,576	$1,576		
Net Investment	$7,802	$7,802	$2,187	
Levelized Carrying Charges:	21.6% [6]	21.6%	21.6%	
Annual Cost:	$1,681	$1,681	$471	
O&M:	$79 [7]	$79	$192 [7]	
Capacity Factor:	66.1% [11]	62.0% [8]	66.7% [5]	
Non-fuel cents/kwh:	26.44	28.20	14.19	
Fuel:	3.41 [9]	3.41	9.95 [10]	29.27
Total cents/kwh:	29.85	31.61	24.14	29.27

Notes: [1] Average of myopia and cost ratio results for Seabrook 2, from Table 6.1, all experience through 1982, and all experience from mid-1980 to 1982; four results.

[6] Bond rate = average of Aaa and Baa.
Cost of money = bond rate + 1.6% = discount rate, from NEPLAN (1982)
= 16.6%
Carrying charge = cost of money + 5%, from NEPLAN (1982).
= 21.6%

[10] 1980 Coal price = 1.83 cents/kwh, from NEPLAN (1982).
1980 Oil price = 4.37 cents/kwh; from Wyman 4 fuel cost in 1982: 5.3 cents in 1982, deflated by 10.1% to 1980.

[11] Forced outage rates from NEPLAN (1976), maintenance from NEPOOL (1979).

* All other notes are listed after Tables 7.1 - 7.4. References to NEPLAN (1976) in that list are actually NEPLAN (1982) for this table.

Inflation =	9.0%	fuel inf. 10.0%	oil inf. 10.1%
past 1990	8.0%	8.0%	10.1%
Inflation, 1980 to COD, with 30 year levelization =	4.89	5.45	6.70

Notes to Tables 7.1 - 7.4

[1] See each table.

[2] NEPLAN (1976) projection for 800 MW coal plant in 1980$ inflated to Seabrook 2 COD.

[3] Average of Table 3.1 (or 4.1 or 5.1 or 6.1, as applicable) results for all duration ratios, times projected Seabrook duration.

[4] Equal to Seabrook COD, for consistency.

[5] NEPLAN (1976).

[6] See each table.

[7] NEPLAN (1976) projection in 1980$, inflated to COD and levelized over 30 years. Includes variable O&M at capacity factor specified below.

[8] From Table 7.7, levelized over a 30 year life.

[9] NEPLAN (1976), inflated and levelized.

[10] See each table.

TABLE 7.5: ANNUAL NUCLEAR O&M EXPENSES, 1968-1981 ($1000)

Plant:	1968	1969	1970	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981
Arkansas 1								4109	6015	8379	12125	18923	NA	
Arkansas 1&2														54422
Beaver Valley									1777	14692	22681	22907	34771	35838
Big Rock Point	865	933	1062	1266	1412	1586	2263	2584	3183	5125	3645	9232	8409	12970
Browns Ferry 1&2								6626	16104					
Browns Ferry 1,2&3										19305	45921	55588	66969	85469
Brunswick 2								4473	10518					
Brunswick 1&2										25378	26633	34206	57516	73150
Calvert Cliffs 1								4241	8984					
Calvert Cliffs 1&2										20158	25997	36397	41628	50409
Connecticut Yankee	2047	2067	4479	3279	3749	6352	4935	9381	9419	9448	8736	18923	35155	37488
Cook 1								1662	7047	10012				
Cook 1&2											15707	26750	32409	37967
Cooper							2691	7386	10211	10218	8306	10232	19004	20455
Crystal River										7600	15613	23992	39841	42313
Davis-Besse										295	14096	10564	44630	41413
Dresden 1	1673	1788												
Dresden 1&2			2294											
Dresden 1,2&3				3639	9142	9050	16731	32895	30092	26999	33932	44579	38130	40361
Duane Arnold							2121	3839	7050	7508	11916	9528	18398	21956
Farley 1										462	12207	22545	25734	
Farley 1&2														41427
Fitzpatrick								6902	10700	17383	19045	25131	33303	36678
Fort Calhoun						529	3413	5962	7449	8493	8116	8504	14332	11472
Fort St. Vrain												12121	16884	18796
Ginna			3199	4391	4082	3536	5391	6597	7356	7942	9819	12819	18924	22482
Hatch 1									5867	9799	12268	13574		
Hatch 1&2													38486	62134
Humboldt	582	646	619	926	897	915	1070	1221	1980	3081	1635	1485	1587	2073
Indian Point 1	2831	2713	3498	3962	6950									
Indian Point 1&2						14854	12737	13195	18285	16525				
Indian Point 2											28167	32643	32964	54506
Indian Point 3									2460	12654	23318	28884	50357	58174

TABLE 7.5: ANNUAL NUCLEAR O&M EXPENSES, 1968-1981 ($1000)

Plant:	1968	1969	1970	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981
Kewaunee							7222	8945	10727	10924	10430	11323	14843	19334
Lacrosse											2638	3041	3318	3955
Maine Yankee						4034	5232	6301	5261	8418	10817	9971	14028	20576
McGuire														2716
Millstone 1				3256	7677	7635	9808	12065	14040	12637	16448	23060	24784	33270
Millstone 2								7	10929	17377	22288	21931	30163	28877
Monticello				1429	2567	5006	5179	8729	6609	11109	9136	10584	21413	18261
Nine Mile Point			1716	2759	3575	4524	6251	5810	5330	9743	6382	11663	32964	26744
North Anna 1											6521	19519		
North Anna 1&2													25390	28857
Oconee 1						911								
Oconee 1,2&3							6982	12449	16735	25038	29600	40177	52003	58789
Oyster Creek			1953	3097	3877	6311	10678	12310	10399	14833	15898	13055	37530	45254
Palisades					753	3160	11778	9601	9848	6569	15393	26344	19251	44140
Peach Bottom 1	1666	1481	1537	1731	1873	1605	1050							
Peach Bottom 2&3							1791	12619	30601	46674	39306	40004	56875	72615
Pilgrim					144	4797	9527	7340	16633	15320	14187	18387	27785	34994
Point Beach 1														
Point Beach 1&2				1309	2305	3647	5229	6159	6592	8014	7395	12461	17904	26820
Prairie Island 1						101								
Prairie Island 1&2							4216	7261	15574	17090	14214	15346	23175	26791
Quad Cities 1&2					2033	6290	9210	14777	16723	17756	22168	23420	38686	37272
Rancho Seco								11607	7193	14000	11834	13720	28408	35542
Robinson				1918	1780	4609	4780	6360	5903	6859	14355	15142	22085	21788
Salem 1										12707	22311	42508	59684	
Salem 1&2														77502
San Onofre	1481	1975	2236	2412	3518	5839	5559	8668	10490	8123	14517	11669	31089	24396
Sequoyah														19216
St. Lucie									3249	7528	15814	14392	16381	23240
Surry 1					607									
Surry 1&2					607	5102	9878	15270	14796	15977	19323	23313	29458	31185

TABLE 7.5: ANNUAL NUCLEAR O&M EXPENSES, 1968-1981 ($1000)

Plant:	1968	1969	1970	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981
Three Mile Island 1							3351	14226	17840	13287	17954	11842	NA	27024
Three Mile Island 2												12402	NA	8394
Trojan									5921	13628	15204	16957	25790	32205
Turkey Point 3					247									
Turkey Point 3&4						4059	9660	15493	18602	15109	18602	22511	30830	30274
Vermont Yankee					414	4957	5692	7682	7912	9775	11191	14208	22586	26795
Yankee-Rowe	1501	1602	1558	1745	2912	2437	3950	4557	4976	6966	7653	10150	22250	22069
Zion 1						44								
Zion 1&2							9234	12735	18268	18104	20383	26954	37655	44864

Year	Arkansas			Beaver Valley			Big Rock Point			Browns Ferry		
	Total Cost	Cost Increase	1983 $	Total Cost	Cost Increase	1983 $	Total Cost	Cost Increase	1983 $	Total Cost	Cost Increase	1983 $
1968							13926	89	287			
1969							13958	32	96			
1970							14324	366	1023			
1971							14554	230	593			
1972							14731	177	432			
1973							14815	84	195			
1974	233027						16012	1197	2415			
1975	238751	5724	10407				16587	575	1034	512653 **		
1976	242204	3453	5962	284856			22907	6320	10702	552357	39704	66749
1977	247069	4865	7997	598716	313860	487988	23971	1064	1668	853325 ***		
1978	253994	6925	10259	582408	-16308	-23883	24409	438	639	885991	32666	47072
1979	268130	14136	18641	576367	-6041	-8067	27014	2605	3473	888350	2359	3092
1980	NA			647575	71208	87849	27262	248	304	890428	2078	2485
1981	916567 **			671283	23708	26909	33356	6094	6863	892715	2287	2503

Year	Brunswick			Calvert Cliffs			Connecticut Yankee			Cook		
	Total Cost	Cost Increase	1983 $	Total Cost	Cost Increase	1983 $	Total Cost	Cost Increase	1983 $	Total Cost	Cost Increase	1983 $
1968							91801					
1969							91841	40	121			
1970							93516	1675	4694			
1971							93669	153	395			
1972							93814	145	346			
1973							94016	202	459			
1974							106212	12196	24285			
1975	382246			428747			108921	2709	4842	538611		
1976	389118	6872	11553	430674	1927	3216	114503	5582	9317	544650	6039	10227
1977	707560 **			765995 **			117238	2735	4252	552238	7588	11895
1978	714928	7368	10617	777711	11716	17158	121288	4050	5931	996177 **		
1979	750828	35900	47055	780095	2384	3183	123037	1749	2335	1025829	29652	39536
1980	776989	26161	31285	790988	10893	13439	137644	14607	18021	1074584	48755	59847
1981	803535	26546	29050	820215	29227	33173	152552	14908	16921	1096310	21726	24468

Year	Cooper			Crystal River			Davis-Besse			Peach Bottom 2 and 3		
	Total Cost	Cost Increase	1983 $	Total Cost	Cost Increase	1983 $	Total Cost	Cost Increase	1983 $	Total Cost	Cost Increase	1983 $
1968												
1969												
1970												
1971												
1972												
1973												
1974	246268									742158		
1975	269287	23019	41399							753981	11823	21132
1976	269287	0	0							761722	7741	12921
1977	302382	33095	51879	365535			271283			794094	32372	50332
1978	384630	82248	120010	415173	49638	71528	635147	363864	530921	807496	13402	19627
1979	384570	-60	-80	419131	3958	5188	326174	-308973	-411964	813792	6296	8407
1980	384569	-1	-1	421055	1924	2301	738544	412370	506190	836708	22916	28271
1981	383748			384011	-37044	-40539	786437	47893	53938	902169	65461	74298

Year	Total Cost	Cost Increase	1983 $	Total Cost	Cost Increase	1983 $	Total Cost	Cost Increase	1983 $	Total Cost	Cost Increase	1983 $
	Dresden			Duane Arnold			Farley			Fitzpatrick		
1968	33467	-899	-2897									
1969	33968	501	1510									
1970	116609 **											
1971	220380 ***											
1972	241479	21099	51526									
1973	235397	-6082	-14110									
1974	237303	1906	3845	288821								
1975	249177	11874	21355	279730	-9091.4	-16350				NA		
1976	256493	7316	12389	279928	198	335				NA		
1977	258522	2029	3181	287561	7633.42	11966	727426			NA		
1978	276887	18365	26797	282345	-5216.4	-7611	734519	7093	10221	NA		
1979	290785	13898	18531	306768	24423	32564	751634	17115	22433	NA		
1980	303201	12416	15241	324186	17418	21381	761329	9695	11594	NA		
1981	307054	3853	4339	339460	15274	17202	1541981 **			367141		

Year	Total Cost	Cost Increase	1983 $	Total Cost	Cost Increase	1983 $	Total Cost	Cost Increase	1983 $	Total Cost	Cost Increase	1983 $
	Fort Calhoun			Fort St. Vrain			Ginna			Hatch		
1968												
1969												
1970							83175					
1971							83075	-100	-258			
1972							83982	907	2167			
1973	173870						85004	1022	2320			
1974	175800	1930	3894				87668	2664	5305			
1975	178572	2772	4985				89750	2082	3721			
1976	178896	324	549				93308	3558	5939	390393		
1977	179994	1098	1721				114141	20833	32391	396799	6406	9842
1978	180328	334	487				121860	7719	11305	4466		
1979	180830	502	669	105610			129112	7252	9684	657326		
1980	192700	11870	14571	101459			136138	7026	8668	947147 **		
1981	198544	5844	6582	120884			159487	23349	26501	693789		

Year	Total Cost	Cost Increase	1983 $	Total Cost	Cost Increase	1983 $	Total Cost	Cost Increase	1983 $	Total Cost	Cost Increase	1983 $
	Humboldt			Indian Point 1 and 2			Indian Point 3			Kewaunee		
1968	22619	139	465	128818	-3	-10						
1969	22688	69	222	127914	-904	-2736						
1970	22764	76	230	128083	169	474						
1971	22850	86	243	128175	92	237						
1972	22947	97	256	128938	763	1823						
1973	22998	51	128	334963 **								
1974	23171	173	381	340188	5225	10404				202193		
1975	24031	860	1648	348218	8030	14353				203389	1196	2151
1976	24543	512	905	359410	11192	18681	NA			205351	1962	3323
1977	26726	2183	3535	370637	11227	17456	NA			205892	541	848
1978	28506	1780	2675	377573 +	6936	10158	NA			209748	3856	5626
1979	28567	61	83	379966	2393	3195	NA			213289	3541	4721
1980	NA			329445			NA			214696	1407	1727
1981	NA			398037	68592	77852	493018			227413	12717	14322

Year	Total Cost	Cost Increase	1983 $	Total Cost	Cost Increase	1983 $	Total Cost	Cost Increase	1983 $	Total Cost	Cost Increase	1983 $
	Lacrosse			Maine Yankee			McGuire			Millstone 1		
1968												
1969												
1970												
1971										96819		
1972										97343	524	1252
1973				219225						98837	1494	3391
1974				221074	1849	3682				98745	-92	-183
1975				233710	12636	22586				99244	499	892
1976				235069	1359	2268				125141	25897	43225
1977				236454	1385	2153				127476	2335	3630
1978	22991			237810	1356	1986				139783	12307	18024
1979	23132	141	188	239987	2177	2907				153135	13352	17829
1980	25987	2855	3505	246847	6860	8463				167438	14303	17646
1981	26237	250	282	262240	15393	17471	905601			247250	79812	90587

Year	Total Cost	Cost Increase	1983 $	Total Cost	Cost Increase	1983 $	Total Cost	Cost Increase	1983 $	Total Cost	Cost Increase	1983 $
	Millstone 2			Monticello			Nine Mile Point			North Anna		
1968												
1969												
1970							162235					
1971				105011			164492	2257	5822			
1972				104937	-74	-181	162416	-2076	-4961			
1973				106869	1932	4482	163212	796	1807			
1974				117996	11127	22448	163389	177	352			
1975	418372			122106	4110	7392	164189	800	1430			
1976	426271	7899	13184	123362	1256	2127	181200	17011	28393			
1977	448751	22480	34952	124390	1028	1611	188087	6887	10708			
1978	463638	14887	21802	126488	2098	3061	187086	-1001	-1466	781739		
1979	464674	1036	1383	134937	8449	11265	204080	16994	22692	783864	2125	2785
1980	477586	12912	15929	139725	4788	5877	217371	13291	16397	1315869 **	0	0
1981	495610	18024	20457	150407	10682	12030	265015	47644	54076	1368195	52326	57262

Year	Total Cost	Cost Increase	1983 $	Total Cost	Cost Increase	1983 $	Total Cost	Cost Increase	1983 $	Total Cost	Cost Increase	1983 $
	Oconee			Oyster Creek			Palisades			Peach Bottom 1		
1968										10624		
1969										10658		
1970				89883						10719		
1971				92121	2238	5773				10890		
1972				92637	516	1233	146687			10821		
1973	155612			92766	129	293	160284	13597	31545	11369		
1974	476443 ***			92198	-568	-1131	180063	19779	39902	10485		
1975	476691	248	446	97151	4953	8853	182297	2234	4018			
1976	478793	2102	3534	108545	11394	19018	185272	2975	5038			
1977	490724	11931	18331	112583	4038	6278	182068	-3204	-5022			
1978	492689	1965	2832	150459	37876	55470	199643	17575	25644			
1979	498935	6246	8187	161745	11286	15070	194651	-4992	-6656			
1980	509438	10503	12560	200255	38510	47510	211505	16854	20689			
1981	520036	10598	11598	222963	22708	25774	255491	43986	49538			

*** 3 units in [illegible]

Year	Pilgrim Total Cost	Pilgrim Cost Increase	Pilgrim 1983 $	Point Beach Total Cost	Point Beach Cost Increase	Point Beach 1983 $	Prairie Island Total Cost	Prairie Island Cost Increase	Prairie Island 1983 $	Quad Cities Total Cost	Quad Cities Cost Increase	Quad Cities 1983 $
1968												
1969												
1970												
1971				73959								
1972	321540			145348 **						200149		
1973	239329			161632	16284	37779	233234			211539	11390	26425
1974	235982	-3347	-6665	161436	-196	-395	405374 **			223882	12343	24901
1975	236464	482	862	164224	2788	5014	410207	4833	8692	237227	13345	24000
1976	241440	4976	8306	167125	2901	4913	413087	2880	4877	241480	4253	7202
1977	257579	16139	25093	196801	29676	46519	423966	10879	17054	247194	5714	8957
1978	261758	4179	6120	171189	-25612	-37371	425182	1216	1774	252951	5757	8400
1979	270428	8670	11577	170668	-521	-695	433659	8477	11303	263741	10790.3	14387
1980	337986	67558	83346	172472	1804	2214	444766	11107	13634	273075	9333.66	11457
1981	358680	20694	23488	188495	16023	18045	457082	12316	13870	278524	5449	6137

Year	Rancho Seco Total Cost	Rancho Seco Cost Increase	Rancho Seco 1983 $	Robinson Total Cost	Robinson Cost Increase	Robinson 1983 $	Salem Total Cost	Salem Cost Increase	Salem 1983 $	San Onofre Total Cost	San Onofre Cost Increase	San Onofre 1983 $
1968										80855		
1969										84439	3584	11533
1970										84714	275	832
1971				77753						85369	655	1847
1972				81999	4246	10369				85547	178	470
1973				82113	114	264				85821	274	688
1974				83272	1159	2359				86244	423	931
1975	343620			84982	1710	3075				86438	194	372
1976	343438	-182	-322	85234	252	424				95496	9058	16011
1977	336050	-7388	-11964	89540	4306	6616	850318			162475	66979	108463
1978	338792	2742	4121	93410	3870	5577	850983	665	974	181601	19126	28746
1979	339538	746	1012	101253	7843	10280	898641	47658	63637	192599	10998	14922
1980	353574	14036	17441	110025	8772	10490	938748	40107.4	49480	211109	18510	23000
1981	365651	12077	13716	113858	3833	4195	1758749 **			251119	40010	45441

Year	Sequoyah Total Cost	Sequoyah Cost Increase	Sequoyah 1983 $	Shippingport Total Cost	Shippingport Cost Increase	Shippingport 1983 $	St. Lucie Total Cost	St. Lucie Cost Increase	St. Lucie 1983 $	Surry Total Cost	Surry Cost Increase	Surry 1983 $
1968												
1969												
1970												
1971												
1972										246707		
1973										396860 **		
1974										402096	5236	10656
1975										406409	4313	7757
1976							470223			408516	2107	3542
1977							486230	16007	24594	412236	3720	5715
1978							495038	8808	12692	419952	7716	11119
1979							499602	4564	5982	409703	-10249	-13434
1980				32125			505287	5685	6799	556083	146380	175052
1981	983542			32123			513640	8353	9141	750969	194886	213271

*** = 3 units in service

Year	Total Cost	Cost Increase	1983 $	Total Cost	Cost Increase	1983 $	Total Cost	Cost Increase	1983 $	Total Cost	Cost Increase	1983 $
	Three Mile Island 1			Three Mile Island 2			Trojan			Turkey Point 3 and 4		
1968												
1969												
1970												
1971												
1972										108709		
1973										231239 **		
1974	398337									235496	4257	8663
1975	400928	2591	4631							244256	8760	15754
1976	399425	-1503	-2509				451978			255705	11449	19248
1977	398895	-530	-824				460666	8688	14069	267648	11943	18350
1978	361902	-36993	-54177	715466			466419	5753	8647	273441	5793	8348
1979	407936	46034	61469	719294	3828	5112	486705	20286	27523	284431	10990	14405
1980	NA			NA			503279	16574	20594	293654	9223	11030
1981	220798			358321			548765	45486	51661	305503	11849	12967

Year	Total Cost	Cost Increase	1983 $	Total Cost	Cost Increase	1983 $	Total Cost	Cost Increase	1983 $	Total Cost	Cost Increase	1983 $
	Vermont Yankee			Yankee-Rowe			Zion					
1968				39572	12	38						
1969				39623	51	154						
1970				39636	13	36						
1971				40271	635	1638						
1972	172042			41500	1229	2937						
1973	184481	12439	28237	42507	1007	2286	275989					
1974	185158	677	1348	44473	1966	3915	565819 **					
1975	185739	581	1038	46101	1628	2910	567987	2168	3899			
1976	193886	8147	13598	46566	465	776	571762	3775	6393			
1977	196331	2445	3801	48332	1766	2746	577903	6141	9626			
1978	198837	2506	3670	48912	580	849	586396	8493	12392			
1979	200835	1998	2668	52192	3280	4380	594941	8545	11393			
1980	217575	16740	20652	55285	3093	3816	625788	30847	37865			
1981	226115	8540	9693	1768			639723	13935	15694			

TABLE 7.7: 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	886								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:	1975	1977	1979	1981
Cumulative	61.7%	62.8%	62.5%	61.5%
Immature Years (1-4)	59.6%	60.8%	60.0%	59.7%
Mature Years (5+)	73.0%	70.8%	67.7%	63.9%

TABLE 7.8: CENTRAL MAINE POWER COMPANY - SEABROOK 2
COST PROJECTIONS BASED ON DATA AVAILABLE JAN. 1979

Year	Seabrook 2 Busbar Cost, cents/kWh Fixed Charges	Nuclear Fuel	Total	Oil Energy Cost Cents/kWh	Cost Difference Pilgrim Oil	Cumulative Difference in PV @ 10.7%
1991	15.74	1.12	16.86	4.85	12.02	10.85
1992	15.18	1.19	16.37	5.15	11.22	20.01
1993	14.66	1.26	15.93	5.46	10.46	27.72
1994	14.00	1.34	15.34	5.80	9.54	34.08
1995	13.59	1.42	15.01	6.16	8.85	39.40
1996	12.95	1.51	14.46	6.55	7.92	43.70
1997	12.51	1.61	14.12	6.95	7.17	47.22
1998	12.09	1.71	13.80	7.38	6.42	50.07
1999	11.68	1.81	13.49	7.84	5.65	52.33
2000	11.29	1.92	13.21	8.33	4.88	54.10
2001	10.87	2.04	12.91	8.84	4.07	55.43
2002	10.48	2.17	12.65	9.39	3.26	56.39
2003	10.09	2.31	12.39	9.97	2.42	57.03
2004	9.69	2.45	12.14	10.59	1.55	57.41
2005	9.57	2.60	12.17	11.25	0.92	57.61
2006	9.40	2.76	12.16	11.94	0.22	57.65
2007	9.23	2.93	12.16	12.69	-0.52	57.56
2008	9.06	3.11	12.17	13.47	-1.30	57.35
2009	8.91	3.31	12.22	14.31	-2.09	57.05
2010	8.76	3.51	12.28	15.19	-2.92	56.67
2011	8.62	3.73	12.35	16.14	-3.79	56.22
2012	8.49	3.96	12.46	17.14	-4.68	55.72
2013	8.37	4.21	12.58	18.20	-5.62	55.17

The assumptions used here are those described in
Exhibit Webb-17, PUC 82-266.
Fixed charges are Webb values, times (4355/ 1779).

TABLE 7.9: CENTRAL MAINE POWER COMPANY - SEABROOK 2
COST PROJECTIONS BASED ON DATA AVAILABLE JANUARY 1980

Year	Seabrook 2 Busbar Cost, cents/kWh Fixed Charges	Nuclear Fuel	Total	Oil Energy Cost Cents/kWh	Cost Difference Pilgrim-Oil	Cumulative Difference in PV @ 14.4%
1988	14.41	0.94	15.34	11.66	3.68	3.22
1989	13.90	0.99	14.90	12.83	2.07	4.80
1990	13.44	1.05	14.49	14.11	0.38	5.05
1991	12.83	1.12	13.95	15.52	-1.58	4.13
1992	12.40	1.19	13.59	17.07	-3.49	2.35
1993	11.84	1.26	13.10	18.78	-5.68	-0.18
1994	11.47	1.34	12.81	20.66	-7.85	-3.24
1995	11.08	1.42	12.50	22.72	-10.22	-6.72
1996	10.71	1.51	12.22	25.00	-12.78	-10.53
1997	10.32	1.61	11.92	27.50	-15.57	-14.59
1998	9.94	1.71	11.65	30.25	-18.59	-18.82
1999	9.59	1.81	11.40	33.27	-21.87	-23.17
2000	9.22	1.92	11.14	36.60	-25.45	-27.60
2001	8.87	2.04	10.91	40.26	-29.35	-32.06
2002	8.75	2.17	10.93	44.28	-33.36	-36.50
2003	8.61	2.31	10.91	48.71	-37.80	-40.89
2004	8.44	2.45	10.89	53.58	-42.70	-45.22
2005	8.29	2.60	10.89	58.94	-48.05	-49.49
2006	8.14	2.76	10.90	64.83	-53.93	-53.68
2007	8.01	2.93	10.94	71.32	-60.37	-57.77
2008	7.88	3.11	11.00	78.45	-67.45	-61.77
2009	7.77	3.31	11.08	86.30	-75.22	-65.67
2010	7.66	3.51	11.17	94.92	-83.75	-69.47
2011	7.57	3.73	11.30	104.42	-93.12	-73.15
2012	7.47	3.96	11.43	114.86	-103.42	-76.73
2013	7.38	4.21	11.59	126.34	-114.76	-80.21
2014	7.32	4.47	11.79	138.98	-127.19	-83.57
2015	7.27	4.75	12.01	152.88	-140.86	-86.83

The assumptions used here are those described in
Exhibit Webb-18, PUC 82-266.
Fixed charges are Webb figures times (3987/2145).

FIG. 7.1: CORRECTED BUSBAR COMPARISON

(Exh. Webb-15, 82-266)

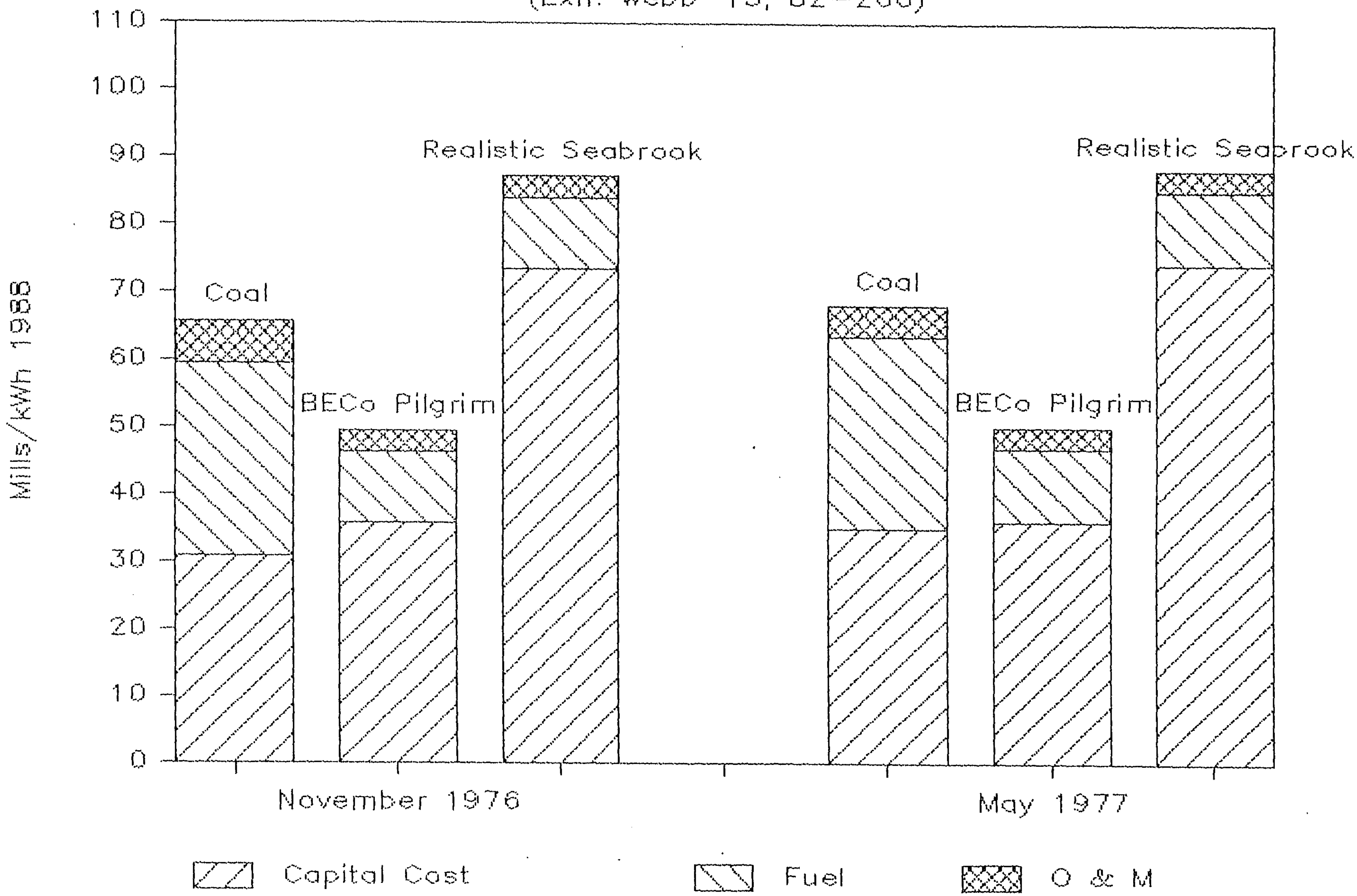


FIG. 7.2: LEVELIZED BUSBAR COSTS

First 28 Years, 1986 Operation

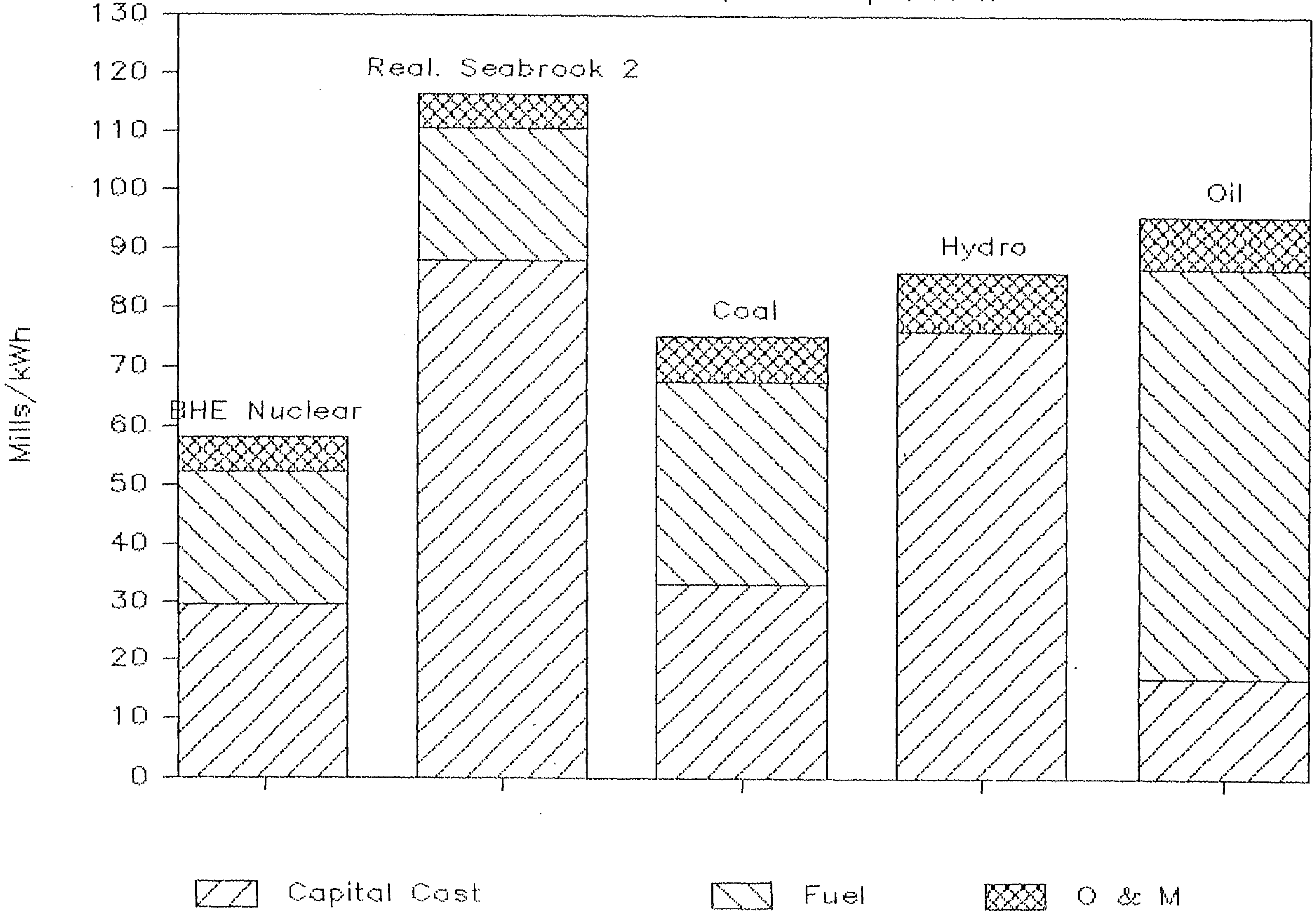


TABLE 8.1: COMPARISON OF FINANCIAL INDICATORS TO NUCLEAR COMMITMENT

INDICATOR for 1972

	UTILITY			
	PSNH	BECo	NORTHEAST	UI
Peak Load (MW)	875	1,912	3,637	836
Sales (GWH)	4,208	9,906	17,515	4,388
Revenues ($ mill.)	$91.7	$269.8	$473.0	$103.7
Net Income ($ mill.)	$11.5	$35.9	$82.0	$13.9
Net Plant in Service ($ mill.)	$255.4	$793.1	NA	$258.2
Book Common Equity ($ mill.)	$93.3	$248.1	$570.4	$88.6
MW Nuclear Commitment	1235	679	1290	540
Nuclear Cost Commitment ($ mill.)	$516.0	$237.2	$458.4	$222.6

RATIO OF INDICATORS TO NUCLEAR COMMITMENT

	PSNH	BECo	NORTHEAST	UI
Peak Load	0.7	2.8	2.8	1.5
Sales	3.4	14.6	13.6	8.1
Revenues	7.4%	39.8%	36.7%	19.2%
Net Income	0.9%	5.28%	6.36%	2.57%
Net Plant in Service	0.2	1.17	NA	0.48
Common Equity	0.1	0.37	0.44	0.16

RATIO OF INDICATORS TO NUCLEAR COST COMMITMENT

	PSNH	BECo	NORTHEAST	UI
Revenues	17.8%	113.8%	103.2%	46.6%
Net Income	2.2%	15.12%	17.89%	6.24%
Net Plant in Service	0.49	3.34	NA	1.16
Common Equity	0.18	1.05	1.24	0.40

TABLE 8.2: COMPARISON OF FINANCIAL INDICATORS TO NUCLEAR COMMITMENT

INDICATOR for 1976

	UTILITY				
	PSNH	BECo	NORTHEAST	UI	MPS
Peak Load (MW)	1,113	1,970	3,774	863	104
Sales (GWH)	4,914	11,711	18,896	4,499	482
Revenues ($ mill.)	$196.7	$552.9	$755.3	$193.8	$17.2
Net Income ($ mill.)	$21.0	$39.8	$111.5	$18.6	$1.8
Net Plant in Service ($ mill.)	$358.9	$1,155.4	$1,993.2	$375.4	$31.9
Book Common Equity ($ mill.)	$162.8	$303.3	$812.8	$142.0	$13.9
MW Nuclear Commitment	1235	679	1258	540	34
Nuclear Cost Commitment ($ mill.)	$1,055.9	$823.6	$1,008.8	$478.9	$29.4

RATIO OF INDICATORS TO NUCLEAR COMMITMENT

	PSNH	BECo	NORTHEAST	UI	MPS
Peak Load	0.9	2.9	3.0	1.6	3.1
Sales	4.0	17.3	15.0	8.33	14.4
Revenues	15.9%	81.5%	60.1%	35.9%	51.1%
Net Income	1.70%	5.86%	8.87%	3.44%	5.31%
Net Plant in Service	0.29	1.70	1.59	0.69	0.95
Common Equity	0.13	0.45	0.65	0.26	0.41

RATIO OF INDICATORS TO NUCLEAR COST COMMITMENT

	PSNH	BECo	NORTHEAST	UI	MPS
Revenues	18.6%	67.1%	74.9%	40.5%	58.4%
Net Income	1.99%	4.83%	11.05%	3.88%	6.06%
Net Plant in Service	0.34	1.40	1.98	0.78	1.09
Common Equity	0.15	0.37	0.81	0.30	0.47

TABLE 8.3: COMPARISON OF FINANCIAL INDICATORS TO NUCLEAR COMMITMENT

INDICATOR for 1978

	UTILITY					
	PSNH	BECo	NORTHEAST	UI	CMP High-Risk	MPS
Peak Load (MW)	1,145	2,031	3,871	953	1173	104
Sales (GWH)	5,384	12,589	19,964	4,712	5,844	534
Revenues ($ mill.)	$260.8	$613.0	841.4	$216.3	$208.2	$19.9
Net Income ($ mill.)	$36.5	$33.9	$108.3	$21.5	$29.6	$2.8
Net Plant in Service ($ mill.)	$719.7	$1,137.5	$2,011.8	$371.2	$513.2	$44.1
Book Common Equity ($ mill.)	$228.3	$355.0	$866.1	$177.6	$196.3	$17.1
MW Nuclear Commitment	1235	679	1023	540	342	34
Nuclear Cost Commitment ($ mill.)	$770.3	$713.9	$1,455.9	$373.7	$241.8	$19.0
RATIO OF INDICATORS TO NUCLEAR COMMITMENT						
Peak Load	0.9	3.0	3.8	1.8	3.4	3.1
Sales	4.4	18.6	19.5	8.7	17.1	15.9
Revenues	21.1%	90.3%	82.2%	40.0%	61.0%	59.2%
Net Income	2.96%	4.99%	10.59%	3.98%	8.67%	8.48%
Net Plant in Service	0.58	1.68	1.97	0.69	1.50	1.31
Common Equity	0.18	0.52	0.85	0.33	0.57	0.51
RATIO OF INDICATORS TO NUCLEAR COST COMMITMENT						
Revenues	33.9%	85.9%	57.8%	57.9%	86.1%	104.6%
Net Income	4.74%	4.75%	7.44%	5.75%	12.25%	14.99%
Net Plant in Service	0.93	1.59	1.38	0.99	2.12	2.32
Common Equity	0.30	0.50	0.59	0.48	0.81	0.90

TABLE 8.4: COMPARISON OF FINANCIAL INDICATORS TO NUCLEAR COMMITMENT

INDICATOR for 1980

	UTILITY					
	PSNH	BECo	NORTHEAST	UI	CMP High-Risk	MPS
Peak Load (MW)	1,117	2,100	4,015	971	1193	105
Sales (GWH)	5,642	12,802	20,562	4,715	$6,038.5	539
Revenues ($ mill.)	$351.2	$886.4	$1,324.5	364.1	$335.3	$27.8
Net Income ($ mill.)	$59.9	$51.7	$114.2	34.5	$26.4	$2.5
Net Plant in Service ($ mill.)	$386.7	$1,200.4	$2,140.8	$359.8	$625.8	$35.8
Book Common Equity ($ mill.)	$387.8	$431.9	$918.0	$223	$208.7	$18.9
MW Nuclear Commitment	895	679	841	483	342	34
Nuclear Cost Commitment ($ mill.)	$1,322.4	$2,073.9	$1,816.7	$757.7	$545.0	$45.6
RATIO OF INDICATORS TO NUCLEAR COMMITMENT						
Peak Load	1.2	3.1	4.8	2.0	3.5	3.1
Sales	6.3	18.9	24.5	9.8	17.7	16.1
Revenues	39.2%	130.6%	157.5%	75.4%	98.2%	82.8%
Net Income	6.69%	7.61%	13.58%	7.15%	7.74%	7.41%
Net Plant in Service	0.43	1.77	2.55	0.75	1.83	1.06
Common Equity	0.43	0.64	1.09	0.46	0.61	0.56
RATIO OF INDICATORS TO NUCLEAR COST COMMITMENT						
Revenues	26.6%	42.7%	72.9%	48.1%	61.5%	61.0%
Net Income	4.53%	2.49%	6.29%	4.55%	4.85%	5.46%
Net Plant in Service	0.29	0.58	1.18	0.47	1.15	0.79
Common Equity	0.29	0.21	0.51	0.29	0.38	0.42

TABLE 8.5: COMPARISON OF FINANCIAL INDICATORS TO NUCLEAR COMMITMENT

INDICATOR for 1982

	UTILITY				
	PSNH	NORTHEAST	UI	CMP High-Risk	MPS
Peak Load (MW)	1,176	4,003	952	1,259	118
Sales (GWH)	5,587	19,591	4,475	6,586.6	558
Revenues ($ mill.)	$423.3	$1,770.0	$436.7	$401.3	$31.1
Net Income ($ mill.)	$92.0	$175.0	$65.8	$41.0	$4.7
Net Plant in Service ($ mill.)	$404.8	$2,249.7	$362.1	$545.0	$35.8
Book Common Equity ($ mill.)	$538.0	$1,145.1	$319.8	$269.4	$24.9
MW Nuclear Commitment	851	837	445	342	34
Nuclear Cost Commitment ($ mill.)	$1,967.8	$2,503.9	$1,049.6	$149.0	$76.6

RATIO OF INDICATORS TO NUCLEAR COMMITMENT

	PSNH	NORTHEAST	UI	CMP High-Risk	MPS
Peak Load	1.4	4.8	2.1	3.7	3.5
Sales	6.6	23.4	10.1	19.3	16.6
Revenues	49.7%	211.4%	98.1%	117.5%	92.7%
Net Income	10.81%	20.90%	14.78%	11.99%	13.88%
Net Plant in Service	0.48	2.69	0.72	0.79	1.07
Common Equity	0.63	1.37	1.0	1.0	0.74

RATIO OF INDICATORS TO NUCLEAR COST COMMITMENT

	PSNH	NORTHEAST	UI	CMP High-Risk	MPS
Revenues	21.5%	70.7%	41.6%	269.4%	40.6%
Net Income	4.68%	6.99%	6.27%	27.49%	6.08%
Net Plant in Service	0.21	0.90	0.35	3.66	0.47
Common Equity	0.27	0.46	0.30	1.81	0.33

TABLE 9.1: MPS FORECAST HISTORY

Forecast for:	Year of Projection 1973	1974	1975	1976	1977	1978	1979	1980	1981	1982	1983	Actual Winter Peak
1970												72.0
1971												80.9
1972												83.8
1973	88.5											82.1
1974	94.4	89.1										87.1
1975	100.6	92.9	92.9									89.9
1976	107.2	99.4	99.4	99.4								104.3
1977	114.3	106.8	103.8	103.8	105.9							98.7
1978	121.9	114.6	110.4	110.4	111.9	105.0						104.0
1979	129.9	122.1	117.4	117.4	118.3	109.2	105.8					101.8
1980	138.5	130.0	124.8	124.8	125.1	114.4	109.8	105.7				104.7
1981	147.6	138.4	132.7	132.7	132.2	119.5	114.1	113.7	113.7			105.8
1982	157.3	147.4	141.0	141.0	139.7	125.0	118.2	119.8	119.8	117.0		118.2
1983	167.7	157.0	149.9	149.9	147.7	130.7	122.9	122.0	122.0	120.0	114.0	117.7
1984	178.8	167.2	159.3	159.3	156.1	136.7	127.7	124.3	124.3	122.0	115.0	
1985	190.6	178.1	169.4	169.4	165.0	143.1	132.3	134.1	134.1	129.0	116.0	
1986	203.1	189.7	180.0	180.0	174.4	149.6	137.3	136.5	136.5	130.0	117.0	
1987	216.5	202.0	191.3	191.3	184.4	156.5	142.3	139.0	139.0	137.0	118.0	
1988		215.1	203.4	203.4	194.9	163.7	147.3	141.4	141.4	141.0	120.0	
1989			216.2	216.2	206.0	171.3	152.9	144.0	144.0	144.0	121.0	
1990				229.8	217.7	179.1	158.4	146.5	146.5	150.0	122.0	
1991					230.1	187.3	164.4	149.2	149.2	152.0	123.0	
1992						196.0	170.3	151.9	151.9	154.0	124.0	
1993							176.5	154.6	154.6	156.0	125.0	
1994								157.4	157.4	158.0	127.0	
1995									160.2	160.0	128.0	
1996										163.0	128.0	
1997										166.0	129.0	
1998										169.0	130.0	
1999										172.0	131.0	
2000										175.0	132.0	

Sources: State of Maine Docket #84-80
Maine Public Service Company Exhibits
Fred Bustard, Exhibit FCB-1, Sheet 2 of 2

Notes: 1. 126 MW projection for 1983 assumed to be a typo.

TABLE 9.2: BHE FORECAST HISTORY

Forecast for:	Jun-71 [1]	Aug-73	Aug-74	Aug-75	Dec-76	Jan-78	Dec-78	Mar-80	Jun-81	Jul-82	Aug-83	Actual Winter Peak
												135.6
1971	144											148.3
1972	156											155.4
1973	169											154.9
1974	182	176										162.1
1975	198	182	168									177.0
1976	215	193	182	185								195.4
1977	234	205	190	196	197							198.3
1978	255	218	205	207	211	208						215.9
1979	276	231	220	220	224	224	252					222.0
1980	301	245	237	232	237	233	273	229				221.2
1981	328	260	251	246	244	243	284	237	231			216.4
1982		276	267	260	258	252	296	245	235	235		234.4
1983		293	285	275	273	264	309	254	241	237	229	235.8
1984		310	304	291	289	276	319	263	248	244	235	
1985				308	306	289	333	272	254	252	245	
1986					323	302	352	280	260	261	252	
1987					342	315	367	288	265	264	257	
1988						330	381	297	270	268	261	
1989						345	397	306	276	272	267	
1990						360	413	315	281	275	272	
1991							430	324	286	278	275	
1992								331	291	282	280	
1993								338	296	287	283	
1994								346	301	291	287	
1995								353	306	294	292	
1996									311	298	295	
1997									316	302	300	
1998									321	307	303	
1999									326	312	307	
2000									331		313	
2001									336		318	
2002											323	

Sources: State of Maine Docket #84-113
BHE response to 29 STAFF 1.

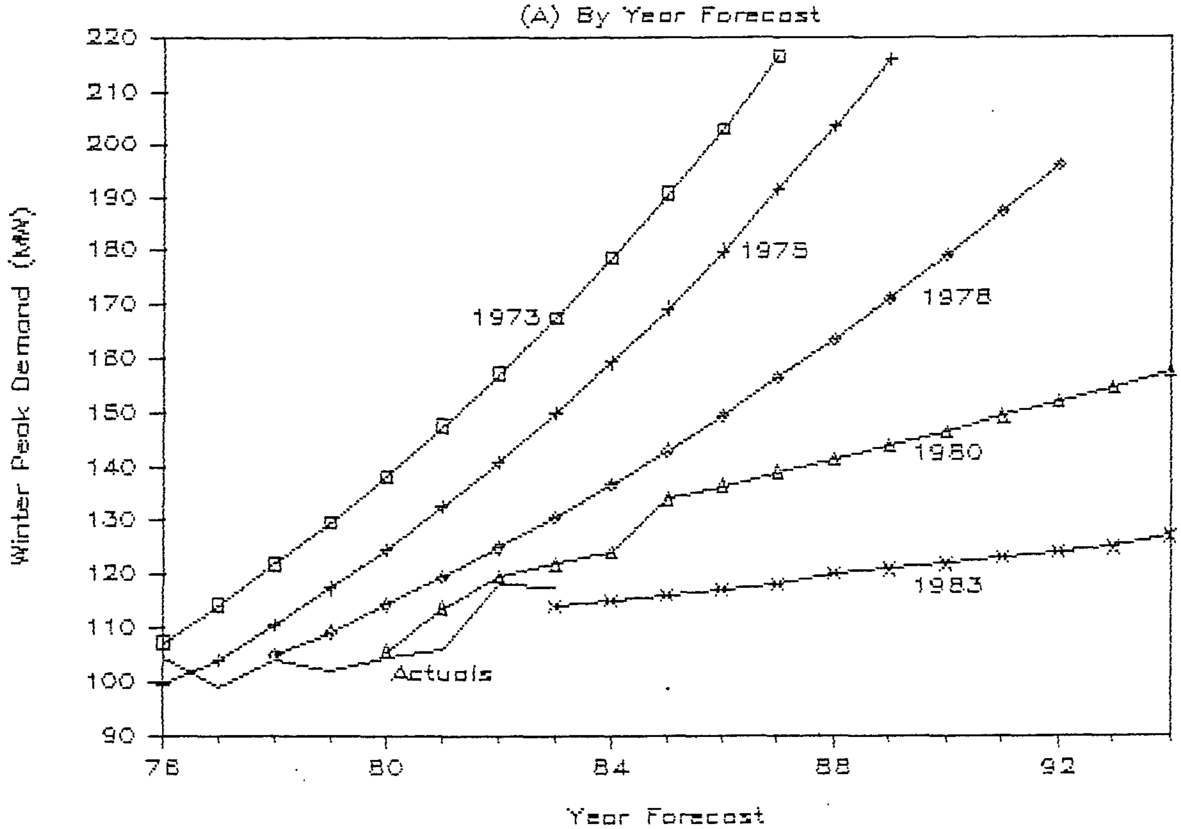
Notes: 1. Month not given, June assumed.

TABLE 9.3: CMP FORECAST HISTORY

Forecast for:	Oct-74 [2]	Jan-75 [2]	Jan-76 [1]	Jan-77 [1]	Nov-77 [2]	Jan-78 [1]	Oct-78 [2]	May-80 [2]	May-81 [6]	Apr-82 [5]	May-83 [6]	Actual Winter Peak
	Date of Projection											
1960												407
1961												444 [4]
1962												468 [4]
1963												480 [4]
1964												514 [5]
1965												542 [5]
1966												559 [5]
1967												606 [5]
1968												649 [5]
1969												674 [5]
1970												759 [5]
1971												790 [5]
1972												868 [5]
1973												849 [5]
1974	911											923 [5]
1975	1039	972										1041 [5]
1976	1118	1031	1025									1089 [5]
1977	1203	1103	1090	1111		1142						1124 [5]
1978	1293	1183	1160	1193	1213	1188	1175					1195 [5]
1979	1386	1269	1241	1265	1280	1280	1235	1244				1207 [5]
1980	1487	1361	1327	1336	1351	1351	1344	1258				1209 [5]
1981	1595	1459	1420	1407	1421	1421	1400	1327	1241	1230		1209 [5]
1982	1710	1565	1520	1482	1492	1492	1456	1389	1262	1297		1259 [3]
1983	1834	1678	1628	1560	1568	1568	1513	1448	1286	1336	1263	1289 [3]
1984	1967	1800	1741	1642	1644	1644	1577	1493	1310	1361	1301	
1985		1931	1852	1727	1725	1725	1641	1531	1346	1379	1312	
1986			1969	1811	1803	1803	1691	1571	1359	1394	1347	
1987				1899	1886	1886	1741	1615	1384	1407	1378	
1988					1969	1969	1796	1664	1410	1424	1411	
1989							1852	1701	1436	1436	1440	
1990							1907	1745	1463	1452	1471	
1991							1964	1788	1491	1473	1499	
1992							2018	1842	1520	1487	1522	
1993							2073	1886	1549	1504	1545	
1994								1961	1579	1525	1569	
1995									1610	1543	1595	
1996											1620	
1997											1646	
1998											1671	
1999											1701	
2000											1729	

Notes:
1. NEPLAN Load and Capacity Reports
2. CMP Load Forecasts.
3. CMP 1983 Annual Report.
4. Staff Data Request C-4, Ques. 217, Docket #82-266 MPUC.
5. CMP Fall 1981 Long Range Forecast, April, 1982
6. Quimby Testimony, Maine Docket #84-120
   Exh.A, CMP May 1983 Long-Range Load Forecast, p.3, Tab. 2.

Figure 9.1: MPS Forecast History



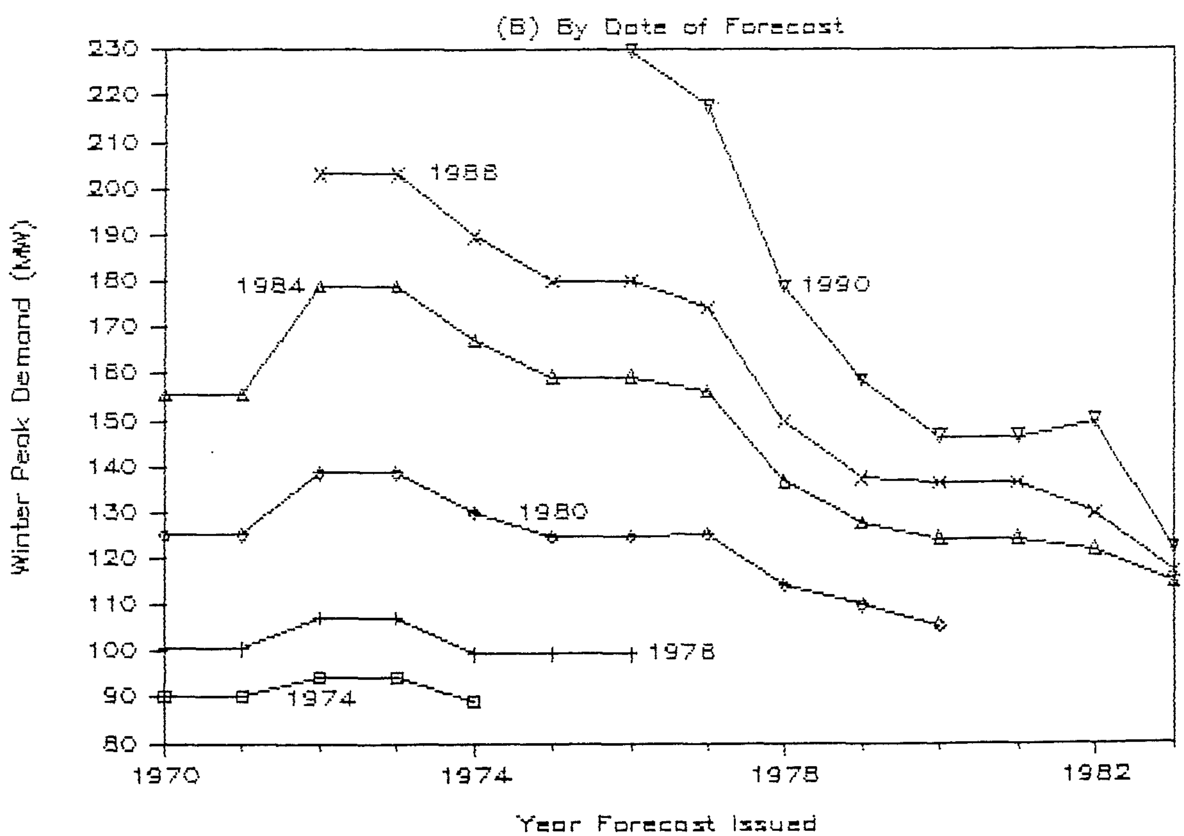


Figure 9.2: BHE Forecast History

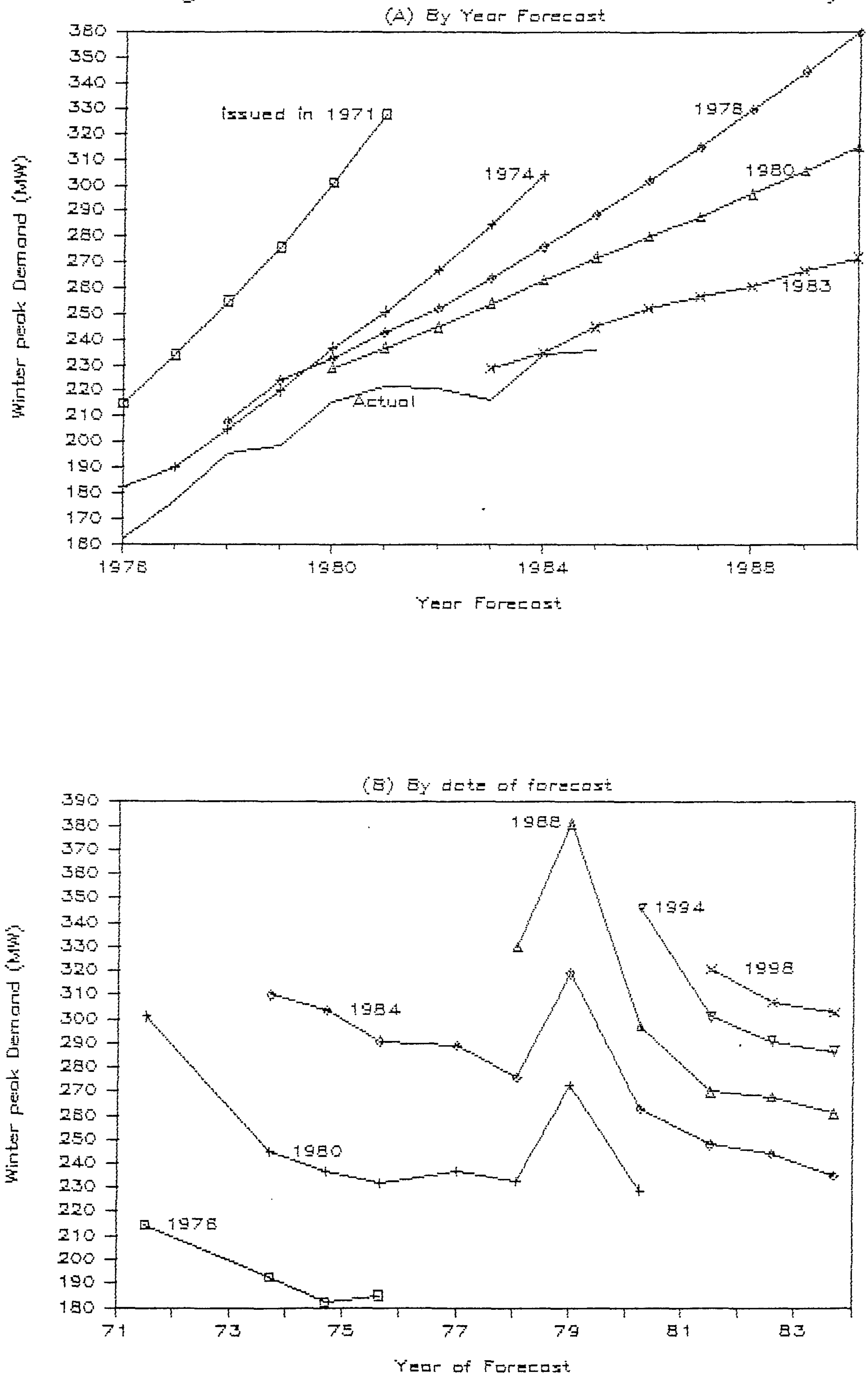
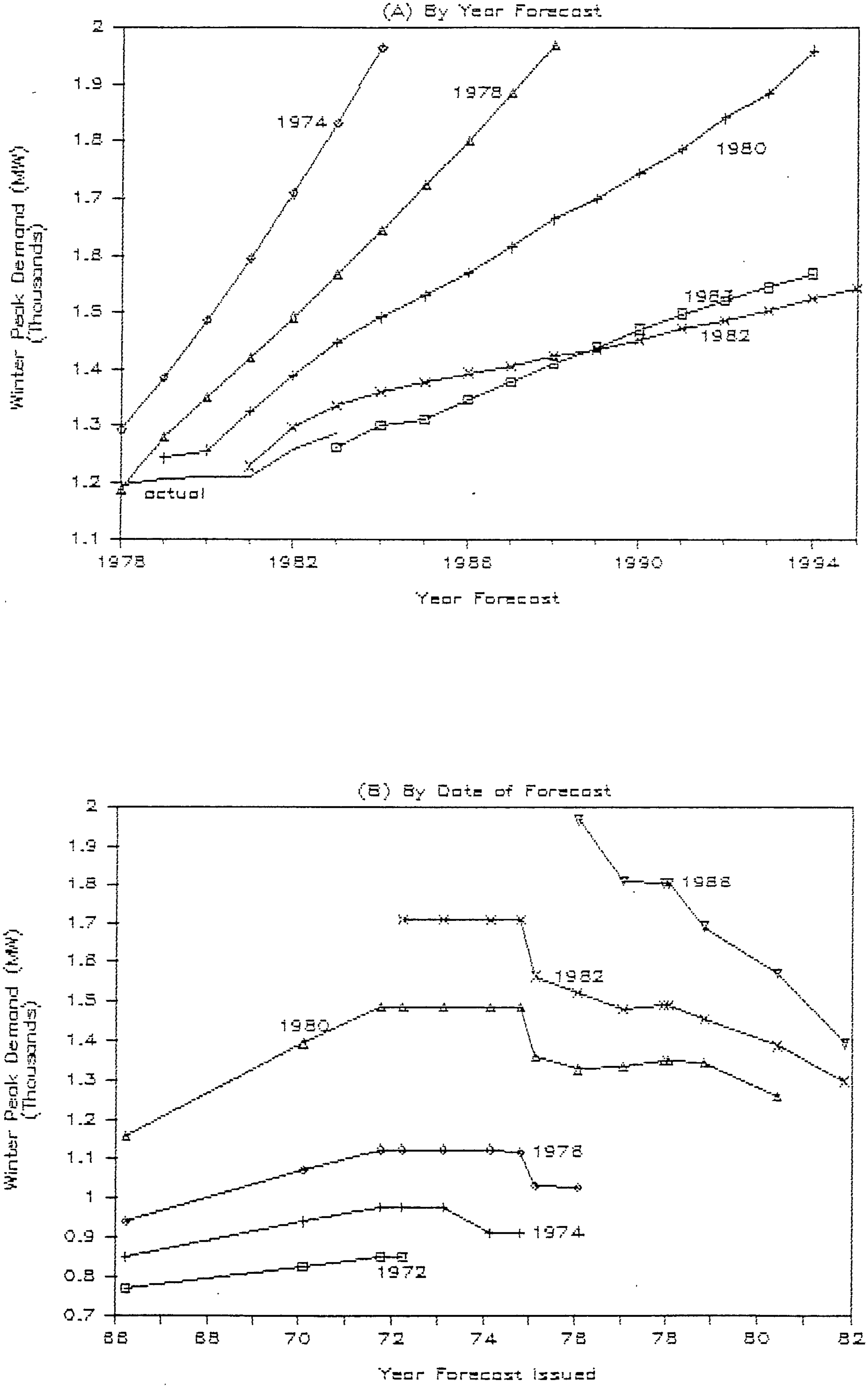


Figure 9.3: CMP Forecast History



APPENDIX B

COST AND SCHEDULE ESTIMATE HISTORIES

I. Completed Plants

II. Incomplete Bechtel Plants

III. Incomplete Non-Bechtel Plants

IV. Canceled Bechtel Plants

V. Canceled Non-Bechtel Plants

Completed Plants (APCOMP3, Myopia 44)

Unit Name	Actuals Cost	Actuals COD	Date of Estimate	Estimates Total Cost	Estimates COD	Est. Years to COD	% Complete
Nine Mile Point	162	Dec-69	Mar-64	68	Nov-68	4.67	0.0
Nine Mile Point	162	Dec-69	Sep-64	68	Jul-68	3.83	0.0
Nine Mile Point	162	Dec-69	Jun-66	88	Nov-68	2.42	34.0
Nine Mile Point	162	Dec-69	Dec-67	134	Jan-69	1.09	75.0
Nine Mile Point	162	Dec-69	Jun-68	134	Jun-69	1.00	88.0
Nine Mile Point	162	Dec-69	Dec-68	134	Dec-69	1.00	94.0
Oyster Creek 1	90	Dec-69	Jun-64		Oct-67	3.33	0.0
Oyster Creek 1	90	Dec-69	Sep-65		Nov-67	2.17	18.0
Oyster Creek 1	90	Dec-69	Mar-66		Dec-67	1.75	30.0
Oyster Creek 1	90	Dec-69	Jun-66		Dec-67	1.50	33.0
Oyster Creek 1	90	Dec-69	Sep-66		Jan-68	1.33	41.0
Oyster Creek 1	90	Dec-69	Mar-67		Apr-68	1.09	66.4
Dresden 2	83	Jul-70	Mar-66		Feb-69	2.92	6.0
Dresden 2	83	Jul-70	Sep-67		Apr-69	1.58	59.0
Dresden 2	83	Jul-70	Dec-68		Jan-70	1.08	84.0
Ginna	83	Jul-70	Dec-65		Jun-69	3.50	0.0
Ginna	83	Jul-70	Mar-66		Jun-69	3.25	0.0
Ginna	83	Jul-70	Sep-68		Oct-69	1.08	80.0
Point Beach 1	74	Dec-70	Jun-66		Apr-70	3.83	0.0
Point Beach 1	74	Dec-70	Sep-66		Apr-70	3.58	0.0
Point Beach 1	74	Dec-70	Mar-69		Aug-70	1.42	53.2
Point Beach 1	74	Dec-70	Dec-69		Dec-70	1.00	71.8
Millstone 1	97	Mar-71	Dec-65		Aug-69	3.67	0.0
Millstone 1	97	Mar-71	Mar-67		Aug-69	2.42	21.7
Millstone 1	97	Mar-71	Sep-67		Aug-69	1.92	35.0
Millstone 1	97	Mar-71	Dec-68		Jan-70	1.08	72.4
Millstone 1	97	Mar-71	Mar-69		Mar-70	1.00	78.3
Millstone 1	97	Mar-71	Sep-69		Oct-70	1.08	86.0
Robinson 2	78	Mar-71	Jun-66		May-70	3.92	0.0
Monticello	105	Jun-71	Jun-66		May-70	3.92	0.0
Dresden 3	104	Nov-71	Mar-66		Feb-70	3.92	2.0
Dresden 3	104	Nov-71	Dec-68		Aug-70	1.66	54.0
Dresden 3	104	Nov-71	Mar-69		Aug-70	1.42	57.0
Dresden 3	104	Nov-71	Jun-69		Dec-70	1.50	66.0
Dresden 3	104	Nov-71	Mar-70		Jun-71	1.25	80.0
Palisades	147	Dec-71	Mar-68	89	May-70	2.17	31.0
Palisades	147	Dec-71	Mar-69	110	Aug-70	1.42	70.0
Point Beach 2	71	Oct-72	Mar-67		Apr-71	4.08	0.0
Point Beach 2	71	Oct-72	Sep-69		Aug-71	1.91	25.4
Point Beach 2	71	Oct-72	Dec-69		Dec-71	2.00	29.7
Point Beach 2	71	Oct-72	Mar-70		Aug-71	1.42	35.2
Point Beach 2	71	Oct-72	Sep-70		Sep-71	1.00	56.1
Vermont Yankee	172	Nov-72	Sep-66	88	Oct-70	4.08	0
Vermont Yankee	172	Nov-72	Sep-69	120	Jul-71	1.83	
Vermont Yankee	172	Nov-72	Mar-70	133	Jul-71	1.33	
Vermont Yankee	172	Nov-72	Jul-71	154	Mar-72	0.67	
Maine Yankee	219	Dec-72	Sep-67	100	May-72	4.67	
Maine Yankee	219	Dec-72	Sep-68	131	May-72	3.66	
Maine Yankee	219	Dec-72	Mar-70	181	May-72	2.17	
Pilgrim 1	231	Dec-72	Jul-65	70	Jul-71	6.00	

Completed Plants (APCOMP3, Myopia 44)

Unit Name	Actuals Cost	Actuals COD	Date of Estimate	Estimates Total Cost	Estimates COD	Est. Years to COD	% Complete
Pilgrim 1	231	Dec-72	Feb-67	105	Jul-71	4.41	
Pilgrim 1	231	Dec-72	Jun-68	122	Sep-71	3.25	
Pilgrim 1	231	Dec-72	Jan-70	153	Sep-71	1.66	
Surry 1	247	Dec-72	Dec-66	130	Mar-71	4.25	0.1
Surry 1	247	Dec-72	Dec-67	144	Mar-71	3.25	4.3
Surry 1	247	Dec-72	Dec-68	165	Mar-71	2.25	15.2
Surry 1	247	Dec-72	Jun-69	165	Apr-71	1.83	33.7
Surry 1	247	Dec-72	Sep-69	165	Jun-71	1.75	45.7
Surry 1	247	Dec-72	Dec-69	189	Jun-71	1.50	45.6
Surry 1	247	Dec-72	Jun-70	189	Oct-71	1.33	79.5
Surry 1	247	Dec-72	Dec-70	189	Feb-72	1.17	88.6
Turkey Point 3	109	Dec-72	Sep-69	99	Jun-71	1.75	52.2
Turkey Point 3	109	Dec-72	Mar-70	111	Jun-71	1.25	66.7
Quad Cities 1	100	Feb-73	Jun-66		Mar-70	3.75	0.0
Quad Cities 1	100	Feb-73	Sep-67		Mar-70	2.50	26.0
Quad Cities 1	100	Feb-73	Dec-68		Oct-70	1.83	37.0
Quad Cities 1	100	Feb-73	Jun-69		Jan-71	1.59	64.0
Quad Cities 1	100	Feb-73	Mar-70		Jul-71	1.33	75.0
Quad Cities 1	100	Feb-73	Jun-70		Jul-71	1.08	82.0
Quad Cities 2	100	Mar-73	Sep-66		Mar-71	4.50	0.0
Quad Cities 2	100	Mar-73	Sep-67		Mar-71	3.50	16.0
Quad Cities 2	100	Mar-73	Dec-68		Apr-71	2.33	38.0
Quad Cities 2	100	Mar-73	Jun-69		Jan-72	2.58	47.0
Quad Cities 2	100	Mar-73	Mar-70		May-72	2.17	56.0
Quad Cities 2	100	Mar-73	Mar-71		May-72	1.17	82.0
Surry 2	150	May-73	Dec-66	108	Mar-72	5.25	0.0
Surry 2	150	May-73	Dec-67	112	Mar-72	4.25	1.4
Surry 2	150	May-73	Dec-68	123	Mar-72	3.25	6.3
Surry 2	150	May-73	Dec-69	138	Mar-72	2.25	20.8
Surry 2	150	May-73	Mar-70	138	Apr-72	2.09	25.8
Surry 2	150	May-73	Sep-70	138	May-72	1.66	37.4
Surry 2	150	May-73	Mar-71	138	Oct-72	1.59	48.8
Surry 2	150	May-73	Jun-71	139	Oct-72	1.34	68.9
Surry 2	150	May-73	Sep-71	141	Dec-72	1.25	76.2
Surry 2	150	May-73	Dec-71	145	Mar-73	1.25	83.3
Surry 2	150	May-73	Mar-72	147	Mar-73	1.00	88.0
Oconee 1	156	Jul-73	Sep-66	78	May-71	4.66	0.0
Oconee 1	156	Jul-73	Dec-66	76	May-71	4.41	0.0
Oconee 1	156	Jul-73	Jun-67	86	May-71	3.92	0.0
Oconee 1	156	Jul-73	Sep-67	93	May-71	3.66	1.0
Oconee 1	156	Jul-73	Sep-69	109	May-71	1.66	24.5
Indian Point 2	206	Aug-73	Jun-66		Jun-69	3.00	7.0
Indian Point 2	206	Aug-73	Sep-68		Apr-70	1.58	56.0
Indian Point 2	206	Aug-73	Mar-69		May-70	1.17	66.0
Indian Point 2	206	Aug-73	Jun-69		Oct-70	1.33	71.0
Indian Point 2	206	Aug-73	Dec-69		May-71	1.41	87.0
Indian Point 2	206	Aug-73	Dec-70		Dec-71	1.00	98.0
Fort Calhoun 1	174	Sep-73	Sep-67	70	May-71	3.66	0.0
Fort Calhoun 1	174	Sep-73	Sep-68	92	May-71	2.66	17.0
Fort Calhoun 1	174	Sep-73	Mar-69	92	May-72	3.17	21.0

Completed Plants (APCOMP3, Myopia 44)

Unit Name	Actuals Cost	Actuals COD	Date of Estimate	Estimates Total Cost	Estimates COD	Est. Years to COD	% Complete
Fort Calhoun 1	174	Sep-73	Jun-69	92	May-71	1.91	25.0
Fort Calhoun 1	174	Sep-73	Sep-69	92	Sep-71	2.00	30.0
Fort Calhoun 1	174	Sep-73	Mar-70	125	Jun-72	2.25	47.0
Fort Calhoun 1	174	Sep-73	Dec-70	125	Nov-72	1.92	76.0
Fort Calhoun 1	174	Sep-73	Sep-71	125	May-73	1.66	89.0
Fort Calhoun 1	174	Sep-73	Dec-71	159	May-73	1.42	85.7
Turkey Point 4	123	Sep-73	Sep-69	41	Jun-72	2.75	52.2
Turkey Point 4	123	Sep-73	Mar-70	80	Jun-72	2.25	66.7
Turkey Point 4	123	Sep-73	Dec-70	81	Jun-72	1.50	65.4
Turkey Point 4	123	Sep-73	Mar-71	83	Jun-72	1.25	68.0
Turkey Point 4	123	Sep-73	Jun-71	96	Jun-72	1.00	72.0
Turkey Point 4	123	Sep-73	Dec-71	126	Dec-72	1.00	84.0
Prairie Isl 1	233	Dec-73	Mar-67	100	May-72	5.17	0.0
Prairie Isl 1	233	Dec-73	Dec-67	105	May-72	4.42	0.5
Prairie Isl 1	233	Dec-73	Sep-70	148	Oct-72	2.08	37.0
Prairie Isl 1	233	Dec-73	Sep-71	148	Dec-72	1.25	74.0
Prairie Isl 1	233	Dec-73	Dec-71	190	Dec-72	1.00	80.0
Prairie Isl 1	233	Dec-73	Sep-72	210	Oct-73	1.08	92.0
Zion 1	276	Dec-73	Mar-67	164	Apr-72	5.09	0
Zion 1	276	Dec-73	Mar-69	205	Apr-72	3.09	12
Zion 1	276	Dec-73	Jun-70	232	Apr-72	1.83	43
Zion 1	276	Dec-73	Dec-70	232	May-72	1.42	57
Zion 1	276	Dec-73	Jun-71	232	Aug-72	1.17	75
Kewaunee	202	Jun-74	Dec-67	85	Jun-72	4.50	0.0
Kewaunee	202	Jun-74	Mar-69	109	Jun-72	3.25	3.5
Kewaunee	202	Jun-74	Mar-70	121	Jun-72	2.25	13.5
Kewaunee	202	Jun-74	Jun-70	123	Jun-72	2.00	20.0
Kewaunee	202	Jun-74	Sep-70	123	Sep-72	2.00	28.0
Kewaunee	202	Jun-74	Sep-71	134	Dec-72	1.25	72.0
Kewaunee	202	Jun-74	Mar-72	134	Mar-73	1.00	87.0
Kewaunee	202	Jun-74	Jun-72	158	Jun-73	1.00	91.0
Kewaunee	202	Jun-74	Sep-72	163	Sep-73	1.00	95.0
Cooper	246	Jul-74	Sep-67	133	Apr-72	4.58	0.0
Cooper	246	Jul-74	Mar-68	127	Apr-72	4.08	0.9
Cooper	246	Jul-74	Dec-70	207	Apr-73	2.33	42.0
Cooper	246	Jul-74	Jun-72	207	Jul-73	1.08	81.1
Peach Bottom 2	522	Jul-74	Dec-66	138	Mar-71	4.25	0.0
Peach Bottom 2	522	Jul-74	Sep-67	163	Mar-71	3.50	1.0
Peach Bottom 2	522	Jul-74	Mar-68	163	Mar-71	3.00	4.4
Peach Bottom 2	522	Jul-74	Sep-69	206	Mar-72	2.50	35.0
Peach Bottom 2	522	Jul-74	Dec-69	218	Mar-72	2.25	43.0
Peach Bottom 2	522	Jul-74	Mar-70	230	May-72	2.17	48.0
Peach Bottom 2	522	Jul-74	Dec-70	230	Dec-72	2.00	70.0
Peach Bottom 2	522	Jul-74	Mar-71	277	Mar-73	2.00	77.0
Peach Bottom 2	522	Jul-74	Jun-71	288	Mar-73	1.75	80.0
Peach Bottom 2	522	Jul-74	Jun-72	352	Sep-73	1.25	72.0
Browns Ferry 1	256	Aug-74	Sep-66	117	Aug-70	3.92	0.0
Browns Ferry 1	256	Aug-74	Dec-66	117	Oct-70	3.83	1.0
Browns Ferry 1	256	Aug-74	Sep-67	124	Oct-70	3.08	8.0
Browns Ferry 1	256	Aug-74	Sep-69	149	Oct-71	2.08	31.0

Completed Plants (APCOMP3, Myopia 44)

	Actuals		Estimates				
Unit Name	Cost	COD	Date of Estimate	Total Cost	COD	Est. Years to COD	% Complete
Browns Ferry 1	256	Aug-74	Jun-70	149	Apr-72	1.83	43.0
Browns Ferry 1	256	Aug-74	Mar-71	185	May-72	1.17	53.0
Browns Ferry 1	256	Aug-74	Sep-71	185	Oct-72	1.08	62.0
Oconee 2	160	Sep-74	Sep-66	75	May-72	5.66	0.0
Oconee 2	160	Sep-74	Jun-67	86	May-72	4.92	0.0
Oconee 2	160	Sep-74	Dec-67	88	May-72	4.42	0.0
Oconee 2	160	Sep-74	Mar-69	93	May-72	3.17	17.7
Oconee 2	160	Sep-74	Sep-69	109	May-72	2.66	24.5
Oconee 2	160	Sep-74	Sep-70	109	Jul-72	1.83	50.0
Oconee 2	160	Sep-74	Mar-71	109	Dec-72	1.75	68.0
Oconee 2	160	Sep-74	Sep-71	137	Feb-73	1.42	71.0
Three Mile I. 1	398	Sep-74	Mar-67	100	May-71	4.17	0
Three Mile I. 1	398	Sep-74	Jun-67	106	May-71	3.92	0
Three Mile I. 1	398	Sep-74	Dec-67	124	May-71	3.41	1
Three Mile I. 1	398	Sep-74	Dec-68	150	Sep-71	2.75	9
Three Mile I. 1	398	Sep-74	Jun-69	162	Sep-71	2.25	18
Three Mile I. 1	398	Sep-74	Sep-69	162	May-72	2.66	23
Three Mile I. 1	398	Sep-74	Dec-69	180	May-72	2.41	26.5
Three Mile I. 1	398	Sep-74	Mar-70	184	May-72	2.17	37.5
Three Mile I. 1	398	Sep-74	Jun-70	184	Jul-72	2.08	46
Three Mile I. 1	398	Sep-74	Sep-70	197	Oct-72	2.08	54.5
Three Mile I. 1	398	Sep-74	Dec-70	262	Oct-72	1.83	59.5
Three Mile I. 1	398	Sep-74	Mar-71	261	Nov-72	1.67	67.5
Three Mile I. 1	398	Sep-74	Sep-71	296	Nov-73	2.17	67
Three Mile I. 1	398	Sep-74	Jun-72	328	Nov-73	1.42	86
Three Mile I. 1	398	Sep-74	Sep-72	363	May-74	1.66	90
Three Mile I. 1	398	Sep-74	Mar-73	373	Jul-74	1.33	91
Three Mile I. 1	398	Sep-74	Jun-73	393	Aug-74	1.17	93
Zion 2	290	Sep-74	Jun-67	153	May-73	5.92	0
Zion 2	290	Sep-74	Mar-69	194	May-73	4.17	9
Zion 2	290	Sep-74	Jun-70	213	May-73	2.92	36
Zion 2	290	Sep-74	Mar-72	235	May-73	1.17	71
Arkansas 1	233	Dec-74	Dec-67	132	Dec-72	5.00	0
Arkansas 1	233	Dec-74	Mar-69	138	Dec-72	3.75	1.0
Arkansas 1	233	Dec-74	Jun-69	132	Dec-72	3.50	1.6
Arkansas 1	233	Dec-74	Mar-72	175	Sep-73	1.50	76.0
Arkansas 1	233	Dec-74	Sep-72	185	Oct-73	1.08	86.8
Arkansas 1	233	Dec-74	Mar-73	200	Mar-74	1.00	96.3
Oconee 3	160	Dec-74	Jun-67	92	Jun-73	6.00	0.0
Oconee 3	160	Dec-74	Dec-67	93	Jun-73	5.50	2.0
Oconee 3	160	Dec-74	Jun-68	88	Jun-73	5.00	7.0
Oconee 3	160	Dec-74	Mar-69	93	Jun-73	4.25	17.7
Oconee 3	160	Dec-74	Sep-69	109	Jun-73	3.75	24.5
Oconee 3	160	Dec-74	Sep-70	109	Jul-73	2.83	25.0
Oconee 3	160	Dec-74	Sep-71	137	Nov-73	2.17	43.0
Oconee 3	160	Dec-74	Mar-73	137	Jun-74	1.25	87.5
Peach Bottom 3	220	Dec-74	Dec-66	125	Jan-73	6.09	NA
Peach Bottom 3	220	Dec-74	Sep-67	145	Jan-73	5.34	NA
Peach Bottom 3	220	Dec-74	Mar-68	145	Jan-73	4.84	1.6
Peach Bottom 3	220	Dec-74	Sep-68	145	Mar-73	4.50	4.5

Completed Plants (APCOMP3, Myopia 44)

Unit Name	Actuals Cost	Actuals COD	Date of Estimate	Estimates Total Cost	Estimates COD	Est. Years to COD	% Complete
Peach Bottom 3	220	Dec-74	Sep-69	193	Mar-73	3.50	12.0
Peach Bottom 3	220	Dec-74	Dec-69	203	Mar-73	3.25	13.0
Peach Bottom 3	220	Dec-74	Mar-70	221	Mar-73	3.00	13.0
Peach Bottom 3	220	Dec-74	Dec-70	221	Oct-73	2.83	30.0
Peach Bottom 3	220	Dec-74	Mar-71	263	Apr-74	3.09	37.0
Peach Bottom 3	220	Dec-74	Jun-72	316	Sep-74	2.25	50.0
Peach Bottom 3	220	Dec-74	Sep-73	316	Dec-74	1.25	91.0
Peach Bottom 3	220	Dec-74	Dec-73	284	Dec-74	1.00	94.0
Prairie Isl 2	172	Dec-74	Dec-67	80	May-74	6.41	0.5
Prairie Isl 2	172	Dec-74	Sep-70	112	May-74	3.66	5.0
Prairie Isl 2	172	Dec-74	Dec-71	145	May-74	2.41	20.0
Prairie Isl 2	172	Dec-74	Sep-72	160	Oct-74	2.08	35.0
Duane Arnold	202	Feb-75	Jun-68	103	Dec-73	5.50	0.0
Duane Arnold	202	Feb-75	Dec-68	107	Dec-73	5.00	0.0
Duane Arnold	202	Feb-75	Jun-69	133	Dec-73	4.50	0.0
Duane Arnold	202	Feb-75	Dec-69	138	Dec-73	4.00	0.0
Duane Arnold	202	Feb-75	Dec-70	148	Dec-73	3.00	10.0
Duane Arnold	202	Feb-75	Mar-72	177	Dec-73	1.75	50.0
Duane Arnold	202	Feb-75	Sep-72	192	Jan-74	1.33	69.0
Browns Ferry 2	256	Mar-75	Sep-66	117	Oct-70	4.08	1.0
Browns Ferry 2	256	Mar-75	Mar-67	117	Feb-70	2.92	3.0
Browns Ferry 2	256	Mar-75	Sep-67	124	Feb-70	2.42	8.0
Browns Ferry 2	256	Mar-75	Mar-68	124	Oct-70	2.58	12.0
Browns Ferry 2	256	Mar-75	Sep-69	149	Oct-71	2.08	31.0
Browns Ferry 2	256	Mar-75	Jun-70	149	Apr-72	1.83	43.0
Browns Ferry 2	256	Mar-75	Sep-70	149	Jan-73	2.34	NA
Browns Ferry 2	256	Mar-75	Mar-71	149	Apr-73	2.09	
Browns Ferry 2	256	Mar-75	Sep-71	149	Jul-73	1.83	
Browns Ferry 2	256	Mar-75	Jun-72	149	Jan-74	1.59	
Browns Ferry 2	256	Mar-75	Mar-73	149	Jul-74	1.33	
Rancho Seco	344	Apr-75	Dec-67	134	May-73	5.42	0.0
Rancho Seco	344	Apr-75	Jun-71	215	May-73	1.92	43.0
Rancho Seco	344	Apr-75	Mar-72	215	Oct-73	1.59	65.0
Rancho Seco	344	Apr-75	Jun-72	264	Oct-73	1.33	75.0
Rancho Seco	344	Apr-75	Sep-72	300	Feb-74	1.42	78.0
Rancho Seco	344	Apr-75	Mar-73	327	Jun-74	1.25	80.5
Rancho Seco	344	Apr-75	Sep-73	328	Oct-74	1.08	92.0
Calvert Cliffs 1	429	May-75	Jun-67	118	Jan-73	5.59	0.0
Calvert Cliffs 1	429	May-75	Dec-67	123	Jan-73	5.09	0.0
Calvert Cliffs 1	429	May-75	Mar-68	125	Jan-73	4.84	0.0
Calvert Cliffs 1	429	May-75	Mar-69	124	Jan-73	3.84	3.0
Calvert Cliffs 1	429	May-75	Sep-70	170	Jan-73	2.34	24.0
Calvert Cliffs 1	429	May-75	Dec-71	210	Jun-73	1.50	58.0
Calvert Cliffs 1	429	May-75	Mar-72	210	Oct-73	1.59	63.0
Calvert Cliffs 1	429	May-75	Jun-72	250	Oct-73	1.33	70.0
Calvert Cliffs 1	429	May-75	Sep-72	250	Feb-74	1.42	72.0
Fitzpatrick	419	Jul-75	Mar-68	224	May-73	5.17	1.0
Fitzpatrick	419	Jul-75	Jun-72	301	Oct-73	1.33	71.0
Fitzpatrick	419	Jul-75	Jun-73	301	Jun-74	1.00	91.0
Cook 1	538	Aug-75	Dec-67	235	Apr-72	4.33	NA

Completed Plants (APCOMP3, Myopia 44)

Unit Name	Actuals Cost	Actuals COD	Date of Estimate	Estimates Total Cost	Estimates COD	Est. Years to COD	% Complete
Cook 1	538	Aug-75	Jun-69	235	Sep-72	3.25	1.0
Cook 1	538	Aug-75	Sep-70	339	Mar-73	2.50	19.0
Cook 1	538	Aug-75	Jun-71	356	Mar-73	1.75	40.0
Cook 1	538	Aug-75	Sep-71	356	Oct-73	2.08	44.0
Cook 1	538	Aug-75	Jun-72	416	Oct-73	1.33	50.5
Cook 1	538	Aug-75	Dec-72	427	Jun-74	1.50	58.0
Cook 1	538	Aug-75	Jun-73	427	Oct-74	1.33	70.5
Cook 1	538	Aug-75	Dec-73	427	Apr-75	1.33	73.4
Brunswick 2	382	Nov-75	Dec-70	195	Mar-74	3.25	10.0
Brunswick 2	382	Nov-75	Dec-71	210	Mar-74	2.25	46.0
Brunswick 2	382	Nov-75	Dec-72	256	Dec-74	2.00	78.0
Brunswick 2	382	Nov-75	Sep-73	309	Dec-74	1.25	79.0
Brunswick 2	382	Nov-75	Dec-73	339	Jan-75	1.08	88.0
Hatch 1	390	Dec-75	Jun-68	160	Jun-73	5.00	0.0
Hatch 1	390	Dec-75	Mar-69	151	Jun-73	4.25	1.5
Hatch 1	390	Dec-75	Mar-70	185	Jun-73	3.25	5.0
Hatch 1	390	Dec-75	Jun-70	184	Jun-73	3.00	7.5
Hatch 1	390	Dec-75	Sep-70	184	Apr-73	2.58	10.0
Hatch 1	390	Dec-75	Sep-72	184	Mar-74	1.49	63.0
Hatch 1	390	Dec-75	Dec-72	282	Apr-74	1.33	69.0
Millstone 2	418	Dec-75	Dec-67	150	Apr-74	6.33	0.0
Millstone 2	418	Dec-75	Mar-68	146	Apr-74	6.08	0.0
Millstone 2	418	Dec-75	Dec-68	179	Apr-74	5.33	0.0
Millstone 2	418	Dec-75	Dec-69	183	Apr-74	4.33	0.0
Millstone 2	418	Dec-75	Dec-70	239	Apr-74	3.33	10.0
Millstone 2	418	Dec-75	Sep-71	252	Apr-74	2.58	24.0
Millstone 2	418	Dec-75	Sep-72	282	Apr-74	1.58	49.0
Millstone 2	418	Dec-75	Mar-73	341	Dec-74	1.75	60.0
Millstone 2	418	Dec-75	Dec-73	380	May-75	1.41	69.0
Trojan	452	Dec-75	Dec-68	196	Sep-74	5.75	0.0
Trojan	452	Dec-75	Mar-69	197	Sep-74	5.50	0.0
Trojan	452	Dec-75	Dec-69	227	Sep-74	4.75	0.0
Trojan	452	Dec-75	Mar-71	228	Sep-74	3.50	3.6
Trojan	452	Dec-75	Mar-72	233	Sep-74	2.50	30.0
Trojan	452	Dec-75	Sep-72	243	Sep-74	2.00	52.0
Trojan	452	Dec-75	Dec-72	284	Jul-75	2.58	57.0
Trojan	452	Dec-75	Sep-73	334	Jul-75	1.83	72.0
Trojan	452	Dec-75	Sep-74	366	Oct-75	1.08	84.0
St. Lucie 1	470	Jun-76	Jun-69	123	Jun-73	4.00	1
St. Lucie 1	470	Jun-76	Sep-69	123	May-73	3.66	1
St. Lucie 1	470	Jun-76	Dec-70	200	Jun-74	3.50	9
St. Lucie 1	470	Jun-76	Jun-71	203	Jun-74	3.00	12
St. Lucie 1	470	Jun-76	Dec-71	218	Jun-74	2.50	17
St. Lucie 1	470	Jun-76	Mar-72	235	Jun-74	2.25	23
St. Lucie 1	470	Jun-76	Jun-72	269	May-75	2.91	25
St. Lucie 1	470	Jun-76	Dec-72	318	May-75	2.41	45
St. Lucie 1	470	Jun-76	Mar-73	318	Jun-75	2.25	48
St. Lucie 1	470	Jun-76	Dec-73	318	Dec-75	2.00	68
St. Lucie 1	470	Jun-76	Jun-74	366	Dec-75	1.50	76.9
St. Lucie 1	470	Jun-76	Dec-74	401	Dec-75	1.00	86

Completed Plants (APCOMP3, Myopia 44)

	Actuals			Estimates			
Unit Name	Cost	COD	Date of Estimate	Total Cost	COD	Est. Years to COD	% Complete
Indian Point 3	570	Aug-76	Sep-67	154	Jul-71	3.83	NA
Indian Point 3	570	Aug-76	Sep-68	156	Jul-71	2.83	NA
Indian Point 3	570	Aug-76	Sep-69	156	Jul-72	2.83	NA
Indian Point 3	570	Aug-76	Sep-70	218	Jul-73	2.83	NA
Indian Point 3	570	Aug-76	Mar-71	256	Jul-73	2.34	NA
Indian Point 3	570	Aug-76	Mar-73	317	Jul-74	1.33	82.0
Indian Point 3	570	Aug-76	Sep-73	400	Oct-74	1.08	85.0
Beaver Valley 1	599	Oct-76	Dec-67	150	Jul-73	5.58	0.0
Beaver Valley 1	599	Oct-76	Mar-68	150	Jun-73	5.25	0.0
Beaver Valley 1	599	Oct-76	Mar-69	189	Jun-73	4.25	0.0
Beaver Valley 1	599	Oct-76	Dec-69	192	Jun-73	3.50	0.5
Beaver Valley 1	599	Oct-76	Sep-70	219	Jun-73	2.75	5.0
Beaver Valley 1	599	Oct-76	Jun-71	219	Dec-73	2.50	23.0
Beaver Valley 1	599	Oct-76	Sep-71	286	Dec-73	2.25	28.0
Beaver Valley 1	599	Oct-76	Dec-71	286	Jun-74	2.50	30.0
Beaver Valley 1	599	Oct-76	Mar-72	309	Oct-74	2.58	35.0
Beaver Valley 1	599	Oct-76	Jun-72	311	Oct-74	2.33	38.0
Beaver Valley 1	599	Oct-76	Sep-72	342	Oct-74	2.08	51.0
Beaver Valley 1	599	Oct-76	Dec-72	340	Oct-74	1.83	58.0
Beaver Valley 1	599	Oct-76	Mar-73	340	May-75	2.17	63.0
Beaver Valley 1	599	Oct-76	Sep-73	409	May-75	1.66	69.0
Beaver Valley 1	599	Oct-76	Mar-74	419	May-75	1.17	85.0
Beaver Valley 1	599	Oct-76	Jun-74	419	Jun-75	1.00	92.0
Beaver Valley 1	599	Oct-76	Sep-74	451	Oct-75	1.08	94.0
Beaver Valley 1	599	Oct-76	Dec-74	451	Dec-75	1.00	94.0
Browns Ferry 3	301	Mar-77	Mar-68	124	Oct-70	2.58	12.0
Browns Ferry 3	301	Mar-77	Jun-69	149	Oct-70	1.33	26.0
Browns Ferry 3	301	Mar-77	Sep-69	149	Oct-71	2.08	31.0
Browns Ferry 3	301	Mar-77	Jun-70	149	Apr-72	1.83	43.0
Browns Ferry 3	301	Mar-77	Sep-70	149	Oct-73	3.08	NA
Browns Ferry 3	301	Mar-77	Mar-71	149	Jan-74	2.84	
Browns Ferry 3	301	Mar-77	Sep-71	149	Feb-74	2.42	
Browns Ferry 3	301	Mar-77	Aug-72	149	Aug-74	2.00	
Browns Ferry 3	301	Mar-77	Sep-72	149	Oct-74	2.08	
Browns Ferry 3	301	Mar-77	Mar-73	149	Dec-74	1.75	
Browns Ferry 3	301	Mar-77	Sep-73	149	Apr-75	1.58	
Browns Ferry 3	301	Mar-77	Mar-74	149	Sep-75	1.50	
Browns Ferry 3	301	Mar-77	Dec-74	149	Jan-76	1.08	
Browns Ferry 3	301	Mar-77	Jun-75	246	Jun-76	1.00	
Brunswick 1	318	Mar-77	Dec-70	194	Mar-76	5.25	4.0
Brunswick 1	318	Mar-77	Jun-71	182	Mar-75	3.75	17.0
Brunswick 1	318	Mar-77	Dec-71	181	Mar-75	3.25	30.0
Brunswick 1	318	Mar-77	Dec-72	214	Dec-75	3.00	42.0
Brunswick 1	318	Mar-77	Sep-73	251	Dec-75	2.25	50.0
Brunswick 1	318	Mar-77	Dec-73	269	Dec-75	2.00	56.0
Brunswick 1	318	Mar-77	Dec-74	281	Mar-76	1.25	71.0
Brunswick 1	318	Mar-77	Mar-75	281	Jun-76	1.25	75.0
Brunswick 1	318	Mar-77	Jun-75	328	Mar-77	1.75	77.0
Brunswick 1	318	Mar-77	Dec-75	329	Mar-77	1.25	86.0
Crystal River 3	366	Mar-77	Mar-67	110	Apr-72	5.09	0.0

Completed Plants (APCOMP3, Myopia 44)

Unit Name	Actuals Cost	Actuals COD	Date of Estimate	Estimates Total Cost	Estimates COD	Est. Years to COD	% Complete
Crystal River 3	366	Mar-77	Jun-68	113	Apr-72	3.83	0.0
Crystal River 3	366	Mar-77	Jun-69	148	Apr-72	2.83	2.0
Crystal River 3	366	Mar-77	Sep-71	190	Sep-73	2.00	37.0
Crystal River 3	366	Mar-77	Dec-72	283	Nov-74	1.92	63.5
Crystal River 3	366	Mar-77	Jun-73	283	Dec-74	1.50	70.0
Crystal River 3	366	Mar-77	Mar-74	283	Mar-75	1.00	91.0
Crystal River 3	366	Mar-77	Dec-74	375	Sep-76	1.75	95.0
Crystal River 3	366	Mar-77	Jun-75	420	Sep-76	1.25	95.0
Calvert Cliffs 2	335	Apr-77	Jun-67	105	Jan-74	6.59	0.0
Calvert Cliffs 2	335	Apr-77	Dec-67	107	Jan-74	6.09	0.0
Calvert Cliffs 2	335	Apr-77	Mar-68	106	Jan-74	5.84	0.0
Calvert Cliffs 2	335	Apr-77	Mar-69	105	Jan-74	4.84	2.0
Calvert Cliffs 2	335	Apr-77	Sep-70	128	Jan-74	3.33	21.0
Calvert Cliffs 2	335	Apr-77	Dec-71	168	Jan-74	2.09	46.0
Calvert Cliffs 2	335	Apr-77	Mar-72	168	Jun-74	2.25	47.0
Calvert Cliffs 2	335	Apr-77	Jun-72	204	Jun-74	2.00	54.0
Calvert Cliffs 2	335	Apr-77	Sep-72	204	Jan-75	2.33	56.0
Calvert Cliffs 2	335	Apr-77	Mar-73	204	Feb-75	1.92	67.0
Calvert Cliffs 2	335	Apr-77	Sep-73	243	Jun-75	1.75	73.0
Calvert Cliffs 2	335	Apr-77	Dec-73	243	Aug-75	1.66	79.0
Calvert Cliffs 2	335	Apr-77	Mar-74	273	Sep-75	1.50	75.0
Calvert Cliffs 2	335	Apr-77	Jun-74	273	Dec-75	1.50	73.0
Calvert Cliffs 2	335	Apr-77	Sep-74	256	Jan-77	2.34	71.9
Calvert Cliffs 2	335	Apr-77	Mar-75	253	Jan-77	1.84	80.6
Calvert Cliffs 2	335	Apr-77	Dec-75	251	Jan-77	1.09	92.1
Salem 1	850	Jun-77	Sep-66	139	May-71	4.70	0.0
Salem 1	850	Jun-77	Mar-67	139	May-71	4.17	0.0
Salem 1	850	Jun-77	Jun-67	149	May-71	3.92	0.0
Salem 1	850	Jun-77	Sep-67	152	Dec-71	4.25	0.0
Salem 1	850	Jun-77	Dec-67	152	Mar-72	4.25	0.0
Salem 1	850	Jun-77	Mar-70	237	Dec-72	2.75	20.0
Salem 1	850	Jun-77	Dec-70	237	Apr-73	2.33	33.0
Salem 1	850	Jun-77	Jun-71	237	Dec-73	2.50	40.0
Salem 1	850	Jun-77	Sep-71	308	Oct-74	3.08	43.0
Salem 1	850	Jun-77	Mar-72	336	Oct-74	2.58	50.0
Salem 1	850	Jun-77	Dec-72	425	Mar-75	2.25	53.0
Salem 1	850	Jun-77	Dec-73	497	Sep-75	1.75	67.0
Salem 1	850	Jun-77	Sep-74	678	Dec-76	2.25	88.3
Salem 1	850	Jun-77	Mar-75	678	Sep-76	1.51	90.5
Davis-Besse 1	558	Nov-77	Dec-68	180	Dec-74	6.00	0.0
Davis-Besse 1	558	Nov-77	Sep-69	201	Dec-74	5.25	0.0
Davis-Besse 1	558	Nov-77	Sep-70	266	Dec-74	4.25	2.0
Davis-Besse 1	558	Nov-77	Jun-72	304	Dec-74	2.50	22.0
Davis-Besse 1	558	Nov-77	Dec-72	349	May-75	2.41	40.0
Davis-Besse 1	558	Nov-77	Sep-73	409	Feb-76	2.42	59.0
Davis-Besse 1	558	Nov-77	Sep-74	434	Jun-76	1.75	72.5
Davis-Besse 1	558	Nov-77	Mar-75	434	Sep-76	1.51	82.3
Davis-Besse 1	558	Nov-77	Jun-75	461	Sep-76	1.25	88.2
Davis-Besse 1	558	Nov-77	Dec-75	533	Mar-77	1.25	95.0
Farley 1	727	Dec-77	Sep-69	164	Apr-75	5.58	0.0

Completed Plants (APCOMP3, Myopia 44)

Unit Name	Actuals Cost	Actuals COD	Date of Estimate	Estimates Total Cost	Estimates COD	Est. Years to COD	% Complete
Farley 1	727	Dec-77	Jun-70	203	Apr-75	4.83	0.0
Farley 1	727	Dec-77	Sep-71	259	Apr-75	3.58	6.0
Farley 1	727	Dec-77	Mar-73	294	Apr-75	2.08	35.5
Farley 1	727	Dec-77	Jun-73	294	Dec-75	2.50	42.3
Farley 1	727	Dec-77	Dec-73	395	Dec-75	2.00	62.7
Farley 1	727	Dec-77	Jun-74	415	Feb-76	1.67	75.0
Farley 1	727	Dec-77	Sep-74	456	Feb-76	1.42	79.2
Farley 1	727	Dec-77	Dec-74	456	Jul-76	1.58	81.0
Farley 1	727	Dec-77	Jun-75	487	Oct-76	1.34	86.0
Farley 1	727	Dec-77	Dec-75	589	Jun-77	1.50	90.0
Farley 1	727	Dec-77	Jun-76	614	Jun-77	1.00	91.0
North Anna 1	782	Jun-78	Mar-69	185	Mar-74	5.00	0.0
North Anna 1	782	Jun-78	Dec-69	281	Mar-74	4.25	1.1
North Anna 1	782	Jun-78	Jun-71	308	Mar-74	2.75	29.0
North Anna 1	782	Jun-78	Sep-71	310	Jun-74	2.75	33.0
North Anna 1	782	Jun-78	Dec-71	344	Jun-74	2.50	34.0
North Anna 1	782	Jun-78	Mar-72	344	Dec-74	2.75	43.2
North Anna 1	782	Jun-78	Sep-72	360	Dec-74	2.25	49.0
North Anna 1	782	Jun-78	Dec-72	407	Dec-74	2.00	55.0
North Anna 1	782	Jun-78	Mar-73	407	Apr-75	2.08	57.0
North Anna 1	782	Jun-78	Sep-73	407	Nov-75	2.17	65.4
North Anna 1	782	Jun-78	Dec-73	431	Nov-75	1.92	69.3
North Anna 1	782	Jun-78	Mar-74	446	May-76	2.17	72.0
North Anna 1	782	Jun-78	Dec-74	504	Jan-77	2.09	80.0
North Anna 1	782	Jun-78	Mar-75	536	Jan-77	1.84	78.2
North Anna 1	782	Jun-78	Dec-75	536	Apr-77	1.33	89.7
North Anna 1	782	Jun-78	Mar-76	567	Apr-77	1.08	88.8
Cook 2	444	Jul-78	Dec-67	235	Apr-72	4.33	NA
Cook 2	444	Jul-78	Jun-69	235	Sep-72	3.25	1.0
Cook 2	444	Jul-78	Sep-70	339	Mar-74	3.50	19.0
Cook 2	444	Jul-78	Sep-75	437	Apr-78	2.58	57.4
Cook 2	444	Jul-78	Dec-76	437	Jun-78	1.50	82.4
Three Mile I. 2	715	Dec-78	Aug-69	214	May-74	4.75	NA
Three Mile I. 2	715	Dec-78	Sep-70	285	May-74	3.66	NA
Three Mile I. 2	715	Dec-78	Sep-71	345	May-75	3.66	NA
Three Mile I. 2	715	Dec-78	Aug-72	465	May-76	3.75	25.0
Three Mile I. 2	715	Dec-78	Jun-73	525	May-77	3.92	27.0
Three Mile I. 2	715	Dec-78	Sep-74	580	May-78	3.66	60.0
Three Mile I. 2	715	Dec-78	Jun-75	630	May-78	2.92	68.0
Three Mile I. 2	715	Dec-78	Aug-76	637	May-78	1.75	81.0
Hatch 2	509	Sep-79	Jun-70	189	Apr-76	5.88	NA
Hatch 2	509	Sep-79	Dec-72	330	Apr-78	5.33	11.0
Hatch 2	509	Sep-79	Sep-73	404	Apr-78	4.58	15.0
Hatch 2	509	Sep-79	Sep-74	513	Apr-78	3.58	23.0
Hatch 2	509	Sep-79	Sep-75	513	Apr-79	3.58	32.0
Hatch 2	509	Sep-79	Jun-76	512	Apr-79	2.83	57.0
Arkansas 2	640	Mar-80	Dec-70	183	Oct-75	4.83	0.0
Arkansas 2	640	Mar-80	Jun-71	190	Oct-75	4.33	0.0
Arkansas 2	640	Mar-80	Dec-71	200	Oct-75	3.83	2.1
Arkansas 2	640	Mar-80	Sep-72	230	Oct-76	4.08	6.9

Completed Plants (APCOMP3, Myopia 44)

Unit Name	Actuals Cost	Actuals COD	Date of Estimate	Estimates Total Cost	Estimates COD	Est. Years to COD	% Complete
Arkansas 2	640	Mar-80	Jun-73	275	Oct-76	3.33	13.6
Arkansas 2	640	Mar-80	Sep-73	275	Dec-76	3.25	16.9
Arkansas 2	640	Mar-80	Dec-73	273	Dec-76	3.00	18.0
Arkansas 2	640	Mar-80	Mar-74	273	Feb-77	2.92	25.0
Arkansas 2	640	Mar-80	Jun-74	318	Feb-77	2.67	33.5
Arkansas 2	640	Mar-80	Sep-74	318	Jun-77	2.75	39.8
Arkansas 2	640	Mar-80	Mar-75	339	Jun-77	2.25	42.7
Arkansas 2	640	Mar-80	Jun-75	339	Oct-77	2.34	46.1
Arkansas 2	640	Mar-80	Sep-75	369	Jan-78	2.34	50.4
Arkansas 2	640	Mar-80	Dec-75	393	Mar-78	2.25	56.4
North Anna 2	532	Dec-80	Sep-70	184	Mar-75	4.50	NA
North Anna 2	532	Dec-80	Sep-71	191	Jun-75	3.75	7.8
North Anna 2	532	Dec-80	Dec-71	198	Jun-75	3.50	10.0
North Anna 2	532	Dec-80	Mar-72	198	Jul-75	3.33	16.3
North Anna 2	532	Dec-80	Sep-72	208	Jul-75	2.83	25.0
North Anna 2	532	Dec-80	Dec-72	227	Jul-75	2.58	28.2
North Anna 2	532	Dec-80	Mar-73	227	Oct-75	2.58	31.0
North Anna 2	532	Dec-80	Jun-73	227	Apr-76	2.83	39.3
North Anna 2	532	Dec-80	Sep-73	227	May-76	2.66	42.0
North Anna 2	532	Dec-80	Mar-74	240	Nov-76	2.67	47.5
North Anna 2	532	Dec-80	Dec-74	264	Sep-77	2.75	58.1
North Anna 2	532	Dec-80	Mar-75	301	Sep-77	2.51	54.1
North Anna 2	532	Dec-80	Dec-75	301	Nov-77	1.92	64.2
North Anna 2	532	Dec-80	Mar-76	311	Nov-77	1.67	67.0
North Anna 2	532	Dec-80	Sep-76	363	May-78	1.66	75.0
North Anna 2	532	Dec-80	Dec-76	381	Aug-78	1.66	76.3
North Anna 2	532	Dec-80	Mar-77	426	Aug-78	1.42	80.1
North Anna 2	532	Dec-80	Sep-77	426	Mar-79	1.49	86.6
North Anna 2	532	Dec-80	Mar-78	467	Mar-79	1.00	90.4
Farley 2	781	Jul-81	Sep-70	183	Apr-77	6.58	0.0
Farley 2	781	Jul-81	Sep-71	233	Apr-77	5.58	0.0
Farley 2	781	Jul-81	Mar-73	268	Apr-77	4.08	5.3
Farley 2	781	Jul-81	Jun-73	268	Jan-77	3.59	10.8
Farley 2	781	Jul-81	Dec-73	329	Jan-77	3.09	17.0
Farley 2	781	Jul-81	Jun-74	338	Jan-77	2.59	27.8
Farley 2	781	Jul-81	Sep-74	363	Jan-77	2.34	34.5
Farley 2	781	Jul-81	Dec-74	363	Jun-77	2.50	41.6
Farley 2	781	Jul-81	Jun-75	365	Sep-77	2.25	42.5
Farley 2	781	Jul-81	Dec-75	477	Apr-79	3.33	41.0
Farley 2	781	Jul-81	Sep-76	499	Apr-79	2.58	42.0
Farley 2	781	Jul-81	Dec-76	572	Apr-79	2.33	42.0
Farley 2	781	Jul-81	Mar-77	689	Apr-79	2.08	42.0
Farley 2	781	Jul-81	Jun-77	689	Apr-80	2.83	45.0
Farley 2	781	Jul-81	Dec-77	662	Apr-80	2.33	53.2
Farley 2	781	Jul-81	Mar-78	635	Apr-80	2.09	57.0
Farley 2	781	Jul-81	Sep-78	652	Apr-80	1.58	72.4
Farley 2	781	Jul-81	Jun-79	687	Sep-80	1.25	82.3
Farley 2	781	Jul-81	Sep-79	684	Sep-80	1.00	83.7
Sequoyah 1	984	Jul-81	Sep-68	161	Oct-73	5.08	0.0
Sequoyah 1	984	Jul-81	Sep-69	187	Oct-73	4.08	1.5

Completed Plants (APCOMP3, Myopia 44)

Unit Name	Actuals Cost	Actuals COD	Date of Estimate	Estimates Total Cost	Estimates COD	Est. Years to COD	% Complete
Sequoyah 1	984	Jul-81	Jun-70	187	Apr-74	3.83	5.0
Sequoyah 1	984	Jul-81	Mar-71	213	Apr-74	3.09	13.0
Sequoyah 1	984	Jul-81	Dec-71	213	Jul-74	2.58	25.0
Sequoyah 1	984	Jul-81	Jun-72	213	Nov-74	2.42	35.0
Sequoyah 1	984	Jul-81	Dec-72	225	Apr-75	2.33	45.0
Sequoyah 1	984	Jul-81	Jun-73	225	Dec-75	2.50	57.0
Sequoyah 1	984	Jul-81	Dec-73	225	Jun-76	2.50	63.0
Sequoyah 1	984	Jul-81	Mar-74	313	Jun-76	2.25	65.0
Sequoyah 1	984	Jul-81	Jun-74	313	Aug-76	2.17	67.0
Sequoyah 1	984	Jul-81	Sep-74	313	Jan-77	2.34	69.0
Sequoyah 1	984	Jul-81	Dec-74	324	Jan-77	2.09	65.0
Sequoyah 1	984	Jul-81	Sep-75	324	Sep-77	2.00	70.0
Sequoyah 1	984	Jul-81	Dec-75	364	Sep-77	1.75	70.0
Sequoyah 1	984	Jul-81	Jun-76	364	May-78	1.91	72.0
Sequoyah 1	984	Jul-81	Sep-76	475	May-78	1.66	80.0
Sequoyah 1	984	Jul-81	Mar-77	475	Sep-78	1.50	75.0
Sequoyah 1	984	Jul-81	Mar-78	535	Jul-79	1.33	86.0
Sequoyah 1	984	Jul-81	Sep-78	632	Oct-79	1.08	92.0
Sequoyah 1	984	Jul-81	Jun-79	632	Jun-80	1.00	98.0
Salem 2	820	Oct-81	Sep-67	128	May-73	5.66	0.0
Salem 2	820	Oct-81	Dec-67	128	Mar-73	5.25	0.0
Salem 2	820	Oct-81	Mar-70	237	Jul-73	3.33	NA
Salem 2	820	Oct-81	Mar-71	237	Apr-74	3.09	NA
Salem 2	820	Oct-81	Jun-71	237	Dec-74	3.50	NA
Salem 2	820	Oct-81	Sep-71	308	May-75	3.66	NA
Salem 2	820	Oct-81	Dec-72	425	Mar-76	3.25	NA
Salem 2	820	Oct-81	Dec-73	497	Sep-76	2.75	NA
Salem 2	820	Oct-81	Mar-74	496	Sep-76	2.51	41.0
Salem 2	820	Oct-81	Sep-74	496	May-79	4.66	48.1
Salem 2	820	Oct-81	Mar-78	619	May-79	1.17	90.6
McGuire 1	906	Dec-81	Sep-70	179	Nov-75	5.17	0.0
McGuire 1	906	Dec-81	Sep-71	220	Nov-75	4.17	0.0
McGuire 1	906	Dec-81	Dec-72	220	Mar-76	3.25	9.0
McGuire 1	906	Dec-81	Sep-73	220	Nov-76	3.17	22.2
McGuire 1	906	Dec-81	Jun-74	220	Apr-77	2.83	34.9
McGuire 1	906	Dec-81	Sep-74	365	Jan-78	3.33	36.9
McGuire 1	906	Dec-81	Dec-74	384	Jan-78	3.09	43.5
McGuire 1	906	Dec-81	Jun-76	384	May-78	1.91	74.2
McGuire 1	906	Dec-81	Dec-76	384	Feb-79	2.17	81.2
McGuire 1	906	Dec-81	Mar-77	466	Jan-79	1.84	75.6
McGuire 1	906	Dec-81	Sep-77	466	Jul-79	1.83	86.0
McGuire 1	906	Dec-81	Mar-78	549	Jul-79	1.33	86.0
McGuire 1	906	Dec-81	Dec-78	549	Feb-80	1.17	96.0
Sequoyah 2	623	Jun-82	Dec-68	161	Oct-73	4.83	0.0
Sequoyah 2	623	Jun-82	Sep-69	187	Oct-73	4.08	1.5
Sequoyah 2	623	Jun-82	Jun-70	187	Apr-74	3.83	5.0
Sequoyah 2	623	Jun-82	Sep-70	187	Dec-74	4.25	NA
Sequoyah 2	623	Jun-82	Dec-71	213	Mar-75	3.25	NA
Sequoyah 2	623	Jun-82	Jun-72	213	Jul-75	3.08	NA
Sequoyah 2	623	Jun-82	Dec-72	225	Dec-75	3.00	NA

Completed Plants (APCOMP3, Myopia 44)

Unit Name	Actuals Cost	Actuals COD	Date of Estimate	Estimates Total Cost	Estimates COD	Est. Years to COD	% Complete
Sequoyah 2	623	Jun-82	Jun-73	225	Aug-76	3.17	NA
Sequoyah 2	623	Jun-82	Dec-73	225	Feb-77	3.17	NA
Sequoyah 2	623	Jun-82	Jun-74	313	Apr-77	2.83	NA
Sequoyah 2	623	Jun-82	Sep-74	313	Sep-77	3.00	NA
Sequoyah 2	623	Jun-82	Sep-75	324	May-78	2.66	NA
Sequoyah 2	623	Jun-82	Jun-76	364	Jan-79	2.58	NA
Sequoyah 2	623	Jun-82	Mar-77	475	May-79	2.17	65.0
Sequoyah 2	623	Jun-82	Mar-78	535	Mar-80	2.00	74.0
Sequoyah 2	623	Jun-82	Sep-78	632	Jun-80	1.75	78.0
Sequoyah 2	623	Jun-82	Mar-79	632	Sep-80	1.51	80.0
Sequoyah 2	623	Jun-82	Sep-79	442	Jun-81	1.75	84.0
Sequoyah 2	623	Jun-82	Dec-80	1094	Jul-82	1.58	96.0
Lasalle 1	1336	Oct-82	Jun-70	360	Oct-75	5.33	0.0
Lasalle 1	1336	Oct-82	Sep-71	360	May-77	5.66	0.0
Lasalle 1	1336	Oct-82	Dec-71	360	Dec-77	6.00	0.0
Lasalle 1	1336	Oct-82	Sep-72	407	Dec-77	5.25	0.0
Lasalle 1	1336	Oct-82	Mar-73	407	May-78	5.17	0.0
Lasalle 1	1336	Oct-82	Jun-73	407	Oct-78	5.33	0.0
Lasalle 1	1336	Oct-82	Sep-73	430	Dec-78	5.25	0.0
Lasalle 1	1336	Oct-82	Dec-74	445	Dec-78	4.00	4.0
Lasalle 1	1336	Oct-82	Sep-75	498	Dec-78	3.25	19.0
Lasalle 1	1336	Oct-82	Sep-76	585	May-79	2.66	39.0
Lasalle 1	1336	Oct-82	Dec-76	585	Sep-79	2.75	45.0
Lasalle 1	1336	Oct-82	Sep-77	675	Sep-79	2.00	55.0
Lasalle 1	1336	Oct-82	Mar-79	808	Mar-80	1.00	86.0
Lasalle 1	1336	Oct-82	Jun-79	918	Dec-80	1.50	89.0
Lasalle 1	1336	Oct-82	Dec-79	1003	Dec-80	1.00	93.0
Lasalle 1	1336	Oct-82	Jun-80	1107	Jun-81	1.00	98.0
Lasalle 1	1336	Oct-82	Dec-80	1184	Apr-82	1.33	99.0
Susquehanna 1	?1947.0	Jun-83	Jun-69	150	27560	6.00	0.0
Susquehanna 1	1947	Jun-83	Sep-69	150	Jun-76	6.75	0.0
Susquehanna 1	1947	Jun-83	Dec-70	250	Jun-78	7.50	0.0
Susquehanna 1	1947	Jun-83	Jun-71	373	Jun-78	7.00	0.0
Susquehanna 1	1947	Jun-83	Dec-71	526	May-79	7.41	0.0
Susquehanna 1	1947	Jun-83	Mar-72	645	May-79	7.16	0.0
Susquehanna 1	1947	Jun-83	Dec-72	703	May-79	6.41	0.0
Susquehanna 1	1947	Jun-83	Sep-73	810	May-79	5.66	0.0
Susquehanna 1	1947	Jun-83	Sep-74	810	Nov-80	6.17	4.0
Susquehanna 1	1947	Jun-83	Dec-74	945	Nov-80	5.92	8.0
Susquehanna 1	1947	Jun-83	Mar-76	1047	Nov-80	4.67	24.0
Susquehanna 1	1947	Jun-83	Sep-76	1032	Nov-80	4.17	32.1
Susquehanna 1	1947	Jun-83	Dec-76	1032	Nov-80	3.92	39.6
Susquehanna 1	1947	Jun-83	Mar-77	1097	Nov-80	3.67	44.0
Susquehanna 1	1947	Jun-83	Mar-78	1195	Feb-81	2.92	61.0
Susquehanna 1	1947	Jun-83	Sep-78	1293	Feb-81	2.42	76.1
Susquehanna 1	1947	Jun-83	Jun-79	1285	Feb-81	1.67	87.9
Susquehanna 1	1947	Jun-83	Sep-79	1607	Jan-82	2.34	70.0
Susquehanna 1	1947	Jun-83	Sep-80	1841	Jan-82	1.33	87.0
Susquehanna 1	1947	Jun-83	Mar-81	2276	May-83	2.17	91.0
Susquehanna 1	1947	Jun-83	Dec-81	2292	May-83	1.41	92.0

Completed Plants (APCOMP3, Myopia 44)

Unit Name	Actuals Cost	Actuals COD	Date of Estimate	Estimates Total Cost	Estimates COD	Est. Years to COD	% Complete
San Onofre 2	2502	Aug-83	Mar-70	189	Jun-76	6.25	0.0
San Onofre 2	2502	Aug-83	Jun-70	213	Jun-76	6.00	0.0
San Onofre 2	2502	Aug-83	Sep-71	363	Jun-78	6.75	0.0
San Onofre 2	2502	Aug-83	Dec-71	409	Jun-78	6.50	0.0
San Onofre 2	2502	Aug-83	Jun-73	655	Jun-79	6.00	0.0
San Onofre 2	2502	Aug-83	Mar-74	655	Jun-79	5.25	0.0
San Onofre 2	2502	Aug-83	Dec-74	893	Jul-81	6.58	0.0
San Onofre 2	2502	Aug-83	Mar-75	1142	Jul-81	6.34	3.0
San Onofre 2	2502	Aug-83	Sep-75	1142	Oct-81	6.08	10.0
San Onofre 2	2502	Aug-83	Jun-76	1210	Oct-81	5.33	23.0
San Onofre 2	2502	Aug-83	Jun-77	1320	Oct-81	4.33	44.0
San Onofre 2	2502	Aug-83	Dec-79	1740	Oct-81	1.83	86.0
San Onofre 2	2502	Aug-83	Mar-80	1824	Dec-81	1.75	86.0
San Onofre 2	2502	Aug-83	Mar-81	2010	Jun-82	1.25	98.0
St. Lucie 2	1430	Aug-83	Dec-72	360	Oct-78	5.83	0
St. Lucie 2	1430	Aug-83	Mar-73	360	Dec-79	6.75	0
St. Lucie 2	1430	Aug-83	Mar-74	360	Dec-80	6.75	0
St. Lucie 2	1430	Aug-83	Jun-74	360	Dec-79	5.50	0
St. Lucie 2	1430	Aug-83	Dec-74	537	Dec-79	5.00	0
St. Lucie 2	1430	Aug-83	Sep-75	537	Dec-80	5.25	0
St. Lucie 2	1430	Aug-83	Dec-75	620	Dec-80	5.00	0
St. Lucie 2	1430	Aug-83	Sep-76	620	Dec-82	6.25	0.7
St. Lucie 2	1430	Aug-83	Dec-76	850	Dec-82	6.00	0.7
St. Lucie 2	1430	Aug-83	Jun-77	850	May-83	5.91	1
St. Lucie 2	1430	Aug-83	Sep-78	845	May-83	4.66	13
St. Lucie 2	1430	Aug-83	Dec-78	919	May-83	4.41	16.8
St. Lucie 2	1430	Aug-83	Jun-80	1100	May-83	2.91	45.1
Summer 1	1283	Jan-84	Mar-71	234	Jan-77	5.84	0.0
Summer 1	1283	Jan-84	Sep-72	297	Jan-77	4.33	0.0
Summer 1	1283	Jan-84	Jun-73	297	Jan-78	4.59	0.1
Summer 1	1283	Jan-84	Jun-74	355	Jan-78	3.59	2.5
Summer 1	1283	Jan-84	Dec-74	355	May-79	4.41	5.0
Summer 1	1283	Jan-84	Jun-76	493	May-79	2.91	33.0
Summer 1	1283	Jan-84	Dec-76	635	May-80	3.41	42.5
Summer 1	1283	Jan-84	Mar-78	675	May-80	2.17	67.0
Summer 1	1283	Jan-84	Sep-78	675	Dec-80	2.25	77.0
Summer 1	1283	Jan-84	Mar-79	756	Dec-80	1.75	82.4
Summer 1	1283	Jan-84	Mar-80	827	Jun-81	1.25	94.8
Summer 1	1283	Jan-84	Sep-80	827	Dec-81	1.25	95.9
Summer 1	1283	Jan-84	Dec-80	1032	Jun-82	1.50	96.7
Summer 1	1283	Jan-84	Jun-82	1174	Jun-83	1.00	100.0
Summer 1	1283	Jan-84	Sep-82	1174	Oct-83	1.08	100.0

Incomplete Bechtel Plants

Unit Name	Date of Estimate	Estimates: Total Cost	Estimates: COD	Est. Years to COD	% Complete
Callaway 1	Jun-74	839	Oct-81	7.33	0
Callaway 1	Dec-74	895	Oct-81	6.83	0
Callaway 1	Mar-76	780	Oct-81	5.58	1
Callaway 1	Dec-76	1088	Jun-82	5.50	2.7
Callaway 1	Jun-77	1088	Oct-82	5.33	6.9
Callaway 1	Dec-77	1122	Oct-82	4.83	11.2
Callaway 1	Mar-80	1261	Oct-82	2.58	64
Callaway 1	Dec-80	1533	Apr-83	2.33	74.6
Callaway 1	Sep-81	2100	Jan-84	2.33	75.5
Callaway 1	Sep-82	2850	Dec-84	2.25	84.5
Callaway 1	Dec-82	2850	Jun-85	2.50	86
Grand Gulf 1	Jun-72	600	Dec-78	6.50	0
Grand Gulf 1	Dec-72	656	Jun-79	6.50	0
Grand Gulf 1	Mar-73	656	Sep-79	6.50	0
Grand Gulf 1	Jun-73	656	Jun-79	6.00	0
Grand Gulf 1	Sep-73	656	Sep-79	6.00	0
Grand Gulf 1	Sep-75	689	Sep-79	4.00	11
Grand Gulf 1	Jun-76	689	Jun-80	4.00	25.9
Grand Gulf 1	Sep-76	935	Jun-80	3.75	32.5
Grand Gulf 1	Jun-77	935	Apr-81	3.83	48
Grand Gulf 1	Dec-77	1174	Apr-81	3.33	57.9
Grand Gulf 1	Mar-79	1203	Apr-81	2.08	77.4
Grand Gulf 1	Dec-79	1203	Apr-82	2.33	80
Grand Gulf 1	Dec-81	2391	Feb-83	1.17	96
Grand Gulf 1	Jun-82	2859	NA	NA	99
Grand Gulf 1	Sep-82	2859	Dec-83	1.25	99
Grand Gulf 2	Sep-73	571	Sep-81	8.00	NA
Grand Gulf 2	Sep-75	NA	Sep-83	8.00	1.6
Grand Gulf 2	Dec-75	699	Sep-83	7.75	6.5
Grand Gulf 2	Sep-76	775	Sep-83	7.00	6.5
Grand Gulf 2	Jun-77	775	Jan-84	6.58	1.7
Grand Gulf 2	Dec-77	954	Jan-84	6.08	2.4
Grand Gulf 2	Jun-79	878	Jan-84	4.58	11.6
Grand Gulf 2	Dec-79	878	Apr-85	5.33	23
Grand Gulf 2	Jun-80	878	Apr-86	5.83	23
Hope Creek 1	Mar-70	574	Mar-75	5.00	0
Hope Creek 1	Dec-71	1039	May-78	6.42	0
Hope Creek 1	Dec-72	1139	May-79	6.42	0
Hope Creek 1	Jun-73	1139	May-81	7.92	0
Hope Creek 1	Dec-73	1461	May-81	7.42	0
Hope Creek 1	Sep-74	1972	Dec-81	7.25	0
Hope Creek 1	Mar-75	1972	Dec-82	7.75	0
Hope Creek 1	Jun-75	2435	Jun-83	8.00	0
Hope Creek 1	Sep-75	1972	Dec-82	7.25	0
Hope Creek 1	Dec-75	2435	Dec-82	7.00	0
Hope Creek 1	Sep-76	2580	May-84	7.67	2
Hope Creek 1	Mar-78	2580	May-84	6.17	6
Hope Creek 1	Jun-78	2890	May-84	5.92	8.5
Hope Creek 1	Sep-79	3585	May-85	5.67	18.5
Hope Creek 1	Jun-80	4310	Dec-86	6.50	23.5
Hope Creek 1	Sep-80	4595	Dec-86	6.25	24
	Jun-81	5465	Dec-86	5.50	30.5

Incomplete Bechtel Plants

Unit Name	Date of Estimate	Estimates: Total Cost	Estimates: COD	Est. Years to COD	% Complete
Hope Creek 1	Sep-81	5512	Dec-86	5.25	33.3
Hope Creek 1	Mar-82	3518	Dec-86	4.75	46
Hope Creek 1	Sep-82	3521	Dec-86	4.25	55.6
Hope Creek 1	Dec-82	3780	Dec-86	4.00	60.6
Limerick 1	Mar-70	252	Mar-75	5.00	0
Limerick 1	Dec-70	414	Mar-75	4.25	1
Limerick 1	Jun-71	414	Sep-75	4.25	1
Limerick 1	Dec-71	414	Nov-76	4.92	1
Limerick 1	Sep-72	414	Aug-78	5.92	1
Limerick 1	Dec-72	694	Aug-78	5.67	1
Limerick 1	Jun-73	694	Apr-79	5.83	1
Limerick 1	Mar-74	694	Oct-79	5.58	1
Limerick 1	Sep-74	1212	Apr-81	6.58	2
Limerick 1	Dec-75	1212	Feb-81	5.17	18.5
Limerick 1	Jun-76	1212	Apr-83	6.83	28.6
Limerick 1	Jun-77	1635	Apr-83	5.83	32
Limerick 1	Jun-79	1695	Apr-93	3.83	52
Limerick 1	Dec-80	2515	Apr-85	4.33	57.6
Limerick 1	Jun-81	2566	Apr-85	3.83	65
Limerick 1	Sep-82	2566	Jan-84	1.33	93.9
Limerick 1	Dec-82	2657	Apr-85	2.33	83.1
Limerick 2	Mar-70	223	Mar-77	7.00	0
Limerick 2	Dec-70	303	Mar-77	6.25	0
Limerick 2	Dec-71	303	Nov-77	5.92	1
Limerick 2	Sep-72	303	Jan-80	7.33	1
Limerick 2	Dec-72	512	Jan-80	7.08	1
Limerick 2	Jun-73	512	Jun-80	7.00	1
Limerick 2	Mar-73	512	Mar-81	8.00	1
Limerick 2	Sep-73	539	Apr-82	8.58	1
Limerick 2	Mar-74	539	Apr-82	8.08	4
Limerick 2	Dec-74	539	Jul-82	7.58	8
Limerick 2	Jun-76	539	Apr-85	8.83	15.3
Limerick 2	Jun-77	949	Apr-85	7.83	22
Limerick 2	Jun-79	909	Apr-85	5.83	35
Limerick 2	Dec-80	1581	Oct-87	6.83	26.6
Limerick 2	Jun-81	1626	Oct-87	6.33	28.4
Limerick 2	Dec-82	3126	Oct-88	5.83	30
Midland 1	Jun-68	NA	Feb-74	5.67	0
Midland 1	Sep-70	NA	Nov-74	4.17	1
Midland 1	Dec-70	NA	Mar-76	5.25	2
Midland 1	Jun-71	NA	Sep-76	5.25	2
Midland 1	Sep-71	NA	May-77	5.67	2
Midland 1	Dec-71	277	May-77	5.42	2
Midland 1	Dec-72	383	Feb-79	6.17	2
Midland 1	Jun-73	385	Mar-80	6.75	2
Midland 1	Dec-73	470	Mar-80	6.25	2.6
Midland 1	Dec-74	470	Mar-82	7.25	9.1
Midland 1	Mar-75	700	Mar-82	7.00	9.1
Midland 1	Jun-76	700	Mar-82	5.75	13
Midland 1	Mar-82	1695	Jul-84	2.33	74
Midland 2	Mar-68	NA	Feb-75	6.92	0
[illegible]	Sep-70	NA	Nov-75	5.17	0.5

Incomplete Bechtel Plants

Unit Name	Date of Estimate	Estimates: Total Cost	Estimates: COD	Est. Years to COD	% Complete
Midland 2	Dec-70	NA	Mar-77	6.25	2
Midland 2	Jun-71	NA	Sep-77	6.25	2
Midland 2	Sep-71	NA	May-78	6.67	2
Midland 2	Dec-71	277	May-78	6.42	2
Midland 2	Dec-72	383	Feb-80	7.17	2
Midland 2	Jun-73	385	Mar-79	5.75	2
Midland 2	Dec-73	470	Mar-79	5.25	2.6
Midland 2	Dec-74	470	Mar-81	6.25	9.1
Midland 2	Mar-75	700	Mar-81	6.00	9.1
Midland 2	Jun-76	700	Mar-81	4.75	16
Midland 2	Sep-82	1695	Dec-83	1.25	84
Palo Verde 1	Jun-74	606	May-81	6.92	0
Palo Verde 1	Sep-74	613	May-81	6.67	0
Palo Verde 1	Mar-75	1000	May-82	7.17	0
Palo Verde 1	Dec-75	975	May-82	6.42	0
Palo Verde 1	Dec-77	969	May-82	4.42	21.9
Palo Verde 1	Mar-78	1263	May-82	4.17	24.6
Palo Verde 1	Sep-78	760	May-82	3.67	28.5
Palo Verde 1	Mar-79	911	May-83	4.17	43
Palo Verde 1	Dec-79	938	May-83	3.42	55.7
Palo Verde 1	Mar-80	1354	May-83	3.17	62.3
Palo Verde 1	Jun-80	1429	May-83	2.92	68.3
Palo Verde 1	Sep-80	1457	May-83	2.67	74.3
Palo Verde 1	Mar-81	1453	May-83	2.17	83.8
Palo Verde 1	Dec-81	1579	May-83	1.42	92.8
Palo Verde 1	Mar-82	1670	May-83	1.17	96.5
Palo Verde 1	Mar-83	1671	May-84	1.17	99.3
Palo Verde 2	Sep-74	586	Nov-82	8.17	0
Palo Verde 2	Mar-75	827	May-84	9.17	0
Palo Verde 2	Dec-75	845	May-84	8.42	0
Palo Verde 2	Mar-78	769	May-84	6.17	7.3
Palo Verde 2	Sep-78	598	May-84	5.67	7.8
Palo Verde 2	Jun-79	710	May-84	4.92	17.6
Palo Verde 2	Dec-79	571	May-84	4.42	26.1
Palo Verde 2	Mar-80	827	May-84	4.17	31.6
Palo Verde 2	Jun-80	820	May-84	3.92	37.7
Palo Verde 2	Sep-80	948	May-84	3.67	43.9
Palo Verde 2	Mar-81	1016	May-84	3.17	55.5
Palo Verde 2	Sep-81	1075	May-84	2.67	68.5
Palo Verde 2	Mar-82	1136	May-84	2.17	82.6
Palo Verde 2	Mar-83	1136	Feb-85	1.92	96.9
Palo Verde 2	Jun-83	1136	Sep-85	2.25	97.9
Palo Verde 3	Sep-74	605	May-84	9.67	0
Palo Verde 3	Mar-75	941	May-86	11.17	0
Palo Verde 3	Dec-75	950	May-86	10.42	0
Palo Verde 3	Dec-76	950	Jun-86	9.50	0
Palo Verde 3	Mar-78	834	Jun-86	8.25	0.9
Palo Verde 3	Sep-78	702	Jun-86	7.75	0.5
Palo Verde 3	Jun-79	833	Jun-86	7.00	1.5
Palo Verde 3	Dec-79	746	Jun-86	6.50	4.5
Palo Verde 3	Mar-80	1088	May-86	6.17	7.6
[illegible]	[illegible]	[illegible]	Jun-86	6.00	10.8

Incomplete Bechtel Plants

Unit Name	Date of Estimate	Estimates Total Cost	COD	Est. Years to COD	% Complete
Palo Verde 3	Sep-80	1212	Jun-86	5.75	12.9
Palo Verde 3	Mar-81	1255	Jun-86	5.25	18.6
Palo Verde 3	Sep-81	1227	Jun-86	4.75	26
Palo Verde 3	Mar-82	1467	May-86	4.17	36.7
Palo Verde 3	Dec-82	2474	May-86	3.42	52.5
Palo Verde 3	Mar-83	1487	May-86	3.17	61.7
Palo Verde 3	Jun-83	1487	Dec-86	3.50	70.8
San Onofre 3	Mar-70	189	Jun-76	6.25	0
San Onofre 3	Jun-70	213	Jun-76	6.00	0
San Onofre 3	Dec-71	409	NA	NA	0
San Onofre 3	Jun-73	655	NA	NA	0
San Onofre 3	Mar-74	655	Jun-80	6.25	0
San Onofre 3	Sep-74	655	Jun-81	6.75	0
San Onofre 3	Dec-74	812	Oct-82	7.83	0
San Onofre 3	Jun-75	934	Oct-82	7.33	1
San Onofre 3	Sep-75	934	Jan-83	7.33	3
San Onofre 3	Jun-76	990	Jan-83	6.58	17
San Onofre 3	Dec-76	996	Jan-83	6.08	20
San Onofre 3	Mar-77	990	Jan-83	5.83	24
San Onofre 3	Jun-77	1080	Jan-83	5.58	30
San Onofre 3	Dec-79	1160	Jan-83	3.08	63
San Onofre 3	Mar-80	1216	Jan-83	2.83	60
San Onofre 3	Sep-80	1216	Feb-83	2.42	66
San Onofre 3	Mar-81	1340	Jul-83	2.33	74
San Onofre 3	Mar-82	1415	Jul-83	1.33	86
San Onofre 3	Jun-82	1477	Sep-83	1.25	89
San Onofre 3	Sep-82	1668	Sep-83	1.00	91
San Onofre 3	Dec-82	1668	May-83	0.42	97
San Onofre 3	Mar-83	1668	Jan-84	0.83	92
Skagit 1	Mar-74	900	Jul-81	7.33	0
Skagit 1	Dec-74	900	Jul-82	7.58	0
Skagit 1	Mar-75	668	Jul-82	7.33	0
Skagit 1	Jun-75	984	Jul-82	7.08	0
Skagit 1	Dec-75	984	Jul-83	7.58	0
Skagit 1	Dec-76	1238	Jul-84	7.58	0
Skagit 1	Sep-77	1601	Mar-85	7.50	0
Skagit 1	Sep-78	1793	Sep-86	8.00	0
Skagit 1	Dec-78	1896	Sep-86	7.75	0
Skagit 1	Jun-79	2072	Jan-87	7.58	0
Skagit 1	Mar-81	4249	Jan-91	9.83	0
Skagit 2	Mar-75	561	Jul-85	10.33	0
Skagit 2	Jun-75	714	Jul-85	10.08	0
Skagit 2	Mar-76	714	Jul-86	10.33	0
Skagit 2	Sep-76	870	Jul-86	9.83	0
Skagit 2	Dec-77	1323	Mar-87	9.25	0
Skagit 2	Jun-78	1418	Sep-88	10.25	0
Skagit 2	Dec-78	1617	Sep-88	9.75	0
Skagit 2	Jun-79	1755	Jan-89	9.58	0
Skagit 2	Mar-81	3560	Jan-93	11.83	0
South Texas 1	Jun-75	574	Oct-80	5.33	NA
South Texas 1	Sep-75	676	Oct-80	5.08	0
South Texas 1	Mar-79	1004	Apr-82	3.08	44

Incomplete Bechtel Plants

Unit Name	Date of Estimate	Estimates: Total Cost	Estimates: COD	Est. Years to COD	% Complete
South Texas 1	Sep-79	1208	Feb-84	4.42	48.3
South Texas 1	Dec-81	1786	Feb-84	2.17	50
South Texas 2	Jun-75	574	Mar-82	6.75	NA
South Texas 2	Sep-75	676	Mar-82	6.50	0
South Texas 2	Mar-79	1004	Apr-83	4.08	12
South Texas 2	Sep-79	1208	Feb-86	6.42	15
South Texas 2	Dec-81	1717	Feb-86	4.17	18
Susquehanna 2	Mar-74	575	Jun-81	7.25	1
Susquehanna 2	Sep-74	575	Jun-82	7.75	1
Susquehanna 2	Dec-74	602	May-82	7.42	6
Susquehanna 2	Mar-75	662	May-82	7.17	1.8
Susquehanna 2	Jun-75	700	May-82	6.92	2
Susquehanna 2	Dec-75	689	May-82	6.42	6
Susquehanna 2	Mar-76	678	May-82	6.17	7
Susquehanna 2	Sep-76	706	May-82	5.67	21.2
Susquehanna 2	Mar-77	713	May-82	5.17	30
Susquehanna 2	Sep-77	710	May-82	4.67	35.9
Susquehanna 2	Mar-78	735	May-82	4.17	44.2
Susquehanna 2	Sep-78	787	May-82	3.67	51.7
Susquehanna 2	Jun-79	843	May-82	2.92	53.6
Susquehanna 2	Sep-79	1081	Jan-83	3.33	45
Susquehanna 2	Dec-79	1082	Jan-83	3.08	46
Susquehanna 2	Jun-80	1082	Aug-82	2.17	53
Susquehanna 2	Sep-80	1153	Aug-82	1.92	55
Susquehanna 2	Mar-81	1217	May-84	3.17	59
Susquehanna 2	Dec-81	1578	Nov-84	2.92	65
Susquehanna 2	Jun-82	1598	Nov-84	2.42	68
Vogtle 1	Sep-71	NA	Apr-78	6.58	0
Vogtle 1	Jun-72	NA	Apr-79	6.83	0
Vogtle 1	Sep-72	NA	Oct-79	7.08	0
Vogtle 1	Dec-72	570	Apr-80	7.33	0
Vogtle 1	Sep-73	630	Apr-80	6.58	0
Vogtle 1	Mar-74	631	Apr-80	6.08	0
Vogtle 1	Jun-74	629	Apr-80	5.83	0
Vogtle 1	Mar-77	629	Jun-83	6.25	0
Vogtle 1	Sep-77	NA	Nov-84	7.17	5
Vogtle 1	Dec-77	1537	Nov-84	6.92	5
Vogtle 1	Sep-78	1586	Nov-84	5.67	5
Vogtle 1	Dec-79	1567	Nov-84	4.92	5
Vogtle 1	Jun-80	1746	May-85	4.92	10
Vogtle 1	Jun-82	4085	Mar-87	4.75	25
Vogtle 1	Sep-82	4613	Mar-87	4.50	40.4
Vogtle 1	Dec-82	3722	Mar-87	4.25	45
Vogtle 2	Sep-71	NA	Apr-79	7.58	0
Vogtle 2	Jun-72	NA	Feb-80	7.67	0
Vogtle 2	Dec-72	NA	Apr-81	8.33	0
Vogtle 2	Mar-73	495	Apr-81	8.08	0
Vogtle 2	Sep-73	543	Apr-81	7.58	0
Vogtle 2	Jun-74	534	Apr-81	6.83	0
Vogtle 2	Dec-77	1075	Nov-85	7.92	3
Vogtle 2	Sep-78	1075	Nov-87	9.17	3
Vogtle 2	Dec-78	1297	Nov-87	8.92	3

Incomplete Bechtel Plants

Unit Name	Date of Estimate	Estimates Total Cost	Estimates COD	Est. Years to COD	% Complete
Vogtle 2	Dec-79	924	Nov-87	7.92	3
Vogtle 2	Jun-80	988	Nov-87	7.42	4
Vogtle 2	Jun-82	1415	Sep-88	6.25	10
Vogtle 2	Sep-82	1653	Sep-88	6.00	12.3
Vogtle 2	Dec-82	1476	Sep-88	5.75	15
WNP 1	Sep-73	626	Sep-80	7.00	0
WNP 1	Mar-75	990	Sep-80	5.50	0
WNP 1	Dec-75	990	Mar-81	5.25	0.7
WNP 1	Jun-76	1147	Mar-81	4.75	1.2
WNP 1	Sep-76	1147	Sep-81	5.00	1.6
WNP 1	Dec-76	1057	Sep-81	4.75	1.8
WNP 1	Mar-77	1087	Sep-81	4.50	2.6
WNP 1	Sep-77	1087	Dec-82	5.25	5.8
WNP 1	Mar-78	1164	Dec-82	4.75	9.3
WNP 1	Mar-79	1772	Dec-83	4.75	22.2
WNP 1	Sep-79	2114	Dec-83	4.25	31.4
WNP 1	Jun-80	2498	Jun-85	5.00	41.1
WNP 1	Sep-80	2369	Jun-85	4.75	41.1
WNP 1	Jun-81	3460	Jun-86	5.00	51
WNP 2	Mar-71	187	Sep-77	6.50	0
WNP 2	Mar-72	193	Sep-77	5.50	0
WNP 2	Jun-72	227	Sep-77	5.25	0
WNP 2	Sep-72	374	Sep-77	5.00	NA
WNP 2	Sep-73	472	Sep-77	4.00	2
WNP 2	Dec-74	562	Sep-77	2.75	13
WNP 2	Mar-75	608	Jun-78	3.25	15.8
WNP 2	Sep-75	608	Sep-78	3.00	24.8
WNP 2	Dec-75	608	Jul-79	3.58	27.8
WNP 2	Mar-76	794	Jul-79	3.33	29.6
WNP 2	Jun-76	794	Dec-79	3.50	29.7
WNP 2	Sep-76	794	Jun-80	3.75	32
WNP 2	Dec-76	901	Sep-80	3.75	35.8
WNP 2	Mar-77	905	Sep-80	3.50	39.6
WNP 2	Mar-78	1001	Sep-80	2.50	60.7
WNP 2	Mar-79	1663	Sep-81	2.50	66.8
WNP 2	Sep-79	1757	Sep-81	2.00	77.6
WNP 2	Jun-80	2392	Jan-83	2.58	85.2
WNP 2	Sep-80	2306	Jan-83	2.33	85.3
WNP 2	Jun-81	2784	Feb-84	2.67	85.9
Wolf Creek	Dec-74	940	Apr-82	7.33	0
Wolf Creek	Mar-77	1029	Apr-83	6.08	1
Wolf Creek	Dec-79	1296	Apr-83	3.33	47.9
Wolf Creek	Sep-80	1653	Apr-84	3.58	68
Wolf Creek	Dec-81	1927	May-84	2.42	79
Wolf Creek	Sep-82	2440	Apr-85	2.58	80
Wolf Creek	Dec-82	2420	Apr-85	2.33	83.3

Incomplete Non-Bechtel Plants

Unit Name	Date of Estimate	Estimates: Total Cost	Estimates: COD	Est. Years to COD	% Complete
Diablo Canyon 1	Mar-66	154	Mar-72	6.01	0
Diablo Canyon 1	Dec-68	154	Jan-73	4.09	0
Diablo Canyon 1	Sep-69	202	Jan-73	3.34	2.2
Diablo Canyon 1	Mar-71	202	May-74	3.17	21
Diablo Canyon 1	Sep-71	320	May-74	2.67	27.5
Diablo Canyon 1	Jun-72	320	Mar-75	2.75	46.5
Diablo Canyon 1	Sep-73	320	Sep-75	2.00	72.2
Diablo Canyon 1	Dec-73	397	Sep-75	1.75	78.3
Diablo Canyon 1	Dec-74	397	May-76	1.42	90.6
Diablo Canyon 1	Sep-75	530	Aug-76	0.92	94.4
Diablo Canyon 1	Jun-76	530	Jun-76	0.00	97.8
Diablo Canyon 1	Sep-76	530	Jun-77	0.75	98.5
Diablo Canyon 1	Jun-77	672	Jun-77	0.00	99.2
Diablo Canyon 1	Sep-77	672	Jun-78	0.75	99.2
Diablo Canyon 1	Jun-78	672	Jun-79	1.00	99.2
Diablo Canyon 1	Jun-79	880	Jun-79	0.00	99.2
Diablo Canyon 1	Sep-79	880	Jun-80	0.75	99.2
Diablo Canyon 1	Mar-80	880	Jun-81	1.25	99.2
Diablo Canyon 1	Sep-80	1051	Jun-81	0.75	96.5
Diablo Canyon 1	Mar-81	1196	Jun-81	0.25	99.3
Diablo Canyon 1	Jun-81	1229	Jun-81	0.00	99.6
Diablo Canyon 1	Sep-81	1262	Jun-82	0.75	99.7
Diablo Canyon 1	Mar-82	1378	Jun-83	1.25	99.8
Diablo Canyon 2	Dec-68	151	Jul-74	5.58	0
Diablo Canyon 2	Sep-69	185	Jul-74	4.83	0
Diablo Canyon 2	Mar-71	185	May-75	4.17	0
Diablo Canyon 2	Sep-71	282	May-75	3.67	2.5
Diablo Canyon 2	Jun-72	282	Mar-76	3.75	9.9
Diablo Canyon 2	Sep-73	282	Jun-76	2.75	33
Diablo Canyon 2	Dec-74	425	Mar-77	2.25	50.2
Diablo Canyon 2	Sep-75	425	Aug-77	1.92	64.8
Diablo Canyon 2	Jun-76	425	Jun-77	1.00	79
Diablo Canyon 2	Jun-77	548	Jun-77	0.00	89.4
Diablo Canyon 2	Sep-77	548	Jun-78	0.75	90.9
Diablo Canyon 2	Mar-78	548	Jun-79	1.25	93.5
Diablo Canyon 2	Dec-78	548	Jun-80	1.50	96.9
Diablo Canyon 2	Jun-79	721	Jun-80	1.00	97.9
Diablo Canyon 2	Dec-79	721	Jun-81	1.50	97.9
Diablo Canyon 2	Sep-80	841	Jun-82	1.75	88.1
Diablo Canyon 2	Mar-81	986	Jun-82	1.25	90.2
Diablo Canyon 2	Jun-81	1025	Jun-82	1.00	90.5
Diablo Canyon 2	Sep-81	1043	Jun-82	0.75	91
Diablo Canyon 2	Mar-82	1126	Jun-83	1.25	91.2
Diablo Canyon 2	Dec-82	1126	Jun-84	1.50	95
Beaver Valley 2	Dec-71	296	Mar-78	6.25	0
Beaver Valley 2	Mar-72	360	Mar-78	6.00	0
Beaver Valley 2	Mar-73	360	Jun-79	6.25	0
Beaver Valley 2	Sep-73	393	Jun-79	5.75	0
Beaver Valley 2	Mar-74	560	Jun-79	5.25	0
Beaver Valley 2	Sep-74	685	Jun-81	6.75	0.05
Beaver Valley 2	Dec-74	685	Apr-81	6.34	0.05

Incomplete Non-Bechtel Plants

Unit Name	Date of Estimate	Estimates: Total Cost	Estimates: COD	Est. Years to COD	% Complete
Beaver Valley 2	Mar-75	796	May-81	6.17	0.05
Beaver Valley 2	Jun-75	796	Apr-81	5.84	0.05
Beaver Valley 2	Sep-75	799	Apr-81	5.59	0.05
Beaver Valley 2	Dec-75	793	Apr-81	5.34	0.05
Beaver Valley 2	Jun-76	927	May-82	5.92	0.1
Beaver Valley 2	Sep-76	922	May-82	5.67	0.5
Beaver Valley 2	Mar-77	935	May-82	5.17	6
Beaver Valley 2	Jun-77	934	May-82	4.92	8
Beaver Valley 2	Dec-77	942	May-82	4.42	15
Beaver Valley 2	Jun-78	1010	May-82	3.92	20
Beaver Valley 2	Sep-78	1415	May-84	5.67	26
Beaver Valley 2	Sep-79	2024	May-84	4.67	34.5
Beaver Valley 2	Dec-79	2024	May-86	6.42	35.2
Beaver Valley 2	Sep-80	2203	May-86	5.67	41.2
Beaver Valley 2	Dec-81	2305	May-86	4.42	47.8
Beaver Valley 2	Dec-82	3076	May-86	3.42	58.1
Bellefonte 1	Dec-70	NA	Jul-77	6.59	0
Bellefonte 1	Dec-71	312	Jul-77	5.59	0
Bellefonte 1	Dec-72	348	Sep-79	6.75	0
Bellefonte 1	Dec-73	348	Dec-79	6.00	0
Bellefonte 1	Sep-74	482	Dec-79	5.25	0
Bellefonte 1	Mar-75	482	Jun-80	5.26	3
Bellefonte 1	Sep-76	587	Jun-80	3.75	24
Bellefonte 1	Sep-77	632	Jun-80	2.75	46
Bellefonte 1	Dec-77	632	Jun-80	2.50	52
Bellefonte 1	Sep-78	792	Sep-81	3.00	60
Bellefonte 1	Sep-79	1001	Sep-83	4.00	69
Bellefonte 1	Dec-80	1659	Dec-85	5.00	75
Bellefonte 1	Sep-81	1854	Jun-86	4.75	77
Bellefonte 1	Mar-82	1769	Jun-86	4.25	79
Bellefonte 1	Jun-82	1769	Nov-86	4.42	80
Bellefonte 1	Sep-82	2214	Nov-86	4.17	81
Bellefonte 2	Dec-70	NA	Apr-78	7.34	0
Bellefonte 2	Dec-71	312	Jul-77		
Bellefonte 2	Dec-72	348	Jun-80	7.50	0
Bellefonte 2	Dec-73	348	Sep-80	6.76	0
Bellefonte 2	Sep-74	482	Dec-79	5.25	
Bellefonte 2	Mar-75	482	Mar-81	6.01	0
Bellefonte 2	Sep-76	587	Mar-81	3.75	
Bellefonte 2	Sep-77	632	Mar-81	2.75	
Bellefonte 2	Dec-77	632	Mar-81	2.50	
Bellefonte 2	Sep-78	792	Jun-82	3.75	42
Bellefonte 2	Sep-79	1001	Jun-84	4.75	48
Bellefonte 2	Sep-80	1001	Sep-86	6.00	57
Bellefonte 2	Mar-81	1659	Sep-86	5.51	59
Bellefonte 2	Sep-81	1854	Sep-86	5.00	
Bellefonte 2	Mar-82	1769	Jun-87	5.25	64
Bellefonte 2	Jun-82	1769	Nov-87	5.42	67
Bellefonte 2	Sep-82	2214	Nov-87	5.17	60
Braidwood 1	Dec-72	501	Oct-79	6.84	0
Braidwood 1	Mar-73	517	Oct-79	6.59	0

Incomplete Non-Bechtel Plants

Unit Name	Date of Estimate	Estimates Total Cost	COD	Est. Years to COD	% Complete
Braidwood 1	Jun-73	517	Oct-80	7.34	0
Braidwood 1	Sep-73	513	May-80	6.67	0
Braidwood 1	Jun-74	567	May-80	5.92	0
Braidwood 1	Sep-74	567	Oct-81	7.09	0
Braidwood 1	Dec-74	616	Oct-81	6.84	0
Braidwood 1	Sep-75	618	Oct-81	6.09	0.25
Braidwood 1	Mar-76	716	Oct-81	5.59	1
Braidwood 1	Sep-76	718	Oct-81	5.08	6
Braidwood 1	Sep-77	829	Oct-81	4.08	21
Braidwood 1	Dec-78	902	Oct-81	2.84	45
Braidwood 1	Jun-79	991	Oct-82	3.34	53
Braidwood 1	Dec-79	1141	Oct-83	3.84	54
Braidwood 1	Jun-80	1585	Oct-85	5.34	56
Braidwood 1	Dec-80	1575	Oct-85	4.84	59
Braidwood 1	Dec-81	1635	Oct-85	3.84	61
Braidwood 2	Dec-72	446	Oct-80	7.84	0
Braidwood 2	Mar-73	413	Oct-80	7.59	0
Braidwood 2	Jun-73	428	Mar-82	8.75	0
Braidwood 2	Sep-73	428	Oct-81	8.09	0
Braidwood 2	Jun-74	417	Oct-81	7.34	0
Braidwood 2	Sep-74	417	Oct-82	8.09	0
Braidwood 2	Dec-74	442	Oct-82	7.84	0
Braidwood 2	Mar-76	485	Oct-82	6.59	1
Braidwood 2	Sep-76	486	Oct-82	6.08	4
Braidwood 2	Sep-77	519	Oct-82	5.08	18
Braidwood 2	Dec-78	601	Oct-82	3.84	36
Braidwood 2	Jun-79	679	Oct-83	4.34	42
Braidwood 2	Dec-79	769	Oct-84	4.84	43
Braidwood 2	Jun-80	1011	Oct-86	6.34	44
Braidwood 2	Dec-80	1015	Oct-86	5.84	47
Braidwood 2	Dec-81	1076	Oct-86	4.84	48
Braidwood 2	Mar-83	1276	Oct-86	3.59	53
Byron 1	Jun-71	400	Oct-78	7.34	0
Byron 1	Dec-71	400	Oct-79	7.84	0
Byron 1	Mar-72	400	Oct-78	6.59	0
Byron 1	Sep-72	464	May-79	6.67	0
Byron 1	Sep-73	464	May-80	6.67	0
Byron 1	Jun-74	537	May-80	5.92	0
Byron 1	Sep-74	537	Oct-80	6.09	0
Byron 1	Dec-74	550	Oct-80	5.84	0
Byron 1	Sep-75	551	Oct-80	5.09	1
Byron 1	Mar-76	663	Oct-80	4.59	6
Byron 1	Sep-76	664	Oct-80	4.08	12
Byron 1	Dec-76	664	Mar-81	4.25	14
Byron 1	Sep-77	835	Mar-81	3.50	27
Byron 1	Dec-77	862	Sep-81	3.75	33
Byron 1	Dec-78	984	Sep-81	2.75	52
Byron 1	Jun-79	1116	Oct-82	3.34	60
Byron 1	Dec-79	1168	Oct-82	2.84	65
Byron 1	Jun-80	1483	Oct-83	3.33	69
Byron 1	Dec-80	1481	Oct-83	2.83	73

Incomplete Non-Bechtel Plants

Unit Name	Date of Estimate	Estimates Total Cost	Estimates COD	Est. Years to COD	% Complete
Byron 1	Dec-81	1635	Feb-84	2.17	79
Byron 1	Mar-83	1979	Jun-84	1.25	89
Byron 2	Jun-71	350	Oct-79	8.34	0
Byron 2	Dec-71	350	Oct-80	8.84	0
Byron 2	Mar-72	350	Oct-79	7.59	0
Byron 2	Jun-72	422	Mar-80	7.75	0
Byron 2	Sep-73	422	May-81	7.67	0
Byron 2	Jun-74	438	May-81	6.92	0
Byron 2	Sep-74	428	Oct-82	8.09	0
Byron 2	Dec-74	477	Oct-82	7.84	0
Byron 2	Sep-75	478	Oct-82	7.09	1
Byron 2	Mar-76	487	Oct-82	6.59	6
Byron 2	Sep-76	489	Oct-82	6.08	9
Byron 2	Sep-77	538	Oct-82	5.08	23
Byron 2	Dec-78	624	Oct-82	3.84	42
Byron 2	Jun-79	702	Oct-83	4.34	48
Byron 2	Dec-79	732	Oct-83	3.84	53
Byron 2	Jun-80	922	Oct-84	4.34	55
Byron 2	Dec-80	924	Oct-84	3.84	59
Byron 2	Dec-81	1093	Feb-85	3.17	63
Carroll County 1	Jun-74	680	Oct-82	8.34	0
Carroll County 1	Sep-74	680	Oct-84	10.09	0
Carroll County 1	Jun-75	860	Oct-84	9.34	0
Carroll County 1	Dec-75	860	Oct-85	9.84	0
Carroll County 1	Mar-76	920	Oct-85	9.59	0
Carroll County 1	Dec-76	1080	Oct-85	8.84	0
Carroll County 1	Dec-78	2016	Oct-88	9.84	0
Carroll County 1	Jun-79	2230	Oct-90	11.34	0
Carroll County 1	Dec-79	2696	Oct-92	12.84	0
Carroll County 1	Jun-80	2891	Oct-92	12.34	0
Carroll County 1	Dec-80	3696	Oct-93	12.84	0
Carroll County 1	Dec-81	NA	Oct-93	11.84	0
Carroll County 1	Mar-82	NA	NA	NA	0
Carroll County 2	Jun-74	560	Oct-83	9.34	0
Carroll County 2	Sep-74	560	Oct-85	11.09	0
Carroll County 2	Jun-75	680	Oct-85	10.34	0
Carroll County 2	Dec-75	680	Oct-86	10.84	0
Carroll County 2	Mar-76	730	Oct-86	10.59	0
Carroll County 2	Dec-76	780	Oct-86	9.84	0
Carroll County 2	Dec-78	1250	Oct-89	10.84	0
Carroll County 2	Jun-79	1425	Oct-91	12.34	0
Carroll County 2	Dec-79	1724	Oct-93	13.84	0
Carroll County 2	Jun-80	1852	Oct-93	13.34	0
Carroll County 2	Dec-80	2414	Oct-94	13.84	0
Carroll County 2	Dec-81	NA	NA	NA	0
Catawba 1	Dec-72	317	NA	NA	NA
Catawba 1	Mar-73	317	Mar-79	6.00	0
Catawba 1	Jun-74	317	Jul-79	5.08	0
Catawba 1	Sep-74	498	Jan-81	6.34	0.5
Catawba 1	Dec-74	542	Jan-81	6.09	0.7
Catawba 1	Mar-77	649	Jul-81	4.34	11.5

Incomplete Non-Bechtel Plants

Unit Name	Date of Estimate	Estimates: Total Cost	Estimates: COD	Est. Years to COD	% Complete
Catawba 1	Mar-78	673	Jul-81	3.34	28
Catawba 1	Mar-79	754	Jul-81	2.34	47
Catawba 1	Sep-79	754	Jul-83	3.83	63
Catawba 1	Jun-80	754	Mar-84	3.75	73
Catawba 1	Sep-80	1034	Mar-84	3.50	76
Catawba 1	Mar-81	1369	Mar-84	3.00	82.2
Catawba 1	Dec-81	1361	Mar-84	2.25	86.4
Catawba 1	Jun-82	1361	Jun-85	3.00	90
Catawba 1	Dec-82	1800	Jun-85	2.50	92
Catawba 2	Dec-72	317	Mar-80	7.25	0
Catawba 2	Jun-74	317	May-80	5.92	0
Catawba 2	Sep-74	498	Jan-82	7.34	0
Catawba 2	Dec-74	542	Jan-82	7.09	0
Catawba 2	Dec-76	542	Jun-83	6.50	9.5
Catawba 2	Mar-77	649	Jan-83	5.84	11.5
Catawba 2	Mar-78	673	Jan-83	4.84	22
Catawba 2	Mar-79	754	Jan-83	3.84	37
Catawba 2	Sep-79	754	Jan-85	5.34	46
Catawba 2	Dec-79	754	Jan-85	5.09	12
Catawba 2	Jun-80	NA	Sep-85	5.25	15
Catawba 2	Sep-80	1034	Sep-85	5.00	16.7
Catawba 2	Mar-81	1369	Sep-85	4.51	29.5
Catawba 2	Dec-81	1567	Sep-85	3.75	35.5
Catawba 2	Jun-82	1567	Jun-87	5.00	45.6
Catawba 2	Dec-82	2100	Jun-87	4.50	47
Clinton 1	Sep-73	404	Jun-80	6.75	0
Clinton 1	Dec-73	435	Jun-80	6.50	0
Clinton 1	Dec-74	561	Jun-81	6.50	0
Clinton 1	Dec-75	705	Jun-81	5.50	0
Clinton 1	Sep-76	825	Jun-81	4.75	6
Clinton 1	Mar-77	825	Dec-81	4.76	10
Clinton 1	Dec-77	1051	Dec-81	4.00	20
Clinton 1	Mar-78	1220	Dec-82	4.76	27
Clinton 1	Dec-78	1297	Dec-82	4.00	36
Clinton 1	Mar-80	1397	Dec-82	2.75	66
Clinton 1	Dec-80	1742	Sep-83	2.75	73
Clinton 1	Mar-82	NA	Sep-83	1.50	82
Clinton 1	Jun-82	1819	Sep-84	2.25	83
Clinton 1	Mar-83	2181	Sep-84	1.51	87.8
Clinton 1	Jun-83	2868	Nov-86	3.42	80.9
Clinton 2	Sep-73	368	Jun-82	8.75	0
Clinton 2	Dec-73	367	Jun-83	9.50	0
Clinton 2	Dec-74	487	Jun-84	9.51	0
Clinton 2	Dec-75	604	Jun-84	8.51	0
Clinton 2	Sep-76	699	Jun-84	7.75	0
Clinton 2	Mar-77	699	Jun-88	11.26	0
Clinton 2	Dec-77	1059	Jun-88	10.51	0
Clinton 2	Mar-82	2181	Jun-88	6.26	3
Clinton 2	Mar-83	NA	Jun-88	5.26	3
Fermi 2	Mar-69	221	Feb-74	4.93	0
Fermi 2	Mar-70	250	Feb-74	3.93	0

Incomplete Non-Bechtel Plants

Unit Name	Date of Estimate	Estimates: Total Cost	Estimates: COD	Est. Years to COD	% Complete
Fermi 2	Sep-70	259	Feb-74	3.42	0
Fermi 2	Jun-71	328	Feb-75	3.67	4.8
Fermi 2	Dec-71	328	Oct-75	3.84	13.2
Fermi 2	Mar-72	409	Oct-75	3.59	17.2
Fermi 2	Jun-72	409	Apr-76	3.84	20.4
Fermi 2	Dec-72	439	Aug-76	3.67	28.5
Fermi 2	Sep-73	500	Apr-77	3.58	44.4
Fermi 2	Dec-73	501	Apr-77	3.33	47.6
Fermi 2	Jun-74	501	Apr-78	3.84	NA
Fermi 2	Sep-74	501	Apr-79	4.58	45
Fermi 2	Jun-75	899	Sep-80	5.26	45
Fermi 2	Mar-77	882	Dec-80	3.76	46
Fermi 2	Mar-79	973	Dec-80	7.76	78.7
Fermi 2	Jun-79	973	Mar-82	2.75	81.5
Fermi 2	Jun-80	1283	Mar-82	1.75	79.4
Fermi 2	Sep-80	1800	Nov-83	3.17	79.4
Fermi 2	Mar-81	1800	Nov-83	2.67	NA
Fermi 2	Jun-81	1968	Nov-83	2.42	85
Fermi 2	Sep-81	1994	Nov-83	2.17	87
Fermi 2	Sep-82	2346	Nov-83	1.17	92
Fermi 2	Jun-83	2696	Jul-84	1.08	96
Hartsville A-1	Mar-73	378.5	Dec-80	7.76	0
Hartsville A-1	Dec-74	601	Dec-80	6.01	0
Hartsville A-1	Sep-75	601	Dec-81	6.25	0
Hartsville A-1	Jun-76	601	Feb-83	6.67	0
Hartsville A-1	Sep-76	602	Feb-83	6.42	4
Hartsville A-1	Dec-76	602	Feb-83	6.17	1
Hartsville A-1	Jun-77	602	Jun-83	6.00	3
Hartsville A-1	Sep-77	854	Jun-83	5.75	5
Hartsville A-1	Sep-78	853	Jun-83	4.75	13
Hartsville A-1	Sep-79	1418	Jul-86	6.84	21
Hartsville A-1	Dec-80	NA	Jul-88	7.59	31
Hartsville A-1	Mar-81	1973	Jul-88	7.34	33
Hartsville A-1	Sep-81	3368	Apr-91	9.59	35
Hartsville A-2	Mar-73	379	Dec-81	8.76	0
Hartsville A-2	Jun-74	NA	Dec-81	7.51	0
Hartsville A-2	Sep-75	601	Dec-82	7.25	0
Hartsville A-2	Jun-76	601	Feb-84	7.67	0
Hartsville A-2	Sep-76	602	Feb-84	7.42	
Hartsville A-2	Dec-76	602	Feb-84	7.17	
Hartsville A-2	Jun-77	602	Jun-84	7.01	1
Hartsville A-2	Sep-77	854	Jun-84	6.75	
Hartsville A-2	Sep-78	853	Jun-84	5.75	
Hartsville A-2	Sep-79	1418	Jul-87	7.84	8
Hartsville A-2	Dec-80	NA	Jul-87	6.58	
Hartsville A-2	Mar-81	1973	Apr-89	8.09	25
Hartsville A-2	Sep-81	3368	Apr-92	10.59	27
LaSalle 2	Jun-70	300	Oct-76	6.34	0
LaSalle 2	Sep-71	300	May-78	6.67	0
LaSalle 2	Dec-71	300	Sep-78	6.76	0
LaSalle 2	Sep-72	330	Sep-78	6.00	0

Incomplete Non-Bechtel Plants

Unit Name	Date of Estimate	Estimates: Total Cost	Estimates: COD	Est. Years to COD	% Complete
LaSalle 2	Mar-73	330	Mar-79	6.00	0
LaSalle 2	Jun-73	330	Oct-79	6.34	0
LaSalle 2	Sep-73	343	May-79	5.67	0
LaSalle 2	Sep-74	343	Oct-79	5.08	3
LaSalle 2	Dec-74	358	Oct-79	4.84	3
LaSalle 2	Sep-75	399	Oct-79	4.08	14
LaSalle 2	Dec-76	400	Sep-80	3.75	37
LaSalle 2	Sep-77	513	Sep-80	3.00	45
LaSalle 2	Dec-78	580	Sep-80	1.75	59
LaSalle 2	Jun-79	729	Dec-81	2.50	69
LaSalle 2	Dec-79	699	Dec-81	2.00	74
LaSalle 2	Jun-80	786	Jun-82	2.00	78
LaSalle 2	Dec-80	874	Dec-82	2.00	81
LaSalle 2	Mar-81	874	Jun-83	2.25	81.5
LaSalle 2	Dec-81	1027	Oct-83	1.83	84
LaSalle 2	Jun-82	1026	Oct-83	1.33	87
LaSalle 2	Mar-83	1018	Apr-84	1.09	97
Marble Hill 1	Dec-74	600	Jun-83	8.50	0
Marble Hill 1	Jun-75	744	Jun-82	7.01	NA
Marble Hill 1	Jun-76	791	Jun-82	6.00	NA
Marble Hill 1	Sep-76	811	Jun-82	5.75	NA
Marble Hill 1	Dec-76	416	Jun-82	5.50	NA
Marble Hill 1	Mar-77	463	Jun-82	5.25	0
Marble Hill 1	Jun-77	505	Jun-82	5.00	0
Marble Hill 1	Sep-77	506	Jun-82	4.75	NA
Marble Hill 1	Dec-77	511	Sep-82	4.75	NA
Marble Hill 1	Jun-78	511	Oct-82	4.34	8
Marble Hill 1	Mar-79	989	NA	NA	19
Marble Hill 1	Jun-79	989	Oct-82	3.34	22.5
Marble Hill 1	Jun-80	2001	Dec-86	6.50	20
Marble Hill 1	Sep-81	2504	Dec-86	5.25	34
Marble Hill 1	Sep-82	2725	Dec-86	4.25	42.9
Marble Hill 2	Dec-74	600	Jun-84	9.51	0
Marble Hill 2	Jun-75	620	Jun-84	9.01	0
Marble Hill 2	Jun-76	670	Jun-84	8.01	0
Marble Hill 2	Sep-76	675	Jun-84	7.75	0
Marble Hill 2	Dec-76	385	Jun-84	7.50	0
Marble Hill 2	Mar-77	317	Jun-84	7.26	0
Marble Hill 2	Jun-77	346	Jun-84	7.01	0
Marble Hill 2	Dec-77	353	Jun-84	6.50	0.4
Marble Hill 2	Mar-78	353	Jan-84	5.84	0.4
Marble Hill 2	Mar-79	818	Jan-84	4.84	5.2
Marble Hill 2	Jun-80	1383	Dec-87	7.50	9
Marble Hill 2	Sep-81	1730	Dec-87	6.25	14
Marble Hill 2	Dec-81	1383	Dec-87	6.00	10
Marble Hill 2	Jun-82	1730	Dec-87	5.50	20
Marble Hill 2	Sep-82	2260	Dec-87	5.25	25
Marble Hill 2	Dec-82	2260	Jun-88	5.50	27.3
McGuire 2	Sep-70	179	Nov-76	6.17	0
McGuire 2	Mar-71	179	Mar-77	6.01	0
McGuire 2	Sep-71	220	Mar-77	5.50	0

Incomplete Non-Bechtel Plants

Unit Name	Date of Estimate	Estimates: Total Cost	Estimates: COD	Est. Years to COD	% Complete
McGuire 2	Sep-73	220	Sep-77	4.00	16.4
McGuire 2	Jun-74	220	Nov-77	3.42	27.7
McGuire 2	Sep-74	365	Jan-79	4.34	29.6
McGuire 2	Dec-74	384	Jan-79	4.09	35.3
McGuire 2	Jun-76	384	May-79	2.92	55.9
McGuire 2	Dec-76	384	Feb-80	3.17	55.6
McGuire 2	Mar-77	466	Jan-80	2.84	50.1
McGuire 2	Sep-77	466	Mar-81	3.50	54
McGuire 2	Mar-78	549	Mar-81	3.00	51
McGuire 2	Mar-79	635	Mar-81	2.00	56
McGuire 2	Sep-79	635	Apr-82	2.58	67
McGuire 2	Jun-80	635	Sep-82	2.25	83
McGuire 2	Sep-80	765	Sep-82	2.00	89
McGuire 2	Mar-81	921	Jun-83	2.25	90.2
McGuire 2	Dec-81	1059	Oct-83	1.83	93.7
McGuire 2	Sep-82	1059	Mar-84	1.50	97.2
McGuire 2	Dec-82	1069	Mar-84	1.25	98
Millstone 3	Mar-74	642	May-79	5.17	0
Millstone 3	Mar-75	793	Nov-79	4.67	5.8
Millstone 3	Dec-75	793	May-82	6.42	7.7
Millstone 3	Jun-76	998	May-82	5.92	9.9
Millstone 3	Mar-77	1173	May-82	5.17	12.3
Millstone 3	Dec-77	1173	May-86	8.42	18.3
Millstone 3	Sep-78	1980	May-86	7.67	24.5
Millstone 3	Dec-80	2573	May-86	5.42	33.3
Millstone 3	Dec-81	2577	May-86	4.42	43
Millstone 3	Dec-82	3539	May-86	3.42	60.3
Nine Mile Point 2	Dec-71	370	Jul-78	6.59	0
Nine Mile Point 2	Sep-72	370	Nov-78	6.17	0
Nine Mile Point 2	Dec-73	602	Nov-78	4.92	0
Nine Mile Point 2	Mar-74	609	May-79	5.17	0
Nine Mile Point 2	Mar-75	749	Oct-82	7.59	1
Nine Mile Point 2	Jun-76	793	Oct-82	6.34	1.4
Nine Mile Point 2	Mar-77	1107	Oct-82	5.59	9.5
Nine Mile Point 2	Jun-77	1156	Oct-82	5.34	12.9
Nine Mile Point 2	Dec-77	1505	Oct-83	5.84	17.5
Nine Mile Point 2	Dec-78	1954	Oct-84	5.84	24.1
Nine Mile Point 2	Mar-80	1963	Oct-84	4.59	37
Nine Mile Point 2	Jun-80	1953	Oct-84	4.34	37.7
Nine Mile Point 2	Dec-80	3612	Oct-86	5.84	29.5
Nine Mile Point 2	Mar-81	3727	Oct-86	5.59	27.7
Nine Mile Point 2	Dec-82	4174	Oct-86	3.84	56.7
Comanche Peak 1	Mar-74	355	Jan-80	5.84	0
Comanche Peak 1	Dec-76	690	Jan-80	3.08	40
Comanche Peak 1	Mar-77	690	Jan-81	3.84	37
Comanche Peak 1	Jun-77	850	Jan-81	3.59	39
Comanche Peak 1	Mar-79	850	Jun-81	2.25	68.8
Comanche Peak 1	Dec-80	1118	Jun-81	0.50	86
Comanche Peak 1	Mar-81	1118	Jun-82	1.25	88
Comanche Peak 1	Jun-82	1720	Jun-84	2.00	91
Comanche Peak 2	Mar-74	355	Jan-82	7.84	0

Incomplete Non-Bechtel Plants

Unit Name	Date of Estimate	Estimates: Total Cost	Estimates: COD	Est. Years to COD	% Complete
Comanche Peak 2	Dec-76	690	Jan-82	5.09	17
Comanche Peak 2	Mar-77	690	Dec-82	5.76	9
Comanche Peak 2	Jun-77	850	Jan-83	5.59	9.67
Comanche Peak 2	Mar-79	850	Jun-83	4.25	26.4
Comanche Peak 2	Sep-80	1118	Dec-82	2.25	50
Comanche Peak 2	Mar-81	1118	Jun-84	3.25	52
Comanche Peak 2	Jun-82	1720	Jun-85	3.00	55
Perry 1	Mar-74	617	Jun-79	5.25	0
Perry 1	Dec-74	676	Jun-79	4.50	0.5
Perry 1	Mar-75	676	Jun-80	5.26	0.5
Perry 1	Jun-75	774	Jun-80	5.01	1.8
Perry 1	Sep-76	1006	Dec-81	5.25	3.4
Perry 1	Mar-77	1011	Dec-81	4.76	5.4
Perry 1	Sep-77	988	Dec-81	4.25	13.3
Perry 1	Dec-78	1159	May-83	4.42	33.2
Perry 1	Mar-79	1185	May-83	4.17	37.7
Perry 1	Jun-79	1187	May-83	3.92	40.6
Perry 1	Jun-80	1701	May-84	3.92	59.4
Perry 1	Mar-81	1710	May-84	3.17	70.9
Perry 1	Sep-81	1884	May-84	2.67	78.8
Perry 1	Mar-83	2643	May-85	2.17	83.8
Perry 2	Mar-74	617	Jun-80	6.26	0
Perry 2	Dec-74	676	Jun-80	5.50	0.5
Perry 2	Mar-75	676	Apr-82	7.09	0.5
Perry 2	Jun-75	774	Apr-82	6.84	1.8
Perry 2	Sep-76	1006	Jun-83	6.75	3.4
Perry 2	Mar-77	1011	Jun-83	6.25	5.4
Perry 2	Sep-77	1123	Jun-83	5.75	6.3
Perry 2	Sep-78	1318	May-85	6.67	20.2
Perry 2	Mar-79	1367	May-85	6.17	22.5
Perry 2	Jun-79	1350	May-85	5.92	26.5
Perry 2	Jun-80	2157	May-88	7.92	46.5
Perry 2	Mar-81	2179	May-88	7.17	52.3
Perry 2	Jun-81	1808	May-88	6.92	39.8
Perry 2	Mar-83	2456	May-88	5.17	38.3
River Bend 1	Mar-73	390	Oct-79	6.59	0
River Bend 1	Jun-73	376	Feb-80	6.67	0
River Bend 1	Mar-74	376	Sep-80	6.51	0
River Bend 1	Jun-74	541	Sep-80	6.26	0
River Bend 1	Mar-75	541	Sep-81	6.51	0
River Bend 1	Dec-76	934	Sep-81	4.75	4
River Bend 1	Mar-77	934	Sep-83	6.51	5
River Bend 1	Dec-77	1172	Sep-83	5.75	5
River Bend 1	Jun-78	1172	Sep-84	6.26	5
River Bend 1	Sep-79	1172	Apr-84	4.59	5.4
River Bend 1	Mar-80	1679	Apr-84	4.09	11.9
River Bend 1	Sep-80	2273	Apr-84	3.58	30
River Bend 1	Sep-81	2275	Apr-84	2.58	38.2
River Bend 1	Dec-81	3645	Dec-85	4.00	46.1
River Bend 1	Sep-82	2474	Dec-85	3.25	51.6
River Bend 2	Mar-73	344	Sep-81	8.51	0

Incomplete Non-Bechtel Plants

Unit Name	Date of Estimate	Estimates: Total Cost	Estimates: COD	Est. Years to COD	% Complete
River Bend 2	Mar-74	344	Sep-82	8.51	0
River Bend 2	Jun-74	478	Sep-82	8.26	0
River Bend 2	Mar-75	478	Sep-83	8.51	0
River Bend 2	Dec-75	678	Sep-83	7.76	4
River Bend 2	Mar-77	678	Sep-85	8.51	5
River Bend 2	Dec-77	868	Sep-85	7.76	5
River Bend 2	Mar-79	868	NA	NA	5
Seabrook 1	Sep-68	NA	Oct-74	6.08	0
Seabrook 1	Dec-68	120	Oct-74	5.84	0
Seabrook 1	Mar-69	186	Oct-74	5.59	NA
Seabrook 1	Sep-69	186	May-75	5.67	NA
Seabrook 1	Jun-73	NA	Nov-79	6.42	0
Seabrook 1	Sep-73	946	Nov-79	6.17	0
Seabrook 1	Mar-74	473	Nov-79	5.67	0
Seabrook 1	Dec-74	523	Nov-79	4.92	0
Seabrook 1	Mar-75	585	Nov-80	5.68	0
Seabrook 1	Mar-76	585	Jun-81	5.25	0
Seabrook 1	Jun-76	585	Nov-81	5.42	0
Seabrook 1	Dec-76	684	Nov-81	4.92	1
Seabrook 1	Dec-77	1375	Dec-82	5.00	8
Seabrook 1	Jun-78	1340	Dec-82	4.50	13
Seabrook 1	Mar-79	1497	Apr-83	4.09	18.9
Seabrook 1	Jun-79	1294	Apr-83	3.84	26.7
Seabrook 1	Mar-80	1601	Apr-83	3.08	36.7
Seabrook 1	Jun-80	1493	Apr-83	2.83	39.7
Seabrook 1	Mar-81	1708	Feb-84	2.92	47
Seabrook 1	Dec-81	1735	Feb-84	2.17	54
Seabrook 1	Mar-83	2540	Dec-84	1.76	73.9
Seabrook 2	Sep-73	NA	Nov-79	6.17	0
Seabrook 2	Mar-74	473	Nov-79	5.67	0
Seabrook 2	Dec-74	523	Nov-81	6.92	0
Seabrook 2	Mar-75	585	Nov-82	7.68	0
Seabrook 2	Mar-76	585	Jun-83	7.25	0
Seabrook 2	Jun-76	585	Nov-83	7.42	0
Seabrook 2	Dec-76	684	Nov-83	6.92	1
Seabrook 2	Dec-77	825	Dec-84	7.01	1
Seabrook 2	Mar-78	980	Dec-84	6.76	2
Seabrook 2	Mar-79	1084	Feb-85	5.93	2.8
Seabrook 2	Jun-79	1287	Feb-85	5.68	5.3
Seabrook 2	Mar-80	1490	Feb-85	4.93	7.28
Seabrook 2	Jun-80	1558	Feb-85	4.67	7.55
Seabrook 2	Mar-81	1763	May-86	5.17	8
Seabrook 2	Dec-81	1825	May-86	4.42	9.2
Seabrook 2	Mar-83	2709	Jul-87	4.34	19.4
Shearon Harris 1	Jun-71	234	Mar-77	5.75	0
Shearon Harris 1	Dec-71	247	Mar-77	5.25	0
Shearon Harris 1	Dec-72	274	Mar-78	5.25	0
Shearon Harris 1	Sep-73	331	Mar-78	4.50	0
Shearon Harris 1	Dec-73	419	Oct-79	5.84	0
Shearon Harris 1	Jun-74	513	Mar-81	6.75	1.7
Shearon Harris 1	Sep-74	502	Mar-81	6.50	1

Incomplete Non-Bechtel Plants

Unit Name	Date of Estimate	Estimates: Total Cost	Estimates: COD	Est. Years to COD	% Complete
Shearon Harris 1	Dec-74	513	Mar-81	6.25	1.5
Shearon Harris 1	Jun-75	730	Mar-84	8.76	1.7
Shearon Harris 1	Dec-75	901	Mar-84	8.25	1.7
Shearon Harris 1	Dec-76	986	Mar-84	7.25	1.7
Shearon Harris 1	Dec-77	1039	Mar-84	6.25	1.7
Shearon Harris 1	Dec-79	1208	Mar-84	4.25	18.5
Shearon Harris 1	Jun-80	1208	Mar-85	4.75	32.8
Shearon Harris 1	Dec-80	1629	Sep-85	4.75	37
Shearon Harris 1	Sep-81	1630	Sep-85	4.00	70
Shearon Harris 1	Mar-82	1882	Sep-85	3.51	58
Shearon Harris 1	Sep-82	1882	Mar-86	3.50	70
Shearon Harris 1	Dec-82	2586	Mar-86	3.25	76
Shearon Harris 2	Jun-71	234	Jun-78	5.75	0
Shearon Harris 2	Dec-71	247	Jun-78	5.25	0
Shearon Harris 2	Dec-72	274	Mar-79	5.25	0
Shearon Harris 2	Sep-73	331	Mar-79	4.50	0
Shearon Harris 2	Dec-73	419	Mar-80	5.84	0
Shearon Harris 2	Jun-74	513	Jun-82	6.75	1
Shearon Harris 2	Sep-74	502	Jun-82	7.75	
Shearon Harris 2	Dec-74	513	Jun-82	7.50	
Shearon Harris 2	Jun-75	730	Mar-86	8.76	1.7
Shearon Harris 2	Dec-75	901	Mar-86	8.25	1.7
Shearon Harris 2	Dec-76	986	Mar-86	7.25	1.7
Shearon Harris 2	Dec-77	1039	Mar-86	6.25	1.7
Shearon Harris 2	Dec-79	1208	Mar-87	4.25	3
Shearon Harris 2	Jun-80	1208	Mar-88	4.75	3.7
Shearon Harris 2	Dec-80	1629	Mar-88	4.75	3.7
Shearon Harris 2	Sep-81	1630	Mar-89	4.00	4
Shearon Harris 2	Mar-82	1882	Mar-89	3.51	4
Shearon Harris 2	Sep-82	1882	Mar-90	3.50	4
Shearon Harris 2	Dec-82	2023	Mar-90	7.25	4
Shoreham	Mar-67	105	May-73	6.17	0
Shoreham	Jun-68	NA	May-73	4.92	0
Shoreham	Mar-69	182	May-75	6.17	0.5
Shoreham	Mar-70	218	May-75	5.17	0.5
Shoreham	Dec-71	309	Apr-77	5.34	1.5
Shoreham	Jun-72	309	May-77	4.92	1.5
Shoreham	Mar-73	309	Jul-77	4.34	1.5
Shoreham	Dec-73	461	Jul-77	3.58	6
Shoreham	Mar-74	461	May-78	4.17	11
Shoreham	Sep-74	695	May-78	3.67	20
Shoreham	Sep-75	695	Sep-78	3.00	43
Shoreham	Dec-75	695	May-79	3.42	47
Shoreham	Jun-76	969	May-79	2.92	55
Shoreham	Sep-77	1188	Sep-80	3.00	62
Shoreham	Sep-78	1293	Sep-80	2.00	75
Shoreham	Dec-78	1337	Dec-80	2.00	78
Shoreham	Jun-79	1581	May-81	1.92	80
Shoreham	Jun-80	1213	Feb-83	2.67	85.5
Shoreham	Sep-80	2213	Feb-83	2.42	88
Shoreham	Dec-80	NA	Mar-83	2.25	90

Incomplete Non-Bechtel Plants

Unit Name	Date of Estimate	Estimates: Total Cost	Estimates: COD	Est. Years to COD	% Complete
Shoreham	Mar-82	2493	Mar-83	1.00	91
Shoreham	Sep-82	2724	Sep-83	1.00	94.7
Shoreham	Dec-82	3150	Dec-83	1.00	95.6
St. Lucie 2	Dec-72	360	Oct-78	5.84	0
St. Lucie 2	Mar-73	360	Dec-79	6.76	0
St. Lucie 2	Mar-74	360	Dec-80	6.76	0
St. Lucie 2	Jun-74	360	Dec-79	5.50	0
St. Lucie 2	Dec-74	537	Dec-79	5.00	0
St. Lucie 2	Sep-75	537	Dec-80	5.25	0
St. Lucie 2	Dec-75	620	Dec-80	5.01	0
St. Lucie 2	Sep-76	620	Dec-82	6.25	0.7
St. Lucie 2	Dec-76	850	Dec-82	6.00	0.7
St. Lucie 2	Jun-77	850	May-83	5.92	1
St. Lucie 2	Sep-78	845	May-83	4.67	13
St. Lucie 2	Dec-78	919	May-83	4.42	16.8
St. Lucie 2	Jun-80	1100	May-83	2.92	45.1
St. Lucie 2	Jun-82	1270	May-83	0.92	84.1
St. Lucie 2	Sep-82	1420	May-83	0.66	89.7
St. Lucie 2	Mar-83	1420	Jul-83	0.33	97.3
Surry 3	Mar-74	NA	Jun-80	6.26	NA
Surry 3	Jun-74	525	Mar-80	5.75	0
Surry 3	Sep-74	525	Dec-80	6.25	0
Surry 3	Dec-74	525	May-83	8.42	0
Surry 3	Mar-75	728	May-83	8.17	0
Surry 3	Jun-75	781	May-83	7.92	0
Surry 3	Mar-76	781	Jun-86	10.26	0
Surry 3	Jun-76	1074	Apr-86	9.84	0
Surry 4	Mar-74	254	Jun-81	7.26	0
Surry 4	Jun-74	322	Mar-81	6.75	0
Surry 4	Sep-74	322	Dec-81	7.25	0
Surry 4	Dec-74	322	May-84	9.42	0
Surry 4	Mar-75	506	May-84	9.18	0
Surry 4	Jun-75	511	May-84	8.92	0
Surry 4	Mar-76	511	Jun-87	11.26	0
Surry 4	Jun-76	765	Apr-87	10.84	0
Waterford 3	Sep-70	230	Jan-77	6.34	0
Waterford 3	Sep-71	289	Jan-77	5.34	0
Waterford 3	Sep-72	350	Jan-77	4.34	0.5
Waterford 3	Mar-73	350	Oct-77	4.59	0.5
Waterford 3	Dec-73	445	Jun-79	5.50	0.5
Waterford 3	Jun-74	445	Jun-80	6.01	0.5
Waterford 3	Dec-74	710	Jun-80	5.50	1
Waterford 3	Dec-75	710	Apr-81	5.34	2.87
Waterford 3	Sep-76	815	Apr-81	4.58	15
Waterford 3	Sep-78	1110	Oct-81	3.08	48.8
Waterford 3	Sep-79	1229	Feb-82	2.42	69.5
Waterford 3	Sep-80	1229	Mar-83	2.50	78.2
Waterford 3	Dec-80	1489	Mar-83	2.25	81.9
Waterford 3	Mar-82	1808	Jul-83	1.33	93.9
Waterford 3	Sep-82	2057	Jan-84	1.33	93.9
Watts Bar 1	Dec-70	NA	Aug-76	5.67	0

Incomplete Non-Bechtel Plants

Unit Name	Date of Estimate	Estimates: Total Cost	Estimates: COD	Est. Years to COD	% Complete
WNP 3	Mar-79	1948	Dec-84	5.76	11.2
WNP 3	Sep-79	2256	Dec-84	5.25	16.6
WNP 3	Sep-80	3130	Jun-86	5.75	22.2
WNP 3	Jun-81	3809	Dec-86	5.50	32
Yellow Creek 1	Mar-75	929	Apr-83	8.09	0
Yellow Creek 1	Sep-75	929	Jun-83	7.75	0
Yellow Creek 1	Mar-76	929	Jun-83	7.25	0
Yellow Creek 1	Jun-76	929	Mar-85	8.75	0
Yellow Creek 1	Sep-77	1048	Mar-85	7.50	0
Yellow Creek 1	Jun-78	1048	May-85	6.92	0
Yellow Creek 1	Sep-78	1172	May-85	6.67	0
Yellow Creek 1	Sep-79	1445	Nov-85	6.17	7
Yellow Creek 1	Dec-80	1364	Apr-88	7.34	18
Yellow Creek 1	Mar-81	1243	Apr-88	7.09	21
Yellow Creek 1	Sep-81	1938	Oct-90	9.09	28
Yellow Creek 1	Mar-82	NA	NA	NA	33
Yellow Creek 1	Sep-82	1938	Oct-90	8.09	33
Yellow Creek 2	Mar-75	929	Apr-84	9.09	NA
Yellow Creek 2	Sep-75	929	Jun-84	8.76	NA
Yellow Creek 2	Jun-76	929	Mar-86	9.75	NA
Yellow Creek 2	Sep-77	1048	Mar-86	8.50	
Yellow Creek 2	Jun-78	1048	May-86	7.92	NA
Yellow Creek 2	Sep-78	1172	Mar-86	7.50	
Yellow Creek 2	Sep-79	1445	Apr-88	8.59	2
Yellow Creek 2	Dec-80	1364	Apr-88	7.34	
Yellow Creek 2	Mar-81	1243	Apr-88	7.09	
Yellow Creek 2	Sep-81	1938	Apr-88	6.59	
Yellow Creek 2	Mar-82	NA	Apr-88	6.09	
Yellow Creek 2	Sep-82	1938			
Zimmer 1	Dec-69	199	Jan-75	5.09	0
Zimmer 1	Mar-70	210	Jan-75	4.84	NA
Zimmer 1	Sep-70	276	Jan-75	4.34	NA
Zimmer 1	Sep-71	288	Oct-76	5.09	0
Zimmer 1	Dec-72	311	Aug-77	4.67	1
Zimmer 1	Sep-74	434	Jan-79	4.34	19
Zimmer 1	Dec-75	502	Jan-79	3.09	40.5
Zimmer 1	Sep-76	531	Jan-79	2.33	58.1
Zimmer 1	Sep-77	531	Jul-79	1.83	77.2
Zimmer 1	Mar-78	664	Jan-80	1.84	81.3
Zimmer 1	Jun-79	850	Jan-81	1.59	92.8
Zimmer 1	Mar-80	850	Feb-82	1.92	92.8
Zimmer 1	Jun-80	1027	Apr-82	1.83	93.8
Zimmer 1	Dec-81	1258	Jan-83	1.08	96.8
Zimmer 1	Mar-82	1258	Jun-83	1.25	97.5
Zimmer 1	Jun-82	1258	Dec-83	1.50	97.96
Zimmer 1	Sep-82	1667	Jan-84	1.33	98.26
Zimmer 1	Dec-82	1667	NA	NA	98.3

Canceled Bechtel Plants

Unit Name	Date of Estimate	Estimates: Total Cost	COD	Est. Years to COD	% Complete
Callaway 2	Jun-74	805	Apr-83	8.84	0
Callaway 2	Dec-74	863	Apr-83	8.34	0
Callaway 2	Mar-76	739	Apr-83	7.09	0.2
Callaway 2	Dec-76	1297	Apr-87	10.34	0.4
Callaway 2	Jun-77	1297	Apr-87	9.84	0.4
Callaway 2	Dec-77	1288	Apr-87	9.34	0.4
Callaway 2	Sep-78	1306	Apr-87	8.59	0.4
Callaway 2	Mar-80	1609	Apr-87	7.09	0.7
Callaway 2	Jun-80	1609	Jun-88	8.01	0.7
Callaway 2	Dec-80	1688	Apr-88	7.34	0.7
Callaway 2	Mar-81	1688	Apr-90	9.09	0.7

Canceled Non-Bechtel Plants

Unit Name	Date of Estimate	Estimates: Total Cost	Estimates: COD	Est. Years to COD	% Complete
Bailly Nuclear 1	Mar-67	113	Dec-72	5.76	NA
Bailly Nuclear 1	Mar-70	161	Feb-76	5.93	NA
Bailly Nuclear 1	Sep-70	160	Feb-76	5.42	NA
Bailly Nuclear 1	Jun-72	244	Jun-77	5.00	0
Bailly Nuclear 1	Sep-74	447	Jun-77	2.75	0.5
Bailly Nuclear 1	Sep-75	447	Jun-95	19.76	0.5
Bailly Nuclear 1	Mar-76	447	Jun-85	9.26	0.5
Bailly Nuclear 1	Sep-76	674	Jun-85	8.75	0.5
Bailly Nuclear 1	Dec-76	674	Nov-82	5.92	0.5
Bailly Nuclear 1	Mar-77	705	Nov-82	5.67	0.5
Bailly Nuclear 1	Sep-77	705	Dec-82	5.25	0.5
Bailly Nuclear 1	Dec-77	705	Jun-84	6.50	0.5
Bailly Nuclear 1	Mar-78	850	Jun-84	6.26	0.5
Bailly Nuclear 1	Dec-78	850	Dec-84	6.01	0.5
Bailly Nuclear 1	Sep-79	1100	Jun-87	7.75	0.5
Bailly Nuclear 1	Dec-80	1100	Jun-89	8.50	0.5
Bailly Nuclear 1	Jun-81	1815	Jun-89	8.01	0.5
Cherokee 1	Sep-73	NA	Jan-81	7.34	0
Cherokee 1	Mar-74	NA	Sep-82	8.51	0
Cherokee 1	Jun-74	NA	Jan-82	7.59	0
Cherokee 1	Sep-74	248	Jan-84	9.34	NA
Cherokee 1	Dec-74	262	Jan-84	9.09	0
Cherokee 1	Dec-75	262	Jan-85	9.09	0
Cherokee 1	Mar-76	262	Jan-84	7.84	0
Cherokee 1	Mar-77	336	Jan-84	6.84	0.5
Cherokee 1	Dec-77	336	Jan-85	7.09	1
Cherokee 1	Mar-78	392	Jan-85	6.84	1
Cherokee 1	Mar-79	402	Jan-85	5.84	4
Cherokee 1	Jun-79	402	Jan-87	7.59	5
Cherokee 1	Mar-80	402	Jan-90	9.84	15
Cherokee 1	Sep-80	729	Jan-90	9.34	17
Cherokee 2	Mar-74	NA	Sep-83	9.51	0
Cherokee 2	Jun-74	NA	Apr-83	8.84	0
Cherokee 2	Sep-74	248	Jan-86	11.34	0
Cherokee 2	Dec-74	262	Jan-86	11.09	0
Cherokee 2	Dec-75	262	Jan-87	11.09	0
Cherokee 2	Mar-76	262	Jan-86	9.84	0
Cherokee 2	Mar-77	336	Jul-86	9.34	0.5
Cherokee 2	Dec-77	336	Jan-87	9.09	1
Cherokee 2	Mar-78	392	Jan-87	8.84	2
Cherokee 2	Mar-79	402	Jan-87	7.84	4
Cherokee 2	Jun-79	402	Jan-89	9.59	5
Cherokee 2	Mar-80	402	Jan-92	11.84	1
Cherokee 2	Sep-80	729	Jan-93	12.34	1
Cherokee 3	Mar-74	NA	Sep-84	10.51	0
Cherokee 3	Sep-74	248	Jan-88	13.34	0
Cherokee 3	Dec-74	262	Jan-88	13.09	0
Cherokee 3	Dec-75	262	Jan-89	13.10	0
Cherokee 3	Mar-76	262	Jan-88	11.84	0
Cherokee 3	Dec-76	262	Jun-89	12.51	0.5
Cherokee 3	Mar-77	336	Jan-89	11.85	0.5

Canceled Non-Bechtel Plants

Unit Name	Date of Estimate	Estimates: Total Cost	COD	Est. Years to COD	% Complete
Cherokee 3	Mar-78	392	Jan-89	10.85	1
Cherokee 3	Mar-79	402	Jan-89	9.85	4
Cherokee 3	Jun-79	402	Jan-91	11.59	4
Cherokee 3	Mar-80	402	Jan-94	13.85	1
Cherokee 3	Sep-80	729	Jan-95	14.34	1
Forked River 1	Mar-75	694	May-82	7.17	0.5
Forked River 1	Dec-76	894	May-83	6.42	0.5
Forked River 1	Jun-78	894	Dec-83	5.50	1
Forked River 1	Dec-78	1150	Dec-83	5.00	4.1
Hartsville B-1	Mar-73	379	Jun-81	8.26	NA
Hartsville B-1	Dec-74	601	Jun-81	6.50	
Hartsville B-1	Sep-75	601	Jun-82	6.75	NA
Hartsville B-1	Jun-76	601	Aug-83	7.17	NA
Hartsville B-1	Sep-76	602	Aug-83	6.92	
Hartsville B-1	Jun-77	602	Dec-83	6.50	NA
Hartsville B-1	Sep-77	854	Dec-83	6.25	
Hartsville B-1	Sep-79	1418	Jun-89	9.76	15
Hartsville B-2	Mar-73	379	Jun-82	9.26	0
Hartsville B-2	Jun-74	378	Jun-82	8.01	NA
Hartsville B-2	Sep-74	379	Jun-82	7.75	NA
Hartsville B-2	Sep-75	601	Jun-83	7.75	NA
Hartsville B-2	Jun-76	601	Aug-84	8.17	NA
Hartsville B-2	Jun-77	602	Dec-84	7.51	NA
Hartsville B-2	Sep-77	854	Dec-84	7.25	
Hartsville B-2	Sep-79	1418	Jun-90	10.76	5
Shearon Harris 3	Jun-71	234	Mar-77	5.75	0
Shearon Harris 3	Sep-71	246	Mar-77	5.50	0
Shearon Harris 3	Dec-72	274	Mar-78	5.25	0
Shearon Harris 3	Sep-73	331	Mar-78	4.50	0
Shearon Harris 3	Dec-73	419	Oct-79	5.84	0
Shearon Harris 3	Jun-74	513	Mar-81	6.75	1
Shearon Harris 3	Dec-77	1039	Mar-90	12.25	0.5
Shearon Harris 3	Dec-79	1208	Mar-91	11.25	0.5
Shearon Harris 3	Jun-80	1208	Mar-94	13.76	0.5
Shearon Harris 4	Dec-77	1039	Mar-88	10.25	0.5
Shearon Harris 4	Dec-79	1208	Mar-89	9.25	0.5
Shearon Harris 4	Jun-80	1208	Mar-92	11.76	0.5
North Anna 3	Mar-73	355	Apr-77	4.09	0.5
North Anna 3	Sep-73	355	Dec-77	4.25	2
North Anna 3	Dec-73	389	Dec-77	4.00	2
North Anna 3	Mar-74	396	Mar-78	4.00	3.3
North Anna 3	Jun-74	396	Dec-78	4.50	3.6
North Anna 3	Dec-74	432	Jun-80	5.50	3.6
North Anna 3	Mar-75	512	Dec-80	5.76	4.8
North Anna 3	Dec-75	512	Apr-81	5.34	6.9
North Anna 3	Mar-76	653	Apr-81	5.09	6.9
North Anna 3	Mar-77	818	Apr-82	5.09	6.9
North Anna 3	Sep-77	818	May-82	4.67	7
North Anna 3	Dec-77	818	Oct-83	5.84	7
North Anna 3	Mar-78	1012	Oct-83	5.59	7
North Anna 3	Mar-79	1012	Apr-86	7.09	7

Canceled Non-Bechtel Plants

Unit Name	Date of Estimate	Estimates: Total Cost	Estimates: COD	Est. Years to COD	% Complete
North Anna 3	Sep-79	1428	Apr-86	6.59	7
North Anna 3	Dec-80	NA	Oct-89	8.84	7
North Anna 3	Mar-81	2175	Oct-89	8.59	7
North Anna 3	Dec-82	4053	Oct-89	6.84	8
North Anna 4	Mar-73	262	Apr-78	5.09	0.5
North Anna 4	Sep-73	262	Jun-78	4.75	2
North Anna 4	Dec-73	268	Jun-78	4.50	2
North Anna 4	Mar-74	281	Dec-79	5.76	1.6
North Anna 4	Jun-74	281	Mar-79	4.75	1.6
North Anna 4	Sep-74	281	Dec-79	5.25	1.7
North Anna 4	Dec-74	295	Dec-80	6.01	1.7
North Anna 4	Mar-75	347	Jul-81	6.34	2
North Anna 4	Dec-75	347	Nov-81	5.92	1.6
North Anna 4	Mar-76	423	Nov-81	5.67	1.6
North Anna 4	Mar-77	568	May-83	6.17	3.5
North Anna 4	Sep-77	568	Jun-83	5.75	3.7
North Anna 4	Dec-77	568	Sep-84	6.76	3.7
North Anna 4	Mar-78	660	Sep-84	6.51	3.7
North Anna 4	Mar-79	660	Apr-87	8.09	3.7
North Anna 4	Sep-79	956	Apr-87	7.59	3.7
Phipps Bend 1	Mar-75	780	Apr-82	7.09	0
Phipps Bend 1	Jun-75	780	Apr-82	6.84	0
Phipps Bend 1	Sep-75	780	Mar-83	7.50	0
Phipps Bend 1	Dec-75	780	Mar-83	7.25	0
Phipps Bend 1	Jun-76	780	Apr-84	7.84	0
Phipps Bend 1	Sep-77	876	Apr-84	6.59	0
Phipps Bend 1	Dec-77	876	Aug-84	6.67	0
Phipps Bend 1	Sep-78	872	Aug-84	5.92	1
Phipps Bend 1	Sep-79	1440	Mar-87	7.50	7
Phipps Bend 1	Dec-80	1440	Feb-89	8.18	14
Phipps Bend 1	Mar-81	2685	Feb-89	7.93	20
Phipps Bend 1	Sep-81	2685	Apr-94	12.59	25
Phipps Bend 1	Dec-82	NA	Apr-94	11.34	27
Phipps Bend 2	Mar-75	780	Apr-83	8.09	NA
Phipps Bend 2	Sep-75	780	Mar-84	8.50	0
Phipps Bend 2	Jun-76	780	Apr-85	8.84	NA
Phipps Bend 2	Sep-77	876	Apr-85		0
Phipps Bend 2	Dec-77	876	Aug-85	7.67	0
Phipps Bend 2	Sep-78	872	Aug-85		0
Phipps Bend 2	Sep-79	1440	Aug-89	9.92	1
Phipps Bend 2	Jun-80	1440	May-94	13.92	4
Phipps Bend 2	Dec-80	1440	Aug-89	8.67	NA
Phipps Bend 2	Dec-82	NA	NA	NA	5
WNP 4	Sep-74	NA	Jun-82	7.75	NA
WNP 4	Dec-74	NA	Mar-82	7.25	0
WNP 4	Jun-75	436	Mar-82	6.75	0
WNP 4	Jun-76	1095	Mar-82	5.75	0.5
WNP 4	Dec-76	1095	Mar-83	6.25	0.8
WNP 4	Mar-77	1003	Mar-83	6.00	1.3
WNP 4	Jun-77	1232	Mar-83	5.75	1.6
WNP 4	Dec-77	1232	Jun-84	6.50	2.8

Canceled Non-Bechtel Plants

Unit Name	Date of Estimate	Estimates: Total Cost	Estimates: COD	Est. Years to COD	% Complete
WNP 4	Mar-78	1610	Jun-84	6.26	3.2
WNP 4	Sep-78	1982	Jun-85	6.75	7.6
WNP 4	Mar-79	2302	Jun-85	6.26	11.6
WNP 4	Dec-79	3348	Jun-86	6.50	14.4
WNP 4	Mar-80	3086	Jun-86	6.25	14.5
WNP 4	Jun-81	4251	Jun-87	6.00	26.5
WNP 5	Mar-74	NA	Mar-83	9.01	0
WNP 5	Jun-75	439	Mar-83	7.75	0
WNP 5	Mar-76	1271	Apr-84	8.09	0
WNP 5	Sep-76	1271	Nov-84	8.17	0
WNP 5	Dec-76	1189	Jan-85	8.09	0
WNP 5	Mar-77	1470	Feb-85	7.93	0
WNP 5	Sep-77	1470	Mar-85	7.50	0
WNP 5	Dec-77	1470	Jul-85	7.59	0
WNP 5	Mar-78	1887	Jul-85	7.34	0
WNP 5	Mar-79	2224	Jun-86	7.26	1.8
WNP 5	Sep-79	2493	Jun-86	6.75	6.4
WNP 5	Jun-80	3705	Jun-87	7.00	6.7
WNP 5	Sep-80	3420	Jun-87	6.75	8.2
WNP 5	Jun-81	4845	Dec-87	6.50	14.3

APPENDIX C

EXCERPT OF TESTIMONY BY PAUL CHERNICK

in M.D.P.U. 19494

April 1, 1979

ANALYSIS AND INFERENCE, INC. RESEARCH AND CONSULTING

10 POST OFFICE SQUARE, SUITE 970 — BOSTON, MASSACHUSETTS 02109 — (617) 542-0611

#4

COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF PUBLIC UTILITIES

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

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

FRANCIS X. BELLOTTI
Attorney General

By: Michael B. Meyer
Assistant Attorney General
Utilities Division
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April 1, 1979

V. CENTRAL MAINE POWER

Q: What materials did you review in preparing this portion of your testimony?

A: We were able to obtain some of Central Maine Power's (CMP) responses to Data Requests from Louise McCarren in a CMP rate case before the Maine Public Utilities Commission, docketed as FC #2322. Apparently, there was no official forecast document, but one of the responses is to the question

> "Please state the methodology used, including all the variables considered. . . (and) a detailed account of the statistical techniques used to assure the accuracy of the growth projections. . ." (1VLM-7)

The responses to this question and follow-up questions appear to present CMP's best explanation of its methodology. The forecast peaks coincide with those in the 1978 NEPOOL Load and Capacity Report.

Q: Please describe the CMP forecast methodology?

A: The sales forecast is composed of Residential, Commercial, Industrial, and Other Sales. Sales in each category are then allocated between months. Losses and Company Use are added to each month's sales to determine territory output, which is multiplied by a monthly load factor to determine monthly peak.

Q: Do you have any general comments on the sales forecast?

A: Yes. Considering the size and forecast growth rate of CMP, the sales forecast is wholly inadequate. As CMP stated:

> In summary, the basis for the forecast is a computer program which produces a forecast of monthly sales, net for load energy and peak loads. The key variables input to the program are as follows:
>
> 1. Residential nonseasonal customers;
> 2. Nonseasonal subclass saturation rates;
> 3. Residential seasonal customers;
> 4. Residential customer average usage by subclass;
> 5. Commercial sales growth rate;
> 6. Industrial sales growth rate;
> 7. Other sales growth rate;
>
> 8a. Lost and Unaccounted For growth rate;
> 8b. Other Company Use Factors; and
> 9. Monthly Load Factors.

In other words, CMP is only really interested in what happens after the sales forecast is developed. The sales forecast shows the result of this neglect. CMP indicates that "Ordinary least square (sic) regression analysis is the statistical technique which is put to greatest use." This technique is obviously inadequate for most purposes: in any case, we cannot determine any situations in which CMP actually used linear regression. The lack of detail and disaggregation in the various classes and the absence of a formal forecast document are also indicative of CMP's cavalier attitude towards forecasting.

It is also interesting that Dr. Joel Brainard of the Brookhaven National Laboratory reviewed CMP's forecast for the rate case mentioned above and testified that ". . . if you use the company's data and their methodology, you will not get the numbers they claim you'll get. . . The error in some cases is quite large." Our review confirmed this finding in several cases.

Q: Please describe the Residential forecast methodology?

A: The Residential class is divided into five subclasses: general, waterheating, spaceheating, all-electric, and seasonal. A Maine population projection was multipled by CMP's fraction of state population and divided by a projection of household size to yield households in CMP's territory. Since CMP apparently uses data on consumption per dwelling, rather than consumption per customer (a peculiar approach, which must cause some data problems), they then presumably scaled the household count upward to include vacant units. Unfortunately, CMP says they "divided by one plus. . . the vacancy rate", when they should have intended to divide by one <u>minus</u> the vacancy rate. It is not clear what in fact they did.

CMP then seems to have determined the number of new "customers" (actually dwellings, since some 11% were assumed to be vacant) in each year and to have apportioned them between the four non-seasonal subclasses by use of utterly undocumented, and very high, penetration rates for electric space and waterheating. In addition, the seasonal customer class is increased by 300 customers annually.

Each subclass "customer" number is then multiplied by an average consumption per dwelling. These average consumptions must capture the effects of dwelling type, dwelling size, family size, appliance saturations (other than space and water heating), average appliance consumption, efficiency standards, retrofitting of insulation, woodburning, building design, and electricity price. None of these factors was explicitly considered. In fact, average consumption for non-seasonal space-heating and all-electric customers was simply projected to increase at 140 KWH annually, presumably based on some data from the late 1960's, when average consumption was rising. Since 1972, average consumption for these two classes has actually _fallen_ by an average of 718 KWH annually; a linear time trend on this period would predict declines of 588 KWH annually. Of course, no historical trend can capture future appliance efficiency and the like.

Similarly, General Residential customers' average consumption was assumed to increase at an amazing 200 KWH annually, waterheating customers at 190 KWH annually, and seasonal customers at 100 KWH per year. While we do not have historical data for these subclasses, it is unlikely that appliance penetrations could counter-balance greater appliance efficiency, insulation retrofit on water heaters and pipes, and all the other conservation measures available to residential customers, so as to produce these large increases. Of course, since CMP has no saturation data for most appliances, it would be difficult to model these effects in detail.

Q: Please describe the commercial methodology?

A: Based on an analysis of historical data, CMP claims that 3.4% annual long-term growth in Maine nonmanufacturing employment is "appropriate". We have not seen the data they used; given their performance in other sectors, CMP's credibility in determining "appropriate" growth is not high.

CMP then multiplied Maine nonmanufacturing employment by KWH per employee to yield Maine commercial sales. The KWH per employee figure is said to be based on a time trend; CMP provides no details, as usual. In any case, this factor increases at 250 KWH/employee/year in most forecast years, and occasionally at 240 KWH/year.

Even if CMP's projection of sales per employee is based on a perceived trend, it is apt to be incorrect for three important reasons. First of all, commercial sales and nonmanufacturing employment have not historically referred to the same establishments. CMP apparently used sales to certain rate classes as a proxy for commercial sales until 1975, at which time they reclassified sales on the basis of SIC. This reclassification may have moved many large commercial customers (e.g., shopping centers) into the commercial class for the first time, dramatically inflating the sales-to-employee ratio and distorting historic trends, which may have already been affected by classification problems. Secondly, no correction has been made in the historical trend to reflect higher electric prices, equipment efficiency, or improved building design. Indeed, given CMP's predilections, the forecast growth may exceed historic rates. Third, CMP does not disaggregate commercial sales in any way, either in historic data or in the forecast.

CMP determined its share of Maine commercial sales by use of the equation:

$$GWHC = \left[.801 * CWHM\right] - 45.2$$

where GWHC is CMP commercial sales in GWH

GWHM is Maine commercial sales in GWH

Obviously, this formulation will increase CMP's share of Maine sales over time. We have no information as to how CMP chose this peculiar function, nor from what data (if any) it is derived, nor whether the other Maine utilities are projecting corresponding decreases in their share of total commercial sales.

Finally, CMP's methodology does not seem to produce its commercial forecast, perhaps because of further reclassifications in 1978. But even the growth rates are not taken from the methodology, CMP holds growth constant at 7.0% from 1983 to 1990, when the methodology should produce steadily declining growth, due to the linear growth in sales/employee and the asymptotic nature of the CMP fraction equation. CMP's methodology yields a 6.4% growth rate in 1990, for example, rather than the 7.0% CMP uses. In fact, it appears that CMP used a higher growth rate than the methodology would produce <u>in every forecast year</u>.

Q: Please describe the industrial sales forecast methodology?

A: Industrial sales are forecast as a whole, without any disaggregation by industrial type, such as SIC code. CMP forecasts 17.7% growth in industrial sales in 1977, followed by a constant (if sloppily calculated) 4.0% growth thereafter, until 1990. CMP claims that "the industrial sales growth rate is based on the long term trend exhibited between 1965 and 1975." This long term trend was actually 3.0% annual growth. In the longer term, 1965-1977, CMP industrial sales grew at 2.6%, which slowed to 2.5% from 1969 to 1977, to 2.1% since 1972, and 1.0% since 1974. How a 17.7% jump and long term 4.0% growth can be "based on" these historic trends is not at all clear. No effort is made to incorporate electricity price or national or local industrial output into the forecast.

Q: Please describe the Other sales forecast?

A: Other sales is projected to grow at 5% annually from 1978 to 1990. This growth appears to be chosen to approximate the overall forecast growth in the major classes. However, these sales have historically fluctuated with no real pattern: since 1966, other sales have grown at a compound rate of 1.6% annually, but they have <u>fallen</u> since 1973 at -5.5%. Almost any moderate growth rate, positive or negative, could be supported in some fashion by this erratic record, but not one as high as 5%. Zero growth might be the most reasonable assumption.

Q: Does this conclude your testimony on the CMP forecast?

A: Yes.

APPENDIX D

EXCERPT OF TESTIMONY BY PAUL CHERNICK

in N.R.C. Docket No. 50-471

June 29, 1979

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UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

BEFORE THE ATOMIC SAFETY AND LICENSING BOARD

In the Matter of BOSTON EDISON COMPANY, et al., Pilgrim Nuclear Generating Station, Unit 2	Docket No. 50-471

JOINT TESTIMONY OF PAUL L. CHERNICK
AND SUSAN C. GELLER ON BEHALF
OF THE COMMONWEALTH OF MASSACHUSETTS

COMMONWEALTH OF MASSACHUSETTS

BY: FRANCIS X. BELLOTTI
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June 29, 1979

II. THE NEPOOL MODEL

Q: What materials have you reviewed in preparing this portion of your testimony?

A: Until recently, we had available only the Report on a Model for Long-Range Forecasting of Electric Energy and Demand to the New England Power Pool by NEPOOL Load Forecasting Task Force and Battelle-Columbus (6/30/77), hereinafter referred to as "the Report". Our requests for further information, both through the EUA forecast case (EFSC 78-33) and through an ongoing investigation into Boston Edison's construction program (DPU 19494/Phase II) had been unsuccessful.

In the latter case, we recently received, through cross-examination of Mr. Bourcier, copies of partial output from the runs of the model which produced the NEPOOL forecast, forty five "Model Documentations" which revise and supplement the Report, and other information which Mr. Bourcier supplied orally. As of the time this testimony was written, no response to our discovery on BECO in this case had been received.

Q: Do you have any special reservations about reviewing the NEPOOL model based on the documentation available to you?

A: Yes. Both the Report and the Documentation raise almost as many questions as they answer, due to the nature and style of the documents:

1. Many relationships are estimated from data which are not provided. In many cases, the exclusion of the data is understandable, considering its bulk, but makes discovery even more important than in relatively self-contained forecasts.

2. Selected functional forms are presented, without the rejected alternatives, a discussion of the criteria for choice, or goodness-of-fit measures.

3. Some important inputs are user specified, and are therefore not presented in the Report.

4. At this writing, only partial results of the Model are available. Such important intermediate results as sales by end use, appliance penetrations, appliance saturations, labor force participation rates, and value added have not been reported.

5. Several important sources on which the model is based are unpublished NEPOOL/Battelle products, testimony in other cases, comments made in panel discussions at industry conferences, and the like. Considering the sophistication of the NEPOOL model, these omissions prevent any thorough review of the model.

Q: Please describe the structure of the model.

A: Conceptually, the NEPOOL model is divided into seven major sections:

1. The demographic submodule, in which population, migration, and labor force participation are determined;

2. The employment submodule, in which employment by industry type is determined;

3. An interface between the economic/demographic module and the power module, which sets household number, housing type mix, and income distribution;

4. The residential power submodule, which determines appliance saturations and average use patterns;

5. The industrial power submodule which determines value added and KWH/ value added for each SIC;

6. The commercial power submodule, which determines base load consumption per employee, saturation of electric space heating and cooling, and weather sensitive load for each commercial category; and

7. The miscellaneous power submodule, which forecasts such uses as street lighting, agriculture, mining, railroads, utility use, and losses.

We will attempt to review briefly a sampling of the deficiencies in each section.

Q: Please discuss the deficiencies in the demographic submodule.

A: The migration equations have some serious flaws. Migration rates are postulated as a linear function of the differential between local and national unemployment. Rather than estimating these relationships over time for each state, NEPOOL estimates <u>across</u> the New England states for the period 1960 to 1970. What is really being measured, then, is the attractiveness of Massachusetts, or Vermont, relative to the rest of the country in the 1960's, rather than the effects of changing unemployment rates. This "cross-sectional fallacy" can be quite dangerous; Figure I illustrates how even the sign of the cross-sectional relationship can be different from that of the relationship which holds for each state. Furthermore, due to the nature of the estimation procedure, neither national unemployment nor time-dependent changes can directly effect the migration rate.

Other problems appear in the migration section. NEPOOL admits that wages influence migration, but wages do not appear as a variable in forecasting migration. Similarly, NEPOOL recognizes that schooling influences migration, yet no attempt was made to identify the impact of expansion of higher education in Massachusetts in the 1960's, which certainly attracted more out of state students in 1970 than a decade earlier. No significance tests are offered for the equations; it is not clear that the relations are not simply artifacts of chance. The statistical tests which are provided by NEPOOL indicate that much of the variation in the data is not explained by the equations. Finally, NEPOOL corrects the equation for young males to take out the effects of the military draft in 1970; it does not appear that the countervailing effect of either the Cold War military activity of 1960 or the function of colleges for draft avoidance in 1970 was similarly factored out.

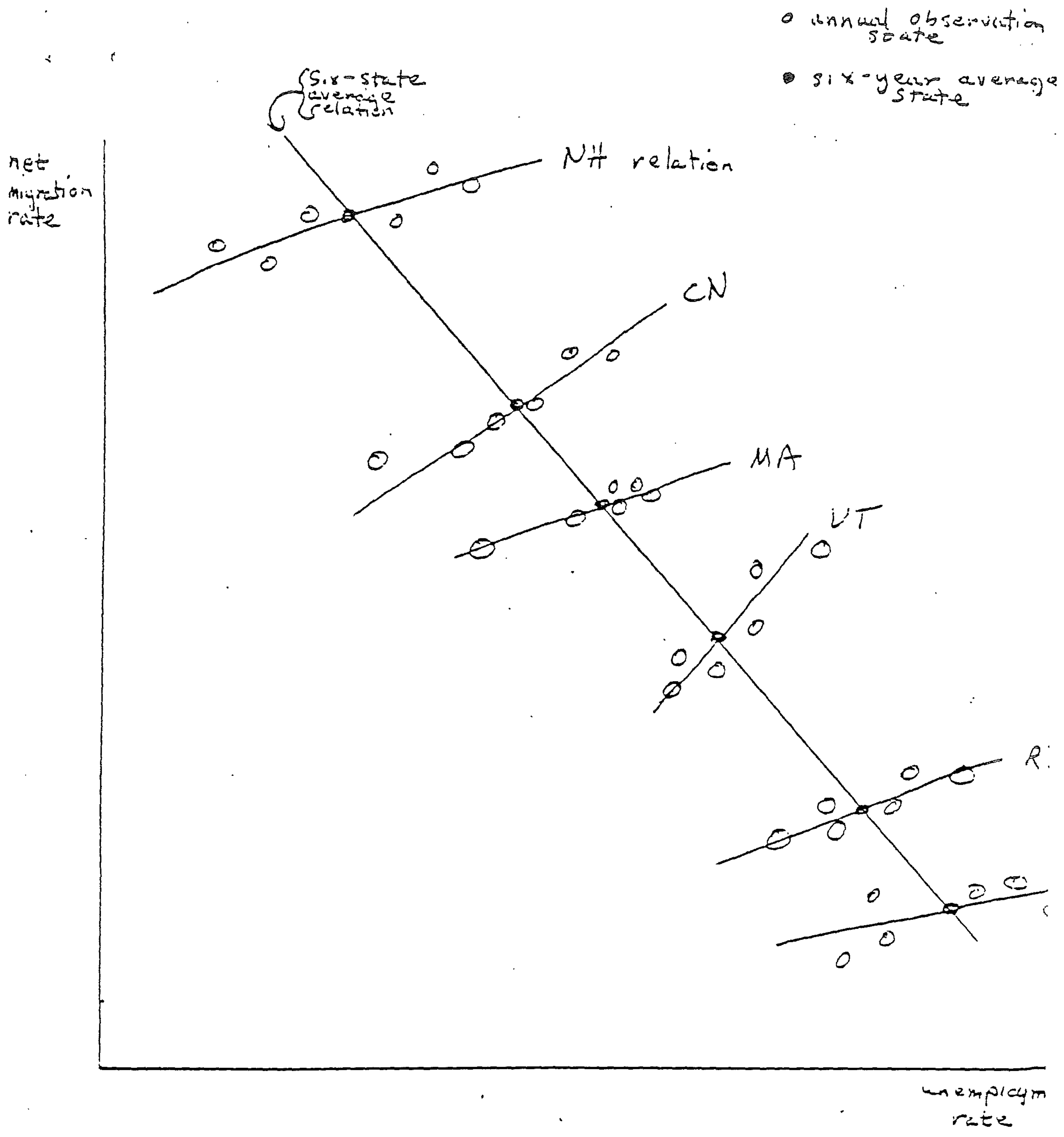


Figure I: Example of the Cross-sectional Fallacy

The sensitivity analyses performed on the migration equations are ambiguously explained in the Report. It is unclear whether the slope coefficients were changed in absolute value or actual level; whether the intercepts, the means, or some other point was held constant when the slopes were increased; and what NEPOOL actually did when it "dropped the error term". In any case, the equations have been revised but no new sensitivity tests were reported.

Q: Do similar errors occur in the estimation of labor force participation rates?

A: Yes. This rate (LFPR) is estimated for each age/sex group as a linear function of jobs per capita and/or of time. Even though data from the years 1960 and 1970 are used, the presence of the time variable probably results in the jobs per capita variable capturing primarily differences between states, just as the migration equations do. For various cohorts, one or both variables are omitted; no reasons are offered for these differences. Finally, having gone to the trouble of estimating some approximation of New England labor forces participation functions, NEPOOL tacks on two time trends based on national projections. It seems that the application of these trends either double counts the effects NEPOOL has attempted to measure directly or eliminates the need for the direct estimation process. In short, it is impossible to determine from the documentation how NEPOOL's LFPR equations were really derived and whether that derivation is reasonable.

Q: How is employment forecasted by NEPOOL?

A: Non-manufacturing employment is forecast as a ratio to state population. Manufacturing employment is forecasted by multiplying exogenous forecasts of national employment growth rates (by SIC) by a "cost index multiplier" to account for differences in local and national costs.

Q: Is the non-manufacturing employment growth forecast reasonable?

A: No. It has two serious problems. First, NEPOOL assumes that all non-manufacturing employment serves local population; in fact, much non-manufacturing employment may be serving businesses and/or serving customers outside the state (e.g., Massachusetts' hospitals and universities, Connecticut's insurance firms, and considerable portions of various states' agriculture and tourism). Second, NEPOOL is apparently projecting non-manufacturing employment per capita in each sector in each state to grow at national rates, despite historic tendencies, in several cases, to grow more slowly and fall more rapidly than the national average. Unfortunately, NEPOOL's documentation on this point is so vague that it is not possible to determine exactly how this projection is performed.

Q: What comments do you have on the cost index multiplier for manufacturing employment?

A: First, NEPOOL's equations imply the relationships listed in Table I _infra_. For example, if national growth is negative and costs are much lower locally, then the faster national employment _falls_, the faster local employment _grows_. This relationship is definitely counter-intuitive.

In addition, NEPOOL provides no documentation for the three complex cost index multiplier curves which it uses for various states. The multipliers often produce _worse_ backcasts than the national growth rates alone.

Q: Are the cost comparisons on which the cost index multipliers operate performed in a reasonable manner?

A: Each SIC's costs are divided into fractions for labor, transportation, taxes, energy and others. For each fraction, a local-to-national cost ratio is derived. Problems arise in all five areas.

With respect to labor costs (RLC), the major problems arise with respect to an equation which adjusts RLC as a function of local

TABLE I

Local to National Cost Ratio	Relationship between Local Growth and National Growth if NG O	NG O
over 1.08	LG = .1NG	LG = 2.1NG
1.07 to 1.08	LG = O	LG = 2NG
.92 to .93	LG = 2NG	LG = O
under .92	LG = 2.1NG	LG = -.1NG

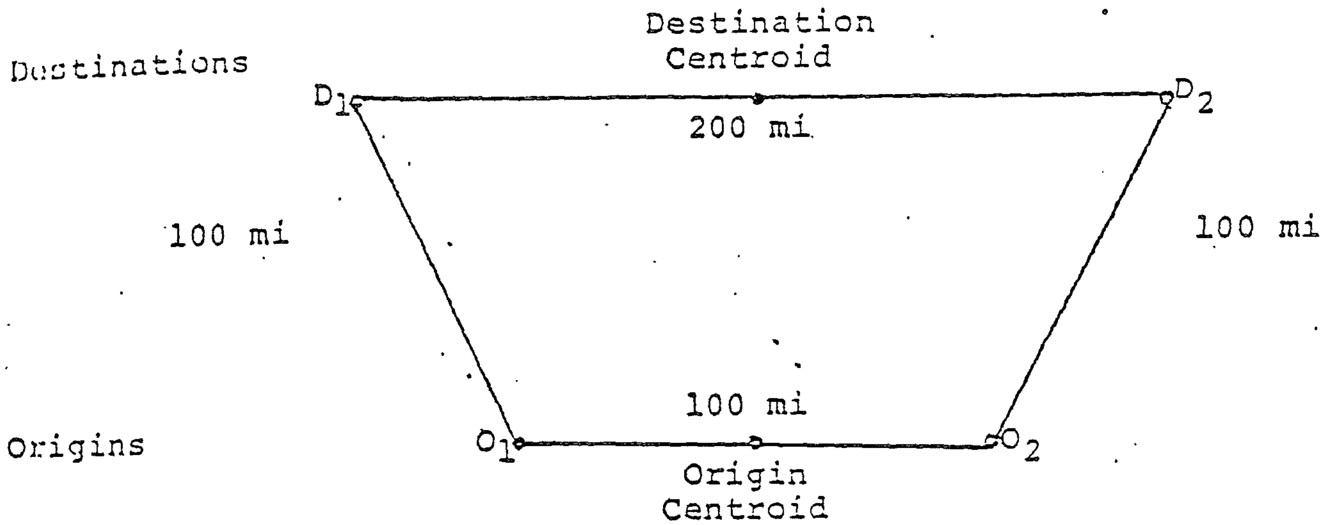
and national unemployment rates. There is no documentation of this equation, and NEPOOL has apparently never tested it. Yet this equation will adjust labor costs downward in the forecast period. Furthermore, NEPOOL adjusts RLC more rapidly when RLC < 1 (local costs are cheaper than national costs) than when RLC > 1. NEPOOL's reasoning on this matter is opaque.

With respect to transportation costs, the major problems concern measurement of distances. While the measurements of distance from New England to other regions are somewhat crude, the real problem arises within New England. NEPOOL assumes that all shipments from any part of a state originate at the state employment centroid and terminate at the New England employment centroid. This will tend to underestimate transportation costs within New England, as illustrated in Figure II, <u>infra</u>.

Q: Are taxes measured better than transportation costs?

A: No, they are very poorly measured. Utility taxes, which probably affect few industrial customers directly, are included in the measure, as are insurance taxes, only a portion of which are paid by manufacturing firms. But real estate taxes, which may be very important costs, are excluded. It may not be possible to accurately measure tax costs to business; it is not clear that a bad measure is more useful than none.

FIGURE II



SUPPOSE:

Shipments originate equally from 0_1 and 0_2
Shipments from each origin are equally divided between D_1 and D

THEN:

Average shipment length = $1/2 \times 100mi + 1/2 \times \sqrt{3} \times 100mi$ = 1

BUT:

Distance between centroids = $\sqrt{\frac{3}{2}} \times 100mi = 86.6mi.$

Figure II: Why centroids are poor measures of distance when regions are close together.

Q: Are there any further problems in the economic submodule?

A: There is one potentially quite serious generic problem. NEPOOL does not seem to have maintained consistency of the internal forecast with the exogenous forecast which drives it. It is not clear that projections of LFPR, or man-hours per employee, or productivity, or wage rates, or energy costs in the NEPOOL model are compatible with the values Wharton Economic Forecasting Associates uses. For example, suppose that WEFA is projecting that low rates of labor productivity growth, shorter weeks, low wages, and high energy costs will generate large employment. If NEPOOL then takes that large employment growth and assumes higher wages, cheaper energy, longer weeks, and higher productivity, the demand forecast will be directly inflated by the lack of consistency.

In fact, in some cases NEPOOL's forecasting may be internally inconsistent, as well. For the manufacturing employment forecast, wage rates are projected to fall compared to national levels, while for determining personal income (and residential electric use) they are projected to rise at historic national rates.

Q: Are appliance saturations projected in a reasonable manner in the residential power submodule?

A: Most appliance saturations are forecast as functions of household income; this is generally a good approach, although family size probably should be included for several appliances. However, the saturation functions suffer from several errors:

1. No distinction is drawn between new market penetration and old market conversions or acquisitions; this may be a serious deficiency for central air conditioning and electric ranges.

2. An income relation is improperly used as though it were an appliance price relation.

3. The effects of electric price and service costs on effective appliance price are neglected.

4. NEPOOL assumes that real appliance prices will fall rapidly although the most recent data available indicates that real prices are rising.

5. Prices of electricity and alternative fuels are not incorporated in any way; increasing electric costs may counteract the effects of the falling real price of appliances which NEPOOL incorporates.

6. The saturation functions are applied to appliances for which the measured price and/or income are not particularly relevant to purchase decisions.

For example, electric penetration of the range and dryer markets will primarily respond to relative fuel prices and efficiencies, to space heating fuel, and, for ranges, to performance. Income should not affect fuel choice, and if falling appliance price has any effect, it would be to reduce the slight capital cost advantage some electric versions enjoy over their gas counterparts. Furthermore, NEPOOL assumes, without any supporting data or analysis, and often in contradiction to available evidence, very high penetrations of dishwashers and room air conditioners in new construction; increases in total refrigerators saturation; accelerated increases in the ratio of frost-free to standard refrigerators; and constant shares of controlled waterheating.

Electric space heating penetrations are forecast by use of an equation that incorporates electric and oil heating capital and operating costs, promotion by the utility, fraction of housing that is single family, and degree of urbanization. Unfortunately, NEPOOL's model incorrectly measures fuel costs (both in the estimation of the model and in forecasting) and some capital costs, inadequately models the advantage of gas heat over oil heat, explains very little of the observed variation in data, ignores demolitions (which inflate penetration rates) and is improperly adjusted by state. For example, the equation was estimated on the basis of data from thirty-two utilities around the country; since heat pumps are very popular in some warm areas, NEPOOL's cost comparisons may be seriously tainted. Problems are also evident in the estimate of alternative fuel cost: gas is not even considered as an alternative for New England, and new furnace efficiency is assumed to be constant from 1966 on. NEPOOL also gives no hint of how the variables (most importantly, electric price) are forecast; in the case of electric price, the effect of rate reform and elimination of promotional rates should also be considered.

Q: Are NEPOOL's projections of average annual use per appliance reasonable?

A: Curiously, the Report and Documentations do not provide this information. NEPOOL provides only "connected load" for each appliance, which is multiplied by a fraction, F (which varies over the days of the week, the seasons, the time of day, between appliances, and in some cases with temperature) to determine hourly demand. The annual sum of these F's then determines use per appliance. Even in the absence of this information, however, several shortcomings are evident.

NEPOOL has determined a relationship between family size and the annual use by ranges, refrigerators, dryers and water heaters. But this relationship is only applied to determine 1970 consumption, despite the fact that household size is projected to fall over time. No family size adjustment is calculated for other appliances, nor does family size affect the distribution of housing types, which is held constant. This error inflates space conditioning use.

Electric water heater consumption increases with dishwasher saturation, but does not respond to dishwasher or clothes washer efficiency improvements, which should have a substantial effect on average consumption. Apparently, NEPOOL does not understand the sources of anticipated efficiency improvement.

Average use by refrigerators, freezers, dishwashers, and dryers are projected to increase by as much as 2% annually. These figures are based on trends in the 1960's in California, in a time of falling electric prices. They are simply irrelevant to NEPOOL's forecast for the 1980's. In addition, since dishwasher and dryer efficiency targets are formulated on a per-load basis, these trends may imply that the targets will not be met and that efficiency may actually decline.

NEPOOL does not apply the DOE efficiency standards so that refrigerators and freezers each comply as a class. NEPOOL recognizes separate frost-free and standard versions of both appliances, and projects a greater saturation of frost-free refrigerators (the forecast split for freezers is not specified). If the efficiency improvements are applied to the two versions separately, NEPOOL would again be predicting that the entire appliance class will not achieve the DOE standards.

In addition, NEPOOL simply ignores the probable enactment of residential appliance efficiency standards beyond the current DOE targets and the inevitable effects of building code changes on electric use by space conditioning and water heating.

Based on "remarks" and "testimony" by NERA personnel, NEPOOL makes a number of peculiar assumptions. They assumed unrealistically high (up to -1.2) short-run price elasticities for several appliances, and rather low (as low ass -0.5) long-run elasticities for other appliances.

Use by refrigerators, freezers, and televisions is amazingly assumed to exhibit no price elasticity at all. The elasticities were arbitrarily manipulated to yield aggregate residential sales in the calibration period.

Use in the miscellaneous category is predicted with the formula:

$$M = (.067 * t + 1.836) * Y * (.996 +.032\ t) * M70 + C$$

where M = miscellaneous appliance use per household
Y = personal income per household
M70 = miscellaneous use in 1970
t = year-1970
C = constant

The first factor is NEPOOL's perceived time trend for appliance expenditures as a fraction of income in the period 1960-1973, which is extrapolated out indefinitely.

normal manner (e.g., by the CPI) and then added a 4.3% growth in appliance sales (due to an assumed falling appliance price) which was already captured in the trend. Again, NEPOOL's failure to document the model precludes adequate review. In any case, NEPOOL's projections of falling appliance prices are improper.

As a result of its triple trending (time, income, and appliance price) miscellaneous appliance use is expected by NEPOOL to increase over three times as fast as overall residential use from 1976 to 1990, at least for some states (not all the data has been made available).

Q: Are there errors in NEPOOL's handling of the interaction of appliances?

A: Yes, in at least two cases. Mr. Bourcier acknowledged one serious error which understates the reduction in range use due to increasing saturation of efficient microwave ovens. In addition, it does not appear that the model projects the net energy savings due to microwave ovens that the Report indicated were appropriate.

The effects of wood stoves on electric space heating use are incorporated for only two states; even in these states, the effects of wood stoves are held constant after 1979.

Q: How does NEPOOL initialize its 1970 appliance consumption figures?

A: NEPOOL found that 1970 residential consumption was overforecast by the model. NEPOOL therefore adjusted downward the average connected loads for most appliances, by a state-specific factor of 3.4% to 22.1%. Miscellaneous use, air conditioning and heating are excluded from the adjustment on the basis that "they were originally N.E. values." In fact, miscellaneous use is based solely on data from Connecticut, the state for which the adjustment is smallest. Large portions of the errors in other states' backcasts may result from differences in miscellaneous consumption from the 200 Connecticut customers from whom the miscellaneous data was extrapolated.

Window air conditioning usage appears to be based on Ohio and Baltimore data and on 1977 estimates by BECO and Northeast Utilities (Documentation 15). None of these sources used any New England consumption data, although New England cooling degree days are considered. Electric heating consumption is based on 169 all-electric homes (perhaps of

identical size and vintage) in Amherst, Massachusetts (Report, p. G-17). Perhaps the 22.1% error for Maine results from an overestimate of average heating consumption in that state based solely on the Amherst sample and weather.

Since it is the unadjusted uses, miscellaneous and space conditioning, which grow fastest in the forecast, NEPOOL's improper exclusion of these uses from the 1970 adjustment increase the overall forecast growth rate.

Q: Is the NEPOOL industrial submodule any better than the residential submodule?

A: No. The same problems in documentation exist, compounded by peculiar formulations, internal contradictions, and outright inaccuracies. There does not appear to be a single measure of goodness-of-fit or significance reported in the entire industrial submodule, for example.

Q: Please describe the industrial submodule.

A: NEPOOL first divides the industrial employment (an output of the economic model) into production and non-production employees. To derive KWH sales, the production employment in each SIC in each state is then multiplied by annual man hours per employee, value added per man hour, and KWH per dollar of value added.

Q: Please describe NEPOOL's forecast of production employment?

A: It seems that rather than model the ratio of production to non-production employees directly, NEPOOL chose to forecast the growth rate in value added per employee for each class and then back out the ratio. This is a roundabout approach, and NEPOOL really does not explain why it is used. Even NEPOOL became confused by this section of the module: on p. H-2 the Report says that the ratio increases if the production productivity growth rate is less than the non-production productivity growth rate (which is true), while on p. H-4 the Report claims th exact opposite. Furthermore, since the non-production employee productivity projections are based on New England data (from unspecified source and years) and the production employee productivity projections are from state data, the data seems to be incommensurate. Finally, NEPOOL's manipulation of the value-added-per-production-employee trending also affects the validity of the ratio.

Q: Please describe NEPOOL's projection of annual man-hours per employee.

A: This factor has been falling since 1970, yet NEPOOL arbitrarily assumes that it started increasing in 1977. In addition, it is not clear whether the national employment forecasts utilized by NEPOOL use the same man-hour assumptions, and whether the data was appropriately selected. On the latter point, NEPOOL indicates that only "selected observations" were used in establishing the hours per employee ratio; it is not clear whether this selection affected other portions of the calibration process. In any case, the sudden increase in man-hours inflates the industrial forecast.

Q: Please describe NEPOOL's forecast of value added per man-hour.

A: NEPOOL uses two models for VAMH. Model 1 is a constant and Model 2 is an exponential growth rate. NEPOOL provides no documentation for their choice of model for each SIC for each state (plus New England and totals). In fact, the New England relationships, to which the states are assumed to converge, are not even provided in the documentation.

Q: How does NEPOOL forecast the ratio of KWH sales per dollar of value added?

A: NEPOOL derived their electric intensity trends for some sort of backcast and calibration procedure, involving the estimation of two trend factors. NEPOOL does not provide:

any rationale for the double trending,

any description of the estimation methodology,

any explanation of the level of aggregation (SIC, state, etc.),

any description of the data, such as its source or comprehensiveness,

any data,

any of the estimated trends, or

any indication of goodness-of-fit or of statistical significance of the equations utilized.

Q: Is price elasticity handled properly in the commercial sector?

A: No. While the short-run elasticity is reasonable (-.2), the long-run elasticity of -1.0 is somewhat low, as NEPOOL admits. NEPOOL claims that this is appropriate, "since the selection of electricity for heating and cooling is treated separately through the saturation functions." But the heating saturation functions are based on upward time trends from the period 1966-1975, which captures the effects of falling prices, and the air conditioning "trends" are not documented at all. (Furthermore, the saturation rates are not corrected for commercial construction rates, which are probably important determinants). Therefore, the saturation trends should be discarded and the long-run elasticity increased to reflect reality.

Another problem occurs in the commercial air conditioning saturation forecasts. Saturations in 1970 are estimated on the basis of numbers of customers with air conditioning, rather than the number of employees in air conditioned commercial space. Since large commercial customers - large office towers, large stores, shopping malls - are already air conditioned, the fraction of air conditioned space (or employees) probably far exceeds the fraction of air conditioned customers. Therefore, NEPOOL is overestimating the potential for expansion.

Q: Are there any other problems with the NEPOOL demand forecast which transcend individual submodules?

A: At least two such problems are evident in the forecast. First, NEPOOL uses a rather low electric price forecast which is completely undocumented. Second, NEPOOL completely neglects the possibility of reforms in utility rates and operation, such as the establishment of time-of use rates, marginal cost pricing, fair backup and purchased power rates (for cogenerators and other power producers), load management, and utility conservation programs (e.g., voltage regulation, energy efficiency audits and consulting, changes in conditions of service).

Q: Do the results generated by the NEPOOL model confirm the existence of the problems you have discussed?

A: Yes. The model was calibrated on the 1970-1976 period and therefore generally fits well in that period. However, NEPOOL's backcasts for sales growth in 1976 and 1977 (where available) exceed actual growth for each of the major customer classes. Similarly, the model overforecast growth in total output by 1.4 percentage points in 1976, by 4.1 points in 1977 and 3.3 points in 1978. If the average post-calibration error continues in the NEPOOL forecast, output will rise at 0.4% in the 1978-89 period, to a total of only 86520 GWH in 1989, which is 36% less than the NEPOOL forecast for that year and only about 4.5% larger than 1978 output.

Peak growth rates were also overstated in both 1977 an 1978 by 3.5 percentage points. If this error continues in the rest of the forecast period, peak demand will grow at 0.3%, to a peak of 16019 MW in 1989. With existing capacity (minus scheduled retirements and retirements of all capacity now in deactivated reserve), currently planned purchases, and the capacity now under construction, New England would have a reserve margin of 54% in 1989.

Q: Please summarize the NEPOOL forecast.

A: NEPOOL appears to have created a model with numerous unjustified growth-producing assumptions including most of the factors mentioned above. NEPOOL then utilized high short-run elasticities and large commercial conservation corrections to neutralize this excessive growth in the calibration period. Once the calibration period ends, the model grows much too rapidly. Continuation of the infated trends, coupled with new growth-producing assumptions and errors, will produce inflated forecasts.

Q: Does this conclude your testimony on the NEPOOL demand forecast?

A: Yes.