#31. Mass DPU 84-25

COMMONWEALTH OF MASSACHUSETTS
BEFORE THE DEPARTMENT OF PUBLIC UTILITIES

WESTERN MASSACHUSETTS ELECTRIC COMPANY	DPU 84-25

TESTIMONY OF PAUL CHERNICK ON BEHALF OF THE ATTORNEY GENERAL

April 6, 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, and predicted that growth rates would be lower than the utilities expected. Many of my criticisms have been incorporated in subsequent forecasts, and load growth has almost universally been lower than the utility forecast.

For example, in my testimony in MEFSC 78-17, filed September 29, 1978, I described a large number of errors in NU's 1978 forecast, most of which would exaggerate growth rates. The 1978 forecast projected a peak of 4670 MW in 1982 and 5342 MW in 1988. Since the 1982 peak was actually 3988 MW (only about 1% greater than the 1978 peak), and since NU's current forecast predicts 4424 MW in 1988, reality has confirmed my criticisms and NU has implicitly accepted them.

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

My projections of nuclear power costs have been more recent, and have yet to be fully confirmed. However, as time goes by, utility projections have tended to confirm my analyses. For example, in the Pilgrim 2 construction permit proceeding (NRC 50-471), Boston Edison was projecting a cost of $1.895 billion. With techniques similar to those used in this testimony, I projected a cost between $3.40 and $4.93 billion in my testimony of June, 1979. Boston Edison's final cost estimate (issued when Pilgrim 2 was canceled in September 1981) stood at $4.0 billion.

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, while PSNH's consultants released an estimate of $10.1 billion. 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

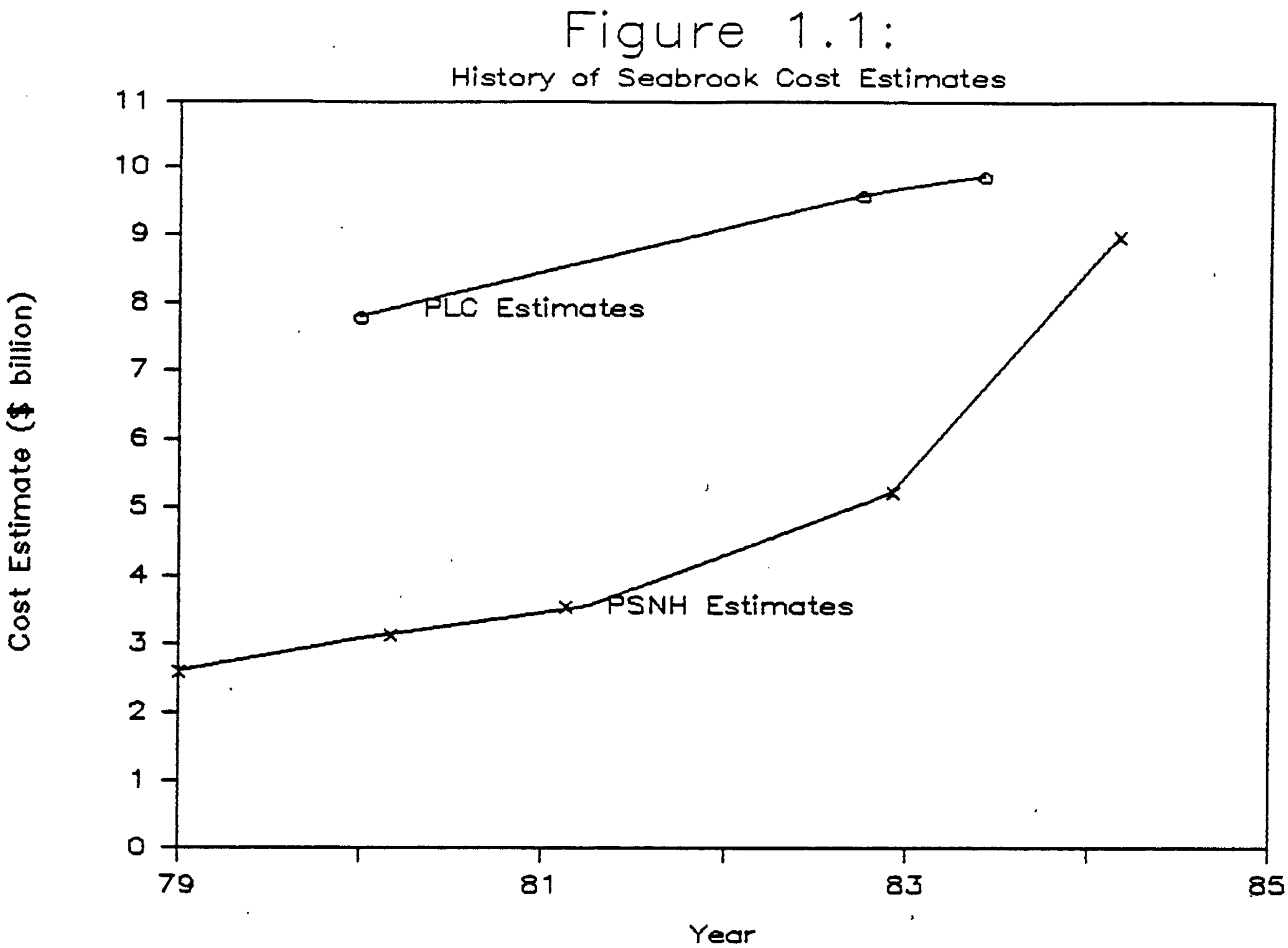
Figure 1.1:
History of Seabrook Cost Estimates
PLC Estimates
PSNH Estimates
Cost Estimate ($ billion)
0
1
2
3
4
5
6
7
8
9
10
11
79
81
83
85
Year

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

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 NU has made some concessions to experience, its estimates for Millstone 3 costs continue to be optimistic, and hence it is still quite easy to improve on them.

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

A. Yes. I authored Report 77-1 for the Technology and Policy Program of the Massachusetts Institute of Technology, Optimal

Pricing for Peak Loads and Joint Production: Theory and Applications to Diverse Conditions. I also authored a paper with Michael B. Meyer "An Improved Methodology for Making Capacity/Energy Allocation for Generation and Transmission Plant", which won an Institute Award from the Institute for Public Utilities. My paper "Revenue Stability Target Ratemaking" was published in Public Utilities Fortnightly. These publications are listed in my resume.

Q: What is the subject of your testimony?

A: I have been asked to review the propriety of placing a portion of CWIP related to Millstone 3 in ratebase, or of otherwise reflecting the cost of that unit in current rates. I have specifically been asked to review the likely benefits of the unit to WMECo ratepayers, when and if it does enter service, and to suggest an appropriate ratemaking approach in light of those benefits.

Q: How is your testimony structured?

A: The next two sections discuss the two possible justifications for completing Millstone 3: the reliability benefits and the reductions in fuel costs. The second section will discuss the magnitude and timing of the reliability benefits of Millstone 3, which may also be thought of as the "need for power" or the requirement that adequate capacity be available to meet peak loads with an adequate reserve margin. In the third section, I will then consider the unit's cost-effectiveness for oil back-out, in the near term and over the course of its useful life. The fourth portion of this testimony will provide the derivation of my estimates of Millstone 3's likely construction cost, operating costs and capacity factor, which are required to assess its effect on fuel costs.[1] Finally, I will make recommendations regarding the disposition of WMECo's CWIP proposal, and regarding rules the DPU might apply in making rates when the unit finally enters service.

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1. The results of Section 4 are summarized at the beginning and end of the section. The costs derived in Section 4 are all in constant, levelized 1984 dollars, and are therefore comparable to current costs and rates.

2 - THE RELIABILITY BENEFITS OF MILLSTONE 3

Q: What are the reliability benefits of Millstone 3?

A: If Millstone 3 enters service, it will to some extent increase the reliability of the New England generation system. This reliability is expected to be more than adequate for many years to come, although there is certainly _some_ benefit from increased reliability in the interim. Once New England reserve margins shrink to the merely adequate range, the presence of Millstone 3 on the system would allow the deferral of other measures to increase reliability, such as construction of new capacity, purchase of power from outside the region, or continued maintenance of existing capacity.

Within the NEPOOL system, each individual utility has a responsibility to maintain a share of the generating capacity required by the pool. While the NEPOOL agreement does not reflect well the relative reliability value of various kinds of capacity, which varies with the size, maintenance requirements, and forced outage rates of the unit, each member utility is in roughly the same position as the pool as a whole. Most participants in Millstone 3 will not need its capacity to meet their capability responsibilities very soon, but it will eventually allow them to defer new investments, or delay expenses, or accelerate the retirement of other units.

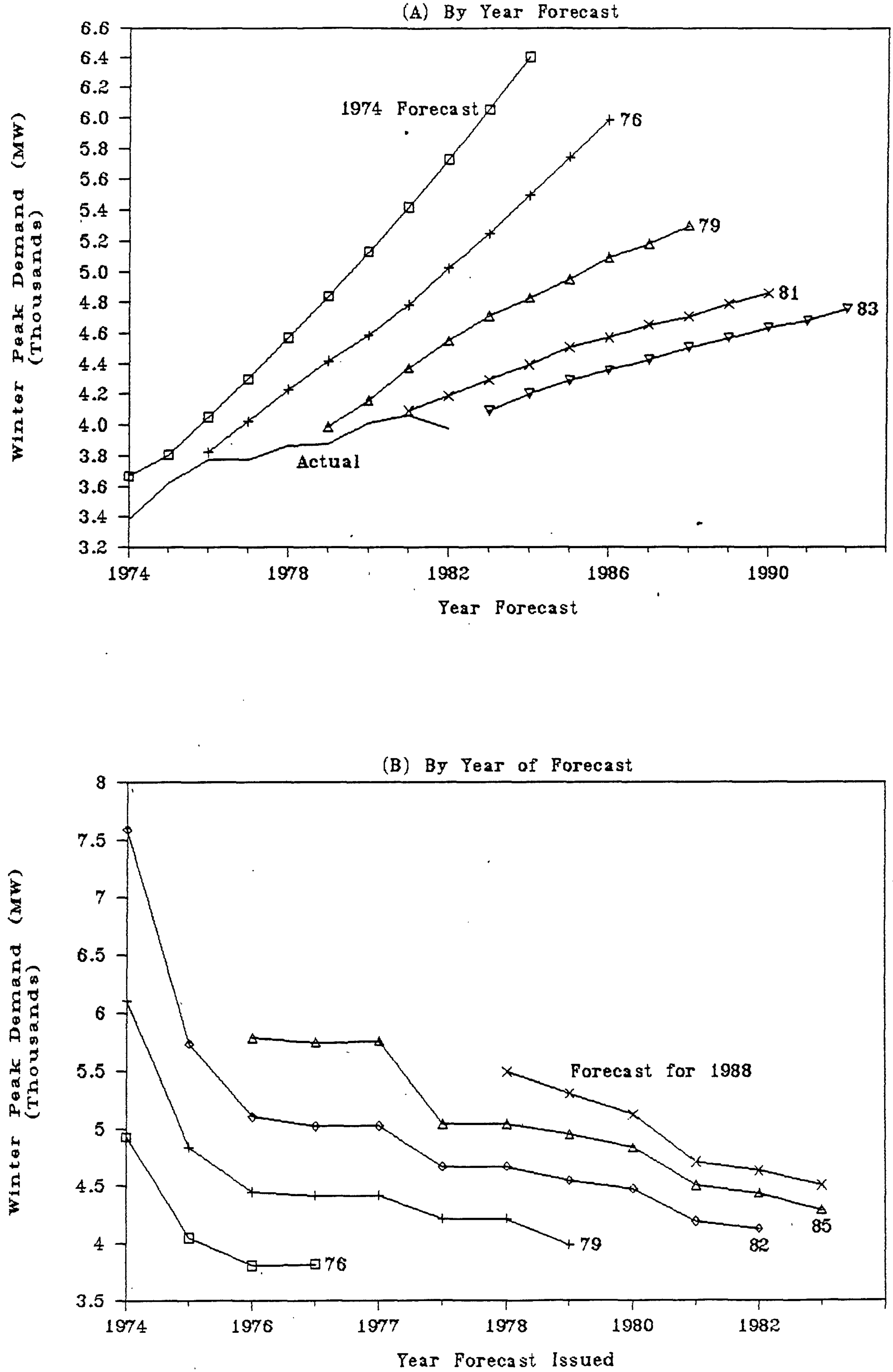
Q: When would Millstone 3 have a reliability benefit to WMECo, under the terms of the NEPOOL agreement?

A: WMECo projects that this point will occur in 1992, when its demand forecast exceeds its projection of available capacity without Millstone 3. This projection may reasonably be viewed with some skepticism, due to three considerable uncertainties: the validity of the WMECo forecast, the level of NEPOOL-required reserves in the 1990's, and the economic justification for the retirement of West Springfield and NU's gas turbines.

Q: Have NU's forecasts been reliable over the last decade?

A: Figure 2.1 displays representative NU peak demand forecasts from 1976 (already two years past the oil embargo) to 1983, and the actual peak loads in each of those years. While NU was the first New England utility to attempt to incorporate sophisticated, causal methodologies in its load forecasting, and while NU was one of the first New England utilities to recognize that load growth was not likely to return to pre-embargo rates, it has had to adjust its load forecast downward in each of the last ten years. This record hardly

Figure 2.1: NU Forecast History



- 13 -

justifies confidence in NU's current projections.

Q: Are there any particular reasons for believing that NU's current forecast will prove to be overstated?

A: Yes. The cost of Millstone 3 itself, if passed along to customers in anything like the traditional manner, will depress sales and reduce the need for the plant. This is true whether or not the unit eventually proves to be less expensive than the oil it is backing out. If it turns out that Millstone 3 is economical, the cost of the remaining oil which NU burns will be even higher than the staggering cost of Millstone 3; further depressing demand.[2]

Q: Have NU's forecasts for WMECo loads been any better than its forecast for its total system loads?

A: No. In 1976, NU projected that WMECo loads would reach 901 MW by 1982. Actual 1982 WMECo peak load was 663 MW, slightly lower than the 677 MW peak in 1976. Figure 2.2 displays the evolution of WMECo's load forecast and actual loads since 1976.

Q: Why is the NEPOOL required reserve margin for the 1990's uncertain?

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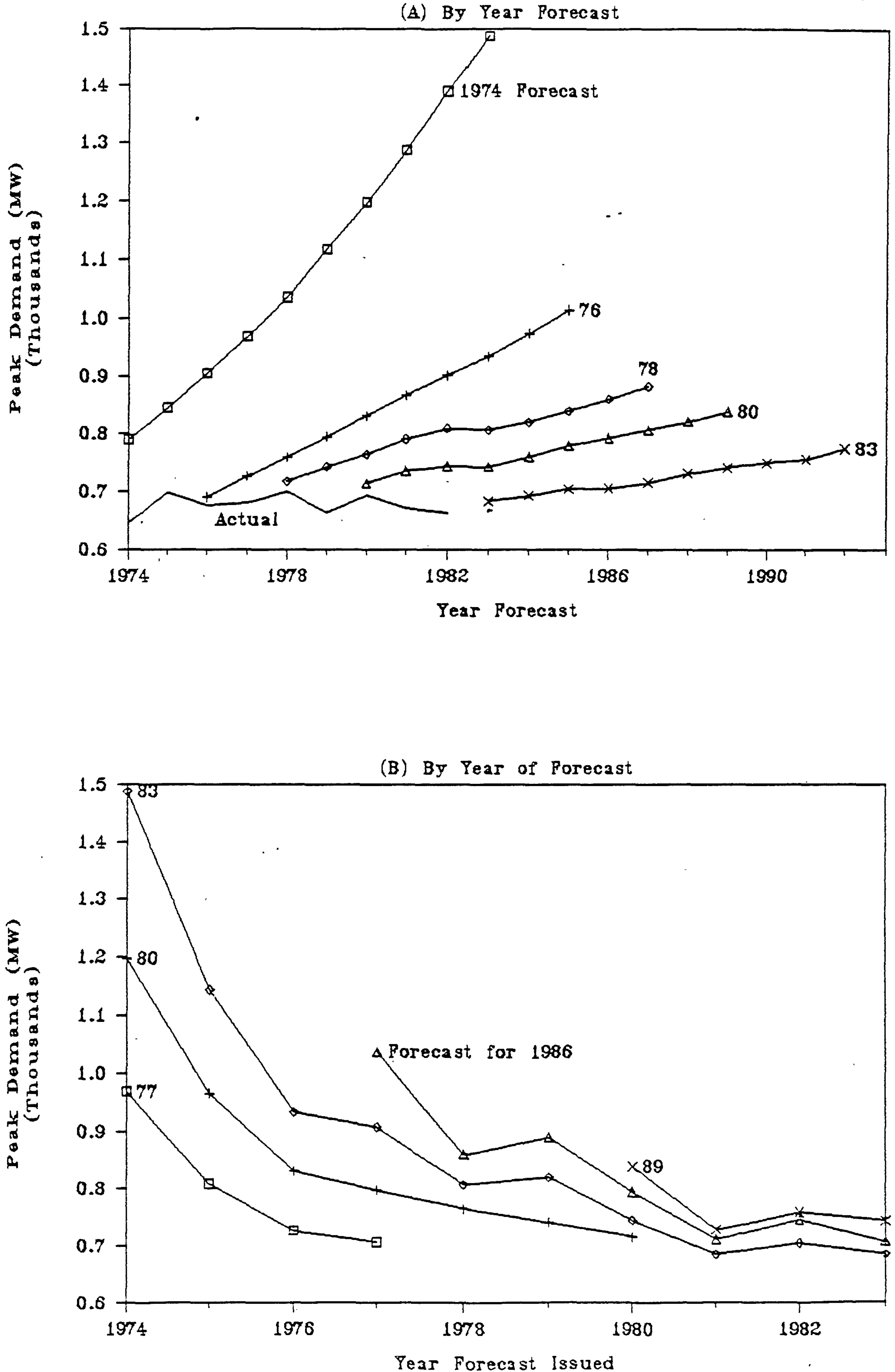
2. For corresponding reasons, NU's failure to include new alternative energy sources in suspect.

Figure 2.2: WMECO Forecast History



A: In 1976, NEPOOL established reserve margins to be used through Power Year 1984/85.[3] The reserve margins were apparently extended in 1982, through Power Year 1988/89.[4] No reserve margin has ever been set past that date, probably in part because reserves are so large that reliability is not a pressing concern for many years to come. The 1976 margins also recognized that the required reserve margin will vary with the number of new nuclear units added in the region: the subsequent cancelation of most of the units contemplated in 1976 would tend to reduce the required reserves.

Q: What is the critical factor in determining when WMECo requires additional capacity by the NEPOOL method?

A: To a large extent, WMECo will need new capacity only when it retires West Springfield. Figure 2.3 shows WMECo's demand and capability responsibility[5] under NU's current forecast, and WMECo's capacity resources without Millstone 3, and for three retirement schedules:

1. retirement of all units on NU's current schedule,

2. extension of West Springfield's life, possibly burning

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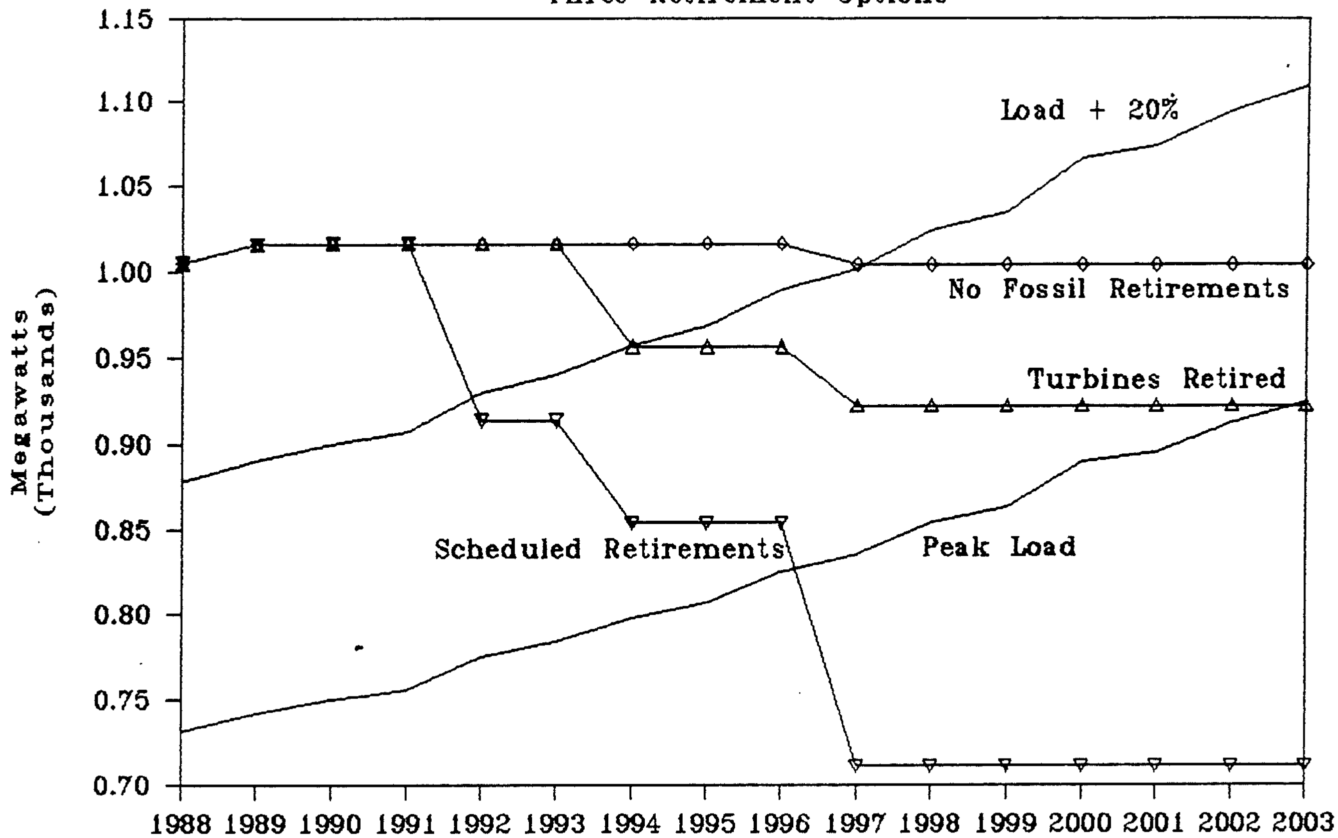
3. See NEPOOL Executive Committee minutes, 6/24/76 and 8/12/77.

4. See NEPLAN (1983).

5. This analysis assumes a 20% reserve requirement, and no capacity transfers within NU.

Figure 2.3: WMECO Load & Capacity

Three Retirement Options



coal, and

3. continued operation of all fossil units.[6]

As can be seen in Figure 2.3, NU's plan requires new capacity in 1992. Keeping West Springfield in service defers the need for additional capacity until 1994, the scheduled retirement date of WMECo's gas turbines at Doreen, Silver Lake, and Woodland Road. If the turbines are not retired, no capacity deficiency occurs until 1998. None of these projections includes any new capacity from cogeneration, trash burning, small power production (whether owned by NU or by others), Hydro Quebec, or any other source.

Q: Does there appear to be any particular need to retire West Springfield and the gas turbines on NU's schedule?

A: Not really. The justification which NU provides for retiring gas turbine capacity (see Q-AG-EJF-25) solely discusses the need for this capacity for voltage support; no economic analysis of the retirement decision is offered. Similarly, the retirement schedule for West Springfield is based on depreciation accruals, rather than on the need for the units or the economics of continuing to operate them. NU did not provide even a single economic study on the choice of converting, retiring, or simply extending the life of West

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6. Yankee Rowe is retired in 1997 is each case.

Springfield. NU's position with regard to West Springfield, as Millstone 3 encounters increased resistance, is somewhat reminiscent of Boston Edison's decision to retire Edgar station[7] to create the perception that Pilgrim 2 was needed.

Q: If and when Millstone 3 is needed, what is it worth to WMECo for reliability purposes?

A: At a first approximation, the NEPOOL capability measurement rules insure that a megawatt of any plant is equally valuable to a participant.[8] The minimum fixed cost of enhanced reliability is probably the cost of combustion turbine capacity. The recently retired Silver Lake turbines only cost about $30/kw-year (see NU Schedule C-3.9); excluding non-avoidable costs (i.e., depreciation, return, and income taxes) the price of keeping these units on line was more like $14/kw-year. NU estimates that the aggregate cost of its combustion turbines is $19.85/kw-year, and NU is retiring most of this capacity in the 1980's and 1990's, apparently without even considering whether the small costs of keeping it available are justified. It is hard to believe that NU (or any other New England utility) has actually used its

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7. Edgar was a fairly efficient station, and perhaps the most coal-convertible plant on BECo's system.

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

turbines enough in the last decade to contribute substantially to wearing them out. As long as the marginal source of capacity in New England consists of existing gas turbines, capacity can hardly cost more than $20/kw-year, and probably much less.

If it does become necessary to supply new capacity, NU estimates that combustion turbines would cost $820/kw in 1995; deflating this estimate to 1984 at 0.5% more than NU's projection of GNP inflation[9] yields a 1984 estimate of $424/kw, which is a good bit higher than BECo's estimate of about $320/kw.[10] Even the $424/kw value is likely to be only about 10% of the cost of Millstone 3, with much lower O&M, capital additions, insurance, and retirement costs.

Substantial additions of combustion turbine capacity would result in higher fuel costs, so for some purposes it may be more appropriate to use the cost of refurbishing existing fossil units. NU estimates this cost as about $500/kw in 1983 dollars (Q-AG-EJF-25). It is not clear whether this estimate includes such additional benefits as improved heat

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9. This approximates the relationship between the GNP deflator and the Handy-Whitman gas turbine index in the 1970-81 period.

10. See Exhibit BE-202, Schedule 1, page 1, DPU 1720.

rates, reduced labor requirements due to greater plant automation, and coal conversion; if so, the costs directly related to capacity maintenance may be somewhat lower.

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

A: The value of Millstone 3 (or any other large nuclear unit) to NEPOOL is considerably less than its value, under NEPOOL capability responsibility formulas, to the individual NEPOOL members which own that plant. Nuclear plants contribute relatively little to reliability for two reasons. First, due to their large maintenance requirements and high forced outage rates, nuclear units are often not available when needed. Second, due to the large size of new nuclear units, sufficient reserves must be provided to back up the simultaneous loss of a thousand megawatts or more. As a result, even with the same forced outage rates, large plants require more reserve capacity than small plants. NEPOOL's own analyses, such as the previously cited Executive Committee minutes, indicate that nuclear capacity requires a reserve of approximately 50%. This is demonstrated in Tables 2.1 and 2.2. Thus, Millstone 3 is worth about 50% of the

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11. Firm capacity can be approximated by pumped hdro, which NU estimates will cost $1930/kw in 1995. NEPOOL projects costs of $370/kw in 1980$, or something over $1000/kw in 1995. The present values of 50% of these costs would fall in the range of $130 to $258/kw in 1985$, or about $16 to $31 million for WMECo's share of Millstone 3.

	Number of New Nuclear Units					
Year	0	1	2	3	4	5
81/82	21880	22445				
82/83	23127	23526	23924	24323		
83/84		24626	25047	25468	25889	
84/85			26035	26480	26925	27370

Table 2.1: Objective Capability (MW) with New Nuclear Units

Source: 8/12/76 NEPOOL Executive Committee Minutes.

Year	Increase In Reserve Per Nuclear Unit (MW)	Nuclear Reduction In Other Capacity Req. (MW)	Firm Load Carried (MW)	Ratio of Firm Load to Nuclear Capacity
	[1]	[2]	[3]	[4]
81/82	565	585	504.3	0.44
82/83	398.7	751.3	647.7	0.56
83/84	421	729	628.4	0.55
84/85	445	705	607.8	0.53
Average				0.52

Table 2.2: Derivation of Nuclear Firm Load Carrying Capacity

Notes:

[1] Calculated from data in Table 2.~~3~~1.

[2]: 1150-[1].

[3]: [2]/1.16; 16% reserves required for 1981/82 and 82/83 with no new nuclear capacity, from 6/24/76 NEPOOL Executive Committee minutes.

[4]: [3]/1150.

cost of firm capacity,[11] or perhaps 60% of the cost of a combustion turbine per installed kw.

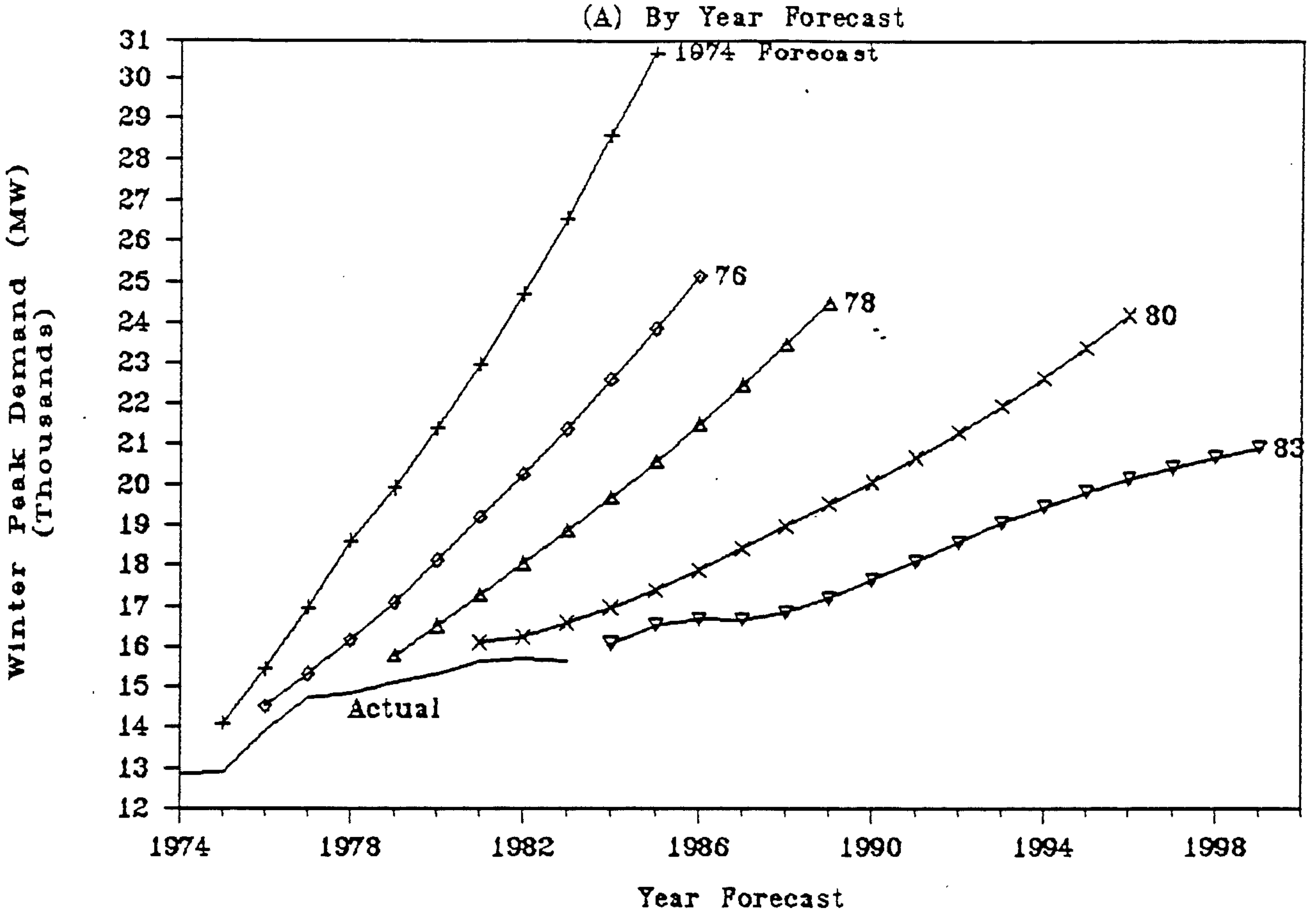
Q: What are NEPOOL's requirements for the limited reliability benefits provided by Millstone 3?

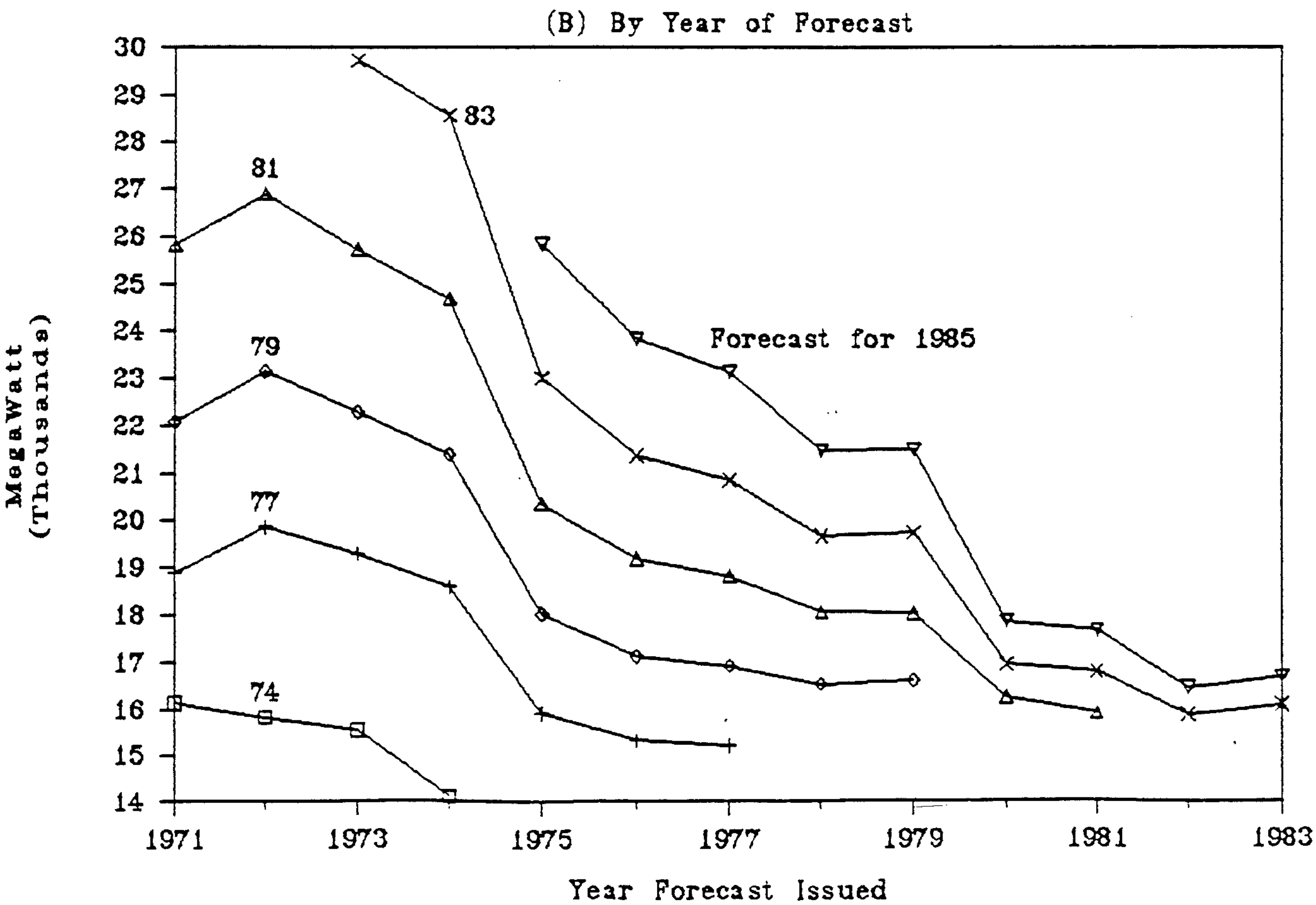
A: NEPOOL would require additional capacity by about 1992 under its current forecast, assuming that Seabrook 1 is completed, but no other generation (hydro, refuse, cogeneration, Canadian purchases) is added before that time. As Figure 2.4 shows, NEPOOL forecasts have been no more accurate than NU forecasts. Even if NEPOOL needed capacity in 1992, that would not justify WMECo customers paying for Millstone 3 in 1984, or even in 1986.

Q: Does this level of reliability benefit in 1992 justify charging ratepayers for Millstone 3 in 1984?

A: No. In fact, I can not see that reliability considerations could justify any cost recovery for Millstone 3 until close to the time when it would be required for reliability purposes. This is the traditional excess capacity argument: ratepayers should not have to carry the extra costs imposed by poor utility planning, when that planning brings on more capacity than is reasonably necessary to provide adequate service.

Figure 2.4: NEPOOL Forecast History





3 - THE BENEFITS OF MILLSTONE 3 FOR OIL DISPLACEMENT

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

A: Millstone 3 is being built almost exclusively for fuel displacement purposes. Like all nuclear units, it will provide lower fuel costs than the oil plants which NEPOOL currently has in abundance.

Q: Have you analyzed the cost-effectiveness of Millstone 3 for oil displacement?

A: I have compared the cost of Millstone 3 under traditional ratemaking to the cost of the oil it would displace, under a variety of assumptions regarding Millstone 3 cost and reliability. This is a fairly lenient type of comparison: an investment may be substantially suboptimal, but still be less expensive than oil. I have not attempted to address the larger issue of whether Millstone 3 is the most economical option for reducing oil use, although my results may be used to form an opinion on this subject.

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

A: Table 3.1 lists, and Figure 3.1 displays, the differences NU projects between Millstone 3 fuel costs and the fuel costs of the fossil (primarily oil-burning) plants it would be backing out. The differential starts in 1986 at about 3.6 cents per kwh, and rises to 16.6 cents per kwh by 2005. These savings are substantial, but they come at the even greater cost of building and operating Millstone 3. Table 3.1 also compares the total costs NU projects for Millstone 3 to NU's projection of the cost of replacement energy.

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

A: It is clear from the information presented in Mr. Ferland's testimony and attachments that even NU expects that the costs of Millstone 3 will exceed the benefits of the unit for most, and probably all, of its useful life.

Q: How are these conclusions supported by Mr. Ferland's testimony?

A: In his Exhibit EJF-4, Mr. Ferland provides WMECo's projections of the rate impact of Millstone 3 over the first twenty years of its life, expressed as nominal cents/kwh for each rate class. In Table 3.2, I repeat the figures Mr. Ferland offers for the residential class; the other classes are quite similar. Since Mr. Ferland did not provide any cost projections beyond 2005, and since WMECo has not

Year	Replacement Fuel	Millstone Fuel	Net Fuel Cost	Millstone Total Cost	Net Total Cost
1986	5.0	1.4	-3.6	19.3	14.3
1987	5.4	1.2	-4.2	17.4	12.0
1988	5.8	1.3	-4.5	16.2	10.4
1989	6.4	1.4	-5.0	15.5	9.1
1990	7.1	1.5	-5.6	15.0	7.9
1991	7.9	1.5	-6.4	14.4	6.5
1992	8.8	1.6	-7.2	13.0	4.2
1993	9.8	1.7	-8.1	12.7	2.9
1994	11.3	2.0	-9.3	12.6	1.3
1995	11.6	2.1	-9.5	12.4	0.8
1996	12.9	2.2	-10.7	12.2	-0.7
1997	13.3	2.3	-11.0	12.3	-1.0
1998	14.1	2.5	-11.6	12.5	-1.6
1999	17.1	2.6	-14.5	12.7	-4.4
2000	18.7	2.7	-16.0	12.8	-5.9
2001	21.0	2.8	-18.2	13.0	-8.0
2002	18.9	3.0	-15.9	13.4	-5.5
2003	17.9	3.1	-14.8	13.5	-4.4
2004	19.5	3.2	-16.3	13.7	-5.8
2005	19.9	3.3	-16.6	14.1	-5.8
2006					

Table 3.1: Comparison of NU Projections of Millstone 3 Fuel Costs and Total Costs to Replacement Power Costs.

Notes: All data from Ferland Study 76, Ex.2.
Net Fuel Cost = Millstone Fuel - Replacement Fuel.
Net Total Cost = Millstone Total Cost - Replacement Fuel.
Negative values are Millstone savings.
All values are in cent per kWh.

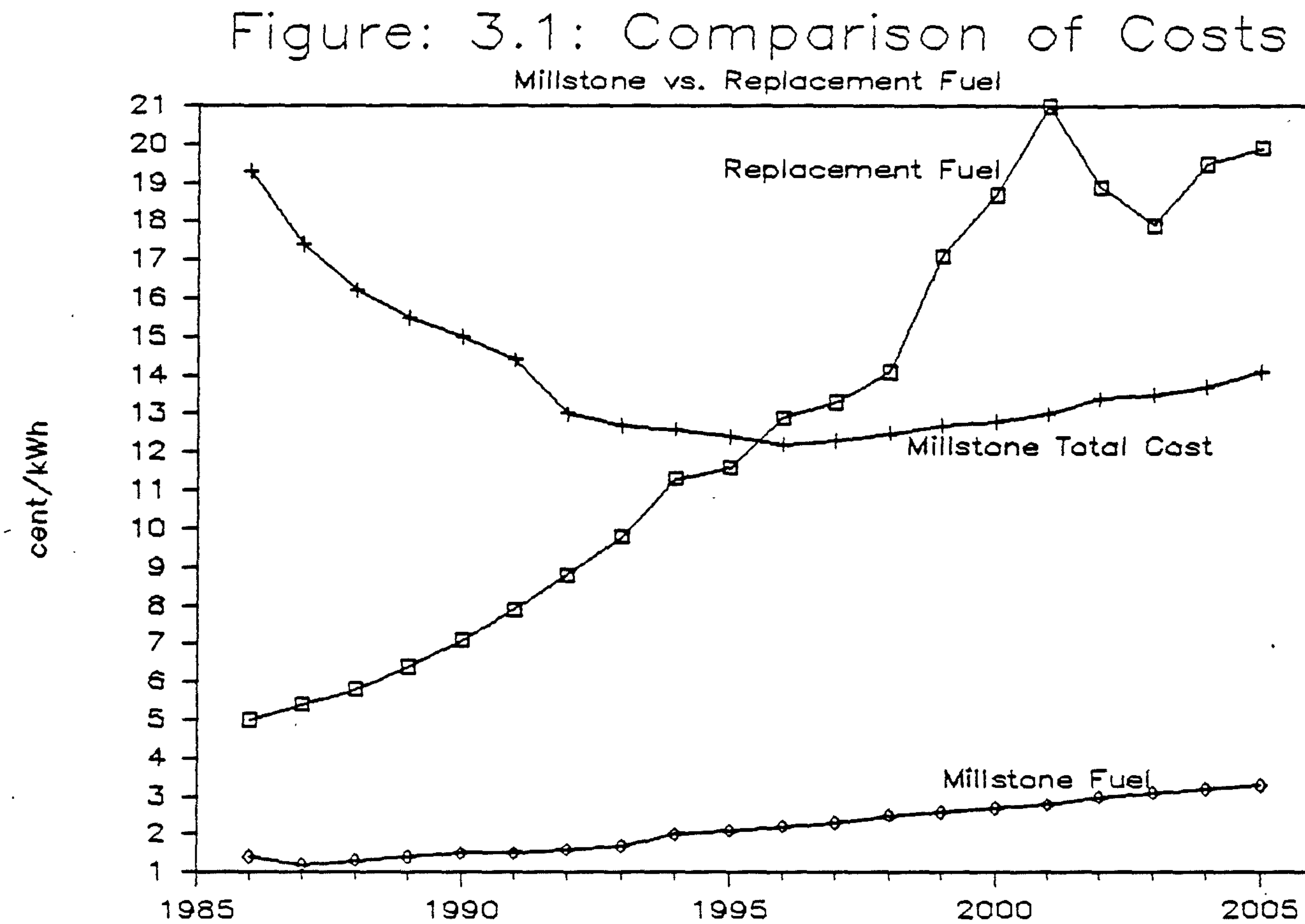


Figure: 3.1: Comparison of Costs
Millstone vs. Replacement Fuel
cent/kWh
Replacement Fuel
Millstone Total Cost
Millstone Fuel
1985
1990
1995
2000
2005

Year	Current Year [1]	Cumulative 1986 to Year	NPV [1] 1986 to Year
		(Nominal Cents/KWH)	
1986	2.8	2.8	2.5
1987	2.3	5.1	4.2
1988	2.0	7.1	5.6
1989	1.7	8.8	6.6
1990	1.5	10.3	7.3
1991	1.2	11.5	7.9
1992	0.9	12.4	8.3
1993	0.6	13.0	8.5
1994	0.3	13.3	8.6
1995	0.1	13.4	8.6
1996	-0.2	13.2	8.5
1997	-0.2	13.0	8.5
1998	-0.4	12.6	8.4
1999	-0.9	11.7	8.3
2000	-1.2	10.5	8.1
2001	-1.5	9.0	7.9
2002	-1.1	7.9	7.8
2003	-0.8	7.1	7.7
2004	-1.0	6.1	7.7
2005	-1.0	5.1	7.6
2006	-1.0	4.1	7.5
2007	-1.0	3.1	7.5
2008	-1.0	2.1	7.4
2009	-1.0	1.1	7.4
2010	-1.0	0.1	7.3
2011	-1.0	-0.9	7.3
2012	-1.0	-1.9	7.3
2013	-1.0	-2.9	7.3
2014	-1.0	-3.9	7.2
2015	-1.0	-4.9	7.2
2016	-1.0	-5.9	7.2
2017	-1.0	-6.9	7.2
2018	-1.0	-7.9	7.2
2019	-1.0	-8.9	7.2
2020	-1.0	-9.9	7.1
2021	-1.0	-10.9	7.1

Table 3.2: Effect of Millstone 3 on Residential Rates

Notes: [1] From Ferland Exhibit EJF-4
[2] NPV (Net Present Value) is calculated from year to current year at a discount rate of 14.08%

provided any such projections in response to discovery requests, I have simply extended this projection at a saving of one cent per kWh, approximately the average of the last four years provided in Exhibit EJF-4, 2002 to 2005. Since the rate impact displayed in Exhibit EJF-4 is quite stable over that period, this seems to be a reasonable assumption. Table 3.2 also provides a running simple total of the rate impact, and a running discounted total,[12] using WMECo's discount rate. Even without discounting the cash flow, Millstone 3 would increase rates for any customer with constant consumption through 2010. By 1995, the consumer would have paid out a total of 13.4 cents extra for each kwh of annual use. For a typical residential customer, using 7500 kwh annually, this would amount to paying out $1000 before the unit starts to save money. Discounting at WMECo's suggested rate makes the situation far worse: even if a customer stays on the system throughout the useful life of Millstone 3,[13] the savings are never large enough to cover the initial investment. Millstone 3 winds up equivalent to a deadweight loss of 7.1 cents per kwh (or $530 for our typical residential customer), paid in 1985.

Q: Have you performed a similar analysis, using the entire cost

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12. I refer to these statistics as the "cumulative net cost" and the "discounted net cost", respectively.

13. This analysis uses NU's speculatively long life.

of the unit, rather than its effect averaged over retail rates?

A: Yes. I have compared the costs of Millstone 3 to those of continued oil consumption, by using the total Millstone 3 cost/kwh figures supplied in Exhibit 2 to Study 76, listed in Mr. Ferland's Exhibit EJF-2. These projections, entirely the work of NU, appear in Table 3.1 as cents per kwh. In Table 3.3, I restate them as millions of dollars per year for WMECo customers, along with the corresponding replacement energy costs, cumulative net cost and discounted net cost. I also project out the WMECo's figures to 2025 at the compound growth rates NU projects for each cost component (replacement and nuclear fuel, carrying charges, and O & M) for 1995 - 2005.

As WMECo has acknowledged, customers would initially be charged more for Millstone 3 than it will save them. The first year in which Millstone 3 would save customers money on balance would be 1996, as in the the cents/kWh analysis in Table 3.2. At that point, the cumulative net cost[14] of the plant to WMECo's customers would have reached $440 million. Not until 2008 would the cumulative net cost reach zero, at

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14. This figure is calculated as the sum of the net cost over previous years.

year	Net Cost	Cumulative Net Cost	Discounted Net Cost
1986	61.3	61.3	53.8
1987	80.5	141.8	115.6
1988	72.2	214.0	164.2
1989	63.0	277.0	201.4
1990	54.7	331.7	229.7
1991	48.5	380.1	251.7
1992	31.4	411.5	264.2
1993	21.6	433.1	271.7
1994	9.7	442.8	274.7
1995	6.0	448.8	276.3
1996	-5.2	443.6	275.1
1997	-7.5	436.1	273.5
1998	-11.9	424.2	271.4
1999	-32.8	391.4	266.2
2000	-44.1	347.3	260.1
2001	-59.6	287.7	252.8
2002	-41.0	246.7	248.5
2003	-32.8	213.9	245.4
2004	-43.4	170.5	241.8
2005	-43.2	127.3	238.7
2006	-49.4	77.9	235.6
2007	-55.8	22.0	232.6
2008	-62.7	-40.7	229.5
2009	-69.6	-110.3	226.6
2010	-77.0	-187.3	223.7
2011	-84.7	-272.0	221.0
2012	-93.0	-365.0	218.3
2013	-101.2	-466.2	215.8
2014	-110.0	-576.2	213.4
2015	-119.3	-695.5	211.1
2016	-129.4	-824.9	208.9
2017	-139.2	-964.1	206.8
2018	-149.9	-1114.0	204.9
2019	-161.1	-1275.0	203.1
2020	-173.3	-1448.3	201.3
2021	-185.1	-1633.4	199.7
2022	-198.0	-1831.4	198.2
2023	-211.5	-2042.9	196.8
2024	-226.3	-2269.2	195.5
2025	-240.6	-2509.8	194.2

Table 3.3: Net cost of Millstone 3 to WMECO Customers, in $ million. NU assumptions. (NU Case).

which point the unit would have reached simple breakeven. At the 14.08% discount rate used by WMECo, discounted breakeven would never occur. The present value of the cost to ratepayers would be almost $200 million.

Figure 3.2 displays the cost of Millstone 3 net of fuel savings for each year of its life, under the assumptions NU uses in its analyses in this case, for traditional ratemaking treatment.[15]

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

A: I have modelled the annual costs of Millstone 3 to WMECo ratepayers under conventional ratemaking techniques, for several sets of alternative assumptions. The inputs on which these analyses are based are the NU projections (and my extrapolations) listed in Table 3.3. Based on the results of my review of NU's projections for Millstone 3 (described in Section 4 of this testimony), I have adjusted NU's projections to reflect more realistic assumptions.

Q: What other cases have you analyzed?

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

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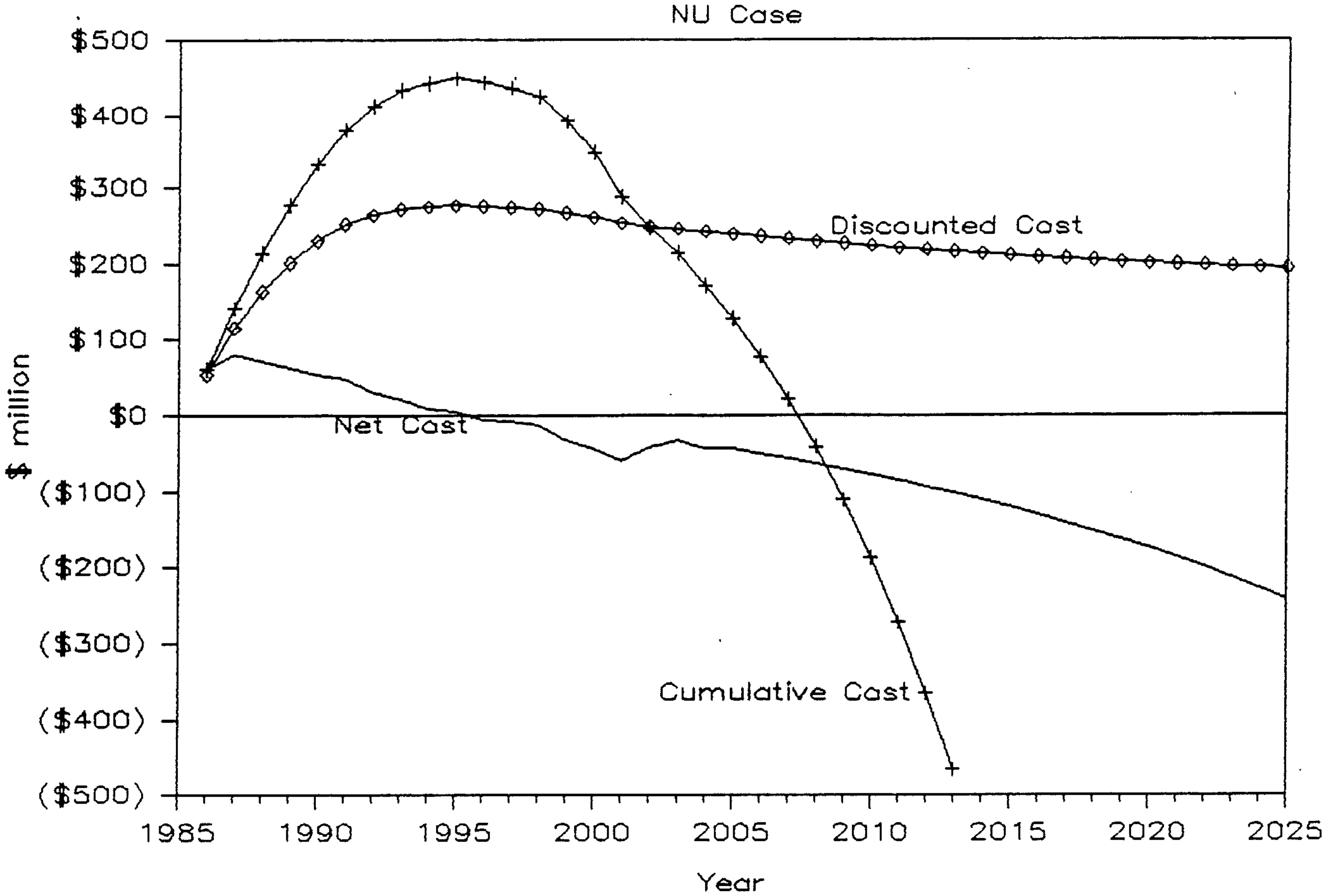
15. NU's phase-in proposal would have little effect on this analysis beyond the phase-in period itself.

Figure 3.2: Net Cost of Millstone 3



1. NU's assumptions, except for the use of a realistic capacity factor,

2. Case 1, but with a construction cost of $4.5 billion, significantly higher than NU's current estimate of $3.54, but still (in my view) an optimistic projection, and

3. Case 1, but with a construction cost of $5.5 billion, which I consider to be a realistic figure if past trends continue.

The results are shown in Tables 3.4 through 3.6, and in Figures 3.3 through 3.5.

Q: Please describe the results of the first of these cases.

A: With a realistic capacity factor, the first year in which Millstone 3 would save customers money on balance would be 1999. In that year, the cumulative net cost of the plant to WMECo's customers would have reached $690 million. Simple breakeven would not be reached until 2016. Again, discounted costs would never break even, and remain above $500 million in 1985 dollars.

Q: Do these results change substantially if the construction cost is adjusted to more realistic values?

A: Yes. With a fairly optimistic cost estimate of $4.5 billion,

year	Net Cost	Cumulative Net Cost	Discounted Net Cost
1986	69.9	69.9	61.2
1987	98.6	168.5	137.0
1988	93.2	261.7	199.8
1989	82.9	344.6	248.7
1990	73.7	418.3	286.9
1991	76.9	495.3	321.8
1992	56.6	551.9	344.3
1993	45.9	597.8	360.3
1994	33.1	630.9	370.5
1995	28.7	659.6	378.1
1996	16.9	676.5	382.1
1997	14.6	691.2	385.1
1998	10.2	701.3	387.0
1999	-10.5	690.8	385.3
2000	-21.7	669.1	382.3
2001	-37.1	632.0	377.8
2002	-18.0	614.0	375.9
2003	-9.8	604.1	374.9
2004	-20.1	584.0	373.3
2005	-19.4	564.7	371.9
2006	-25.3	539.4	370.3
2007	-31.4	508.0	368.6
2008	-37.9	470.1	366.8
2009	-44.4	425.7	364.9
2010	-51.3	374.4	363.0
2011	-58.6	315.8	361.1
2012	-66.3	249.5	359.2
2013	-74.0	175.5	357.3
2014	-82.2	93.4	355.5
2015	-90.7	2.7	353.8
2016	-99.9	-97.3	352.1
2017	-109.0	-206.3	350.5
2018	-118.7	-325.0	348.9
2019	-128.9	-454.0	347.5
2020	-140.0	-593.9	346.1
2021	-150.7	-744.6	344.8
2022	-162.4	-907.0	343.5
2023	-174.5	-1081.5	342.4
2024	-187.8	-1269.3	341.3
2025	-200.5	-1469.8	340.2

Table 3.4: Net cost of Millstone 3 to WMECO Customers, in $ million. NU assumptions, 54% CF. (Case 1).

year	Net Cost	Cumulative Net Cost	Discounted Net Cost
1986	91.8	91.8	80.5
1987	131.1	222.9	181.2
1988	124.3	347.2	264.9
1989	112.0	459.2	331.1
1990	101.3	560.5	383.5
1991	107.1	667.6	432.1
1992	83.2	750.8	465.1
1993	71.1	821.8	489.9
1994	56.9	878.8	507.3
1995	51.2	930.0	521.1
1996	38.5	968.5	530.1
1997	35.9	1004.3	537.5
1998	31.1	1035.5	543.1
1999	10.2	1045.7	544.7
2000	-1.2	1044.4	544.5
2001	-16.9	1027.5	542.5
2002	2.1	1029.7	542.7
2003	10.1	1039.7	543.6
2004	-0.4	1039.4	543.6
2005	0.3	1039.6	543.6
2006	-5.9	1033.7	543.3
2007	-12.3	1021.5	542.6
2008	-19.0	1002.5	541.7
2009	-25.8	976.7	540.6
2010	-33.0	943.7	539.3
2011	-40.5	903.2	538.0
2012	-48.4	854.9	536.6
2013	-56.3	798.5	535.2
2014	-64.8	733.7	533.8
2015	-73.6	660.1	532.4
2016	-83.0	577.2	531.0
2017	-92.3	484.8	529.6
2018	-102.3	382.6	528.3
2019	-112.7	269.8	527.0
2020	-123.9	145.9	525.8
2021	-134.9	11.0	524.6
2022	-146.8	-135.8	523.5
2023	-159.2	-294.9	522.4
2024	-172.6	-467.5	521.4
2025	-185.6	-653.1	520.5

Table 3.5: Net cost of Millstone 3 to WMECO Customers, in $ million. $4.5 billion, 54% CF. (Case 2).

year	Net Cost	Cumulative Net Cost	Discounted Net Cost
1986	114.7	114.7	100.6
1987	164.9	279.6	227.3
1988	156.6	436.3	332.8
1989	142.4	578.6	416.8
1990	130.0	708.6	484.1
1991	138.5	847.1	546.9
1992	110.8	957.9	591.0
1993	97.3	1055.2	624.9
1994	81.8	1137.0	649.9
1995	74.7	1211.7	669.9
1996	60.9	1272.6	684.2
1997	58.0	1330.6	696.1
1998	53.0	1383.5	705.7
1999	31.8	1415.3	710.7
2000	20.1	1435.4	713.5
2001	4.1	1439.5	714.0
2002	23.2	1462.7	716.5
2003	30.8	1493.5	719.4
2004	20.1	1513.6	721.0
2005	20.7	1534.4	722.5
2006	14.3	1548.7	723.4
2007	7.6	1556.3	723.8
2008	0.7	1557.1	723.9
2009	-6.4	1550.6	723.6
2010	-13.9	1536.8	723.1
2011	-21.6	1515.2	722.4
2012	-29.7	1485.4	721.5
2013	-38.0	1447.4	720.6
2014	-46.7	1400.8	719.5
2015	-55.7	1345.0	718.5
2016	-65.3	1279.7	717.4
2017	-74.9	1204.8	716.3
2018	-85.2	1119.6	715.2
2019	-95.8	1023.8	714.1
2020	-107.2	916.6	713.0
2021	-118.5	798.1	712.0
2022	-130.6	667.5	711.0
2023	-143.2	524.4	710.0
2024	-156.7	367.7	709.1
2025	-170.0	197.6	708.2

Table 3.6: Net cost of Millstone 3 to WMECO Customers, in $ million. $5.5 billion, 54% CF. (Case 3).

Figure 3.3: Net Cost of Millstone 3

NU assumptions, 54% CF (Case 1)

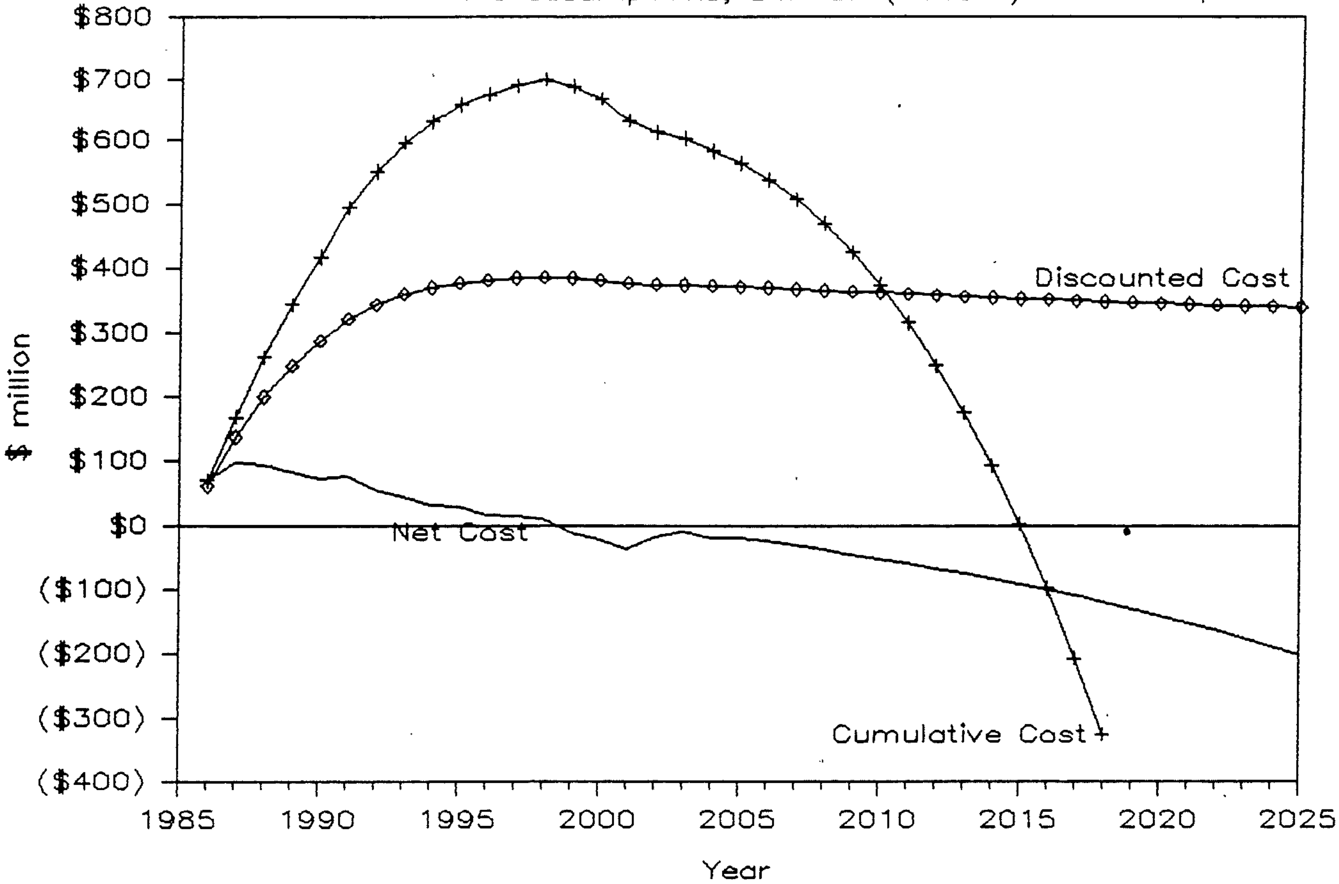


Figure 3.4: Net Cost of Millstone 3

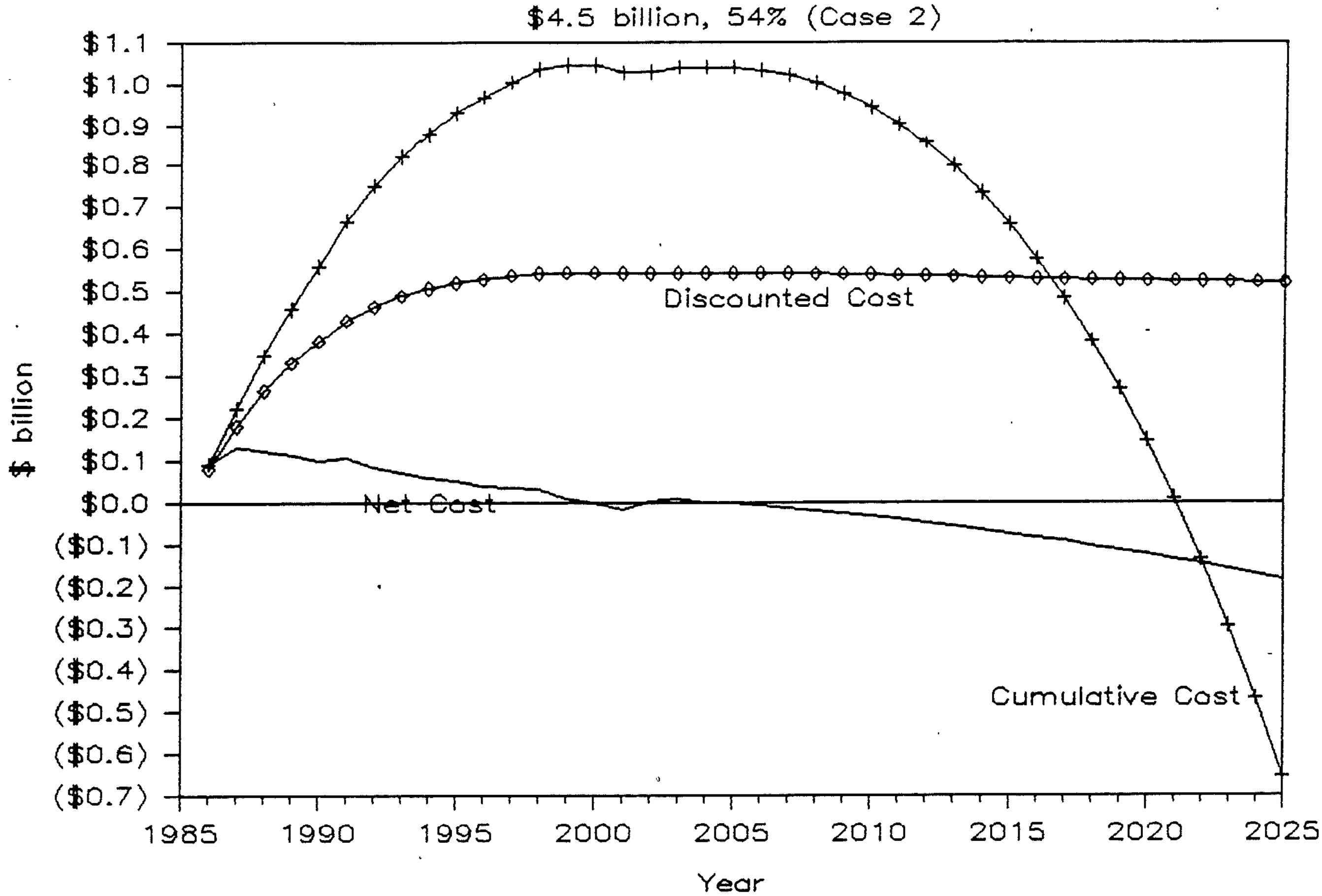
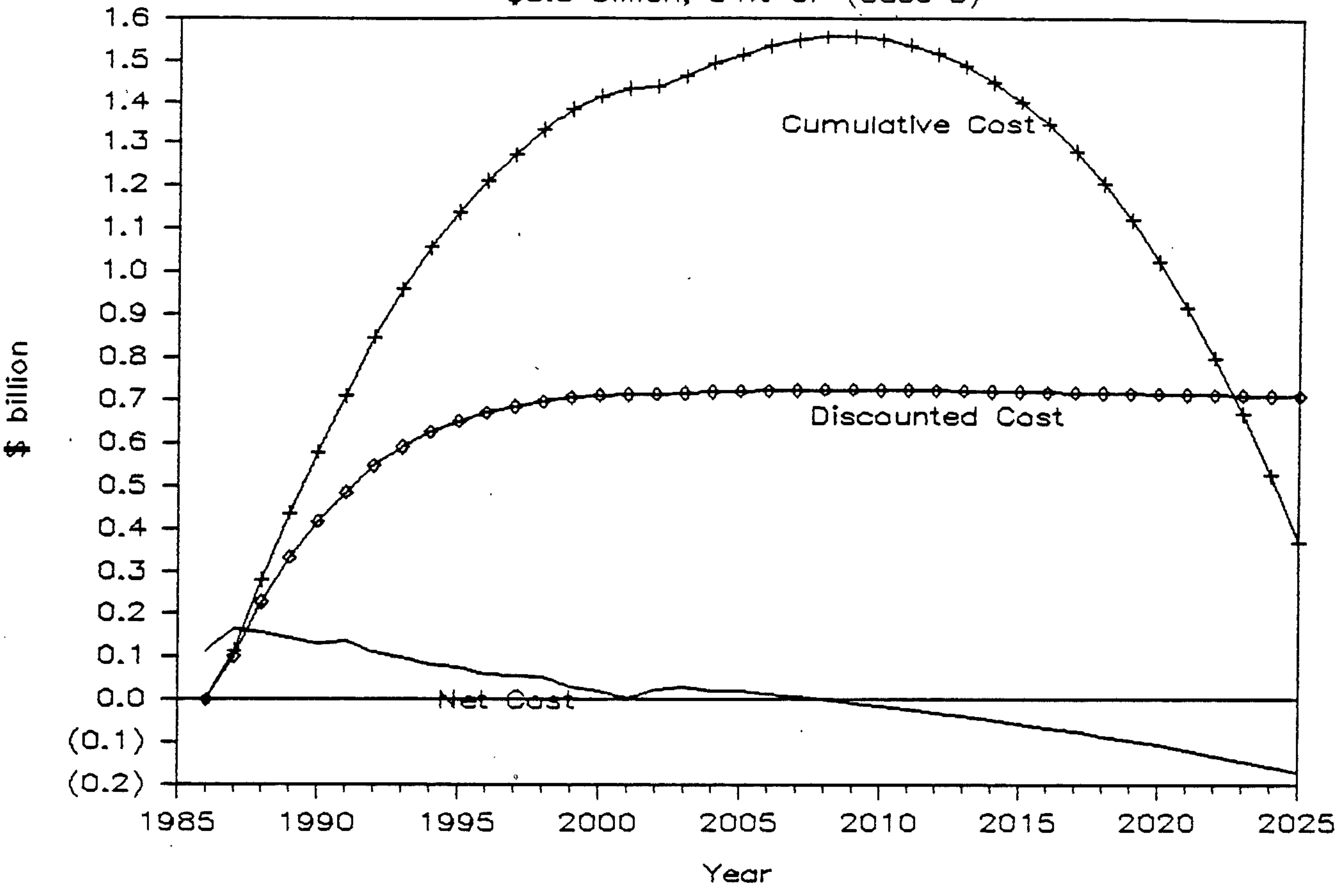


Figure 3.5: Net Cost of Millstone 3

$5.5 billion, 54% CF (Case 3)



Millstone 3 would cost ratepayers more than the oil it displaces each year until the turn of the century, by which time the cumulative net cost of the plant to WMECo's customers would have reached a billion dollars. It would break even (total displaced oil cost would equal total charges to ratepayers) around 2022. The present value of net costs to ratepayers would total half a billion dollars. Increasing the construction cost to $5.5 billion (which I consider to be a realistic possibility) pushes crossover out to 2009; in this situation, even simple breakeven never occurs, and the net present cost is about $700 million. I approximated the effect of these higher costs by increasing NU's projected carrying costs proportionately: this has the effect of implicitly correcting some of NU's optimism regarding capital additions and decommissioning, which I believe NU includes in its carrying charges.

Even the $5.5 billion case (Case 3) is probably somewhat optimistic, since it assumes a very long useful life, projects only modest O & M costs, ignores insurance and various overhead expenses, and still understates decommissioning costs and capital additions.

Table 3.7 summarizes some measures of cost-effectiveness for the cents/kWh analysis and each of the four total-cost cases:

	Cents/kWh	NU Case	Case 1	Case 2	Case 3
INPUTS: [1]					
Construction Costs (billion)	$3.54	$3.54	$3.54	$4.50	$5.50
Capacity Factors	NU	NU	54%	54%	54%
Other Inputs					
RESULTS:					
Crossover Year	1996	1996	1999	2000	2009
Simple Breakeven Year	2011	2008	2016	2022	never
Cumulative Cost at Crossover (million)	$1000 [2]	$443.6	$690.8	$1,044.4	$1,550.6
Net Present Cost (million)	$530.0 [2]	$194.3	$340.2	$520.5	$708.2

Table 3.7: Summary of Millstone 3 Cost-Benefit Measures.

Notes: [1] All other inputs from NU or extrapolation of NU projections
[2] Dollar cost to typical residential customer.
[3] Uses historic O&M trends.

the years of crossover and simple breakeven, the cumulative net cost to ratepayers at crossover, and the net present cost.

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

A: The dates I calculated are meaningful for all ratepayers collectively, but not individually. Due to load growth (if NU is correct that WMECo and NU loads will grow substantially), the later benefits of Millstone 3 will be diluted more than the early costs, and only customers whose loads grow at the same rate as the system as a whole will break even at these dates. New customers and those with rapidly increasing energy consumption will realize positive cumulative benefits faster than I calculated, while customers who conserve in response to the high rates caused by Millstone 3 will break even later, if at all. Customers who leave the system before their breakeven date end up with a net loss, regardless of what happens to ratepayers as a group.[16]

Customers also vary in terms of their discount rates. NU's estimated 14.08% rate, which I used in my calculations, is

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16. The elderly are particularly likely to pay for Millstone 3 without receiving commensurate benefits.

estimated in a manner consistent with standard utility practice. While this rate may be appropriate for general utility purposes, it is almost certainly lower than the discount rate that many ratepayers would apply in making their own oil-backout decisions. This would be particularly true for customers with limited access to capital, such as low-income households, and financially strapped industrial operations. Higher discount rates would imply even higher discounted net present costs.

Q: Can you compare the cost of canceling Millstone 3 now, to the cost of completing and running it?

A: Yes. WMECo estimates that its share of the cancelation costs of Millstone 3 as of the middle of 1984 would be $287.2 million. To make this figure comparable to the previously calculated present values of operating the plant, let us suppose that NU accrues AFUDC at 9.5% to 1985, and then recovers the entire investment.[17] The cost of this outcome would be $314.5 million, which is less than any of my cost projections, except the NU case (those results are summarized in Table 3.7). It is unlikely that the cost would be recovered immediately, however: a lengthy amortization period would be more normal practice. If the $314.5 million were

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17. I have not formed any opinion as to whether any or all of the sunk costs should be collected from the ratepayers, under either the completion scenario or the cancelation scenario.

recovered as an equal nominal sum over a period of years, like a mortgage, with interest at 9.5% on the balance,[18] the present value is more like $223 to $261 million, depending on whether the recovery stretches over 30 years or 10 years.

It therefore appears to be almost a certainty that WMECo's customers would be better off if Millstone 3 were canceled promptly than if the unit were completed. They have very little to gain from completing the plant, and enormous potential losses. If WMECo could sell its share of Millstone 3 for as little as $240/kw,[19] its customers would be better off selling than owning the capacity, even under NU's cost and performance assumptions.[20] These conclusions are valid regardless of how the Department chooses to treat the currently sunk costs of Millstone 3, so long as the treatment is the same for cancelation and completion.

Q: What can be concluded from these analyses?

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18. This should be sufficient to make the shareholders whole, so we are still discussing options in which all costs are borne by the ratepayers.

19. This figure might be increased somewhat to reflect the reliability benefits of Millstone. Depending on the type and timing of the reliability needs, this might double the value of the plant to $500/kw.

20. Perhaps the optimal outcome for WMECo would be for municipal utilities to buy the plant and sell a share of the power back to WMECo at their lower carrying charges.

A: First, even using NU's own projections, Millstone 3 will not save money for WMECo customers who pay for the plant's early, uneconomic years, unless they remain customers for most of the plant's useful life. Second, given NU's own projections, many customers would be better off if Millstone 3 had never been started, or had been canceled long ago. Third, if Millstone's cost and performance are consistent with past experience and trends, it is almost certain to be a poor investment for virtually all the ratepayers, and for customers as a whole.

4 - THE COST OF POWER FROM MILLSTONE 3

Q: How have you estimated the cost of Millstone 3?

A: I have attempted to determine realistic estimates for the duration of Millstone 3 construction, its construction costs, and the various costs of running and decommissioning the unit. Based upon analyses of historical performance and trends:

1. I expect Millstone 3 to come on line sometime late in 1987, or more likely in 1988.

2. I expect the unit to cost about $5.5 billion.

3. Capacity factors for Millstone 3 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 Millstone 3 will cost about 13 cents/kWh, in levelized 1984 dollars. The actual prices charged to ratepayers will include inflation and will be much larger: about 30 cents/kWh in its first year. Sunk costs account for only about 6 cents/kWh, so the costs of completing and running Millstone 3 are likely to be about 7 cents/kWh, in 1984 dollars.

A detailed analysis of these costs is presented below, including a comparison of my estimates to those of NU.

4.1 - CONSTRUCTION DURATION

Q: Are there any special problems in determining whether NU's current in-service date estimate for Millstone 3 is reasonable?

A: Yes. I have generally assessed the reasonableness of nuclear construction schedules by examining the actual construction durations and the schedule estimation records of the individual utility, the architect-engineer, and/or the nuclear industry as a whole. This is more difficult for Millstone 3, for three reasons, all related to NU's decision in 1977 to reschedule the unit's in-service date to 1986. First, there is very little history of Millstone 3 schedule estimates, since NU has not attempted to project the earliest date at which Millstone 3 could be completed, which is the normal utility practice. Instead, NU has determined some years ago that it wants to complete Millstone 3 by May, 1986, and has not yet found that goal to be unattainable. Secondly, the fact that NU's schedule projections are different in kind and purpose than those of other utilities[21] makes extrapolation from other plants' experience rather more complicated. The relationship between NU's schedule for

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21. The Millstone 3 schedule projections are also not readily comparable even to those of NU for Millstone 2, for the same reasons.

Millstone 3 and conventional utility nuclear schedules must be established before the industry data can be applied to Millstone 3. Finally, since Millstone 3 can not be expected to be quite like other units which started construction at the same time, nor quite like other units which are completed at the same time, the straightforward comparisons offered by techniques such as regression analysis are less applicable than they are for more conventionally scheduled units.

Q: Are there specific reasons to believe that Millstone 3 will reach commercial operation somewhat after the date projected by NU?

A: Yes. Those reasons include:

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

2. NU's construction duration projection 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.

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

A: Table 4.1 provides this data for all units in commercial

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
St Lucie 2	06-Apr-83 (L)	08-Aug-83	4.1
Average			13.~~5~~0

Table 4.1: Recent Experience in Start-up Intervals

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 365/12 days.

(4) Telephone inquiry, TVA.

(5) Telephone inquiry, NRC.

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

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 13-plant average of 13.5 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. Four other units received operating licenses in 1982 and 1983, but have not yet reached commercial operation: San Onofre 2, Grand Gulf 1, McGuire 2, and San Onofre 3. Each of these units is already over a year from OLIS,[22] and the group as a whole will increase the average startup.

Q: What is NU's projection for the Millstone 3 start-up period?

A: NU currently projects a start-up period of eight or nine months for Millstone 3. This projection is considerably more optimistic than would be suggested by the historical experience. In addition, NU does not expect Millstone 3 to be ready for fuel load for three months after license

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22. As of March 8, 1984, the four units had held operating licenses for an average of 20.4 months. Grand Gulf still held only a low-power license, after almost 21 months.

issuance. Since the plants in Table 4.1 generally loaded fuel within a month (and often within days) of licensing, it would seem that the startup period for Millstone 3 would be longer than average. If NU's projections of construction progress and operating license date were correct, but the start-up period were the average 14 month duration from Table 4.1, Millstone 3 would enter commercial operation in October, 1986. Including two more months for the projected delay in Millstone 3 fuel load would bring the in-service date to December, 1986.

Q: What are the construction duration projections for other nuclear power plants, and how do they compare to those for Millstone 3?

A: Table 4.2 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 Millstone 3 as of June 30, 1983. On average, these nineteen units were 76% complete and were projected to reach commercial operation in November, 1985. At its reported construction pace over thae last year,[23] Millstone 3 was about two months behind the average. Table 4.2 also updates the status of this cohort to February 1984. At that point,

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23. NU reports progress from 60.3% complete at the end of 1982 to 81% complete at the end of 1983, or about 1.7% per month.

Unit	Reported % Complete (1)	Estimated Commercial Operation Date	
	as of 6/83	as of 6/83 (1)	updated (3)
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	(5)(6)
Midland 2	85	Feb-85	Jul-86 (6)
Perry 1	83.8	May-85	Dec-85 (6)
Bellefonte 1	83	Nov-86	Apr-88 (6)
Clinton	80.6	Nov-86	Nov-86
Shearon Harris 1	79	Mar-86	Mar-86
Seabrook 1	78.7	Dec-84	Jul-86 (6)
Hope Creek 1	71	Dec-86	Dec-86
River Bend 1	71	Dec-85	Dec-85
Nine Mile Pt. 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 (6)
Bellefonte 2	63	Nov-87	Apr-90 (6)
Comanche Peak 2	63	Jun-85 (2)	Aug-86 (6)
Average	75.9 (4)	Nov-85	Aug-86

Table 4.2: Projected Completion Dates, Units comparable to Millstone 3 in Stage of Completion

Notes:
1. From Nuclear News, August 1983. All units between 57% and 87% complete are listed.
2. Month not given, June assumed.
3. Except as noted, from "Electric Utilities and the Nuclear Issue", February 7, 1984, Goldman Sachs.
4. Average excluding Midland 1 is 75.4%.
5. Commercial Operation Date indefi excluded from average.
6. From news reports and utilities.

one of the units was on indefinite status, and the average COD for the other 18 was August 1986. Based on reported percentage complete, NU was more conservative than the utility consensus in June 1983, but had converged with (or become more optimistic than) the consensus by early this year.

Q: Was NU more or less optimistic than the industry as a whole, as of the time of the last official cost estimate for Millstone 3?

A: Oddly enough, the answer to that question is critically dependent on how the completion percentage for Millstone 3 as of August 1982 is estimated. Table 4.3 repeats the previous comparison for June, 1982, the date of the last Nuclear News survey prior to the Millstone 3 cost forecast: all units within 15 points of the 45% completion reported for Millstone 3 are included. The fifteen units in Table 4.3 were reported to be an average of 43% complete, and were projected to be in service in October, 1986, actually later than Millstone 3 was scheduled.[24] It therefore appears that a standard industry projection in mid-1982 would have anticipated an in-service date of around August, 1986 for a 45% complete unit, such as Millstone 3 was said to be. The 45% figure appears to be

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24. In addition, three TVA units in the comparison group were on indefinite status.

Unit	Reported % Complete (1)	Estimated Commercial Operation Date
South Texas 1	60	Jun-86 (2)
WPPSS 3	53.8	Dec-86
Beaver Valley 2	53.3	May-86
Watts Bar 2	52	Dec-85
Hope Creek 1	50	Dec-86
River Bend 1	50	Dec-85
Commanche Peak 2	49	Jun-85 (2)
Braidwood 2	48	Oct-86
Hartsville A1	44	(3)
Nine Mile Pt. 2	44	Oct-86
Perry 2	42.4	May-88
Catawba 2	41.8	Jun-87
Palo Verde 3	39.1	May-86
Marble Hill 1	35	Jun-86 (2)
Yellow Creek 1	35	(3)
Hartsville A2	34	(3)
Vogtle 1	32	Mar-87
Limerick 2	30	Oct-87
Average	44.1 (4)	Oct-86 (5)

Table 4.3: Projected Completion Dates, Units comparable to Millstone 3 in Stage of Completion

Notes:
(1) From Nuclear News, August 1982. All units between 30% and 60% complete are listed.
(2) Month not given, June assumed.
(3) Commercial Operation Date Indefinite.
(4) Average excluding plants with indefinite commercial operation dates is 42.8%.
(5) Indefinite dates excluded from average.

representative of NU's contemporaneous estimates of Millstone 3 progress, since NU also reported to DOE that Millstone 3 was 47.9% complete on September 30, 1982.

At some point after the 1982 cost estimate, NU radically revised its estimated of Millstone 3 completion, and reported 60.3% progress by the end of the year. Extrapolating subsequent reported progress back to June 1982, it is reasonable to infer that NU's new approach (whatever that is) would have estimated that Millstone 3 was about 55% complete at the time of the survey. Table 4.4 presents a comparison of the cohort ranging from 40% to 70% complete in June 1982. This comparison indicates that, by NU's new definition of progress, the Millstone 3 commercial operation date projection was exactly the same as industry projections.[25]

Thus, a charitable interpretation would indicate that NU's estimate of Millstone 3 COD was consistent with standard industry practice at the time of its last official estimate, and even a bit more conservative than standard industry practice as recently as June, 1983, but that the industry consensus has once again caught up with NU. A more critical reading of NU's record would lead to the conclusion that NU

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25. The two indefinite units were again excluded from the analysis.

Unit	Reported % Complete (1)	Estimated Commercial Operation Date
Seabrook 1	70	Feb-84
Bellefonte 2	65	Nov-89
Susquehanna 2	65	Oct-84 (2)
Byron 2	64	Feb-85
Shearon Harris 1	64	Sep-85
WPPSS 1	62.5	(3)
Braidwood 1	62	Oct-85
South Texas 1	60	Jun-86 (4)
WPPSS 3	53.8	Dec-86
Beaver Valley 2	53.3	May-86
Watts Bar 2	52	Dec-85
Hope Creek 1	50	Dec-86
River Bend 1	50	Dec-85
Commanche Peak 2	49	Jun-85 (4)
Braidwood 2	48	Oct-86
Hartsville A1	44	(3)
Nine Mile Pt. 2	44	Oct-86
Perry 2	42.4	May-88
Catawba 2	41.8	Jun-87
Average	54.8 (5)	May-86 (6)

Table 4.4: Projected Completion Dates, Units comparable to Millstone 3 in Stage of Completion

Notes:
(1) From Nuclear News, August 1982. All units between 40% and 70% complete are listed.
(2) Date indicated as late-84, October assumed.
(3) Commercial Operation Date indefinite.
(4) Month not given, June assumed.
(5) Average excluding plants with indefinite commercial operation dates is 55.0%.
(6) Indefinite dates excluded from average.

has never been more cautious than the industry, and may indeed have been more optimistic than the consensus: this view would ascribe the apparent conservatism in June 1983 to NU's overstatement of the percentage completion of Millstone 3. I can not determine which of these conclusions is correct, but it appears that using industry experience in projecting the construction performance of Millstone 3 is more likely to err on the optimistic side than the pessimistic.

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 one or more estimates of the in-service date made when the plant was believed to be one to five years from COD. Table 4.5 summarizes the results of that analysis. For the typical estimate in the three-to-four year range (comparable to the 8/82 estimate for Millstone 3), the actual construction duration that was more than twice the projected remaining duration. Even interpolating with the more favorable data for estimates in the 4-5 year range produces a ratio of 1.93, which would yield COD projections only a few months earlier than would the results from the 3-4 year data.

Estimated Time to Completion (years)	Number of Estimates	Average Projected Time to Complete (years)	Average Duration Ratio
1 - 1.99	199	1.42	1.964
2 - 2.99	152	2.38	2.128
3 - 3.99	86	3.39	2.016
4 - 5	49	4.41	1.774

Table 4.5: Historical Nuclear Duration Myopia

As of the August, 1982 estimate, Millstone 3 was anticipated to be 45 months from COD. As discussed above, this was quite close to the standard industry projection for a unit at Millstone 3's stage of completion. Doubling this interval yields a prediction of commercial operation 90 months from August 1982, or in February, 1990. Even if a new estimate by Stone and Webster[26] this Spring concluded that May 1986 was still feasible as an in-service date, industry experience indicates that mid-1988 would be a better estimate.

This analysis assumes that the comparison group of utilities is 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 NU's estimate is still better than the historical average. It is also possible that NU's current over-optimism on its schedule (and particularly regarding its recent progress towards completion) exceeds the current general level of over confidence both currently.

Q: What dates are realistic commercial operation at Millstone 3?

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26. The architect/engineer for Millstone 3, and the major cost estimator.

A: Table 4.6 summarizes my previous calculations. Over a: the historic trends continued, Millstone 3 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 Millstone 3 is to be completed NU must do much better in maintaining its schedule than has been industry experience. We may approximate such an improvement by averaging the most optimistic duration estimates from the startup period correction (which assumes no startup delay due to later fuel load) and from the myopia analysis (which assumes that a new standard A/E projection for Millstone 3's service date would confirm the 5/86 COD). This case, biased though it is towards Millstone 3, would still predict a COD in November, 1987.

Method	Projected COD
NU OLIS plus Historic Startup	Oct-86
plus 2 months for Fuel Load Delay	Dec-86
Schedule Myopia from NU 8/82 Estimate	Feb-90
from Hypothetical 5/84 Estimate (with 5/86 COD)	May-88

Table 4.6: Summary of Estimates for Millstone 3 Commercial Operation Date

4.2 - CAPITAL COSTS

Q: Are NU's estimates of Millstone 3 capital costs consistent with historical experience?

A: No. As I noted in connection with schedule estimates, NU's unusual estimation procedures and construction schedule complicate the projection of Millstone 3's cost. However, there is evidence which indicates that NU is still being optimistic in its projection of Millstone 3's final cost. This evidence includes some econometric studies, 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.[27]

Q: What econometric studies of nuclear plant construction cost are relevant to Millstone 3?

A: Most econometric nuclear cost studies, such as those of National Economic Research Associates (Perl 1981, 1982; NERA 1984), by W.E. Mooz (1978, 1979) of the Rand Corporation, and by C. Komanoff (1981), model the cost of completing a nuclear unit as a function of, among other things, the date at which

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27. For the two latter analyses, we have data specific to NU, and even to Millstone 3.

the unit received a construction permit.[28] Perl (1978) is relatively unusual in utilizing the completion date as an explanatory variable. Since the cost trends in nuclear construction are widely attributed to changing regulatory requirements during the construction period, the completion date may be more important than the starting date.[29] The distinction may not be important for units which lie on the general industry trend line, but is more likely to matter for Millstone 3, where construction was deliberately stretched out. Thus, the approach of the Perl (1978) study is in some ways the most appealing for projecting Millstone 3 construction costs.

Q: Is it appropriate to estimate the capital cost of Millstone 3 from the results of the 1978 Perl study?

A: There are also serious drawbacks to the use of this study. The data is quite stale, since it ends in 1977, and excludes all effects of the Three Mile Island accident. With that caveat, it is interesting to note that my previous attempts to extrapolate the results reported in Perl (1978) to Seabrook 1, which will be roughly contemporaneous with

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28. Komanoff uses some alternative measures, such as the size of the nuclear industry at the time of the construction permit; Perl (1981) uses chronological groupings of units, rather than dates.

29. Perl (1982) takes the compromise approach of using the middle of the construction period as a time variable.

Millstone 3, produced estimates very close to those of NU for Millstone 3.

Q: Can useful figures be derived from the more recent Perl studies?

A: It is not readily apparent how this can be done with any of the later studies.[30] Perl (1981) uses irregular groups of units, organized by construction permit issuance date, which makes any application to future units quite difficult. In Perl (1982), the basis of the estimated $1727/kw (in 1982$), for a two-unit 1100 MW plant in the Northeast in 1985, is too obscure to allow extrapolation to Millstone 3. For example, Perl assumes past cost trends stop, but is not clear where he stops them. Since he reports real escalation of 14.9% for each year that the construction midpoint advances, this is a significant issue. In any case, it is clear that nuclear escalation has not slowed dramatically since Perl's previous study.

Q: Other than the Perl studies, do the other regression studies support similar cost estimates for Millstone 3?

A: As I noted, the other studies rely primarily on construction permit date and order. In addition, the Mooz studies are

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30. NERA (1984) may also be the work of Perl; it will be discussed below.

fairly old at this point, and the more recent Komanoff study was deliberately manipulated to exclude any effects of the accident at Three Mile Island.

The NERA (1984) study for Central Maine Power projects a cost specifically for Millstone 3. Despite the selectivity problem shared by most models which use construction permit date as the primary time variable,[31] that study estimated that Millstone 3 would cost $3617/kw (or $4.16 billion) if it goes on line in January of 1987. This projection is 17.5% higher than NU's official $3.54 billion estimate, and only about 6.2% of that difference can be attributed to the AFUDC accrued in the extra eight months of construction.

Q: How does the past record of A/E cost estimates support the capital cost forecasts of the econometric models?

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

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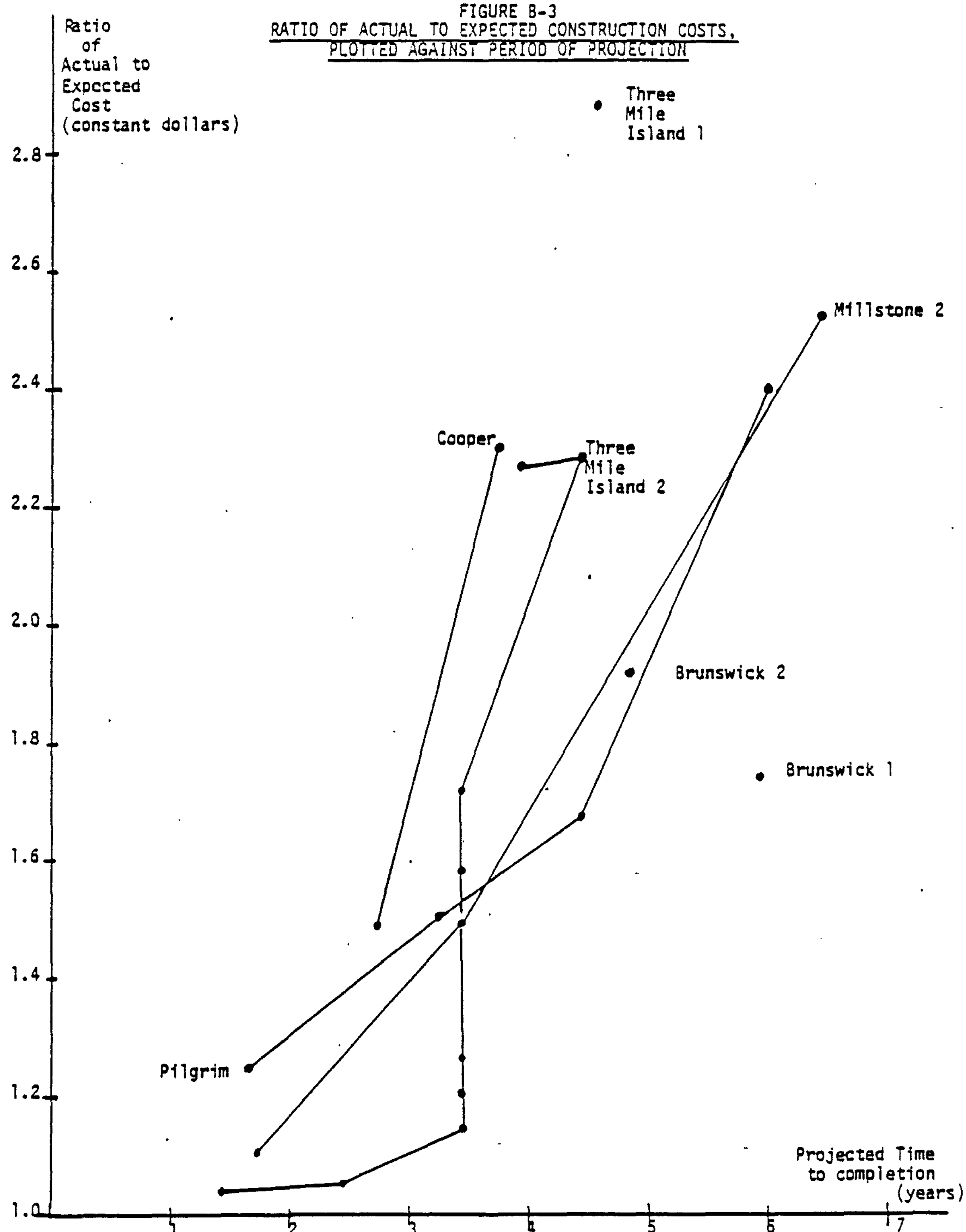
31. The best units of the later cohorts are already completed and in the data base, while the most problem-plagued and expensive are not.

Figure 4.1

FIGURE B-3
RATIO OF ACTUAL TO EXPECTED CONSTRUCTION COSTS, PLOTTED AGAINST PERIOD OF PROJECTION



B-88

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

increases. The data are displayed in Figure 4.1. The four equations are:

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

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

$$R = (1 + .147)^{t} \quad (3)$$

$$R = .844\ (1 + .195)^{t} \quad (4)$$

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 4.7 evaluates these four equations for the lead time forecast by NU as of the August 1982 cost estimate (3.75 years). As noted above, NU's value of _t_ is consistent with the industry consensus, given the reported state of completion for Millstone 3. If instead NU's recent completion figures are exceptionally optimistic, Millstone 3 may really be further from completion and subject to even greater cost overruns.

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 1.7 for Millstone 3. Multiplying NU's forecast cost of $3080/kw by 1.7 yields a

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32. NU projects 5.3% GNP inflation to 1990. 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.

	Ratio of Actual to Forecast Cost	Corrected Cost per Kw	Total Plant Cost (billion)
	[1]	[2]	[3]
Equation 1	1.765	$5,433	$6.248
Equation 2	1.723	$5,303	$6.099
Equation 3	1.672	$5,146	$5.919
Equation 4	1.646	$5,066	$5.827
Average	1.702	$5,239	$6.025

Table 4.7: Real Myopia Results

Notes: [1] For t= 3.75
[2]: [1]* $3078/kw
[3]: [1]* $3.54 billion

corrected estimate of \$5240/kw in May 1986. Adding 7% inflation[32] to an in-service date of November 1987 raises the cost to 5800/kw, or \$6.67 billion for the plant.

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,[33] 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 from 1 to 5 years into the future, along with the cost overrun and the value of <u>m</u> (the myopia factor) for each estimate. The average value of the cost overrun and the myopia factor for each group of

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

Estimated Time to Completion	Number of Estimates	Average Cost Ratio	Average Myopia
(years)			
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 - 5	34	2.54	22.5%

Table 4.8: Nominal Cost Overruns and Myopia Factors

cost forecasts are reproduced in Table 4.8.[34] For the Millstone 3 estimate of August 1982, the relevant time to estimated completion was again 3.75 years, so the relevant results are those for <u>t</u> between 3 and 4 years, for which the average cost ratio was 2.29. Stated alternatively, the cost overrun was 129%. The average myopia for those estimates was 25.9%; raised to the 3.75 power, this myopia factor predicts a cost overrun of 137% for the Millstone 3 cost estimate of August 1982. Applying these cost overruns to the estimate of $3080/kw produces an adjusted estimate in the range of $7050/kw to $7300/kw, for a plant cost of over $8 billion.

Q: Have you performed a similar analysis for Millstone 3's cost history?

A: Yes. Table 4.9 derives the annual percentage rate of increase in the Millstone 3 cost estimate from various starting points to the 8/82 estimate. The annual rate of escalation of NU's estimate has stabilized appreciably since the large cost increase which accompanied the delay of Millstone 3 to 1986. The more recent time periods display average cost trends of around 15%, while the average annual percentage increase in the Millstone 3 cost estimate from 1/75 to 7/78 was 30%.

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34. The averages listed in Appendix B include the turnkey and demonstration reactors.

DATE OF ESTIMATE	Jul-71	Mar-73	Jan-75	Jan-76	Mar-77	Jul-78	Jul-80	Aug-82
YEARS SINCE LAST ESTIMATE	---	1.7	1.8	1.0	1.2	1.3	2.0	2.1
YEARS TO 8/82	11.1	9.4	7.6	6.6	5.4	4.1	2.1	---
ESTIMATED COST ($M)	400	650	807	1010	1185	2000	2600	3540
INCREASE SINCE LAST EST. (%)	---	62.5%	24.2%	25.2%	17.3%	68.8%	30.0%	36.2%
INCREASE SINCE LAST EST. (ANNUALIZED)	---	33.8%	12.5%	25.2%	14.7%	48.0%	14.0%	16.0%
INCREASE TO 8/82 (%)	785.0%	444.6%	338.7%	250.5%	198.7%	77.0%	36.2%	---
INCREASE TO 8/82 (ANNUAL)	21.7%	19.7%	21.5%	21.0%	22.4%	15.0%	16.0%	---
FINAL COST IF TREND CONTINUES TO 5/86	7399	6949	7353	7231	7547	5978	6168	---

ble 4-9: Growth Rates in NU Cost Estimates for Millstone 3

tes: Line 8 equals line 4 multiplied by (1+line 8)^(Years between 5/86 and line 1).

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 Millstone 3 enters service. For NU's COD estimate of 5/86, 3.75 years of escalation must be added: at 15% annually, this would increase the final cost by about 69%, to around $6 billion. Using the best estimate of the COD derived above (11/87), we must add 1.5 more years of cost estimate revisions, or an additional 23%. This translates to a plant cost estimate of $7.4 billion (or $6415/kw) when the unit goes commercial.

Q: Is there any reason to believe that the current NU cost estimate is any more reliable than NU's previous cost estimates, or than utility cost estimates in general?

A: Unfortunately, the formal treatment of contingency is still quite minimal: only about a 3% contingency is provided, despite a historical record which indicates that estimates four years into the future should include a contingency on the order of 100%. Nonetheless, there is some cause for hope that the estimate may be a little more conservative than usual. The reasons for optimism include:

- NU claims to use a "no exclusions" approach to cost estimating, which is said to increase the latest estimate by $100 million compared to standard practice,

- NU further asserts that S&W "utilized a more detailed analytical technique when developing the allowance for indeterminates", which increased the estimate $130 million, and

- the inflation rate of 10% is almost certain to be excessive, and may result in the estimate being overstated (compared to normal utility practice) by as much as $150 million.[35]

Since NU indicates that the first item would have been covered by contingency in normal practice, and since contingency has indeed been decreased by $125 million since the previous estimate, this probably does not represent any unusual conservatism on the part of NU, but I will include it to establish a highly optimistic cost trend. With these adjustments, the standard-practice version of the 8/82 estimate would be $3160 million. That would represent a 21.5% increase over the previous estimate, or 9.8% annually. If costs continue to increase at this rate to 5/86, Millstone 3 would come in at about $4.5 billion. Continuing this rate of increase to 11/87 would result in a final cost of $5.2 billion.

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35. This effect is estimated at two years (half the remaining construction period) of inflation at a 5% differential (the 10% assumed, minus perhaps 5% actual), times the $1.5 billion in direct costs remaining to be spent.

Q: What Millstone 3 construction cost estimates do you find most reasonable?

A: Table 4.10 displays the results of the various methodologies I used. The estimates range from about $3900 to $7300/kw, for a total plant cost of about $4.5 to $8.4 billion. If we could correct for past errors in inflation projections, the top end of the range would probably be more like $6.5 billion. I will use $5.5 billion (or $4800/kw) as a mid-range value in my subsequent analysis. Perhaps NU can actually bring the unit in near $4 billion, in which case it will certainly be considered one of the more successful nuclear-constructing utilities,[36] but I strongly doubt that the cost can be held below $4.5 billion, which I will use as a low-end projection.

Q: How do these total cost figures compare to the cost of completing Millstone 3?

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. NU estimates that the total sunk investment in Millstone 3 by the middle of 1984 will be $2.72 billion, or $2363/kw.

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36. At least in terms of constraining cost overruns in the last four years of construction.

Method	Variant	$/kw	Total Cos
			($ billion,
Real Myopia	NU COD	$5,240	$6.0
	11/87 COD	$5,800	$6.7
			~~$0.0~~
Nominal Myopia		$6,283	$7.2
			~~$0.0~~
Nominal Cost Ratio		$6,345	$7.3
			~~$0.0~~
Millstone History	standard: NU COD	$5,202	$6.0
	standard: 11/87 COD	$6,415	$7.4
	optimistic: NU COD	$3,900	$4.5
	optimistic: 11/87 COD	$4,489	$5.2

Table 4.10: Millstone 3 Cost Estimate Summary

4.3 - CAPACITY FACTOR

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

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

$$CF = \text{Output}/(RC \times \text{hours})$$

where CF = capacity factor, and

RC = rated capacity.

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

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

The difference between capacity factor and availability factor is illustrated in Figure 4.2. 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 Millstone 3 power costs?

A: The three most common measures of capacity are

Maximum Dependable Capacity (MDC);

Design Electric Rating (DER); and

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

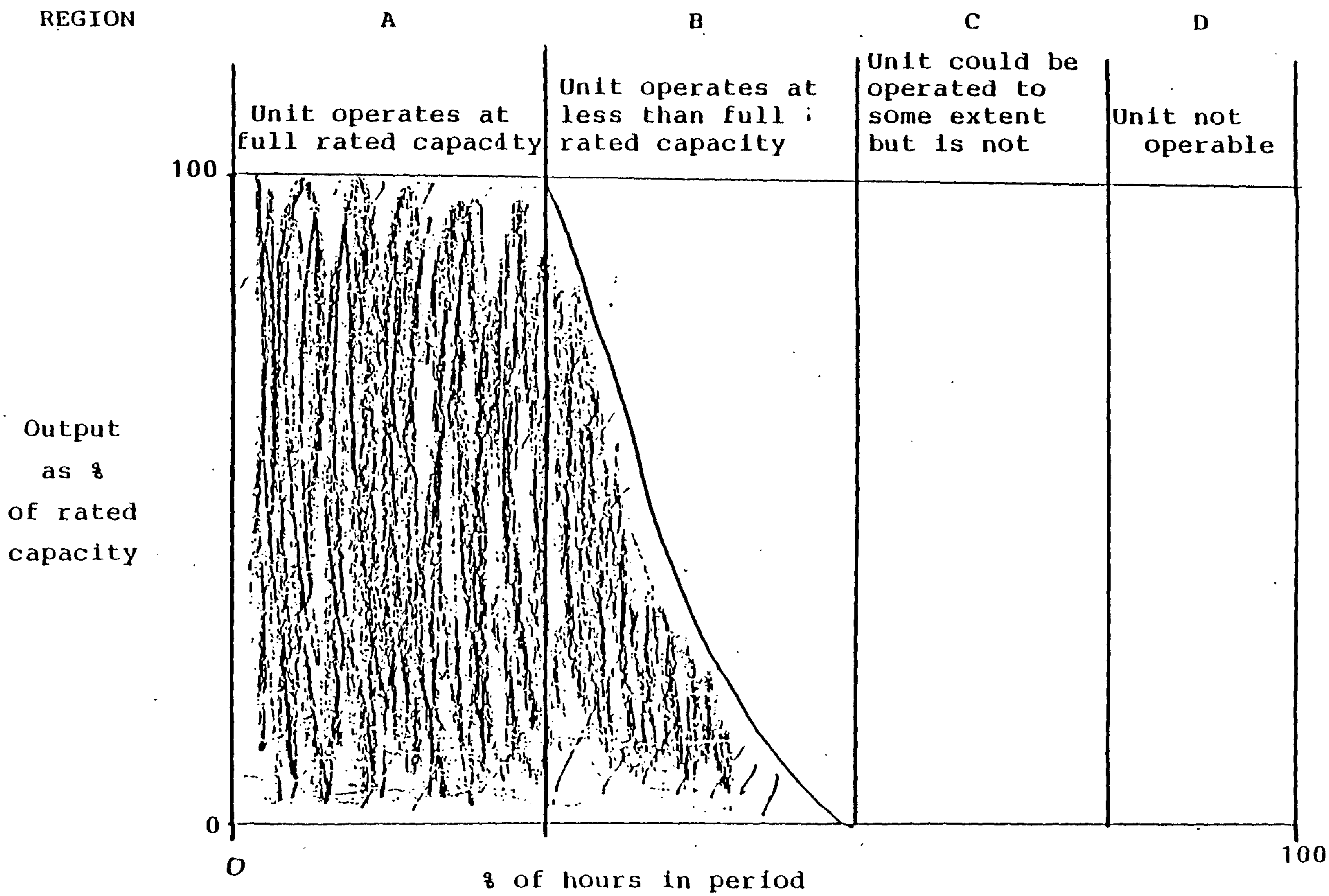

Figure 4.2: Diagrammatic Description of Availability Factor and Capacity Factor

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 Millstone 3 power cost would present no problem if the MDC's for Millstone 3 were known for each year of its life. Unfortunately, these capacities will not be known until Millstone 3 actually operates and its various problems and limitations appear. All that is known now are initial estimates of the DER and IGN, which I take to be 1150 MW and 1194 MW,[37] 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

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37. I do not have a value of IGN for Millstone 3, so I have used that for Seabrook, also an 1150 MW Westinghouse reactor.

ratings, which would seem to be the capacity measure most consistent with the 1150 MW expectation for Millstone 3. This problem can also be avoided through the use of the MGN ratings.

Q: Are NU's projections of Millstone 3 capacity factors reasonable?

A: No, they are significantly overstated. NU ignores all previous analyses of reactor performance, and instead bases its projections on its own erroneous and fanciful manipulation of historical data. After discussing the available information on nuclear capacity factors, and presenting consisstent projections for Millstone 3, I will describe NU's errors in detail.

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 4.11 shows the results of the equations which can be evaluated for Millstone 3. 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

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
Values 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

Table 4.11: Capacity Factor Equations and Projections from Easterling (1981)

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

very small units.[38] The equation predicts capacity factors for a unit like Millstone 3 of 53% in the first year, rising to 63% in year 5. The NERA study itself uses a 59% overall 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

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38. 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.

of SCRAM mechanisms at Salem. Assuming that the future is like the average of NERA's data,[39] the levelized projection would be some 5.8 percentage points lower, or about 54.2%.

Therefore, average life-time capacity-factor estimates for units like Millstone 3 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 Millstone 3 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.[40]

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

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

40. 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.

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).

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

A: No. Table 4.12 displays the difference between NU's projections and Easterling's results. The capacity factors assumed by NU (and indeed by most New England utilities) are much too high. This should not be very surprising: NU'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 NU's projections, I have performed the calculations presented in Tables 4.12 and 4.13. 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 NU would predict an average of 66%. Clearly, NU's expectations are out of line with reality. While the performance of these six units slightly exceeds Easterling's projections, it is not clear

Predicted Capacity Factors	year: 1 (3)	2	3	4	5	6	7+
Easterling (1)	47.2%	47.2%	47.2%	49.6%	52.0%	54.3%	54.3%
NU (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

Table 4.12: Comparison of Capacity Factor Predictions

Notes:
1. See text.
2. From NU's response to Data Request FCAC 2-10(a), DPU 1300.
3. First partial year.

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 average of about 55%.

Q: Does NU offer any support for its capacity factor projections?

A: Yes. NU's attempt to justify the use of its very high capacity factor projections is found in an NU memo (Calderone, 1982). The memo uses data through 1981 for the same six units used in my Table 4.13, but reaches very different conclusions. These differences result from four fairly simple errors in NU's analysis:

1. MDC capacity factors are used instead of DER factors;

2. capacity factors for previous years are not even calculated with the 1981 MDC capacity factors, but with the varying (and sometimes much lower) MDC reported in individual years;

3. NU arbitrarily eliminates data from especially poor performance unit-years; and

4. NU arbitrarily "adjusts" the capacity factors by removing certain outages.

The second point is especially troublesome, since NU does not specify that the capacity ratings reported in the study were not actually used for several of the calculations.

Q: Are the outages which Calderone removes from his adjusted data truly irrelevant in projecting capacity factors for Millstone 3?

A: No, not for the most part. The types of outages which Calderone considers to be "extraordinary" include inspection and repair of safety-related equipment, regulatory re-evaluation of design, and mechanical failure of a turbine blade. I see no reason to believe that Millstone 3 will be luckier than the average plant in avoiding safety-related regulatory reviews of equipment or design, or that the NRC will run out of safety issues in the foreseeable future, or that Millstone 3 will not experience an average amount of equipment failure. Therefore, none of these outages should have been removed from the dataset. The only "extraordinary" outage identified by Calderone which would truly be unlikely at Millstone 3 is the 1000 hour outage at Trojan in 1979[41] attributed to "Excess Hydro Available". This report is somewhat suspect, for two reasons. First, that outage started with a 608 hour outage for "Maintenance,

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41. A trivial power reduction for the same reason is reported in 1980.

surveillance, and containment leak rate testing", and it is not at all clear that Trojan, a notoriously unreliable unit, was really ready to go back on line after 608 hours. Second, in order for economic dispatch considerations to require the backing down of a nuclear unit in the Northwest, hydro output would have to be great enough to serve all regional loads and to fully load the transmission lines south to oil-dependent California and east to the coal-burning mountain states. While it is conceivable for this condition to occur for well over a month, it seems unlikely enough to require better documentation than the utility's assertion that its plant was ready to go back on line.

Q: Assuming hypothetically that some of these outages were truly atypical and should have been removed from the dataset, was the adjustment for them computed properly?

A: No. Calderone assumed that, if the unit had not been out of service for the "extraordinary" outage, it would have operated at 100% of rated capacity for the entire period. This is a simply fantastic assumption, and greatly overstates the effect of his adjustments. For example, in 1978 Trojan operated at a 42.6% capacity factor for 3623 hours which Calderone considers ordinary, and was out of service for 5137 allegedly "extraordinary" hours, for an overall capacity factor of 17.6%. Calderone's adjusted capacity factor is not the 42.6% of the ordinary hours; rather it is the weighted average of the ordinary experience and the preposterous projection of 5137 continuous hours at full power, or 76.2% overall. Not only does Calderone throw away data he does not like, but he freely substitutes data which he prefers.

Q: Have you corrected Calderone's analysis?

A: Yes. Table 4.14 repeats the calculations in Calderone, for actual DER data,[42] and extended through September of 1983. The analysis is performed both for Calderone's data set, and with the addition of the four large PWR's which entered commercial operation in 1981. I accept Calderone's conclusion 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 Millstone 3: Calderone's attitude that "it can't happen here" is entirely unjustified.[43] 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

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42. Original DER ratings are used throughout this section of my analysis.

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

NIT	DER NET (3)	first year	CAPACITY FACTOR BY CALENDAR YEAR (2) 1	2	3	4	5	6	7	8	9	10
ION 1	1050	74	37.8%	53.4%	51.6%	54.7%	73.6%	60.2%	70.6%	67.3%	51.0%	58.6%
ION 2	1050	75	52.5%	50.3%	68.2%	73.2%	51.8%	57.2%	57.2%	56.1%	58.4%	
OOK 1	1090	76	71.1%	50.1%	65.8%	59.3%	67.5%	71.0%	56.1%	63.0%		
ROJAN	1130	77	65.6%	16.8%	53.2%	61.2%	64.9%	48.5%	23.8%			
ALEM 1	1090	78	47.4%	21.4%	59.4%	64.8%	42.9%	42.9%				
OOK 2	1100	79	61.8%	69.3%	66.3%	72.6%	79.7%					
EQUOYAH 1	1148	82	48.8%	78.2%								
ALEM 2	1115	82	81.3%	8.1%								
CGUIRE 1	1180	82	41.6%	35.6%								
EQUOYAH 2	1148	82	50.8%	52.2%								
VERAGES ALL NITS (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%								

able 4.14: Historical Capacity Factors (DER)
Unadjusted Data
Nuclear Units Similar in Characteristic to Millstone 3

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

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 4.15. Depending on the dataset used, the average capacity factor which results from this analysis is 55.8% to 57.4%; the mature capacity factor is actually lower, in the 55.1% to 55.8% range. Thus, using a capacity factor definition which is consistent and meaningful for Millstone 3, and using all the data, Calderone's approach supports capacity factor projections much closer to Easterling's results than to NU's assumptions.

CAPACITY FACTOR
BY CALENDAR YEAR

	1	2	3	4	5	6	7	8	9	10
Average from all plants [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 from first six units [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%									

Table 4.15: Adjustment of 1000-MW PWR Capacity Factors for Deviations at Salem 1 and Trojan

Notes:
[1] From Table 4.14.
[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.

4.4 - CARRYING CHARGES

Q: What annual carrrying charge should be applied to the cost of Millstone 3?

A: For the levelized cost analysis, I have assumed a 10% real cost of capital (including income taxes) 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.[44] I also use a 1% levelized property tax rate, based on NU's prediction of an initial rate of about 0.7% escalating at about 4% in real terms.[45] 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.

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44. 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.

45. This calculation neglects property taxes on capitalized additions to the plant.

For the nominal dollar analysis presented in Section 3, I have adopted and extrapolated NU's carrying charge figures.

Q: What other costs must be added to the Millstone 3 carrying costs to determine the total cost of Millstone 3 power?

A: The other components of the costs of Millstone 3 which are directly assignable to that plant are:

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

4.5 - FUEL COST

Q: What nuclear fuel costs have you used?

A: I used NU's estimates of 1.4 cents/kWh for Millstone 3 fuel in 1986, rising to 3.3 cents in 2005. These figures are listed in Table 3.1. I have projected nuclear fuel costs out to 2025 at the compound growth rate of NU's projections for 1995 - 2005, which is 5.1%. Deflating these costs at NU's projection of the GNP deflator and levelizing the constant-dollar results yields 1.1 cents/kWh in 1984 dollars.

4.6 - NON-FUEL O & M

Q: Is NU's estimate of Millstone 3 non-fuel O & M expense reasonable?

A: No. NU bases its O & M cost forecast on recent O & M costs for Millstone 2, but assumes that nuclear O & M increases only at about the inflation rate, despite very rapid historical growth rates in nuclear O & M. Table 4.16 reports the annual O & M for the Millstone, Pilgrim and Yankee units since their first full year of operation.[46] 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 4.16 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 4.17 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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46. 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.

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 4.16: New England Nuclear O&M Histories

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%
Average		$36,532	$2,858.8	13.5%
1983$[1]		$39,739		

Table 4.17: Calculation of Average New England Experience, Non-Fuel Nuclear O & M Expense, Constant Dollars

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

(in 1983 dollars) and of annual geometric growth rates,[47] and the six-unit average of each parameter. Each unit is analyzed from its first full year of service through 1982.

Table 4.18 extrapolates the linear and geometric average trends and displays the 1987 nominal O & M cost and the levelized O & M cost (in 1984$) for Millstone 3 over a 25 year life. Protracted geometric growth in real O & M cost would probably lead to retirement of the unit around the turn of the century, as it would then be prohibitively expensive to operate (unless the alternatives were 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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47. 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.

Method / Year	Linear 1983 $	Linear Current $	Geometric 1983 $	Geometric Current $
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	$72,232	$131,270	$277,767	$583,087
1987-2022	$74,862	$145,761	$429,940	$1,089,408

Table 4.18: Annual Non-Fuel O & M Expense ($1000) for Millstone 3, Extrapolated from New England Experience

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 Millstone 3 operation. Various recent estimates of major accident probabilities range from 1/200 to 1/1000 per reactor year (See Chernick, et al., 1981; 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.

4.7 - CAPITAL ADDITIONS

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

A: NU's estimate of annual capital additions (or interim replacements) in the early years of the plant's life is $8.70/kW-year, in 1982 dollars. NU's initial estimate appears to be of the proper order-of-magnitude, if a little low.

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 Millstone 3 in 1983 dollars.

4.8 - INSURANCE

Q: What value have you used for the cost of insuring Millstone 3?

A: I have assumed that NU obtains the following insurance for:

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 NU to additional costs, which may be greater (on the average) than the insurance premium. Indeed, even with all the insurance listed, NU would still not be fully covered in the event of the total and permanent loss of Millstone 3.

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

4.9 - DECOMMISSIONING

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

4.10 - TOTAL MILLSTONE 3 GENERATION COST

Q: What is your estimate of the cost of power from Millstone 3?

A: I estimate that the total cost of power will be about 12 or 13 cents/kWh, levelized in 1984 dollars. Excluding sunk costs as of mid-1984, the remaining cost is still close to 7 cents/kWh. These figures are derived in Table 4.19.

Q: What does this analysis tell us about the economic viability of Millstone 3?

A: It is clear that Millstone 3 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 Millstone 3. It is also very likely that the cost of completing and running Millstone 3, ignoring the sunk costs, will be higher than the most economical supply plan available at this point. Thus, cancelation of Millstone 3 is probably in the best interests of WMECo ratepayers and those of New England as a whole,[48] unless the utility shareholders are to absorb both all sunk costs to date and a sizable fraction of future costs. This option may be foreclosed for NU beyond a certain point, since

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

Cost Basis	Entire Cost	Remaining Costs
Cost per kw		
Construction Costs	$3,815	$1,452
Fixed Charge Rate	12.0%	12.0%
Cost per kw-yr		
Annual Capital Costs	$458	$174
Non-fuel O&M	$66	$66
Capital Additions	$18	$18
Insurance	$10	$10
Decommissioning	$9	$9
Total Non-fuel	$561	$277
Capacity Factor	54%	54%
Cost per kwh (cents)		
Non-fuel	11.9	5.9
Fuel	1.2	1.2
Total	13.0	7.0

Table 4.19: Total Power for Millstone

Notes: All costs are levelized in real 1984 dollars. Assumes Cost of $ 5.5 billion, COD of Nov-88 .

its shareholders' equity is not very much larger than the tax-effected cost of writing off its current investment in the plant.

5 - CONCLUSIONS

Q: What do you conclude from your examination of the need for, and economics of, Millstone 3?

A: I conclude that Millstone 3 will, on the whole, represent a net loss to WMECo's ratepayers if the entire cost of the plant is recovered under normal ratemaking treatment. Even the cost of completing and operating the unit is likely to be greater than its benefits. Under traditional ratemaking, customers in the late 1980's and most (perhaps all) of the 1990's would be heavily taxed to reduce the cost of power in the next century.

Q: What implications do your observations have for ratemaking?

A: There are four major implications. First, even under traditional ratemaking, without an early phase-in, the lag between the costs and benefits of Millstone 3 is excessive; the early phase-in would exacerbate this problem, and should not be allowed unless it is absolutely necessary for some reason (such as the inability of the utility to raise capital) of which I am not aware. Second, because the benefits and costs under traditional ratemaking would be so out of line, and would tend to fall on very different groups of ratepayers, the cost of the plant should be recovered in a manner which more closely follows the benefits. Mr. Meyer will discuss some of the options for such cost recovery. Third, given the poor economics of the project, there are likely to be considerable prudence questions when the unit comes on line; WMECo should be put on notice that it will not recover more than the plant's fuel savings until those questions are resolved. Fourth, NU's decisions regarding the continued construction of Millstone 3 are likely to be influenced by its expectations concerning its ratemaking treatment. In particular, the sooner NU knows that its current plan to recover the vast majority of the plant's cost before the extent of its benefits is determined, will not be allowed, the sooner NU may publicly adopt realistic estimates of the plant's costs and performance, and make more intelligent decisions about its future.

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 reject WMECo's CWIP proposal, to indicate a desire to phase Millstone 3 into rates <u>after</u> it enters service, to indicate that such phase-in will (at least roughly) follow the pattern of savings from the plant, and to initiate proceedings on the prudence of WMECo's Millstone 3 decisions to date (and as they evolve in the future) and on the detailed ratemaking treatment of the unit. I would further recommend that the Commission warn WMECo that West Springfield should not be retired (or allowed to run down for lack of maintenance) without explicit Commission approval, and that retirement of West Springfield without such approval could result in WMECo's rates being set as if West Springfield were still in service and converted to coal. Finally, I believe that WMECo such be instructed to attempt the sale of all (or failing in that, part) of its Millstone 3 share at less than its booked cost.

Q: Does this conclude your testimony?

A: Yes.

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Appendix B:

Myopia Data

Unit Name	...Actuals... Cost	COD	Estimat Year	Qr	Estimated Cost	COD	Years to COD	Cost Ratio	Myopia (%)	Duration Ratio
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
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	162	69 12	64	1	68	68 11	4.67	2.39	20.5%	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	100	73 3	66	3	77	71 3	4.50	1.30	6.0%	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	71	72 10	67	1	54	71 4	4.08	1.32	7.1%	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 =	40	49	49		46	49	49	37	37	49
Average	497	77 3	69	2	225	73 11	4.41	2.47	21.6%	1.774
Dresden 3	104	71 11	66	1		70 2	3.92			1.447

Unit Name	...Actuals... Cost	COD	Estimat Year	Qr	Estimated Cost	COD	Years to COD	Cost Ratio	Myopia (%)	Duration Ratio
Monticello	105	71 6	66	2		70 5	3.92			1.277
Robinson 2	78	71 3	66	2	76	70 5	3.92	1.02	0.6%	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	162	69 12	64	3	68	68 7	3.83	2.39	25.5%	1.370
Point Beach 1	74	70 12	66	2	61	70 4	3.83	1.21	5.2%	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	100	73 2	66	2	90	70 3	3.75	1.11	2.9%	1.778
Fort Calhoun 1	176	73 9	67	3	70	71 5	3.67	2.51	28.5%	1.636
Millstone 1	97	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	74	70 12	66	3	61	70 4	3.58	1.21	5.5%	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	83	70 7	65	4	64	69 6	3.50	1.30	7.8%	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	100	73 3	67	3	82	71 3	3.50	1.22	5.9%	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	90	69 12	64	2	59	67 10	3.33	1.52	13.5%	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	83	70 7	66	1	65	69 6	3.25	1.28	7.9%	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

Unit Name	...Actuals... Cost	COD		Estimat Year	Qr	Estimated Cost	COD		Years to COD	Cost Ratio	Myopia (%)	Duration Ratio
Lasalle 1	1367	82	10	75	3	498	78	12	3.25	2.74	36.4%	2.179
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	2		76	8	3.17			2.842
Sequoyah 2		82	6	73	4		77	2	3.17			2.684
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	206	73	8	66	2	106	69	6	3.00	1.94	24.8%	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	74	3		77	9	3.00			2.583
Sequoyah 2		82	6	72	4		75	12	3.00			3.167
St. Lucie 1	486	76	6	71	2	203	74	6	3.00	2.40	33.8%	1.667
For 3<=t<4, N =	66	86		86		71	86		86	63	63	86
Average	409	77	4	70	2	216	73	11	3.39	2.15	23.3%	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	83	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

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	3	310	74	6	2.75	2.52	40.0%	2.455
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	72	4	227	75	7	2.58	2.39	40.1%	3.097
North Anna 2	542	80	12	73	1	227	75	10	2.58	2.39	40.1%	3.000
Quad Cities 2	100	73	3	69	2	82	72	1	2.58	1.22	8.0%	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	100	73	2	67	3	88	70	3	2.50	1.14	5.3%	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	4	449	76	6	2.50			3.033
Sequoyah 1		81	7	73	2	449	75	12	2.50			3.233
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	72	4	349	75	5	2.42	1.93	31.2%	2.034
Davis-Besse 1	672	77	11	73	3	409	76	2	2.42	1.64	22.8%	1.724
Millstone 1	97	71	3	67	1	81	69	8	2.42	1.20	7.7%	1.655
Nine Mile Point	162	69	12	66	2	88	68	11	2.42	1.84	28.8%	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

Unit Name	...Actuals... Cost	COD	Estimat Year	Qr	Estimated Cost	Estimated COD	Years to COD	Cost Ratio	Myopia (%)	Duration Ratio
Beaver Valley 1	599	76 10	72	2	311	74 10	2.33	1.93	32.4%	1.857
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	72	3	204	75 1	2.33	1.64	23.7%	1.964
Calvert Cliffs 2	335	77 4	74	3	256	77 1	2.33	1.31	12.3%	1.107
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	76	4	572	79 4	2.33	1.31	12.3%	1.964
Farley 2	750	81 7	77	4	662	80 4	2.33	1.13	5.5%	1.536
Farley 2	750	81 7	74	3	363	77 1	2.33	2.07	36.5%	2.929
Humboldt	24	63 8	60	2	3	62 10	2.33	8.16	145.8%	1.357
Quad Cities 2	100	73 3	68	4	82	71 4	2.33	1.22	8.9%	1.821
Salem 1		77 6	70	4	474	73 4	2.33			2.786
Sequoyah 1		81 7	72	4	449	75 4	2.33			3.679
Sequoyah 1		81 7	74	3	625	77 1	2.33			2.929
Arkansas 2	640	80 3	75	4	393	78 3	2.25	1.63	24.2%	1.889
Arkansas 2	640	80 3	75	1	339	77 6	2.25	1.89	32.6%	2.222
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	74	3	1356	76 12	2.25			1.222
Salem 1		77 6	72	4	850	75 3	2.25			2.000
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	90	69 12	65	3	59	67 11	2.17	1.52	21.4%	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	100	73 3	70	1	96	72 5	2.17	1.04	1.9%	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

Unit Name	...Actuals... Cost	COD	Estimat Year Qr	Estimated Cost	COD	Years to COD	Cost Ratio	Myopia (%)	Duration Ratio
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
Farley 2	750	81 7	78 1	635	80 4	2.08	1.18	8.3%	1.600
Farley 2	750	81 7	77 1	689	79 4	2.08	1.09	4.2%	2.080
Humboldt	24	63 8	60 3	3	62 10	2.08	8.16	173.9%	1.400
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 2	184	72 7	2.08	2.18	45.3%	2.040
Three Mile I.	401	74 9	70 3	197	72 10	2.08	2.04	40.6%	1.920
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 2	123	72 6	2.00	1.65	28.6%	2.000
Kewaunee	203	74 6	70 3	123	72 9	2.00	1.65	28.6%	1.875
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	71 1	277	73 3	2.00	1.92	38.4%	1.667
Peach Bottom 2	531	74 7	70 4	230	72 12	2.00	2.31	51.9%	1.792
Point Beach 2	71	72 10	69 4	54	71 12	2.00	1.32	15.0%	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 =	121	152	152	146	152	152	120	120	152
Average	500	77 5	72 1	318	74 9	2.38	1.97	31.0%	2.128
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	69 2	92	71 5	1.92	1.91	40.2%	2.217
Fort Calhoun 1	176	73 9	70 4	125	72 11	1.92	1.41	19.5%	1.435
McGuire 1	921	81 12	76 2	384	78 5	1.92	2.40	57.9%	2.870
Millstone 1	97	71 3	67 3	84	69 8	1.92	1.15	7.7%	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	71	72 10	69 3	54	71 8	1.92	1.32	15.7%	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
Humboldt	24	63 8	60 4	4	62 10	1.83	6.12	168.6%	1.455
McGuire 1	921	81 12	77 3	466	79 7	1.83	1.98	45.0%	2.318
McGuire 1	921	81 12	77 1	466	79 1	1.83	1.98	45.0%	2.591
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	100	73 2	68 4	88	70 10	1.83	1.14	7.3%	2.273

Unit Name	...Actuals... Cost	COD	Estimat Year	Qr	Estimated Cost	COD	Years to COD	Cost Ratio	Myopia (%)	Duration Ratio
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
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	90	69 12	66	1	59	67 12	1.75	1.52	27.2%	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	104	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	83	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
Humboldt	24	63 8	61	1	6	62 10	1.58	4.08	143.0%	1.526
Indian Point 1	126	62 9	60	2	68	62 1	1.58	1.86	47.8%	1.421
Indian Point 2	206	73 8	68	3	106	70 4	1.58	1.94	52.2%	3.105
Millstone 2	426	75 12	72	3	282	74 4	1.58	1.51	29.8%	2.053
Quad Cities 1	100	73 2	69	2	88	71 1	1.58	1.14	8.5%	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

Unit Name	...Actuals... Cost	COD	Estimat Year Qr	Estimated Cost	COD	Years to COD	Cost Ratio	Myopia (%)	Duration Ratio
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	104	71 11	69 2	81	70 12	1.50	1.28	18.0%	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
North Anna 2	542	80 12	77 3	426	79 3	1.50	1.27	17.4%	2.167
Oyster Creek 1	90	69 12	66 2	67	67 12	1.50	1.34	21.6%	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	104	71 11	69 1	81	70 8	1.42	1.28	19.1%	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	206	73 8	69 4	106	71 5	1.42	1.94	59.9%	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	74	70 12	69 1	61	70 8	1.42	1.21	14.6%	1.235
Point Beach 2	71	72 10	70 1	54	71 8	1.42	1.32	21.8%	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	73 2	427	74 10	1.33	1.28	20.0%	1.625
Cook 1	545	75 8	72 2	416	73 10	1.33	1.31	22.4%	2.375
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
Humboldt	24	63 8	61 2	8	62 10	1.33	3.06	131.3%	1.625
Indian Point 1	126	62 9	60 3	77	62 1	1.33	1.64	44.9%	1.500
Indian Point 2	206	73 8	69 2	106	70 10	1.33	1.94	64.6%	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	90	69 12	66 3	67	68 1	1.33	1.34	24.7%	2.438
Quad Cities 1	100	73 2	70 1	102	71 7	1.33	0.98	-1.4%	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 1	281	76 6	1.25	1.13	10.5%	1.600
Brunswick 1	318	77 3	75 4	329	77 3	1.25	0.97	-2.6%	1.000
Brunswick 1	318	77 3	74 4	281	76 3	1.25	1.13	10.5%	1.800

Unit Name	...Actuals... Cost	COD		Estimat Year	Qr	Estimated Cost	COD		Years to COD	Cost Ratio	Myopia (%)	Duration Ratio
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	2	461	76	9	1.25	1.46	35.3%	1.933
Davis-Besse 1	672	77	11	75	4	533	77	3	1.25	1.26	20.4%	1.533
Dresden 3	104	71	11	70	1	95	71	6	1.25	1.09	7.3%	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
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
Humboldt	24	63	8	61	3	10	62	11	1.17	2.45	115.3%	1.643
Indian Point 2	206	73	8	69	1	106	70	5	1.17	1.94	76.8%	3.786
McGuire 1	921	81	12	78	4	549	80	2	1.17	1.68	55.8%	2.571
Monticello	105	71	6	69	1	74	70	5	1.17	1.42	35.0%	1.929
Quad Cities 2	100	73	3	71	1	99	72	5	1.17	1.01	0.9%	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	83	70	7	68	4		70	1	1.08			1.462
Ginna	83	70	7	68	3	65	69	10	1.08	1.28	25.6%	1.692
Indian Point 1	126	62	9	60	4	89	62	1	1.08	1.42	38.1%	1.615
Indian Point 1	126	62	9	61	1	93	62	4	1.08	1.36	32.6%	1.385
Millstone 1	97	71	3	69	3	92	70	10	1.08	1.05	4.8%	1.385
Millstone 1	97	71	3	68	4	90	70	1	1.08	1.08	7.0%	2.077
Nine Mile Point	162	69	12	67	4	134	69	1	1.08	1.21	19.3%	1.846
North Anna 1	782	78	6	76	1	567	77	4	1.08	1.38	34.5%	2.077
Oyster Creek 1	90	69	12	67	1	67	68	4	1.08	1.34	31.2%	2.538
Pilgrim 1	239	72	12	71	1		72	4	1.08			1.615
Quad Cities 1	100	73	2	70	2	108	71	7	1.08	0.93	-6.8%	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	2	419	75	6	1.00	1.43	42.9%	2.333
Beaver Valley 1	599	76	10	74	4	451	75	12	1.00	1.33	32.8%	1.833
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

Unit Name	...Actuals... Cost	COD		Estimat Year	Qr	Estimated Cost	COD		Years to COD	Cost Ratio	Myopia (%)	Duration Ratio
Indian Point 2	206	73	8	70	4	106	71	12	1.00	1.94	94.4%	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	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
Lasalle 1	1367	82	10	79	1	808	80	3	1.00	1.69	69.2%	3.583
Millstone 1	97	71	3	69	1	90	70	3	1.00	1.08	7.6%	2.000
Nine Mile Point	162	69	12	68	4	134	69	12	1.00	1.21	21.1%	1.000
Nine Mile Point	162	69	12	68	2	134	69	6	1.00	1.21	21.1%	1.500
North Anna 2	542	80	12	78	1	467	79	3	1.00	1.16	16.1%	2.750
Peach Bottom 3	223	74	12	73	4	284	74	12	1.00	0.79	-21.4%	1.000
Point Beach 1	74	70	12	69	4	61	70	12	1.00	1.21	21.2%	1.000
Point Beach 2	71	72	10	70	3	54	71	9	1.00	1.32	32.2%	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 =	178	199		199		188	199		199	171	171	199
Average	413	75	8	72	3	359	74	3	1.42	1.43	27.1%	1.964

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	[illegible]	11714	17150	[illegible]
Calvert Cliffs 1&2	79	1828	780095	2384	3183	1.74
Calvert Cliffs 1&2	80	1828	790988	10893	[illegible]	[illegible]

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	41395	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	383746			
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	3840	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	583	NA			
Fitzpatrick	81	983	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	657376			
Hatch	80	1701	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	25787	2655	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	36.45
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	78[illegible]737			
North Anna	79	979	783664	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	8305	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	896641	47658	63637	54.42
Salem	80	1170	938748	40107.47	49480	42.29

papers relating to the computation of such charges at least twenty-one (21) days before the commencement of a hearing which sets the energy and capacity rates.

Standard charges must be proposed for inspections, meters, and common or standard interconnection costs. In addition, the utility shall propose an incremental cost of capital, including tax effects, to be used in calculating carrying charges for non-standard interconnection items.

IV. Rates for Sales to Qualifying Facilities

All qualifying facilities will be supplied with supplementary power under existing general rate schedules. Qualifying facilities desiring interruptible, back-up or maintenance power service will be covered under existing general rate schedules where in place; otherwise, qualifying facilities should negotiate such rates with the utility and may petition the Department for a rate setting hearing under these three types of service until such time as the Department sets standard rates.

Charges for sales to a qualifying facility will no be greater than those for sales to other customers with load charactoristics on the utility similar to the load of the sales to the QF.

CERTIFICATE OF SERVICE

I hereby certify that today I have served copies of the Comments of the Attorney General in D.P.U. 535 on all parties.

Robert L. Dewees, Jr.
Robert L. Dewees, Jr.
Assistant Attorney General
Utilities Division
Public Protection Bureau
727-1085

Dated: February 13, 1981

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	185	55285	3093	3816	20.63
Yankee-Rowe	81	185	1768			
Yankee-Rowe	82	185				
Zion 1	73	1098	275989			
Zion 1&2	74	2196	565819			
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	

#310 8/10/84

Additional Testimony of Paul Chernick

Q: Are you the same Paul Chernick who filed direct testimony in this case?

A: Yes.

Q: What is the purpose of this additional testimony?

A: Its purpose is to clarify my position in this case. It is necessitated by certain portions of the rebuttal testimony of Mr. Gmeiner and especially Mr. Staszesky. That testimony goes beyond answering the points raised in my original testimony, and does contain mischaracterizations of my analyses, misstatements of fact, and attacks on my motivations and behavior in this case and previous cases. I have limited myself to issues which are particularly relevant to this proceeding.

Q: How do the Montaup witnesses misrepresent your testimony?

A: The most serious examples are in the areas of

- the nature and purpose of my analysis of historical cost overruns and inservice date delays, i.e., the myopia analysis,

- the foreseeability of specific events and of the general trend in nuclear cost estimates,
- the inevitability of the cancelation of Pilgrim 2,
- the significance of intervenor testimony in various regulatory proceedings,
- the significance of the BECo internal studies on the financial strain related to Pilgrim 2, and
- the role of Canadian power in the Pilgrim 2 planning decisions.

Q: How do the Montaup witnesses misrepresent your myopia analysis?

A: In attempting to discredit my approach, Mr. Staszesky (pages 37-38) and Mr. Gmeiner (pages 1-2) both claim that I would advocate the same adjustment to any nuclear cost estimate "without regard" for the quality of the estimate. Neither witness provides any basis for this charge, and Montaup did not request any clarification of my methodology in discovery. My testimony clearly indicates that the myopia corrections are appropriate only "[i]f the nuclear industry's ability to forecast costs had not improved" (page 11), and "if the factors which had caused other nuclear power plant estimates to be incorrect also operated for Pilgrim 2" (page 12). See also pages 25 and 55.

In fact, where I have encountered cost estimates which were not typical of general utility practice, I have made appropriate corrections. [1] Montaup has access to all of these pieces of testimony.[2]

Q: Is it true, as Mr. Gmeiner claims, that you would have increased the 1972 Pilgrim 2 "construction cost estimate three-fold whether Edison had estimated $100 million or $1 billion", and that "if Edison had estimated that it would take only one year to build the plant, Mr. Chernick's method would produce a much lower estimate"?

A: No. Mr. Gmeiner's interpretations are belied by both my direct testimony and by my actual practice in other cases. Specifically, if BECo had suggested that Pilgrim 2 could have

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1. In my New Hampshire and Connecticut Seabrook testimony (identified as NHPUC DE81-312 and CPUC 83-03-01, in Appendix A to my original testimony), I corrected wildly over-optimistic PSNH schedule estimates for Seabrook to be consistent with typical contemporaneous utility practice before performing myopia analyses. In Massachusetts DPU 84-25 and 84-49/50 (see Appendix A to my original for full cites), I compared the official schedule estimates for Millstone 3 and Seabrook to industry averages for units at similar stages of construction, to determine whether the reported schedules were significantly different than standard practice. In MDPU 84-25, I adjusted the current estimate to remove any costs which might represent unusual contingency allowances, before applying a myopia multiplier.

2. At Montaup's request, I made all of my previous testimony available; Montaup has not taken the opportunity to refer to any of it. I assume that Montaup already has all of the relevant testimony.

been built in one year, it would be the sanity of management and not its prudence which would be at issue.

Q: How do Mr. Gmeiner's comparisons of cost estimates bear on your myopia analysis?

A: Mr. Gmeiner makes two interesting points in attempting to demonstrate the adequacy of Montaup's review of Pilgrim 2 costs, but which actually do nothing of the sort. First, he observes (pages 3-4) that the Pilgrim 2 estimates were consistent with, or even somewhat higher than, generic estimates made at the same time, including estimates from the same sources I quoted as warning about the difficulty in controlling nuclear costs. Second, he finds (pages 5-7 and Exhibits MEC-435 and MEC-436) that Pilgrim 2 cost estimates were comparable to those of other plants scheduled for commercial operation in the same time frame. His argument seems to be that Pilgrim 2 cost estimates were thus as good as could be expected at the time (or perhaps even correct, in some sense), and that Montaup had fulfilled its duty to its customers by noting these facts.

This comparison actually shows that the Pilgrim 2 estimates were fairly close to standard utility or A/E nuclear cost estimates, which had already been wrong innumerable times by the mid-1970's. There are of course substantial problems in performing detailed comparisons of raw cost estimates across plants.[3] Mr. Staszesky discusses these comparison problems (page 37, lines 5-19); while his criticism has nothing to do with any of my testimony, it does indicate the limits on Mr. Gmeiner's approach. Even so, Mr. Gmeiner's comparisons indicate that Montaup could and should have suspected that BECo's cost estimates for Pilgrim 2 similar to, the dismal industry standard, and thus of comparable accuracy.

It is important to note that the myopia analysis basically suggests that BECo and Montaup were imprudent in accepting Pilgrim 2 estimates which were based on a consistently flawed methodology. Nothing in their rebuttal provides any evidence that it was prudent to ignore the trends which were evident by the mid-1970's.

Q: How does the witnesses discussion of "bottom-up" cost estimation relate to your myopia analysis?

A: Mr. Gmeiner, at the top of page 3, and Mr. Staszesky (page 36, line 24, through page 37, line 5, and again on page 38, lines 2-6), both support the traditional approach for estimating nuclear costs: design the plant (at some level of

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3. There are some particular problems in Mr. Gmeiner's comparisons. For example, he does not correct for such obvious factors as dual units and CWIP in ratebase, both of which will tend to reduce the cost of other nuclear units relative to Pilgrim 2. In addition, the figure he quotes as a 1976 Baughman and Joskow estimate was actually a 1974 UE&C estimate, which Baughman and Joskow use without review.

detail), count up the quantities involved, estimate the labor requirements associated with the installation, multiply materials and labor quantities by price estimates to project total construction costs, and add in inflation and AFUDC to complete the estimate.[4]

This discussion might leave the Commission with the incorrect impression that I have some fundamental disagreement with the engineering cost estimation approach. In fact, I consider the engineering approach to be the most desirable approach where it works: it appears to work fairly well in fossil-fueled plant construction. For example, Detroit Edison is nearing completion at both the Fermi 2 nuclear unit and the Belle River coal plant. The Fermi schedule and cost estimates have slipped repeatedly, while the Belle River schedule has been quite stable and the cost estimate has declined recently, and in many other areas as well. The bottom-up approach can not be expected to work well for projects whose design is subject to continuous change.[5] Not only is the plant on the drawing board different than the one which will be built (introducing one kind of estimation error), but the process of redesigning the plant in the

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4. Some indirect costs may require slightly different treatment, but the basic bean-counting approach is the same.

5. Mr. Staszesky makes this point in his direct testimony to justify the belated cancelation of Pilgrim 2.

middle of construction also introduces inefficiencies and higher costs. As a result, the basic engineering estimates are simply a snapshot of the cost of building the **currently designed** plant, rather than a best guess of what the final plant will look like and cost.

While nuclear cost estimates have usually included a small contingency,[6] my original testimony demonstrated that by 1972 any utility should have been wary of applying the bottom-up approach to nuclear plants, and that by 1976 it was apparent that the process simply was not working. While the bottom-up estimate of plant costs provided some information, a very large allowance for the effects of regulatory changes -- on the order of 100% or more -- would have to be added to produce a realistic best estimate. BECo certainly could have done this with any of the cost estimates its engineers provided, and thereby produced a reasonable projection of the actual cost. BECo chose not to do so, and Montaup chose not to make such a correction itself nor to pressure BECo to do so. Neither witness has offered any substantive excuse for presenting "estimates" to their regulators and investors which they knew (or should have known) were not sincere best

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6. These contingency factors might allow for problems common to all complex construction, such as minor interferences between activities, brief jurisdictional labor disputes, and small oversights in the estimates.

estimates for the plant which could eventually be built.

Q: Does either Montaup witness provide any evidence indicating that it was reasonable to assume in the late 1970's that the bottom-up approach produced unbiased Pilgrim 2 cost estimates, which had a reasonable chance of being achieved without a large additional contingency?

A: No. They do not seem to argue that the "bottom-up" approach has been verified, or validated, or time-tested for nuclear construction, but rather that it was standard procedure. For example, Mr. Staszesky seems to argue that BECo's estimation process was prudent, because it was "the accepted engineering practice throughout the period" (page 38). Similarly, Mr. Gmeiner also seems to equate the accuracy with conformity (page 3, line 17, through page 7, line 2). He seems to believe that the Pilgrim 2 estimates were good because they agreed with those of other people who were consistently wrong. Mr. Staszesky essentially quotes Mr. Gmeiner's position on this point (page 38). Thus, both witnesses appear to believe that using biased estimates was acceptable, and perhaps even laudable, because it was the industry norm.

Q: How do the Montaup witnesses misrepresent your testimony regarding the foreseeability of specific events and of the general trend in nuclear cost estimates?

A: Essentially, they assert that the cost estimate increases from 1972 to 1981 could not have been anticipated without specific knowledge of future events. In fact, I demonstrate that the history of cost revisions, even by 1972 and certainly by 1976, should have caused both BECo and Montaup to expect further revisions, unless the underlying trends affecting nuclear construction changed dramatically.

Q: What evidence do the Montaup witnesses offer to support their claim that the cost increases and schedule delays discussed in your testimony were unforeseeable?

A: Mr. Gmeiner suggests that BECo could not have improved its estimates without prior knowledge of "the accident at TMI and its regulatory effect, or other factors, such as double-digit inflation and high interest rates, which were to push up nuclear costs in the years ahead" (page 2, lines 21-49). The example he selects to illustrate this point actually demonstrates the irrelevance of all of his specific unforeseeable events:

> There was no way that Edison could have foreseen a cost anything like $1236 million when it made the initial $402 million estimate in 1972.

In fact, the Pilgrim 2 cost estimate rose to $1230 million by 1975, just three years after the initial estimate, long before TMI or the high inflation and interest rates of the late 1970's and early 1980's. It is difficult to imagine how the relatively modest increases in time-related costs by 1975 could have tripled the cost estimate in such a short time:

most of this escalation must be attributed to revisions in scope due to the continuing evaluation of safety regulation.

Mr. Staszesky takes a more obscure approach to this issue: he accuses me of faulting BECo specifically for failing to foresee the TMI accident (page 13, line 8, to page 14, line 16). This misunderstanding on his part is inexplicable, since he cites a section of my testimony which says nothing of the sort, and which in any case examines the decisions BECo made in mid-1980. I do believe that it was fair to expect BECo to have noticed the TMI accident by then.

Q: Did your original testimony present any evidence that substantial increases in the Pilgrim 2 cost estimate were foreseeable?

A: Yes. In addition to the persistent errors in nuclear estimates over the 15 years preceding the cancelation of Pilgrim 2, I showed that observers within the industry foresaw substantial increases in nuclear costs and substantial delays in schedules. Prime examples of this recognition would include the quotes from Florida Power and Light[7] on page 60, and from F.C. Olds on pages 26 and 27. All of these observers, within the utility industry,

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7. Due to a typographical error, this utility is also identified as Florida Power Corporation in my original.

recognized that delays and cost increases were likely to continue, and that current projections were not reliable.

Q: How do the Montaup witnesses misrepresent your testimony regarding the inevitability of the cancelation of Pilgrim 2?

A: Mr. Staszesky starts his rebuttal by summarizing my testimony as "advocating . . . that Boston Edison should have known at some early point that it was inevitable that the Pilgrim 2 project would ultimately be cancelled" (page 1). In fact, my testimony indicates that BECo should have known in 1972 that Pilgrim 2 was likely to be more expensive than the current estimates projected, and that by 1976 BECo should have known that the plant was almost certain to be much more expensive than current projections (and hence of doubtful economic and financial feasibility), unless some dramatic change occurred within the industry. I would agree that cancelation was inevitable by 1980.

Q: How do the Montaup witnesses misrepresent your testimony regarding the significance of intervenor testimony in various regulatory proceedings?

A: On the first page of his testimony, Mr. Staszesky paraphrases my testimony, as arguing that BECo was remiss by failing to immediately rely on my testimony and that of Mr. Levy, and only in that failure.[8] I repeatedly describe various testimony and other information which came to (or should have come to) BECo's attention as "warnings", not as pronouncements. BECo should have been aware previously of all of the considerations raised in those proceedings, but if it were not so aware, we certainly brought them to BECo's attention at that point. BECo's refusal to consider the facts, trends, and problems we raised, and its decisions to wish them away rather than resolve them, are certainly imprudent. If I warned Mr. Staszesky that the ceiling was falling, I would not necessarily expect him to run for cover, but I would be very surprised if he did not look at the ceiling. I would like to emphasize that these outside warnings were secondary considerations in my discussion of the prudence of BECo's and Montaup's actions. Even if no intervenor had ever tried to enlighten BECo, its failure to respond in any appropriate fashion to ample warning in the history of nuclear cost estimates, including its own, and in the utility industry literature, was highly imprudent.

Q: Do the Montaup witnesses misrepresent your testimony regarding the significance for the BECo internal studies on the financial strain related to Pilgrim 2?

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8. This is a theme repeated several times by Mr. Staszesky in various forms. On page 17, for example, the same point is restated to suggested that the only negative information about Pilgrim 2 available to BECo was my "opinions."

A: Yes. Mr. Staszesky discusses these documents, which raised questions about BECo's ability to finance Pilgrim 2 even at a cost estimate close to BECo's low official estimates, at length on pages 18-21. Perhaps the most important point here is that Mr. Staszesky claims that I use the documents "for the truth of the matters contain herein", and that my use of the documents is invalidated by the fact that they are not corporate documents reflecting corporate recommendations.

Mr. Staszesky's position might be sensible if this proceeding were a stockholders' suit, attempting to allocate the blame for BECo's errors in its Pilgrim 2 planning, between management and the directors. That is not my purpose: I have not reached any conclusion as to whether the fault lies with management or with the directors, and my testimony does not state whether management ever recommended cancelation of Pilgrim 2. Again, I described these documents as "warning" BECo of foreseeable problems (page 48). They certainly establish that BECo could have known that Pilgrim 2, even at the official cost estimates, would stretch BECo's financial capability. BECo does not seem to have then considered the financial effects of attempting to build Pilgrim 2 at a range of reasonable cost estimates. The fact that management (and/or the Board of Directors) chose to reject these warnings does not negate their implications: BECo was aware of the financial problems it would face with Pilgrim 2, and yet BECo largely ignored those problems, without any reasonable basis.

Q: How do the Montaup witnesses misrepresent your testimony regarding the role of Canadian power in the Pilgrim 2 planning decisions?

A: Mr. Staszesky suggests on page 28 that I assert that "availability of Canadian power should have warned the New England utilties' about a lack of need for pursuing nuclear projects." That is incorrect. Mr. Staszesky refers to page 21 of my testimony, which very clearly discusses economic considerations which may have supported the prudence of beginning the Pilgrim 2 project in 1972 (subject to a high level of vigilance in the continuing review of the project), in part because current options, such as Hydro Quebec power, were not then available. He responds to this supportive statement about 1972 conditions as if it were an attack on BECo's behavior in the late 1970's.

Q: How do the witnesses misrepresent the historical record?

A: The primary area in which the Montaup witnesses distort history is their discussion of their various regulatory decisions which approved construction of Pilgrim 2, or Montaup's increased participation in Seabrook. For example, Mr. Gmeiner, on pages 7-9, defends Montaup's actions (or lack of action) with regard to Pilgrim 2 by citing the DPU's favorable decision in DPU 19738. [9] Similarly, large portions of Mr. Staszesky's testimony cite various regulatory decisions to support his assertions that Pilgrim 2's cost estimates were reasonable at the time they were made, that BECo's decisions to continue spending money on Pilgrim 2 were prudent, and that my testimony in those proceedings (and by some extrapolation, in this proceeding as well) was not convincing to the regulators. Both witnesses state (or in some cases imply) that the regulators in those proceedings had before them the same information which was available to the utiltie~, and perhaps even the same information which I have presented in this case, and that the regulators concurred with the utilities, given the available evidence.

Q: Did the DPU and the NRC have before them the same information which was available to the utilities, and which you summarized in your original testimony?

A: No. On the contrary, many of the important decisions supporting the economic viability of Pilgrim 2 appear to have been made (at least in part) because the regulators were not convinced that the cost trends [10] identified by me and other

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9. This proceeding was concerned with Montaup's request to purchase additional Seabrook shares, and is also referred to as DPU 20055 and the Sale of Shares Case. It is Exhibit 59.

10. The relevance of load forecasts to the economics of Pilgrim 2 has generally been minor (and probably more important for financial feasibility than for cost/benefit analysis) compared to projections of construction cost, schedule, and operating costs

intervenor witnesses were sufficiently robust or persistent, and the regulators then relied on the utilities' judgement. Had the utilties presented in those cases data comparable to the information which I presented in my original testimony in this proceeding, the subsequent decisions might have been different.

Q: Does Mr. Staszesky's rebuttal accurately portray the evidence before the various regulators in the case he describes?

A: Not really. For example, he describes the treatment of nuclear construction cost estimates in DPU 19494 as follows:

> The Department listened to testimony for literally weeks about the construction cost estimates. It had the benefit of the "errors" supposedly demonstrated by statistical studies of other cost estimates pointed out to it. (page 12, lines 21-26).

It is not clear what Mr. Staszesky means by "statistical studies of other cost estimates": so far as I know, the only cost estimate history before the DPU was that of Pilgrim 1, and statistical studies of cost estimate histories were introduced to the DPU only after I developed my myopia analysis methodology for DPU 19738, by which time the record in DPU 19494 (BECo's Pilgrim 2 construction case) was closed.

Q: Mr. Staszesky says that the DPU had before it "Mr.

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and reliability.

Chernick's" 'expert' opinions" (page 14), and "had the advantage of the 'wisdom' of Mr. Chernick before it" (page 16) when it approved the construction of Pilgrim 2. How does the record in DPU 19494 compare to your original testimony in this case?

A: So far as I know, virtually none of the data, literature, citations, or analyses presented in my original here were before any regulatory agency reviewing Pilgrim 2, and any of these particular data or citations which may have been before the DPU were not in my testimony, but someone else's.

Q: Why was that the case?

A: I was not a witness on nuclear cost, schedule, or economics in that proceeding. For one of the major topics of my present testimony, the history of nuclear cost estimates, I had essentially no data available to me. In the NRC proceeding, where I did testify on nuclear construction cost, the only cost estimate history I had was that of Pilgrim 1. Even in DPU 19738, I had only a few more cost estimate histories: Connecticut Yankee, Millstone 1 and 2, Salem (for the combined cost of two nuclear units and a gas turbine), and TMI 2. Most of these were turnkey units, incomplete histories, or otherwise of limited use.

Q: Why was your data base so limited?

A: At the time, I did not have any large source of nuclear cost estimate histories, nor did I know of any such source. I repeatedly requested cost estimate history data from the utilities, but other than Pilgrim 1 and the Northeast Utilties units listed above, the utilities provided very little data. Montaup and the other parties to DPU 19738 went so far as to refuse to supply histories for units in which they owned entitlements: Vermont and Maine Yankee. Neither BECo or Montaup provided any of the AEC/ERDA/EIA summaries of the HQ/EIA-254 forms. The original data source for my myopia analyses, reporting quarterly on utility cost estimates and schedule for nuclear construction. Nor did they even mention the existence of the HQ/EIA-254's. It is conceivable, if unlikely, that Montaup was unaware of the existence of any of the broad summaries of cost estimates, but BECo, which filed HQ-254's, must have known of them. The utilities' responses satisfied the DPU, but certainly did not provide the information necessary to assess the reliability of nuclear cost estimates.

Q: Why did you start testifying on nuclear power plant construction costs?

A: Even from my small database, it was apparent that utilities and architect/engineers were seriously and consistently underestimating the costs of nuclear plants. The repeated assertions that the estimation problems were solved and that <u>this</u> was the right estimate had worn thin, and the specific reasons for expecting the cost of stabilize (such as reduced NRC activity, or more complete design) were not very convincing. The myopia analysis provided a simple correction for utility over-optimism. Had the utilties spent more effort on comparing my simple observations to the historical data they had available, and less on convincing regulators that my data was unrepresentative, they might have saved hundreds of millions of dollars which were wasted on Pilgrim 2 and Seabrook.

Mr. Staszesky seems to be offended that I now consider myself to be an expert in areas, such as nuclear power plant costs, in which I did not consider myself an expert five years ago (page 12). If the practice, at BECo, Montaup and other utilities, were not so unrealistic and outdated, it would not have been so easy for me (and many other outside analysts, as well) to catch up to the state of practice and make a substantial contribution. The same is true for construction scheduling, capacity factors, O&M, and a number of other topics.

Q: Is Mr. Staszesky correct in stating that "[t]he present Chernick testimony is but another presentation of the same testimony that he has presented on at least three occasions"?

A: No. It would have been impossible for me to present this testimony previously, because I lacked the data. My present testimony has only the slightest similarity to my testimony in DPU 19494 and 19738, and before the NRC. Only the utilities could have presented this information in those cases, and they did not choose to do so.

Q: Were there other misrepresentations for the historical record in Mr. Staszesky's rebuttal testimony?

A: In support of his contention that I should have included additional information in my original testimony, Mr. Staszesky asserts "the fact that Mr. Chernick is fully aware of the history of [the internal BECo documents which discussed the financial problems resulting from Pilgrim 2] and the prior proceedings" (page 21). As Mr. Staszesky notes on rebuttal, I was not a witness in DPU 906 (nor did I have any role in the proceeding), and I was also not the Commonwealth's witness on financial qualifications in the NRC proceedings. Given the very limited use to which I put these documents (which as I have noted, did not include the "truth of the matters contained therein"), I have not reviewed the lengthy records of proceedings in which I was not involved. I can not imagine on what basis Mr. Staszesky expected that I performed a historical search for some hypothetical information (which Mr. Staszesky did not produce, or even establish the existence of) which might have some bearing on the use to which I put them.

Mr. Staszesky also invests non-existent sections of my testimony in previous cases, such as construction schedule projections in DPU 19494 (page 14).

Q: What allegations do the witnesses make regarding your conduct in this and prior cases?

A: There are several such allegations, which comprise the bulk of Mr. Staszesky's testimony. The subjects include

- my alleged attempt to "deceive" the Commission by not discussing prior regulatory decisions,

- my alleged practice of filing direct testimony which I was not willing to try to defend on cross-examination, and

- the purpose of my previous testimony.

Q: How does Mr. Staszesky accuse you of attempting to deceive the Commission?

A: Mr. Staszesky repeatedly accuses me of deception and inaccuracy because I "failed" to mention that many of my criticisms of BECo, Montaup, and other utilities' planning were rejected by various regulatory agencies. This line of attack starts on pages 2 and 3 and continues throughout much of his rebuttal. His attempt to portray my original testimony as deceitful is directly related to his misrepresentations of my testimony about the warning which I (and others) offered BECo in various proceedings: if Mr. Staszesky were to acknowledge BECo's responsibility to carefully review the considerations before it, BECo's failure to do so would be equally imprudent, regardless of whether or not various regulators were impressed by particular arguments. I have already discussed Mr. Staszesky's misrepresentation of my testimony on this point.

If Mr. Staszesky really believes that the prior regulatory decisions are important, and that I somehow hoped to deceive the Commission by neglecting to mention those decisions, then he must believe that I somehow expected the decisions would not come to the Commission's attention. Of course, the exact opposite is true: it is only reasonable to expect the Commission to be fully aware of these decisions. As Mr. Staszesky notes, the DPU 19494 decision is already in the record; the others are apparently published and readily available, especially to Montaup and BECo, which were parties to the proceedings. My testimony does not, of course, describe every event that affected New England nuclear construction in the last 15 years, and if Mr. Staszesky believes that some of the events I omitted are pertinent, he is welcome to note them. There is no basis for his assertion that I sought to deceive the Commission.

Q: What were Mr. Staszesky's charges regarding your previous performance as an expert witness?

A: On page 11, lines 24-30, and much more generally on page 33, line 14-18, he accuses me of testifying to matters which I was not prepared to defend [11] on cross-examination. Despite his claim that I collapsed in this manner "frequently", and in fact "whenever . . . pressed in cross-examination", he provides no specific instances to which I can respond.

Q: What were Mr. Staszesky's charges regarding the purpose of your testimony in previous cases?

A: On pages 34-35, Mr. Staszesky's testimony includes a series of unsubstantiated claims on this subject, purporting to explain why BECo ignored the data that I brought to its attention. Mr. Staszesky asserts that

- the essential thrust of the Chernick testimony (both then and now) . . . was an attempt to support pre-conceived conclusions by mathematical or statistical manipulation . . .

- the purpose of much of Mr. Chernick's testimony in prior cases was to impugn our integrity and to advocate, rather than to persuade . . .

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11. Or even attempt to defend; success is not the issue here.

- the purpose of these efforts was to oppose the project as a political or philosophical matter, rather than on the merits . . .

- either Mr. Chernick _et al_. did not understand the subject matter or their efforts were not even intended to be honest assertions of opinion genuinely held, but rather malicious efforts to discredit the integrity of the Company's presentation.

In support of this extended indictment, Mr. Staszesky offers only one example, from my testimony in the current case, which does little to explain how Mr. Staszesky formed the opinions of my work which he claims to have held six years ago. In any case, while his vague factual argument regarding contingency might demonstrate that we disagree about whether a particular manipulation of cost estimates was appropriate, given a particular set of circumstances, it does not demonstrate any of my alleged offenses against BECo.[12] He

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12. From Mr. Staszesky's discussion of his justification for **reducing** contingency by one dollar for each dollar the base cost estimate increases (page 34, line 22, to page 35, line 18), it is difficult to determine how BECo conceptualized the nature of uncertainty in nuclear construction costs. His assertion that contingency decreases in a measure equal to new components or systems which are designed into a plant is not explained well enough to allow for a detailed examination, but it certainly does not sound like a recognition that the plant on the drawing board **can not be built.** Perhaps BECo used "contingency" as a discretionary category, closely resembling "miscellaneous", which can take on whatever meaning is convenient, and which is not a

offers no examples in which I "manipulated" anything, no examples from the cases in question in which I "impugned" anyone's integrity, no examples of technical positions which I could only have taken "as a political or philosophical matter", and no evidence of "malice". In fact, my testimony in all of the cases to which Mr. Staszesky refers are filled with specific observations that various utility assumptions and projections were undocumented, that other projections were at variance with the data, that significant considerations were neglected in the utilties' analyses, and that trends evident in the historical data are neither incorporated in the projections nor shown to be irrelevant. These are all matters in which Mr. Staszesky may disagree with my observations, or with their relevance to the decisions BECo made, but which were neither manipulative, political, malicious, nor assaults on anyone's integrity. Again, it is difficult to reconcile Mr. Staszesky's descriptions to the testimony I actually filed.

Q: Does Mr. Staszesky include your original testimony in this case in this set of accusations?

A: Yes. Mr. Staszesky specifically accuses me of mathematical manipulations to prove a pre-conceived conclusion in the current case; this must be a reference to my myopia analysis,

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vital part of a reasonable cost estimate. Unfortunately, nuclear contingency has not had either of these properties for well over a decade now.

since the few other calculations I perform seem to be straight-forward and non-controversial. Neither Mr. Staszesky, nor anyone else, has ever demonstrated (nor, so far as I know, even tried to demonstrate) that the powerful and consistent myopia results are artifacts of manipulation. In fact, the myopia results are simple, unvarnished summaries of the historical record.

Q: You mentioned that Mr. Staszesky's sole example for this set of charges related to BECo's manipulation of contingency which you discussed previously. Does this have any relevance to his charges against you?

A: Not really. The only time I recall mentioning this point was in the original testimony in this case [13], so it can not explain Mr. Staszesky's refusal to consider the points I actually brought to BECo's attention during the period 1978-80. Once more, Mr. Staszesky does not document the claim that the Attorney General was "rebuffed", nor the claim that the manipulation in question was "standard industry practice", nor the assertion that this practice was "fully explained". I believe that I was present at the cross-examination of Mr. Maroni in DPU 19494 at which he explained how the contingency in the new forecast was backed

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13. The only really critical observation about the practice was to quote Mr. Staszesky's resentment at having it atrributed to BECo. Despite his current indignation, he does not appear to assert that I misquoted him.

out so that the total cost estimate would not increase, and I do not remember any justification of the practice. Perhaps Mr. Staszesky presented such a justification in DPU 906, after he recovered from his resentment; if so, it has not come to my attention and Mr. Staszesky does nothing to shed light on the issue in the current proceeding.

Q: Were there any other similar accusations in Mr. Staszesky's testimony?

A: Yes. Mr. Staszesky also concluded that "the purpose of much of Mr. Chernick's testimony in prior cases was . . . to advocate, rather than to persuade". Given the large number of meanings of the term "advocate", and his failure to provide any examples to support this assertion, it is not clear what distinction Mr. Staszesky wishes to make here. It is hard to see how any such distinction could justify BECo's failure to examine the data behind the trends pointed out by its critics.

Mr. Staszesky's meaning, if not his reasoning, is clearer when he suggests (pages 1, 33, and 35) that the Attorney General's Utility Division was engaged in a "generalized anti-nuclear" campaign, and "has consistently over many years demonstrated an anti-nuclear bias". I am at a loss to understand the basis for Mr. Staszesky's confusion. As I discussed in my original testimony, the responsible professionals on the Attorney General's staff (who were then in the Utilities Section of the Consumer Protection Division) had been disturbed by the rate increases which followed commercial operation of Millstone 2. As a result, these professionals, carrying out their consumer protection responsibility, attempted to question the need for Pilgrim 2 before it entered construction, to avoid a repeat of the Millstone 2 events. Once the review process started (which was the point at which I joined the Attorney General's staff), it became clear to us that BECo's justifications for its load forecast, and later the Pilgrim 2 cost estimate, were very thin. I can not think of any situation in which we gave Mr. Staszesky any reason to believe that we were doing (or at least thought we were doing) anything other than our duty to the public: protecting ratepayers by first determining whether BECo was stubbornly attempting to build a plant it did not need and could not afford; and once convinced that this was the case, by the presenting to the regulators the best evidence available to us. Unfortunately, we were not privy to much of the information available to Montaup and BECo, and we were unsuccessful in preventing continued expenditures.

Q: Does this conclude your additional testimony?

A: Yes.

AFFIDAVIT

COMMONWEALTH OF MASSACHUSETTS

Paul L. Chernick, being duly sworn, deposes and says: that he has read the foregoing questions and answers labeled as his testimony, and if asked the questions therein his answers in response would be as shown; that the facts contained in said answers are true to the best of his knowledge, information and belief.

Paul L. Chernick

Paul L. Chernick

Subscribed and sworn before me
this 9th day of August, 1984.

Barbara H. Garman

My Commission Expires: 12/15/89