MASS DPU. 84-49 & 84-50

#32.

THE COMMONWEALTH OF MASSACHUSETTS
BEFORE THE DEPARTMENT OF PUBLIC UTILITIES

RE: THE APPLICATION OF THE FITCHBURG GAS AND ELECTRIC COMPANY FOR AUTHORITY TO ISSUE SECURITIES	DPU 84-49 and DPU 84-50

**TESTIMONY OF PAUL CHERNICK
ON BEHALF OF THE
ATTORNEY GENERAL OF MASSACHUSETTS**

April 13, 1984

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TESTIMONY OF PAUL CHERNICK

ON BEHALF OF THE ATTORNEY GENERAL

1 - INTRODUCTION AND QUALIFICATIONS

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

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

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

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

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

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

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

A: Yes. I have testified approximately twenty-five times on utility issues before this Department, and such other agencies as the Massachusetts Energy Facilities Siting Council, the Texas Public Utilities Commission, the Illinois Commerce Commission, the New Mexico Public Service Commission, the District of Columbia Public Service Commission, the New Hampshire Public Utilities Commission, the Connecticut Department of Public Utility Control, 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, including those of Northeast Utilities, Boston Edison, the NEPOOL forecasts, and various smaller utilities, and predicted that growth rates would be lower than the utilities expected. Many of my specific criticisms have been incorporated in subsequent forecasts, load growth has almost universally been lower than the utilities forecast, and my general conclusions have been implicitly accepted by the repeated downward revisions in utility forecasts.

My projections of nuclear power costs have been more recent. However, utility projections have already confirmed many of my projections. 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 cancelled) stood at $4.0 billion.

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. I 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, 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 semi-official cost estimate of $9.0 billion, with in-service dates of 7/85 and 12/90. Thus, PSNH has moved its in-service date estimates, and increased its cost estimates, substantially towards my projections. Figure 1.1 compares the history of PSNH cost estimates for Seabrook to my estimates. Other estimates of Seabrook cost have followed my projections even more closely, as shown in Table 1.1.

In MDPU 20055 and again in MDPU 20248, I criticized PSNH's failure to recognize interim replacements, its error in ignoring real escalation in O & M, and its wildly unrealistic estimate of an 80% mature capacity factor (even the Massachusetts utilities seeking to purchase Seabrook shares were more realistic about capacity factors). I suggested interim replacements of $9.48/kw-yr., annual O & M increases of $1.5 million/unit (both in 1977 $) and 60% capacity factors. PSNH now includes capital additions, escalates real O & M at about 1% (about $0.1 million per unit annually), and projects a mature capacity factor of 72%. Thus, PSNH has implicitly accepted my criticisms, even though the O & M escalation and capacity factor projections are still very optimistic. While my original analyses (and the studies I relied on) were based on data only through 1978, experience in 1979-81 confirms the patterns of large capital additions, rapid O & M escalation, and low capacity factors. The 60% capacity factor figure, in particular, has been widely accepted by regulators (such as the California Energy Commission) and even utilities (such as Commonwealth Edison and now Central Maine Power).

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. While utilities have generally made some concessions to experience, nuclear cost and performance estimates continue to be optimistic, and hence it is still quite easy to improve on them.

Q: Have you been involved in previous cases concerning the capacity planning of Fitchburg Gas and Electric?

A: Yes. As I noted above, I testified in DPU 20055, the 1980 proceeding on the sale of Seabrook shares to Fitchburg (FGE) and other Massachusetts utilities by PSNH and other utilities. In that proceeding, I warned FGE that its load forecast was based on unsubstantiated opinions that existing industrial customers would expand operations, and that new industrial load would be added at a fairly rapid rate. The projected load growth did not occur. I also warned the Massachusetts utilities and the Commission that Seabrook would cost at least twice, and probably more than three times, the $2.6 billion cost estimate the utilities were using in their economic analyses. PSNH's current estimate of $9 billion is about 3.5 times the figure its witnesses presented in 20055.

Q: What is the subject of your testimony?

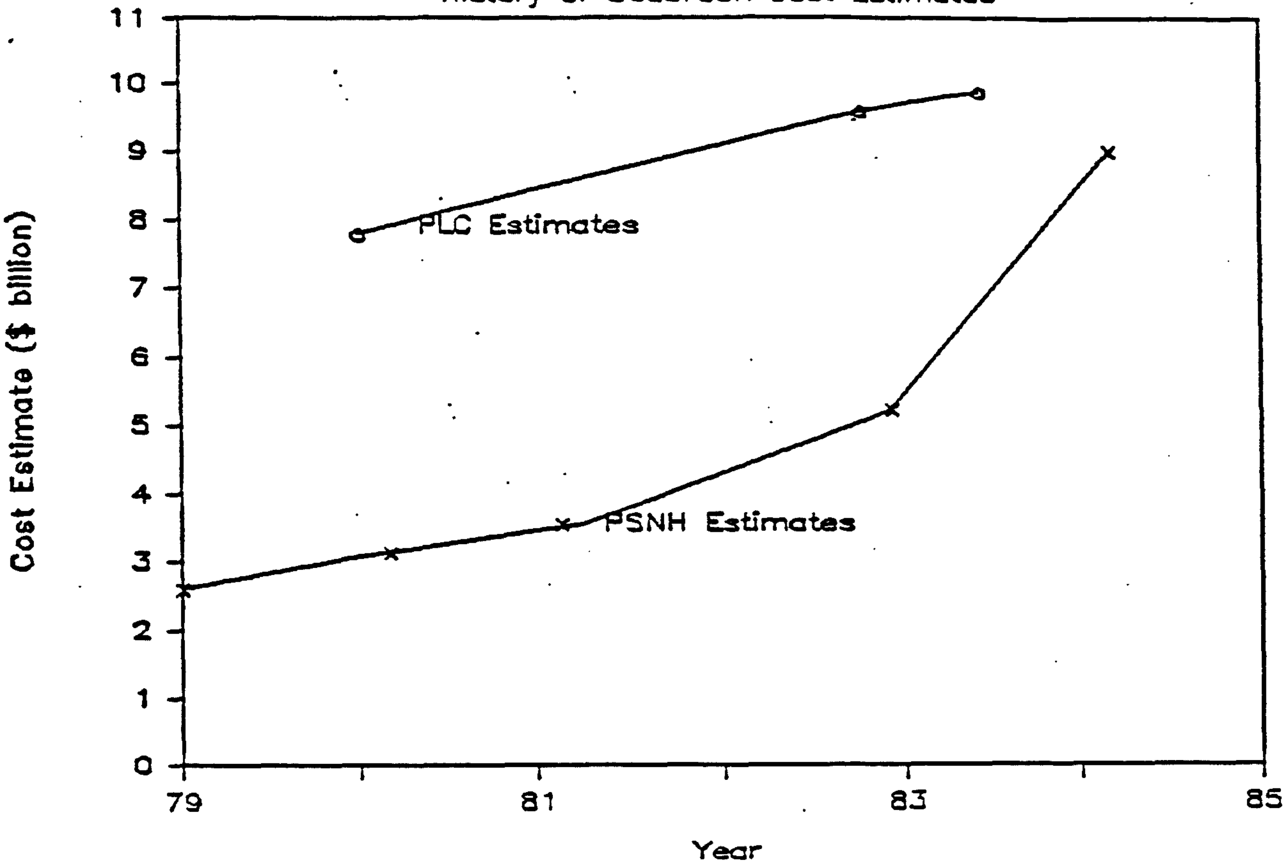
A: I have been asked to review FGE's construction program, and particularly the Seabrook project. I have specifically been asked to review whether the units are likely to enter service, how much it would cost to complete and operate them, and whether it is desirable to complete them.

Q: How is your testimony structured?

A: Section 2 considers the issues facing FGE in connection with Seabrook, and presents recommendations regarding appropriate FGE actions. Section 3 discusses the cost of the Seabrook units, including operating costs and capacity factor. Section 4 presents my conclusions and recommendations for the Commission.

Figure 1.1:

History of Seabrook Cost Estimates



Party	Date	Cost Estimate ($ billion)	Unit 1 COD	Unit 2 COD
1. Maine PUC	11/30/82	8.17	7/1/85	10/1/88
2. NEPCO	3/30/83	6.6	mid 85	early 89
3. New Hampshire PUC	4/29/83	8 - 9 +	1986	1990 +
4. Connecticut DPUC	8/22/83	7.75 +		
5. UE&C	1/31/84	10.1	4/17/87	
6. MMWEC	2/16/84	9	12/1/86	11/92
7. CMP	2/17/84	10.3	1/87	1/90

Table 1.1: Third-Party Projections of Seabrook Cost and Schedules

2 - SEABROOK AND FITCHBURG

Q: Have the conditions affecting the FG&E construction program changed substantially since the Department's review of the Seabrook purchase in DPU 20055, et al., and since the last FG&E rate case?

A: Yes. The largest portion of FG&E's construction program is its participation in the Seabrook project. The official cost estimates for this plant have increased from $2.8 billion, when DPU 20055 was filed, to $5.2 billion last year, to $9 billion today, as illustrated in Figure 1.1. The projected in-service dates of the two units have slipped from 1983 and 1985, to 1984 and 1987 last year, to 1986 and 1990 today. The cost estimates of the architect/engineer for the project are even higher than the official estimates by PSNH. As a result of these cost increases and schedule delays, PSNH is currently unable to raise capital, and faces insolvency in the near future. The joint owners, including FG&E, have been asked to assist PSNH in various ways. A majority of the ownership group has voted to cancel Seabrook 2, and even PSNH has voted for cancelation, under certain conditions. The cost and schedule histories of the Seabrook units, and my projections for their costs and schedule, are discussed in

Section 3 of this testimony.

The second-largest portion of FG&E's construction program is its participation in the third unit at Millstone Point. There have been no new cost estimates for Millstone 3 since August 1982, but there have been some significant developments. First, WMECo's presentation in DPU 84-25 indicates that Millstone 3 will cost its customers more than it saves them over the first 20 or 25 years of the unit's life, and that it will never pay back the investment in present value dollars. This point is explained in my testimony in DPU 84-25. In addition, my testimony in that case points out that more realistic assumptions about capacity factors, construction costs, or O&M expenses,[1] would lead to the conclusion that NU customers would be better off if the plant were canceled promptly. For example, I project that the cost of completing the plant will increase by at least $1 billion, and probably $2 billion, above current official estimates.

In this testimony, I will only be addressing the issues directly related to FG&E's participation in the Seabrook

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1. Correcting NU's projections for any one of these inputs would be sufficient.

project, due to their immediacy.

Q: What issues does FG&E face regarding Seabrook?

A: I believe that there are three areas of primary importance to FG&E with regard to Seabrook at this time. These areas are

1. the future of Unit 2

2. the PSNH bailout plans, and

3. the effect of recent changes on the future of Unit 1.

I will discuss each of these subjects in turn.

Q: What should FG&E do about Seabrook 2?

A: FG&E should be doing everything that it can to disassociate itself from Unit 2. This would include continuing to vote for unconditional cancelation, opposing all direct expenditures on Seabrook 2, and examining its options (perhaps in concert with other joint owners) in terms of legal action against PSNH. So far as I can see, there is no economic justification for any of the joint owners paying for any costs related to Unit 2, other than for the settlement of construction contracts and other cancelation costs. The lack of economic justification for Unit 2 is demonstrated in Section 3 of this testimony.

Q: Is there no chance that some other entity, such as Bechtel, will purchase the second unit and complete it?

A: I do not believe that there is. Despite some speculation, no engineering firm or other third party has yet made any public offer to finance and complete any nuclear unit at its own risk. Since Unit 2 would cost more to complete and operate than its power would be worth, no unregulated firm could hope to make money from it without extensive subsidies, even if the existing investments were handed over free of charge. It really does not make sense for any entity to attempt to finish Seabrook 2, and the usual organizations which might try it in other situations, such as a large state government, or a major power marketing agency, do not exist.

Q: Isn't Seabrook 2 already canceled?

A: That is not clear. It is my understanding that Unit 2 is "conditionally" canceled effective December 1984, subject to diversion of part of the Hydro Quebec project cost savings from the participants' ratepayers to PSNH shareholders. In the meantime, it appears that Seabrook 2 construction is continuing at some non-trivial level.

Q: What is your understanding of the proposals regarding assistance from other utilities to PSNH?

A: It is my understanding that the joint owners have discussed, at some level agreed to, a plan to divert a portion of Hydro

Quebec savings from New England ratepayers to PSNH shareholders, to limit PSNH's exposure to the costs of canceling Seabrook 2. This proposal appears to be justified by its supporters as a means to secure PSNH's support for canceling Unit 2, and perhaps to prevent some unspecified New Hampshire retaliation against the Hydro Quebec line. There also seem to be less specific proposals, suggesting that the joint owners make low-interest or zero-interest loans, or other contributions to PSNH, to enable it to continue construction of Unit 1.

Q: What should FG&E do with regard to these various plans to help PSNH out of its current financial distress?

A: I do not believe that FG&E should do anything to assist PSNH, for three basic reasons. First, these proposals do not appear to have any real benefits for FG&E's ratepayers or shareholders; both groups have enough problems without taking on those of PSNH.

Second, PSNH's troubles are primarily self-inflicted, so the company does not warrant any special consideration. PSNH has consistently produced particularly low and unrealistic cost estimates for Seabrook. These cost estimates were accompanied by correspondingly unrealistic schedules (at times, the most agressive schedules in the country) and inflated estimates of construction progress. This behavior has been so extreme that PSNH has subsequently been forced to report negative progress (i.e., to revise the estimate of current construction progress below the inflated level reported months before) in three cost estimates since 1979. It would have been very difficult for PSNH not to know that its estimates were highly optimistic. PSNH has repeatedly ignored warnings from regulators and its joint owners regarding the dangers, and even the futility, of attempting to build Unit 2.

Third, it is not clear that a $200 million[2] bailout will save PSNH. As demonstrated in Section 3, Unit 1 will cost at least 50% more than PSNH predicts, and may cost as much as PSNH was expecting to spend for both units. It is difficult to see how a utility which is already unable to raise capital could absorb part of the cost of a write-off from Unit 2, and still finance an additional $1 or $2 billion, for a plant which will require a massive rate increase, if and when it enters service.

Q: But is it not worth something to FG&E and the other participants to secure PSNH's cooperation in canceling

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2. It is my understanding that this is the size of the currently proposed Seabrook 2 assistance plan.

Seabrook 2?

A: That cooperation is really no longer at issue. If PSNH really tries to continue work on Unit 2, it will undoubtedly go into receivership. Therefore, while PSNH may wish to continue construction if it does not receive the bailout, that option is practically foreclosed by the cost of Seabrook 2 and by PSNH's finances.

Q: Does the possibility that PSNH's troubles could result in the cancelation of Unit 1 provide any justification for the bailout by the joint owners or other New England utilities and ratepayers?

A: Not at all. Seabrook 1 is not likely to pay for the costs of completing and running it, even without side payments to PSNH. Most ratepayers in New England would probably be better off if Seabrook 1 were canceled today, than if it were finished, even if the ratepayers have to pay for every dime of the investment to date.

The best that can be hoped for (and this is extremely optimistic) is that Seabrook 1 will have slightly positive net benefits over the course of its useful life. It can not be worth very much more investment to secure those benefits, even if they exist. This is particularly true if the ratepayers in the 1980's are being asked to bear additional burdens for a plant which will raise their rates for the rest of the century.[3]

Q: Is assistance to PSNH to facilitate completion of Unit 1 any more appealing than assistance in covering the costs of abandoning Unit 2?

A: Not really. As I noted above, Unit 1 is just not attractive enough to justify any extraordinary expense on its behalf; the ordinary expenses will be more than sufficient.

Q: Is any form of Seabrook bailout a better deal for the joint owners if they receive the right to purchase ownership shares in Seabrook 1 for less than PSNH's investment to date?

A: Absolutely not. The value of Seabrook 1 to New England is probably less than the cost of completing and operating it, even ignoring sunk cost, so no utility should want to increase its ownership share, even if the plant were being given away. It is not clear whether any utilities are willing to pay even a nominal sum for Seabrook entitlements; if there are any such utilities, FG&E should certainly attempt to negotiate a sale of its own share. If FG&E can sell out at any substantial price, such as half of the

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3. My testimony in DPU 84-25 shows that, even using most of NU's assumptions, Millstone 3 will not repay the investment in it until well into the next century. Seabrook 1 is likely to be at least as expensive as Millstone 3.

investment to date (which would amount to about $1000 to $1500/kw), its customers and shareholders would be quite fortunate.

Q: What should FG&E's response be to the recent changes in the estimates of Seabrook 1 risk, cost, and schedule?

A: FG&E should certainly not increase its commitment to Unit 1, either directly or indirectly. The cost figures which I present in Section 3 of this testimony indicate that Unit 1 may be more expensive than alternative power sources, and may be extremely difficult to finance. FG&E should reassess its involvement with Seabrook 1 in view of the recent changes, and the likely future developments for this unit.

3 - THE COST OF POWER FROM SEABROOK

Q: How have you estimated the cost of Seabrook?

A: I have attempted to determine realistic estimates for the duration of Seabrook construction, its construction costs, and the various costs of running and decommissioning each unit. Based upon analyses of historical performance and trends:

1. I do not expect Seabrook 1 to come on line before 1988, at the earliest; cancelation of that unit remains a possibility. I consider completion of Seabrook 2 to be extremely unlikely; even if funds could be found to complete it, and even if its exorbitant cost did not make cancelation desirable, it probably could not be completed until the end of the century.

2. I expect that Unit 1 would cost at least $6 billion (and quite likely more) to complete, and that Unit 2 would cost in excess of $10 billion, if it were completed.

3. Capacity factors for units of Seabrook's size and type will probably average in the range of 50% to 55%.

4. I expect non-fuel O & M to escalate much faster than general inflation; the capital cost of the plant will also increase significantly during its lifetime.

Including decommissioning, insurance, fuel, and other factors listed above, power from Seabrook 1 would cost about 15 or 16 cents/kWh, in levelized 1984 dollars. The actual prices charged to ratepayers will include inflation and will be much larger. Sunk costs account for only about 6 or 7 cents/kWh, so the costs of completing and running Seabrook 1 are likely to be about 9 cents/kWh, in 1984 dollars. If Unit 2 were completed, its power would cost even more than that of Seabrook 1, even in levelized constant dollars, but its sunk costs are much lower, about 2.5 cents/kWh. Thus, the forward costs of Unit 2 would be something in excess of 13 cents/kwh, in 1984 dollars.

A detailed analysis of these costs is presented below, including a comparison of my estimates to the most recent available by PSNH.

3.1 - CONSTRUCTION DURATION

Q: Are there specific reasons to believe that Seabrook will reach commercial operation somewhat after the date projected by PSNH?

A: Yes. Those reasons include:

1. PSNH'S allowance for the interval between operating license issuance (OLIS) and commercial operation date (COD) is much shorter than recent experience.

2. PSNH projections of rates of construction progress have been consistently over-optimistic in the past.

3. PSNH's projections are inconsistent with historic rates of construction progress on Seabrook.

4. PSNH's estimates of Seabrook COD's have always been over-optimistic in the past, and there is no reason to believe we have seen the last revision.

5. PSNH's construction duration projection for Seabrook 1, once the most aggressive in the nation, is now quite similar to those of other nuclear plants at similar stages of construction, and actual nuclear construction durations have almost always exceeded projections by substantial amounts.

6. Virtually all plants at a stage of completion comparable to Seabrook 2 have already been canceled.

Q: What is the recent experience for the start-up interval from OLIS to COD?

A: Table 3.1 provides this data for all units in commercial operation which have received operating licenses since the beginning of 1978. The shortest start-up period, 4.1 months, was that of St. Lucie 2, which has become something of an industry legend due to its rapid construction. The corresponding intervals for the other units range from 8.1 months, to over 20 months, with a 14-plant average of 12.9 months. In addition, Diablo Canyon 1, which has been listed as 99% or more complete since at least late 1977, received an operating license in 1981, only to have it suspended two months later. Diablo Canyon 1 will increase the average start-up period when (and if) it finally reaches commercial operation. Three other units received operating licenses in 1982 and 1983, but have not yet reached commercial operation: San Onofre 2, Grand Gulf 1, and San Onofre 3.[4] Each of these

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4. This analysis is complicated somewhat by the apparent use of two commercial operation dates (COD's) for some units, such as San Onofre 1 and La Salle 1: one date is used for ratemaking and another for other purposes. I have used the COD reported to the NRC, where possible.

TABLE 3.1: RECENT EXPERIENCE IN START-UP INTERVALS

Unit	Date of Issuance, First Operating License [1]	Commercial Operation Date [2]	Start-up Interval [3]
	(OLIS)	(COD)	(months)
Three Mile Island 2	08-Feb-78 (F)	30-Dec-78	10.7
Hatch 2	13-Jun-78 (F)	05-Sep-79	14.8
Arkansas 2	01-Sep-78 (L)	26-Mar-80	18.8
Sequoyah 1	29-Feb-80 (L)	01-Jul-81	16.0
North Anna 2	11-Apr-80 (L)	14-Dec-80	8.1
Salem 2	18-Apr-80 (L)	13-Oct-81	17.9
Farley 2	23-Oct-80 (L)	30-Jul-81	9.2
McGuire 1	23-Jan-81 (Z)	01-Dec-81	10.3
Sequoyah 2	25-Jun-81 (L)	01-Jun-82 [4]	11.2
LaSalle 1	17-Apr-82 (Z)	01-Jan-84 [5] [6]	20.5
Susquehanna 1	17-Jul-82 (L)	08-Jun-83 [5]	10.7
Summer 1	06-Aug-82 (L)	01-Jan-84 [5]	16.9
McGuire 2	03-Mar-83 (L)	01-Mar-84 [5]	11.9
St Lucie 2	06-Apr-83 (L)	08-Aug-83	4.1
AVERAGE:			12.9

Notes:

[1] From NRC Gray Books and "Historical Profile of U.S. Nuclear Power Development", Atomic Industrial Forum, 12/31/81 and 1/1/83.
Full licenses are indicated by (F), low power licenses by (L), and zero-power licenses by (Z).

[2] Same sources as for OLIS.

[3] All months are treated as having 30.5 days.

[4] Telephone inquiry, TVA.

[5] Telephone inquiry, NRC.

[6] Utility had previously announced COD of 10/20/82; apparently now amended.

units is already over a year from OLIS,[5] and the group as a whole will increase the average startup.

Q: What is PSNH's projection for the Seabrook start-up period?

A: PSNH currently projects a start-up period of seven months for Seabrook 1, and only five months for Seabrook 2.[6] This projection is considerably more optimistic than would be suggested by the historical experience. If PSNH's projections of construction progress and operating license date were correct, but the start-up period were the average 13 month duration from Table 3.1, Seabrook 1 would enter commercial operation in January, 1987.

Q: To what extent has PSNH over-estimated the past rate of Seabrook construction?

A: At the end of the first quarter of 1979, PSNH estimated that Unit I was 18.85% complete, and that it would be 39.13% complete one year later, for annual progress of 20.28%. But at the end of the first quarter of 1980, Unit I was estimated to be only 36.70% complete: the reported progress was 17.85%, or 88% of the projected rate. In fact, the reported progress

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5. As of April 1, 1984, the three units had held operating licenses for an average of more than 20 months. Grand Gulf still held only a low-power license, after almost 21 months.

6. PSNH does not appear to have published an estimate of OLIS for its new schedule, so I have used the very similar fuel load date.

was apparently greater than the actual progress, since a period of negative reported progress followed.

In March 1980, PSNH produced a new construction estimate, which projected that Unit I would be 67.7% complete by June, 1981; but reported completion in June, 1981 was only 50.8%. Over this 15-month period, reported progress was only 45.5% of projected progress. Table 3.2 repeats these calculations and repeats them through the estimates of November 1982 and March 1984. Averaging the progress ratio (weighted by the months covered by each estimate), and ignoring PSNH's over-optimism in the March, 1980, progress report, produces an average progress-to-estimate ratio for the last 60 months period of 48.9%. Stated differently, each percentage point progress in construction has taken over twice as long as PSNH expected. Corresponding progress-to-estimate ratios could be calculated for Seabrook 2, but these would be very low. A more optimistic approach for Unit 2 is to calculate an average progress-to-estimate ratio for the total project, as I have done in Table 3.3. This total project ratio has averaged 46.05%; construction has taken about 2.2 times as long as expected.

If construction of Unit 1 takes 100% longer than projected in March, 1984 (21 months to December 31, 1985, not including startup), the unit will be ready for an operating license 42

TABLE 3.2: RATIO OF REPORTED TO FORECAST PROGRESS: SEABROOK 1

Date:	Mar-79	Mar-80	Jun-81	Nov-82	Mar-84
a. Forecast Construction Stage (% complete) [1]	-	39.1%	67.7%	82.0%	96.0%
b. Reported Construction Stage (% complete)	18.9%	36.7%	50.8%	65.6%	73.0%
c. Forecast Progress (forecast increase from last reported % complete) [2]	-	20.3%	31.0%	31.2%	30.4%
d. Reported Actual Progress Since Last Report	-	17.9%	14.1%	14.8%	7.4%
e. Progress Ratio (d./c.)	-	0.88	0.45	0.48	0.24

AVERAGE PROGRESS RATIO FOR SEABROOK 1: 0.489

Notes: [1] As forecast at previous date listed.

TABLE 3.3: RATIO OF REPORTED TO FORECAST PROGRESS: TOTAL PROJECT

Date:	Mar-79	Mar-80	Jun-81	Nov-82	Mar-84
a. Forecast Construction Stage (% complete) [1]	-	30.2%	55.8%	62.0%	76.4%
b. Reported Construction Stage (% complete)	13.3%	26.5%	36.6%	51.4%	56.3%
c. Forecast Progress (forecast increase from last reported % complete)	-	16.9%	29.3%	25.4%	25.0%
d. Reported Actual Progress Since Last Report	-	13.2%	10.1%	14.8%	4.9%
e. Progress Ratio (d./c.)	-	0.78	0.35	0.58	0.20

AVERAGE PROGRESS RATIO FOR TOTAL PROJECT: 0.460

Notes: [1] As forecast at previous date listed.

months later, or in September, 1987. If construction of the total project continues at 46.05% of projected rates (thus assuming that Unit 2 speeds up as Unit 1 slows down), completion of Unit 2 will take 117% longer than projected. As of March 1984, completion of Unit 2 was projected to be 77 months in the future (at July 31, 1990): with 117% slippage, Unit 2 would be complete in 167 months, or February 1998.

Adding a year and a month for start-up produces in-service dates of October 1988 and February 1999.

Q: What are PSNH's historic rates of construction progress, and what in-service dates do those rates suggest?

A: From March 1979 to March 1984, reported progress on Unit 1 averaged 0.90% per month, and reported progress on Unit 2 averaged 0.36% per month. PSNH has projected sustained peak monthly construction rates of approximately 2% for Unit 1.[7] PSNH has also predicted that the last 10% or so of construction will proceed more slowly, at about 0.7% per month, or about 35% of the peak rate.

If PSNH is only able to maintain a reported rate of progress

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7. PSNH's graphs of projected completion rates are much more difficult to read in the current forecast than in earlier documents, so I have not tried to interpret the PSNH projections for Unit 2.

on Unit 1 of 1.0% per month (still somewhat better than the historic level) through the 90% completion point, and 35% of that rate (or .35%/month) thereafter, construction will take 17 months past March 1984 to reach 90% complete, plus 29 more months for the last 10%, and will end about January 1988.

If Unit 2 continues its past glacial construction rate until Unit 1 is complete in January, 1988 (at which point Unit 2 would be 40% complete), then accelerates to 1% per month until 90% complete, and reaches completion 29 months later, that would stretch the Unit 2 completion date to July, 1994. If Unit I is completed later, or if Unit 2 cannot speed up until Unit I is in commercial operation, Unit 2 would be completed even later. An additional year for startup must be added to these projections, bringing commercial operation to 1/1989 and 7/1995.

Q: Has PSNH changed its projections for Seabrook's dates of commercial operation substantially over the last few years?

A: Yes. As shown in Table 3.4 , the COD's were estimated as 11/81 and 11/83 in December 1976. Over the last four years, PSNH has slipped its estimate of the Seabrook 1 COD 56 months to 7/86, and the Seabrook 2 estimate 85 months to 12/90.

Q: If the historical patterns of COD slippage continue, when would the Seabrook units actually reach commercial

TABLE 3.4: PROJECTION OF SEABROOK SCHEDULE SLIPPAGE

Date of PSNH Estimate:	Dec-76	Mar-78	Jan-79	Mar-80	Apr-81	Dec-82	Mar-84
SEABROOK UNIT #1							
1. PSNH ESTIMATED C.O.D.	Nov-81	Dec-82	Apr-83	Apr-83	Feb-84	Dec-84	Jul-86
2. PSNH: MONTHS UNTIL C.O.D.	59	57	51	37	34	24	28
3. TOTAL PROGRESS TO NEXT ESTIMATE (months)	2	6	14	3	10	-4	--
4. TOTAL PROGRESS TO MARCH 1984 (months)	30	28	22	8	6	-4	--
5. ELAPSED TIME TO MARCH 1984 (months)	87	72	62	48	35	15	--
6. PROGRESS RATIO TO MARCH 1984 (%)	35.1%	39.6%	36.2%	17.7%	15.8%	-30.0%	--
7. PROJECTED MONTHS TO GO	80	71	77	159	178	NA	--
8. PROJECTED C.O.D.	Nov-90	Feb-90	Aug-90	Jun-97	Jan-99	NA	--

Date of PSNH Estimate:	Dec-76	Mar-78	Jan-79	Mar-80	Apr-81	Dec-82	Mar-84
SEABROOK UNIT #2							
1. PSNH ESTIMATED C.O.D.	Nov-83	Dec-84	Feb-85	Feb-85	May-86	Jul-87	Dec-90
2. PSNH: MONTHS UNTIL C.O.D.	83	81	73	59	61	55	81
3. TOTAL PROGRESS TO NEXT ESTIMATE (months)	2	8	14	-2	6	-27	--
4. TOTAL PROGRESS TO MARCH 1984 (months)	1	0	-8	-22	-21	-27	--
5. ELAPSED TIME TO MARCH 1984 (months)	87	72	62	48	35	15	--
6. PROGRESS RATIO TO MARCH 1984 (%)	1.7%	0.0%	-13.7%	-46.8%	-58.8%	-177.4%	--

Notes: Line 6 = Line 4 / Line 5
Line 7 = PSNH's 1984-estimate of the number of months until C.O.D. (Line 2) divided by the Progress Ratio (Line 6).
Line 8 = Mar-84 + Line 7

operation?

A: Table 3.4 derives the COD progress ratios[8] of each unit from each earlier estimate to the March 1984 estimate. The COD progress ratio is the reduction in months left in the construction schedule (that is, progress towards the COD), divided by elapsed months. If the schedule did not change between estimates, the progress ratio would be 1.0. For various time periods ending with the 3/84 estimate, the progress ratio for Seabrook 1 ranges from less than zero to almost 40%. For example, for each month that went by from March 1980 to March 1984, completion drew nearer by only .177 months (about 5 days). To put it another way, it has taken Seabrook 1 at least 2.5 months to get one month closer to completion (using the 40% progress ratio from 3/78, the best period on record). For Seabrook 2, the progress ratio to 3/84 is negative or negligible for all periods: less than two months of progress have been claimed in the last 87. At this rate, completion of Unit 2 would take 400 years.

Table 3.4 extrapolates the historic trends to determine when Unit 1 would enter service, assuming that PSNH continues to be as wrong about its COD as it has been in the past. These dates assume that the estimated completion dates continue to

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8. These are not the same as the percent-complete progress ratios discussed above.

TABLE 3.5: June 1983 ESTIMATED COMMERCIAL OPERATION DATES
Percent complete comparable to SEABROOK 1 (58% to 88%)

Unit	Construction Stage (% complete)	C.O.D.-Estimates June 1983	C.O.D.-Estimates Current [2]
Wolf Creek	87%	Feb-85	Feb-85
Byron 1	86%	Feb-84	Feb-85
Limerick 1	86%	Apr-85	Apr-85
Midland 1	85%	Aug-85	
Midland 2	85%	Feb-85	Dec-86
Perry 1	83.8%	May-85	Dec-85
Bellefonte 1	83%	Nov-86	Apr-88
Clinton 1	80.6%	Nov-86	Nov-86
Shearon Harris 1	79%	Mar-86	Mar-86
SEABROOK 1	73% [1]	Dec-84 [4]	Jul-86
Millstone 3	72%	May-86	
Hope Creek 1	71%	Dec-86	Dec-86
River Bend 1	71%	Dec-85	Dec-85
Nine Mile Point 2	70%	Oct-86	Nov-86
Byron 2	69%	Feb-85	May-86
Braidwood 1	68%	Oct-85	May-86
Beaver Valley 2	67.8%	May-86	May-86
Palo Verde 3	65%	May-86	May-87
WNP-3	64%	indef. [4]	
Bellefonte 2	63%	Nov-86	Apr-90
Comanche Peak 2	63%	Jun-85 [3]	Aug-86
WNP-1	62.5%	indef. [4]	
AVERAGE	74.4%	Dec-85	Aug-86

Source: Nuclear News, August 1983.

Notes:
[1] From March 1984 report; Seabrook excluded from average.
[2] From various media and utility reports.
[3] Month not stated; June assumed.
[4] Excluded from average.

recede as they have in the past. Depending on the time period used for trending, Unit 1 could be expected to enter service between February 1990 and the end of the century, or based upon the last year or so, never. The lack of progress towards a Unit 2 COD confirms my prediction that the unit will be canceled.

Q: What are the construction duration projections for other nuclear power plants, and how do they compare to those for Seabrook?

A: Table 3.5 lists the reported percent complete and the scheduled in-service date for each nuclear unit which was within 15 percentage points of the reported percent complete for Seabrook 1 as of June 30, 1983.[9] On average, these twenty-one units were 74.4% complete: the nineteen with scheduled in-service dates averaged about 76% complete and were projected to reach commercial operation in December, 1985. At its reported construction pace over thae last year,[10] Seabrook 1 was about five months behind the average. Table 3.5 also updates the status of this cohort to the present time. Another of the units is now on indefinite

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9. At that time, PSNH estimated that Unit 1 was 78.7% complete. As of March 1984, PSNH revised its estimate to 73%; I use this figure for this comparison.

10. PSNH reports progress from 65.6% complete in November 1982 to 73% complete at the end of February 1984, or about 0.6% per month.

TABLE 3.6: June 1981 ESTIMATED COMMERCIAL OPERATION DATES
Percent Complete comparable to Seabrook 2 (0% and 20%)

Unit	June 1981 Construction Stage (% complete)	June 1981 Estimated C.O.D.	Current C.O.D.
Cherokee 1	18	indef.	CANCELLED(1983)
Vogtle 1	18	May-85	
Hope Creek 2	17.8	Dec-89	CANCELLED(1981)
Hartsville B1	17	indef.	CANCELLED(1982)
WPPSS 5	13.7	Dec-87	CANCELLED(1982)
Marble Hill 2	11	Oct-87	CANCELLED(1984)
Vogtle 2	10	Nov-86	
North Anna 3	8.8	Jun-89 [1]	CANCELLED(1982)
SEABROOK 2	8	May-86	
Hartsville B2	7	indef.	CANCELLED(1982)
Phipps Bend 2	5	indef.	CANCELLED(1982)
S. Harris 2	3	Mar-88	CANCELLED(1983)
Yellow Creek 2	3	indef.	indef.
S. Harris 3	1	Mar-94	CANCELLED(1981)
S. Harris 4	1	Mar-92	CANCELLED(1981)
Callaway 2	0.5	Jun-90 [1]	CANCELLED(1981)
Clinton 2	0	indef.	CANCELLED(1983)
River Bend 2	0	indef.	CANCELLED(1984)

Sources: Nuclear News, August 1981
"Historical Profile of U.S. Nuclear Power Development"
Atomic Industrial Forum, Dec. 31, 1981 and Jan. 1, 1983.

Notes: [1] month not given, June assumed

TABLE 3.7: June 1983 ESTIMATED COMMERCIAL OPERATION DATES
Percent complete comparable to SEABROOK 2 (0% t0 35%)

Unit	June 1983 Construction Stage (% complete)	June 1983 Estimated C.O.D.	Current C.O.D.
Yellow Creek 1	35	indef.	
Hartsville A2	34	indef.	
Marble Hill 2	30.7	Jun-88	CANCELLED(1984)
Limerick 2	30	Oct-87	
Grand Gulf 2	25	indef.	
South Texas 2	23	Jun-89	
SEABROOK 2	21.7	Jul-87	
Vogtle 2	15.6	Sep-88	
S. Harris 2	4	Mar-90	CANCELLED(1983)
Yellow Creek 2	3	indef.	indef.
Carroll County 1	0	2001	
Carroll County 2	0	2002	
River Bend 2	0	indef.	CANCELLED(1984)
Skagit 1	0	Jun-91	CANCELLED(1983)
Skagit 2	0	Jun-93	CANCELLED(1983)

Sources: Nuclear News, August 1983.
"Historical Profile of U.S. Nuclear Power Develoment."

status, and the average COD for the other 18 is August 1986. Based on reported percentage complete, PSNH's projection of the Seabrook 1 COD was consistent with others in the industry.

It is more difficult to make this comparison for Seabrook 2, since virtually all other nuclear plants in its early stage of construction have already been canceled. Table 3.6 presents the percent complete and projected COD of all units with construction permits and less than 20% complete as of June 1981, and their current status. Table 3.7 lists the units which were reported to be less than 40% complete in June 1983, and their current status.

Q: Have the construction duration estimates of the nuclear industry as a whole generally been accurate?

A: No. The U.S. nuclear industry has been universally over-confident in its construction schedule projections. Appendix B presents the estimated and actual construction durations for all the units which have reached commercial operation and for which I have been able to obtain both the actual cost and one or more estimates of the in-service date made when the plant was believed to be over one year from COD. Table 3.8 summarizes the results of that analysis. For the typical estimate in the two-to-three year range (comparable to the 3/84 estimate for Seabrook 1), the actual

TABLE 3.8: HISTORICAL NUCLEAR DURATION MYOPIA

Estimated Time to Completion (years)	Number of Estimates	Average Projected Time to Complete (years)	Average Duration Ratio
1 - 1.99	191	1.42	1.983
2 - 2.99	150	2.38	2.138
3 - 3.99	86	3.39	2.016
4 - 4.99	45	4.36	1.799
5 - 5.99	36	5.34	1.635
6 +	14	6.32	1.522

construction duration that was more than twice the projected remaining duration. For the estimates over six years in the future (comparable to the current estimate for Seabrook 2), the ratio is 1.52.

As of the March, 1984 estimate, Seabrook 1 was anticipated to be 28 months from COD. As discussed above, this was quite close to the standard industry projection for a unit at Seabrook's stage of completion. Multiplying this interval by 2.128 yields a prediction of commercial operation 60 months from March 1984, or in March, 1989. For Seabrook 2, the anticipated duration was 82 months. Multiplying this duration by 1.52 would predict 125 months from March 1, 1984, or July, 1994.

This analysis assumes that PSNH and the comparison group of utilities are just as over-optimistic as the historical group from which the duration ratio was estimated. It is possible that other utilities are generally more realistic now than they were in the 1960's and 1970's, and hence that PSNH's estimate is a bit better than the historical average. The historical experience appears to have been quite stable over time, however, and there is no evidence of any recent emergence of a learning curve.

Q: What dates are realistic estimates for commercial operation at Seabrook?

A: Table 3.9 summarizes my previous calculations. Over all, if the historic trends continued, Seabrook 1 might enter commercial operation around the end of the decade. It is unlikely that many nuclear units will still be under construction at that point: those not completed will be canceled either voluntarily or when their owners can no longer pay for them. If Seabrook 1 is to be completed PSNH must do much better in maintaining its schedule than has been industry experience or its own experience. We may approximate such an improvement by using the most favorable for the trending techniques, the percent completion progress ratio, which predicts a COD in October, 1988.

There is little in the historical record which provides any hope that Seabrook 2 can be completed. Where a COD is required in the subsequent analyses, I will use the July, 1995 projection from past progress rates.

TABLE 3.9: SUMMARY OF COMMERCIAL OPERATION PROJECTIONS

Projection Method	Unit 1 C.O.D.	Unit 2 C.O.D.
-Completion Progress Ratio	Oct-88	Feb-99
-Past Progress Rates	Jan-89	Jul-95
-Schedule Slippage (most optimistic)	Feb-90	never
-Industry Schedule Myopia	Mar-89	Jul-94

3.2 - CAPITAL COSTS

Q: Are PSNH's estimates of Seabrook capital costs consistent with historical experience?

A: No. There is considerable evidence which indicates that PSNH is still being optimistic in its projection of Seabrook's final cost. This evidence includes the historical tendency of architect/engineers (A/E's) and utilities to underestimate nuclear construction costs, and the continuing increases in cost estimates for nuclear plants under construction, and particularly for Seabrook.

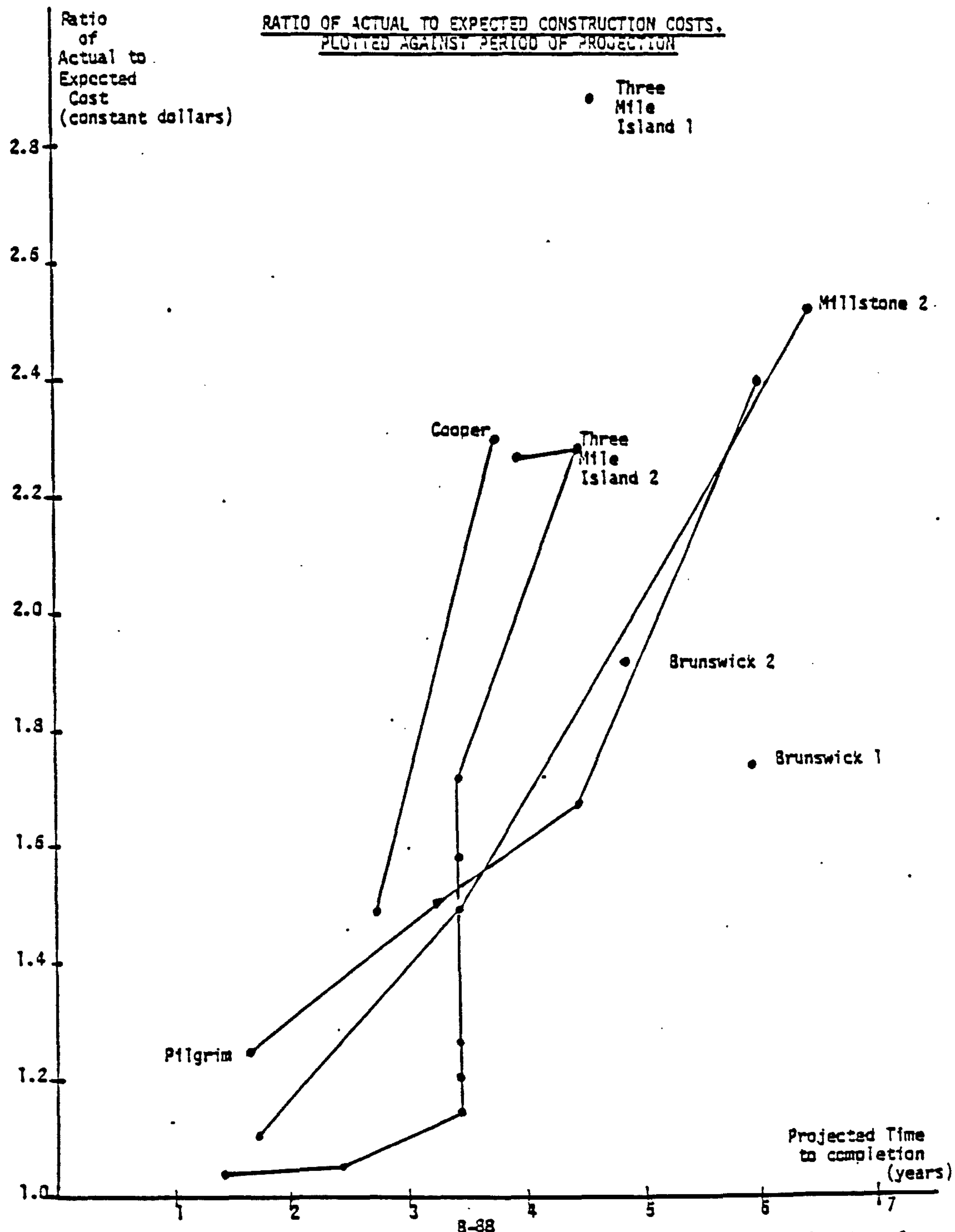
Q: How does the past record of A/E cost estimates indicate that the capital cost projections for Seabrook are apt to be low?

A: In a report prepared by Analysis and Inference for the NRC (Chernick, et al., 1981), we calculated the ratio of actual to forecast costs for several nuclear power plants, and derived four equations estimating the relationship between real cost overruns and the length of time into the future for which the forecast is being made. We defined this relationship as myopia: a failure to forecast future cost increases. The data are displayed in Figure 3.1. The four equations are:

$$R = 1 + .204t \quad (1)$$

$$R = .598 + .300t \quad (2)$$

FIGURE 3.1



8-88

NOTE: Lines are drawn connecting estimates for the same reactors in chronological order of estimate date.

$$R = (1 + .147)^t \qquad (3)$$

$$R = .844\ (1 + .195)^t \qquad (4)$$

where R is the ratio of actual to expected costs in real dollars, and t is the expected years to completion at the time of the estimate. Table 3.10 evaluates these four equations for the lead time forecast by PSNH as of the March 1984 cost estimate (2.33 years). As noted above, PSNH's value of t is consistent with the industry consensus, given the reported state of completion for Seabrook.

Averaging the results of the four equations (all of which are statistically significant at the 99.9% level), for the two schedule projections, produces an estimated actual-to-forecast real cost ratio of 1.36 for Seabrook 1 and 2.58 for Seabrook 2. Multiplying PSNH's forecast cost of $3826/kw by 1.36 yields a corrected estimate of $5190/kw in July 1986, or about $6 billion for Unit 1. Adding 7% inflation[11] to an in-service date of October 1988 raises the cost to $6.95 billion for the unit. A similar process yields an estimate of $9883/kw for Seabrook 2, in 1990's or about $17 billion for the unit, if it is complete in 1995, as shown in Table

----

11. DRI projects 5.3% GNP inflation to 1990 and then 6.1% to the end of the century. The Handy-Whitman annual nuclear inflation rate exceeded the GNP inflation rate by an average of 1.7 points, 1970-82. If this relationship continues, nuclear construction costs would be expected to rise at 7% in the 1980's and 7.8% in the 1990's.

TABLE 3.10: REAL MYOPIA RESULTS

	SEABROOK 1		SEABROOK 2	
Equation	Inputs	Ratio of Actual to Forecast Cost (R)	Inputs	Ratio of Actual to Forecast Cost (R)
1.	t = 2.33	1.475	t = 6.7	2.377
2.		1.297		2.623
3.		1.377		2.524
4.		1.278		2.809
AVERAGE RATIO:		1.357		2.583
CORRECTED COST: [1]		$5,191 per KW		$9,883 per KW
TOTAL UNIT COST:				
-at PSNH COD [2]		$5.97 billion		$11.37 billion
-at Oct-88 [3]		$6.95 billion		--
-at Jul-95		--		$17.29 billion

Notes: [1] Average Ratio * $3825/kw
[2] July 31,1986 and December 31,1990.
[3] Assumes 7% inflation to 1990 and 7.8% thereafter.

3.10.

Q: Have you performed a similar myopia analysis in nominal dollars?

A: Yes. I have calculated the cost overruns and evaluated Equation 3 (which I consider the most intuitively appealing of the myopia forms) in nominal terms for 49 of the 58 non-turnkey units which have reached commercial operation,[12] based on a series of utility reports to the AEC, ERDA, and now the EIA of the DOE. These are versions of the "Quarterly Progress Report on Status of Reactor Construction" identified as Form HQ-254, and later as Form EIA-254. Some supplementary data was taken from compilations of these quarterly utility reports (AEC, various; ERDA, various), and from other reports by various utilities for their own units. Appendix B provides the data for estimates for more than a year into the future, along with the cost overrun and the value of m (the myopia factor) for each estimate. The average value of the cost overrun and the myopia factor for each group of cost forecasts are reproduced in Table 3.11. For the Seabrook estimate of March 1984, the estimated time to completion was again 2.33 years for Unit 1, so the relevant results are those for t between 2 and 3 years, for

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12. The cost data for the other nine units was either missing from our database, or combined as total costs for multi-unit plants.

TABLE 3.11: NOMINAL COST OVERRUNS AND MYOPIA FACTORS

Estimated Time to Completion (years)	Number of Estimates	Average Cost Ratio	Average Myopia
1 - 1.99	132	1.38	23.9%
2 - 2.99	110	1.91	30.0%
3 - 3.99	53	2.29	25.9%
4 - 4.99	31	2.51	22.6%
5 - 5.99	27	3.06	22.4%
6 +	13	3.57	21.9%

which the average cost ratio was 1.91. Stated alternatively, the cost overrun was 91%. The average myopia for those estimates was 30%; raised to the 2.33 power, this myopia factor predicts a cost overrun of 84%. Applying these cost overruns to the estimate of $3826/kw produces an adjusted estimate in the range of $7040/kw to $7300/kw, for a unit cost of over $8 billion.

For Seabrook 2, the relevant ratio is 3.57, the myopia factor is 21.9%, and the resulting costs are $13,660 to $14,560/kw, or about $16 billion.

Q: Have you performed a similar analysis for Seabrook's cost history?

A: Yes. Table 3.12 derives the annual percentage rates of increase in the Seabrook cost estimates[13] from various starting points to the 3/84 estimate. There is no evidence that the annual rate of escalation of PSNH's estimate has stabilized appreciably in recent years. The latest cost estimate represented an average cost trend of around 50% annually, while the average annual percentage increase in the Seabrook cost estimate from 12/76 to 3/80 was only 15%.

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13. The cost data is from PSNH's reports to DOE: the division of costs between units appears to be different than the divisions in PSNH's public pronouncements, supporting my earlier contention that PSNH has at least recently) manipulated the cost accounting to favor Unit 2.

TABLE 3.12a: GROWTH RATES IN PSNH COST ESTIMATES: SEABROOK 1

DATE OF ESTIMATE:	Dec-76	Mar-78	Jan-79	Mar-80	Apr-81	Dec-82	Mar-84
1. MONTHS SINCE LAST ESTIMATE	___	15	10	14	13	20	15
2. MONTHS TO Mar-84	87	72	62	48	35	15	0
3. ESTIMATED COST ($ million)	1007	1340	1294	1493	1735	2540	4400
4. INCREASE SINCE LAST ESTIMATE (%)	--	33.1%	-3.4%	15.4%	16.2%	46.4%	73.2%
5. INCREASE SINCE LAST ESTIMATE (ANNUALIZED)	--	25.8%	-4.1%	13.1%	14.9%	25.7%	55.4%
6. INCREASE TO Mar-84 (%)	336.9%	228.4%	240.0%	194.7%	153.6%	73.2%	--
7. INCREASE TO Mar-84 (ANNUAL)	22.6%	22.0%	26.8%	31.1%	37.7%	55.4%	--
8. FINAL COST IF TREND CONTINUES							
a. TO: Jul-86 (million)	$7,082	$6,994	$7,660	$8,278	$9,282	$12,317	--
b. TO: Oct-88 (million)	$11,215	$10,942	$13,086	$15,243	$19,091	$33,294	--

TABLE 3.12b: GROWTH RATES IN PSNH COST ESTIMATES: SEABROOK 2

DATE OF ESTIMATE:	Dec-76	Mar-78	Jan-79	Mar-80	Apr-81	Dec-82	Mar-84
1. MONTHS SINCE LAST ESTIMATE	—	15	10	14	13	20	15
2. MONTHS TO Mar-84	87	72	62	48	35	15	0
3. ESTIMATED COST ($ million)	1007	980	1287	1558	1825	2709	4400
4. INCREASE SINCE LAST ESTIMATE (%)	--	-2.7%	31.3%	21.1%	17.1%	48.4%	62.4%
5. INCREASE SINCE LAST ESTIMATE (ANNUALIZED)	--	-2.2%	38.5%	17.9%	15.7%	26.8%	47.6%
6. INCREASE TO Mar-84 (%)	336.9%	349.0%	241.9%	182.4%	141.1%	62.4%	--
7. INCREASE TO Mar-84 (ANNUAL)	22.6%	28.5%	26.9%	29.7%	35.3%	47.6%	--
8. FINAL COST IF TREND CONTINUES							
a. TO: Dec-90 (million)	$17,447	$23,945	$22,051	$25,502	$33,950	$61,054	--
b. TO: Jul-95 (million)	$44,422	$75,575	$65,811	$84,005	$135,787	$363,623	--

Given a COD, and assuming the continuation of a historic rate of escalation in the cost estimate, we can calculate the value of the cost estimate at the time each Seabrook enters service. For PSNH's Unit 1 COD estimate of 7/86, 2.33 years of escalation must be added: at 22% annually, this would increase the final cost by about 60%, to around $7 billion. Using an optimistic, but realistic, estimate of the COD derived above (10/88), we must add 2.25 more years of cost estimate revisions. This translates to a unit cost estimate of $11 billion (or $9500/kw) when the unit goes commercial.

For Unit 2, PSNH projects 6.75 years of construction; if the 23% long term growth rate in its cost continued, the cost of the unit would increase by a factor of about 4, to some $17 billion. It is interesting to note that the period of this extrapolation is comparable to the time Seabrook has already been under construction. Continuing the projection out to a more likely completion date produces an estimate in excess of $44 billion; this is another illustration of the unlikelihood of completion.

Q: What Seabrook construction cost estimates do you find most reasonable?

A: Table 3.13 displays the results of the various methodologies I used. The estimates for Seabrook 1 range from about $5000

TABLE 3.13: CONSTRUCTION COST ESTIMATE SUMMARY IN $/kw

Method	C.O.D.	Cost Estimate SEABROOK 1	Cost Estimate SEABROOK 2
Real Myopia			
	PSNH	$5,190	$9,880
	Realistic [1]	$6,043	$15,040
Nominal Myopia		$7,040	$13,390
Seabrook Cost Estimate History			
	PSNH	$6,080	$17,450
	Realistic	$9,510	$26,530

Notes: [1] C.O.D.s of October, 1988 and July, 1995.

to $9500/kw, for a total cost of about $6 to $11 billion. Past errors in inflation projections probably account for some of the results at the top end of the range. I will use $6 billion (or $5200/kw), a rather optimistic figure, in my subsequent analysis.

For Seabrook 2, this analysis can only lead to the conclusion that the unit will be too expensive to complete. The lowest estimate is about $10,000/kw, or $11.5 billion, or PSNH's schedule. The lowest estimate on a realistic schedule is over $15 billion: I will be quite optimistic, and assume $10 billion on a realistic schedule (the realistic schedule reduces the constant-dollar equivalent of any particular nominal cost).

Q: Do any of the recent developments in the management of the Seabrook project indicate that any of your results are pessimistic?

A: No. The significant developments appear to be the arrival of Mr. Derricksen from Florida Power and Light (FP&L) to manage the project for PSNH, and the sharp rift between PSNH and the architect/engineer, United Engineers and Constructors (UE&C). The second event can only spell more trouble in managing the plant, but PSNH seems to be placing great confidence in Mr. Derricksen. This stikes me as ill-founded.

While Mr. Derricksen is to be congratulated for completing St. Lucie 2 very quickly, and close to schedule, it should be noted that he is not a miracle worker. At FP&L, he was working with an established team which developed its skills on three previous nuclear units; at Seabrook, he will be working with the existing fragmented structure of PSNH, Yankee Atomic, UE&C, Fuel Supply Services (an FP&L subsidiary), and the oversight of MAC and the joint owners. Since all these entities put together were only able to identify a couple hundred million dollars in cost overruns as recently as the end of 1983 (only 3 months before the $4 or $5 billion cost increase, depending on whether one uses UE&C's figures or PSNH's), Mr. Derricksen's ability to substantially influence events seems highly questionable. In addition, FP&L's plants have not really been bargains, even if they were built fast: the cost estimate histories of the four units are displayed in Table 3.14.

Q: How do these total cost figures compare to the cost of completing Seabrook?

A: A portion of the total construction costs are sunk: either invested in property which cannot be sold to recover the cost, or committed in contracts which cannot be fully voided. PSNH estimates that the total sunk investment in Seabrook 1 by the middle of 1984 will be about $3 billion,

TABLE 3.14: COST AND SCHEDULE ESTIMATE HISTORIES
FP&L NUCLEAR UNITS

Unit Name	Date of Estimate Year	Qr	Estimated Cost	COD		Years to COD	Cost Ratio	Myopia	Duration Ratio
Turkey Point 3	67	3	66	70	?	2.75	1.65	1.199	1.909
Turkey Point 3	69	3	99	71	?	1.75	1.10	1.055	1.857
Turkey Point 3	70	1	111	71	?	1.25	0.98	0.983	2.200
	Actual		109	72	12				
Turkey Point 4	67	3	66	71	?	3.75	1.92	1.190	1.600
Turkey Point 4	69	3		72	?	2.75			1.455
Turkey Point 4	70	1	80	72	?	2.25	1.58	1.227	1.556
Turkey Point 4	70	4	81	72	?	1.50	1.57	1.348	1.833
Turkey Point 4	71	1	83	72	?	1.25	1.53	1.403	2.000
Turkey Point 4	71	2	96	72	?	1.00	1.32	1.321	2.250
Turkey Point 4	71	4	126	72	12	1.00	1.01	1.006	1.750
	Actual		127	73	9				
St. Lucie 1	69	2	123	73	6	4.00	3.95	1.410	1.750
St. Lucie 1	69	3	123	73	5	3.67	3.95	1.455	1.841
St. Lucie 1	70	4	200	74	6	3.50	2.43	1.289	1.571
St. Lucie 1	71	2	203	74	6	3.00	2.39	1.338	1.667
St. Lucie 1	71	4	218	74	6	2.50	2.23	1.378	1.800
St. Lucie 1	72	1	235	74	6	2.25	2.07	1.381	1.889
St. Lucie 1	72	2	269	75	5	2.92	1.81	1.225	1.371
St. Lucie 1	72	4	318	75	5	2.42	1.53	1.192	1.448
St. Lucie 1	73	1	318	75	6	2.25	1.53	1.207	1.444
St. Lucie 1	73	4	318	75	12	2.00	1.53	1.236	1.250
St. Lucie 1	74	2	366	75	12	1.50	1.33	1.208	1.333
St. Lucie 1	74	4	401	75	12	1.00	1.21	1.212	1.500
	Actual		486	76	6				
St. Lucie 2	72	4	360	78	10	5.83	3.97	1.267	1.829
St. Lucie 2	73	1	360	79	12	6.75	3.97	1.227	1.543
St. Lucie 2	74	1	360	80	12	6.75	3.97	1.227	1.395
St. Lucie 2	74	2	360	79	12	5.50	3.97	1.285	1.667
St. Lucie 2	74	4	537	79	12	5.00	2.66	1.216	1.733
St. Lucie 2	75	3	537	80	12	5.25	2.66	1.205	1.508
St. Lucie 2	75	4	620	80	12	5.00	2.31	1.182	1.533
St. Lucie 2	76	3	620	82	12	6.25	2.31	1.143	1.107
St. Lucie 2	76	4	850	82	12	6.00	1.68	1.091	1.111
St. Lucie 2	77	2	850	83	5	5.92	1.68	1.092	1.042
St. Lucie 2	78	3	845	83	5	4.67	1.69	1.119	1.054
St. Lucie 2	78	4	919	83	5	4.42	1.56	1.105	1.057
St. Lucie 2	80	2	1100	83	5	2.92	1.30	1.094	1.086
	Actual		1430	83	8				

Notes: All estimates for 1 or more years into the future included.
Unknown months (indicated by "?") assumed to be June.

and the sunk costs for Seabrook 2 will be $1 billion.

Q: How does Mr. Foote's analysis of Seabrook 2 costs differ from yours?

A: While I believe it has some important deficiencies, I would like to note that Mr. Foote's analysis is concrete evidence that FG&E's opposition to completion of Seabrook 2 is serious and well-founded. It represents a lucid and critical review of PSNH's estimates: such reviews, especially by small utilities, are all too rare. Essentially, Mr. Foote assumes that the cost of completing Unit 2 will mimic that actual and projected cost of Millstone 3, inflated to represent the difference in time between the point at which Millstone 3 construction accelerated, and the point at which Seabrook 2 would resume active construction. This approach makes three errors. First, Mr. Foote assumed that major construction on Unit 2 would resume in July 1985, coninciding with fuel load at Unit 1. While this fuel load date was more realistic than PSNH's projection at the time, it only incorporated PSNH's acknowledged slippage to that point, and is now earlier than PSNH's projection. In addition, it is not clear that construction on Unit 2 could be accelerated until Unit 1 was in commercial operation and generating revenues for the most severely strapped of the joint owners. Second, Mr. Foote assumed that Millstone 3 will actually be completed at the current cost estimate: this is highly speculative, at best, as demonstrated in my testimony in DPU 84-25. Third, Mr. Foote assumes that the real cost of constructing nuclear plants will not increase from the early 1980's to the early 1990's, in contrast to the continuous real increases over the last 15 years.

While FG&E's analysis of Seabrook 2 costs is overly optimistic, it does make the central point. Unit 2 will simply be more expensive than can be justified by its value to the utilities and their customers.

3.3 - CAPACITY FACTOR

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

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

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

CF = Output/(RC x hours)

where CF = capacity factor, and

RC = rated capacity.

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

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

The difference between capacity factor and availability factor is illustrated in Figure 3.2. The capacity factor is the ratio of the shaded area in regions A and B to the area of the rectangle, while the availability factor is the sum of the width of regions A, B, and C. Clearly, if the rated capacity is actually the maximum capacity of the unit, the availability factor will always be at least as large as the capacity factor and will generally be larger. Specifically, the availability factor includes the unshaded portion of region B, and all of region C, which are not included in the capacity factor.

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

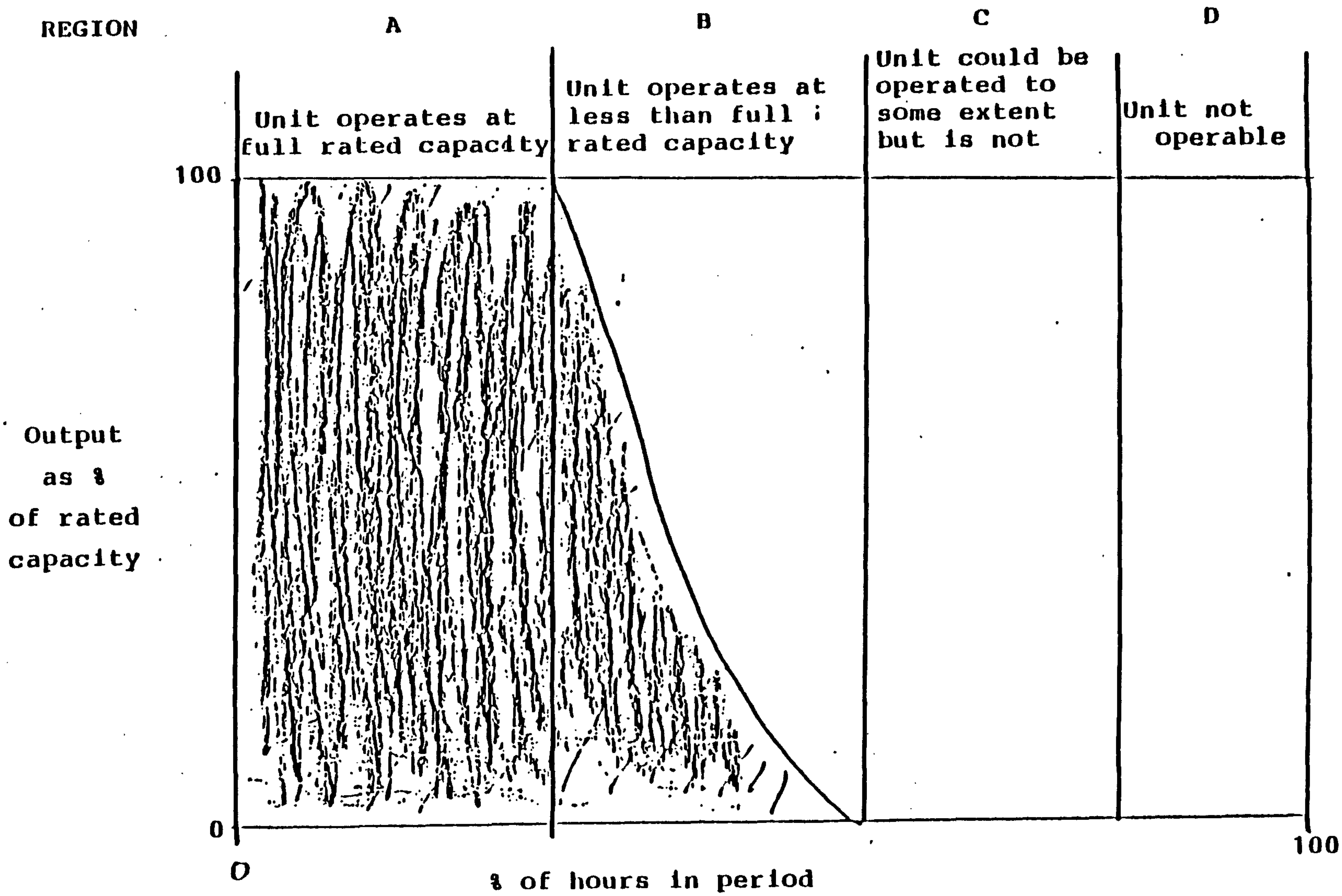
A: The three most common measures of capacity are

Maximum Dependable Capacity (MDC);

Design Electric Rating (DER); and

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

FIGURE 3.2



Diagrammatic Description of Availability Factor and Capacity Factor

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

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

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

The use of MDC capacity factors in forecasting Seabrook power cost would present no problem if the MDC's for Seabrook were known for each year of its life. Unfortunately, these capacities will not be known until Seabrook actually operates and its various problems and limitations appear. All that is known now are initial estimates of the DER and IGN, which I take to be 1150 MW and 1194 MW, respectively. Since it is impossible to project output without consistent definitions of Capacity Factor and Rated Capacity, only DER and IGN capacity factors are useful for planning purposes. Using MDC capacity factors with DER ratings is as inappropriate as multiplying a kilometers/liter fuel efficiency measure by miles to try to estimate gallons of gasoline consumed; the units are different, and in the case of MDC, unknown.

Actually, DER designations have also changed for some plants. The new, and often lower, DER's will produce different observed capacity factors than the original DER's. For example, Komanoff (1978) reports that Pilgrim's original DER was 670 MW, equal to its current MDC, not the 655 MW value now reported for DER. Therefore, in studying historical capacity factors for forecasting the performance of new reactors, it is appropriate to use the original DER ratings, which would seem to be the capacity measure most consistent with the 1150 MW expectation for Seabrook. This problem can also be avoided through the use of the MGN ratings.

Q: Are PSNH's projections of Seabrook capacity factors reasonable?

A: No, they are significantly overstated. PSNH ignores all previous analyses of reactor performance, and instead bases its projections on a 1973 EBASCO estimate, which used no actual data, modified slightly to partially reflect New England experience with much smaller units trought the mid-1970's.

Q: Have any studies been performed of the historic capacity factors for operating reactors?

A: Yes. Several statistical analyses of the capacity factors of actual operating nuclear plants have been performed, including those for the Council on Economic Priorities (CEP) (Komanoff, 1978), Sandia Laboratories studies for the NRC (Easterling, 1979, 1981) and the NERA studies perviously described (Perl, 1978, 1982; NERA, 1984).

The CEP study utilized data through 1977 and projected a levelized capacity factor for the first ten full operating years for Westinghouse 1150 MW reactors at 54.8%. This projection is based on a statistical analysis which predicts a 46.1% capacity factor in year 1, rising to 62.3% in year 10. An alternative model found that capacity factors actually peak in year 5, at 59.1% and slowly decline to 55.2% in year

10, indicating that maturation does not continue to improve capacity factors indefinitely. However, in recognition of a perceived improvement in plants completed after 1973, Komanoff increases his 10 year levelized projection by 1.8 percentage points, over the historic trend.

The first NRC study projects capacity factors on the basis of maximum generator nameplate (MGN). The prediction for an 1194 MW (MGN) PWR, expressed in terms of an 1150 MW DER, would be 51.6% in the second full year of operation, 55.0% in the third full year, and 58.3% thereafter. No further maturation was detected. All results for the first partial year and first full year of operation are excluded. Assuming that first year capacity factors are as good as second year capacity factors, a plant with a 30-year life would average 57.7% over its life, or 56.1% levelized at a 10% discount rate.

The second NRC study uses the same methodology and reaches similar, if somewhat more pessimistic, conclusions. Easterling develops several equations for PWR's, using different data sets and different maturation periods, and concludes that maturation may continue through year 5. Table 3.14 shows the results of the equations which can be evaluated for Seabrook. The first equation uses all data and four-year maturation, the second excludes three unit-years of particularly poor performance, the third introduces 5-year maturation, and last excludes all data from units under 700 MW. Levelized average capacity factors from these equations range from 48% to 53%.

The first NERA study presents capacity factor estimates of 63.6% for 1100 MW PWR's and 63.1% for 1200 MW plants, again excluding initial partial years of operation. These figures appear to represent levelized averages of the values generated by a regression equation, which predicts 1150 MW plant capacity factors of 54.8% in year one, rising to 66.5% in year 30. As previously noted, however, the projection of continued maturation past year 10 (or even year 5) is not supported by the historic record. The NERA projection for year 10 is 65.3% and that for year five is 63.8%.

The second NERA study uses a very different functional form in the capacity factor equation, and mixes in BWR's and some very small units.[14] The equation predicts capacity factors for a unit like Seabrook of 53% in the first year, rising to 63% in year 5. The NERA study itself uses a 59% overall

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14. In general, these very small units do not fall on the size trend of the larger units. In fact, it may be impossible for them to do so, since extrapolating the size trends observed in the 500 - 1000 MW range back to the 100-MW range may produce capacity factor projections close to or exceeding 100%. As a result, small units are apt to reduce the estimated size coefficient.

capacity factor in its cost calculations.

The most recent NERA study (NERA 1984) performs a regression analysis on PWR's alone, but still includes some very small units. Data through 1981 is used in the regression, but only the best performance, observed in the period 1975 to 1978, is actually used in the projection. On this basis, NERA concludes that the appropriate levelized capacity factor for 1150 MW PWR's is 60%. This is a rather optimistic assumption, excluding some 59% of NERA's data, primarily to remove all effects of the problems of 1979-81. These problems included the effects of the Three Mile Island accident, which in itself can hardly be considered unique; the frequency of major accidents will be discussed below. Other problems in the post-1979 period had nothing to do with the TMI accident: examples include the computational errors in earthquake-resistant design features discovered in 1979, problems with steam-generator corrosion and pipe cracking, and the failure of SCRAM mechanisms at Salem. Assuming that the future is like the average of NERA's data,[15] the levelized projection would be some 5.8 percentage points lower, or about 54.2%.

Therefore, average life-time capacity-factor estimates for

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15. Of the data used in the regression, 24% was prior to 1975, 41% was from 1975-78, and 35% was from 1979-81.

units like Seabrook would seem to lie in the range of 50% to 60%, based on regression analyses of the historical record. There is a great deal of variation from the average, however; the regressions typically explain less than a third of the variation in the data, and the first NRC study derived 95% prediction intervals of about 10% in years 2 to 5, 8% in years 2 to 10, and 7.3% for years 2 to 28. Roughly speaking, those earlier, more optimistic NRC results predict that 19 out of every 20 nuclear units of the Seabrook size and type would have average lifetime capacity factors between 50.3% and 64.9%, with the 20th unit having a capcity factor outside that range. Actually, the variation would be somewhat larger, due to the greater variation in the first partial year and the first full year.[16]

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

A: Easterling's studies are fully reviewable (unlike the NERA studies) and were conducted to advocate nuclear power development (unlike the CEP study), so based on these studies, I feel most comfortable using the levelized value of 52% from the most optimistic equation in Easterling (1981).

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

Q: Are PSNH's projections for Seabrook capacity factor reasonable?

A: No. Table 3.15 displays the difference between PSNH's projections and Easterling's results. The capacity factors assumed by PSNH (and indeed by most New England utilities) are much too high. This should not be very surprising: PSNH's projections are based on the NEPOOL GTF assumptions, which were derived in 1973 without the use of any actual nuclear capacity factor data.

As a check on the accuracy of the NRC/Easterling capacity factors, compared to PSNH's projections, I have performed the calculations presented in Tables 3.16 and 3.17. For the six PWR's over 1000 MW which had entered service by 1979, the average capacity factor as of October 1983 was 56.1%. The capacity factor estimates which I derived from Easterling (1981) predict an average of 52.9%, while PSNH would predict an average of 66%. Clearly, PSNH's expectations are out of line with reality. While the performance of these six units slightly exceeds Easterling's projections, it is not clear which is the better predictor. Easterling has more data, especially in mature years, but includes smaller units. The actual six-unit average will vary with refueling schedules and has less data. At most, the actual data suggests a 3% upward revision in the Easterling actual, to levelized

TABLE 3.15: CAPACITY FACTOR EQUATIONS AND PROJECTIONS FROM EASTERLING

Equation	3.1	3.2	3.3	3.4
Coefficients:				
Constant	75.7	73.1	77.3	68.3
AGE	3.4	4.0		
AGE5			2.4	2.3
MGN/100	-3.5	-3.3	-3.2	-2.3
Capacity Factor Value at Age:				
2	42.3	43.3	45.6	47.2
3	45.8	47.4	48.1	49.6
4	49.3	51.6	50.6	52.0
5	49.3	51.6	53.0	54.3
25-yr levelized	47.7	49.7	51.0	52.4
35-yr levelized	47.8	49.8	51.1	52.5

Notes: [1] AGE takes values 2, 3 and 4.
[2] AGE5 takes values 2, 3, 4 and 5.

TABLE 3.16: COMPARISON OF CAPACITY FACTOR PREDICTIONS

		Calendar Years of Experience						
		1	2	3	4	5	6	7+
Predicted Capacity Factors:		[2]						
Easterling [1]		47.2%	47.2%	47.2%	49.6%	52.0%	54.3%	54.3%
PSNH [2]		60.0%	63.0%	65.0%	65.0%	65.0%	65.0%	70.0%
Unit Years of Experience as of 30-Sep-83								
	COD							
Salem 1	30-Jun-77	0.51	1.00	1.00	1.00	1.00	1.00	0.75
Zion 1	31-Dec-73	0.00	1.00	1.00	1.00	1.00	1.00	4.76
Zion 2	17-Sep-74	0.29	1.00	1.00	1.00	1.00	1.00	3.75
Cook 1	27-Aug-75	0.35	1.00	1.00	1.00	1.00	1.00	2.75
Cook 2	01-Jul-78	0.50	1.00	1.00	1.00	1.00	0.75	0.00
Trojan	20-May-76	0.62	1.00	1.00	1.00	1.00	1.00	1.75

Notes: [1] See Table 3.15: Equation 3.4.
[2] First partial year.

TABLE 3.17: COMPARISON OF CAPACITY FACTOR PROJECTIONS

Unit	MW	Actual [1]	Easterling [2]	PSNH
Salem 1	1090	46.3%	51.8%	64.9%
Zion 1	1050	57.9%	54.5%	67.2%
Zion 2	1050	57.6%	54.1%	66.7%
Cook 1	1090	61.1%	52.8%	66.2%
Cook 2	1100	64.2%	50.8%	64.1%
Trojan	1130	48.6%	51.3%	65.5%
Average (3)		56.1%	52.9%	66.0%

Notes: [1] From original DER rating, and cumulative output; NRC Gray Book, October 1983.

[2] Includes 2.4 points per 100 MW decrease in size.

[3] Weighted by experience.

average of about 55%.

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

A: Yes. Table 3.18 presents the annual capacity factors for the units used in the previous analysis, through September 1983. The analysis also performed with the addition of the four large PWR's which entered commercial operation in 1981. I have accepted a suggestion (originally made by NU) that the very low capacity factors for Trojan in 1978 and for Salem 1 in 1979 are not generated by the same sort of random process which accounts for the other variation in nuclear capacity factor. However, there is no reason to believe that some comparable problem can not occur for Seabrook.[17] Hence, I delete these two observations from the individual year calculations, and instead reflect the probability of a major problem by computing the average effect. For example, compared to the results for all the other plants, these two events reduced capacity factors by an average of 47.8% from average second year performance, in 50.5 unit-years of experience, for a 0.9% reduction in all capacity factors. This calculation is shown in Table 3.19. Depending on the dataset used, the average capacity factor which results from

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17. In fact, it appears that something <u>worse</u> has happened at Salem 2 in 1983, and that Salem 1 is now starting another "unusual" outage.

TABLE 3.18: HISTORICAL CAPACITY FACTORS (DER)
Nuclear Units Similar in Characteristic to Seabrook
Unadjusted data.

UNIT	DER NET [3]	first year	CAPACITY FACTOR BY CALENDAR YEAR [2] 1	2	3	4	5	6	7	8	9	10
ZION 1	1050	74	37.8%	53.4%	51.6%	54.7%	73.6%	60.2%	70.6%	67.3%	51.0%	58.6%
ZION 2	1050	75	52.5%	50.3%	68.2%	73.2%	51.8%	57.2%	57.2%	56.1%	58.4%	
COOK 1	1090	76	71.1%	50.1%	65.8%	59.3%	67.5%	71.0%	56.1%	63.0%		
TROJAN	1130	77	65.6%	16.8%	53.2%	61.2%	64.9%	48.5%	23.8%			
SALEM 1	1090	78	47.4%	21.4%	59.4%	64.8%	42.9%	42.9%				
COOK 2	1100	79	61.8%	69.3%	66.3%	72.6%	79.7%					
SEQUOYAH 1	1148	82	48.8%	78.2%								
SALEM 2	1115	82	81.3%	8.1%								
MCGUIRE 1	1180	82	41.6%	35.6%								
SEQUOYAH 2	1148	82	50.8%	52.2%								
AVERAGES:												
ALL UNITS [1]	1106		55.9%	43.0%	60.7%	64.3%	62.7%	56.7%	53.8%	62.1%	54.2%	58.6%
FIRST SIX	1085		56.0%	55.8%								

Notes:
[1] Values for year 2 for Trojan and Salem 1 are excluded from average.
[2] Computed from NRC-reported net output and original DER.
[3] Original reported value.

TABLE 3.19: ADJUSTMENT OF 1000-MW PWR CAPACITY FACTORS FOR DEVIATIONS AT SALEM 1 AND TROJAN

	CAPACITY FACTOR BY CALENDAR YEAR									
	1	2	3	4	5	6	7	8	9	10
AVERAGE ALL UNITS [1]	55.9%	43.0%	60.7%	64.3%	62.7%	56.7%	53.8%	62.1%	54.2%	58.6%
Salem/Trojan deviation [2]		47.8%								
unit-years [3]		50.5								
deviation/unit-year		0.9%								
Average adjusted for Salem/Trojan [5]	54.9%	42.1%	59.8%	63.4%	61.7%	55.7%	52.8%	61.1%	53.3%	57.6%
all years	55.8%									
>5 years	55.8%									
AVERAGE FIRST SIX [1]	56.0%	55.8%	60.7%	64.3%	62.7%	56.7%	53.8%	62.1%	54.2%	58.6%
Salem/Trojan deviation [4]		73.3%								
unit-years [3]		43.5								
deviation/unit-year		1.7%								
Average adjusted for Salem/Trojan [5]	54.3%	54.1%	59.1%	62.6%	61.0%	55.0%	52.1%	60.4%	52.5%	56.9%
all years	57.4%									
>5 years	55.1%									

Notes: [1] From Table 3.18
[2] 2*43 - 16.8 - 21.4.
[3] 1983 weighted as .75 years; excludes Salem 1 and Trojan second years.
[4] 2*55.8 - 16.8 - 21.4.
[5] Simple averages minus Salem/Trojan deviation per unit/year.

this analysis is 55.8% to 57.4%; the mature capacity factor is actually lower, in the 55.1% to 55.8% range. This approach also indicates that Easterling's results are very close to the performance of large PWR's.

3.4 - CARRYING CHARGES

Q: What annual carrrying charge should be applied to the cost of Seabrook?

A: For the levelized cost analysis, I have assumed a 10% real cost of capital (including income taxes)[18] and a unit lifetime of 25 years, as a compromise between possibilities of 20 years and 30 years. The shorter lifetime is based on an analysis of the experience of smaller nuclear units, as discussed in Chernick, et al. (1981, pp. 101-109), while the longer lifetime is a more standard industry assumption.[19] I also use a 1% levelized property tax rate. Over 25 years, the levelized annual fixed charges for capital, and depreciation would be 11%, or 12% with property taxes. With this fixed charge rate and a 54% capacity factor, each \$1000/kw results in a levelized carrying cost of 2.53 cents/kWh, so \$4000/kw yields a carrying charge of 10.1 cents/kWh, for example.

Q: What other costs must be added to the Seabrook carrying costs to determine the total cost of Seabrook power?

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18. This choice seems somewhat low at this point.

19. In addition to the small units which were discussed in Chernick, et al., 1981, San Onofre 1 has been out of service for about two years and may also have been retired de facto after only 14 years of service.

A: The other components of the costs of Seabrook which are directly assignable to that plant are:

- fuel;
- non-fuel operation and maintenance (O&M) expense;
- interim replacements (capital additions);
- insurance; and
- decommissioning.

3.5 - FUEL COST

Q: What nuclear fuel costs have you used?

A: I used PSNH's 1982 estimates of Seabrook fuel costs, which rise from 1.006 cents/kWh in 1986 to 1.471 cents in 1994 for Unit 1, and 1.233 cents in 1987 to 1.43 cents in 1994 for Unit 2. Deflating these costs at DRI's projection of the GNP deflator and levelizing the constant-dollar results yields about 1 cent/kWh in 1984 dollars for either unit. The costs would probably be higher on PSNH's new schedule, and especially on a realistic schedule, due to the increased interest costs.

3.6 - NON-FUEL O & M

Q: Is PSNH's estimate of Seabrook non-fuel O & M expense reasonable?

A: No. PSNH bases its O & M cost forecast on recent O & M costs for Maine Yankee, but assumes that nuclear O & M increases only at about the inflation rate, despite very rapid historical growth rates in nuclear O & M. Table 3.20 reports the annual O & M for the Millstone, Pilgrim and Yankee units since their first full year of operation.[20] The average annual growth rate in the O & M figures reported for New England nuclear units through 1982 ranges from 16% to 27% for the various units, in nominal terms. Table 3.20 also displays the GNP inflation index for each year, and the constant-dollar escalation of the O & M expenses. Even after subtracting inflation, O & M expense has been rising at 8% to 18% annually.

Table 3.21 presents the 1982 O & M cost for each of the six commercial-sized New England nuclear units. The table also presents the least-squares estimates of annual linear growth

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20. The very small Yankee Rowe unit is omitted, but the time pattern of its O&M costs is quite similar to those of the larger units.

TABLE 3.20: NEW ENGLAND NUCLEAR O & M HISTORIES

Year	Conn. Yankee	Mill-stone 1	Mill-stone 2	Pilgrim	Vermont Yankee	Maine Yankee	GNP Deflator
	($ thousand)						
1968	2047						82.54
1969	2067						86.79
1970	4479						91.45
1971	3279						96.01
1972	3749	7677					100.00
1973	6352	7635		4797	4957	4034	105.75
1974	4935	9808		9527	5692	5232	115.08
1975	9381	12065		7340	7682	6301	125.79
1976	9419	14040	10929	16633	7912	5261	132.34
1977	9448	12637	17377	15320	9775	8418	140.05
1978	8736	16448	22288	14187	11191	10817	150.42
1979	18923	23060	21931	18387	14208	9971	163.42
1980	35155	24784	30163	27785	22586	14028	178.42
1981	37488	33270	28877	34994	26795	20576	195.14
1982	35722	33463	45247	42437	33764	28556	206.88
Annual Growth Rate to 1982:							
Nominal:	22.7%	15.9%	22.5%	27.4%	23.8%	24.3%	7.7%
Real:	14.87%	7.93%	17.62%	18.25%	14.87%	15.36%	

TABLE 3.21: CALCULATION OF AVERAGE NEW ENGLAND EXPERIENCE
Non-Fuel Nuclear O & M Expense, Constant Dollars

Unit	Period Analyzed	1982 O & M	Least - Squares Annual Growth: Linear Increase	Least - Squares Annual Growth: Geometric Increase
		(1000)	(1000 1983$)	
Conn. Yankee	1969-82	$35,722	$2,477.2	15.4%
Millstone 1	1972-82	$33,463	$2,102.8	9.0%
Millstone 2	1976-82	$45,247	$3,674.1	12.9%
Pilgrim	1973-82	$42,437	$3,327.2	15.3%
Vermont Yankee	1973-82	$33,764	$2,712.6	15.1%
Maine Yankee	1973-82	$28,556	$2,008.6	13.7%
AVERAGES:				
1982$		$36,532	$2,858.8	13.5%
1983$ [1]		$39,739		

Notes: [1] 1983$ = 1982$*1.0423

(in 1983 dollars) and of annual geometric growth rates,[21] and the six-unit average of each parameter. Each unit is analyzed from its first full year of service through 1982.

Table 3.22 extrapolates the linear and geometric average trends and displays the 1987 nominal O & M cost and the levelized O & M cost (in 1984$) for Seabrook over a 25 year life. Protracted geometric growth in real O & M cost would probably lead to retirement of the all nuclear units around the turn of the century, as they would then be prohibitively expensive to operate (unless the alternatives managed to be even more expensive).

High costs of O & M and necessary capital additions were responsible for the retirement (formal or de facto) of Indian Point 1, Humboldt Bay, and Dresden 1, after only 12, 13, and 18 years of operation, respectively. Thus, rising costs caught up to most of the small pre-1965 reactors during the 1970's: only Big Rock Point and Yankee Rowe remain from that cohort. The operator of LaCrosse, a small reactor of 1969 vintage, has announced plans to retire it in the late 1980's. To be on the optimistic side, I have assumed a continuation of the linear trends in New England nuclear cost escalation,

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21. The curves all fit the data fairly well; if there is an overall difference in fit, it is the geometric curves which better follow the data.

TABLE 3.22: ANNUAL NON-FUEL O & M EXPENSE FOR SEABROOK
Extrapolated from New England Experience

Year	LINEAR 1983 $ (thousand)	LINEAR Current $ (thousand)	GEOMETRIC 1983 $ (thousand)	GEOMETRIC Current $ (thousand)
1987	$54,033	$66,431	$74,917	$92,458
1992	$68,327	$110,413	$141,235	$228,230
1997	$82,621	$179,513	$266,260	$578,511
2002	$96,915	$283,121	$501,959	$1,466,396
2007	$111,208	$436,816	$946,305	$3,716,987
2012	$125,502	$662,810	$1,783,995	$9,421,733
2017	$139,796	$992,681	$3,363,230	$23,881,990
2022	$154,090	$1,471,180	$6,340,439	$60,535,514
LEVELIZED				
1987-2012: [1]	$72,232	$131,270	$277,767	$583,087
1997-2022: [2]	$100,820	$325,042	$987,203	$1,089,408

Notes: 1. Approximately the useful life of Seabrook 1.
2. Approximately the useful life of Seabrook 2.

which would produce 25-year real levelized O&M costs of about $66/kw in 1984 dollars.

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

A: I believe that it is. Several more major nuclear accidents or near-misses are likely to occur before the scheduled end of Seabrook operation. Various recent estimates of major accident probabilities range from 1/200 to 1/1000 per reactor year (See Chernick, et al., 1981; Miniarick and Kukielka, 1982). Thus, major accidents can be expected every two to ten years once 100 reactors are operating. If anything, the 1968-83 period has been relatively favorable for nuclear operations.

3.7 - CAPITAL ADDITIONS

Q: What is a reasonable estimate of capital additions to Seabrook?

A: I gathered data for all plants for which cost data was available from FERC and DOE compilations of FERC Form 1 data (now reported on p. 403), through 1981. The data for each plant includes all years in which no units were added or deleted, and for which the data was not clearly in error. Average plant size in the dataset was 841 MW. The available experience totalled 378 unit-years of operation, and the average annual capital addition was $18.5/kw, or about $21.3 million annually for a Seabrook unit in 1983 dollars.

3.8 - INSURANCE

Q: What value have you used for the cost of insuring Seabrook?

A: I have assumed that PSNH obtains the following insurance per unit:

1. liability coverage of $160 million, for the 1981 average premium of $380,000;

2. property coverage of $300 million from the commercial pool (ANI//MAERP), at the high-end premium of $1.75 million;

3. additional property coverage of $375 million from the self-insurance pool (NML) for the TMI 1 premium of $1.38 million;

4. replacement power coverage of $156 million from the self-insurance pool (NEIL) for $1.69 million;

5. decommissioning accident coverage of one billion dollars for $2.19 million; and

6. non-accident-initiated premature decommissioning coverage of $250 million for $2.42 million.

All values are 1981 dollars from Chernick, et al. (1981), except for the NEIL premium, which is from the NEIL circular of December 18, 1979. The decommissioning insurances may be from new or existing pools. These coverages have total estimated premiums of $9.81 million in 1981 dollars, or about $11.4 million in 1984 dollars (incuding just GNP inflation). While only the liability and some property coverage are currently required, failure to utilize insurance exposes the ratepayers and stockholders of the owners to additional costs, which may be greater (on the average) than the insurance premium. Indeed, even with all the insurance listed, the owners would still not be fully covered in the event of the total and permanent loss of Seabrook.

On a cents-per-kWh basis, $11.4 million annually is $9.5/kw or 0.2 cents/kWh.

3.9 - DECOMMISSIONING

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

A: Chernick, et al. (1981) estimates that non-accidental decommissioning of a large reactor will cost about $250 million in 1981 dollars. This is equivalent to about $311 million in 1984 dollars (using the nuclear inflation figures discussed above), or about $270/kw for Seabrook. Assuming that the decommissioning fund accumulates uniformly (in constant dollars) over the life of the plant, and that it is invested in risk-free assets (such as Treasury securities) which earn essentially zero real return, the annual contribution (in 1984 dollars) would be about $9.4 per kw-year over a 25 year life.

3.10 - TOTAL SEABROOK GENERATION COST

Q: What is your estimate of the cost of power from Seabrook?

A: I estimate that the total cost of power from Seabrook 1 will be about 13 or 14 cents/kWh, levelized in 1984 dollars. Excluding sunk costs as of mid-1984, the remaining cost is still about 7 cents/kWh. These figures are derived in Table 3.23. The costs in Table 3.23 are all in 1984 constant levelized dollars, to make them easier to compare to today's prices and the costs of current power supply options. The actual prices charged will include inflation and will not be levelized: the first year cost for Seabrook 1 under traditional ratemaking would be in the 30 to 35 cent/kwh range, depending on the cost of capital and the treatment of tax credits.

Table 3.23 also calculates the levelized costs for Seabrook 2, under some extremely optimistic cost projections. The total cost of Seabrook 2 would be only about two cents more than that for Unit 1 (not a suprising result, considering that these are constant dollars and that the Unit 2 cost is particularly understated), or 15 to 16 cents. This is still three to four times the present cost of oil-fired electricity, in constant dollars. Since so little of Seabrook 2's eventual cost has been spent to date, the

TABLE 3.23: TOTAL POWER COSTS FOR SEABROOK

Cost Basis	SEABROOK UNIT #1 Entire Cost	SEABROOK UNIT #1 Remaining Costs	SEABROOK UNIT #2 Entire Cost	SEABROOK UNIT #2 Remaining Costs
Cost per kw				
Construction Costs	$4,180	$1,571	$4,687	$3,818
Fixed Charge Rate	12.0%	12.0%	12.0%	12.0%
Cost per kw-yr				
Annual Capital Costs	$502	$189	$562	$458
Non-fuel O&M	$63	$63	$88	$88
Capital Additions	$18	$18	$18	$18
Insurance	$10	$10	$10	$10
Decommissioning	$9	$9	$9	$9
Total Non-fuel	$601	$288	$687	$583
Capacity Factor	54%	54%	54%	54%
Cost per kwh (cents)				
Non-fuel	12.7	6.1	14.5	12.3
Fuel	1.0	1.0	1.0	1.0
Total	13.7	7.1	15.5	13.3

Notes: All costs are levelized in real 1984 dollars.
Assumptions for Unit 1:
Oct-88 COD, Total Cost $6 billion, $3 billion sunk.
Assumptions for Unit 2:
Jul-95 COD, Total Cost $10 billion, $1 billion sunk.

remaining cost is in excess of 13 cents.

Q: What does this analysis tell us about the economic viability of Seabrook 1?

A: It is clear that Seabrook 1 will be very expensive. It is almost certain that some mix of utility-owned generation, customer-owned generation, purchased power, and conservation programs would be less expensive than Seabrook. It is also very likely that the cost of completing and running Seabrook, ignoring the sunk costs, will be higher than the most economical supply plan available at this point. Thus, cancelation of Seabrook is probably in the best interests of FG&E ratepayers and those of New England as a whole,[22] unless the utility shareholders are to absorb both all sunk costs to date and a sizable fraction of future costs. At best,[23] Seabrook 1 may be a slightly desirable investment, but it certainly is not worth making any extraordinary efforts to save.

As noted previously, and as indicated in Table 3.23, the costs of completing and operating Seabrook 2 are exorbitant

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22. It is possible that this would not be true for the customers of the municipal utilities with access to tax-exempt financing.

23. If oil prices rise rapidly, other energy sources prove difficult to develop, and Seabrook 1 is completed and operated at relatively low costs, and runs reliabily for a long life.

under any circumstances, and should be avoided by prompt cancelation of the unit.

4 - CONCLUSIONS

Q: What are your recommendations to the Department in this case?

A: For all the previously stated reasons, I believe that it would be appropriate and helpful for the Department to take the following actions:

- warn FG&E that further investments in Seabrook are particularly at the shareholders' risk, and that FG&E should be doing all it can to limit such risk;

- prohibit the use of any funds raised by securities issuances for further expenditures on Seabrook 2, other than costs related directly to cancelation;

- declare Seabrook 2 to be unconditionally canceled, and order FG&E to stop all further payment towards Seabrook 2, other than for cancelation costs;

- strongly urge FG&E to assess all available legal remedies;

- prohibit the use of any ratepayer funds or funds raised by the issuance of securities for the purpose of advance payments or other forms of assistance to PSNH;

- indicate that FG&E's entire share of the savings from Hydro Quebec are to be available to FG&E ratepayers, as currently planned

- require a full assessment of Seabrook 1 in the next FG&E rate case; and

- require FG&E to report frequently to the Department on the status of Seabrook.

Q: Does this conclude your testimony?

A: Yes.

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APPENDIX B:

COST MYOPIA DATA

Unit Name	...Actuals... Cost	COD		Estimat Year	Qr	Estimated Cost	COD		Years to COD	Cost Ratio	Myopia %	Duration Ratio
Pilgrim 1	239	72	12	64	1		71	10	7.58			1.154
Calvert Cliffs 2	335	77	4	67	2	105	74	1	6.58	3.19	19.3%	1.494
Farley 2	750	81	7	70	3	183	77	4	6.58	4.10	23.9%	1.646
San Onofre 2	2502	83	8	74	4	893	81	7	6.58	2.80	16.9%	1.316
Millstone 2	426	75	12	67	4	150	74	4	6.33	2.84	17.9%	1.263
San Onofre 2	2502	83	8	75	1	1142	81	7	6.33	2.19	13.2%	1.329
San Onofre 2	2502	83	8	70	1	379	76	6	6.25	6.60	35.3%	2.147
Calvert Cliffs 2	335	77	4	67	4	107	74	1	6.08	3.13	20.7%	1.534
Millstone 2	426	75	12	68	1	146	74	4	6.08	2.92	19.3%	1.274
San Onofre 2	2502	83	8	75	3	1142	81	10	6.08	2.19	13.8%	1.301
Davis-Besse 1	672	77	11	68	4	180	74	12	6.00	3.74	24.6%	1.486
Lasalle 1	1367	82	10	71	4	360	77	12	6.00	3.80	24.9%	1.806
San Onofre 2	2502	83	8	75	2	812	81	6	6.00	3.08	20.6%	1.361
San Onofre 2	2502	83	8	70	2	427	76	6	6.00	5.86	34.3%	2.194
For 6<=t, N =	14	14		14		13	14		14	13	13	14
Average	1397	80	3	70	3	464	77	0	6.32	3.57	21.9%	1.522
Zion 2	292	74	9	67	2		73	5	5.92			1.225
Calvert Cliffs 2	335	77	4	68	1	106	74	1	5.83	3.16	21.8%	1.557
Trojan	452	75	12	68	4	196	74	9	5.75	2.31	15.6%	1.217
Lasalle 1	1367	82	10	71	3	360	77	5	5.67	3.80	26.5%	1.956
Salem 2		81	10	67	3	128	73	5	5.67			2.485
Beaver Valley 1	599	76	10	67	4		73	7	5.58			1.582
Calvert Cliffs 1	431	75	5	67	2	118	73	1	5.58	3.65	26.1%	1.418
Farley 1	727	77	12	69	3	164	75	4	5.58	4.44	30.6%	1.478
Farley 2	750	81	7	71	3	233	77	4	5.58	3.22	23.3%	1.761
Duane Arnold	280	75	2	68	2	103	73	12	5.50	2.72	19.9%	1.212
Trojan	452	75	12	69	1	197	74	9	5.50	2.29	16.3%	1.227
Rancho Seco	344	75	4	67	4	134	73	5	5.42	2.56	19.0%	1.354
Hatch 2	515	79	9	72	4	330	78	4	5.33	1.56	8.7%	1.266
Lasalle 1	1367	82	10	73	2	407	78	10	5.33	3.36	25.5%	1.750
Lasalle 1	1367	82	10	70	2	360	75	10	5.33	3.80	28.4%	2.313
Millstone 2	426	75	12	68	4	179	74	4	5.33	2.38	17.7%	1.313
San Onofre 2	2502	83	8	76	2	1210	81	10	5.33	2.07	14.6%	1.344
Beaver Valley 1	599	76	10	68	1		73	6	5.25			1.635
Brunswick 1	318	77	3	70	4	194	76	3	5.25	1.64	9.9%	1.190
Davis-Besse 1	672	77	11	69	3	201	74	12	5.25	3.35	25.9%	1.556
Lasalle 1	1367	82	10	72	3	407	77	12	5.25	3.36	26.0%	1.921
Lasalle 1	1367	82	10	73	3	430	78	12	5.25	3.18	24.6%	1.730
Salem 2		81	10	67	4	128	73	3	5.25			2.635
San Onofre 2	2502	83	8	74	1	655	79	6	5.25	3.82	29.1%	1.794
Surry 2	155	73	5	66	4	108	72	3	5.25	1.44	7.2%	1.222
Fitzpatrick	419	75	7	68	1		73	5	5.17			1.419
Lasalle 1	1367	82	10	73	1	407	78	5	5.17	3.36	26.4%	1.855
McGuire 1	921	81	12	70	3	179	75	11	5.17	5.15	37.3%	2.177
Calvert Cliffs 1	431	75	5	67	4	123	73	1	5.08	3.50	28.0%	1.459
Crystal River 3	419	77	3	67	1	110	72	4	5.08	3.81	30.1%	1.967
Sequoyah 1		81	7	68	3	322	73	10	5.08			2.525
Zion 1	276	73	12	67	1		72	4	5.08			1.328
Arkansas 1	239	74	12	67	4	132	72	12	5.00	1.81	12.6%	1.400
Duane Arnold	280	75	2	68	4	107	73	12	5.00	2.62	21.2%	1.233
Hatch 1	390	75	12	68	2		73	6	5.00			1.500
North Anna 1	782	78	6	69	1	185	74	3	5.00	4.23	33.4%	1.850

Unit Name	...Actuals... Cost	COD		Estimat Year	Qr	Estimated Cost	COD		Years to COD	Cost Ratio	Myopia %	Duration Ratio
For 5<=t<=6, N =	33	36		36		30	36		36	27	27	36
Average	749	78	6	69	3	264	75	2	5.34	3.06	22.4%	1.635
Arkansas 2	640	80	3	70	4	183	75	10	4.83	3.50	29.6%	1.914
Calvert Cliffs 1	431	75	5	68	1	125	73	1	4.83	3.45	29.2%	1.483
Calvert Cliffs 2	335	77	4	69	1	105	74	1	4.83	3.19	27.2%	1.672
Farley 1	727	77	12	70	2	203	75	4	4.83	3.58	30.2%	1.552
Peach Bottom 3	223	74	12	68	1	145	73	1	4.83	1.54	9.3%	1.397
Sequoyah 2		82	6	68	4	322	73	10	4.83			2.793
Trojan	452	75	12	69	4	227	74	9	4.75	1.99	15.6%	1.263
Nine Mile Point 1		69	12	64	1		68	11	4.67			1.232
Salem 2		81	10	74	3	496	79	5	4.67			1.518
Cooper	269	74	7	67	3	133	72	4	4.58	2.02	16.6%	1.491
Hatch 2	515	79	9	73	3	404	78	4	4.58	1.27	5.4%	1.309
Duane Arnold	280	75	2	69	2	133	73	12	4.50	2.10	18.0%	1.259
Kewaunee	203	74	6	67	4		72	6	4.50			1.444
North Anna 2	542	80	12	70	3	184	75	3	4.50	2.95	27.1%	2.278
Peach Bottom 3	223	74	12	68	3	145	73	3	4.50	1.54	10.1%	1.389
Quad Cities 2		73	3	66	3		71	3	4.50			1.444
Arkansas 2	640	80	3	71	2	190	75	10	4.33	3.37	32.3%	2.019
Cook 1	545	75	8	67	4	235	72	4	4.33	2.32	21.4%	1.769
Cook 2	452	78	7	67	4	235	72	4	4.33	1.92	16.3%	2.442
Millstone 2	426	75	12	69	4	183	74	4	4.33	2.33	21.5%	1.385
San Onofre 2	2502	83	8	77	2	1320	81	10	4.33	1.90	15.9%	1.423
Beaver Valley 1	599	76	10	69	1	189	73	6	4.25	3.17	31.2%	1.784
Davis-Besse 1	672	77	11	70	3	266	74	12	4.25	2.53	24.4%	1.686
Hatch 1	390	75	12	69	1	151	73	6	4.25	2.59	25.0%	1.588
North Anna 1	782	78	6	69	4	281	74	3	4.25	2.78	27.2%	2.000
Salem 1		77	6	67	3	152	71	12	4.25			2.294
Salem 1		77	6	67	4	152	72	3	4.25			2.235
Sequoyah 2		82	6	70	3	373	74	12	4.25			2.765
Surry 1	247	72	12	66	4	130	71	3	4.25	1.90	16.3%	1.412
Surry 2	155	73	5	67	4	112	72	3	4.25	1.39	8.0%	1.275
McGuire 1	921	81	12	71	3	220	75	11	4.17	4.19	41.0%	2.460
Salem 1		77	6	67	1	139	71	5	4.17			2.460
Three Mile I.	401	74	9	67	1		71	5	4.17			1.800
Zion 2	292	74	9	69	1	194	73	5	4.17	1.51	10.3%	1.320
Arkansas 2	640	80	3	72	3	230	76	10	4.08	2.78	28.5%	1.837
Browns Ferry 2		75	3	66	3	235	70	10	4.08			2.082
Cooper	269	74	7	68	1	127	72	4	4.08	2.12	20.2%	1.551
Farley 2	750	81	7	73	1	268	77	4	4.08	2.80	28.7%	2.041
Point Beach 2		72	10	67	1		71	4	4.08			1.367
Sequoyah 1		81	7	69	3	373	73	10	4.08			2.898
Sequoyah 2		82	6	69	3	373	73	10	4.08			3.122
Vermont Yankee	184	72	11	66	3	88	70	10	4.08	2.10	19.9%	1.510
Duane Arnold	280	75	2	69	4	138	73	12	4.00	2.03	19.3%	1.292
Lasalle 1	1367	82	10	74	4	445	78	12	4.00	3.07	32.4%	1.958
St. Lucie 1	486	76	6	69	2	123	73	6	4.00	3.95	41.0%	1.750
For 4<=t<5, N =	33	45		45		40	45		45	31	31	45
Average	541	77	5	69	2	243	73	11	4.36	2.51	22.6%	1.799
Dresden 3		71	11	66	1		70	2	3.92			1.447
Monticello		71	6	66	2		70	5	3.92			1.277

Unit Name	...Actuals... Cost	COD		Estimat Year	Qr	Estimated Cost	COD		Years to COD	Cost Ratio	Myopia %	Duration Ratio
Robinson 2		71	3	66	2		70	5	3.92			1.213
Salem 1		77	6	67	2	149	71	5	3.92			2.553
Three Mile I.	401	74	9	67	2	106	71	5	3.92	3.78	40.4%	1.851
Arkansas 2	640	80	3	71	4	200	75	10	3.83	3.20	35.4%	2.152
Browns Ferry 1		74	8	66	4	235	70	10	3.83			2.000
Calvert Cliffs 1	431	75	5	69	1	124	73	1	3.83	3.47	38.4%	1.609
Crystal River 3	419	77	3	68	2	113	72	4	3.83	3.71	40.8%	2.283
Nine Mile Point 1		69	12	64	3		68	7	3.83			1.370
Point Beach 1		70	12	66	2		70	4	3.83			1.174
Sequoyah 1		81	7	70	2	373	74	4	3.83			2.891
Sequoyah 2		82	6	70	2	373	74	4	3.83			3.130
Arkansas 1	239	74	12	69	1	138	72	12	3.75	1.73	15.7%	1.533
Brunswick 1	318	77	3	71	2	182	75	3	3.75	1.75	16.1%	1.533
North Anna 2	542	80	12	71	3	191	75	6	3.75	2.84	32.1%	2.467
Quad Cities 1		73	2	66	2		70	3	3.75			1.778
Fort Calhoun 1	176	73	9	67	3	70	71	5	3.67	2.51	28.5%	1.636
Millstone 1		71	3	65	4		69	8	3.67			1.432
Salem 2		81	10	71	3		75	5	3.67			2.750
St. Lucie 1	486	76	6	69	3	123	73	5	3.67	3.95	45.5%	1.841
Farley 1	727	77	12	71	3	259	75	4	3.58	2.81	33.4%	1.744
Farley 2	750	81	7	73	2	268	77	1	3.58	2.80	33.3%	2.256
Hatch 2	515	79	9	75	3	513	79	4	3.58	1.00	0.1%	1.116
Hatch 2	515	79	9	74	3	513	78	4	3.58	1.00	0.1%	1.395
Hatch 2	515	79	9	72	3	189	76	4	3.58	2.72	32.3%	1.953
Point Beach 1		70	12	66	3		70	4	3.58			1.186
Arkansas 1	239	74	12	69	2	132	72	12	3.50	1.81	18.4%	1.571
Beaver Valley 1	599	76	10	69	4	192	73	6	3.50	3.12	38.4%	1.952
Cook 2	452	78	7	70	3	339	74	3	3.50	1.33	8.5%	2.238
Ginna		70	7	65	4		69	6	3.50			1.310
North Anna 2	542	80	12	71	4	198	75	6	3.50	2.74	33.3%	2.571
Peach Bottom 3	223	74	12	69	3	193	73	3	3.50	1.16	4.3%	1.500
Quad Cities 2		73	3	67	3		71	3	3.50			1.571
Salem 2		81	10	71	2		74	12	3.50			2.952
St. Lucie 1	486	76	6	70	4	200	74	6	3.50	2.43	28.9%	1.571
Trojan	452	75	12	71	1	228	74	9	3.50	1.98	21.6%	1.357
Three Mile I.	401	74	9	67	4	124	71	5	3.42	3.23	41.0%	1.976
Arkansas 2	640	80	3	73	2	275	76	10	3.33	2.33	28.8%	2.025
Calvert Cliffs 2	335	77	4	70	3	128	74	1	3.33	2.62	33.5%	1.975
Farley 2	750	81	7	75	4	477	79	4	3.33	1.57	14.5%	1.675
McGuire 1	921	81	12	74	3	365	78	1	3.33	2.52	32.0%	2.175
Millstone 2	426	75	12	70	4	239	74	4	3.33	1.78	19.0%	1.500
North Anna 2	542	80	12	72	1	198	75	7	3.33	2.74	35.3%	2.625
Oyster Creek 1		69	12	64	2		67	10	3.33			1.650
Salem 2		81	10	70	1		73	7	3.33			3.475
Arkansas 2	640	80	3	73	3	275	76	12	3.25	2.33	29.7%	2.000
Brunswick 1	318	77	3	71	4	181	75	3	3.25	1.76	19.0%	1.615
Brunswick 2	389	75	11	70	4	195	74	3	3.25	2.00	23.7%	1.513
Cook 1	545	75	8	69	2	235	72	9	3.25	2.32	29.5%	1.897
Cook 2	452	78	7	69	2	235	72	9	3.25	1.92	22.3%	2.795
Ginna		70	7	66	1		69	6	3.25			1.333
Hatch 1	390	75	12	70	1	185	73	6	3.25	2.11	25.8%	1.769
Kewaunee	203	74	6	69	1	109	72	6	3.25	1.87	21.2%	1.615
Lasalle 1	1367	82	10	75	3	498	78	12	3.25	2.74	36.4%	2.179

Unit Name	...Actuals... Cost	COD		Estimat Year	Qr	Estimated Cost	COD		Years to COD	Cost Ratio	Myopia %	Duration Ratio
McGuire 1	921	81	12	72	4	220	76	3	3.25	4.19	55.4%	2.769
Peach Bottom 3	223	74	12	69	4	203	73	3	3.25	1.10	3.0%	1.538
Salem 2		81	10	72	4		76	3	3.25			2.718
Sequoyah 2		82	6	71	4		75	3	3.25			3.231
Surry 1	247	72	12	67	4	144	71	3	3.25	1.71	18.0%	1.538
Surry 2	155	73	5	68	4	123	72	3	3.25	1.26	7.5%	1.359
Fort Calhoun 1	176	73	9	69	1	92	72	5	3.17	1.91	22.7%	1.421
McGuire 1	921	81	12	73	3	220	76	11	3.17	4.19	57.2%	2.605
Sequoyah 2		82	6	73	4		77	2	3.17			2.684
Sequoyah 2		82	6	73	2		76	8	3.17			2.842
Browns Ferry 1		74	8	67	3	373	70	10	3.08			2.243
Browns Ferry 3		77	3	70	3		73	10	3.08			2.108
Farley 2	750	81	7	73	4	329	77	1	3.08	2.28	30.6%	2.459
McGuire 1	921	81	12	74	4	384	78	1	3.08	2.40	32.8%	2.270
Peach Bottom 3	223	74	12	71	1	263	74	4	3.08	0.85	-5.2%	1.216
Salem 1		77	6	71	3	616	74	10	3.08			1.865
Salem 2		81	10	71	1		74	4	3.08			3.432
Sequoyah 1		81	7	71	1	425	74	4	3.08			3.351
Sequoyah 2		82	6	72	2		75	7	3.08			3.243
Zion 1	276	73	12	69	1	205	72	4	3.08	1.35	10.1%	1.541
Arkansas 2	640	80	3	73	4	273	76	12	3.00	2.34	32.8%	2.083
Brunswick 1	318	77	3	72	4	214	75	12	3.00	1.49	14.2%	1.417
Duane Arnold	280	75	2	70	4	148	73	12	3.00	1.89	23.7%	1.389
Hatch 1	390	75	12	70	2	184	73	6	3.00	2.12	28.5%	1.833
Indian Point 2		73	8	66	2		69	6	3.00			2.389
Peach Bottom 2	531	74	7	68	1	163	71	3	3.00	3.26	48.2%	2.111
Peach Bottom 3	223	74	12	70	1	221	73	3	3.00	1.01	0.3%	1.583
Salem 1		77	6	69	1	280	72	3	3.00			2.750
Sequoyah 2		82	6	72	4		75	12	3.00			3.167
Sequoyah 2		82	6	74	3		77	9	3.00			2.583
St. Lucie 1	486	76	6	71	2	203	74	6	3.00	2.40	33.8%	1.667
For 3<=t<4, N =	53	86		86		61	86		86	53	53	86
Average	484	77	4	70	2	239	73	11	3.39	2.29	25.9%	2.016
Arkansas 2	640	80	3	74	1	273	77	2	2.92	2.34	33.9%	2.057
Browns Ferry 2		75	3	67	1	235	70	2	2.92			2.743
Dresden 2		70	7	66	1		69	2	2.92			1.486
St. Lucie 1	486	76	6	72	2	269	75	5	2.92	1.81	22.5%	1.371
Zion 2	292	74	9	70	2	213	73	5	2.92	1.37	11.4%	1.457
Crystal River 3	419	77	3	69	2	148	72	4	2.83	2.83	44.4%	2.735
Farley 2	750	81	7	77	2	689	80	4	2.83	1.09	3.0%	1.441
Hatch 2	515	79	9	76	2	512	79	4	2.83	1.01	0.2%	1.147
McGuire 1	921	81	12	74	2	220	77	4	2.83	4.19	65.8%	2.647
North Anna 2	542	80	12	73	2	227	76	4	2.83	2.39	36.0%	2.647
North Anna 2	542	80	12	72	3	208	75	7	2.83	2.61	40.2%	2.912
Oconee 3	160	74	12	70	3	109	73	7	2.83	1.47	14.6%	1.500
Peach Bottom 3	223	74	12	70	4	221	73	10	2.83	1.01	0.4%	1.412
Sequoyah 2		82	6	74	2	312	77	4	2.83			2.824
Arkansas 2	640	80	3	74	3	318	77	6	2.75	2.01	29.0%	2.000
Beaver Valley 1	599	76	10	70	3	219	73	6	2.75	2.73	44.2%	2.212
Lasalle 1	1367	82	10	76	4	585	79	9	2.75	2.34	36.2%	2.121
North Anna 1	782	78	6	72	1	344	74	12	2.75	2.27	34.8%	2.273
North Anna 1	782	78	6	71	3	310	74	6	2.75	2.52	40.0%	2.455

Unit Name	...Actuals... Cost	COD		Estimat Year	Qr	Estimated Cost	COD		Years to COD	Cost Ratio	Myopia %	Duration Ratio
North Anna 1	782	78	6	71	2	308	74	3	2.75	2.54	40.3%	2.545
North Anna 2	542	80	12	74	4	264	77	9	2.75	2.05	29.9%	2.182
Salem 1		77	6	70	1	474	72	12	2.75			2.636
Salem 2		81	10	73	4		76	9	2.75			2.848
Three Mile I.	401	74	9	68	4	150	71	9	2.75	2.67	43.0%	2.091
Arkansas 2	640	80	3	74	2	318	77	2	2.67	2.01	30.0%	2.156
Fort Calhoun 1	176	73	9	68	3	92	71	5	2.67	1.91	27.5%	1.875
Lasalle 1	1367	82	10	76	3	585	79	5	2.67	2.34	37.5%	2.281
North Anna 2	542	80	12	74	1	240	76	11	2.67	2.26	35.7%	2.531
North Anna 2	542	80	12	73	3	227	76	5	2.67	2.39	38.6%	2.719
Sequoyah 2		82	6	75	3		78	5	2.67			2.531
Three Mile I.	401	74	9	69	3	162	72	5	2.67	2.47	40.5%	1.875
Beaver Valley 1	599	76	10	72	1	309	74	10	2.58	1.94	29.2%	1.774
Browns Ferry 2		75	3	68	1	373	70	10	2.58			2.710
Browns Ferry 3		77	3	68	1	373	70	10	2.58			3.484
Farley 2	750	81	7	76	3	499	79	4	2.58	1.50	17.1%	1.871
Farley 2	750	81	7	74	2	338	77	1	2.58	2.22	36.1%	2.742
Hatch 1	390	75	12	70	3	184	73	4	2.58	2.12	33.8%	2.032
Millstone 2	426	75	12	71	3	252	74	4	2.58	1.69	22.6%	1.645
North Anna 2	542	80	12	73	1	227	75	10	2.58	2.39	40.1%	3.000
North Anna 2	542	80	12	72	4	227	75	7	2.58	2.39	40.1%	3.097
Quad Cities 2		73	3	69	2		72	1	2.58			1.452
Salem 1		77	6	72	1	671	74	10	2.58			2.032
Sequoyah 1		81	7	71	4	425	74	7	2.58			3.710
Sequoyah 2		82	6	76	2		79	1	2.58			2.323
Trojan	452	75	12	72	4	284	75	7	2.58	1.59	19.7%	1.161
Beaver Valley 1	599	76	10	71	2	219	73	12	2.50	2.73	49.5%	2.133
Beaver Valley 1	599	76	10	71	4	286	74	6	2.50	2.09	34.4%	1.933
Cook 1	545	75	8	70	3	339	73	3	2.50	1.61	20.9%	1.967
Davis-Besse 1	672	77	11	72	2	304	74	12	2.50	2.21	37.4%	2.167
Farley 1	727	77	12	73	2	294	75	12	2.50	2.47	43.7%	1.800
Farley 2	750	81	7	74	4	363	77	6	2.50	2.07	33.7%	2.633
North Anna 1	782	78	6	71	4	344	74	6	2.50	2.27	38.9%	2.600
North Anna 2	542	80	12	75	1	301	77	9	2.50	1.80	26.5%	2.300
Peach Bottom 2	531	74	7	69	3	206	72	3	2.50	2.58	46.0%	1.933
Quad Cities 1		73	2	67	3		70	3	2.50			2.167
Salem 1		77	6	71	2	474	73	12	2.50			2.400
Salem 2		81	10	74	1	496	76	9	2.50			3.033
Sequoyah 1		81	7	73	2	449	75	12	2.50			3.233
Sequoyah 1		81	7	73	4	449	76	6	2.50			3.033
St. Lucie 1	486	76	6	71	4	218	74	6	2.50	2.23	37.8%	1.800
Trojan	452	75	12	72	1	233	74	9	2.50	1.94	30.3%	1.500
Browns Ferry 2		75	3	67	3	373	70	2	2.42			3.103
Davis-Besse 1	672	77	11	73	3	409	76	2	2.42	1.64	22.8%	1.724
Davis-Besse 1	672	77	11	72	4	349	75	5	2.42	1.93	31.2%	2.034
Millstone 1		71	3	67	1		69	8	2.42			1.655
Nine Mile Point 1		69	12	66	2		68	11	2.42			1.448
Sequoyah 1		81	7	72	2	425	74	11	2.42			3.759
St. Lucie 1	486	76	6	72	4	318	75	5	2.42	1.53	19.2%	1.448
Three Mile I.	401	74	9	69	4	180	72	5	2.42	2.23	39.3%	1.966
Arkansas 2	640	80	3	75	2	339	77	10	2.33	1.89	31.3%	2.036
Arkansas 2	640	80	3	75	3	369	78	1	2.33	1.73	26.6%	1.929
Beaver Valley 1	599	76	10	72	2	311	74	10	2.33	1.93	32.4%	1.857

Unit Name	...Actuals... Cost	COD	Estimat Year Qr	Estimated Cost	COD	Years to COD	Cost Ratio	Myopia %	Duration Ratio
Browns Ferry 2		75 3	70 3	447	73 1	2.33			1.929
Calvert Cliffs 1	431	75 5	70 3	170	73 1	2.33	2.53	48.9%	2.000
Calvert Cliffs 2	335	77 4	74 3	256	77 1	2.33	1.31	12.3%	1.107
Calvert Cliffs 2	335	77 4	72 3	204	75 1	2.33	1.64	23.7%	1.964
Cook 2	452	78 7	75 4	437	78 4	2.33	1.03	1.4%	1.107
Cooper	269	74 7	70 4	207	73 4	2.33	1.30	11.9%	1.536
Farley 2	750	81 7	77 4	662	80 4	2.33	1.13	5.5%	1.536
Farley 2	750	81 7	76 4	572	79 4	2.33	1.31	12.3%	1.964
Farley 2	750	81 7	74 3	363	77 1	2.33	2.07	36.5%	2.929
Quad Cities 2		73 3	68 4		71 4	2.33			1.821
Salem 1		77 6	70 4	474	73 4	2.33			2.786
Sequoyah 1		81 7	74 3	625	77 1	2.33			2.929
Sequoyah 1		81 7	72 4	449	75 4	2.33			3.679
Arkansas 2	640	80 3	75 1	339	77 6	2.25	1.89	32.6%	2.222
Arkansas 2	640	80 3	75 4	393	78 3	2.25	1.63	24.2%	1.889
Beaver Valley 1	599	76 10	71 3	286	73 12	2.25	2.09	38.9%	2.259
Brunswick 1	318	77 3	73 3	251	75 12	2.25	1.27	11.2%	1.556
Brunswick 2	389	75 11	71 4	210	74 3	2.25	1.85	31.5%	1.741
Calvert Cliffs 2	335	77 4	72 1	168	74 6	2.25	2.00	36.0%	2.259
Farley 2	750	81 7	75 2	365	77 9	2.25	2.05	37.7%	2.704
Fort Calhoun 1	176	73 9	70 1	125	72 6	2.25	1.41	16.4%	1.556
Kewaunee	203	74 6	70 1	121	72 6	2.25	1.68	26.0%	1.889
North Anna 1	782	78 6	72 3	360	74 12	2.25	2.17	41.1%	2.556
Peach Bottom 2	531	74 7	69 4	218	72 3	2.25	2.43	48.5%	2.037
Peach Bottom 3	223	74 12	72 2	316	74 9	2.25	0.71	-14.3%	1.111
Salem 1		77 6	72 4	850	75 3	2.25			2.000
Salem 1		77 6	74 3	1356	76 12	2.25			1.222
Sequoyah 1		81 7	74 1	625	76 6	2.25			3.259
St. Lucie 1	486	76 6	73 1	318	75 6	2.25	1.53	20.8%	1.444
St. Lucie 1	486	76 6	72 1	235	74 6	2.25	2.07	38.1%	1.889
Surry 1	247	72 12	68 4	165	71 3	2.25	1.50	19.6%	1.778
Surry 2	155	73 5	69 4	138	72 3	2.25	1.13	5.4%	1.519
Three Mile I.	401	74 9	69 2	162	71 9	2.25	2.47	49.6%	2.333
Beaver Valley 1	599	76 10	73 1	340	75 5	2.17	1.76	29.8%	1.654
McGuire 1	921	81 12	76 4	384	79 2	2.17	2.40	49.8%	2.308
North Anna 1	782	78 6	74 1	446	76 5	2.17	1.75	29.6%	1.962
North Anna 1	782	78 6	73 3	407	75 11	2.17	1.92	35.2%	2.192
Oconee 3	160	74 12	71 3	137	73 11	2.17	1.17	7.6%	1.500
Oyster Creek 1		69 12	65 3		67 11	2.17			1.962
Palisades	147	71 12	68 1	89	70 5	2.17	1.65	25.9%	1.731
Peach Bottom 2	531	74 7	70 1	230	72 5	2.17	2.31	47.1%	2.000
Quad Cities 2		73 3	70 1		72 5	2.17			1.385
Sequoyah 1		81 7	74 2	625	76 8	2.17			3.269
Sequoyah 2		82 6	77 1		79 5	2.17			2.423
Three Mile I.	401	74 9	71 3	296	73 11	2.17	1.35	15.0%	1.385
Three Mile I.	401	74 9	70 1	184	72 5	2.17	2.18	43.3%	2.077
Beaver Valley 1	599	76 10	72 3	342	74 10	2.08	1.75	30.8%	1.960
Browns Ferry 1		74 8	69 3	447	71 10	2.08			2.360
Browns Ferry 2		75 3	69 3	447	71 10	2.08			2.640
Browns Ferry 3		77 3	69 3	447	71 10	2.08			3.600
Calvert Cliffs 2	335	77 4	71 4	168	74 1	2.08	2.00	39.3%	2.560
Cook 1	545	75 8	71 3	356	73 10	2.08	1.53	22.6%	1.880
Farley 1	727	77 12	73 1	294	75 4	2.08	2.47	54.5%	2.280

Unit Name	...Actuals... Cost	COD		Estimat Year	Qr	Estimated Cost	COD		Years to COD	Cost Ratio	Myopia %	Duration Ratio
Farley 2	750	81	7	77	1	689	79	4	2.08	1.09	4.2%	2.080
Farley 2	750	81	7	78	1	635	80	4	2.08	1.18	8.3%	1.600
North Anna 1	782	78	6	73	1	407	75	4	2.08	1.92	36.8%	2.520
North Anna 1	782	78	6	74	4	504	77	1	2.08	1.55	23.5%	1.680
Sequoyah 1		81	7	74	4	648	77	1	2.08			3.160
Surry 2	155	73	5	70	1	138	72	4	2.08	1.13	5.9%	1.520
Three Mile I.	401	74	9	70	3	197	72	10	2.08	2.04	40.6%	1.920
Three Mile I.	401	74	9	70	2	184	72	7	2.08	2.18	45.3%	2.040
Brunswick 1	318	77	3	73	4	269	75	12	2.00	1.18	8.8%	1.625
Brunswick 2	389	75	11	72	4	256	74	12	2.00	1.52	23.3%	1.458
Calvert Cliffs 2	335	77	4	72	2	204	74	6	2.00	1.64	28.2%	2.417
Crystal River 3	419	77	3	71	3	190	73	9	2.00	2.21	48.5%	2.750
Farley 1	727	77	12	73	4	395	75	12	2.00	1.84	35.7%	2.000
Fort Calhoun 1	176	73	9	69	3	92	71	9	2.00	1.91	38.2%	2.000
Kewaunee	203	74	6	70	3	123	72	9	2.00	1.65	28.6%	1.875
Kewaunee	203	74	6	70	2	123	72	6	2.00	1.65	28.6%	2.000
Lasalle 1	1367	82	10	77	3	675	79	9	2.00	2.03	42.3%	2.542
North Anna 1	782	78	6	72	4	407	74	12	2.00	1.92	38.6%	2.750
Peach Bottom 2	531	74	7	70	4	230	72	12	2.00	2.31	51.9%	1.792
Peach Bottom 2	531	74	7	71	1	277	73	3	2.00	1.92	38.4%	1.667
Point Beach 2		72	10	69	4		71	12	2.00			1.417
Sequoyah 1		81	7	75	3	648	77	9	2.00			2.917
Sequoyah 2		82	6	78	1		80	3	2.00			2.125
St. Lucie 1	486	76	6	73	4	318	75	12	2.00	1.53	23.7%	1.250
Trojan	452	75	12	72	3	243	74	9	2.00	1.86	36.4%	1.625
For 2<=t<3, N =	110	150		150		136	150		150	110	110	150
Average	542	77	8	72	2	337	74	11	2.38	1.91	30.0%	2.138
Calvert Cliffs 2	335	77	4	73	1	204	75	2	1.92	1.64	29.6%	2.130
Crystal River 3	419	77	3	72	4	283	74	11	1.92	1.48	22.7%	2.217
Fort Calhoun 1	176	73	9	70	4	125	72	11	1.92	1.41	19.5%	1.435
Fort Calhoun 1	176	73	9	69	2	92	71	5	1.92	1.91	40.2%	2.217
McGuire 1	921	81	12	76	2	384	78	5	1.92	2.40	57.9%	2.870
Millstone 1		71	3	67	3		69	8	1.92			1.826
North Anna 1	782	78	6	73	4	431	75	11	1.92	1.81	36.4%	2.348
North Anna 2	542	80	12	75	4	301	77	11	1.92	1.80	35.9%	2.609
Point Beach 2		72	10	69	3		71	8	1.92			1.609
Rancho Seco	344	75	4	71	2	215	73	5	1.92	1.60	27.7%	2.000
Sequoyah 1		81	7	76	2	727	78	5	1.92			2.652
Beaver Valley 1	599	76	10	72	4	340	74	10	1.83	1.76	36.2%	2.091
Browns Ferry 1		74	8	70	2	447	72	4	1.83			2.273
Browns Ferry 2		75	3	70	2	447	72	4	1.83			2.591
Browns Ferry 3		77	3	70	2	447	72	4	1.83			3.682
Calvert Cliffs 2	335	77	4	75	1	253	77	1	1.83	1.33	16.6%	1.136
McGuire 1	921	81	12	77	1	466	79	1	1.83	1.98	45.0%	2.591
McGuire 1	921	81	12	77	3	466	79	7	1.83	1.98	45.0%	2.318
North Anna 1	782	78	6	75	1	536	77	1	1.83	1.46	22.9%	1.773
Oconee 2	160	74	9	70	3	109	72	7	1.83	1.47	23.5%	2.182
Quad Cities 1		73	2	68	4		70	10	1.83			2.273
San Onofre 2	2502	83	8	79	4	1740	81	10	1.83	1.44	21.9%	2.000
Surry 1	247	72	12	69	2	165	71	4	1.83	1.50	24.5%	1.909
Three Mile I.	401	74	9	70	4	262	72	10	1.83	1.53	26.1%	2.045
Trojan	452	75	12	73	3	334	75	7	1.83	1.35	17.9%	1.227

Unit Name	...Actuals... Cost	COD		Estimat Year	Qr	Estimated Cost	COD		Years to COD	Cost Ratio	Myopia %	Duration Ratio
Zion 1	276	73	12	70	2	232	72	4	1.83	1.19	9.9%	1.909
Brunswick 1	318	77	3	75	2	328	77	3	1.75	0.97	-1.7%	1.000
Calvert Cliffs 2	335	77	4	73	3	243	75	6	1.75	1.38	20.2%	2.048
Cook 1	545	75	8	71	2	356	73	3	1.75	1.53	27.5%	2.381
Crystal River 3	419	77	3	74	4	375	76	9	1.75	1.12	6.6%	1.286
Davis-Besse 1	672	77	11	74	3	434	76	6	1.75	1.55	28.4%	1.810
Duane Arnold	280	75	2	72	1	177	73	12	1.75	1.58	29.9%	1.667
Millstone 2	426	75	12	73	1	341	74	12	1.75	1.25	13.6%	1.571
Oconee 2	160	74	9	71	1	109	72	12	1.75	1.47	24.7%	2.000
Oyster Creek 1		69	12	66	1		67	12	1.75			2.143
Peach Bottom 2	531	74	7	71	2	288	73	3	1.75	1.84	41.8%	1.762
Salem 1		77	6	73	4	993	75	9	1.75			2.000
San Onofre 2	2502	83	8	80	1	1824	81	12	1.75	1.37	19.8%	1.952
Sequoyah 1		81	7	75	4	727	77	9	1.75			3.190
Sequoyah 2		82	6	78	3		80	6	1.75			2.143
Sequoyah 2		82	6	79	3		81	6	1.75			1.571
Surry 1	247	72	12	69	3	165	71	6	1.75	1.50	25.8%	1.857
Beaver Valley 1	599	76	10	73	3	409	75	5	1.67	1.46	25.7%	1.850
Calvert Cliffs 2	335	77	4	73	4	243	75	8	1.67	1.38	21.3%	2.000
Dresden 3		71	11	68	4		70	8	1.67			1.750
Farley 1	727	77	12	74	2	415	76	2	1.67	1.75	40.0%	2.100
Fort Calhoun 1	176	73	9	71	3	125	73	5	1.67	1.41	22.7%	1.200
North Anna 2	542	80	12	76	3	363	78	5	1.67	1.49	27.2%	2.550
North Anna 2	542	80	12	76	1	311	77	11	1.67	1.74	39.6%	2.850
North Anna 2	542	80	12	76	4	381	78	8	1.67	1.42	23.6%	2.400
Salem 2		81	10	77	3	1356	79	5	1.67			2.450
Sequoyah 1		81	7	76	3	949	78	5	1.67			2.900
Surry 2	155	73	5	70	3	138	72	5	1.67	1.13	7.4%	1.600
Three Mile I.	401	74	9	72	1	206	73	11	1.67	1.95	49.1%	1.500
Three Mile I.	401	74	9	71	1	261	72	11	1.67	1.54	29.4%	2.100
Three Mile I.	401	74	9	72	3	363	74	5	1.67	1.10	6.1%	1.200
Calvert Cliffs 1	431	75	5	72	1	210	73	10	1.58	2.05	57.4%	2.000
Dresden 2		70	7	67	3		69	4	1.58			1.789
Farley 1	727	77	12	74	4	456	76	7	1.58	1.60	34.3%	1.895
Farley 2	750	81	7	78	3	652	80	4	1.58	1.15	9.2%	1.789
Indian Point 2		73	8	68	3		70	4	1.58			3.105
Millstone 2	426	75	12	72	3	282	74	4	1.58	1.51	29.8%	2.053
Quad Cities 1		73	2	69	2		71	1	1.58			2.316
Rancho Seco	344	75	4	72	1	215	73	10	1.58	1.60	34.5%	1.947
Sequoyah 2		82	6	80	4		82	7	1.58			0.947
Surry 2	155	73	5	71	1	138	72	10	1.58	1.13	7.8%	1.368
Arkansas 1	239	74	12	72	1	175	73	9	1.50	1.36	23.0%	1.833
Calvert Cliffs 1	431	75	5	71	4	210	73	6	1.50	2.05	61.4%	2.278
Calvert Cliffs 2	335	77	4	74	1	273	75	9	1.50	1.23	14.7%	2.056
Calvert Cliffs 2	335	77	4	74	2	273	75	12	1.50	1.23	14.7%	1.889
Cook 1	545	75	8	72	4	427	74	6	1.50	1.28	17.6%	1.778
Cook 2	452	78	7	76	4	437	78	6	1.50	1.03	2.2%	1.056
Crystal River 3	419	77	3	73	2	283	74	12	1.50	1.48	29.9%	2.500
Davis-Besse 1	672	77	11	75	1	434	76	9	1.50	1.55	33.9%	1.778
Dresden 3		71	11	69	2		70	12	1.50			1.611
Farley 1	727	77	12	75	4	589	77	6	1.50	1.24	15.1%	1.333
Hatch 1	390	75	12	72	3	184	74	3	1.50	2.12	65.1%	2.167
Lasalle 1	1367	82	10	79	2	918	80	12	1.50	1.49	30.4%	2.222

Unit Name	...Actuals... Cost	COD		Estimat Year	Qr	Estimated Cost	COD		Years to COD	Cost Ratio	Myopia %	Duration Ratio
North Anna 2	542	80	12	77	3	426	79	3	1.50	1.27	17.4%	2.167
Oyster Creek 1		69	12	66	2		67	12	1.50			2.333
Pilgrim 1	239	72	12	70	2		71	12	1.50			1.667
Salem 1		77	6	75	1	1356	76	9	1.50			1.500
Sequoyah 1		81	7	77	1	949	78	9	1.50			2.889
Sequoyah 2		82	6	79	1		80	9	1.50			2.167
St. Lucie 1	486	76	6	74	2	366	75	12	1.50	1.33	20.8%	1.333
Surry 1	247	72	12	69	4	189	71	6	1.50	1.31	19.4%	2.000
Calvert Cliffs 1	431	75	5	72	3	250	74	2	1.42	1.72	46.8%	1.882
Dresden 3		71	11	69	1		70	8	1.42			1.882
Farley 1	727	77	12	74	3	456	76	2	1.42	1.60	39.0%	2.294
Fort Calhoun 1	176	73	9	71	4	159	73	5	1.42	1.11	7.3%	1.235
Indian Point 2		73	8	69	4		71	5	1.42			2.588
Millstone 2	426	75	12	73	4	380	75	5	1.42	1.12	8.4%	1.412
North Anna 2	542	80	12	77	1	426	78	8	1.42	1.27	18.5%	2.647
Oconee 2	160	74	9	71	3	137	73	2	1.42	1.17	11.8%	2.118
Palisades	147	71	12	69	1	110	70	8	1.42	1.33	22.5%	1.941
Point Beach 1		70	12	69	1		70	8	1.42			1.235
Point Beach 2		72	10	70	1		71	8	1.42			1.824
Rancho Seco	344	75	4	72	3	300	74	2	1.42	1.15	10.1%	1.824
Three Mile I.	401	74	9	72	2	328	73	11	1.42	1.22	15.2%	1.588
Zion 1	276	73	12	70	4	232	72	5	1.42	1.19	13.0%	2.118
Browns Ferry 3		77	3	69	2	447	70	10	1.33			5.813
Calvert Cliffs 1	431	75	5	72	2	250	73	10	1.33	1.72	50.4%	2.188
Cook 1	545	75	8	72	2	416	73	10	1.33	1.31	22.4%	2.375
Cook 1	545	75	8	73	2	427	74	10	1.33	1.28	20.0%	1.625
Cook 1	545	75	8	73	4	427	75	4	1.33	1.28	20.0%	1.250
Duane Arnold	280	75	2	72	3	192	74	1	1.33	1.46	32.7%	1.813
Farley 1	727	77	12	75	2	487	76	10	1.33	1.49	35.1%	1.875
Fitzpatrick	419	75	7	72	2		73	10	1.33			2.313
Hatch 1	390	75	12	72	4	282	74	4	1.33	1.38	27.6%	2.250
Indian Point 2		73	8	69	2		70	10	1.33			3.125
Lasalle 1	1367	82	10	80	4	1184	82	4	1.33	1.15	11.4%	1.375
McGuire 1	921	81	12	78	1	549	79	7	1.33	1.68	47.4%	2.813
North Anna 1	782	78	6	75	4	536	77	4	1.33	1.46	32.7%	1.875
Oyster Creek 1		69	12	66	3		68	1	1.33			2.438
Quad Cities 1		73	2	70	1		71	7	1.33			2.188
Rancho Seco	344	75	4	72	2	264	73	10	1.33	1.30	21.9%	2.125
Sequoyah 1		81	7	78	1	1069	79	7	1.33			2.500
Surry 1	247	72	12	70	2	189	71	10	1.33	1.31	22.1%	1.875
Surry 2	155	73	5	71	2	139	72	10	1.33	1.12	8.7%	1.438
Three Mile I.	401	74	9	73	1	373	74	7	1.33	1.07	5.6%	1.125
Brunswick 1	318	77	3	75	4	329	77	3	1.25	0.97	-2.6%	1.000
Brunswick 1	318	77	3	75	1	281	76	6	1.25	1.13	10.5%	1.600
Brunswick 1	318	77	3	74	4	281	76	3	1.25	1.13	10.5%	1.800
Brunswick 2	389	75	11	73	3	309	74	12	1.25	1.26	20.3%	1.733
Crystal River 3	419	77	3	75	2	420	76	9	1.25	1.00	-0.2%	1.400
Davis-Besse 1	672	77	11	75	4	533	77	3	1.25	1.26	20.4%	1.533
Davis-Besse 1	672	77	11	75	2	461	76	9	1.25	1.46	35.3%	1.933
Dresden 3		71	11	70	1		71	6	1.25			1.333
Farley 2	750	81	7	79	2	687	80	9	1.25	1.09	7.3%	1.667
Kewaunee	203	74	6	71	3	134	72	12	1.25	1.52	39.6%	2.200
Oconee 3	160	74	12	73	1	137	74	6	1.25	1.17	13.5%	1.400

Unit Name	...Actuals... Cost	COD	Estimat Year	Qr	Estimated Cost	COD	Years to COD	Cost Ratio	Myopia %	Duration Ratio
Peach Bottom 2	531	74 7	72	2	352	73 9	1.25	1.51	38.9%	1.667
Peach Bottom 3	223	74 12	73	3	316	74 12	1.25	0.71	-24.2%	1.000
Rancho Seco	344	75 4	73	1	327	74 6	1.25	1.05	4.0%	1.667
San Onofre 2	2502	83 8	81	1	2010	82 6	1.25	1.24	19.1%	1.933
Surry 2	155	73 5	71	4	145	73 3	1.25	1.07	5.7%	1.133
Surry 2	155	73 5	71	3	141	72 12	1.25	1.10	8.1%	1.333
Beaver Valley 1	599	76 10	74	1	419	75 5	1.17	1.43	35.8%	2.214
Browns Ferry 1		74 8	71	1	555	72 5	1.17			2.929
Indian Point 2		73 8	69	1		70 5	1.17			3.786
McGuire 1	921	81 12	78	4	549	80 2	1.17	1.68	55.8%	2.571
Monticello		71 6	69	1		70 5	1.17			1.929
Quad Cities 2		73 3	71	1		72 5	1.17			1.714
Salem 2		81 10	78	1	1469	79 5	1.17			3.071
Surry 1	247	72 12	70	4	189	72 2	1.17	1.31	25.7%	1.714
Three Mile I.	401	74 9	73	2	393	74 8	1.17	1.02	1.7%	1.071
Zion 1	276	73 12	71	2	232	72 8	1.17	1.19	16.0%	2.143
Zion 2	292	74 9	72	1	235	73 5	1.17	1.24	20.5%	2.143
Arkansas 1	239	74 12	72	3	185	73 10	1.08	1.29	26.5%	2.077
Beaver Valley 1	599	76 10	74	3	451	75 10	1.08	1.33	29.9%	1.923
Browns Ferry 1		74 8	71	3	555	72 10	1.08			2.692
Brunswick 2	389	75 11	73	4	339	75 1	1.08	1.15	13.6%	1.769
Calvert Cliffs 2	335	77 4	75	4	251	77 1	1.08	1.34	30.7%	1.231
Cooper	269	74 7	72	2	207	73 7	1.08	1.30	27.5%	1.923
Dresden 2		70 7	68	4		70 1	1.08			1.462
Ginna		70 7	68	3		69 10	1.08			1.692
Millstone 1		71 3	68	4		70 1	1.08			2.077
Millstone 1		71 3	69	3		70 10	1.08			1.385
Nine Mile Point 1		69 12	67	4		69 1	1.08			1.846
North Anna 1	782	78 6	76	1	567	77 4	1.08	1.38	34.5%	2.077
Oyster Creek 1		69 12	67	1		68 4	1.08			2.538
Pilgrim 1	239	72 12	71	1		72 4	1.08			1.615
Quad Cities 1		73 2	70	2		71 7	1.08			2.462
Rancho Seco	344	75 4	73	3	328	74 10	1.08	1.05	4.4%	1.462
Sequoyah 1		81 7	78	3	1264	79 10	1.08			2.615
Trojan	452	75 12	74	3	366	75 10	1.08	1.23	21.5%	1.154
Arkansas 1	239	74 12	73	1	200	74 3	1.00	1.19	19.4%	1.750
Beaver Valley 1	599	76 10	74	4	451	75 12	1.00	1.33	32.8%	1.833
Beaver Valley 1	599	76 10	74	2	419	75 6	1.00	1.43	42.9%	2.333
Crystal River 3	419	77 3	74	1	283	75 3	1.00	1.48	48.1%	3.000
Farley 1	727	77 12	76	2	614	77 6	1.00	1.18	18.5%	1.500
Farley 2	750	81 7	79	3	684	80 9	1.00	1.10	9.6%	1.833
Fitzpatrick	419	75 7	73	2		74 6	1.00			2.083
Indian Point 2		73 8	70	4		71 12	1.00			2.667
Kewaunee	203	74 6	72	2	158	73 6	1.00	1.29	28.7%	2.000
Kewaunee	203	74 6	72	1	134	73 3	1.00	1.52	51.8%	2.250
Kewaunee	203	74 6	72	3	163	73 9	1.00	1.25	24.8%	1.750
Lasalle 1	1367	82 10	79	1	808	80 3	1.00	1.69	69.2%	3.583
Lasalle 1	1367	82 10	79	4	1003	80 12	1.00	1.36	36.3%	2.833
Lasalle 1	1367	82 10	80	2	1107	81 6	1.00	1.23	23.5%	2.333
Millstone 1		71 3	69	1		70 3	1.00			2.000
Nine Mile Point 1		69 12	68	2		69 6	1.00			1.500
Nine Mile Point 1		69 12	68	4		69 12	1.00			1.000
North Anna 2	542	80 12	78	1	467	79 3	1.00	1.16	16.1%	2.750

Unit Name	...Actuals... Cost	COD		Estimat Year	Qr	Estimated Cost	COD		Years to COD	Cost Ratio	Myopia %	Duration Ratio
Peach Bottom 3	223	74	12	73	4	284	74	12	1.00	0.79	-21.4%	1.000
Point Beach 1		70	12	69	4		70	12	1.00			1.000
Point Beach 2		72	10	70	3		71	9	1.00			2.083
Sequoyah 1		81	7	79	2	1264	80	6	1.00			2.083
St. Lucie 1	486	76	6	74	4	401	75	12	1.00	1.21	21.3%	1.500
Surry 2	155	73	5	72	1	147	73	3	1.00	1.06	5.7%	1.167
Turkey Point 4	127	73	9	71	4	126	72	12	1.00	1.01	0.6%	1.750
For 1<=t<2, N =	136	191		191		149	191		191	132	132	191
Average	508	76	2	73	1	433	74	9	1.42	1.38	23.9%	1.983

Appendix C:

Capital Additions Data

Plant	Yr	Rating	Total Cost	Cost Increase	1983 $	/MW-yr
Arkansas	74	902	233027			
Arkansas	75	902	238751	5724	10407	11.54
Arkansas	76	902	242204	3453	5962	6.61
Arkansas	77	902	247069	4865	7997	8.87
Arkansas	78	902	253994	6925	10259	11.37
Arkansas	79	902	268130	14136	18641	20.67
Arkansas	80	NA	NA			
Arkansas	81	1845	916567			
Beaver Valley	76	923	284856			
Beaver Valley	77	923	598716	313860	487988	528.70
Beaver Valley	78	923	582408	-16308	-23883	-25.88
Beaver Valley	79	923	576367	-6041	-8067	-8.74
Beaver Valley	80	923	647575	71208	87849	95.18
Beaver Valley	81	924	671283	23708	26909	29.12
Big Rock Point	63	54	14412			
Big Rock Point	64	54	14349	-63	-221	-4.10
Big Rock Point	65	75	13750	-599	-2106	-28.07
Big Rock Point	66	75	13793	43	149	1.99
Big Rock Point	67	75	13837	44	146	1.94
Big Rock Point	68	75	13926	89	287	3.82
Big Rock Point	69	75	13958	32	96	1.29
Big Rock Point	70	75	14324	366	1023	13.64
Big Rock Point	71	75	14554	230	593	7.91
Big Rock Point	72	75	14731	177	432	5.76
Big Rock Point	73	75	14815	84	195	2.60
Big Rock Point	74	75	16012	1197	2415	32.20
Big Rock Point	75	75	16587	575	1034	13.79
Big Rock Point	76	75	22907	6320	10702	142.70
Big Rock Point	77	75	23971	1064	1668	22.24
Big Rock Point	78	75	24409	438	639	8.52
Big Rock Point	79	75	27014	2605	3473	46.31
Big Rock Point	80	75	27262	248	304	4.06
Big Rock Point	81	75	33356	6094	6863	91.51
Browns Ferry 1&2	75	2304	512653			
Browns Ferry 1&2	76	2304	552357	39704	66749	28.97
Browns Ferry 1,2,3	77	3456	853325			
Browns Ferry 1,2,3	78	3456	885991	32666	47072	13.62
Browns Ferry 1,2,3	79	3456	888350	2359	3092	0.89
Browns Ferry 1,2,3	80	3456	890428	2078	2485	0.72
Browns Ferry 1,2,3	81	3456	892715	2287	2503	0.72
Brunswick 1&2	77	1733	707560			
Brunswick 1&2	78	1733	714928	7368	10617	6.13
Brunswick 1&2	79	1733	750828	35900	47055	27.15
Brunswick 1&2	80	1733	776989	26161	31285	18.05
Brunswick 1&2	81	1733	803535	26546	29050	16.76
Brunswick 2	75	866	382246			
Brunswick 2	76	866	389118	6872	11553	13.34
Calvert Cliffs 1	75	918	428747			
Calvert Cliffs 1	76	918	430674	1927	3216	3.50
Calvert Cliffs 1&2	77	1828	765995			
Calvert Cliffs 1&2	78	1828	777711	11716	17158	9.39
Calvert Cliffs 1&2	79	1828	780095	2384	3183	1.74
Calvert Cliffs 1&2	80	1828	790988	10893	13439	7.35

Calvert Cliffs 1&2	81	1828	820215	29227	33173	18.15
Connecticut Yankee	68	600	91801			
Connecticut Yankee	69	600	91841	40	121	0.20
Connecticut Yankee	70	600	93516	1675	4694	7.82
Connecticut Yankee	71	600	93669	153	395	0.66
Connecticut Yankee	72	600	93814	145	346	0.58
Connecticut Yankee	73	600	94016	202	459	0.76
Connecticut Yankee	74	600	106212	12196	24285	40.48
Connecticut Yankee	75	600	108921	2709	4842	8.07
Connecticut Yankee	76	600	114503	5582	9317	15.53
Connecticut Yankee	77	600	117238	2735	4252	7.09
Connecticut Yankee	78	600	121288	4050	5931	9.89
Connecticut Yankee	79	600	123037	1749	2335	3.89
Connecticut Yankee	80	600	137644	14607	18021	30.03
Connecticut Yankee	81	600	152552	14908	16921	28.20
Connecticut Yankee	82	600				
Cook 1	75	1089	538611			
Cook 1	76	1089	544650	6039	10227	9.39
Cook 1	77	1089	552238	7588	11895	10.92
Cook 1&2	78	2200	996177			
Cook 1&2	79	2285	1025829	29652	39536	17.30
Cook 1&2	80	2250	1074584	48755	59847	26.60
Cook 1&2	81	2285	1096310	21726	24468	10.71
Cooper	74	835	246268			
Cooper	75	835	269287	23019	41399	49.58
Cooper	76	835	269287	0	0	0.00
Cooper	77	835	302382	33095	51879	62.13
Cooper	78	836	384630	82248	120010	143.55
Cooper	79	836	384570	-60	-80	-0.10
Cooper	80	836	384569	-1	-1	.00
Cooper	81	778	383748			
Crystal River	77	801	365535			
Crystal River	78	890	415173	49638	71528	80.37
Crystal River	79	890	419131	3958	5188	5.83
Crystal River	80	890	421055	1924	2301	2.59
Crystal River	81	801	384011	-37044	-40539	-50.61
Davis-Besse	77	960	271283			
Davis-Besse	78	906	635147	363864	530921	586.01
Davis-Besse	79	906	326174	-308973	-411964	-454.71
Davis-Besse	80	962	738544	412370	506190	526.18
Davis-Besse	81	962	786437	47893	53938	56.07
Dresden 1	62	208	34180			
Dresden 1	63	208	34442	262	921	4.43
Dresden 1	64	208	34468	26	91	0.44
Dresden 1	65	208	34451	-17	-60	-0.29
Dresden 1	66	208	34352	-99	-343	-1.65
Dresden 1	67	208	34366	14	46	0.22
Dresden 1	68	208	33467	-899	-2897	-13.93
Dresden 1	69	208	33968	501	1510	7.26
Dresden 1&2	70	1018	116609			
Dresden 1,2,3	71	1828	220380			
Dresden 1,2,3	72	1865	241479	21099	51526	27.63
Dresden 1,2,3	73	1865	235397	-6082	-14110	-7.57
Dresden 1,2,3	74	1865	237303	1906	3845	2.06
Dresden 1,2,3	75	1865	249177	11874	21355	11.45
Dresden 1,2,3	76	1865	256493	7316	12389	6.64

Dresden 1,2,3	77	1865	258522	2029	3181	1.71
Dresden 1,2,3	78	1865	276887	18365	26797	14.37
Dresden 1,2,3	79	1865	290785	13898	18531	9.94
Dresden 1,2,3	80	1865	303201	12416	15241	8.17
Dresden 1,2,3	81	1865	307054	3853	4339	2.33
Duane Arnold	74	565	288821			
Duane Arnold	75	565	279730	-9091.42	-16350	-28.94
Duane Arnold	76	565	279928	198	335	0.59
Duane Arnold	77	565	287561	7633.428	11966	21.18
Duane Arnold	78	597	282345	-5216.42	-7611	-12.75
Duane Arnold	79	597	306768	24423	32564	54.55
Duane Arnold	80	597	324186	17418	21381	35.81
Duane Arnold	81	597	339460	15274	17202	28.81
Farley	77	888	727426			
Farley	78	888	734519	7093	10221	11.51
Farley	79	888	751634	17115	22433	25.26
Farley	80	888	761329	9695	11594	13.06
Farley	81	1776	1541981			
Fitzpatrick	75	849	NA			
Fitzpatrick	76	849	NA			
Fitzpatrick	77	849	NA			
Fitzpatrick	78	883	NA			
Fitzpatrick	79	883	NA			
Fitzpatrick	80	883	NA			
Fitzpatrick	81	883	367141			
Fort Calhoun	73	481	173870			
Fort Calhoun	74	481	175800	1930	3894	8.09
Fort Calhoun	75	481	178572	2772	4985	10.36
Fort Calhoun	76	481	178896	324	549	1.14
Fort Calhoun	77	481	179994	1098	1721	3.58
Fort Calhoun	78	481	180328	334	487	1.01
Fort Calhoun	79	481	180830	502	669	1.39
Fort Calhoun	80	481	192700	11870	14571	30.29
Fort Calhoun	81	481	198544	5844	6582	13.68
Fort St. Vrain	79	343	105610			
Fort St. Vrain	80	342	101459			
Fort St. Vrain	81	342	120884			
Ginna	70	517	83175			
Ginna	71	517	83075	-100	-258	-0.50
Ginna	72	517	83982	907	2167	4.19
Ginna	73	517	85004	1022	2320	4.49
Ginna	74	517	87668	2664	5305	10.26
Ginna	75	517	89750	2082	3721	7.20
Ginna	76	517	93308	3558	5939	11.49
Ginna	77	517	114141	20833	32391	62.65
Ginna	78	517	121860	7719	11305	21.87
Ginna	79	517	129112	7252	9684	18.73
Ginna	80	517	136138	7026	8668	16.77
Ginna	81	517	159487	23349	26501	51.26
Hatch	76	850	390393			
Hatch	77	850	396799	6406	9842	11.58
Hatch	78	850	4466			
Hatch	79	851	657326			
Hatch	80	1700	947147			
Hatch	81	852	693789			
Humboldt	63	60	24471			

Humboldt	64	60	23786	-685	-2566	-42.77
Humboldt	65	60	24176	390	1461	24.35
Humboldt	66	60	22224	-1952	-7101	-118.35
Humboldt	67	60	22480	256	892	14.87
Humboldt	68	60	22619	139	465	7.75
Humboldt	69	60	22688	69	222	3.70
Humboldt	70	60	22764	76	230	3.83
Humboldt	71	60	22850	86	243	4.04
Humboldt	72	60	22947	97	256	4.27
Humboldt	73	65	22998	51	128	1.97
Humboldt	74	65	23171	173	381	5.86
Humboldt	75	65	24031	860	1648	25.35
Humboldt	76	65	24543	512	905	13.92
Humboldt	77	65	26726	2183	3535	54.39
Humboldt	78	65	28506	1780	2675	41.16
Humboldt	79	65	28567	61	83	1.27
Humboldt	80	65	NA			
Humboldt	81	65	NA			
Indian Point 1	63	275	126218			
Indian Point 1	64	275	126255	37	131	0.48
Indian Point 1	65	275	126330	75	266	0.97
Indian Point 1	66	275	128891	2561	8808	32.03
Indian Point 1	67	275	128821	-70	-230	-0.84
Indian Point 1	68	275	128818	-3	-10	-0.03
Indian Point 1	69	275	127914	-904	-2736	-9.95
Indian Point 1	70	275	128083	169	474	1.72
Indian Point 1	71	275	128175	92	237	0.86
Indian Point 1	72	275	128938	763	1823	6.63
Indian Point 1&2	73	1288	334963			
Indian Point 1&2	74	1288	340188	5225	10404	8.08
Indian Point 1&2	75	1288	348218	8030	14353	11.14
Indian Point 1&2	76	1288	359410	11192	18681	14.50
Indian Point 1&2	77	1288	370637	11227	17456	13.55
Indian Point 2	78	1288	377573	6936	10158	7.89
Indian Point 2	79	1288	379966	2393	3195	2.48
Indian Point 2	80	1013	329445			
Indian Point 2	81	1013	398037	68592	77852	76.85
Indian Point 3	76	1125	NA			
Indian Point 3	77	1125	NA			
Indian Point 3	78	1068	NA			
Indian Point 3	79	1068	NA			
Indian Point 3	80	1013	NA			
Indian Point 3	81	1013	493018			
Kewaunee	74	535	202193			
Kewaunee	75	535	203389	1196	2151	4.02
Kewaunee	76	535	205351	1962	3323	6.21
Kewaunee	77	535	205892	541	848	1.59
Kewaunee	78	535	209748	3856	5626	10.52
Kewaunee	79	535	213289	3541	4721	8.82
Kewaunee	80	535	214696	1407	1727	3.23
Kewaunee	81	535	227413	12717	14322	26.77
Lacrosse	78	60	22991			
Lacrosse	79	50	23132	141	188	3.76
Lacrosse	80	50	25987	2855	3505	70.09
Lacrosse	81	50	26237	250	282	5.63
Maine Yankee	73	830	219225			

Maine Yankee	74	830	221074	1849	3682	4.44
Maine Yankee	75	830	233710	12636	22586	27.21
Maine Yankee	76	830	235069	1359	2268	2.73
Maine Yankee	77	830	236454	1385	2153	2.59
Maine Yankee	78	864	237810	1356	1986	2.30
Maine Yankee	79	864	239987	2177	2907	3.36
Maine Yankee	80	864	246847	6860	8463	9.80
Maine Yankee	81	864	262240	15393	17471	20.22
Maine Yankee	82	864				
McGuire	81	1220	905601			
Millstone 1	71	661	96819			
Millstone 1	72	661	97343	524	1252	1.89
Millstone 1	73	661	98837	1494	3391	5.13
Millstone 1	74	661	98745	-92	-183	-0.28
Millstone 1	75	661	99244	499	892	1.35
Millstone 1	76	661	125141	25897	43225	65.39
Millstone 1	77	661	127476	2335	3630	5.49
Millstone 1	78	661	139783	12307	18024	27.27
Millstone 1	79	661	153135	13352	17829	26.97
Millstone 1	80	661	167438	14303	17646	26.70
Millstone 1	81	661	247250	79812	90587	137.04
Millstone 1	82	661				
Millstone 2	75	909	418372			
Millstone 2	76	909	426271	7899	13184	14.50
Millstone 2	77	909	448751	22480	34952	38.45
Millstone 2	78	909	463638	14887	21802	23.98
Millstone 2	79	909	464674	1036	1383	1.52
Millstone 2	80	909	477586	12912	15929	17.52
Millstone 2	81	909	495610	18024	20457	22.51
Millstone 2	82	909				
Monticello	71	568	105011			
Monticello	72	568	104937	-74	-181	-0.32
Monticello	73	568	106869	1932	4482	7.89
Monticello	74	568	117996	11127	22448	39.52
Monticello	75	568	122106	4110	7392	13.01
Monticello	76	568	123362	1256	2127	3.74
Monticello	77	568	124390	1028	1611	2.84
Monticello	78	568	126488	2098	3061	5.39
Monticello	79	568	134937	8449	11265	19.83
Monticello	80	568	139725	4788	5877	10.35
Monticello	81	568	150407	10682	12030	21.18
Nine Mile Point	70	620	162235			
Nine Mile Point	71	641	164492	2257	5822	9.08
Nine Mile Point	72	641	162416	-2076	-4961	-7.74
Nine Mile Point	73	641	163212	796	1807	2.82
Nine Mile Point	74	641	163389	177	352	0.55
Nine Mile Point	75	641	164189	800	1430	2.23
Nine Mile Point	76	641	181200	17011	28393	44.30
Nine Mile Point	77	641	188087	6887	10708	16.70
Nine Mile Point	78	641	187086	-1001	-1466	-2.29
Nine Mile Point	79	641	204080	16994	22692	35.40
Nine Mile Point	80	641	217371	13291	16397	25.58
Nine Mile Point	81	642	265015	47644	54076	84.23
North Anna	78	979	781739			
North Anna	79	979	783864	2125	2785	2.85
North Anna	80	1959	1315869	0	0	0.00

North Anna	81	1959	1368195	52326	57262	29.23
Oconee 1	73	886	155612			
Oconee 1,2,3	74	2660	476443			
Oconee 1,2,3	75	2660	476691	248	446	0.17
Oconee 1,2,3	76	2660	478793	2102	3534	1.33
Oconee 1,2,3	77	2660	490724	11931	18331	6.89
Oconee 1,2,3	78	2661	492689	1965	2832	1.06
Oconee 1,2,3	79	2661	498935	6246	8187	3.08
Oconee 1,2,3	80	2661	509438	10503	12560	4.72
Oconee 1,2,3	81	2666	520036	10598	11598	4.35
Oyster Creek	70	550	89883			
Oyster Creek	71	550	92121	2238	5773	10.50
Oyster Creek	72	550	92637	516	1233	2.24
Oyster Creek	73	550	92766	129	293	0.53
Oyster Creek	74	550	92198	-568	-1131	-2.06
Oyster Creek	75	550	97151	4953	8853	16.10
Oyster Creek	76	550	108545	11394	19018	34.58
Oyster Creek	77	550	112583	4038	6278	11.42
Oyster Creek	78	550	150459	37876	55470	100.85
Oyster Creek	79	550	161745	11286	15070	27.40
Oyster Creek	80	550	200255	38510	47510	86.38
Oyster Creek	81	550	222963	22708	25774	46.86
Palisades	72	811	146687			
Palisades	73	811	160284	13597	31545	38.90
Palisades	74	811	180063	19779	39902	49.20
Palisades	75	811	182297	2234	4018	4.95
Palisades	76	811	185272	2975	5038	6.21
Palisades	77	811	182068	-3204	-5022	-6.19
Palisades	78	811	199643	17575	25644	31.62
Palisades	79	811	194651	-4992	-6656	-8.21
Palisades	80	811	211505	16854	20689	25.51
Palisades	81	811	255491	43986	49538	61.08
Pathfinder	67	75	24932			
Peach Bottom 1	67	46	10692			
Peach Bottom 1	68	46	10624			
Peach Bottom 1	69	46	10658			
Peach Bottom 1	70	46	10719			
Peach Bottom 1	71	46	10890			
Peach Bottom 1	72	46	10821			
Peach Bottom 1	73	46	11369			
Peach Bottom 1	74	46	10485			
Peach Bottom 2,3	74	2304	742158			
Peach Bottom 2,3	75	2304	753981	11823	21132	9.17
Peach Bottom 2,3	76	2304	761722	7741	12921	5.61
Peach Bottom 2,3	77	2304	794094	32372	50332	21.85
Peach Bottom 2,3	78	2304	807496	13402	19627	8.52
Peach Bottom 2,3	79	2304	813792	6296	8407	3.65
Peach Bottom 2,3	80	2304	836708	22916	28271	12.27
Peach Bottom 2,3	81	2304	902169	65461	74298	32.25
Pilgrim	72	655	321540			
Pilgrim	73	655	239329			
Pilgrim	74	655	235982	-3347	-6665	-10.18
Pilgrim	75	655	236464	482	862	1.32
Pilgrim	76	655	241440	4976	8306	12.68
Pilgrim	77	655	257579	16139	25093	38.31
Pilgrim	78	687	261758	4179	6120	8.91

Pilgrim	79	687	270428	8670	11577	16.85
Pilgrim	80	687	337986	67558	83346	121.32
Pilgrim	81	687	358680	20694	23488	34.19
Pilgrim	82	687	430711	72031	75350	109.68
Point Beach 1	71	523	73959			
Point Beach 1&2	72	1047	145348			
Point Beach 1&2	73	1047	161632	16284	37779	36.08
Point Beach 1&2	74	1047	161436	-196	-395	-0.38
Point Beach 1&2	75	1047	164224	2788	5014	4.79
Point Beach 1&2	76	1047	167125	2901	4913	4.69
Point Beach 1&2	77	1047	196801	29676	46519	44.43
Point Beach 1&2	78	1047	171189	-25612	-37371	-35.69
Point Beach 1&2	79	1047	170668	-521	-695	-0.66
Point Beach 1&2	80	1047	172472	1804	2214	2.12
Point Beach 1&2	81	1047	188495	16023	18045	17.24
Prairie Isl.	73	593	233234			
Prairie Isl.	74	1186	405374			
Prairie Isl.	75	1186	410207	4833	8692	7.33
Prairie Isl.	76	1186	413087	2880	4877	4.11
Prairie Isl.	77	1186	423966	10879	17054	14.38
Prairie Isl.	78	1186	425182	1216	1774	1.50
Prairie Isl.	79	1186	433659	8477	11303	9.53
Prairie Isl.	80	1186	444766	11107	13634	11.50
Prairie Isl.	81	1186	457082	12316	13870	11.70
Quad Cities 1&2	72	1656	200149			
Quad Cities 1&2	73	1656	211539	11390	26425	15.96
Quad Cities 1&2	74	1656	223882	12343	24901	15.04
Quad Cities 1&2	75	1656	237227	13345	24000	14.49
Quad Cities 1&2	76	1656	241480	4253	7202	4.35
Quad Cities 1&2	77	1656	247194	5714	8957	5.41
Quad Cities 1&2	78	1656	252951	5757	8400	5.07
Quad Cities 1&2	79	1656	263741	10790.33	14387	8.69
Quad Cities 1&2	80	1656	273075	9333.666	11457	6.92
Quad Cities 1&2	81	1656	278524	5449	6137	3.71
Rancho Seco	75	928	343620			
Rancho Seco	76	928	343438	-182	-322	-0.35
Rancho Seco	77	928	336050	-7388	-11964	-12.89
Rancho Seco	78	928	338792	2742	4121	4.44
Rancho Seco	79	928	339538	746	1012	1.09
Rancho Seco	80	928	353574	14036	17441	18.79
Rancho Seco	81	928	365651	12077	13716	14.78
Robinson	71	768	77753			
Robinson	72	768	81999	4246	10369	13.50
Robinson	73	768	82113	114	264	0.34
Robinson	74	768	83272	1159	2359	3.07
Robinson	75	768	84982	1710	3075	4.00
Robinson	76	768	85234	252	424	0.55
Robinson	77	768	89540	4306	6616	8.61
Robinson	78	768	93410	3870	5577	7.26
Robinson	79	768	101253	7843	10280	13.39
Robinson	80	768	110025	8772	10490	13.66
Robinson	81	769	113858	3833	4195	5.45
Salem	77	1170	850318			
Salem	78	1170	850983	665	974	0.83
Salem	79	1169	898641	47658	63637	54.42
Salem	80	1170	938748	40107.47	49480	42.29

Salem	81	2343	1758749			
San Onofre	68	450	80855			
San Onofre	69	450	84439	3584	11533	25.63
San Onofre	70	450	84714	275	832	1.85
San Onofre	71	450	85369	655	1847	4.10
San Onofre	72	450	85547	178	470	1.05
San Onofre	73	450	85821	274	688	1.53
San Onofre	74	450	86244	423	931	2.07
San Onofre	75	450	86438	194	372	0.83
San Onofre	76	450	95496	9058	16011	35.58
San Onofre	77	450	162475	66979	108463	241.03
San Onofre	78	450	181601	19126	28746	63.88
San Onofre	79	450	192599	10998	14922	33.16
San Onofre	80	450	211109	18510	23000	51.11
San Onofre	81	450	251119	40010	45441	100.98
Sequoyah	81	1220	983542			
Shippingport	80	100	32125			
Shippingport	81	100	32123			
St. Lucie	76	850	470223			
St. Lucie	77	850	486230	16007	24594	28.93
St. Lucie	78	850	495038	8808	12692	14.93
St. Lucie	79	850	499602	4564	5982	7.04
St. Lucie	80	850	505287	5685	6799	8.00
St. Lucie	81	850	513640	8353	9141	10.75
Surry	72	847	246707			
Surry	73	1695	396860			
Surry	74	1695	402096	5236	10656	6.29
Surry	75	1695	406409	4313	7757	4.58
Surry	76	1695	408516	2107	3542	2.09
Surry	77	1695	412236	3720	5715	3.37
Surry	78	1695	419952	7716	11119	6.56
Surry	79	1695	409703	-10249	-13434	-7.93
Surry	80	1695	556083	146380	175052	103.28
Surry	81	1695	750969	194886	213271	125.82
Three Mile Isl. 1	74	871	398337			
Three Mile Isl. 1	75	871	400928	2591	4631	5.32
Three Mile Isl. 1	76	871	399425	-1503	-2509	-2.88
Three Mile Isl. 1	77	871	398895	-530	-824	-0.95
Three Mile Isl. 1	78	871	361902	-36993	-54177	-62.20
Three Mile Isl. 1	79	871	407936	46034	61469	70.57
Three Mile Isl. 1	80	NA	NA			
Three Mile Isl. 1	81	435	220798			
Three Mile Isl. 2	78	961	715466			
Three Mile Isl. 2	79	961	719294	3828	5112	5.32
Three Mile Isl. 2	80	NA	NA			
Three Mile Isl. 2	81	480	358321			
Trojan	76	1216	451978			
Trojan	77	1216	460666	8688	14069	11.57
Trojan	78	1216	466419	5753	8647	7.11
Trojan	79	1216	486705	20286	27523	22.63
Trojan	80	1216	503279	16574	20594	16.94
Trojan	81	1216	548765	45486	51661	42.48
Turkey Point 3	72	760	108709			
Turkey Point 3&4	73	1519	231239			
Turkey Point 3&4	74	1519	235496	4257	8663	5.70
Turkey Point 3&4	75	1519	244256	8760	15754	10.37

Turkey Point 3&4	76	1519	255705	11449	19248	12.67
Turkey Point 3&4	77	1519	267648	11943	18350	12.08
Turkey Point 3&4	78	1519	273441	5793	8348	5.50
Turkey Point 3&4	79	1519	284431	10990	14405	9.48
Turkey Point 3&4	80	1519	293654	9223	11030	7.26
Turkey Point 3&4	81	1519	305503	11849	12967	8.54
Vermont Yankee	72	514	172042			
Vermont Yankee	73	563	184481	12439	28237	50.15
Vermont Yankee	74	563	185158	677	1348	2.39
Vermont Yankee	75	563	185739	581	1038	1.84
Vermont Yankee	76	563	193886	8147	13598	24.15
Vermont Yankee	77	563	196331	2445	3801	6.75
Vermont Yankee	78	563	198837	2506	3670	6.52
Vermont Yankee	79	563	200835	1998	2668	4.74
Vermont Yankee	80	563	217575	16740	20652	36.68
Vermont Yankee	81	563	226115	8540	9693	17.22
Vermont Yankee	82	563				
Yankee-Rowe	62	152	38162			
Yankee-Rowe	63	185	38398	236	837	4.52
Yankee-Rowe	64	185	38622	224	795	4.29
Yankee-Rowe	65	185	38766	144	511	2.76
Yankee-Rowe	66	185	39390	624	2146	11.60
Yankee-Rowe	67	185	39560	170	559	3.02
Yankee-Rowe	68	185	39572	12	38	0.21
Yankee-Rowe	69	185	39623	51	154	0.83
Yankee-Rowe	70	185	39636	13	36	0.20
Yankee-Rowe	71	185	40271	635	1638	8.85
Yankee-Rowe	72	185	41500	1229	2937	15.87
Yankee-Rowe	73	185	42507	1007	2286	12.36
Yankee-Rowe	74	185	44473	1966	3915	21.16
Yankee-Rowe	75	185	46101	1628	2910	15.73
Yankee-Rowe	76	185	46566	465	776	4.20
Yankee-Rowe	77	185	48332	1766	2746	14.84
Yankee-Rowe	78	185	48912	580	849	4.59
Yankee-Rowe	79	185	52192	3280	4380	23.67
Yankee-Rowe	80	135	55285	3093	3816	20.63
Yankee-Rowe	81	185	1768			
Yankee-Rowe	82	185				
Zion 1	73	1098	275989			
Zion 1&2	74	2196	565619			
Zion 1&2	75	2196	567987	2168	3899	1.78
Zion 1&2	76	2196	571762	3775	6393	2.91
Zion 1&2	77	2196	577903	6141	9626	4.38
Zion 1&2	78	2196	586396	8493	12392	5.64
Zion 1&2	79	2196	594941	8545	11393	5.19
Zion 1&2	80	2196	625788	30847	37865	17.24
Zion 1&2	81	2196	639723	13935	15694	7.15
				averages	15542.72	$18.48
					378	378
				ave MW	841.0	