COMMONWEALTH OF PENNSYLVANIA
BEFORE THE PUBLIC UTILITIES COMMISSION

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| THE PENNSYLVANIA PUBLIC UTILITIES COMMISSION V. PENNSYLVANIA POWER & LIGHT COMPANY | Docket No. R-842651 |

**TESTIMONY OF PAUL CHERNICK ON BEHALF OF THE PENNSYLVANIA OFFICE OF CONSUMER ADVOCATE**

November 1984

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# TESTIMONY OF PAUL CHERNICK

## 1 - INTRODUCTION AND QUALIFICATIONS

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

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

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 thirty times on utility issues before such agencies as the Massachusetts Department of Public Utilities, the Massachusetts Energy Facilities Siting Council, the Texas Public Utilities Commission, the Illinois Commerce Commission, the New Mexico Public Service Commission, the District of Columbia Public Service Commission, the New Hampshire Public Utilities Commission, the Connecticut Department of Public Utility Control, the Michigan Public Service Commission, the Maine Public Utilities Commission, and the Atomic Safety and Licensing Board of the U.S. Nuclear Regulatory Commission. A detailed list of my previous testimony is contained in my resume.

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

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

A: Several of my criticisms of utility projections have been confirmed by subsequent events or by the utilities themselves. In the late 1970's, I pointed out numerous errors in the load forecasts of several New England utilities, and of the New England Power Pool (NEPOOL), and predicted that growth rates would be lower than the utilities expected. Many of my criticisms have been incorporated in subsequent forecasts, load growth has almost universally been lower than the utility forecast, and the utility forecasts have been revised downward repeatedly.

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. 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,[1] Public Service of New Hampshire (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.

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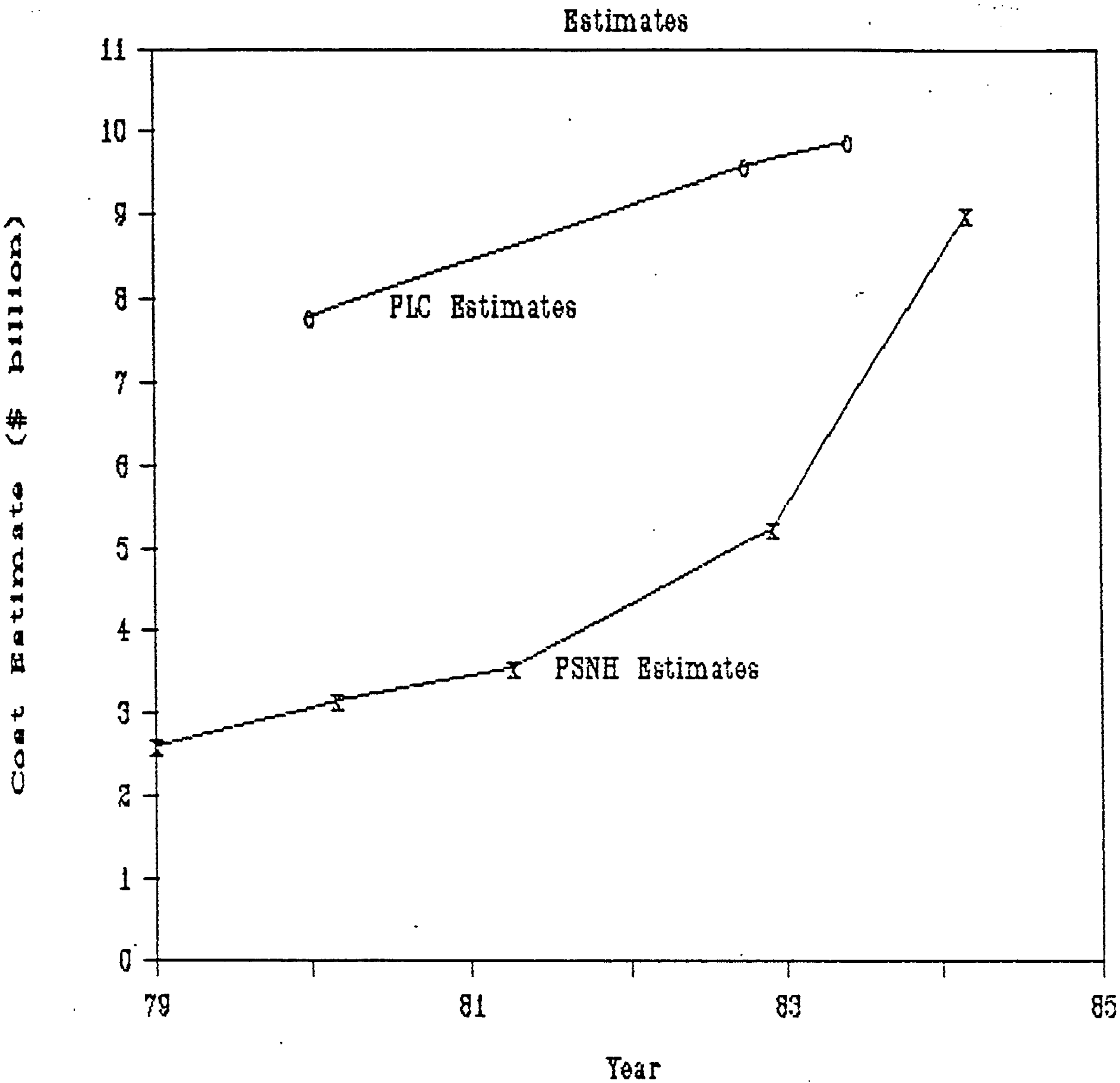
1. See Appendix A for full citations.

Figure 1.1: History of Seabrook Cost



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. 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 for large PWR's. PSNH now includes capital additions, escalates real O & M slightly faster than inflation, and projects a mature capacity factor of 72%. Thus, PSNH has implicitly accepted my criticisms, even though the O & M escalation and capacity factor projections are still very optimistic. While my original analyses (and the studies I relied on) were based on data only through 1978, experience in 1979-83 confirms the patterns of large capital additions, rapid O & M escalation, and low capacity factors. The 60% PWR capacity factor figure, in particular, has been widely accepted by regulators (such as the California Energy Commission) and even utilities (such as Commonwealth Edison and 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 expectations were inconsistent with reality. While PP&L's projections are more realistic than was typical in the late 1970's, its estimates for Susquehanna 2 costs continue to be overly optimistic.

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

A: Yes. I authored Report 77-1 for the Technology and Policy Program of the Massachusetts Institute of Technology, Optimal Pricing for Peak Loads and Joint Production: Theory and Applications to Diverse Conditions. I also authored a paper with Michael B. Meyer "An Improved Methodology for Making Capacity/Energy Allocation for Generation and Transmission Plant", which won an Institute Award from the Institute for Public Utilities. My paper "Revenue Stability Target Ratemaking" was published in Public Utilities Fortnightly, and another article "Opening the Utility Market to Conservation: A Competitive Approach" was presented at the recent conference of the International Association of Energy Economists, and will be published in the conference proceedings. 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 Susquehanna 2 in ratebase, or of otherwise reflecting the cost of that unit in current rates. I have specifically been asked to review the need for Susquehanna 2 to provide reliable service, and the likely benefits of the unit to PP&L ratepayers, when it enters service, and to suggest an appropriate ratemaking approach in light of that analysis.

Q: How is your testimony structured?

A: The following two sections discuss the two possible justifications for Susquehanna 2: the reliability benefits and the reductions in fuel costs. The second section will discuss the magnitude and timing of the reliability benefits of Susquehanna 2, 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 back-out of more expensive fuel, 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 Susquehanna 2's likely operating costs and capacity factor, which are required to assess its effect on fuel costs.[2] In the final section, I will make recommendations regarding the need for, and economic benefits of, Susquehanna 2; and regarding the disposition of PP&L's rate increase request related to that unit (including the phase-in proposal). I will also recommend alternative ratemaking treatment for the unit.

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2. 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 SUSQUEHANNA 2

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

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

Q: What are the reliability benefits of Susquehanna 2?

A: Susquehanna 2 is not needed for reliability. When Susquehanna 2 enters service, it will to some marginal extent increase the reliability of the PJM 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 PJM reserve margins shrink to the merely adequate range, the presence of Susquehanna 2 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 PJM system, each individual utility has a responsibility to maintain a share of the generating capacity required by the pool. While the PJM agreement does not reflect well the relative reliability value of various kinds of capacity, which varies with the size and maintenance requirements, as well as the forced outage rates of each unit, each member utility is in roughly the same position as the pool as a whole. PP&L will not need the capacity of Susquehanna 2 to meet its capability responsibilities for at least the rest of the decade and probably musch longer, but it may eventually allow PP&L to defer new investments, or delay expenses, or accelerate the retirement of other units.

Q: When would Susquehanna 2 have a reliability benefit to PP&L, under the terms of the PJM agreement?

A: PP&L projects that this point will occur in 1998, when its "planned objective" demand forecast exceeds its projection of available capacity without Susquehanna 2.[3] This projection is likely to overstate the need for Sussquehanna 2, due to the considerable uncertainties in the validity of the PP&L forecast, in the level of reserves which PJM will require PP&L to maintain in the 1990's, and in the validity of excluding from the supply projection of any new generation (other than the Holtwood and Safe Harbor expansions).

Q: Have PP&L's forecasts been reliable over the last decade?

A: Figure 2.1 displays representative PP&L peak demand forecasts from late 1975 (already two years past the oil embargo) to 1983, and the actual peak loads in each of those years. PP&L has had to adjust its load forecast downward several times over the last eight years. This record hardly justifies confidence in PP&L's current projections.

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

A: Yes. The cost of Susquehanna 2 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 fossil fuels it is backing out. If it

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3. This date is not affected substantially by the ACE sale. Approval of the JCP&L sale could move this date to 1991. Corrections of the problems discussed below may well move the date back to the late 1990's, even with the JCP&L sale.

Figure 2.1: PP&L Forecast History

(A) By Year Forecast

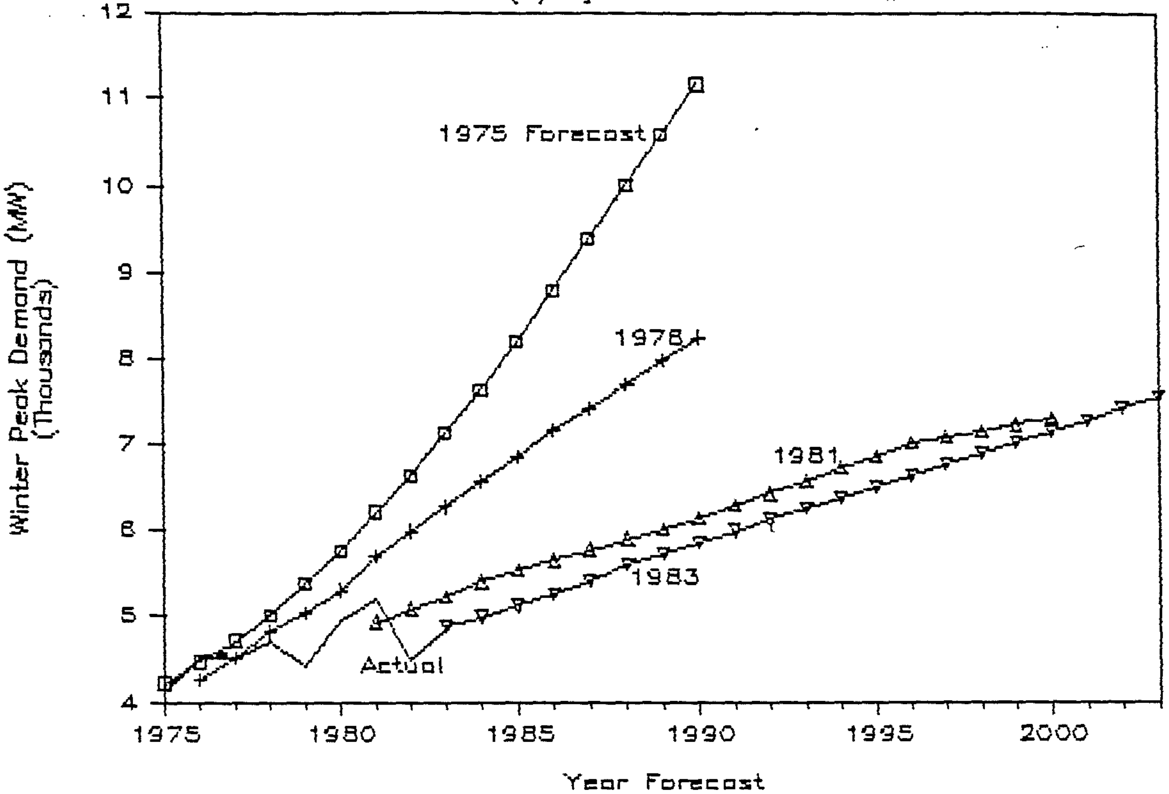
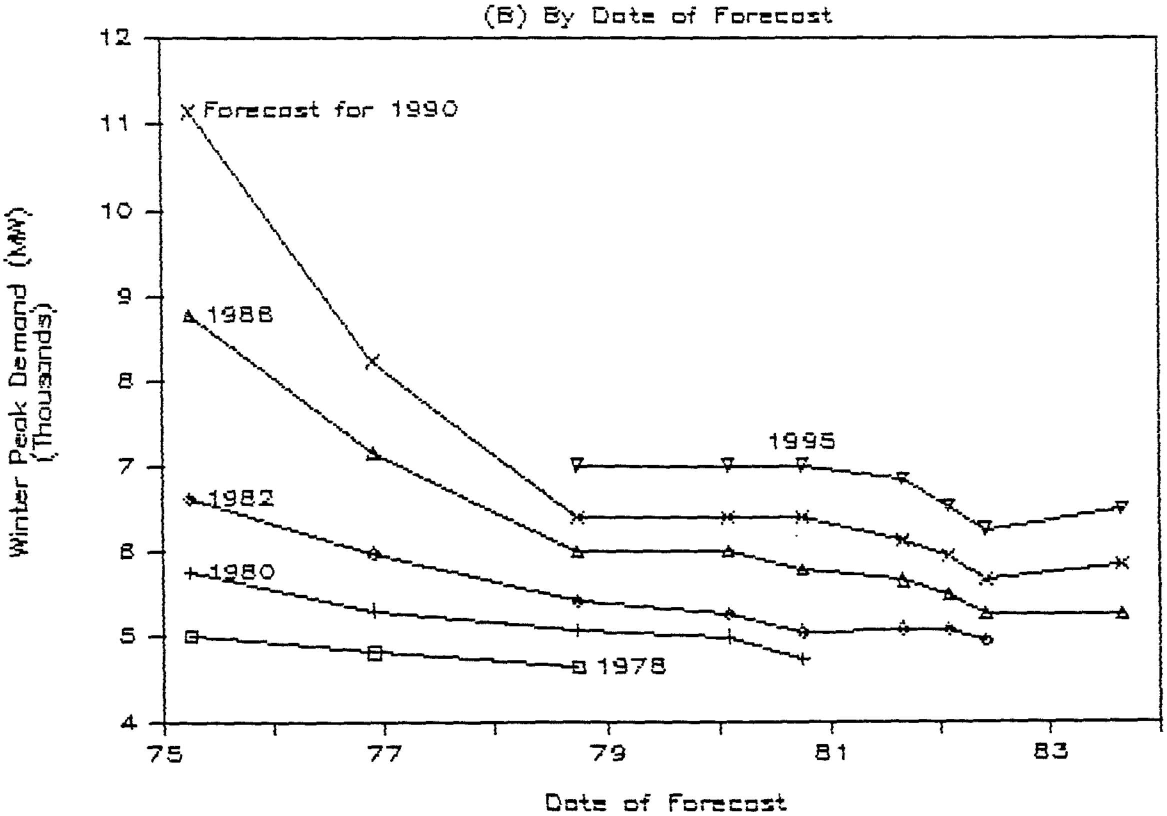



Figure 2.1: PP&L Forecast History

(B) By Date of Forecast



turns out that Susquehanna 2 is economical, the cost of the remaining fuel which PP&L burns will be even higher than the impressive cost of Susquehanna 2, further depressing demand.[4]

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

A: PP&L predicts that the level of reserves required of it by PJM will increase steadily over the next few decades. The basis for this belief seems to be a 1978 study (Interrogatory Staff 35) which projected, among other things, that PJM would shift from a summer-peaking to a winter-peaking pool, and that other utilities' forced outage rates (FOR's) will tend to improve relative to PP&L FOR's. The first assumption (which appears to be the more important by far) is rather suspect. Considering the availability and costs of alternative heating sources and space heating conservation, winter load growth much in excess of summer load growth seems unlikely.[5]

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4. For corresponding reasons, the high cost of Susquehanna 2 and/or the fuel it displaces PP&L's failure to include new alternative energy sources in its forecasts is suspect.

5. There are also alternatives, and especially conservation options, which displace primarily summer loads, but there are few which are as inexpensive and abundant as the space-heating options.

PP&L's second point may be correct in the short term, while the Susquehanna units are immature, but the addition of Limerick and Hope Creek 1 will help drive up the forced outage rates of Philadelphia Electric and PSE&G, as well. PJM's overall reserve requirements will tend to increase somewhat as more nuclear capacity is added to the system, but this may be partly offset by greater interties to other regions. It is not clear that PP&L's average forced outage rate will be very much closer to the pool average than it is now, or that the overall pool reserve will be much higher than it is now, at the end of the century.

Q: Is it appropriate to assume that no new generation will be added in PP&L's service territory in the next 25 years?

A: No. None of PP&L's capacity projections includes any new economic capacity from cogeneration, trash-burning, small power production, or any other source, whether owned by PP&L or by others, beyond the current plans for expansions of two existing hydro facilities.[6]

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

A: Yes. PP&L projects very rapid real (inflation-adjusted) increases in fossil fuel prices: if rates for power purchased

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6. One of these expansions (Holtwood) appears to be essentially required by the terms of PP&L's license from FERC.

under PURPA are based on the same avoided costs PP&L uses in evaluating the economics of Susquehanna, the incentives for independent power production will increase substantially in the next couple of decades.

Q: If and when Susquehanna 2 is needed, what is it worth to PP&L for reliability purposes?

A: At a first approximation, the PJM capability measurement rules insure that a megawatt of any plant is equally valuable to a participant.[7] The minimum fixed cost of enhanced reliability is probably the cost of combustion turbine capacity.

If it does become necessary to supply new capacity, that capacity can be obtained inexpensively. As shown in Table 2.1, Pennsylvania's existing combustion turbines cost about $167/kw in 1983 dollars; inflating this estimate to 1985 at 0.5% more than GNP inflation[8] yields a 1985 estimate of $186/kw, or only about 9% of the cost of Susquehanna 2, with much lower fixed O&M, capital additions, insurance, and

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7. This approximation somewhat overstates the value of Susquehanna 2 to PP&L, since large nuclear units tend to drive up the reserve requirement for the pool, and hence the reserves allocated to each of the members. Susquehanna 2 will also increase PP&L's average forced outage rate.

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

retirement costs. Gas turbines can also be brought on line with only a year or two lead time, so they are unlikely to be excess capacity when they are installed. Thus, it is clear that most of the cost of Susquehanna would never have been incurred for reliability

Q: What is the reliability value of Susquehanna 2 to PJM?

A: The value of Susquehanna 2 (or any other large nuclear unit) to PJM is considerably less than its value, under PJM capability responsibility formulas, to the individual PJM members which own that plant. Nuclear plants contribute relatively little to reliability for two reasons. First, due to their large maintenance requirements, nuclear units are often not available when needed.[9] Second, due to the large size of new nuclear units, sufficient reserves must be provided to back up the simultaneous loss of a thousand megawatts or more. As a result, even with the same forced outage rates, large plants require more reserve capacity than small plants.

Analyses performed by the New England Power Pool (NEPOOL) indicate that nuclear capacity requires a reserve of approximately 50%. This is demonstrated in Tables 2.2 and

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

2.3. The size effect would be less pronounced on the larger PJM system, but the reliability of large nuclear units is less than NEPOOL assumed.

Q: Does this possible reliability benefit at or after the turn of the century justify charging ratepayers for Susquehanna 2 in 1985?

A: No. In fact, I can not see that reliability considerations, standing alone, could justify any cost recovery for Susquehanna 2 until close to the time when it would be required for reliability purposes for PP&L. This is the traditional excess capacity argument: ratepayers should not have to carry the extra costs imposed when the utility brings on more capacity than is reasonably necessary to provide adequate service.

## 3 - THE BENEFITS OF SUSQUEHANNA 2 FOR FUEL DISPLACEMENT

Q: You have explained why Susquehanna 2 will have very limited reliability benefits. What is the unit's major benefit to PP&L and the PJM system?

A: In the light of its much higher cost per kw than other capacity, it is clear that Susquehanna 2 is being built almost exclusively for fuel displacement purposes. Like all nuclear units, it will provide lower fuel costs than the fossil-fueled plants which PJM currently has in abundance.

Q: Have you analyzed the cost-effectiveness of Susquehanna 2 for fuel displacement?

A: I have compared the cost of Susquehanna 2 under traditional ratemaking to the power it would displace, under a variety of assumptions regarding Susquehanna 2 cost and reliability. This is a fairly lenient type of comparison: an investment may be substantially suboptimal, but still be less expensive than existing coal plants, or especially oil. I have not attempted to address the larger issue of whether Susquehanna 2 is the most economical option for reducing fuel cost.

Q: How much lower than oil and coal costs will the fuel cost of Susquehanna 2 be?

A: Table 3.1 lists, and Figure 3.1 displays, the differences PP&L projects between Susquehanna 2 fuel costs and the fuel costs of the fossil (primarily coal-burning) plants it would be backing out. The projected differential starts in 1985 at about 2.9 cents per kWh, and rises to 30.3 cents per kWh by 2000, and to 107.7 cents/kWh in 2022. Over the first 10 years of the life of Susquehanna 2, PP&L projects that the savings value of a kWh of Susquehanna power will increase at 19.8% annually, or about 13% annually above the inflation rate.[10] These savings are substantial, but they come at the even greater cost of building and operating Susquehanna 2.

Q: How cost-effective is Susquehanna 2 under PP&L's current assumptions?

A: It is clear from the information presented in PP&L's testimony and exhibits that even PP&L expects that the costs of the entire Susquehanna plant will exceed the benefits of the unit for much, and perhaps most, of its useful life. Since Susquehanna 1 will displace the most expensive fuel, Susquehanna 2 will tend to be less valuable than the first

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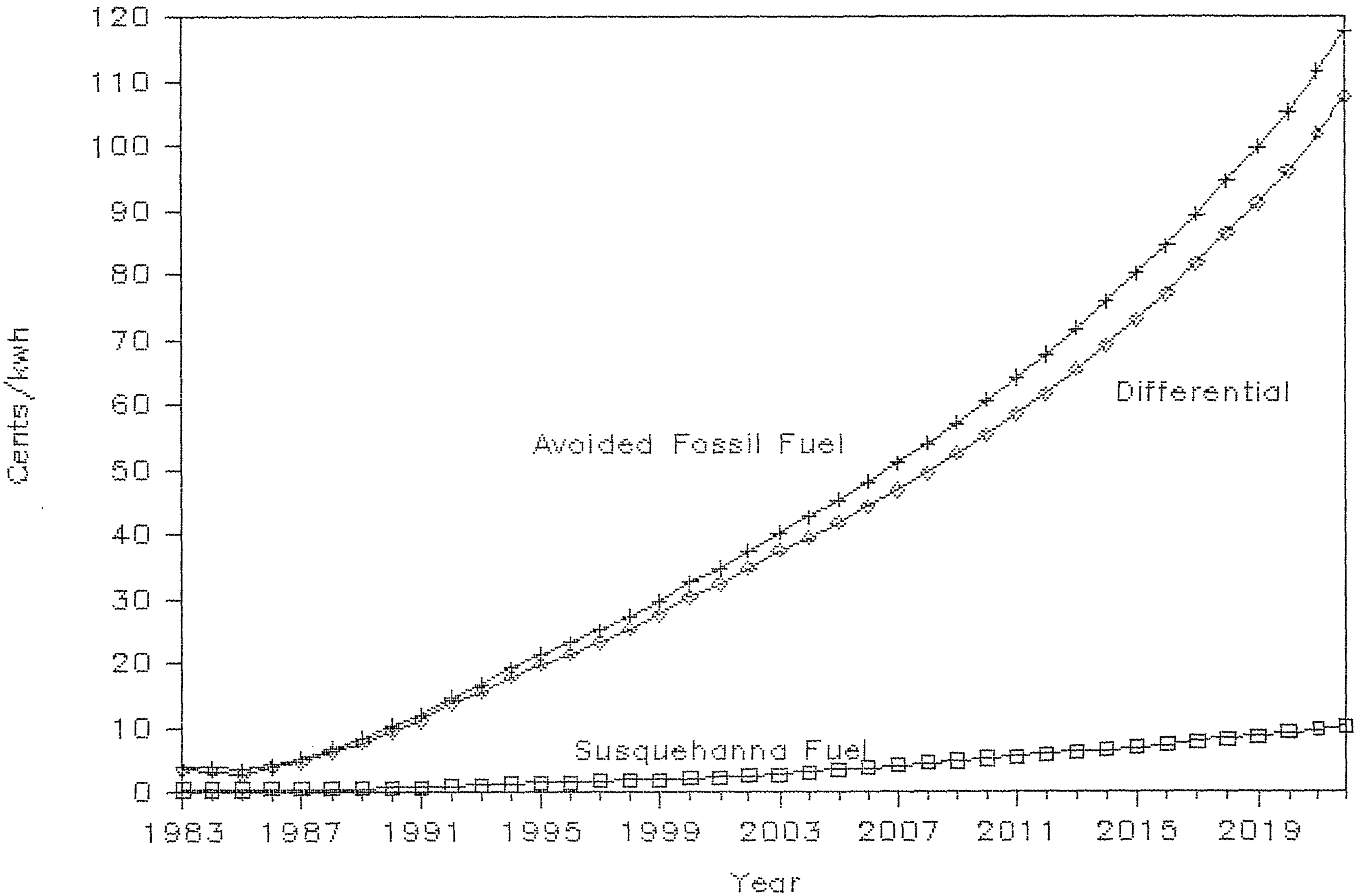
10. It is difficult to understand why this would be so. PP&L is only projecting a cost of $102/barrel for 1% sulfur residual oil in 1995; at 6 million BTU/barrel and 10,000 BTU/kWh (both fairly pessimistic estimates), the cost of power generated from that oil would only be 17 cents/kWh, while PP&L projects an avoided fuel cost of 21.4 cents/kWh in 1995. Of course, some Susquehanna power would replace coal, and most interchange sales would involve split savings of some sort, so the operating savings would be expected to be less than the price of oil-fired power, not greater.

# Fig 3.1: PP&L PROJECTED FUEL SAVINGS



unit. Unit 2 is also more expensive than its predecessor.

Q: How do PP&L's data support the conclusion that Susquehanna will not pay for itself soon?

A: In Table 3.2, I provide projections of the rate impact of the Susquehanna Station over its life, based on PP&L assumptions of cost, benefits, useful life, and load growth. Table 3.2 also provides a running simple total of the rate impact, and a running discounted total at a 15% discount rate.[11]. Even without discounting the cash flow, Susquehanna 2 would increase rates for PP&L customers as a whole until 1995. By 1990, the consumers would have paid out almost $1 billion extra. Discounting[12] the costs and benefits makes the situation slightly worse, pushing discounted breakeven to 1999. After PP&L's speculatively long unit life of 38 years, the discounted net savings are roughly $1.3 billion dollars (in 1984 terms): a large value, but still smaller than the initial investment. These relationships are plotted in Figure 3.2.<u>Thus, based on PP&L's own assumptions, Susquehanna 2 does not have positive present value benefits until the end</u>

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11. I refer to these statistics as the "cumulative net cost" and the "discounted net cost", respectively. As explained in Section 4, the discount rate is an approximation of the low end of customer discount rates, and is also PP&L's marginal cost of capital.

12. Discounting is necessary to make the costs and benefits in various years comparable: a dollar in 1995 is worth less than one in 1985.

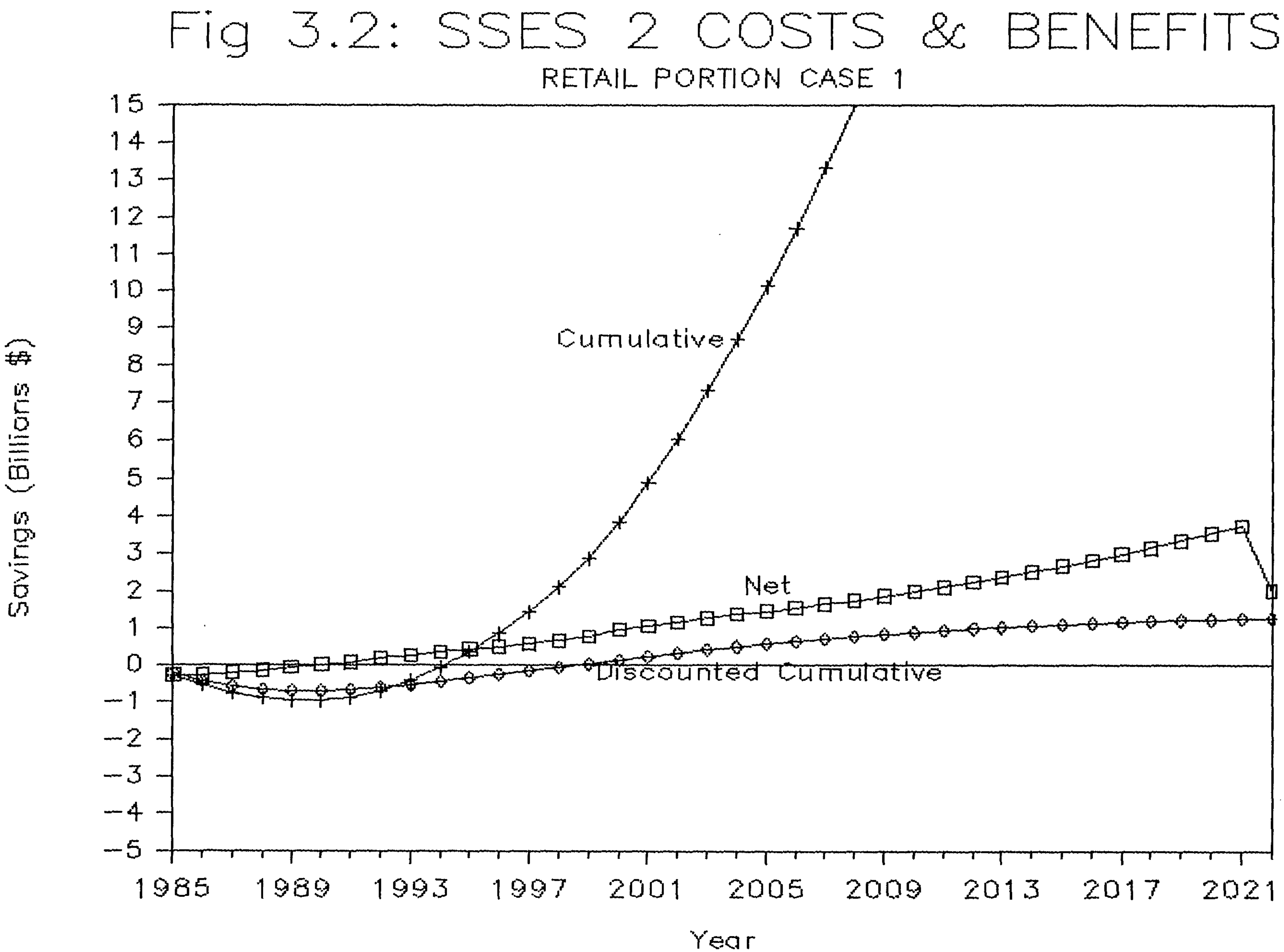


Fig 3.2: SSES 2 COSTS & BENEFITS
RETAIL PORTION CASE 1
Savings (Billions $)
15
14
13
12
11
10
9
8
7
6
5
4
3
2
1
0
−1
−2
−3
−4
−5
Cumulative
Net
Discounted Cumulative
1985
1989
1993
1997
2001
2005
2009
2013
2017
2021
Year

of the century.

Q: Are Table 3.2 and Figure 3.2 entirely the work of PP&L?

A: Almost. I assumed that 50% of the capital additions were attributable to Unit 2, but this is a relatively minor cost item. I even relied on PP&L regarding the share of savings attributable to Unit 2. PP&L offered the judgement that Unit 2 benefits would be 45% of the plants's benefits, without any apparent analytical basis. Thus, the value of Unit 2 power per kWh is projected to be 90% of the average value of the plant's power: I assume this ratio remains intact throughout the life of the plant, although the Unit 2 share of savings will vary with refueling cycles in the early years.

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

A: I have modelled the annual costs of Susquehanna 2 to PP&L ratepayers under conventional ratemaking techniques, for two sets of alternative assumptions. The inputs on which these analyses are based are the PP&L projections listed in Table 3.2, which I have labeled Case 1. In the other cases, which are based on the results of my review of PP&L's projections for Susquehanna 2 (described in Section 4 of this testimony), I have adjusted PP&L's projections to reflect more realistic assumptions, or at least assumptions more consistent with experience to date.

Q: What other cases have you analyzed?

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

- Case 2, which uses PP&L's assumptions, except for the use of realistic capacity factors, representing actual BWR performance in the 1980's,

- Case 3, which is the same as Case 2, but with annual capital additions 2.7 times as large as PP&L assumes, O&M expenses which continue to escalate at historical rates, decommissioning costs twice as large as PP&L assumes, and charges for return representing the debt and preferred rates of the issues which financed Susquehanna 2.

The results are shown in Tables 3.3 and 3.4, and in Figures 3.3 and 3.4. It is important to recognize that both of these cases use PP&L's very optimistic assumption that Susuehanna 2 will last 38 years, and also use PP&L's very high estimates of escalation in the value of operatings savings per kilowatt-hour.

Q: Please describe the results of the Case 2.

A: With realistic capacity factors (as described in Section 4.1 of this testimony), the first year in which Susquehanna 2 would save customers money on balance would be 1991. In that year, the cumulative net cost of the plant to PP&L's customers would have exceeded almost $1 billion. Simple

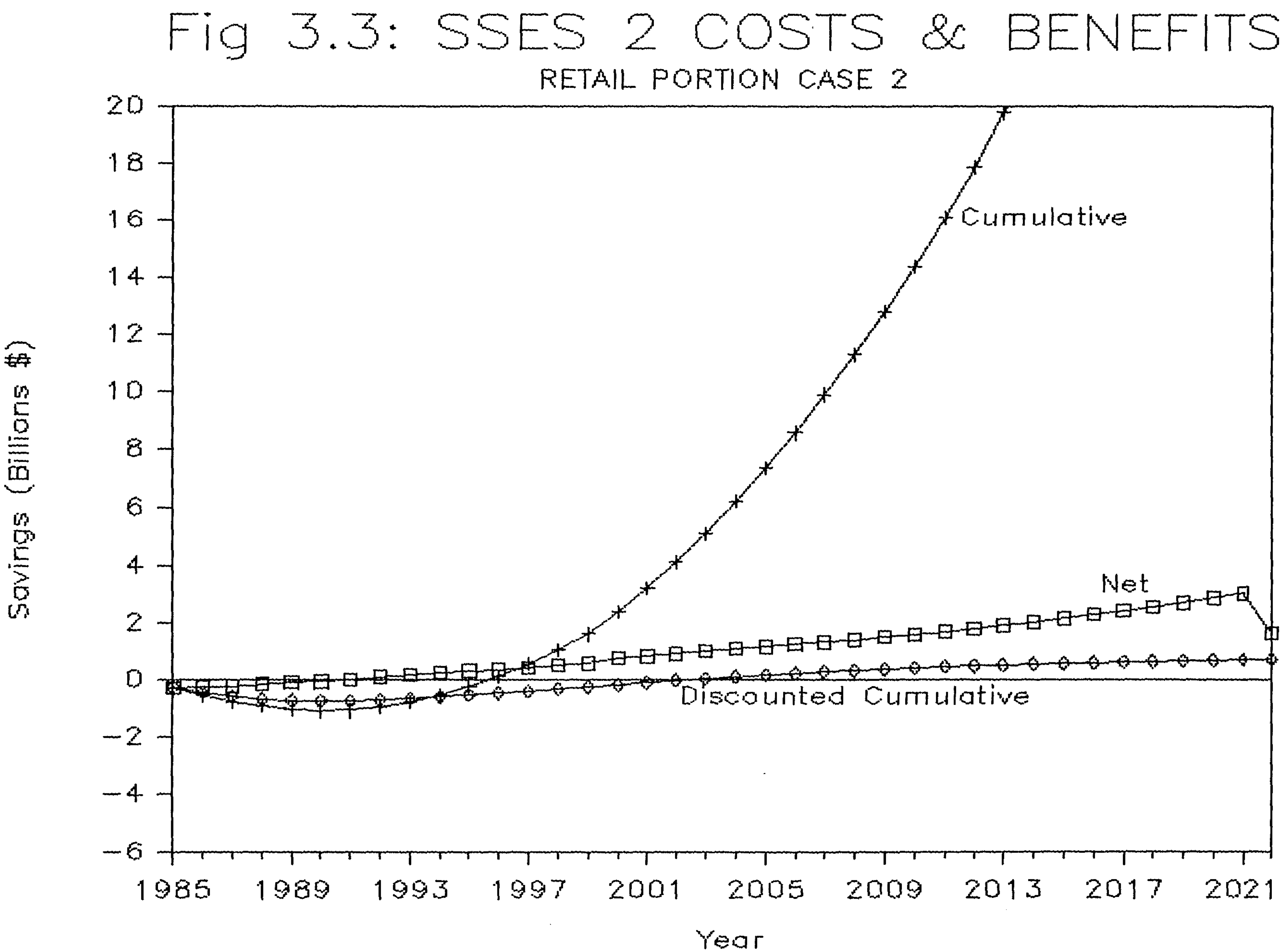
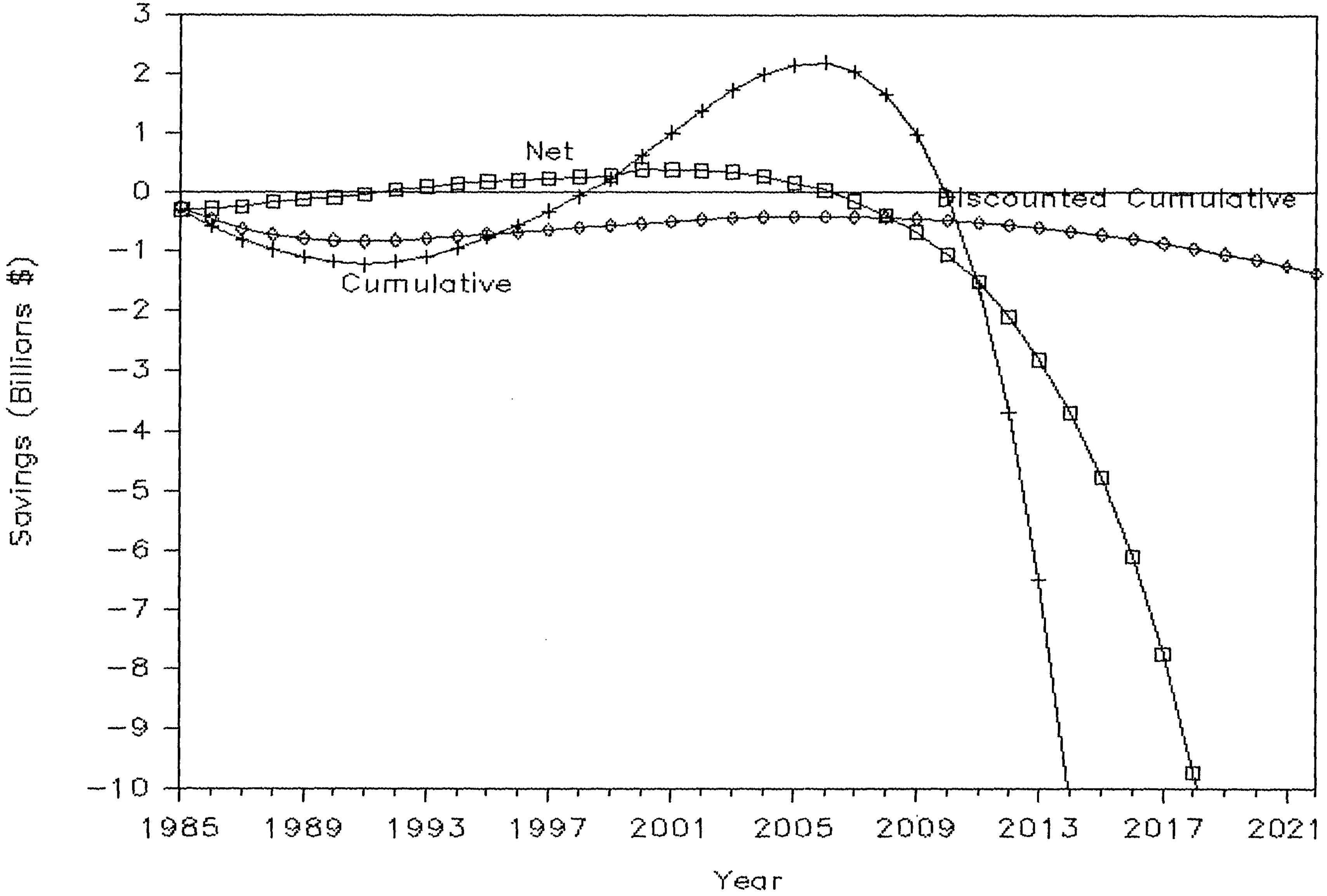


Fig 3.3: SSES 2 COSTS & BENEFITS
RETAIL PORTION CASE 2
Savings (Billions $)
20
18
16
14
12
10
8
6
4
2
0
-2
-4
-6
Cumulative
Net
Discounted Cumulative
1985
1989
1993
1997
2001
2005
2009
2013
2017
2021
Year

# Fig 3.4: SSES 2 COSTS & BENEFITS

RETAIL PORTION CASE 3



breakeven would not be reached until 1996. Discounted costs would break even in 2013, nineteen years into the Unit's useful life, and the total discounted benefit would be about $700 million in 1984 dollars.

Q: Do these results change substantially in Case 3, where the operating costs are adjusted to more realistic values?

A: Yes. With realistic operating cost estimates, Susquehanna 2 would cost ratepayers more than PP&L's projected operating savings each year until 1992, by which time the cumulative net cost of the plant to PP&L's customers would have exceeded $1.2 billion, and would reach simple breakeven in 1999. It would never break even in present value terms: total discounted operating savings would be less than total charges to ratepayers throughout the plant's life. The present value of net costs to ratepayers would reach more than 800 million dollars in the early 1990's, and would only decrease to about $400 million by 2006, after which costs would again exceed benefits. If the plant remained in service until 2022, the present value of the loss would rise above $1.3 billion, but continuation of the historical trend in O&M costs would probably result in retirement of the plant in the first decade of the next century. At that point, the present value cost (for Unit 2) about $400 million, not including the cost of the undepreciated portion of the plant, and the remaining funds required for decommissioning, which would also be in the hundreds of millions of dollars.

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

A: The dates I calculated may be meaningful for all ratepayers collectively, but not individually. Due to load growth (if PP&L is correct that loads will grow substantially), the later benefits of Susquehanna 2 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 Susquehanna 2 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.[13]

Q: Have you performed similar analyses, averaging the Susquehanna 2 rate effect over customer rates?

A: Yes. Tables 3.5 to 3.7 provide this information for retail rates, calculated as the net savings from Unit 2 for each kWh of annual use, and for a residential customer, using 8000 kWh annually. The growth in sales tends to dilute the savings to

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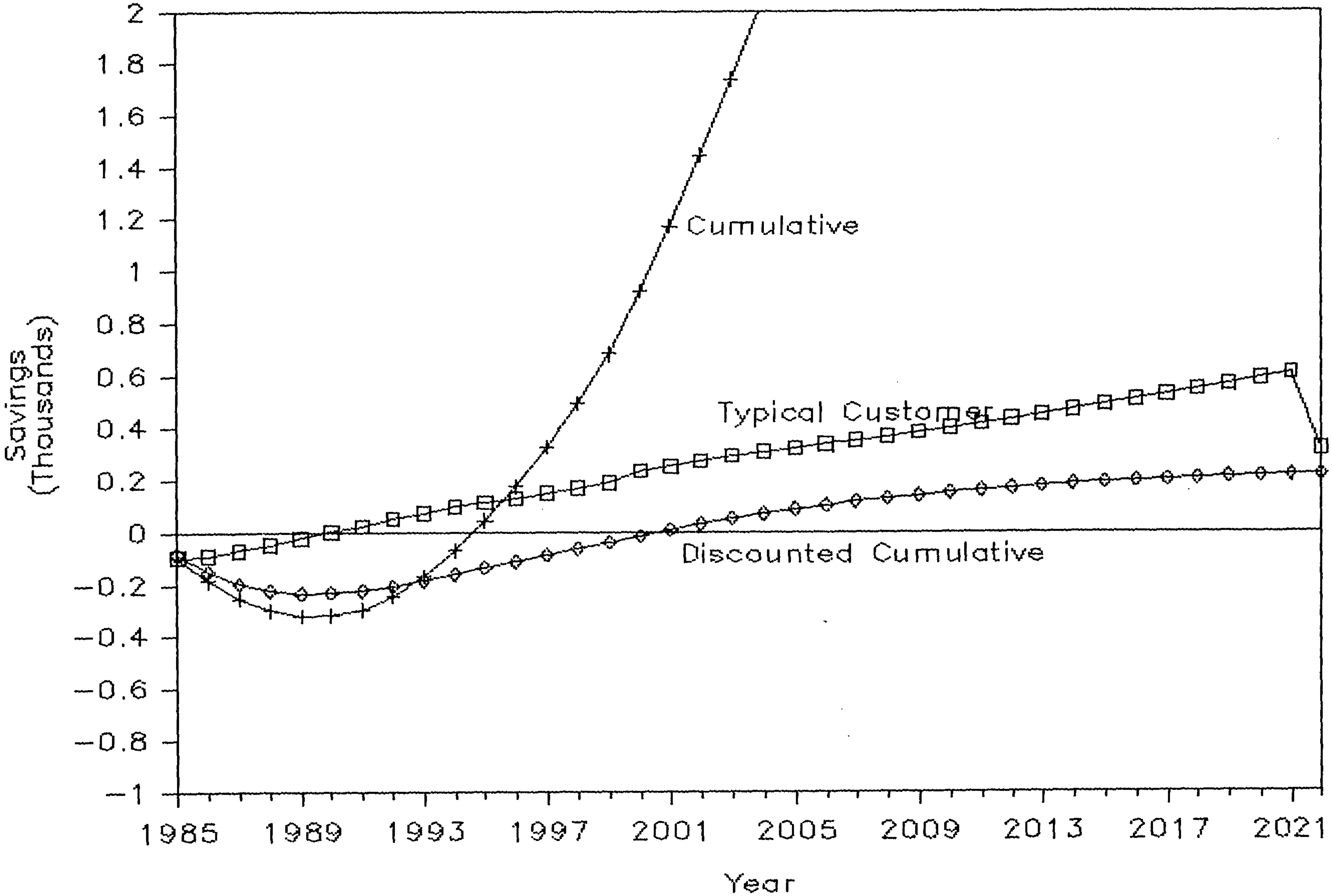
13. The elderly are particularly likely to pay for Susquehanna 2 without receiving commensurate benefits.

individual customers. In Table 3.5, for Case 1, PP&L's assumptions, the crossover point, where annual rates decrease, comes in 1990, and simple breakeven, where a customer whose usage is constant finally sees a net benefit from the plant, comes in 1995. Both of these points occur in the same year for the system and for the individual customer, despite the dilution due to load growth. At a 15% discount rate, discounted breakeven occurs two years later for the customer than for the system, in 2001. For the 8000 kWh residential customer, this Case would amount to paying out $320 more before the unit starts to save money. The same customer will wait 17 years to break even in present value, and wind up after 38 years with a saving equivalent to $220 in 1984. That analysis assumes that the customer stays on the system for 38 years, and that Susquehanna 2 survives equally long. A customer who left the system in the early 1990's would have suffered a net loss due to Susquehanna 2 of more than $230 in 1984. These results occur even under the high optimistic PP&L assumptions.

Tables 3.6 and 3.7 repeat this analysis based on the assumptions in Tables 3.3 and 3.4, respectively. The three cents/kWh projections are graphed in Figures 3.5 through 3.7. The most significant difference between the system and the customer occurs in Case 2: the system reaches discounted breakeven in 2003, but the customer with constant usage

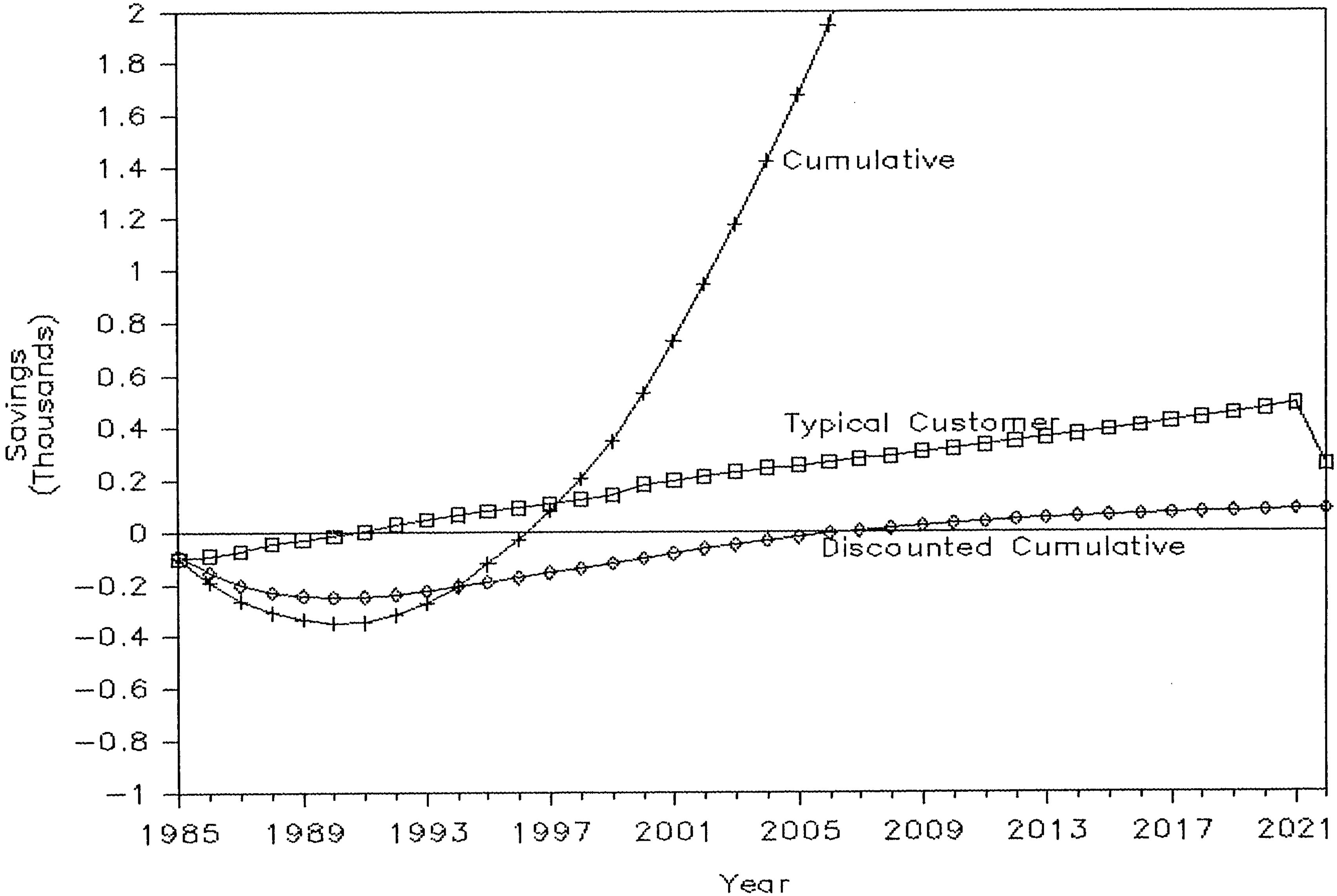
# Fig 3.5: SUSQUEHANNA 2

RETAIL RATE EFFECTS CASE 1



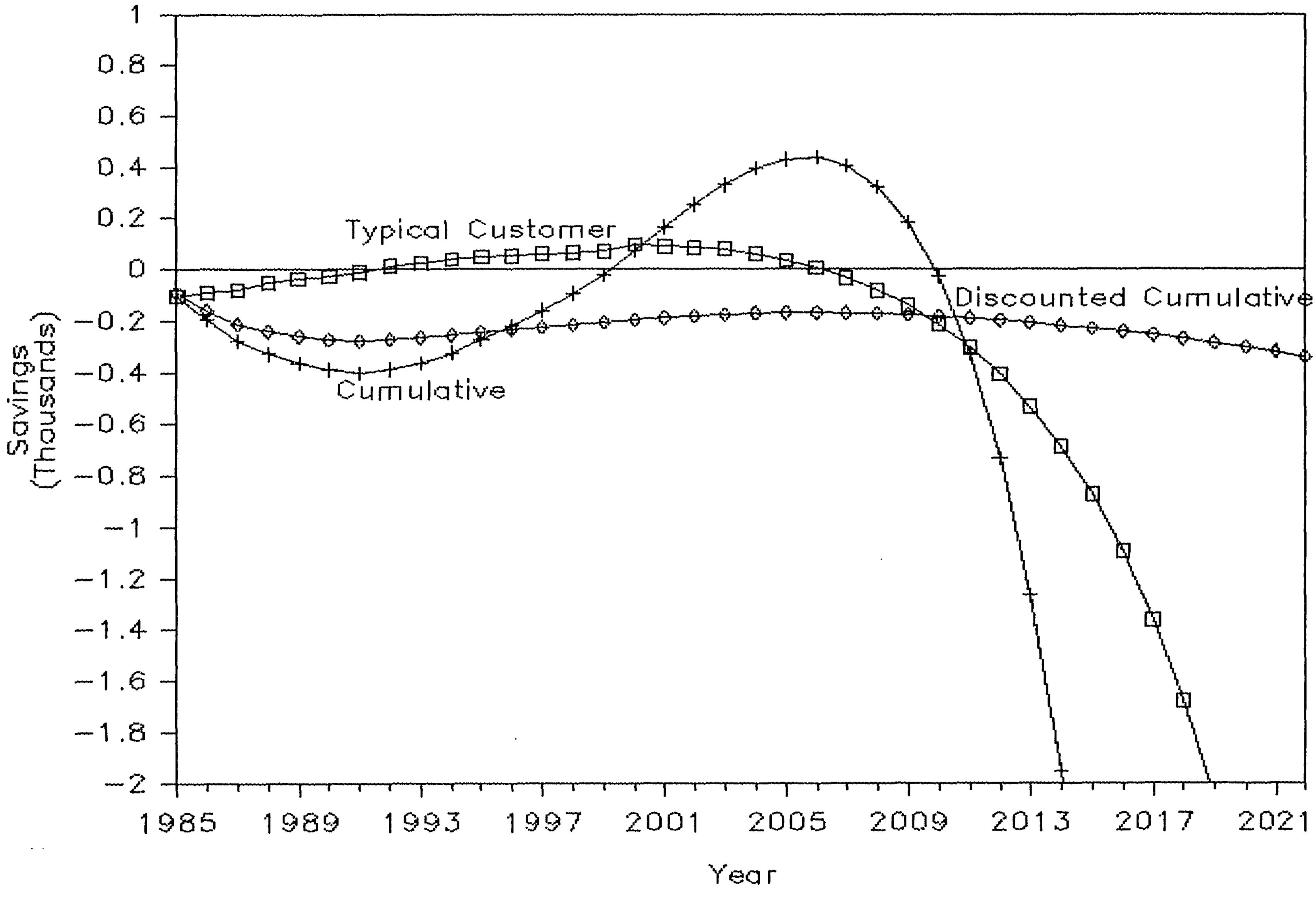
# Fig 3.6: SUSQUEHANNA 2

RETAIL RATE EFFECTS CASE 2



# Fig 3.7: SUSQUEHANNA 2

RETAIL RATE EFFECTS CASE 2



reaches that point in 2007. If past trends continue (Case 3), the customer never breaks even in present value.

Table 3.8 summarizes some measures of cost-effectiveness for each of the three total-cost cases and each of the cents/kWh analyses: the years of crossover, simple breakeven, and discounted breakeven, the cumulative net cost to ratepayers at crossover, and the net present cost.

Q: Do these results indicate whether Susquehanna is likely to be a good investment under conventional ratemaking treatment for the customers who pay for its early years?

A: The particular cases I presented above were selected from a wide range of possible outcomes. It is almost certain that PP&L's projections represent a best case for Susquehanna economics, but it is difficult to determine what a comparable worst case would look like.

What is clear from this analysis is that Susquehanna will be very expensive in its early years, as compared to its benefits, and that plausible performance and cost levels, and cost trends, would prevent Susquehanna Unit 2 from ever saving money for PP&L's customers. Furthermore, what might pay off for the system over 35 years may be highly uneconomic for individual customers over 10 to 15 years.

The variation in effects between customers is even greater than that suggested by the differences in net benefits for various time periods. Customers also vary in terms of their discount rates. The 15% discount rate which I used in my calculations, is very similar to PP&L's estimated 14.6% marginal cost of capital; use of the 14.6% rate would be consistent with standard utility practice. While this rate may be appropriate for some utility purposes, it is almost certainly lower than the discount rate that many ratepayers would apply in making their own decisions regarding energy cost reduction. 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: What can be concluded from these analyses?

A: First, even using PP&L's own projections, Susquehanna 2 will not save money for PP&L customers who pay for the plant's early, uneconomic years, unless they remain customers for at least fifteen years. Second, given PP&L's own projections, many customers would be better off if Susquehanna 2 had never been started, or had been canceled or sold off long ago. Third, if Susquehanna 2's cost and performance are consistent with past experience and trends, it is likely to be a poor investment for virtually all the ratepayers, and for customers as a whole.

## 4 - THE COST OF POWER FROM SUSQUEHANNA 2

Q: How have you estimated the cost of Susquehanna 2?

A: I have attempted to determine realistic estimates for the duration of Susquehanna 2 construction, its construction costs, and the various costs of running and decommissioning the unit. Based upon analyses of historical performance and trends:

1. Capacity factors (based on design rating) for Susquehanna 2 will probably average about 51% in the first four years and 60% thereafter, as compared to PP&L's average of 59% in the first four years and 70% thereafter.

2. Non-fuel O & M must be expected to continue escalating much faster than general inflation, and faster than PP&L is projecting.

3. The capital cost of the plant will also increase significantly during its lifetime, at about twice the rate PP&L projects.

4. Decommissioning and insurance must be expected to cost more than PP&L currently estimates.

This section also discusses choices of rates of return and discount rates used in evaluating the costs and benefits of Susquehanna 2 costs and benefits to ratepayers.

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

## 4.1 - CAPACITY FACTOR

Q: How can the annual kilowatt-hours output of electricity from each kilowatt of Susquehanna 2 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 PP&L are wholly unrealistic, it may be helpful to consider the role of capacity factors in determining the cost of Susquehanna 2 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 Susquehanna 2'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 4.1. The capacity factor is the ratio of the shaded area in regions A and B to the area of the rectangle, while the availability factor is the sum of the width of regions A, B, and C. Clearly, if the rated capacity is actually the maximum capacity of the unit, the availability factor will always be at least as large as the capacity factor and will generally be larger. Specifically, the availability factor includes the unshaded portion of region B, and all of region C, which are not included in the capacity factor.

Q: What is the appropriate measure of "rated capacity" for determining historical capacity factors to be used in forecasting Susquehanna 2 power costs?

A: The three most common measures of capacity are

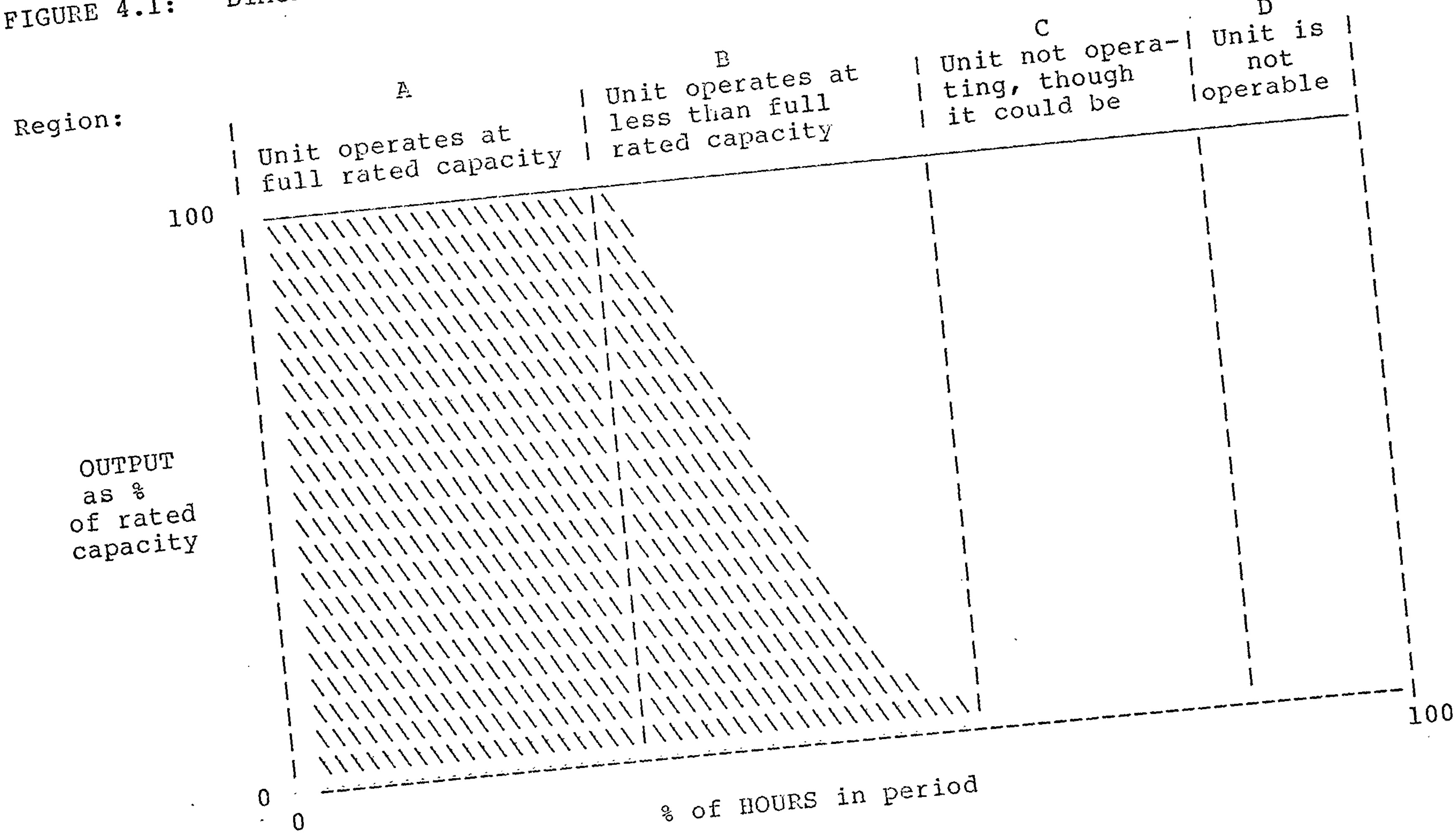
Maximum Dependable Capacity (MDC);

Design Electric Rating (DER); and

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

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

FIGURE 4.1: DIAGRAMMATIC DESCRIPTION OF AVAILABILITY FACTOR AND CAPACITY FACTOR




1. CAPACITY FACTOR = AVERAGE OUTPUT / RATED CAPACITY
   (Shaded Area / Area of Rectangle)

2. AVAILABILITY FACTOR = POSSIBLE HOURS OF PRODUCTION / TOTAL HOURS
   (Sum of widths A,B, & C)

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 Susquehanna 2 power cost would present no problem if the MDC's for

Susquehanna 2 were known for each year of its life. Unfortunately, these capacities will not be known until Susquehanna 2 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 1050 MW and 1152 MW, respectively. Since it is impossible to project output without consistent definitions of Capacity Factor and Rated Capacity, only DER and IGN capacity factors are useful for planning purposes. I use DER capacity factors in my analysis.

Actually, DER designations have also changed for some plants. The new, and often lower, DER's will produce different observed capacity factors than the original DER's. For example, Komanoff (1978) reports that Pilgrim's original DER was 670 MW, equal to its current MDC, not the 655 MW value now reported for DER. Therefore, in studying historical capacity factors for forecasting the performance of new reactors, it is appropriate to use the original DER ratings, which would seem to be the capacity measure most consistent with the 1050 MW expectation for Susquehanna 2. This problem can also be avoided through the use of the MGN ratings, although MGN ratings tend to be nominal, with limited relation to actual capability.

Q: Are PP&L's projections of Susquehanna 2 capacity factors reasonable?

A: No, they are significantly overstated. PP&L assumes that Susquehanna 2 will exceed previous reactor performance. After discussing the available information on nuclear capacity factors, and presenting consistent projections for Susquehanna 2, I will describe some of PP&L'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 BWR 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 a study by National Economic Research Associates (Perl, 1981).

The Komanoff study, the third in an annual series, utilized data through 1977 and projected a levelized capacity factor for the first eight full operating years for 1050 MW BWR reactors at 48.4%, correcting the size trend on the assumption that the Brown's Ferry fire was not size related. An alternative statistical analysis predicted a 44.2% capacity factor in years 1-4, rising to 51.6% in years 5 and later.[14]

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14. This study is now rather dated. However, considering the crucial role of Mr. Komanoff in applying statistical techniques

The first NRC study projects capacity factors on the basis of maximum generator nameplate (MGN). The prediction for an 1152 MW (MGN) BWR, expressed in terms of an 1050 MW DER, would be 49.9% in the second full year of operation, 52.1% in the third full year, and 54.3% thereafter. No further maturation was detected. All results for the first partial year and first full year of operation were excluded.

The second NRC study uses the same methodology and reaches similar, if somewhat more optimistic, conclusions. Easterling develops several equations for BWR's, using different data sets and different maturation periods, and concludes that maturation may continue through year 5. Table 4.1 shows the results of the equations which can be evaluated for Susquehanna 2. The first equation uses all data and four-year maturation, the second excludes two unit-years of particularly poor performance, the third introduces 5-year maturation, and the last excludes the size variable. The size variable is of low statistical significance in Easterling's results, but there is strong evidence which supports the belief that size does affect performance.[15]

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to capacity factor analysis, it would not be appropriate to exclude some mention of his work.

15. This evidence includes strong size trends in fossil plant performance, PWR performance, and even BWR performance excluding the two largest plants, as discussed below. PP&L's witness, Mr. Koppe, has repeatedly acknowledged the existence of a size trend

The use of the MGN measure of size introduces some problems in interpreting Easterling's results. Susquehanna, with a DER of 1050 MW, has the same nominal generator rating as units with DER's of 1065 to 1098 MW. To determine a more typical MGN for a 1050 MW DER plant, I computed the average MGN/DER ratio for the plants in Easterling's data set, which was 1.0442, compared to the 1.0971 value for Susquehanna. Table 4.1 presents the results of Easterling's regressions for a 1152 MW MGN BWR, a 1050*1.0442 = 1096 MW MGN BWR, and the DER capacity factors computed from the normalized MGN results.

Perl (1981) uses a very different functional form in the capacity factor equation, includes a vintage variable, and mixes in PWR's and some very small units.[16] The resulting equation predicts capacity factors rising from 55.9% in year 1 to 65.5% in year 5 at a 1050 MW unit (like Susquehanna 2). Contrary to NERA's normal practice, this regression allows the age effect to continue linearly for an unspecified period, so it is difficult to interpret the results past the

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for BWR's.

16. 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.

end of the maturation period. The NERA study itself uses a 61% overall capacity factor in its cost calculations for Limerick, similar in size and design to Susquehanna.

Q: Have you conducted your own regression analysis of BWR capacity factors?

A: Yes. The data is listed in Appendix B, and the results of my regressions are given in Table 4.2. Projections for Susquehanna 2 performance, based on those results, are presented in Table 4.3. As shown in Table 4.2, I incorporated the following variables:

1. unit size, in original DER,
2. unit age, with maturation assumed at 5 years,
3. the portion of a refueling outage which occurred in the year, usually taking the values of 0 or 1,
4. an indicator for units of more than 1000 MW, and
5. indicators for various recent years.

Data were available for 192 full calendar years of operation at BWR's of more than 300 MW from 1974 to 1983. A small amount of pre-1974 operating experience could not be used for lack of refueling data.

Equation 1 demonstrates that 1979 was a better year for BWR performance (although not significantly so), and that each of the following years has been progressively worse. Despite the steady downward trend in recent years, I grouped the post-1979 data in Equation 2, which shows that 1980's performance has been 9.3 percentage points below 1970's performance. Equation 3 repeats Equation 2, omitting Brown's Ferry in 1975 and 1976. Table 4.3 provides the projections of Equations 1, 2, and 3 for Susquehanna 2, assuming that it enters service January 1, 1985, that it operates under the conditions which have prevailed recently, and that it shares in whatever benefits have allowed Browns Ferry and Peach Bottom to escape the size trend that affects PWR's and smaller BWR's. Depending on the Equation, the mature capacity factor ranges from 54% to 60%.

Q: What capacity factor value should be used in estimating Susquehanna 2 power cost?

A: Average life-time capacity-factor estimates for units like Susquehanna 2 would seem to lie in the range of 50% to 65% 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% for years 2 to 10 at 1100 MW BWR's. Roughly speaking, those earlier NRC results predict that 19 out of every 20 nuclear units of the Susquehanna 2 size and type would have average ten-year capacity factors between 37% and 47%, with the 20th unit having a capacity 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.[17]

Predicting the future effects of regulation, of safety issues, and of aging is difficult at best. Overall, I feel most comfortable using the results from Equation 3 in Table 4.3, which uses data through 1983, corrects for the variations due to refueling patterns, and allows for the explicit selection of the operating conditions assumed for the future, which I freeze at average 1980-1983 conditions, some three points above 1983 results. Improvements in these conditions could also be assumed, but given the persistence of sub-average conditions and the downward trend in every year since 1979, deterioration seems more likely than improvement. Thus, I believe the best current estimates for Susquehanna are 50%, 44%, 58% and 51% in years one to four (averaging 50%), and an average of 60% threafter.

Q: Are PP&L's projections for Susquehanna 2 capacity factor reasonable?

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17. 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: No. To compare the accuracy of the capacity factors I derived above from the Easterling results, and PP&L's projections, to actual results, I have performed the calculations presented in Table 4.4. For the five BWR's over 1000 MW which had entered service by 1979, the average capacity factor as of December 1983 was 56.7%. The capacity factor estimates which I derived from Easterling (1981) predict an average of 61.1%, while PP&L would predict an average of 65.9%. Clearly, PP&L's expectations are highly optimistic. The performance of each of these five units is somewhat below the Easterling results; this is true even if the Browns Ferry 1 and 2 data is adjusted to remove the direct effects of the fire at that plant. The actual five-unit average will vary with refueling schedules, is based on only two plants and two utilities, and has less data than either Easterling or I used. At the very least, the actual data supports the conclusion that the Easterling results do not understate capacity factors, based on average historical conditions. My results are similar to Easterling's for those average conditions.

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

A: Yes. Table 4.5 presents the annual capacity factors for the units used in the previous analysis, through December 1983. No other large (over 1000 MW, or even over 825 MW) BWR's have completed a full year of commercial operation. I have assumed that the very low capacity factors for Browns Ferry in 1975 and in 1976, resulting from the fire at that plant, 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 (if not exactly identical) problem can not occur for Susquehanna. Hence, I delete these three observations from the individual year calculations, and instead reflect the probability of a major problem by computing the average effect. Compared to the results for all the other plants, this event reduced capacity factors by a total of 82.3 percentage points from average first year performance, and 48.0 points from second year performance, in 41 unit-years of experience, for a 3.2% reduction in all capacity factors. This calculation is also shown in Table 4.5. The average capacity factor which results from this analysis is 57.1%; the mature capacity factor is 56.3%. The overall and immature average are somewhat overstated because they include data from before the Three Mile Island accident, which has depressed capacity factors consistently over the last four years. Even so, this analysis indicates that PP&L's projections for Susquehanna 2 capacity factor are much higher than the actual performance of large BWR's.

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

A: I believe that it is, for two reasons. First, the regulatory effects of Three Mile Island have depressed PWR capacity factors for the last five years, and BWR capacity factors for the last four years, with no sign of recovery to previous levels. Second, several more major nuclear accidents or near-misses are likely to occur before the scheduled end of Susquehanna 2 operation. Various recent estimates of major accident probabilities range from 1/200 to 1/1000 per reactor year (See Chernick, et al., 1981; Minarick and Kukielka, 1982). These estimates are based on both the implicit probability assessments of nuclear insurers, who must actually bet their own money on being correct, and on engineering models of actual reactor performance. Thus, major accidents can be expected every two to ten years once 100 reactors are operating. If anything, the 1968-83 period has been relatively favorable for nuclear operations, and BWR performance appears to be deteriorating steadily in the 1980's.

Q: What are the errors in PP&L's capacity factor projections?

A: Mr. Koppe, who supplies PP&L's capacity factor projections, makes at least two kinds of errors. First, he assumes that the string of nuclear operating and safety problems, which have developed over the last decade or so, has ended. While he is undoubtedly correct that the fire at Browns Ferry, or the exact accident that occurred at Three Mile Island, will not recur, it is perfectly possible that a third event (and more thereafter) will have just as significant direct and regulatory effects. Indeed, the assessments of major accident probabilities which I listed above indicate that such events must be expected periodically. While we all may hope that the operational problems of nuclear power plants are over, it does not seem reasonable to set charges for ratepayers based on the assumption that everything will go well in the future.

Second, at least one of his specific adjustments to past experience appears to be incorrect. Mr. Koppe notes that the mature capacity factors of the plants in his historical database[18] are about three percentage points below their equivalent availability factors (EAF's). EAF is a subjective measure, reported by the operating utility and representing only the utility's opinion of what the unit might have done, if not for factors which the utility may wish to consider to be "economic". These "economic" factors include, for example, reductions in output to delay a refueling outage until other nuclear units have completed maintenance or repair procedures. Mr. Koppe assumes that Susquehanna 2 will have a capacity factor similar to historical EAF's, rather

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18. His selection of plants is quite similar to mine: he excludes two units used in my regressions.

than historical CF's. Under the best of conditions, EAF is a performance measure of limited usefulness, due to its subjective nature., such as conflicts with other nuclear outages. Furthermore, the calculation of EAF assumes that the unit would have run perfectly if not for the "economic" limitation.

Even if EAF were not such a flawed measure, there is little reason to believe that historical EAF's would provide better (or even as accurate) predictors of Susquahanna CF than would historical CF's. Mr. Koppe suggests that EAF's differ from CF's only because of "load following" and "load leveling", which Susquehanna 2 will not do. He also suggests that Susquehanna will be unusual in that it will be base-loaded. In fact, essentially all nuclear units in the US are base-loaded, and the evidence for load following, per se, is scant.

The error in Mr. Koppe's assumption about load following, and its relevance to Susquehanna, can best be seen by examining the EAF's and CF's reported for existing PJM nuclear units. These data (taken from a report Mr. Koppe authored) are listed in Table 4.6: there are sizable differences between EAF and CF for existing nuclear units in the pool, despite baseload operation and a much less nuclear-rich mix of capacity than will exist with Limerick, Hope Creek, and

Susquehanna in service. It is clear from that Table that EAF's are useless for predicting capacity factors for PJM nuclear units: it appears likely that Susquehanna will have reported EAF's higher than its CF's, at least in some years.

4.2 - CARRYING CHARGES

Q: How should the annual carrrying charges for Susquehanna 2 be calculated?

A: The carrying charges are determined by the cost of capital, income and other taxes, and the assumed unit lifetime. I have assumed a useful life for Susquehanna 2 of 25 years, as a compromise between possibilities of 20 years and 30 years. The shorter lifetime is based on an analysis of the experience of smaller nuclear units, as discussed in Chernick, et al. (1981, pp. 101-109), while the longer lifetime is a more standard industry assumption.[19] For the cost of capital, I have computed the average cost of capital using debt and preferred rates from Susquehanna's construction period, as shown in Tables 4.7 to 4.9; Table 4.9 uses the capital structure and equity return assumed by PP&L's "Overview" in this case.

For the nominal dollar analysis presented in Section 3, I have adopted and extrapolated PP&L's tax figures.

Q: What other costs must be added to the Susquehanna 2 carrying

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

costs to determine the total cost of Susquehanna 2 power?

A: The other components of the costs of Susquehanna 2 which are directly assignable to that plant are:

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

Q: Have you computed a discount rate applicable to PP&L's investment in Susquehanna?

A: I have calculated PP&L's marginal cost of capital, in Table 4.10, based on PP&L's projected cost of new debt & preferred, and the implied return on equity in its $330 million rate request. This is a standard approximation for utility discount rates, but is not really the proper approach for determining the discount rate to be applied to customer charges for Susquehanna.

Q: Is PP&L's use of a 9.7% discount rate appropriate?

A: No. It is important to recall that this discount rate is being used to discount cash charges to customers,[20] and should therefore reflect the time and risk preferences of the customers, rather then of PP&L itself, or of its shareholders. The discount rate used should reflect the degree of risk involved in the projected stream of costs and benefits. If Susquehanna just broke even for the customers (had a 0 net present value) at 10%, for example, it would be equivalent to a return of 10%. For an investment with the risk characteristics of Susquehanna, this is an implausibly low target return, roughly equivalent to a ten-year payback.[21] This is roughly the return one would expect from an investment approximately equivalent to risk-free Treasury securities. I do not believe that any reasonable person would suggest that Susquehanna is as safe an investment as government bonds.

In addition, when electric ratepayers have the opportunity to make conservation investments, even ones much less risky than Susquehanna, they generally appear to require returns well in excess of 10%, and even well in excess of the 15% that I use

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20. It is meaningless to apply discount rates to anything other than cash, and the discounting is applied to net customer savings, not to PP&L's cash outlays.

21. This simplification would be correct if the benefits to the ratepayers were very long-lived and constant, which they are not. Since traditional ratemaking front-loads the costs of new plants, and since the benefits of Susquehanna grow over its lifetime, the payback would be later than ten years.

as a discount rate. Industrial firms, for example, will rarely make non-productive investments with expected paybacks of more than four years, and for some firms this target is less than one year. Similarly, Hausman (1979) found that residential consumers used real discount rates of 15-25% in comparing appliances of differing efficiencies. These high discount rates indicate that most consumers would not be willing to pay the costs of Susquehanna, if they could expect a savings return of only 14%, and they would not even consider it at the 10% discount rate which PP&L appears to prefer.

Given the considerations outined above, the 15% discount rate I use is probably a minimum reasonable value, and a considerably higher figure (say 20%) may be appropriate. First, PP&L is basing its discount rate on its costs of capital, rather than the customer's discount rates;this is a common error in utility practice. Second, PP&L incorrectly calculates even its own cost of capital by using the "after tax cost of money" computation, which subtracts the tax benefits from the debt portion of the capital structure. This is an appropriate calculation of corporate discount rates only if the subject investment is as risky as the company's average investment[22] and if either (a) revenues do

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22. Susquehanna must be much riskier than PP&L's average business risk, for its distribution, transmission, and even fossil

not vary with financial structure (which is true for most corporations, but not for utilities), or (b) there is no cash return on the investment (which is true for AFUDC, but not for rate base). If the return on investment is to be covered by increased revenues, taxes must be added to the cost of money, not subtracted, to establish a discount rate at which the consumers would be indifferent between expensing and capitalizing expenditures. This point is illustrated in Table 4.11, which compares a $1000 cash expenditure with the same cost rate-based and depreciated over 10 years, under traditional rate-base treatment, and shows that the present value of the annual revenue requirements is equal to the initial investment only for a discount rate equal to the average return, plus taxes on the equity portion. Since the utility is paid a cash return on its investment, it must pay additional taxes if it capitalizes, rather than expenses, the $1000 cost in the example. Hence, the discount rate at which the consumers are "neutral" between expensing and capitalizing is the overall rate of return, plus income taxes. Only if the capitalized investment yields no current return will the net-of-tax rate be the discount rate at which ratepayers are indifferent between expensing and capitalizing the cost.

While the preceding calculation is an interesting one, it

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generation.

only determines the breakeven discount rate in the choice between capitalizing and expensing costs, not what actual <u>consumer</u> discount rates are. As I explained above, only the <u>consumers</u>' actual time preferences should matter in selecting a discount rate.

### 4.3 - FUEL COST

Q: What nuclear fuel costs have you used?

A: I used PP&L's estimates of 0.6 cents/kWh for Susquehanna fuel in 1985, rising to 10.3 cents in 2022. These figures are listed in Table 3.1.

4.4 - NON-FUEL O & M

Q: How have you estimated non-fuel O & M expense for Susquehanna 2?

A: I have examined the available historical data on nuclear O&M for domestic nuclear plants. Table 4.12 lists the non-fuel O&M for each U.S. nuclear plant for each full operating year from 1968 to the most recent available data. Years in which units were added have been deleted.

Table 4.13 restates this data a little more conveniently for all two-unit plants which were on line before 1980, along with the GNP deflator. Table 4.13 also presents the annual nominal and real compound growth rates for each plant.

Table 4.14 presents the results of five regressions using the data for plants of more than 300 MW, from Table 4.12, in 1983 dollars. A total of 413 observations were available. All five equations indicate that real O&M costs have increased at 13.6% to 13.8% annually, and that the economies-of-scale factor for nuclear O&M is about 0.50 to 0.57, so doubling the size of a plant (in Equations 1 and 2) or of a unit (in Equations 3 - 5) increases the O&M cost by about 42-48%. Equations 1 and 2 indicate that, once total plant size has been accounted for, the number of units is inconsequential, and the effect on O&M expense is statistically insignificant: indeed, the two equations disagree on the direction of the small effects they do detect. Equations 3 and 4 both measure size as MW per unit, and they both find that the effect of adding a second identical unit is just a little less than the effect of doubling the size of the first unit: 43% for Equation 3 and 39% for Equation 4.[23] Equation 5 tests for extra costs in the Northeast, which are commonly found in studies of nuclear plant construction and operating costs, but is otherwise identical to Equation 3. Indeed, there is a highly significant differential: Northeast plants cost 28% more to operate than other plants (using the definition of North Atlantic from the Handy-Whitman index). I will use this Equation as the basis of my projection.

Q: What O&M projection would your regression results predict for Susquehanna 2?

A: Table 4.15 extrapolates the results for Equation 5 for a first and a second unit of 1152 MW MGN, and displays the annual nominal O & M cost implied for each Susquehanna unit over the period 1983 - 2022, which is PP&L's projection of the plant's useful life. The same table compares these

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23. The two equations do treat extra units differently after the second: a third unit increases costs by another 39% (or 55% of the first-unit cost) in Equation 4, but only by 23% (or 33% of the first-unit cost) in Equation 3. The treatment of additional units in Equation 3 seems more plausible, in that each succeeding unit should be progressively less expensive to run.

results with PP&L's projections.

Q: Are PP&L's projections reasonable?

A: Based on national trends, PP&L's projections for O&M for the plant are highly optimistic, but not implausible: PP&L predicts somewhat high costs in the first few years, but a very low real growth rate.[24] The proportion of costs allocated to the second unit, as compared to the first, is much larger than would be expected from national data. Thus, I believe that PP&L's projection of Unit 2 O&M costs can be used as a plausible, but quite optimistic estimate of those costs. However, as Equation 5 indicates, Susquehanna is likely to be much more expensive to operate than plants outside the Northeast. Indeed, it appears from the first-year data at Susquehanna 1, and from PP&L's short-term projections of O&M costs, that Susquehanna is a particularly expensive plant to operate. Annualizing first-year non-fuel O&M at Susquehanna 1[25] yields a 1983 first-unit O&M cost of $63.8 million, compared to the Equation 5 projection of $52.2 million.

Protracted geometric growth in real O & M cost at historical rates would probably lead to retirement of this plant (and

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24. PP&L's O&M estimates apparently are meant to include insurance, so they are further understated.

25. $35 million over 29 weeks.

most nuclear plants) fairly early in the century, as it would then be prohibitively expensive to operate (unless the alternatives were even more expensive than PP&L predicts). High costs of O & M and necessary capital additions were responsible for the retirement (formal or de facto) of Indian Point 1, Humboldt Bay, and Dresden 1, after only 12, 13, and 18 years of operation, respectively. Thus, rising costs caught up to most of the small pre-1965 reactors during the 1970's: only Big Rock Point and Yankee Rowe remain from that cohort. The operator of LaCrosse, a small reactor of 1969 vintage, has announced plans to retire it in the late 1980's. San Onofre 1, a 450 MW unit, appears to have been retired, as well, after about 15 years of service.

On the other hand, our experience with nuclear O&M escalation stretches over only 15 years (1968-1983), so projecting continued real escalation past the year 2000 (another 15 years into the future) is rather speculative.

On the whole, I believe that my projection of $33 million in 1985, with 20.6% annual escalation is more likely than PP&L's projection of $55 million in 1985, with only 8.1% annual escalation.

4.5 - CAPITAL ADDITIONS

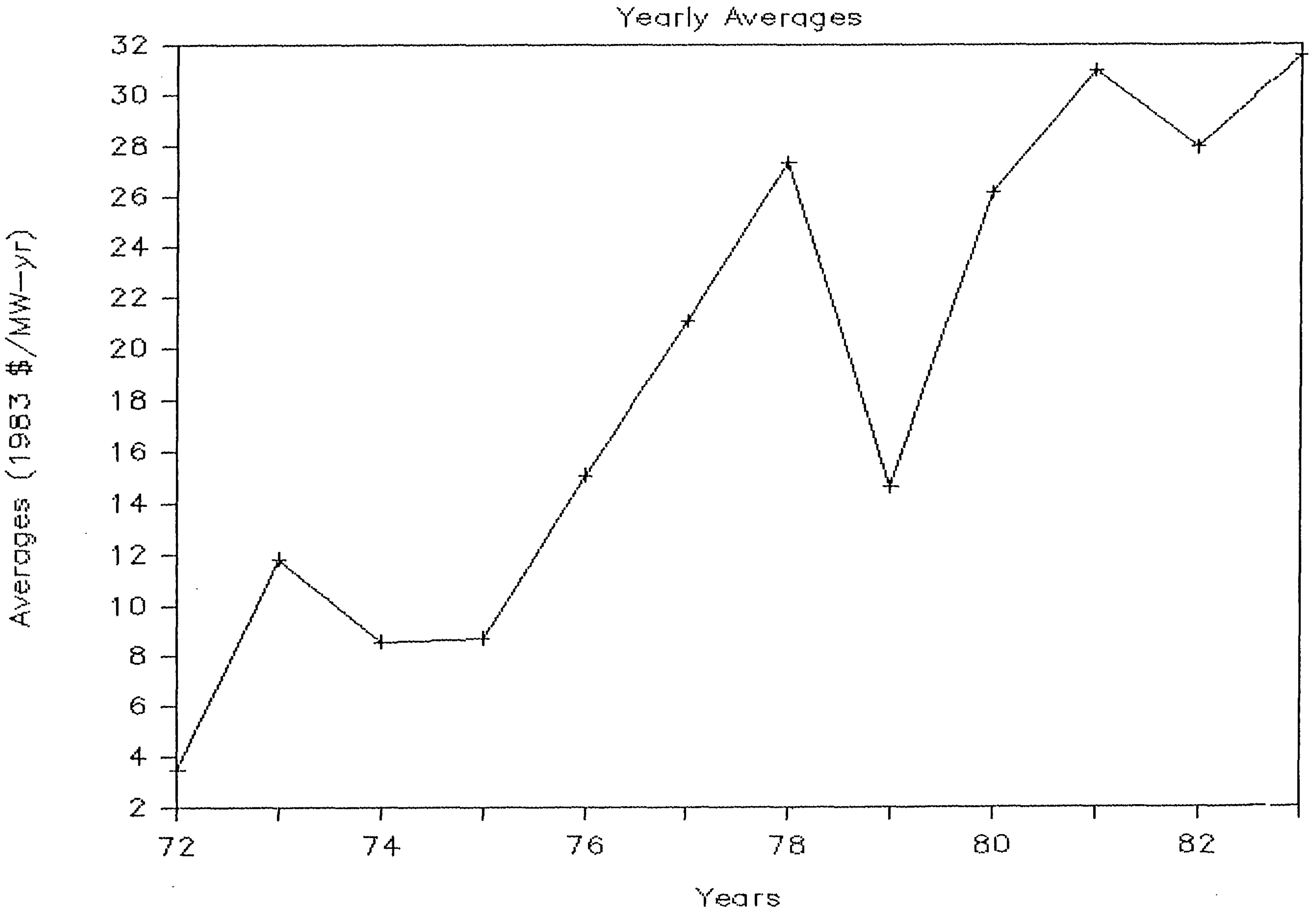
Q: Is PP&L's estimate of capital additions to Susquehanna 2 reasonable?

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

Q: How did you estimate capital additions?

A: I gathered data for all plants for which cost data was available from FERC and DOE compilations of FERC Form 1 data (now reported on p. 403), through 1983. The data is listed in Table 4.12. Each plant is included for all years in which no units were added or deleted, and for which the data were not clearly in error. The available experience totalled 477 unit-years of operation, and the average annual capital addition in the database was \$19.4/kw expressed in MGN terms, or about \$22.3 million annually for Susquehanna 2 (at 1152 MW, MGN) in 1983 dollars. As Figure 4.2 and Table 4.16 show, levels of capital additions have increased over time. Over the last seven years, the average may have stabilized at about \$26.2/kw-yr, or it may be increasing at about \$2/kw-$yr^2$. Some of the trend in the data may result from plant aging, and another portion is undoubtedly related to TMI-inspired regulatory charges, so extrapolating the trend

Figure 4.2: Nuclear Capital Additions



out is somewhat speculative. If capital additions continue at \$26.2/kw-yr in 1983 Handy-Whitman dollars, and if the nuclear Handy-Whitman index continues to run 1.4 points above the GNP deflation (which I project at 4% in 1984 and 6% thereafter, essentially the same as PP&L), the annual capital additions for both units at Susquehanna would be as shown in Table 4.17, which also shows PP&L's projections of capital additions. The overall upward trend is evident from 1972-78, as well, so any TMI-related effect constitutes a continuation of the trend, rather than a unique event. I therefore assume that capital additions at Susquehanna 2 will continue at recent levels, starting at \$34 million in 1985 and rising at 7.4% annually. PP&L assumes a complicated pattern of additions, starting at \$25 million in 1985, falling dramatically to \$15 million in 1989, and then rising at only about 6% through 2017.

4.6 - INSURANCE

Q: What would a reasonable estimate be for the cost of insuring Susquehanna 2?

A: I would assume that PP&L would want to obtain the following insurance:

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 (including just GNP inflation). While only the liability and some property coverage are currently required, failure to utilize insurance exposes the ratepayers and stockholders of PP&L to additional costs, which may be greater (on the average) than the insurance premium. Indeed, even with all the insurance listed, PP&L would still not be fully covered in the event of the total and permanent loss of Susquehanna 2.

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

Q: How does this figure compare to PP&L's estimate?

A: PP&L reports (Exhibit Future 1, Schedule D-11) that it expects to spend $1.913 million for nuclear insurance at Susquehanna 2 in 1985, implying an insurance cost of $2.126 million for the entire unit. This may well be all that PP&L spends, but the result will be a heavily under-insured plant. Since annualized insurance expenditures at Unit 1 were $6.5 million in 1983, it is difficult to understand why the insurance cost for Unit 2 should be so much lower. Even the unit 1 1983 expenditures, with inflation to 1984, would still be substantially lower than the full coverage I have defined.

4.7 - DECOMMISSIONING

Q: What allowance for decommissioning should be included in the cost of Susquehanna 2 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. 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 $12.4 million per year over a 25 year life, or $7.8 million annually for a 10 year life.

Q: How does this compare to PP&L's assumed decommissioning cost?

A: PP&L uses a traditional engineering estimate of decommissioning costs of $124 million/unit in 1983 dollars, or about $131 million in 1984 dollars. Decommissioning cost estimates have been subject to the same sort of errors and escalation as have estimates of nuclear construction and O&M costs. Also, experience with decommissioning has been limited to small units with little operating history.

## 5 - CONCLUSIONS

Q: What do you conclude from your examination of the need for, and economics of, Susquehanna 2?

A: First, I conclude that Susquehanna 2 will not be required for system reliability in the rest of this decade, and probably for much longer. Second, I conclude that Susquehanna 2 does not provide an economic benefit to the ratepayers under normal ratemaking treatment, and will represent a net loss to PP&L's ratepayers (in 1985 and for at least the next six years) if the entire cost of the plant is recovered. Even if PP&L's optimistic cost and operating projections are achieved, and even if operating savings are as large as PP&L predicts, rates would be higher for the rest of the decade to pay for Susquehanna 2, and the cumulative discounted rate effect will represent an increase until near the end of the century. The effects on individual customers will be even more severe, as would the effects if historical patterns in operating cost and reliability continue. Under traditional ratemaking, customers in the 1980's and much (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 two major implications. First, because the benefits and costs under traditional ratemaking would be so out of line, and would tend to fall on very different groups of ratepayers, the cost of the plant should be recovered in a manner which more closely follows the benefits over time. In other words, a substantial phase-in of plant costs is absolutely necessary to produce any semblance of equity. Second, it is doubtful that the entire cost of the second unit will ever be justified by its operating savings for customers, and it is almost certain that the plant will have little or no reliability value.[26] Thus, there is substantial question as to whether the entire investment is useful to the ratepayers.

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

A: For all the previously stated reasons, I believe that it would be appropriate and equitable for the Department to reject PP&L's phase-in proposal, to indicate an intention to phase Susquehanna 2 into rates so as to (at least roughly) follow the pattern of savings from the plant, and limit initial base-rate cost recovery for Unit 2 to the level of its benefits in each year.

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26. Whether or not these benefits materialize later in the plant's life, even PP&L appears to agree that they will not exist within the five-year time frame used in the PP&L phase-in proposal.

Q: How could the goals you suggest be implemented?

A: There are several ratemaking approaches which might be used to reduce the inequities of the Susquehanna 2 rate effects. First, since Susquehanna 2, as a whole, is neither needed for reliabile operation nor beneficial in reducing rates, the Commission may quite reasonably keep the entire unit out of rates. If the shareholders must pay the costs of the unit, it is only fair to allow them the benefits produced by the unit. Thus, both the costs and the operatings savings of Susquehanna 2 could be kept below the line: in effect, Unit 2 would become the world's largest small power producer.[27] It is my understanding that PP&L's ECR mechanism would have to be amended to allow the shareholders to retain the actual operating savings from the plant.

Second, the Commission could place the unit above the line, but disallow the equity portion of return on the investment. This would have the effect of allowing recovery of all direct costs for the unit, including the associated debt service and return of the initial investment through depreciation, while denying the shareholders a return on an investment which is not really useful to the ratepayers, who would bear a substantial cost in exchange for receiving the operating

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27. This approach is also very similar to treating the initial years of the unit's operation as if it represented pre-commercial generation.

savings.

Third, the Commission could allow no return on the investment at all, but instead allow the company to collect all of the other costs (depreciation, O&M, etc.) and the energy savings. This is an essentially arbitrary way to split the costs between ratepayers and shareholders.

Fourth, the Commission may exclude a mix of capacity from rate base, rather than excluding Susquehanna 2. This is the basic approach the Commission took with respect to Susquehanna 1.

As I noted above, if PP&L is correct in its projections, the unusual ratemaking will remain in effect for a fairly small portion of the life of Susquehanna 2, until it starts to produce real benefits for ratepayers, at which point the Commission will presumably wish to switch to standard ratebase treatment.

Q: Would equitable ratemaking be achieved by the fourth option you listed above, the repetition of the Commission's treatment of Susquehanna Unit 1 excess capacity, through exclusion of a "slice of the system" from rate base?

A: That would help somewhat, but would not really solve the equity problems or provide the proper signals to Pennsylvania utilities. The equity problems would not be solved because Susquehanna 2 would still increase rates to customers in the short run (since the slice-of-the-system is much less expensive than Susquehanna) without commensurate benefits, and regardless of whether the unit is beneficial in the long run. The signal given by the slice-of-the-system approach is that excess MW's of capacity are the problem. In fact, Susquehanna 2 at its current cost would be excessively expensive (at least in the near term) even if its capacity were immediately useful; Susquehanna 2 at a much lower cost would be desirable even if PP&L had a 100% reserve margin. If the Commission wants to control costs to ratepayers from (at least temporarily) uneconomic plants, it can do so more clearly by matching cost recovery to benefits than by excluding a mix of MW's from rate base.

Q: How could the "slice of the system" approach be improved, so as to be more equitable to ratepayers in this decade?

A: While this approach is not the most logical response to the problems posed by Susquehanna 2, it can be improved in at least two ways. First, the rather optimistic operating savings projected by PP&L could be guaranteed in some way, such as by denying recovery of any ECR costs due to Susquehanna savings falling below PP&L's expectations. Second, the slice could be a taken as a slice of base-load capacity (e.g., all coal and nuclear capacity), excluding the less expensive peaking and hydro plants; after all, the problem of Susquehanna is less a matter of too many megawatts than it is a matter of too much expensive base-load capacity.

Q: Is there a ratemaking treatment which for Susquehanna 2 which you particularly recommend?

A: Yes. I would suggest that the Commission treat the unit as being in service, but limit annual cost recovery to the projected energy savings for jurisdictional ratepayers, which PP&L projects to be $136 million in 1985.[28] From the ratepayer's point of view, these additional non-fuel base rates would be offset by the reduction in the fuel charges (either in base rates or in the ECR). From the company's viewpoint, fuel revenues will still match fuel costs, leaving $136 million in revenues towards the costs of Susquehanna 2, or $111 million after payment for the Allegheny buyback.

Q: How would this initial value be updated to reflect changes in the value of operatings savings, and in the output of Susquehanna 2?

A: The Commission could either require PP&L to file a new rate case whenever PP&L wishes to adjust this recovery to fit

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28. This figure includes the cost of the Allegheny buyback; after the buyback cost is subtracted, the net savings are $111 million. If the buyback cost is treated as part of base rates, it is appropriate to use $136 million as the savings figure.

changed circumstances (as it does with other costs) or it could establish a rate rider mechanism with provision for review and approval of PP&L's projections of operating savings, and for reconciliation of previous estimates. In either case, PP&L's cost recovery would be dependent on its estimates, and the reconciliation must provide incentives for accurate projections, or at least remove the incentives for overly optimistic projections. The most direct means for accomplishing this would be to offset projection errors in one year by an equal adjustment to recovery in the following year. If, for example, the 1985 energy savings turns out to be \$120 million, rather than the projected \$136 million, the 1986 recovery can be reduced by \$16 million.[29] Alternatively, the Commission may wish to damp the annual effects of these errors, by amortising them (with interest) over several years, or by applying them as a reduction in rate base.

If PP&L is correct in its projections of operating savings; of Susquehanna operating costs, reliability, and useful life; and of its own discount rate, PP&L may eventually be made whole for its Susquehanna investment by just collecting the operating savings. If PP&L concludes that Unit 2 is not

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29. In order to provide PP&L with an incentive to operate the plant reliably, the Commission may wish to allow the company to retain a portion (such as one half) of the savings from performance in excess of expectations.

likely to pay for itself over the course of its life, it should say so clearly, and ask the Commission to allow it to collect more than the value of the unit. In that situation, the Commission would have to decide whether the additional investments were prudent, used and useful, and whether they should be recovered from the ratepayers, and if so, how and over what time period. This is a decision for the future, however; at this point, it appears to be appropriate to simply limit the Unit 2 cost recovery to its fuel savings.

Q: What effect would your recommendation have on this rate case?

A: The effect would be to limit PP&L's annual jurisdictional cost recovery for Susquehanna 2 to $136 million in 1985. If PP&L's projections prove to be accurate, this would have the same dollar outcome as the below-the-line treatment discussed previously.

Q: Does this conclude your testimony?

A: Yes.

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Tables Accompanying

the Testimony of

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TABLE 2.1: COST OF PENNSYLVANIA COMBUSTION TURBINES [1]

| Plant | Blossburg | Warren | Croydon | Richmond |
|---|---|---|---|---|
| Utility | Pennsylvania Electric Co. | Pennsylvania Electric Co. | Philadelphia Electric Co. | Philadelphia Electric Co. |
| MW | 23.6 | 53.1 | 546 | 730 |
| Total Cost | $1,950 | $6,034 | $66,790 | $22,255 |
| $/KW | $82.63 | $113.63 | $122.33 | $30.49 |
| Initial Year | 1971 | 1972 | 1974 | 1970 |
| Ratio of Handy-Whitman Gas Turbine Index (1983 : Initial Years) | 2.40 | 2.35 | 2.28 | 2.47 |
| $/KW (1983$) [2] | $198.14 | $267.04 | $279.09 | $75.41 |

| | |
|---|---|
| Average $/KW across plants, MW weighted | $167.29 |

Notes: [1] Data from: Energy Information Administration, Historical Plant Cost and Annual Production Expenses for Selected Electric Plants 1982 (DOE/EIA-0455(82)

[2] Assumes all capacity installed initial year, and that there have been no capital additions since then. These assumptions overstate the 1983$ cost.

TABLE 2.2: OBJECTIVE CAPABILITY (MW) WITH NEW NUCLEAR UNITS

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

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

TABLE 2.3: DERIVATION OF NUCLEAR FIRM LOAD CARRYING CAPACITY

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

Notes: [1] Calculated from data in Table 2.3.

[2]: 1150-[1].

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

[4]: [3]/1150.

TABLE 3.1: PP&L PROJECTED FUEL SAVINGS

| Year | Susquehanna Fuel Cost | Avoided Fossil Fuel Cost | Differential |
|---|---|---|---|
| | cents/kwh [1] | cents/kwh [2] | cents/kwh [3] |
| 1983 | 0.5 | 4.0 | 3.5 |
| 1984 | 0.5 | 3.9 | 3.4 |
| 1985 | 0.6 | 3.5 | 2.9 |
| 1986 | 0.6 | 4.5 | 3.9 |
| 1987 | 0.6 | 5.4 | 4.8 |
| 1988 | 0.7 | 7.0 | 6.4 |
| 1989 | 0.8 | 8.5 | 7.7 |
| 1990 | 0.8 | 10.4 | 9.5 |
| 1991 | 0.9 | 12.0 | 11.1 |
| 1992 | 1.1 | 14.8 | 13.8 |
| 1993 | 1.2 | 16.7 | 15.5 |
| 1994 | 1.3 | 19.3 | 17.9 |
| 1995 | 1.5 | 21.4 | 19.8 |
| 1996 | 1.7 | 23.1 | 21.4 |
| 1997 | 1.8 | 25.1 | 23.3 |
| 1998 | 2.0 | 27.3 | 25.4 |
| 1999 | 2.1 | 29.6 | 27.5 |
| 2000 | 2.2 | 32.5 | 30.3 |
| 2001 | 2.4 | 34.8 | 32.4 |
| 2002 | 2.6 | 37.5 | 34.9 |
| 2003 | 2.8 | 40.3 | 37.5 |
| 2004 | 3.1 | 42.7 | 39.6 |
| 2005 | 3.5 | 45.5 | 42.0 |
| 2006 | 3.8 | 48.1 | 44.4 |
| 2007 | 4.2 | 51.0 | 46.9 |
| 2008 | 4.6 | 54.0 | 49.4 |
| 2009 | 4.8 | 57.2 | 52.4 |
| 2010 | 5.3 | 60.7 | 55.4 |
| 2011 | 5.6 | 64.1 | 58.5 |
| 2012 | 5.9 | 67.6 | 61.7 |
| 2013 | 6.2 | 71.6 | 65.4 |
| 2014 | 6.6 | 75.7 | 69.1 |
| 2015 | 7.0 | 80.0 | 73.0 |
| 2016 | 7.4 | 84.4 | 77.0 |
| 2017 | 7.8 | 89.4 | 81.6 |
| 2018 | 8.2 | 94.5 | 86.3 |
| 2019 | 8.7 | 99.9 | 91.2 |
| 2020 | 9.2 | 105.3 | 96.1 |
| 2021 | 9.7 | 111.6 | 101.9 |
| 2022 | 10.3 | 118.0 | 107.7 |

Notes:

[1] Column labeled "DIR NUC FUEL COST PLANT," page 39, divided by "PLANT GEN GWH," page 40, Attachment 1, IR1PA4.

[2] Columns [1] + [3].

[3] Column labeled "OPER BEN DUE TO SUSQ," page 40, divided by "PLANT GEN GWH," page 40, Attachment 1, IR1PA4.

TABLE 3.2: SUSQUEHANNA UNIT 2 COSTS AND BENEFITS, RETAIL PORTION
CASE 1 (PP&L ASSUMPTIONS)

| Year | Capital-Related | | | | Cap Adds | O&M | Decom | Total Non-Fuel | Operating Savings | Net Savings | Cumulative Savings | Discounted Cumulative Savings |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Deprec. | Return | Taxes | Total | | | | | | | | |
| | [1] | [2] | [3] | [4] | [5] | [6] | [7] | [8] | [9] | [10] | [11] | [12] |
| 1985 | 14.4 | 184.2 | 129.1 | 327.7 | 5.3 | 51.1 | 2.5 | 386.6 | 111.5 | -275.1 | -275.1 | -239.3 |
| 1986 | 16.1 | 174.3 | 125.4 | 315.8 | 8.5 | 63.5 | 2.7 | 390.4 | 124.9 | -265.5 | -540.7 | -440.0 |
| 1987 | 18.1 | 165.9 | 122.8 | 306.8 | 11.2 | 57.6 | 2.8 | 378.4 | 165.7 | -212.7 | -753.4 | -579.9 |
| 1988 | 20.4 | 158.4 | 118.6 | 297.4 | 13.4 | 72.1 | 3.0 | 385.9 | 241.6 | -144.4 | -897.7 | -662.4 |
| 1989 | 22.9 | 150.7 | 114.4 | 287.9 | 15.2 | 78.6 | 3.2 | 385.0 | 317.1 | -67.9 | -965.6 | -696.2 |
| 1990 | 25.7 | 142.8 | 111.2 | 279.6 | 16.9 | 83.0 | 3.4 | 382.8 | 389.4 | 6.6 | -959.1 | -693.4 |
| 1991 | 29.4 | 137.9 | 109.4 | 276.6 | 19.0 | 91.4 | 3.7 | 390.6 | 466.9 | 76.3 | -882.8 | -664.7 |
| 1992 | 34.9 | 137.5 | 111.5 | 284.0 | 22.0 | 107.1 | 4.2 | 417.2 | 603.7 | 186.5 | -696.3 | -603.7 |
| 1993 | 39.2 | 128.8 | 107.1 | 275.1 | 24.1 | 119.9 | 4.4 | 423.6 | 687.3 | 263.7 | -432.6 | -528.7 |
| 1994 | 44.0 | 119.6 | 113.8 | 277.4 | 26.5 | 128.7 | 4.7 | 437.3 | 798.8 | 361.5 | -71.1 | -439.4 |
| 1995 | 49.4 | 115.9 | 113.2 | 278.5 | 29.1 | 142.3 | 5.0 | 454.9 | 885.7 | 430.8 | 359.7 | -346.8 |
| 1996 | 56.9 | 114.4 | 115.3 | 286.6 | 32.7 | 161.3 | 5.5 | 486.1 | 977.9 | 491.8 | 851.5 | -254.9 |
| 1997 | 65.4 | 112.3 | 117.3 | 295.1 | 36.7 | 174.1 | 5.9 | 511.8 | 1089.9 | 578.1 | 1429.7 | -160.9 |
| 1998 | 75.2 | 109.3 | 119.2 | 303.7 | 41.1 | 194.2 | 6.4 | 545.3 | 1213.2 | 667.9 | 2097.5 | -66.5 |
| 1999 | 86.4 | 105.3 | 120.9 | 312.6 | 45.9 | 217.3 | 6.9 | 582.7 | 1345.8 | 763.1 | 2860.7 | 27.3 |
| 2000 | 52.2 | 100.2 | 100.6 | 253.0 | 52.1 | 232.6 | 7.5 | 545.3 | 1512.8 | 967.6 | 3828.2 | 130.7 |
| 2001 | 52.2 | 95.73 | 96.88 | 244.8 | 57.1 | 253.6 | 7.9 | 563.4 | 1619.4 | 1056.0 | 4884.2 | 228.8 |
| 2002 | 52.2 | 91.28 | 93.16 | 236.7 | 60.9 | 279.6 | 8.3 | 585.5 | 1745.7 | 1160.2 | 6044.4 | 322.5 |
| 2003 | 52.2 | 86.82 | 89.44 | 228.5 | 64.9 | 294.4 | 8.8 | 596.6 | 1867.0 | 1270.5 | 7314.9 | 411.8 |
| 2004 | 52.2 | 82.37 | 85.71 | 220.3 | 69.2 | 322.2 | 9.3 | 621.0 | 1986.4 | 1365.5 | 8680.3 | 495.2 |
| 2005 | 52.2 | 77.93 | 82.00 | 212.1 | 73.7 | 355.9 | 9.9 | 651.6 | 2099.6 | 1448.1 | 10128.4 | 572.2 |
| 2006 | 52.2 | 73.48 | 78.29 | 204.0 | 78.5 | 372.2 | 10.4 | 665.0 | 2219.3 | 1554.3 | 11682.7 | 644.0 |
| 2007 | 52.2 | 69.04 | 74.56 | 195.8 | 83.6 | 406.6 | 11.0 | 697.0 | 2345.8 | 1648.8 | 13331.5 | 710.2 |
| 2008 | 52.2 | 64.59 | 70.85 | 187.7 | 89.0 | 447.2 | 11.6 | 735.6 | 2479.5 | 1744.0 | 15075.5 | 771.2 |
| 2009 | 52.2 | 60.14 | 67.13 | 179.5 | 94.8 | 465.1 | 12.3 | 751.7 | 2620.8 | 1869.2 | 16944.6 | 827.9 |
| 2010 | 52.2 | 55.70 | 63.43 | 171.3 | 101.0 | 507.0 | 13.0 | 792.4 | 2770.2 | 1977.8 | 18922.5 | 880.2 |
| 2011 | 52.2 | 51.25 | 59.70 | 163.2 | 107.7 | 539.4 | 13.7 | 824.0 | 2928.1 | 2104.2 | 21026.6 | 928.5 |
| 2012 | 52.2 | 46.80 | 55.99 | 155.0 | 114.9 | 576.1 | 14.5 | 860.6 | 3095.0 | 2234.5 | 23261.1 | 973.1 |
| 2013 | 52.2 | 42.36 | 52.27 | 146.8 | 122.7 | 614.3 | 15.4 | 899.2 | 3271.5 | 2372.3 | 25633.4 | 1014.4 |
| 2014 | 52.2 | 37.91 | 48.56 | 138.7 | 131.4 | 655.5 | 16.2 | 941.7 | 3457.9 | 2516.2 | 28149.6 | 1052.4 |
| 2015 | 52.2 | 33.47 | 44.84 | 130.5 | 141.0 | 699.3 | 17.2 | 988.0 | 3655.0 | 2667.1 | 30816.6 | 1087.4 |
| 2016 | 52.2 | 29.02 | 41.12 | 122.4 | 151.9 | 746.7 | 18.1 | 1039.1 | 3863.4 | 2824.2 | 33640.9 | 1119.6 |
| 2017 | 52.2 | 24.57 | 37.41 | 114.2 | 164.7 | 796.0 | 19.2 | 1094.0 | 4083.6 | 2989.6 | 36630.4 | 1149.3 |
| 2018 | 52.2 | 20.13 | 33.69 | 106.0 | 177.0 | 851.2 | 20.3 | 1154.5 | 4316.4 | 3161.9 | 39792.3 | 1176.6 |
| 2019 | 52.2 | 15.68 | 29.97 | 97.9 | 186.0 | 912.5 | 21.4 | 1217.7 | 4562.4 | 3344.7 | 43137.0 | 1201.7 |
| 2020 | 52.2 | 11.22 | 26.26 | 89.7 | 191.6 | 981.1 | 22.6 | 1285.0 | 4822.4 | 3537.5 | 46674.5 | 1224.8 |
| 2021 | 52.2 | 6.79 | 22.55 | 81.6 | 193.5 | 1055.4 | 23.9 | 1354.4 | 5097.3 | 3742.9 | 50417.4 | 1246.1 |
| 2022 | 26.1 | 2.20 | 10.29 | 38.6 | 79.7 | 563.0 | 12.6 | 693.9 | 2693.9 | 2000.0 | 52417.4 | 1256.0 |

All values in millions of dollars.

Notes on following page.

NOTES FOR TABLE 3.2

[1] Column labeled "DEPR UNIT 2," pages 35-38, Attachment 1, IR1PA4.
[2] Column labeled "RETURN UNIT 2," pages 35-38, Attachment 1, IR1PA4.
[3] Column labeled "TAXES UNIT 2," pages 35-38, Attachment 1, IR1PA4.
[4] Columns [1] + [2] + [3].
[5] The sum of columns labeled "DEPR ADD," "RETURN ADD," and "TAXES ADD," pages 35-38, Attachment 1, IR1PA4; divided by 2.
[6] The sum of columns labeled "DIRECT O&M UNIT 2," "IND NUC FUEL COST UNIT 2," and "NUC FUEL DISP COST UNIT 2," pages 35-38, Attachment 1, IR1PA4.
[7] Column labeled "DECOM COST UNIT 2," pages 35-38, Attachment 1, IR1PA4.
[8] Columns [4] + [5] + [6] + [7].
[9] Column labeled "OPER BEN DUE TO SUSQ," page 40, divided by "PLANT GEN GWH," page 40, multiplied by "SUSQ 2 GEN GWH," page 40, Attachment 1, IR1PA4; multiplied by .90 (Value of Unit 2 savings/kWh as fraction of plant savings/kWh).
[10] Columns [9] - [8].
[11] From Column [10].
[12] Discount rate = 15.0%; from Column [10].

TABLE 3.3: SUSQUEHANNA UNIT 2 COSTS AND BENEFITS, RETAIL PORTION
CASE 2 (RECENT HISTORICAL CAPACITY FACTORS)

| | Capital-Related | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Year | Deprec. | Return | Taxes | Total | Cap Adds | O&M | Decom | Total Non-Fuel | Operating Savings | Net Savings | Cumulative Savings | Discounted Cumulative Savings |
| | [1] | [2] | [3] | [4] | [5] | [6] | [7] | [8] | [9] | [10] | [11] | [12] |
| 1985 | 14.4 | 184.2 | 129.1 | 327.7 | 5.3 | 50.4 | 2.5 | 385.9 | 94.3 | -291.6 | -291.6 | -253.6 |
| 1986 | 16.1 | 174.3 | 125.4 | 315.8 | 8.5 | 63.5 | 2.7 | 390.4 | 125.8 | -264.6 | -556.3 | -453.7 |
| 1987 | 18.1 | 165.9 | 122.8 | 306.8 | 11.2 | 57.3 | 2.8 | 378.1 | 154.2 | -223.9 | -780.2 | -600.9 |
| 1988 | 20.4 | 158.4 | 118.6 | 297.4 | 13.4 | 72.1 | 3.0 | 385.9 | 242.7 | -143.3 | -923.4 | -682.8 |
| 1989 | 22.9 | 150.7 | 114.4 | 287.9 | 15.2 | 78.3 | 3.2 | 384.6 | 294.4 | -90.2 | -1013.6 | -727.7 |
| 1990 | 25.7 | 142.8 | 111.2 | 279.6 | 16.9 | 82.2 | 3.4 | 382.0 | 333.7 | -48.3 | -1061.9 | -748.5 |
| 1991 | 29.4 | 137.9 | 109.4 | 276.6 | 19.0 | 90.5 | 3.7 | 389.7 | 400.2 | 10.5 | -1051.4 | -744.6 |
| 1992 | 34.9 | 137.5 | 111.5 | 284.0 | 22.0 | 106.1 | 4.2 | 416.3 | 517.4 | 101.2 | -950.3 | -711.5 |
| 1993 | 39.2 | 128.8 | 107.1 | 275.1 | 24.1 | 118.9 | 4.4 | 422.5 | 589.1 | 166.6 | -783.7 | -664.2 |
| 1994 | 44.0 | 119.6 | 113.8 | 277.4 | 26.5 | 127.6 | 4.7 | 436.2 | 684.6 | 248.4 | -535.3 | -602.8 |
| 1995 | 49.4 | 115.9 | 113.2 | 278.5 | 29.1 | 141.2 | 5.0 | 453.8 | 759.1 | 305.4 | -229.9 | -537.1 |
| 1996 | 56.9 | 114.4 | 115.3 | 286.6 | 32.7 | 160.1 | 5.5 | 484.9 | 838.2 | 353.4 | 123.4 | -471.1 |
| 1997 | 65.4 | 112.3 | 117.3 | 295.1 | 36.7 | 172.8 | 5.9 | 510.5 | 934.2 | 423.8 | 547.2 | -402.2 |
| 1998 | 75.2 | 109.3 | 119.2 | 303.7 | 41.1 | 192.8 | 6.4 | 543.9 | 1039.9 | 496.0 | 1043.2 | -332.1 |
| 1999 | 86.4 | 105.3 | 120.9 | 312.6 | 45.9 | 215.7 | 6.9 | 581.1 | 1153.6 | 572.4 | 1615.6 | -261.8 |
| 2000 | 52.2 | 100.2 | 100.6 | 253.0 | 52.1 | 231.0 | 7.5 | 543.6 | 1296.7 | 753.1 | 2368.7 | -181.3 |
| 2001 | 52.2 | 95.73 | 96.88 | 244.8 | 57.1 | 251.8 | 7.9 | 561.7 | 1388.1 | 826.4 | 3195.1 | -104.5 |
| 2002 | 52.2 | 91.28 | 93.16 | 236.7 | 60.9 | 277.8 | 8.3 | 583.7 | 1496.3 | 912.6 | 4107.7 | -30.8 |
| 2003 | 52.2 | 86.82 | 89.44 | 228.5 | 64.9 | 292.4 | 8.8 | 594.6 | 1600.3 | 1005.7 | 5113.4 | 39.9 |
| 2004 | 52.2 | 82.37 | 85.71 | 220.3 | 69.2 | 320.1 | 9.3 | 618.9 | 1702.6 | 1083.7 | 6197.1 | 106.1 |
| 2005 | 52.2 | 77.93 | 82.00 | 212.1 | 73.7 | 353.7 | 9.9 | 649.4 | 1799.7 | 1150.3 | 7347.4 | 167.2 |
| 2006 | 52.2 | 73.48 | 78.29 | 204.0 | 78.5 | 369.9 | 10.4 | 662.7 | 1902.3 | 1239.5 | 8587.0 | 224.5 |
| 2007 | 52.2 | 69.04 | 74.56 | 195.8 | 83.6 | 404.2 | 11.0 | 694.6 | 2010.7 | 1316.1 | 9903.0 | 277.4 |
| 2008 | 52.2 | 64.59 | 70.85 | 187.7 | 89.0 | 444.7 | 11.6 | 733.0 | 2125.3 | 1392.3 | 11295.3 | 326.0 |
| 2009 | 52.2 | 60.14 | 67.13 | 179.5 | 94.8 | 462.4 | 12.3 | 749.0 | 2246.4 | 1497.4 | 12792.8 | 371.5 |
| 2010 | 52.2 | 55.70 | 63.43 | 171.3 | 101.0 | 504.2 | 13.0 | 789.6 | 2374.5 | 1584.9 | 14377.7 | 413.4 |
| 2011 | 52.2 | 51.25 | 59.70 | 163.2 | 107.7 | 536.4 | 13.7 | 821.0 | 2509.8 | 1688.8 | 16066.5 | 452.2 |
| 2012 | 52.2 | 46.80 | 55.99 | 155.0 | 114.9 | 572.9 | 14.5 | 857.4 | 2652.9 | 1795.5 | 17862.0 | 488.0 |
| 2013 | 52.2 | 42.36 | 52.27 | 146.8 | 122.7 | 610.9 | 15.4 | 895.9 | 2804.1 | 1908.3 | 19770.3 | 521.2 |
| 2014 | 52.2 | 37.91 | 48.56 | 138.7 | 131.4 | 652.0 | 16.2 | 938.2 | 2963.9 | 2025.7 | 21796.0 | 551.8 |
| 2015 | 52.2 | 33.47 | 44.84 | 130.5 | 141.0 | 695.6 | 17.2 | 984.3 | 3132.9 | 2148.6 | 23944.6 | 580.0 |
| 2016 | 52.2 | 29.02 | 41.12 | 122.4 | 151.9 | 742.8 | 18.1 | 1035.2 | 3311.5 | 2276.3 | 26220.9 | 606.0 |
| 2017 | 52.2 | 24.57 | 37.41 | 114.2 | 164.7 | 791.8 | 19.2 | 1089.8 | 3500.2 | 2410.4 | 28631.3 | 629.9 |
| 2018 | 52.2 | 20.13 | 33.69 | 106.0 | 177.0 | 846.8 | 20.3 | 1150.1 | 3699.7 | 2549.7 | 31180.9 | 651.9 |
| 2019 | 52.2 | 15.68 | 29.97 | 97.9 | 186.0 | 907.8 | 21.4 | 1213.0 | 3910.6 | 2697.6 | 33878.5 | 672.2 |
| 2020 | 52.2 | 11.22 | 26.26 | 89.7 | 191.6 | 976.1 | 22.6 | 1280.1 | 4133.5 | 2853.5 | 36732.0 | 690.8 |
| 2021 | 52.2 | 6.79 | 22.55 | 81.6 | 193.5 | 1050.2 | 23.9 | 1349.2 | 4369.1 | 3019.9 | 39751.9 | 708.0 |
| 2022 | 26.1 | 2.20 | 10.29 | 38.6 | 79.7 | 560.2 | 12.6 | 691.2 | 2309.1 | 1617.9 | 41369.8 | 716.0 |

All values in millions of dollars.

Notes: Same as Table 3.2 except as noted below.

[6] Column [6] as defined in Table 3.2 except the column labeled "NUC FUEL DISP COST UNIT 2" is multiplied by PLC CF, divided by PPL CF. PLC CF from Eq. 3 in Table 4.3.

[9] Column [9] as defined in Table 3.2 multiplied by PLC CF, divided by PPL CF.

TABLE 3.4: SUSQUEHANNA UNIT 2 COSTS AND BENEFITS, RETAIL PORTION
CASE 3 (CONTINUING PAST EXPERIENCE)

| Year | Capital-Related Deprec. | Capital-Related Return | Capital-Related Taxes | Capital-Related Total | Cap Adds | O&M | Decom | Total Non-Fuel | Operating Savings | Net Savings | Cumulative Savings | Discounted Cumulative Savings |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | [1] | [2] | [3] | [4] | [5] | [6] | [7] | [8] | [9] | [10] | [11] | [12] |
| 1985 | 14.4 | 194.0 | 129.1 | 337.5 | 14.6 | 37.2 | 5.1 | 394.4 | 94.3 | -300.1 | -300.1 | -261.0 |
| 1986 | 16.1 | 183.6 | 125.4 | 325.2 | 23.3 | 41.2 | 5.3 | 394.9 | 125.8 | -269.1 | -569.2 | -464.5 |
| 1987 | 18.1 | 174.8 | 122.8 | 315.7 | 30.7 | 48.4 | 5.7 | 400.5 | 154.2 | -246.3 | -815.5 | -626.4 |
| 1988 | 20.4 | 166.9 | 118.6 | 305.9 | 36.8 | 57.0 | 6.0 | 405.7 | 242.7 | -163.1 | -978.6 | -719.6 |
| 1989 | 22.9 | 158.8 | 114.4 | 296.0 | 41.7 | 68.5 | 6.4 | 412.6 | 294.4 | -118.1 | -1096.7 | -778.4 |
| 1990 | 25.7 | 150.4 | 111.2 | 287.2 | 46.2 | 81.7 | 6.8 | 421.9 | 333.7 | -88.1 | -1184.8 | -816.5 |
| 1991 | 29.4 | 145.3 | 109.4 | 284.0 | 51.9 | 96.2 | 7.3 | 439.5 | 400.2 | -39.3 | -1224.1 | -831.2 |
| 1992 | 34.9 | 144.9 | 111.5 | 291.3 | 60.3 | 117.1 | 8.3 | 477.0 | 517.4 | 40.4 | -1183.7 | -818.0 |
| 1993 | 39.2 | 135.7 | 107.1 | 282.0 | 66.0 | 142.2 | 8.8 | 499.1 | 589.1 | 90.0 | -1093.8 | -792.5 |
| 1994 | 44.0 | 126.0 | 113.8 | 283.8 | 72.4 | 166.9 | 9.4 | 532.6 | 684.6 | 152.0 | -941.7 | -754.9 |
| 1995 | 49.4 | 122.1 | 113.2 | 284.7 | 79.6 | 200.7 | 10.1 | 575.0 | 759.1 | 184.1 | -757.6 | -715.3 |
| 1996 | 56.9 | 120.6 | 115.3 | 292.8 | 89.6 | 243.1 | 10.9 | 636.4 | 838.2 | 201.9 | -555.8 | -677.6 |
| 1997 | 65.4 | 118.3 | 117.3 | 301.1 | 100.5 | 285.4 | 11.8 | 698.9 | 934.2 | 235.4 | -320.4 | -639.3 |
| 1998 | 75.2 | 115.2 | 119.2 | 309.5 | 112.5 | 342.6 | 12.8 | 777.5 | 1039.9 | 262.4 | -58.0 | -602.2 |
| 1999 | 86.4 | 111.0 | 120.9 | 318.2 | 125.7 | 411.9 | 13.8 | 869.7 | 1153.6 | 283.9 | 225.9 | -567.3 |
| 2000 | 52.2 | 105.6 | 100.6 | 258.4 | 142.8 | 484.9 | 14.9 | 901.0 | 1296.7 | 395.7 | 621.6 | -525.1 |
| 2001 | 52.2 | 100.9 | 96.88 | 250.0 | 156.4 | 581.3 | 15.8 | 1003.5 | 1388.1 | 384.6 | 1006.2 | -489.3 |
| 2002 | 52.2 | 96.2 | 93.16 | 241.6 | 166.7 | 700.3 | 16.7 | 1125.2 | 1496.3 | 371.0 | 1377.3 | -459.3 |
| 2003 | 52.2 | 91.5 | 89.44 | 233.1 | 177.7 | 829.0 | 17.6 | 1257.5 | 1600.3 | 342.9 | 1720.1 | -435.2 |
| 2004 | 52.2 | 86.8 | 85.71 | 224.7 | 189.4 | 996.2 | 18.6 | 1429.0 | 1702.6 | 273.7 | 1993.8 | -418.5 |
| 2005 | 52.2 | 82.1 | 82.00 | 216.3 | 201.7 | 1200.4 | 19.7 | 1638.2 | 1799.7 | 161.5 | 2155.3 | -409.9 |
| 2006 | 52.2 | 77.4 | 78.29 | 207.9 | 214.8 | 1424.7 | 20.8 | 1868.2 | 1902.3 | 34.0 | 2189.3 | -408.4 |
| 2007 | 52.2 | 72.7 | 74.56 | 199.5 | 228.8 | 1712.7 | 22.0 | 2163.0 | 2010.7 | -152.3 | 2037.0 | -414.5 |
| 2008 | 52.2 | 68.1 | 70.85 | 191.1 | 243.7 | 2061.8 | 23.3 | 2519.9 | 2125.3 | -394.6 | 1642.4 | -428.3 |
| 2009 | 52.2 | 63.4 | 67.13 | 182.7 | 259.6 | 2454.6 | 24.6 | 2921.5 | 2246.4 | -675.1 | 967.3 | -448.8 |
| 2010 | 52.2 | 58.7 | 63.43 | 174.3 | 276.6 | 2952.1 | 26.0 | 3429.0 | 2374.5 | -1054.5 | -87.2 | -476.6 |
| 2011 | 52.2 | 54.0 | 59.70 | 165.9 | 294.9 | 3537.2 | 27.5 | 4025.5 | 2509.8 | -1515.7 | -1602.9 | -511.4 |
| 2012 | 52.2 | 49.3 | 55.99 | 157.5 | 314.7 | 4244.3 | 29.0 | 4745.6 | 2652.9 | -2092.7 | -3695.5 | -553.2 |
| 2013 | 52.2 | 44.6 | 52.27 | 149.1 | 336.1 | 5095.0 | 30.7 | 5610.9 | 2804.1 | -2806.8 | -6502.3 | -602.0 |
| 2014 | 52.2 | 39.9 | 48.56 | 140.7 | 359.6 | 6120.5 | 32.4 | 6653.2 | 2963.9 | -3689.3 | -10191.6 | -657.7 |
| 2015 | 52.2 | 35.3 | 44.84 | 132.3 | 386.0 | 7356.0 | 34.3 | 7908.6 | 3132.9 | -4775.7 | -14967.3 | -720.4 |
| 2016 | 52.2 | 30.6 | 41.12 | 123.9 | 416.0 | 8845.5 | 36.2 | 9421.6 | 3311.5 | -6110.2 | -21077.4 | -790.2 |
| 2017 | 52.2 | 25.9 | 37.41 | 115.5 | 450.9 | 10639.5 | 38.3 | 11244.3 | 3500.2 | -7744.0 | -28821.4 | -867.1 |
| 2018 | 52.2 | 21.2 | 33.69 | 107.1 | 484.5 | 12802.7 | 40.5 | 13434.7 | 3699.7 | -9735.0 | -38556.4 | -951.2 |
| 2019 | 52.2 | 16.5 | 29.97 | 98.7 | 509.1 | 15410.5 | 42.8 | 16061.1 | 3910.6 | -12150.5 | -50706.9 | -1042.4 |
| 2020 | 52.2 | 11.8 | 26.26 | 90.3 | 524.6 | 18555.1 | 45.2 | 19215.2 | 4133.5 | -15081.7 | -65788.6 | -1140.9 |
| 2021 | 52.2 | 7.2 | 22.55 | 81.9 | 529.7 | 22345.2 | 47.8 | 23004.7 | 4369.1 | -18635.5 | -84424.1 | -1246.7 |
| 2022 | 26.1 | 2.3 | 10.29 | 38.7 | 218.2 | 26772.2 | 25.3 | 27054.4 | 2309.1 | -24745.3 | -109169.5 | -1368.9 |

All values in millions of dollars.

Notes: Same as Table 3.3 except as noted below.

[2] Column [2] as defined in Table 3.2 multiplied by 13.15, divided by 12.48.

[5] Column [5] as defined in Table 3.2 multiplied by present value of PLC Cap Adds, divided by present value of PPL Cap Adds. PPL Cap Adds and PLC Cap Adds from Columns [1] and [2] of Table 4.17. Present value calculated with 1985-2022 data discounted at 15.0%.

[6] Column [6] as defined in Table 3.3 except the column labeled "DIRECT O&M UNIT 2" is replaced by Column [5] from Table 4.15.

[7] Column [7] as defined in Table 3.2 multiplied by 2.

TABLE 3.5: SUSQUEHANNA 2 RETAIL RATE EFFECTS
CASE 1 (PP&L ASSUMPTIONS)

| Year | Susquehanna 2 Net Savings | Retail Sales | Reduction in Rates | Savings for Typical Customer (Residential) | Cumulative Savings | Discounted Cumulative Savings |
|---|---|---|---|---|---|---|
| | $ million | GWH | cents/kwh | $/year | | |
| | [1] | [2] | [3] | [4] | [5] | [6] |
| 1985 | -275.1 | 23003 | -1.2 | ($95.69) | ($95.69) | ($83.21) |
| 1986 | -265.5 | 23772 | -1.1 | ($89.36) | ($185.05) | ($150.78) |
| 1987 | -212.7 | 24574 | -0.9 | ($69.24) | ($254.29) | ($196.30) |
| 1988 | -144.4 | 25477 | -0.6 | ($45.33) | ($299.62) | ($222.22) |
| 1989 | -67.9 | 26029 | -0.3 | ($20.87) | ($320.50) | ($232.60) |
| 1990 | 6.6 | 26614 | .0 | $1.97 | ($318.52) | ($231.75) |
| 1991 | 76.3 | 27278 | 0.3 | $22.38 | ($296.14) | ($223.33) |
| 1992 | 186.5 | 27942 | 0.7 | $53.39 | ($242.75) | ($205.88) |
| 1993 | 263.7 | 28605 | 0.9 | $73.76 | ($169.00) | ($184.92) |
| 1994 | 361.5 | 29199 | 1.2 | $99.04 | ($69.96) | ($160.43) |
| 1995 | 430.8 | 29792 | 1.4 | $115.68 | $45.72 | ($135.57) |
| 1996 | 491.8 | 30386 | 1.6 | $129.49 | $175.21 | ($111.37) |
| 1997 | 578.1 | 30979 | 1.9 | $149.30 | $324.51 | ($87.10) |
| 1998 | 667.9 | 31573 | 2.1 | $169.23 | $493.73 | ($63.19) |
| 1999 | 763.1 | 32206 | 2.4 | $189.57 | $683.30 | ($39.89) |
| 2000 | 967.6 | 32830 | 2.9 | $235.78 | $919.08 | ($14.69) |
| 2001 | 1056.0 | 33464 | 3.2 | $252.44 | $1,171.52 | $8.77 |
| 2002 | 1160.2 | 34098 | 3.4 | $272.19 | $1,443.71 | $30.76 |
| 2003 | 1270.5 | 34723 | 3.7 | $292.71 | $1,736.43 | $51.33 |
| 2004 | 1365.5 | 35400 | 3.9 | $308.58 | $2,045.01 | $70.18 |
| 2005 | 1448.1 | 36090 | 4.0 | $320.99 | $2,366.00 | $87.24 |
| 2006 | 1554.3 | 36794 | 4.2 | $337.95 | $2,703.95 | $102.85 |
| 2007 | 1648.8 | 37511 | 4.4 | $351.64 | $3,055.59 | $116.98 |
| 2008 | 1744.0 | 38243 | 4.6 | $364.82 | $3,420.41 | $129.72 |
| 2009 | 1869.2 | 38988 | 4.8 | $383.53 | $3,803.94 | $141.37 |
| 2010 | 1977.8 | 39749 | 5.0 | $398.07 | $4,202.01 | $151.89 |
| 2011 | 2104.2 | 40524 | 5.2 | $415.39 | $4,617.40 | $161.43 |
| 2012 | 2234.5 | 41314 | 5.4 | $432.68 | $5,050.08 | $170.07 |
| 2013 | 2372.3 | 42120 | 5.6 | $450.58 | $5,500.66 | $177.90 |
| 2014 | 2516.2 | 42941 | 5.9 | $468.77 | $5,969.43 | $184.98 |
| 2015 | 2667.1 | 43778 | 6.1 | $487.37 | $6,456.81 | $191.38 |
| 2016 | 2824.2 | 44632 | 6.3 | $506.23 | $6,963.04 | $197.16 |
| 2017 | 2989.6 | 45502 | 6.6 | $525.61 | $7,488.65 | $202.38 |
| 2018 | 3161.9 | 46390 | 6.8 | $545.28 | $8,033.93 | $207.09 |
| 2019 | 3344.7 | 47294 | 7.1 | $565.77 | $8,599.70 | $211.34 |
| 2020 | 3537.5 | 48216 | 7.3 | $586.93 | $9,186.63 | $215.17 |
| 2021 | 3742.9 | 49157 | 7.6 | $609.14 | $9,795.77 | $218.63 |
| 2022 | 2000.0 | 50115 | 4.0 | $319.27 | ********** | $220.20 |

Notes: [1] From Table 3.2.
[2] From Table II, Exh. JOB-1, (Total - 86% of other) extrapolated at 1.95% 2003-2022.
[3] Columns [1]/[3].
[4] Using 8000 kwh/year.
[5] From Column [4].
[6] Discount rate = 15.0%; from Column [4].

TABLE 3.6: SUSQUEHANNA 2 RETAIL RATE EFFECTS
CASE 2 (RECENT HISTORICAL CAPACITY FACTORS)

| Year | Susquehanna 2 Net Savings | Retail Sales | Reduction in Rates | Savings for Typical Customer (Residential) | Cumulative Savings | Discounted Cumulative Savings |
|---|---|---|---|---|---|---|
| | $ million | GWH | cents/kwh | $/year | | |
| | [1] | [2] | [3] | [4] | [5] | [6] |
| 1985 | -291.6 | 23003 | -1.3 | ($101.42) | ($101.42) | ($88.19) |
| 1986 | -264.6 | 23772 | -1.1 | ($89.06) | ($190.48) | ($155.53) |
| 1987 | -223.9 | 24574 | -0.9 | ($72.89) | ($263.37) | ($203.46) |
| 1988 | -143.3 | 25477 | -0.6 | ($44.99) | ($308.36) | ($229.18) |
| 1989 | -90.2 | 26029 | -0.3 | ($27.72) | ($336.08) | ($242.96) |
| 1990 | -48.3 | 26614 | -0.2 | ($14.51) | ($350.59) | ($249.24) |
| 1991 | 10.5 | 27278 | .0 | $3.07 | ($347.52) | ($248.08) |
| 1992 | 101.2 | 27942 | 0.4 | $28.96 | ($318.56) | ($238.62) |
| 1993 | 166.6 | 28605 | 0.6 | $46.58 | ($271.98) | ($225.37) |
| 1994 | 248.4 | 29199 | 0.9 | $68.07 | ($203.91) | ($208.55) |
| 1995 | 305.4 | 29792 | 1.0 | $82.00 | ($121.91) | ($190.92) |
| 1996 | 353.4 | 30386 | 1.2 | $93.03 | ($28.88) | ($173.54) |
| 1997 | 423.8 | 30979 | 1.4 | $109.43 | $80.55 | ($155.75) |
| 1998 | 496.0 | 31573 | 1.6 | $125.67 | $206.22 | ($137.99) |
| 1999 | 572.4 | 32206 | 1.8 | $142.19 | $348.42 | ($120.51) |
| 2000 | 753.1 | 32830 | 2.3 | $183.51 | $531.93 | ($100.90) |
| 2001 | 826.4 | 33464 | 2.5 | $197.56 | $729.49 | ($82.54) |
| 2002 | 912.6 | 34098 | 2.7 | $214.11 | $943.60 | ($65.24) |
| 2003 | 1005.7 | 34723 | 2.9 | $231.71 | $1,175.31 | ($48.96) |
| 2004 | 1083.7 | 35400 | 3.1 | $244.91 | $1,420.22 | ($34.00) |
| 2005 | 1150.3 | 36090 | 3.2 | $254.98 | $1,675.21 | ($20.45) |
| 2006 | 1239.5 | 36794 | 3.4 | $269.51 | $1,944.72 | ($8.00) |
| 2007 | 1316.1 | 37511 | 3.5 | $280.68 | $2,225.40 | $3.28 |
| 2008 | 1392.3 | 38243 | 3.6 | $291.25 | $2,516.65 | $13.45 |
| 2009 | 1497.4 | 38988 | 3.8 | $307.26 | $2,823.91 | $22.79 |
| 2010 | 1584.9 | 39749 | 4.0 | $318.98 | $3,142.90 | $31.21 |
| 2011 | 1688.8 | 40524 | 4.2 | $333.40 | $3,476.30 | $38.87 |
| 2012 | 1795.5 | 41314 | 4.3 | $347.68 | $3,823.97 | $45.81 |
| 2013 | 1908.3 | 42120 | 4.5 | $362.44 | $4,186.42 | $52.11 |
| 2014 | 2025.7 | 42941 | 4.7 | $377.40 | $4,563.82 | $57.81 |
| 2015 | 2148.6 | 43778 | 4.9 | $392.64 | $4,956.45 | $62.97 |
| 2016 | 2276.3 | 44632 | 5.1 | $408.01 | $5,364.46 | $67.63 |
| 2017 | 2410.4 | 45502 | 5.3 | $423.78 | $5,788.24 | $71.83 |
| 2018 | 2549.7 | 46390 | 5.5 | $439.70 | $6,227.94 | $75.63 |
| 2019 | 2697.6 | 47294 | 5.7 | $456.30 | $6,684.24 | $79.06 |
| 2020 | 2853.5 | 48216 | 5.9 | $473.44 | $7,157.68 | $82.15 |
| 2021 | 3019.9 | 49157 | 6.1 | $491.48 | $7,649.16 | $84.94 |
| 2022 | 1617.9 | 50115 | 3.2 | $258.27 | $7,907.44 | $86.21 |

Notes: [1] From Table 3.3.
[2] From Table II, Exh. JDB-1, (Total - 86% of other) extrapolated at 1.95% 2003-2022.
[3] Columns [1]/[3].
[4] Using 8000 kwh/year.
[5] From Column [4].
[6] Discount rate = 15.0%; from Column [4].

TABLE 3.7: SUSQUEHANNA 2 RETAIL RATE EFFECTS
CASE 3 (CONTINUING PAST EXPERIENCE)

| Year | Susquehanna 2 Net Savings | Retail Sales | Reduction in Rates | Savings for Typical Customer (Residential) | Cumulative Savings | Discounted Cumulative Savings |
|---|---|---|---|---|---|---|
| | $ million [1] | GWH [2] | cents/kwh [3] | $/year [4] | [5] | [6] |
| 1985 | -300.1 | 23003 | -1.3 | ($104.37) | ($104.37) | ($90.76) |
| 1986 | -269.1 | 23772 | -1.1 | ($90.57) | ($194.94) | ($159.24) |
| 1987 | -246.3 | 24574 | -1.0 | ($80.19) | ($275.12) | ($211.96) |
| 1988 | -163.1 | 25477 | -0.6 | ($51.20) | ($326.32) | ($241.24) |
| 1989 | -118.1 | 26029 | -0.5 | ($36.30) | ($362.63) | ($259.28) |
| 1990 | -88.1 | 26614 | -0.3 | ($26.49) | ($389.12) | ($270.74) |
| 1991 | -39.3 | 27278 | -0.1 | ($11.52) | ($400.64) | ($275.07) |
| 1992 | 40.4 | 27942 | 0.1 | $11.56 | ($389.08) | ($271.29) |
| 1993 | 90.0 | 28605 | 0.3 | $25.16 | ($363.92) | ($264.14) |
| 1994 | 152.0 | 29199 | 0.5 | $41.66 | ($322.27) | ($253.84) |
| 1995 | 184.1 | 29792 | 0.6 | $49.44 | ($272.83) | ($243.22) |
| 1996 | 201.9 | 30386 | 0.7 | $53.15 | ($219.68) | ($233.28) |
| 1997 | 235.4 | 30979 | 0.8 | $60.78 | ($158.90) | ($223.40) |
| 1998 | 262.4 | 31573 | 0.8 | $66.49 | ($92.41) | ($214.01) |
| 1999 | 283.9 | 32206 | 0.9 | $70.51 | ($21.90) | ($205.34) |
| 2000 | 395.7 | 32830 | 1.2 | $96.44 | $74.54 | ($195.04) |
| 2001 | 384.6 | 33464 | 1.1 | $91.94 | $166.48 | ($186.49) |
| 2002 | 371.0 | 34098 | 1.1 | $87.05 | $253.53 | ($179.46) |
| 2003 | 342.9 | 34723 | 1.0 | $79.00 | $332.53 | ($173.91) |
| 2004 | 273.7 | 35400 | 0.8 | $61.84 | $394.37 | ($170.13) |
| 2005 | 161.5 | 36090 | 0.4 | $35.81 | $430.18 | ($168.23) |
| 2006 | 34.0 | 36794 | 0.1 | $7.40 | $437.57 | ($167.88) |
| 2007 | -152.3 | 37511 | -0.4 | ($32.48) | $405.09 | ($169.19) |
| 2008 | -394.6 | 38243 | -1.0 | ($82.54) | $322.55 | ($172.07) |
| 2009 | -675.1 | 38988 | -1.7 | ($138.52) | $184.03 | ($176.28) |
| 2010 | -1054.5 | 39749 | -2.7 | ($212.24) | ($28.21) | ($181.89) |
| 2011 | -1515.7 | 40524 | -3.7 | ($299.22) | ($327.43) | ($188.76) |
| 2012 | -2092.7 | 41314 | -5.1 | ($405.22) | ($732.65) | ($196.85) |
| 2013 | -2806.8 | 42120 | -6.7 | ($533.10) | ($1,265.75) | ($206.11) |
| 2014 | -3689.3 | 42941 | -8.6 | ($687.32) | ($1,953.07) | ($216.49) |
| 2015 | -4775.7 | 43778 | -10.9 | ($872.70) | ($2,825.78) | ($227.96) |
| 2016 | -6110.2 | 44632 | -13.7 | ($1,095.21) | ($3,920.98) | ($240.46) |
| 2017 | -7744.0 | 45502 | -17.0 | ($1,361.52) | ($5,282.50) | ($253.98) |
| 2018 | -9735.0 | 46390 | -21.0 | ($1,678.82) | ($6,961.33) | ($268.48) |
| 2019 | -12150.5 | 47294 | -25.7 | ($2,055.30) | ($9,016.63) | ($283.91) |
| 2020 | -15081.7 | 48216 | -31.3 | ($2,502.33) | ($11,518.96) | ($300.25) |
| 2021 | -18635.5 | 49157 | -37.9 | ($3,032.84) | ($14,551.80) | ($317.47) |
| 2022 | -24745.3 | 50115 | -49.4 | ($3,950.15) | ($18,501.95) | ($336.97) |

Notes: [1] From Table 3.4.
[2] From Table II, Exh. JOB-1, (Total - 86% of other) extrapolated at 1.95% 2003-2022.
[3] Columns [1]/[3].
[4] Using 8000 kwh/year.
[5] From Column [4].
[6] Discount rate = 15.0%; from Column [4].

TABLE 3.8: SUMMARY OF COST-EFFECTIVENESS MEASURES

| | Case 1 | | Case 2 | | Case 3 | |
|---|---|---|---|---|---|---|
| | Total | Savings for Typical Customer (Residential)[1] | Total | Savings for Typical Customer (Residential)[1] | Total | Savings for Typical Customer (Residential)[1] |
| Table | 3.2 | 3.5 | 3.3 | 3.6 | 3.4 | 3.7 |
| Crossover Year | 1990 | 1990 | 1991 | 1991 | 1992 | 1992 |
| Breakeven Year | 1995 | 1995 | 1996 | 1997 | 1999 | 2000 |
| Discounted Breakeven Year | 1999 | 2001 | 2003 | 2007 | Never | Never |
| Cumulative Savings at Crossover | ($959.1) million | ($318.52) | ($1,051.4) million | ($347.52) | ($1,138.7) million | ($389.08) |
| Terminal Discounted Savings | $1,256.0 million | $220.20 | $716.0 million | ($86.21) | ($1,368.9) million | ($336.97) |

Notes: [1] Effect on 8000 kWh/year ratepayer.

TABLE 4.1: EASTERLING BWR CAPACITY FACTOR EQUATIONS
AND RESULTS FOR SUSQUEHANNA 2: 1152 MW

| Equation: | 2.1 | 2.2 | 2.3 | 2.4 | AVERAGE |
|---|---|---|---|---|---|
| Coefficients: | | | | | |
| Constant | 41.3 | 44.4 | 44.4 | 39.3 | |
| AGE | 7.1 | 6.2 | | | |
| AGE5 | | | 5.0 | 5.2 | |
| MGN/100 | -0.9 | -0.8 | -0.6 | | |
| MGNCF (1152 MW) at year= | | | | | |
| 2 | 45.1 | 47.6 | 47.5 | 49.7 | |
| 3 | 52.2 | 53.8 | 52.5 | 54.9 | |
| 4 | 59.3 | 60.0 | 57.5 | 60.1 | |
| 5 | 59.3 | 60.0 | 62.5 | 65.3 | |
| MGN2-CF (DER * 1.0442 = 1096.4 MW) at year= | | | | | |
| 2 | 45.6 | 48.0 | 47.8 | 49.7 | |
| 3 | 52.7 | 54.2 | 52.8 | 54.9 | |
| 4 | 59.8 | 60.4 | 57.8 | 60.1 | |
| 5 | 59.8 | 60.4 | 62.8 | 65.3 | |
| DERCF (1050 MW) at year= | | | | | |
| 2 | 47.6 | 50.2 | 49.9 | 51.9 | 49.9 |
| 3 | 55.1 | 56.6 | 55.2 | 57.3 | 56.0 |
| 4 | 62.5 | 63.1 | 60.4 | 62.8 | 62.2 |
| 5 | 62.5 | 63.1 | 65.6 | 68.2 | 64.8 |

TABLE 4.2: BWR CAPACITY FACTOR REGRESSIONS

| | Equation 1 | | Equation 2 | | Equation 3 | |
|---|---|---|---|---|---|---|
| | Coef | t-stat | Coef | t-stat | Coef | t-stat |
| CONSTANT | 70.75% | 7.2 | 70.22% | 7.2 | 76.86% | 8.4 |
| SIZE [1] | -0.03% | -2.7 | -0.03% | -2.7 | -0.03% | -3.0 |
| AGE5 [2] | 4.44% | 4.3 | 4.55% | 4.7 | 3.57% | 3.8 |
| REFUEL [3] | -8.70% | -3.7 | -8.40% | -3.6 | -10.19% | -4.6 |
| GT1000 [4] | 11.25% | 2.3 | 11.15% | 2.3 | 14.73% | 3.2 |
| YEAR INDICATORS [5] | | | | | | |
| 1979 | 2.86% | 0.7 | --- | --- | --- | --- |
| 1980 | -4.76% | -1.2 | --- | --- | --- | --- |
| 1981 | -7.67% | -2.0 | --- | --- | --- | --- |
| 1982 | -9.39% | -2.3 | --- | --- | --- | --- |
| 1983 | -12.47% | -3.1 | --- | --- | --- | --- |
| post-1979 [6] | --- | --- | -9.29% | -3.7 | -9.541% | -4.0 |
| ADJUSTED R | | 0.177 | | 0.179 | | 0.202 |
| F STATISTIC | | 5.6 | | 9.3 | | 10.5 |
| OBSERVATIONS [7] | | 192 | | 192 | | 189 |

Notes: [1] SIZE = Design Electrical Rating (DER) in MW.
[2] AGE5 = minimum of Age (years from COD to middle of current year), or 5.
[3] Refuel=number of refuelings in year (usually 0 or 1).
[4] GT1000 = 1, if SIZE > 1000, 0 otherwise.
[5] Indicator=1 in this year, 0 otherwise.
[6] 1980 or later.
[7] Full calendar years of BWR operation, >300 MW, 1974-83.
[8] Excludes Browns Ferry 1975-76.

TABLE 4.3: BWR CAPACITY FACTOR PROJECTIONS FOR SUSQUEHANNA 2

| YEAR | Value of REFUEL | Equation 1 | Equation 2 | Equation 3 |
|---|---|---|---|---|
| 1985 | 0 | 39.59% | 42.89% | 50.46% |
| 1986 | 1 | 35.33% | 39.05% | 43.85% |
| 1987 | 0 | 48.46% | 52.00% | 57.61% |
| 1988 | 1 | 44.20% | 48.15% | 51.00% |
| 1989 | 1 | 48.63% | 52.70% | 54.57% |
| 1990+ | 0.67 | 53.72% | 57.75% | 59.72% |

Notes: All projections assume 1983 conditions continue. Results of Equation 1 would be 8.9% higher at average historical conditions, and results of Equations 2 and 3 would be 5% higher.

TABLE 4.4: COMPARISON OF CAPACITY FACTOR PROJECTIONS

| | Calendar Years of Experience | | | | | | |
|---|---|---|---|---|---|---|---|
| Predicted Capacity Factors: | 1 [1] | 2 | 3 | 4 | 5 | 6 | 7+ |
| PP&L: [2] | 58.5% | 54.6% | 59.1% | 64.7% | 70.0% | 70.0% | 70.0% |
| Easterling: [3] | 49.9% | 49.9% | 56.0% | 62.2% | 64.8% | 64.8% | 64.8% |

| | As of: 31-May-84 | Unit Years of Experience in each Calendar Year | | | | | | |
|---|---|---|---|---|---|---|---|---|
| Unit | COD | 1 | 2 | 3 | 4 | 5 | 6 | 7+ |
| Browns Ferry 1 | 01-Aug-74 | 0.42 | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 | 4.41 |
| Browns Ferry 2 | 01-Mar-75 | 0.84 | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 | 3.42 |
| Browns Ferry 3 | 01-Mar-77 | 0.84 | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 | 1.41 |
| Peach Bottom 2 | 05-Jul-74 | 0.49 | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 | 4.41 |
| Peach Bottom 3 | 23-Dec-74 | 0.02 | 1.00 | 1.00 | 1.00 | 1.00 | 1.00 | 4.41 |

| Unit | Original DER (MW) | Actual [4] | PP&L | Easterling |
|---|---|---|---|---|
| Browns Ferry 1 [5] | 1098 | 50.3% | 66.3% | 61.5% |
| Browns Ferry 2 | 1098 | 53.6% | 65.5% | 60.6% |
| Browns Ferry 3 | 1098 | 57.8% | 64.3% | 59.5% |
| Peach Bottom 2 | 1065 | 60.9% | 66.2% | 61.4% |
| Peach Bottom 3 | 1065 | 61.4% | 66.6% | 62.0% |
| Average [6] | | 56.7% | 65.9% | 61.1% |

Notes:
[1] First partial year
[2] From: Attachment 1, IR I PA4
[3] DERCF Averages from Table 4.1
[4] Cumulative Net Elec. Energy/ Report Period Hours/ DER; From NRC Gray Book, June, 1984.
[5] Browns Ferry Net DER from Komanoff (1981)
[6] Weighted by experience.

TABLE 4.5: HISTORICAL CAPACITY FACTORS (DER)
Nuclear Units Similar in Characteristics to Susquehanna

| UNIT | DER NET [3] | first full year | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | CAPACITY FACTOR BY CALENDAR YEAR [2] | | | | | | | | |
| BROWNS FERRY 1 | 1098 | 75 | 14.0% | 13.5% | 52.4% | 60.5% | 77.9% | 62.9% | 45.8% | 81.9% | 22.6% |
| BROWNS FERRY 2 | 1098 | 76 | 16.2% | 64.7% | 57.7% | 77.4% | 58.3% | 77.7% | 46.3% | 66.4% | |
| BROWNS FERRY 3 | 1098 | 78 | 57.7% | 57.0% | 71.9% | 65.1% | 50.9% | 56.1% | | | |
| PEACH BOTTOM 2 | 1065 | 75 | 54.5% | 59.5% | 43.1% | 72.8% | 91.9% | 46.4% | 71.1% | 51.4% | 47.7% |
| PEACH BOTTOM 3 | 1065 | 75 | 56.6% | 64.7% | 51.2% | 74.7% | 65.4% | 77.3% | 33.6% | 91.5% | 26.0% |
| AVERAGES [1] | | | | | | | | | | | |
| per year: | 1085 | | 56.3% | 61.5% | 55.3% | 70.1% | 68.9% | 64.1% | 49.2% | 72.8% | 32.1% |
| cumulative: | -- | | | years 1-4: | | 61.3% | | | | years 5+: | 59.5% |
| ADJUSTMENT FOR THE BROWNS FERRY FIRE [4] | | | | | | | | | | | |
| Browns Ferry deviation [4] | | | 82.3% | 48.0% | | | | | | | |
| unit-years | | | | 41 | | | | | | | |
| deviation/unit-year | | | | 3.2% | | | | | | | |
| ADJUSTED AVERAGE | | | | | | | | | | | |
| per year: [5] | | | 53.1% | 58.3% | 52.1% | 66.9% | 65.7% | 60.9% | 46.0% | 69.6% | 28.9% |
| cumulative: [6] | | | | years 1-4: | | 58.1% | | | | years 5+: | 56.3% |

Notes:
[1] Values for years 1 and 2 for Browns Ferry 1, and for year 1 for Browns Ferry 2 are excluded from average.
[2] Computed from NRC-reported net output and original DER.
[3] Browns Ferry DER from Komanoff (1981).
[4] 2 * 56.3% - 14.0% - 16.2%, and 61.5%-13.5%, resp.
[5] Simple averages minus Browns Ferry deviation per unit/year.
[6] Cumulative (unadjusted) averages minus Browns Ferry deviation per unit-year.

TABLE 4.6: COMPARISON OF CAPACITY FACTOR TO EQUIVALENT AVAILABILITY FACTOR
PJM NUCLEAR UNITS

| | | 1970 | 1971 | 1972 | 1973 | 1974 | 1975 | 1976 | 1977 | 1978 | 1979 | 1980 | 1981 | 1982 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Calvert | EAF | | | | | | 76.0 | 89.2 | 65.0 | 61.2 | 54.4 | 60.0 | 79.3 | 69.6 |
| Cliffs 1 | CF | | | | | | 76.0 | 85.0 | 64.8 | 60.7 | 54.4 | 58.8 | 79.3 | 69.6 |
| | EAF-CF | | | | | | 0.0 | 4.2 | 0.2 | 0.5 | 0.0 | 1.2 | 0.0 | 0.0 |
| Calvert | EAF | | | | | | | | 80.4 | 67.8 | 71.2 | 89.6 | 72.4 | 64.9 |
| Cliffs 2 | CF | | | | | | | | 80.4 | 67.8 | 71.2 | 83.0 | 70.3 | 64.9 |
| | EAF-CF | | | | | | | | 0.0 | 0.0 | 0.0 | 6.6 | 2.1 | 0.0 |
| Three Mile | EAF | | | | | 79.2 | 77.2 | 60.4 | 76.2 | 79.2 | 12.4 | 0.0 | 0.0 | 0.0 |
| Island 1 | CF | | | | | 79.2 | 77.2 | 60.4 | 76.2 | 79.2 | 12.4 | 0.0 | 0.0 | 0.0 |
| | EAF-CF | | | | | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Peach | EAF | | | | | 76.5 | 54.5 | 59.9 | 43.4 | 73.4 | 92.2 | 47.6 | 72.8 | 54.1 |
| Bottom 2 | CF | | | | | 76.5 | 54.5 | 59.7 | 43.4 | 72.8 | 91.9 | 46.8 | 71.1 | 51.6 |
| | EAF-CF | | | | | 0.0 | 0.0 | 0.2 | 0.0 | 0.6 | 0.3 | 0.8 | 1.7 | 2.5 |
| Peach | EAF | | | | | | 56.6 | 66.0 | 51.3 | 75.8 | 66.4 | 77.3 | 34.0 | 93.0 |
| Bottom 3 | CF | | | | | | 56.6 | 64.7 | 51.3 | 74.8 | 65.5 | 77.3 | 34.0 | 91.5 |
| | EAF-CF | | | | | | 0.0 | 1.3 | 0.0 | 1.0 | 0.9 | 0.0 | 0.0 | 1.5 |
| Salem 1 | EAF | | | | | | | | 42.4 | 47.9 | 21.8 | 63.7 | 67.7 | 43.1 |
| | CF | | | | | | | | 42.4 | 47.6 | 21.8 | 59.4 | 64.8 | 43.0 |
| | EAF-CF | | | | | | | | 0.0 | 0.3 | 0.0 | 4.3 | 2.9 | 0.1 |
| Salem 2 | EAF | | | | | | | | | | | | 75.0 | 81.9 |
| | CF | | | | | | | | | | | | 75.0 | 81.3 |
| | EAF-CF | | | | | | | | | | | | 0.0 | 0.6 |
| Oyster | EAF | 76.6 | 78.5 | 76.3 | 63.3 | 64.8 | 55.3 | 67.6 | 57.1 | 70.1 | 81.0 | 34.4 | 46.2 | 56.6 |
| Creek | CF | 76.6 | 78.0 | 76.3 | 63.0 | 64.7 | 55.3 | 67.6 | 57.1 | 64.0 | 80.1 | 34.3 | 46.2 | 35.4 |
| | EAF-CF | 0.0 | 0.5 | 0.0 | 0.3 | 0.1 | 0.0 | 0.0 | 0.0 | 6.1 | 0.9 | 0.1 | 0.0 | 21.2 |
| Average (EAF-CF) | | 1.0 | | | | | | | | | | | | |

Source: Electric Power Research Institute, Nuclear Unit Operating Experience: 1980-1982 Update; April 1984, Appendix F. (EPRI NP-3480)

TABLE 4.7: PENNSYLVANIA POWER & LIGHT COMPANY
Calculation of Composite Cost Rate of Long-Term Debt, Susquehanna 2 Construction Period

| 1st Mortgage Bonds (1) | % to Total | Effective Int. Rate | Avg. Wgtd. Cost Rate |
|---|---|---|---|
| 9-7/8% Series due 1985 | 1.27 | 10.12 | 0.13 |
| 15% Series due 1986 | 0.64 | 15.15 | 0.10 |
| 14-3/4% Series due 1986 | 1.91 | 14.86 | 0.28 |
| 16-1/2% Series due 1986-90 | 3.54 | 16.63 | 0.59 |
| 16-1/2% Series due 1987-91 | 1.99 | 16.62 | 0.33 |
| 12-1/8% Series due 1989-93 | 1.91 | 12.23 | 0.23 |
| 14% Series due 1990 | 4.78 | 14.15 | 0.68 |
| 16-1/8% Series due 1992 | 3.82 | 16.45 | 0.63 |
| 9-1/4% Series due 2004 | 3.06 | 9.30 | 0.28 |
| 9-3/4% Series due 2005 | 4.78 | 9.91 | 0.47 |
| 9-3/4% Series due 2005 | 3.82 | 9.86 | 0.38 |
| 8-1/4% Series due 2006 | 5.73 | 8.34 | 0.48 |
| 8-1/2% Series due 2007 | 3.82 | 8.67 | 0.33 |
| 15-5/8% Series Due 2010 | 3.82 | 15.92 | 0.61 |
| 13-1/4% Series due 2012 | 3.82 | 13.55 | 0.52 |
| 13-1/8% Series due 2013 | 4.78 | 13.34 | 0.64 |
| 13-1/2% Series due 1994 | 4.78 | 13.72 | 0.66 |
| 14% Series due 1994 | 4.78 | 14.18 | 0.68 |
| 14% Series due 1995 | 4.78 | 14.18 | 0.68 |
| 7-7/8% Series due 2000 | 0.15 | 8.11 | 0.01 |
| 8-1/8% Series due 2006-2010 | 0.61 | 8.34 | 0.05 |
| 11-1/4% Series due 2002 | 0.57 | 11.62 | 0.07 |
| 11-1/2% Series due 2012 | 2.1 | 11.85 | 0.25 |
| 10-5/8% Series due 2014 | 1.44 | 10.96 | 0.16 |
| | 72.7 % | | 12.68 % |

Notes: (1) Data from Schedule B-6, Exhibit Future 1.

TABLE 4.8: PENNSYLVANIA POWER & LIGHT COMPANY
Composite Cost Rate of Preferred and Preference Stock, Susquehanna 2 Construction Period

| | % to Total (1) | Effective Cost Rate | Weighted Cost Rate |
|---|---|---|---|
| Series Preferred | | | |
| 4.50% | 5.44 | 5.03 | 0.27 |
| 9.24% | 6.46 | 9.47 | 0.61 |
| 8.00% | 4.62 | 8.06 | 0.37 |
| 7.75% | 4.93 | 7.80 | 0.38 |
| 8.00%, Second | 1.03 | 8.06 | 0.08 |
| 7.50% | 1.54 | 7.54 | 0.12 |
| 8.25% | 5.13 | 8.29 | 0.43 |
| 8.75% | 6.16 | 8.82 | 0.54 |
| 10.75% | 2.72 | 10.83 | 0.29 |
| 11.00%, Adjustable | 1.54 | 11.06 | 0.17 |
| 11.00% | 2.67 | 11.05 | 0.30 |
| 11.25% | 1.54 | 11.33 | 0.17 |
| 14.00% | 3.49 | 14.10 | 0.49 |
| Preference | | | |
| $13.00 | 1.63 | 13.53 | 0.22 |
| $11.00 | 3.93 | 11.40 | 0.45 |
| $11.60 | 5.13 | 12.36 | 0.63 |
| $ 8.625 | 5.23 | 8.68 | 0.45 |
| $15.00 | 5.13 | 16.10 | 0.83 |
| $13.00, Second | 5.13 | 13.90 | 0.71 |
| $13.68 | 5.13 | 14.65 | 0.75 |
| Total Preferred and Preference Stock | 78.58 % | | 10.54 % |

Notes: (1) Data from Schedule B-7, Exhibit Future 1.

TABLE 4.9: COMPOSITE COST OF CAPITAL, SUSQUEHANNA 2 CONSTRUCTION PERIOD

| Return | Capitalization | Embedded Cost | Return |
|---|---|---|---|
| Long-Term Debt | 47.30% | 12.68% | 6.00% |
| Preferred & Preference | 17.70% | 10.54% | 1.87% |
| Common Equity | 35.00% | 15.10% | 5.29% |
| Total | 100.00% | | 13.15% |

TABLE 4.10: MARGINAL COMPOSITE COST OF CAPITAL, 1985
PENNSYLVANIA POWER AND LIGHT

| Return | Capitalization | Embedded Cost | Return |
|---|---|---|---|
| Long-Term Debt | 47.30% | 14.18% | 6.71% |
| Preferred & Preference | 17.70% | 14.65% | 2.59% |
| Common Equity | 35.00% | 15.10% | 5.29% |
| Total | 100.00% | | 14.59% |

TABLE 4.11: CHOOSING A UTILITY DISCOUNT RATE BASED ON THE COST OF RATEBASING INVESTMENTS

| | | | | | |
|---|---|---|---|---|---|
| | | | | tax | |
| Debt | 50.0% | 13.0% | 6.5% | rate | 50.0% |
| Equity | 50.0% | 16.0% | 8.0% | | |

| | |
|---|---|
| Weighted Average | 14.50% |
| Weighted Average + 50% Tax Effect on Equity: | 22.50% |
| Weighted Average - 50% Tax Effect on Debt: | 11.25% |

| Year | Cash | Deprec. at 10% | Rate-making Return + Taxes | Total | Year-end Ratebase |
|---|---|---|---|---|---|
| 0 | 1000 | | | | 1000 |
| 1 | | 100 | 225.0 | 325.0 | 900 |
| 2 | | 100 | 202.5 | 302.5 | 800 |
| 3 | | 100 | 180.0 | 280.0 | 700 |
| 4 | | 100 | 157.5 | 257.5 | 600 |
| 5 | | 100 | 135.0 | 235.0 | 500 |
| 6 | | 100 | 112.5 | 212.5 | 400 |
| 7 | | 100 | 90.0 | 190.0 | 300 |
| 8 | | 100 | 67.5 | 167.5 | 200 |
| 9 | | 100 | 45.0 | 145.0 | 100 |
| 10 | | 100 | 22.5 | 122.5 | 0 |

| Present Value at: | | | |
|---|---|---|---|
| | 14.50% | 1000 | 1269 |
| | 22.50% | 1000 | 1000 |
| | 11.25% | 1000 | 1417 |

TABLE 4.12: NON-FUEL O&M AND CAPITAL ADDITIONS DATA

| Plant | Yr | Rating | Total Cost | Cost Increase | 1983 $ | /MW-yr | O&M - Fuel | O&M -F 1983 $ | New Unit Date | 2nd Unit Same Year |
|---|---|---|---|---|---|---|---|---|---|---|
| Arkansas 1 | 74 | 902 | 233027 | | | | 0 | | 19-Dec-74 | |
| Arkansas 1 | 75 | 902 | 238751 | 5724 | 10407 | 11.54 | 4109 | 7044 | | |
| Arkansas 1 | 76 | 902 | 242204 | 3453 | 5962 | 6.61 | 6015 | 9801 | | |
| Arkansas 1 | 77 | 902 | 247069 | 4865 | 7997 | 8.87 | 8379 | 12901 | | |
| Arkansas 1 | 78 | 902 | 253994 | 6925 | 10259 | 11.37 | 12125 | 17381 | | |
| Arkansas 1 | 79 | 902 | 268130 | 14136 | 18641 | 20.67 | 18923 | 24969 | | |
| Arkansas 1 | 80 | NA | NA | | | | NA | NA | 26-Mar-80 | |
| Arkansas 1&2 | 81 | 1845 | 916567 | | | | 54422 | 60136 | | |
| Arkansas 1&2 | 82 | 1845 | 927141 | 10574 | 11034 | 5.98 | 54496 | 56801 | | |
| Arkansas 1&2 | 83 | 1853 | 935827 | 8686 | 8686 | 4.69 | 64928 | 64928 | | |
| Beaver Valley | 76 | 923 | 599697 | | | | 1777 | 2895 | 30-Sep-76 | |
| Beaver Valley | 77 | 923 | 598716 | -981 | -1525 | -1.65 | 14692 | 22621 | | |
| Beaver Valley | 78 | 923 | 582408 | -16308 | -23883 | -25.88 | 22681 | 32514 | | |
| Beaver Valley | 79 | 923 | 576367 | -6041 | -8067 | -8.74 | 22907 | 30225 | | |
| Beaver Valley | 80 | 923 | 647575 | 71208 | 87849 | 95.18 | 34771 | 42023 | | |
| Beaver Valley | 81 | 924 | 671283 | 23708 | 26909 | 29.12 | 35838 | 39601 | | |
| Beaver Valley | 82 | 923 | 748515 | 77232 | 80791 | 87.53 | 49144 | 51223 | | |
| Beaver Valley | 83 | 923 | 803564 | 55049 | 55049 | 59.64 | 65738 | 65738 | | |
| Big Rock Point | 63 | 54 | 14412 | | | | 645 | 1941 | 15-Dec-62 | |
| Big Rock Point | 64 | 54 | 14349 | -63 | -221 | -4.10 | 666 | 1973 | | |
| Big Rock Point | 65 | 75 | 13750 | -599 | -2106 | -28.07 | 715 | 2073 | | |
| Big Rock Point | 66 | 75 | 13793 | 43 | 149 | 1.99 | 763 | 2143 | | |
| Big Rock Point | 67 | 75 | 13837 | 44 | 146 | 1.94 | 1086 | 2962 | | |
| Big Rock Point | 68 | 75 | 13926 | 89 | 287 | 3.82 | 865 | 2260 | | |
| Big Rock Point | 69 | 75 | 13958 | 32 | 96 | 1.29 | 933 | 2318 | | |
| Big Rock Point | 70 | 75 | 14324 | 366 | 1023 | 13.64 | 1062 | 2504 | | |
| Big Rock Point | 71 | 75 | 14554 | 230 | 593 | 7.91 | 1266 | 2843 | | |
| Big Rock Point | 72 | 75 | 14731 | 177 | 432 | 5.76 | 1412 | 3045 | | |
| Big Rock Point | 73 | 75 | 14815 | 84 | 195 | 2.60 | 1586 | 3234 | | |
| Big Rock Point | 74 | 75 | 16012 | 1197 | 2415 | 32.20 | 2263 | 4240 | | |
| Big Rock Point | 75 | 75 | 16587 | 575 | 1034 | 13.79 | 2584 | 4430 | | |
| Big Rock Point | 76 | 75 | 22907 | 6320 | 10702 | 142.70 | 3183 | 5186 | | |
| Big Rock Point | 77 | 75 | 23971 | 1064 | 1668 | 22.24 | 5125 | 7891 | | |
| Big Rock Point | 78 | 75 | 24409 | 438 | 639 | 8.52 | 3645 | 5225 | | |
| Big Rock Point | 79 | 75 | 27014 | 2605 | 3473 | 46.31 | 9232 | 12181 | | |
| Big Rock Point | 80 | 75 | 27262 | 248 | 304 | 4.06 | 8409 | 10163 | | |
| Big Rock Point | 81 | 75 | 33356 | 6094 | 6863 | 91.51 | 12970 | 14332 | | |
| Big Rock Point | 82 | 75 | 37068 | 3712 | 3862 | 51.49 | 15513 | 16169 | | |
| Big Rock Point | 83 | 75 | 39382 | 2314 | 2314 | 30.85 | 16416 | 16416 | | |
| Browns Ferry 1&2 | 75 | 2304 | 512653 | | | | 6626 | 11358 | 01-Aug-74 | 01-Mar-75 |
| Browns Ferry 1&2 | 76 | 2304 | 552357 | 39704 | 66749 | 28.97 | 16104 | 26239 | | |
| Browns Ferry 1,2,3 | 77 | 3456 | 853325 | | | | 19305 | 29723 | 01-Mar-77 | |
| Browns Ferry 1,2,3 | 78 | 3456 | 885991 | 32666 | 47072 | 13.62 | 45921 | 65829 | | |
| Browns Ferry 1,2,3 | 79 | 3456 | 888350 | 2359 | 3092 | 0.89 | 55588 | 73347 | | |
| Browns Ferry 1,2,3 | 80 | 3456 | 890428 | 2078 | 2485 | 0.72 | 66969 | 80936 | | |
| Browns Ferry 1,2,3 | 81 | 3456 | 892715 | 2287 | 2503 | 0.72 | 85469 | 94443 | | |
| Browns Ferry 1,2,3 | 82 | 3456 | 915514 | 22799 | 23404 | 6.77 | 92271 | 96174 | | |
| Browns Ferry 1,2,3 | 83 | | | | | | | 0 | | |
| Brunswick 2 | 75 | 866 | 382246 | | | | 4473 | 7668 | 03-Nov-75 | |
| Brunswick 2 | 76 | 866 | 389118 | 6872 | 11553 | 13.34 | 10518 | 17138 | | |

TABLE 4.12: NON-FUEL O&M AND CAPITAL ADDITIONS DATA

| Plant | Yr | Rating | Total Cost | Cost Increase | 1983 $ | /MW-yr | O&M - Fuel | O&M -F 1983 $ | New Unit Date | 2nd Unit Same Year |
|---|---|---|---|---|---|---|---|---|---|---|
| Brunswick 1&2 | 77 | 1733 | 707560 | | | | 25378 | 39074 | 18-Mar-77 | |
| Brunswick 1&2 | 78 | 1733 | 714928 | 7368 | 10617 | 6.13 | 26633 | 38179 | | |
| Brunswick 1&2 | 79 | 1733 | 750828 | 35900 | 47055 | 27.15 | 34206 | 45134 | | |
| Brunswick 1&2 | 80 | 1733 | 776989 | 26161 | 31285 | 18.05 | 57516 | 69511 | | |
| Brunswick 1&2 | 81 | 1733 | 803535 | 26546 | 29050 | 16.76 | 73150 | 80831 | | |
| Brunswick 1&2 | 82 | 1755 | 805771 | 2236 | 2295 | 1.31 | 112235 | 116982 | | |
| Brunswick 1&2 | 83 | 1698 | 892994 | 87223 | 87223 | 51.37 | 64972 | 64972 | | |
| Calvert Cliffs 1 | 75 | 918 | 428747 | | | | 4241 | 7270 | 08-May-75 | |
| Calvert Cliffs 1 | 76 | 918 | 430674 | 1927 | 3216 | 3.50 | 8984 | 14638 | | |
| Calvert Cliffs 1&2 | 77 | 1828 | 765995 | | | | 20158 | 31037 | 01-Apr-77 | |
| Calvert Cliffs 1&2 | 78 | 1828 | 777711 | 11716 | 17158 | 9.39 | 25997 | 37267 | | |
| Calvert Cliffs 1&2 | 79 | 1828 | 780095 | 2384 | 3183 | 1.74 | 36397 | 48025 | | |
| Calvert Cliffs 1&2 | 80 | 1828 | 790988 | 10893 | 13439 | 7.35 | 41628 | 50310 | | |
| Calvert Cliffs 1&2 | 81 | 1828 | 820215 | 29227 | 33173 | 18.15 | 50409 | 55702 | | |
| Calvert Cliffs 1&2 | 82 | 1828 | 852313 | 32098 | 33577 | 18.37 | 61969 | 64590 | | |
| Calvert Cliffs 1&2 | 83 | 1770 | 903868 | 51555 | 51555 | 29.13 | 50301 | 50301 | | |
| Connecticut Yankee | 68 | 600 | 91801 | | | | 2047 | 5348 | 01-Jan-68 | |
| Connecticut Yankee | 69 | 600 | 91841 | 40 | 121 | 0.20 | 2067 | 5135 | | |
| Connecticut Yankee | 70 | 600 | 93516 | 1675 | 4694 | 7.82 | 4479 | 10561 | | 14-Jan-00 |
| Connecticut Yankee | 71 | 600 | 93669 | 153 | 395 | 0.66 | 3279 | 7364 | | 13-Jan-00 |
| Connecticut Yankee | 72 | 600 | 93814 | 145 | 346 | 0.58 | 3749 | 8084 | | 12-Jan-00 |
| Connecticut Yankee | 73 | 600 | 94016 | 202 | 459 | 0.76 | 6352 | 12952 | | 12-Jan-00 |
| Connecticut Yankee | 74 | 600 | 106212 | 12196 | 24285 | 40.48 | 4935 | 9247 | | 13-Jan-00 |
| Connecticut Yankee | 75 | 600 | 108921 | 2709 | 4842 | 8.07 | 9381 | 16081 | | 13-Jan-00 |
| Connecticut Yankee | 76 | 600 | 114503 | 5582 | 9317 | 15.53 | 9419 | 15347 | | 13-Jan-00 |
| Connecticut Yankee | 77 | 600 | 117238 | 2735 | 4252 | 7.09 | 9448 | 14547 | | 13-Jan-00 |
| Connecticut Yankee | 78 | 600 | 121288 | 4050 | 5931 | 9.89 | 8736 | 12523 | | 13-Jan-00 |
| Connecticut Yankee | 79 | 600 | 123037 | 1749 | 2335 | 3.89 | 18923 | 24969 | | 12-Jan-00 |
| Connecticut Yankee | 80 | 600 | 137644 | 14607 | 18021 | 30.03 | 35155 | 42487 | | 13-Jan-00 |
| Connecticut Yankee | 81 | 600 | 152552 | 14908 | 16921 | 28.20 | 37488 | 41424 | | 13-Jan-00 |
| Connecticut Yankee | 82 | 600 | 167878 | 15326 | 16032 | 26.72 | 35723 | 37234 | | |
| Connecticut Yankee | 83 | 600 | 182739 | 14861 | 14861 | 24.77 | 48671 | 48671 | | |
| Cook 1 | 75 | 1089 | 538611 | | | | 1662 | 2849 | 23-Aug-75 | |
| Cook 1 | 76 | 1089 | 544650 | 6039 | 10227 | 9.39 | 7047 | 11482 | | |
| Cook 1 | 77 | 1089 | 552238 | 7588 | 11895 | 10.92 | 10012 | 15415 | | |
| Cook 1&2 | 78 | 2200 | 996177 | | | | 15707 | 22516 | 01-Jul-78 | |
| Cook 1&2 | 79 | 2285 | 1025829 | 29652 | 39536 | 17.30 | 26750 | 35296 | | |
| Cook 1&2 | 80 | 2250 | 1074584 | 48755 | 59847 | 26.60 | 32409 | 39169 | | |
| Cook 1&2 | 81 | 2285 | 1096310 | 21726 | 24468 | 10.71 | 37967 | 41954 | | |
| Cook 1&2 | 82 | 2285 | 1118610 | 22300 | 23200 | 10.15 | 50859 | 53010 | | |
| Cook 1&2 | 83 | 2222 | 1145590 | 26980 | 26980 | 12.14 | 57904 | 57904 | | |
| Cooper | 74 | 835 | 246268 | | | | 2691 | 5042 | 15-Jul-74 | |
| Cooper | 75 | 835 | 269287 | 23019 | 41399 | 49.58 | 7386 | 12661 | | |
| Cooper | 76 | 835 | 269287 | 0 | 0 | 0.00 | 10211 | 16637 | | |
| Cooper | 77 | 835 | 302382 | 33095 | 51879 | 62.13 | 10218 | 15732 | | |
| Cooper | 78 | 836 | 384630 | 82248 | 120010 | 143.55 | 8306 | 11907 | | |
| Cooper | 79 | 836 | 384570 | -60 | -80 | -0.10 | 10232 | 13501 | | |
| Cooper | 80 | 836 | 384569 | -1 | -1 | .00 | 19004 | 22967 | | |
| Cooper | 81 | 778 | 383748 | -821 | -925 | -1.19 | 20455 | 22603 | | |
| Cooper | 82 | 836 | 384358 | 610 | 635 | 0.76 | 23482 | 24475 | | |

TABLE 4.12: NON-FUEL O&M AND CAPITAL ADDITIONS DATA

| Plant | Yr | Rating | Total Cost | Cost Increase | 1983 $ | /MW-yr | O&M - Fuel | O&M -F 1983 $ | New Unit Date | 2nd Unit Same Year |
|---|---|---|---|---|---|---|---|---|---|---|
| Cooper | 83 | | | | | | | | | |
| Crystal River | 77 | 801 | 365535 | | | | 7600 | 11701 | 13-Mar-77 | |
| Crystal River | 78 | 890 | 415173 | 49638 | 71528 | 80.37 | 15613 | 22382 | | |
| Crystal River | 79 | 890 | 419131 | 3958 | 5188 | 5.83 | 23992 | 31657 | | |
| Crystal River | 80 | 890 | 421055 | 1924 | 2301 | 2.59 | 39841 | 48150 | | |
| Crystal River | 81 | 801 | 384011 | -37044 | -40539 | -50.61 | 42313 | 46756 | | |
| Crystal River | 82 | 801 | 385759 | 1748 | 1794 | 2.24 | 46796 | 48775 | | |
| Crystal River | 83 | 868 | 396620 | 10861 | 10861 | 12.51 | 63505 | 63505 | | |
| Davis-Besse | 77 | 960 | 271283 | | | | 295 | 454 | 31-Dec-77 | |
| Davis-Besse | 78 | 906 | 635147 | 363864 | 530921 | 586.01 | 14096 | 20207 | | |
| Davis-Besse | 79 | 906 | 671140 | 35993 | 47991 | 52.97 | 21737 | 28681 | | |
| Davis-Besse | 80 | 962 | 738544 | 67404 | 82739 | 86.01 | 44630 | 53938 | | |
| Davis-Besse | 81 | 962 | 786437 | 47893 | 53938 | 56.07 | 41413 | 45761 | | |
| Davis-Besse | 82 | 962 | 846126 | 59689 | 62098 | 64.55 | 59955 | 62491 | | |
| Davis-Besse | 83 | 934 | 870233 | 24107 | 24107 | 25.81 | 51099 | 51099 | | |
| Dresden 1 | 62 | 208 | 34180 | | | | 1252 | 3823 | | |
| Dresden 1 | 63 | 208 | 34442 | 262 | 921 | 4.43 | 1266 | 3809 | | |
| Dresden 1 | 64 | 208 | 34468 | 26 | 91 | 0.44 | 1071 | 3174 | | |
| Dresden 1 | 65 | 208 | 34451 | -17 | -60 | -0.29 | 1264 | 3665 | | |
| Dresden 1 | 66 | 208 | 34352 | -99 | -343 | -1.65 | 1163 | 3267 | | |
| Dresden 1 | 67 | 208 | 34366 | 14 | 46 | 0.22 | 1912 | 5215 | | |
| Dresden 1 | 68 | 208 | 33467 | -899 | -2897 | -13.93 | 1673 | 4371 | | |
| Dresden 1 | 69 | 208 | 33968 | 501 | 1510 | 7.26 | 1788 | 4442 | | |
| Dresden 1&2 | 70 | 1018 | 116609 | | | | 2294 | 5409 | 11-Aug-70 | |
| Dresden 1,2,3 | 71 | 1828 | 220380 | | | | 3639 | 8173 | 15-Oct-71 | |
| Dresden 1,2,3 | 72 | 1865 | 241479 | 21099 | 51526 | 27.63 | 9142 | 19713 | | |
| Dresden 1,2,3 | 73 | 1865 | 235397 | -6082 | -14110 | -7.57 | 9050 | 18453 | | |
| Dresden 1,2,3 | 74 | 1865 | 237303 | 1906 | 3845 | 2.06 | 16731 | 31350 | | |
| Dresden 1,2,3 | 75 | 1865 | 249177 | 11874 | 21355 | 11.45 | 32895 | 56389 | | |
| Dresden 1,2,3 | 76 | 1865 | 256493 | 7316 | 12389 | 6.64 | 30092 | 49031 | | |
| Dresden 1,2,3 | 77 | 1865 | 258522 | 2029 | 3181 | 1.71 | 26999 | 41569 | | |
| Dresden 1,2,3 | 78 | 1865 | 276887 | 18365 | 26797 | 14.37 | 33932 | 48642 | | |
| Dresden 1,2,3 | 79 | 1865 | 290785 | 13898 | 18531 | 9.94 | 44579 | 58821 | | |
| Dresden 1,2,3 | 80 | 1865 | 303201 | 12416 | 15241 | 8.17 | 38130 | 46082 | | |
| Dresden 1,2,3 | 81 | 1865 | 307054 | 3853 | 4339 | 2.33 | 40361 | 44599 | | |
| Dresden 1,2,3 | 82 | 1865 | 331590 | 24536 | 25526 | 13.69 | 43740 | 45590 | | |
| Dresden 1,2,3 | 83 | 1666 | 331590 | 0 | 0 | 0.00 | 44800 | 44800 | | |
| Duane Arnold | 74 | 565 | 288821 | | | | 2121 | 3975 | 22-Jun-74 | |
| Duane Arnold | 75 | 565 | 279730 | -9091.42 | -16350 | -28.94 | 3839 | 6581 | | |
| Duane Arnold | 76 | 565 | 279928 | 198 | 335 | 0.59 | 7050 | 11487 | | |
| Duane Arnold | 77 | 565 | 287561 | 7633.428 | 11966 | 21.18 | 7508 | 11560 | | |
| Duane Arnold | 78 | 597 | 282345 | -5216.42 | -7611 | -12.75 | 11916 | 17082 | | |
| Duane Arnold | 79 | 597 | 306768 | 24423 | 32564 | 54.55 | 9528 | 12572 | | |
| Duane Arnold | 80 | 597 | 324186 | 17418 | 21381 | 35.81 | 18398 | 22235 | | |
| Duane Arnold | 81 | 597 | 339460 | 15274 | 17202 | 28.81 | 21956 | 24261 | | |
| Duane Arnold | 82 | 597 | 365309 | 25849 | 26892 | 45.05 | 29239 | 30476 | | |
| Duane Arnold | 83 | | | | | | | 0 | | |
| Farley 1 | 77 | 888 | 727426 | | | | 462 | 711 | 01-Dec-77 | |
| Farley 1 | 78 | 888 | 734519 | 7093 | 10221 | 11.51 | 12207 | 17499 | | |
| Farley 1 | 79 | 888 | 751634 | 17115 | 22433 | 25.26 | 22545 | 29748 | | |

TABLE 4.12: NON-FUEL O&M AND CAPITAL ADDITIONS DATA

| Plant | Yr | Rating | Total Cost | Cost Increase | 1983 $ | /MW-yr | O&M - Fuel | O&M -F 1983 $ | New Unit Date | 2nd Unit Same Year |
|---|---|---|---|---|---|---|---|---|---|---|
| Farley 1 | 80 | 888 | 761329 | 9695 | 11594 | 13.06 | 25734 | 31101 | | |
| Farley 1&2 | 81 | 1776 | 1541981 | | | | 41427 | 45777 | 30-Jul-81 | |
| Farley 1&2 | 82 | 1777 | 1611172 | 69191 | 71028 | 39.97 | 52488 | 54708 | | |
| Farley 1&2 | 83 | 1722 | 1642869 | 31697 | 31697 | 18.41 | 57333 | 57333 | | |
| Fitzpatrick | 75 | 849 | NA | | | | 6902 | 11831 | 15-Jul-75 | |
| Fitzpatrick | 76 | 849 | NA | | | | 10700 | 17434 | | |
| Fitzpatrick | 77 | 849 | NA | | | | 17383 | 26764 | | |
| Fitzpatrick | 78 | 883 | NA | | | | 19045 | 27301 | | |
| Fitzpatrick | 79 | 883 | NA | | | | 25131 | 33160 | | |
| Fitzpatrick | 80 | 883 | NA | | | | 33303 | 40248 | | |
| Fitzpatrick | 81 | 883 | 367141 | | | | 36678 | 40529 | | |
| Fitzpatrick | 82 | 883 | 344597 | -22544 | -23583 | -26.71 | 31504 | 32836 | | |
| Fitzpatrick | 83 | | | | | | | 0 | | |
| Fort Calhoun | 73 | 481 | 173870 | | | | 529 | 1079 | 15-Sep-73 | |
| Fort Calhoun | 74 | 481 | 175800 | 1930 | 3894 | 8.09 | 3413 | 6395 | | |
| Fort Calhoun | 75 | 481 | 178572 | 2772 | 4985 | 10.36 | 5962 | 10220 | | |
| Fort Calhoun | 76 | 481 | 178896 | 324 | 549 | 1.14 | 7449 | 12137 | | |
| Fort Calhoun | 77 | 481 | 179994 | 1098 | 1721 | 3.58 | 8493 | 13076 | | |
| Fort Calhoun | 78 | 481 | 180328 | 334 | 487 | 1.01 | 8116 | 11634 | | |
| Fort Calhoun | 79 | 481 | 180830 | 502 | 669 | 1.39 | 8504 | 11221 | | |
| Fort Calhoun | 80 | 481 | 192700 | 11870 | 14571 | 30.29 | 14332 | 17321 | | |
| Fort Calhoun | 81 | 481 | 198544 | 5844 | 6582 | 13.68 | 11472 | 12677 | | |
| Fort Calhoun | 82 | 481 | 211041 | 12497 | 13001 | 27.03 | 18934 | 19735 | | |
| Fort Calhoun | 83 | | | | | | | 0 | | |
| Fort St. Vrain | 79 | 343 | 105610 | | | | 12121 | 15993 | | |
| Fort St. Vrain | 80 | 342 | 101459 | -4151 | -5095 | -14.90 | 16884 | 20405 | | |
| Fort St. Vrain | 81 | 342 | 120884 | 19425 | 21877 | 63.97 | 18796 | 20770 | | |
| Fort St. Vrain | 82 | 342 | 112793 | -8091 | -8418 | -24.61 | 20316 | 21175 | | |
| Fort St. Vrain | 83 | 342 | 134684 | 21891 | 21891 | 64.01 | NA | NA | | |
| Ginna | 70 | 517 | 83175 | | | | 3199 | 7543 | 15-Jul-70 | |
| Ginna | 71 | 517 | 83075 | -100 | -258 | -0.50 | 4391 | 9862 | | |
| Ginna | 72 | 517 | 83982 | 907 | 2167 | 4.19 | 4082 | 8802 | | |
| Ginna | 73 | 517 | 85004 | 1022 | 2320 | 4.49 | 3536 | 7210 | | |
| Ginna | 74 | 517 | 87668 | 2664 | 5305 | 10.26 | 5391 | 10101 | | |
| Ginna | 75 | 517 | 89750 | 2082 | 3721 | 7.20 | 6597 | 11309 | | |
| Ginna | 76 | 517 | 93308 | 3558 | 5939 | 11.49 | 7356 | 11986 | | |
| Ginna | 77 | 517 | 114141 | 20833 | 32391 | 62.65 | 7942 | 12228 | | |
| Ginna | 78 | 517 | 121860 | 7719 | 11305 | 21.87 | 9819 | 14076 | | |
| Ginna | 79 | 517 | 129112 | 7252 | 9684 | 18.73 | 12819 | 16914 | | |
| Ginna | 80 | 517 | 136138 | 7026 | 8668 | 16.77 | 18924 | 22871 | | |
| Ginna | 81 | 517 | 159487 | 23349 | 26501 | 51.26 | 22482 | 24843 | | |
| Ginna | 82 | 517 | 182754 | 23267 | 24339 | 47.08 | 29570 | 30821 | | |
| Ginna | 83 | 496 | 214985 | 32231 | 32231 | 64.98 | 25839 | 25839 | | |
| Hatch 1 | 76 | 850 | 390393 | | | | 5867 | 9560 | 31-Dec-75 | |
| Hatch 1 | 77 | 850 | 396799 | 6406 | 9842 | 11.58 | 9799 | 15087 | | |
| Hatch 1 | 78 | 850 | 409113 | 12314 | 17744 | 20.88 | 12268 | 17586 | | |
| Hatch 1&2 | 79 | 1702 | 918419 | | | | 27094 | 35750 | 05-Sep-79 | |
| Hatch 1&2 | 80 | 1700 | 947147 | 28728 | 34355 | 20.21 | 38486 | 46512 | | |
| Hatch 1&2 | 81 | 1704 | 969365 | 22218 | 24314 | 14.27 | 62010 | 68521 | | |
| Hatch 1&2 | 82 | 1704 | 1004824 | 35459 | 36400 | 21.36 | 67689 | 70552 | | |

TABLE 4.12: NON-FUEL O&M AND CAPITAL ADDITIONS DATA

| Plant | Yr | Rating | Total Cost | Cost Increase | 1983 $ | /MW-yr | O&M - Fuel | O&M -F 1983 $ | New Unit Date | 2nd Unit Same Year |
|---|---|---|---|---|---|---|---|---|---|---|
| Hatch 1&2 | 83 | 1633 | 1134116 | 129291 | 129291 | 79.17 | 105745 | 105745 | | |
| Humboldt | 63 | 60 | 24471 | | | | 331 | 996 | | |
| Humboldt | 64 | 60 | 23786 | -685 | -2566 | -42.77 | 525 | 1556 | | |
| Humboldt | 65 | 60 | 24176 | 390 | 1461 | 24.35 | 629 | 1824 | | |
| Humboldt | 66 | 60 | 22224 | -1952 | -7101 | -118.35 | 562 | 1579 | | |
| Humboldt | 67 | 60 | 22480 | 256 | 892 | 14.87 | 630 | 1718 | | |
| Humboldt | 68 | 60 | 22619 | 139 | 465 | 7.75 | 582 | 1520 | | |
| Humboldt | 69 | 60 | 22688 | 69 | 222 | 3.70 | 646 | 1605 | | |
| Humboldt | 70 | 60 | 22764 | 76 | 230 | 3.83 | 619 | 1460 | | |
| Humboldt | 71 | 60 | 22850 | 86 | 243 | 4.04 | 926 | 2080 | | |
| Humboldt | 72 | 60 | 22947 | 97 | 256 | 4.27 | 897 | 1934 | | |
| Humboldt | 73 | 65 | 22998 | 51 | 128 | 1.97 | 915 | 1866 | | |
| Humboldt | 74 | 65 | 23171 | 173 | 381 | 5.86 | 1070 | 2005 | | |
| Humboldt | 75 | 65 | 24031 | 860 | 1648 | 25.35 | 1221 | 2093 | | |
| Humboldt | 76 | 65 | 24543 | 512 | 905 | 13.92 | 1980 | 3226 | | |
| Humboldt | 77 | 65 | 26726 | 2183 | 3535 | 54.39 | 3081 | 4744 | | |
| Humboldt | 78 | 65 | 28506 | 1780 | 2675 | 41.16 | 1635 | 2344 | | |
| Humboldt | 79 | 65 | 28567 | 61 | 83 | 1.27 | 1485 | 1959 | | |
| Humboldt | 80 | 65 | NA | | | | 1587 | 1918 | | |
| Humboldt | 81 | 65 | NA | | | | 2073 | 2291 | | |
| Indian Point 1 | 63 | 275 | 126218 | | | | 2762 | 8310 | 15-Sep-62 | |
| Indian Point 1 | 64 | 275 | 126255 | 37 | 131 | 0.48 | 2894 | 8575 | | |
| Indian Point 1 | 65 | 275 | 126330 | 75 | 266 | 0.97 | 2626 | 7615 | | |
| Indian Point 1 | 66 | 275 | 128891 | 2561 | 8808 | 32.03 | 2929 | 8228 | | |
| Indian Point 1 | 67 | 275 | 128821 | -70 | -230 | -0.84 | 3184 | 8684 | | |
| Indian Point 1 | 68 | 275 | 128818 | -3 | -10 | -0.03 | 2831 | 7396 | | |
| Indian Point 1 | 69 | 275 | 127914 | -904 | -2736 | -9.95 | 2713 | 6740 | | |
| Indian Point 1 | 70 | 275 | 128083 | 169 | 474 | 1.72 | 3498 | 8248 | | |
| Indian Point 1 | 71 | 275 | 128175 | 92 | 237 | 0.86 | 3962 | 8898 | | |
| Indian Point 1 | 72 | 275 | 128938 | 763 | 1823 | 6.63 | 6950 | 14986 | | |
| Indian Point 1&2 | 73 | 1288 | 334963 | | | | 14854 | 30288 | 15-Aug-73 | |
| Indian Point 1&2 | 74 | 1288 | 340188 | 5225 | 10404 | 8.08 | 12737 | 23866 | | |
| Indian Point 1&2 | 75 | 1288 | 348218 | 8030 | 14353 | 11.14 | 13195 | 22619 | | |
| Indian Point 1&2 | 76 | 1288 | 359410 | 11192 | 18681 | 14.50 | 18285 | 29793 | | |
| Indian Point 1&2 | 77 | 1288 | 370637 | 11227 | 17456 | 13.55 | 16525 | 25443 | | |
| Indian Point 1&2 | 78 | 1288 | 377573 | 6936 | 10158 | 7.89 | 28167 | 40378 | | |
| Indian Point 1&2 | 79 | 1288 | 379966 | 2393 | 3195 | 2.48 | 32643 | 43072 | | |
| Indian Point 2 | 80 | 1013 | 329445 | | | | 32964 | 39839 | | |
| Indian Point 2 | 81 | 1013 | 398037 | 68592 | 77852 | 76.85 | 54506 | 60229 | | |
| Indian Point 2 | 82 | 1013 | 461010 | 62973 | 65875 | 65.03 | 68664 | 71568 | | |
| Indian Point 2 | 83 | 1022 | 477418 | 16408 | 16408 | 16.05 | 48549 | 48549 | | |
| Indian Point 3 | 76 | 1125 | NA | | | | 2460 | 4008 | 30-Aug-76 | |
| Indian Point 3 | 77 | 1125 | NA | | | | 12654 | 19483 | | |
| Indian Point 3 | 78 | 1068 | NA | | | | 23318 | 33427 | | |
| Indian Point 3 | 79 | 1068 | NA | | | | 28884 | 38112 | | |
| Indian Point 3 | 80 | 1013 | NA | | | | 50357 | 60859 | | |
| Indian Point 3 | 81 | 1013 | 493018 | | | | 58174 | 64282 | | |
| Indian Point 3 | 82 | 1013 | 522350 | 29332 | 30684 | 30.29 | 82542 | 86033 | | |
| Indian Point 3 | 83 | NA | NA | | | | NA | NA | | |
| Kewaunee | 74 | 535 | 202193 | | | | 7222 | 13532 | 16-Jun-74 | |

TABLE 4.12: NON-FUEL O&M AND CAPITAL ADDITIONS DATA

| Plant | Yr | Rating | Total Cost | Cost Increase | 1983 $ | /MW-yr | O&M - Fuel | O&M -F 1983 $ | New Unit Date | 2nd Unit Same Year |
|---|---|---|---|---|---|---|---|---|---|---|
| Kewaunee | 75 | 535 | 203389 | 1196 | 2151 | 4.02 | 8945 | 15334 | | |
| Kewaunee | 76 | 535 | 205351 | 1962 | 3323 | 6.21 | 10727 | 17478 | | |
| Kewaunee | 77 | 535 | 205892 | 541 | 848 | 1.59 | 10924 | 16819 | | |
| Kewaunee | 78 | 535 | 209748 | 3856 | 5626 | 10.52 | 10430 | 14952 | | |
| Kewaunee | 79 | 535 | 213289 | 3541 | 4721 | 8.82 | 11323 | 14941 | | |
| Kewaunee | 80 | 535 | 214696 | 1407 | 1727 | 3.23 | 14843 | 17939 | | |
| Kewaunee | 81 | 535 | 227413 | 12717 | 14322 | 26.77 | 19334 | 21364 | | |
| Kewaunee | 82 | 535 | 236500 | 9087 | 9454 | 17.67 | 21978 | 22908 | | |
| Kewaunee | 83 | 563 | 252718 | 16218 | 16218 | 28.81 | 22603 | 22603 | | |
| LaSalle | 82 | 1078 | 1336166 | | | | 4819 | 5023 | | |
| LaSalle | 83 | 1122 | 1344053 | 7887 | 7887 | 7.03 | 32800 | 32800 | | |
| Lacrosse | 78 | 60 | 22991 | | | | 2638 | 3782 | | |
| Lacrosse | 79 | 50 | 23132 | 141 | 188 | 3.76 | 3041 | 4013 | | |
| Lacrosse | 80 | 50 | 25987 | 2855 | 3505 | 70.09 | 3318 | 4010 | | |
| Lacrosse | 81 | 50 | 26237 | 250 | 282 | 5.63 | 3955 | 4370 | | |
| Lacrosse | 82 | | | | | | | 0 | | |
| Lacrosse | 83 | | | | | | | 0 | | |
| Maine Yankee | 73 | 830 | 219225 | | | | 4034 | 8226 | 01-Jan-73 | |
| Maine Yankee | 74 | 830 | 221074 | 1849 | 3682 | 4.44 | 5232 | 9803 | | |
| Maine Yankee | 75 | 830 | 233710 | 12636 | 22586 | 27.21 | 6301 | 10801 | | |
| Maine Yankee | 76 | 830 | 235069 | 1359 | 2268 | 2.73 | 5261 | 8572 | | |
| Maine Yankee | 77 | 830 | 236454 | 1385 | 2153 | 2.59 | 8418 | 12961 | | |
| Maine Yankee | 78 | 864 | 237810 | 1356 | 1986 | 2.30 | 10817 | 15506 | | |
| Maine Yankee | 79 | 864 | 239987 | 2177 | 2907 | 3.36 | 9971 | 13157 | | |
| Maine Yankee | 80 | 864 | 246847 | 6860 | 8463 | 9.80 | 14028 | 16954 | | |
| Maine Yankee | 81 | 864 | 262240 | 15393 | 17471 | 20.22 | 20576 | 22737 | | |
| Maine Yankee | 82 | 864 | 269738 | 7498 | 7844 | 9.08 | 28554 | 29762 | | |
| Maine Yankee | 83 | 864 | 275713 | 5975 | 5975 | 6.92 | 21557 | 21557 | | |
| McGuire 1 | 81 | 1220 | 905601 | | | | 2716 | 3001 | 01-Dec-81 | |
| McGuire 1 | 82 | 1220 | 909146 | 3545 | 3708 | 3.04 | 37258 | 38834 | | |
| McGuire 1&2 | 83 | 2440 | 903347 | | | | 42131 | 42131 | 01-Mar-84 ? | |
| Millstone 1 | 71 | 661 | 96819 | | | | 3256 | 7313 | 28-Dec-70 | |
| Millstone 1 | 72 | 661 | 97343 | 524 | 1252 | 1.89 | 7677 | 16554 | | |
| Millstone 1 | 73 | 661 | 98837 | 1494 | 3391 | 5.13 | 7635 | 15568 | | |
| Millstone 1 | 74 | 661 | 98745 | -92 | -183 | -0.28 | 9808 | 18378 | | |
| Millstone 1 | 75 | 661 | 99244 | 499 | 892 | 1.35 | 12065 | 20682 | | |
| Millstone 1 | 76 | 661 | 125141 | 25897 | 43225 | 65.39 | 14040 | 22876 | | |
| Millstone 1 | 77 | 661 | 127476 | 2335 | 3630 | 5.49 | 12637 | 19457 | | |
| Millstone 1 | 78 | 661 | 139783 | 12307 | 18024 | 27.27 | 16448 | 23579 | | |
| Millstone 1 | 79 | 661 | 153135 | 13352 | 17829 | 26.97 | 23060 | 30427 | | |
| Millstone 1 | 80 | 661 | 167438 | 14303 | 17646 | 26.70 | 24784 | 29953 | | |
| Millstone 1 | 81 | 661 | 247250 | 79812 | 90587 | 137.04 | 33270 | 36763 | | |
| Millstone 1 | 82 | 661 | 275880 | 28630 | 29949 | 45.31 | 33465 | 34880 | | |
| Millstone 1 | 83 | 662 | 282531 | 6651 | 6651 | 10.05 | 43569 | 43569 | | |
| Millstone 2 | 75 | 909 | 418372 | | | | 7 | 12 | 26-Dec-75 | |
| Millstone 2 | 76 | 909 | 426271 | 7899 | 13184 | 14.50 | 10929 | 17807 | | |
| Millstone 2 | 77 | 909 | 448751 | 22480 | 34952 | 38.45 | 17377 | 26755 | | |
| Millstone 2 | 78 | 909 | 463638 | 14887 | 21802 | 23.98 | 22288 | 31950 | | |
| Millstone 2 | 79 | 909 | 464674 | 1036 | 1383 | 1.52 | 21931 | 28938 | | |
| Millstone 2 | 80 | 909 | 477586 | 12912 | 15929 | 17.52 | 30163 | 36454 | | |

TABLE 4.12: NON-FUEL O&M AND CAPITAL ADDITIONS DATA

| Plant | Yr | Rating | Total Cost | Cost Increase | 1983 $ | /MW-yr | O&M - Fuel | O&M -F 1983 $ | New Unit Date | 2nd Unit Same Year |
|---|---|---|---|---|---|---|---|---|---|---|
| Millstone 2 | 81 | 909 | 495610 | 18024 | 20457 | 22.51 | 28877 | 31909 | | |
| Millstone 2 | 82 | 909 | 529017 | 33407 | 34946 | 38.44 | 45248 | 47162 | | |
| Millstone 2 | 83 | 910 | 557977 | 28960 | 28960 | 31.82 | 56452 | 56452 | | |
| Monticello | 71 | 568 | 105011 | | | | 1429 | 3209 | 30-Jun-71 | |
| Monticello | 72 | 568 | 104937 | -74 | -181 | -0.32 | 2567 | 5535 | | |
| Monticello | 73 | 568 | 106869 | 1932 | 4482 | 7.89 | 5006 | 10208 | | |
| Monticello | 74 | 568 | 117996 | 11127 | 22448 | 39.52 | 5179 | 9704 | | |
| Monticello | 75 | 568 | 122106 | 4110 | 7392 | 13.01 | 8729 | 14963 | | |
| Monticello | 76 | 568 | 123362 | 1256 | 2127 | 3.74 | 6609 | 10768 | | |
| Monticello | 77 | 568 | 124390 | 1028 | 1611 | 2.84 | 11109 | 17104 | | |
| Monticello | 78 | 568 | 126488 | 2098 | 3061 | 5.39 | 9136 | 13097 | | |
| Monticello | 79 | 568 | 134937 | 8449 | 11265 | 19.83 | 10584 | 13965 | | |
| Monticello | 80 | 568 | 139725 | 4788 | 5877 | 10.35 | 21413 | 25879 | | |
| Monticello | 81 | 568 | 150407 | 10682 | 12030 | 21.18 | 18261 | 20178 | | |
| Monticello | 82 | 568 | 171425 | 21018 | 21866 | 38.50 | 30799 | 32102 | | |
| Monticello | 83 | 580 | 227698 | 56273 | 56273 | 97.02 | 21963 | 21963 | | |
| Nine Mile Point | 70 | 620 | 162235 | | | | 1716 | 4046 | 15-Dec-69 | |
| Nine Mile Point | 71 | 641 | 164492 | 2257 | 5822 | 9.08 | 2759 | 6196 | | |
| Nine Mile Point | 72 | 641 | 162416 | -2076 | -4961 | -7.74 | 3575 | 7709 | | |
| Nine Mile Point | 73 | 641 | 163212 | 796 | 1807 | 2.82 | 4524 | 9225 | | |
| Nine Mile Point | 74 | 641 | 163389 | 177 | 352 | 0.55 | 6251 | 11713 | | |
| Nine Mile Point | 75 | 641 | 164189 | 800 | 1430 | 2.23 | 5810 | 9960 | | |
| Nine Mile Point | 76 | 641 | 181200 | 17011 | 28393 | 44.30 | 5330 | 8685 | | |
| Nine Mile Point | 77 | 641 | 188087 | 6887 | 10708 | 16.70 | 9743 | 15001 | | |
| Nine Mile Point | 78 | 641 | 187086 | -1001 | -1466 | -2.29 | 6382 | 9149 | | |
| Nine Mile Point | 79 | 641 | 204080 | 16994 | 22692 | 35.40 | 11663 | 15389 | | |
| Nine Mile Point | 80 | 641 | 217371 | 13291 | 16397 | 25.58 | 32964 | 39839 | | |
| Nine Mile Point | 81 | 642 | 265015 | 47644 | 54076 | 84.23 | 26744 | 29552 | | |
| Nine Mile Point | 82 | 620 | 281922 | 16907 | 17686 | 28.53 | 21480 | 22388 | | |
| Nine Mile Point | 83 | 640 | 367746 | 85824 | 85824 | 134.10 | 25248 | 25248 | | |
| North Anna 1 | 78 | 979 | 781739 | | | | 6521 | 9348 | 06-Jun-78 | |
| North Anna 1 | 79 | 979 | 783864 | 2125 | 2785 | 2.85 | 19519 | 25755 | | |
| North Anna 1&2 | 80 | 1959 | 1315869 | | | | 25390 | 30685 | 14-Dec-80 | |
| North Anna 1&2 | 81 | 1959 | 1368195 | 52326 | 57262 | 29.23 | 28857 | 31887 | | |
| North Anna 1&2 | 82 | 1959 | 1416217 | 48022 | 49297 | 25.16 | 43493 | 45333 | | |
| North Anna 1&2 | 83 | 1894 | 1472934 | 56717 | 56717 | 29.95 | 49578 | 49578 | | |
| Oconee 1 | 73 | 886 | 155612 | | | | 911 | 1858 | 16-Jul-73 | |
| Oconee 1,2,3 | 74 | 2660 | 476443 | | | | 6982 | 13082 | 09-Sep-74 | 16-Dec-74 |
| Oconee 1,2,3 | 75 | 2660 | 476691 | 248 | 446 | 0.17 | 12449 | 21340 | | |
| Oconee 1,2,3 | 76 | 2660 | 478793 | 2102 | 3534 | 1.33 | 16735 | 27267 | | |
| Oconee 1,2,3 | 77 | 2660 | 490724 | 11931 | 18331 | 6.89 | 25038 | 38550 | | |
| Oconee 1,2,3 | 78 | 2661 | 492689 | 1965 | 2832 | 1.06 | 29600 | 42432 | | |
| Oconee 1,2,3 | 79 | 2661 | 498935 | 6246 | 8187 | 3.08 | 40177 | 53013 | | |
| Oconee 1,2,3 | 80 | 2661 | 509438 | 10503 | 12560 | 4.72 | 52003 | 62848 | | |
| Oconee 1,2,3 | 81 | 2666 | 520036 | 10598 | 11598 | 4.35 | 58789 | 64962 | | |
| Oconee 1,2,3 | 82 | 2666 | 532168 | 12132 | 12454 | 4.67 | 88016 | 91739 | | |
| Oconee 1,2,3 | 83 | 2733 | 539959 | 7791 | 7791 | 2.85 | 77956 | 77956 | | |
| Oyster Creek | 70 | 550 | 89883 | | | | 1953 | 4605 | 15-Dec-69 | |
| Oyster Creek | 71 | 550 | 92121 | 2238 | 5773 | 10.50 | 3097 | 6956 | | |
| Oyster Creek | 72 | 550 | 92637 | 516 | 1233 | 2.24 | 3877 | 8360 | | |

TABLE 4.12: NON-FUEL O&M AND CAPITAL ADDITIONS DATA

| Plant | Yr | Rating | Total Cost | Cost Increase | 1983 $ | /MW-yr | O&M - Fuel | O&M -F 1983 $ | New Unit Date | 2nd Unit Same Year |
|---|---|---|---|---|---|---|---|---|---|---|
| Oyster Creek | 73 | 550 | 92766 | 129 | 293 | 0.53 | 6311 | 12868 | | |
| Oyster Creek | 74 | 550 | 92198 | -568 | -1131 | -2.06 | 10678 | 20008 | | |
| Oyster Creek | 75 | 550 | 97151 | 4953 | 8853 | 16.10 | 12310 | 21102 | | |
| Oyster Creek | 76 | 550 | 108545 | 11394 | 19018 | 34.58 | 10399 | 16944 | | |
| Oyster Creek | 77 | 550 | 112583 | 4038 | 6278 | 11.42 | 14833 | 22838 | | |
| Oyster Creek | 78 | 550 | 150459 | 37876 | 55470 | 100.85 | 15898 | 22790 | | |
| Oyster Creek | 79 | 550 | 161745 | 11286 | 15070 | 27.40 | 13055 | 17226 | | |
| Oyster Creek | 80 | 550 | 200255 | 38510 | 47510 | 86.38 | 37530 | 45357 | | |
| Oyster Creek | 81 | 550 | 222963 | 22708 | 25774 | 46.86 | 45254 | 50006 | | |
| Oyster Creek | 82 | 550 | 256407 | 33444 | 34985 | 63.61 | 60812 | 63384 | | |
| Oyster Creek | 83 | 650 | 331441 | 75034 | 75034 | 115.44 | 72992 | 72992 | | |
| Palisades | 72 | 811 | 146687 | | | | 753 | 1624 | 15-Nov-71 | |
| Palisades | 73 | 811 | 160284 | 13597 | 31545 | 38.90 | 3160 | 6443 | | |
| Palisades | 74 | 811 | 180063 | 19779 | 39902 | 49.20 | 11778 | 22069 | | |
| Palisades | 75 | 811 | 182297 | 2234 | 4018 | 4.95 | 9601 | 16458 | | |
| Palisades | 76 | 811 | 185272 | 2975 | 5038 | 6.21 | 9848 | 16046 | | |
| Palisades | 77 | 811 | 182068 | -3204 | -5022 | -6.19 | 6569 | 10114 | | |
| Palisades | 78 | 811 | 199643 | 17575 | 25644 | 31.62 | 15393 | 22066 | | |
| Palisades | 79 | 811 | 194651 | -4992 | -6656 | -8.21 | 26344 | 34760 | | |
| Palisades | 80 | 811 | 211505 | 16854 | 20689 | 25.51 | 19251 | 23266 | | |
| Palisades | 81 | 811 | 255491 | 43986 | 49538 | 61.08 | 44140 | 48775 | | |
| Palisades | 82 | 811 | 282667 | 27176 | 28273 | 34.86 | 38452 | 40078 | | |
| Palisades | 83 | 810 | 375573 | 92906 | 92906 | 114.70 | 55154 | 55154 | | |
| Pathfinder | 67 | 75 | 24932 | | | | 769 | 2097 | 25-May-67 | |
| Peach Bottom 1 | 67 | 46 | 10692 | | | | 849 | 2316 | 01-Jun-67 | |
| Peach Bottom 1 | 68 | 46 | 10624 | -68 | -217 | -4.73 | 1666 | 4352 | | |
| Peach Bottom 1 | 69 | 46 | 10658 | 34 | 103 | 2.24 | 1481 | 3680 | | |
| Peach Bottom 1 | 70 | 46 | 10719 | 61 | 171 | 3.72 | 1537 | 3624 | | |
| Peach Bottom 1 | 71 | 46 | 10890 | 171 | 441 | 9.59 | 1731 | 3888 | | |
| Peach Bottom 1 | 72 | 46 | 10821 | -69 | -165 | -3.58 | 1873 | 4039 | | |
| Peach Bottom 1 | 73 | 46 | 11369 | 548 | 1244 | 27.04 | 1605 | 3273 | | |
| Peach Bottom 1 | 74 | 46 | 10485 | -884 | -1760 | -38.27 | 1050 | 1967 | | |
| Peach Bottom 2,3 | 74 | 2304 | 742158 | | | | 1791 | 3356 | 05-Jul-74 | 23-Dec-74 |
| Peach Bottom 2,3 | 75 | 2304 | 753981 | 11823 | 21132 | 9.17 | 12619 | 21632 | | |
| Peach Bottom 2,3 | 76 | 2304 | 761722 | 7741 | 12921 | 5.61 | 30601 | 49860 | | |
| Peach Bottom 2,3 | 77 | 2304 | 794094 | 32372 | 50332 | 21.85 | 46674 | 71862 | | |
| Peach Bottom 2,3 | 78 | 2304 | 807496 | 13402 | 19627 | 8.52 | 39306 | 56346 | | |
| Peach Bottom 2,3 | 79 | 2304 | 813792 | 6296 | 8407 | 3.65 | 40004 | 52785 | | |
| Peach Bottom 2,3 | 80 | 2304 | 836708 | 22916 | 28271 | 12.27 | 56875 | 68736 | | |
| Peach Bottom 2,3 | 81 | 2304 | 902169 | 65461 | 74298 | 32.25 | 72615 | 80240 | | |
| Peach Bottom 2,3 | 82 | 2304 | 953400 | 51231 | 53592 | 23.26 | 81669 | 85123 | | |
| Peach Bottom 2,3 | 83 | 2196 | 975127 | 21727 | 21727 | 9.89 | 116074 | 116074 | | |
| Pilgrim | 72 | 655 | 321540 | | | | 144 | 311 | 09-Dec-72 | |
| Pilgrim | 73 | 655 | 239329 | | | | 4797 | 9781 | | |
| Pilgrim | 74 | 655 | 235982 | -3347 | -6665 | -10.18 | 9527 | 17851 | | |
| Pilgrim | 75 | 655 | 236464 | 482 | 862 | 1.32 | 7340 | 12582 | | |
| Pilgrim | 76 | 655 | 241440 | 4976 | 8306 | 12.68 | 16633 | 27101 | | |
| Pilgrim | 77 | 655 | 257579 | 16139 | 25093 | 38.31 | 15320 | 23588 | | |
| Pilgrim | 78 | 687 | 261758 | 4179 | 6120 | 8.91 | 14187 | 20337 | | |
| Pilgrim | 79 | 687 | 270428 | 8670 | 11577 | 16.85 | 18387 | 24261 | | |

TABLE 4.12: NON-FUEL O&M AND CAPITAL ADDITIONS DATA

| Plant | Yr | Rating | Total Cost | Cost Increase | 1983 $ | /MW-yr | O&M - Fuel | O&M -F 1983 $ | New Unit Date | 2nd Unit Same Year |
|---|---|---|---|---|---|---|---|---|---|---|
| Pilgrim | 80 | 687 | 337986 | 67558 | 83346 | 121.32 | 27785 | 33580 | | |
| Pilgrim | 81 | 687 | 358680 | 20694 | 23488 | 34.19 | 34994 | 38668 | | |
| Pilgrim | 82 | 687 | 430711 | 72031 | 75350 | 109.68 | 42437 | 44232 | | |
| Pilgrim | 83 | 685 | 427831 | -2880 | -2880 | -4.20 | 46268 | 46268 | | |
| Point Beach 1 | 71 | 523 | 73959 | | | | 1309 | 2940 | 31-Dec-70 | |
| Point Beach 1&2 | 72 | 1047 | 145348 | | | | 2305 | 4970 | 30-Sep-72 | |
| Point Beach 1&2 | 73 | 1047 | 161632 | 16284 | 37779 | 36.08 | 3647 | 7436 | | |
| Point Beach 1&2 | 74 | 1047 | 161436 | -196 | -395 | -0.38 | 5229 | 9798 | | |
| Point Beach 1&2 | 75 | 1047 | 164224 | 2788 | 5014 | 4.79 | 6159 | 10558 | | |
| Point Beach 1&2 | 76 | 1047 | 167125 | 2901 | 4913 | 4.69 | 6592 | 10741 | | |
| Point Beach 1&2 | 77 | 1047 | 196801 | 29676 | 46519 | 44.43 | 8014 | 12339 | | |
| Point Beach 1&2 | 78 | 1047 | 171189 | -25612 | -37371 | -35.69 | 7395 | 10601 | | |
| Point Beach 1&2 | 79 | 1047 | 170668 | -521 | -695 | -0.66 | 12461 | 16442 | | |
| Point Beach 1&2 | 80 | 1047 | 172472 | 1804 | 2214 | 2.12 | 17904 | 21638 | | |
| Point Beach 1&2 | 81 | 1047 | 188495 | 16023 | 18045 | 17.24 | 26820 | 29636 | | |
| Point Beach 1&2 | 82 | 1047 | 192297 | 3802 | 3955 | 3.78 | 31951 | 33302 | | |
| Point Beach 1&2 | 83 | 1048 | 194910 | 2613 | 2613 | 2.49 | 34273 | 34273 | | |
| Prairie Isl. 1 | 73 | 593 | 233234 | | | | 101 | 206 | 16-Dec-73 | |
| Prairie Isl. 1&2 | 74 | 1186 | 405374 | | | | 4216 | 7900 | 21-Dec-74 | |
| Prairie Isl. 1&2 | 75 | 1186 | 410207 | 4833 | 8692 | 7.33 | 7261 | 12447 | | |
| Prairie Isl. 1&2 | 76 | 1186 | 413087 | 2880 | 4877 | 4.11 | 15574 | 25376 | | |
| Prairie Isl. 1&2 | 77 | 1186 | 423966 | 10879 | 17054 | 14.38 | 17090 | 26313 | | |
| Prairie Isl. 1&2 | 78 | 1186 | 425182 | 1216 | 1774 | 1.50 | 14214 | 20376 | | |
| Prairie Isl. 1&2 | 79 | 1186 | 433659 | 8477 | 11303 | 9.53 | 15346 | 20249 | | |
| Prairie Isl. 1&2 | 80 | 1186 | 444766 | 11107 | 13634 | 11.50 | 23175 | 28008 | | |
| Prairie Isl. 1&2 | 81 | 1186 | 457082 | 12316 | 13870 | 11.70 | 26791 | 29604 | | |
| Prairie Isl. 1&2 | 82 | 1186 | 478688 | 21606 | 22478 | 18.95 | 28169 | 29360 | | |
| Prairie Isl. 1&2 | 83 | 1120 | 499848 | 21160 | 21160 | 18.89 | 29383 | 29383 | | |
| Quad Cities 1&2 | 72 | 1656 | 200149 | | | | 2033 | 4384 | 15-Aug-72 | 15-Sep-72 |
| Quad Cities 1&2 | 73 | 1656 | 211539 | 11390 | 26425 | 15.96 | 6290 | 12826 | | |
| Quad Cities 1&2 | 74 | 1656 | 223882 | 12343 | 24901 | 15.04 | 9210 | 17257 | | |
| Quad Cities 1&2 | 75 | 1656 | 237227 | 13345 | 24000 | 14.49 | 14777 | 25331 | | |
| Quad Cities 1&2 | 76 | 1656 | 241480 | 4253 | 7202 | 4.35 | 16723 | 27248 | | |
| Quad Cities 1&2 | 77 | 1656 | 247194 | 5714 | 8957 | 5.41 | 17756 | 27338 | | |
| Quad Cities 1&2 | 78 | 1656 | 252951 | 5757 | 8400 | 5.07 | 22168 | 31778 | | |
| Quad Cities 1&2 | 79 | 1656 | 263741 | 10790 | 14387 | 8.69 | 23420 | 30902 | | |
| Quad Cities 1&2 | 80 | 1656 | 273075 | 9334 | 11457 | 6.92 | 38686 | 46754 | | |
| Quad Cities 1&2 | 81 | 1656 | 278524 | 5449 | 6137 | 3.71 | 37272 | 41186 | | |
| Quad Cities 1&2 | 82 | 1656 | 311157 | 32633 | 33950 | 20.50 | 42185 | 43970 | | |
| Quad Cities 1&2 | 83 | 1666 | 320341 | 9184 | 9184 | 5.51 | 44448 | 44448 | | |
| Rancho Seco | 75 | 928 | 343620 | | | | 11607 | 19897 | 17-Apr-75 | |
| Rancho Seco | 76 | 928 | 343438 | -182 | -322 | -0.35 | 7193 | 11720 | | |
| Rancho Seco | 77 | 928 | 336050 | -7388 | -11964 | -12.89 | 14000 | 21555 | | |
| Rancho Seco | 78 | 928 | 338792 | 2742 | 4121 | 4.44 | 11834 | 16964 | | |
| Rancho Seco | 79 | 928 | 339538 | 746 | 1012 | 1.09 | 13720 | 18103 | | |
| Rancho Seco | 80 | 928 | 353574 | 14036 | 17441 | 18.79 | 28408 | 34333 | | |
| Rancho Seco | 81 | 928 | 365651 | 12077 | 13716 | 14.78 | 35542 | 39274 | | |
| Rancho Seco | 82 | 928 | 369225 | 3574 | 3722 | 4.01 | 36330 | 37867 | | |
| Rancho Seco | 83 | | | | | | | 0 | | |
| Robinson | 71 | 768 | 77753 | | | | 1918 | 4308 | 07-Mar-71 | |

TABLE 4.12: NON-FUEL O&M AND CAPITAL ADDITIONS DATA

| Plant | Yr | Rating | Total Cost | Cost Increase | 1983 $ | /MW-yr | O&M - Fuel | O&M -F 1983 $ | New Unit Date | 2nd Unit Same Year |
|---|---|---|---|---|---|---|---|---|---|---|
| Robinson | 72 | 768 | 81999 | 4246 | 10369 | 13.50 | 1780 | 3838 | | |
| Robinson | 73 | 768 | 82113 | 114 | 264 | 0.34 | 4609 | 9398 | | |
| Robinson | 74 | 768 | 83272 | 1159 | 2359 | 3.07 | 4780 | 8956 | | |
| Robinson | 75 | 768 | 84982 | 1710 | 3075 | 4.00 | 6360 | 10902 | | |
| Robinson | 76 | 768 | 85234 | 252 | 424 | 0.55 | 5903 | 9618 | | |
| Robinson | 77 | 768 | 89540 | 4306 | 6616 | 8.61 | 6859 | 10561 | | |
| Robinson | 78 | 768 | 93410 | 3870 | 5577 | 7.26 | 14355 | 20578 | | |
| Robinson | 79 | 768 | 101253 | 7843 | 10280 | 13.39 | 15142 | 19980 | | |
| Robinson | 80 | 768 | 110025 | 8772 | 10490 | 13.66 | 22085 | 26691 | | |
| Robinson | 81 | 769 | 113858 | 3833 | 4195 | 5.45 | 21788 | 24076 | | |
| Robinson | 82 | 769 | 125878 | 12020 | 12339 | 16.05 | 43164 | 44990 | | |
| Robinson | 83 | 739 | 128046 | 2168 | 2168 | 2.93 | 37309 | 37309 | | |
| Salem 1 | 77 | 1170 | 850318 | | | | 12707 | 19565 | 30-Jun-77 | |
| Salem 1 | 78 | 1170 | 850983 | 665 | 974 | 0.83 | 22311 | 31983 | | |
| Salem 1 | 79 | 1169 | 898641 | 47658 | 63637 | 54.42 | 42508 | 56088 | | |
| Salem 1 | 80 | 1170 | 938748 | 40107 | 49480 | 42.29 | 59684 | 72131 | | |
| Salem 1&2 | 81 | 2343 | 1758749 | | | | 77502 | 85640 | 13-Oct-81 | |
| Salem 1&2 | 82 | 2343 | 1806872 | 48123 | 50341 | 21.49 | 156615 | 163239 | | |
| Salem 1&2 | 83 | 2294 | 1739122 | -67750 | -67750 | -29.53 | 160582 | 160582 | | |
| San Onofre 1 | 68 | 450 | 80855 | | | | 1481 | 3869 | 01-Jan-68 | |
| San Onofre 1 | 69 | 450 | 84439 | 3584 | 11533 | 25.63 | 1975 | 4907 | | |
| San Onofre 1 | 70 | 450 | 84714 | 275 | 832 | 1.85 | 2236 | 5272 | | |
| San Onofre 1 | 71 | 450 | 85369 | 655 | 1847 | 4.10 | 2412 | 5417 | | |
| San Onofre 1 | 72 | 450 | 85547 | 178 | 470 | 1.05 | 3518 | 7586 | | |
| San Onofre 1 | 73 | 450 | 85821 | 274 | 688 | 1.53 | 5839 | 11906 | | |
| San Onofre 1 | 74 | 450 | 86244 | 423 | 931 | 2.07 | 5559 | 10416 | | |
| San Onofre 1 | 75 | 450 | 86438 | 194 | 372 | 0.83 | 8668 | 14859 | | |
| San Onofre 1 | 76 | 450 | 95496 | 9058 | 16011 | 35.58 | 10490 | 17092 | | |
| San Onofre 1 | 77 | 450 | 162475 | 66979 | 108463 | 241.03 | 8123 | 12507 | | |
| San Onofre 1 | 78 | 450 | 181601 | 19126 | 28746 | 63.88 | 14517 | 20810 | | |
| San Onofre 1 | 79 | 450 | 192599 | 10998 | 14922 | 33.16 | 11669 | 15397 | | |
| San Onofre 1 | 80 | 450 | 211109 | 18510 | 23000 | 51.11 | 31089 | 37573 | | |
| San Onofre 1 | 81 | 450 | 251119 | 40010 | 45441 | 100.98 | 24396 | 26958 | | |
| San Onofre 1 | 82 | 456 | 298461 | 47342 | 49306 | 108.13 | 36830 | 38388 | | |
| San Onofre 2 | 83 | 1127 | 2145708 | | | | -12790 | -12790 | 08-Aug-83 | |
| Sequoyah 1 | 81 | 1220 | 983542 | | | | 19216 | 21234 | 01-Jul-81 | |
| Sequoyah 1&2 | 82 | 2441 | 1606807 | | | | 47756 | 49776 | 01-Jun-82 | |
| Sequoyah 1&2 | 83 | | | | | | | 0 | | |
| Shippingport | 80 | 100 | 32125 | | | | 7375 | 8913 | | |
| Shippingport | 81 | 100 | 32123 | -2 | -2 | -0.02 | 8601 | 9504 | | |
| Shippingport | 82 | 100 | NA | | | | 6122 | 6381 | | |
| St. Lucie 1 | 76 | 850 | 470223 | | | | 3249 | 5294 | 21-Dec-76 | |
| St. Lucie 1 | 77 | 850 | 486230 | 16007 | 24594 | 28.93 | 7528 | 11591 | | |
| St. Lucie 1 | 78 | 850 | 495038 | 8808 | 12692 | 14.93 | 15814 | 22670 | | |
| St. Lucie 1 | 79 | 850 | 499602 | 4564 | 5982 | 7.04 | 14392 | 18990 | | |
| St. Lucie 1 | 80 | 850 | 505287 | 5685 | 6799 | 8.00 | 16381 | 19797 | | |
| St. Lucie 1 | 81 | 850 | 513640 | 8353 | 9141 | 10.75 | 23240 | 25680 | | |
| St. Lucie 1 | 82 | 850 | 529891 | 16251 | 16682 | 19.63 | 21853 | 22777 | | |
| St. Lucie 1&2 | 83 | 1706 | 1817237 | | | | 28845 | 28845 | 08-Aug-83 | |
| Surry 1 | 72 | 847 | 246707 | | | | 607 | 1309 | 22-Dec-72 | |

TABLE 4.12: NON-FUEL O&M AND CAPITAL ADDITIONS DATA

| Plant | Yr | Rating | Total Cost | Cost Increase | 1983 $ | /MW-yr | O&M - Fuel | O&M -F 1983 $ | New Unit Date | 2nd Unit Same Year |
|---|---|---|---|---|---|---|---|---|---|---|
| Surry 1&2 | 73 | 1695 | 396860 | | | | 5102 | 10403 | 01-May-73 | |
| Surry 1&2 | 74 | 1695 | 402096 | 5236 | 10656 | 6.29 | 9878 | 18509 | | |
| Surry 1&2 | 75 | 1695 | 406409 | 4313 | 7757 | 4.58 | 15270 | 26176 | | |
| Surry 1&2 | 76 | 1695 | 408516 | 2107 | 3542 | 2.09 | 14796 | 24108 | | |
| Surry 1&2 | 77 | 1695 | 412236 | 3720 | 5715 | 3.37 | 15977 | 24599 | | |
| Surry 1&2 | 78 | 1695 | 419952 | 7716 | 11119 | 6.56 | 19323 | 27700 | | |
| Surry 1&2 | 79 | 1695 | 409703 | -10249 | -13434 | -7.93 | 23313 | 30761 | | |
| Surry 1&2 | 80 | 1695 | 556083 | 146380 | 175052 | 103.28 | 29458 | 35602 | | |
| Surry 1&2 | 81 | 1695 | 750969 | 194886 | 213271 | 125.82 | 31185 | 34459 | | |
| Surry 1&2 | 82 | 1695 | 783058 | 32089 | 32941 | 19.43 | 33088 | 34487 | | |
| Surry 1&2 | 83 | 1648 | 805393 | 22335 | 22335 | 13.55 | 55428 | 55428 | | |
| Three Mile Isl. 1 | 74 | 871 | 398337 | | | | 3351 | 6279 | 02-Sep-74 | |
| Three Mile Isl. 1 | 75 | 871 | 400928 | 2591 | 4631 | 5.32 | 14226 | 24386 | | |
| Three Mile Isl. 1 | 76 | 871 | 399425 | -1503 | -2509 | -2.88 | 17840 | 29068 | | |
| Three Mile Isl. 1 | 77 | 871 | 398895 | -530 | -824 | -0.95 | 13287 | 20458 | | |
| Three Mile Isl. 1 | 78 | 871 | 361902 | -36993 | -54177 | -62.20 | 17954 | 25737 | | |
| Three Mile Isl. 1 | 79 | 871 | 407936 | 46034 | 61469 | 70.57 | 11842 | 15625 | | |
| Three Mile Isl. 1 | 80 | NA | NA | | | | NA | NA | | |
| Three Mile Isl. 1 | 81 | 435 | 220798 | | | | 27024 | 29862 | | |
| Three Mile Isl. 2 | 78 | 961 | 715466 | | | | 0 | 0 | 30-Dec-78 | |
| Three Mile Isl. 2 | 79 | 961 | 719294 | 3828 | 5112 | 5.32 | 12402 | 16364 | | |
| Three Mile Isl. 2 | 80 | NA | NA | | | | NA | NA | | |
| Three Mile Isl. 2 | 81 | 480 | 358321 | | | | 8394 | 9275 | | |
| Trojan | 76 | 1216 | 451978 | | | | 5921 | 9647 | 20-May-76 | |
| Trojan | 77 | 1216 | 460666 | 8688 | 14069 | 11.57 | 13628 | 20983 | | |
| Trojan | 78 | 1216 | 466419 | 5753 | 8647 | 7.11 | 15204 | 21795 | | |
| Trojan | 79 | 1216 | 486705 | 20286 | 27523 | 22.63 | 16957 | 22374 | | |
| Trojan | 80 | 1216 | 503279 | 16574 | 20594 | 16.94 | 25790 | 31169 | | |
| Trojan | 81 | 1216 | 548765 | 45486 | 51661 | 42.48 | 32205 | 35587 | | |
| Trojan | 82 | 1216 | 565576 | 16811 | 17509 | 14.40 | 30629 | 31924 | | |
| Trojan | 83 | 1216 | 573894 | 8318 | 8318 | 6.84 | 28841 | 28841 | | |
| Turkey Point 3 | 72 | 760 | 108709 | | | | 247 | 533 | 04-Dec-72 | |
| Turkey Point 3&4 | 73 | 1519 | 231239 | | | | 4059 | 8277 | 07-Sep-73 | |
| Turkey Point 3&4 | 74 | 1519 | 235496 | 4257 | 8663 | 5.70 | 9660 | 18100 | | |
| Turkey Point 3&4 | 75 | 1519 | 244256 | 8760 | 15754 | 10.37 | 15493 | 26558 | | |
| Turkey Point 3&4 | 76 | 1519 | 255705 | 11449 | 19248 | 12.67 | 18602 | 30309 | | |
| Turkey Point 3&4 | 77 | 1519 | 267648 | 11943 | 18350 | 12.08 | 15109 | 23263 | | |
| Turkey Point 3&4 | 78 | 1519 | 273441 | 5793 | 8348 | 5.50 | 18602 | 26666 | | |
| Turkey Point 3&4 | 79 | 1519 | 284431 | 10990 | 14405 | 9.48 | 22511 | 29703 | | |
| Turkey Point 3&4 | 80 | 1519 | 293654 | 9223 | 11030 | 7.26 | 30830 | 37260 | | |
| Turkey Point 3&4 | 81 | 1519 | 305503 | 11849 | 12967 | 8.54 | 30274 | 33453 | | |
| Turkey Point 3&4 | 82 | 1519 | 417224 | 111721 | 114687 | 75.50 | 32066 | 33422 | | |
| Turkey Point 3&4 | 83 | 1456 | 527224 | 110000 | 110000 | 75.55 | 45517 | 45517 | | |
| Vermont Yankee | 72 | 514 | 172042 | | | | 414 | 893 | 30-Nov-72 | |
| Vermont Yankee | 73 | 563 | 184481 | 12439 | 28237 | 50.15 | 4957 | 10108 | | |
| Vermont Yankee | 74 | 563 | 185158 | 677 | 1348 | 2.39 | 5692 | 10665 | | |
| Vermont Yankee | 75 | 563 | 185739 | 581 | 1038 | 1.84 | 7682 | 13169 | | |
| Vermont Yankee | 76 | 563 | 193886 | 8147 | 13598 | 24.15 | 7912 | 12892 | | |
| Vermont Yankee | 77 | 563 | 196331 | 2445 | 3801 | 6.75 | 9775 | 15050 | | |
| Vermont Yankee | 78 | 563 | 198837 | 2506 | 3670 | 6.52 | 11191 | 16043 | | |

TABLE 4.12: NON-FUEL O&M AND CAPITAL ADDITIONS DATA

| Plant | Yr | Rating | Total Cost | Cost Increase | 1983 $ | /MW-yr | O&M - Fuel | O&M -F 1983 $ | New Unit Date | 2nd Unit Same Year |
|---|---|---|---|---|---|---|---|---|---|---|
| Vermont Yankee | 79 | 563 | 200835 | 1998 | 2668 | 4.74 | 14208 | 18747 | | |
| Vermont Yankee | 80 | 563 | 217575 | 16740 | 20652 | 36.68 | 22586 | 27296 | | |
| Vermont Yankee | 81 | 563 | 226115 | 8540 | 9693 | 17.22 | 26795 | 29609 | | |
| Vermont Yankee | 82 | 563 | 231880 | 5765 | 6031 | 10.71 | 33764 | 35192 | | |
| Vermont Yankee | 83 | 563 | 255209 | 23329 | 23329 | 41.44 | 46310 | 46310 | | |
| Yankee-Rowe | 62 | 152 | 38162 | | | | 1282 | 3915 | 01-Jul-60 | |
| Yankee-Rowe | 63 | 185 | 38398 | 236 | 837 | 4.52 | 1312 | 3947 | | |
| Yankee-Rowe | 64 | 185 | 38622 | 224 | 795 | 4.29 | 1121 | 3322 | | |
| Yankee-Rowe | 65 | 185 | 38766 | 144 | 511 | 2.76 | 1403 | 4068 | | |
| Yankee-Rowe | 66 | 185 | 39390 | 624 | 2146 | 11.60 | 1505 | 4228 | | |
| Yankee-Rowe | 67 | 185 | 39560 | 170 | 559 | 3.02 | 1307 | 3565 | | |
| Yankee-Rowe | 68 | 185 | 39572 | 12 | 38 | 0.21 | 1501 | 3921 | | |
| Yankee-Rowe | 69 | 185 | 39623 | 51 | 154 | 0.83 | 1602 | 3980 | | |
| Yankee-Rowe | 70 | 185 | 39636 | 13 | 36 | 0.20 | 1558 | 3674 | | |
| Yankee-Rowe | 71 | 185 | 40271 | 635 | 1638 | 8.85 | 1745 | 3919 | | |
| Yankee-Rowe | 72 | 185 | 41500 | 1229 | 2937 | 15.87 | 2912 | 6279 | | |
| Yankee-Rowe | 73 | 185 | 42507 | 1007 | 2286 | 12.36 | 2437 | 4969 | | |
| Yankee-Rowe | 74 | 185 | 44473 | 1966 | 3915 | 21.16 | 3950 | 7401 | | |
| Yankee-Rowe | 75 | 185 | 46101 | 1628 | 2910 | 15.73 | 4557 | 7812 | | |
| Yankee-Rowe | 76 | 185 | 46566 | 465 | 776 | 4.20 | 4976 | 8108 | | |
| Yankee-Rowe | 77 | 185 | 48332 | 1766 | 2746 | 14.84 | 6966 | 10725 | | |
| Yankee-Rowe | 78 | 185 | 48912 | 580 | 849 | 4.59 | 7653 | 10971 | | |
| Yankee-Rowe | 79 | 185 | 52192 | 3280 | 4380 | 23.67 | 10150 | 13393 | | |
| Yankee-Rowe | 80 | 185 | 55285 | 3093 | 3816 | 20.63 | 22250 | 26890 | | |
| Yankee-Rowe | 81 | 185 | 63717 | 8432 | 9570 | 51.73 | 22069 | 24386 | | |
| Yankee-Rowe | 82 | 185 | 72149 | 8432 | 8821 | 47.68 | 24320 | 25349 | | |
| Yankee-Rowe | 83 | 185 | 72503 | 354 | 354 | 1.91 | 18987 | 18987 | | |
| Zion 1 | 73 | 1098 | 275989 | | | | 44 | 90 | 15-Oct-73 | |
| Zion 1&2 | 74 | 2196 | 565819 | | | | 9234 | 17302 | 15-Sep-74 | |
| Zion 1&2 | 75 | 2196 | 567987 | 2168 | 3899 | 1.78 | 12735 | 21830 | | |
| Zion 1&2 | 76 | 2196 | 571762 | 3775 | 6393 | 2.91 | 18268 | 29765 | | |
| Zion 1&2 | 77 | 2196 | 577903 | 6141 | 9626 | 4.38 | 18104 | 27874 | | |
| Zion 1&2 | 78 | 2196 | 586396 | 8493 | 12392 | 5.64 | 20383 | 29219 | | |
| Zion 1&2 | 79 | 2196 | 594941 | 8545 | 11393 | 5.19 | 26954 | 35565 | | |
| Zion 1&2 | 80 | 2196 | 625788 | 30847 | 37865 | 17.24 | 37655 | 45508 | | |
| Zion 1&2 | 81 | 2196 | 639723 | 13935 | 15694 | 7.15 | 44864 | 49575 | | |
| Zion 1&2 | 82 | 2196 | 650175 | 10452 | 10874 | 4.95 | 52617 | 54842 | | |
| Zion 1&2 | 83 | 2170 | 680259 | 30084 | 30084 | 13.86 | 45956 | 45956 | | |

TABLE 4.13: TWIN UNIT NUCLEAR O&M HISTORIES ($ thousand)

| Year | GNP Deflator | Arkansas | Calvert Cliffs | Cook | Farley | Hatch | North Anna | Peach Bottom* | Point Beach | Prairie Island | Quad Cities | Surry | Turkey Point | Zion |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1973 | 105.75 | | | | | | | | 3647 | | 6290 | | | |
| 1974 | 115.08 | | | | | | | | 5229 | | 9210 | 9878 | 9660 | |
| 1975 | 125.79 | | | | | | | 12619 | 6159 | 7261 | 14777 | 15270 | 15493 | 12735 |
| 1976 | 132.34 | | | | | | | 30601 | 6592 | 15574 | 16723 | 14796 | 18602 | 18268 |
| 1977 | 140.05 | | | | | | | 46674 | 8014 | 17090 | 17756 | 15977 | 15109 | 18104 |
| 1978 | 150.42 | | 25997 | | | | | 39306 | 7395 | 14214 | 22168 | 19323 | 18602 | 20383 |
| 1979 | 163.42 | | 36397 | 26750 | | | | 40004 | 12461 | 15346 | 23420 | 23313 | 22511 | 26954 |
| 1980 | 178.42 | | 41628 | 32409 | | 38486 | | 56875 | 17904 | 23175 | 38686 | 29458 | 30830 | 37655 |
| 1981 | 195.14 | 54422 | 50409 | 37967 | | 62010 | 28857 | 72615 | 26820 | 26791 | 37272 | 31185 | 30274 | 44864 |
| 1982 | 206.88 | 54496 | 61969 | 50859 | 52488 | 67689 | 43493 | 81669 | 31951 | 28169 | 42185 | 33088 | 32066 | 52617 |
| 1983 | 215.33 | 64928 | 50301 | 57904 | 57333 | 105745 | 49578 | 116074 | 34273 | 29383 | 44448 | 55428 | 45517 | 45956 |
| ANNUAL GROWTH RATES TO 1983: | | | | | | | | | | | | | | |
| NOMINAL: | 7.4% | 9.23% | 14.11% | 21.30% | 9.23% | 40.06% | 31.07% | 31.97% | 25.11% | 19.09% | 21.60% | 21.12% | 18.80% | 17.40% |
| REAL: | | 3.98% | 6.21% | 13.21% | 4.94% | 31.55% | 24.78% | 23.39% | 16.53% | 11.35% | 13.25% | 12.98% | 10.81% | 9.77% |

Notes: * Units 2 and 3

TABLE 4.14: RESULTS OF REGRESSION ON O&M DATA

| | Equation 1 | | Equation 2 | | Equation 3 | | Equation 4 | | Equation 5 | |
|---|---|---|---|---|---|---|---|---|---|---|
| | Coef | t-stat | Coef | t-stat | Coef | t-stat | Coef | t-stat | Coef | t-stat |
| CONSTANT | -3.76 | -6.88 | -3.48 | -6.92 | -3.76 | -6.88 | -4.14 | -7.77 | -3.90 | -7.49 |
| ln(MW) [2] | 0.56 | 7.86 | 0.50 | 7.33 | -- | -- | -- | -- | -- | -- |
| ln(UNITS) | -0.05 | -0.48 | -- | -- | 0.52 | 10.41 | -- | -- | 0.63 | 12.58 |
| YEAR [3] | 0.13 | 22.45 | 0.13 | 22.60 | 0.13 | 22.45 | 0.13 | 22.78 | 0.13 | 23.93 |
| UNITS | -- | -- | 0.03 | 0.54 | -- | -- | 0.33 | 10.98 | -- | -- |
| ln(MW/unit) | -- | -- | -- | -- | 0.56 | 7.86 | 0.57 | 8.04 | 0.54 | 7.95 |
| NE [4] | -- | -- | -- | -- | -- | -- | -- | -- | 0.25 | 6.69 |
| Adjusted R | | 0.71 | | 0.71 | | 0.71 | | 0.71 | | 0.73 |
| F statistic | | 329.2 | | 329.2 | | 329.2 | | 340.1 | | 284.4 |

Notes: [1] The dependent variable in each equation is ln(non-fuel O&M in 1983$)
[2] MW = number of MegaWatt in Design Electrical Rating (DER)
[3] YEAR = Calendar Year - 1900; e.g., 1985 = 85.
[4] NE is a dummy variable which measures whether the plant is located in the Northeast Region (defined as Handy Whitman's North Atlantic Region), where Susquehanna 2 is located. NE = 1 if located in Northeast Region, 0 if elsewhere.

TABLE 4.15: PROJECTIONS OF ANNUAL NON-FUEL O&M EXPENSE FOR SUSQUEHANNA ($ million)

| Year | PP&L Projections UNIT 1 nominal | PP&L Projections UNIT 2 nominal | From Equation #5 (Table 4.14) UNIT 1 1983$ | From Equation #5 (Table 4.14) UNIT 1 nominal | From Equation #5 (Table 4.14) UNIT 2 1983$ | From Equation #5 (Table 4.14) UNIT 2 nominal | Ratio Nominal Projections, Unit 2 Eq.5 / PP&L |
|---|---|---|---|---|---|---|---|
| | [1] | | [2] | [3] | [4] | [5] | |
| 1985 | 69.40 | 54.81 | 57.45 | 59.74 | 31.69 | 32.96 | 0.6013 |
| 1986 | 72.19 | 75.28 | 65.38 | 72.07 | 36.07 | 39.76 | 0.5281 |
| 1987 | 77.21 | 65.23 | 74.41 | 86.95 | 41.05 | 47.97 | 0.7353 |
| 1988 | 75.70 | 84.85 | 84.68 | 104.89 | 46.71 | 57.86 | 0.6820 |
| 1989 | 86.10 | 90.58 | 96.38 | 126.54 | 53.17 | 69.81 | 0.7707 |
| 1990 | 93.32 | 93.32 | 109.69 | 152.66 | 60.51 | 84.21 | 0.9024 |
| 1991 | 101.62 | 101.62 | 124.83 | 184.16 | 68.86 | 101.59 | 0.9997 |
| 1992 | 110.51 | 110.51 | 142.07 | 222.17 | 78.37 | 122.56 | 1.1090 |
| 1993 | 120.06 | 120.06 | 161.69 | 268.02 | 89.20 | 147.85 | 1.2314 |
| 1994 | 130.38 | 130.38 | 184.02 | 323.33 | 101.51 | 178.36 | 1.3681 |
| 1995 | 141.47 | 141.47 | 209.43 | 390.05 | 115.53 | 215.17 | 1.5210 |
| 1996 | 152.17 | 152.17 | 238.35 | 470.55 | 131.48 | 259.58 | 1.7059 |
| 1997 | 163.62 | 163.62 | 271.26 | 567.66 | 149.64 | 313.15 | 1.9138 |
| 1998 | 175.87 | 175.87 | 308.72 | 684.82 | 170.30 | 377.78 | 2.1481 |
| 1999 | 189.00 | 189.00 | 351.35 | 826.14 | 193.82 | 455.74 | 2.4113 |
| 2000 | 203.06 | 203.06 | 399.87 | 996.64 | 220.59 | 549.79 | 2.7076 |
| 2001 | 218.15 | 218.15 | 455.09 | 1202.32 | 251.05 | 663.26 | 3.0404 |
| 2002 | 234.18 | 234.18 | 517.93 | 1450.46 | 285.71 | 800.14 | 3.4168 |
| 2003 | 251.47 | 251.47 | 589.45 | 1749.79 | 325.17 | 965.27 | 3.8385 |
| 2004 | 269.95 | 269.95 | 670.85 | 2110.91 | 370.07 | 1164.48 | 4.3138 |
| 2005 | 289.67 | 289.67 | 763.49 | 2546.55 | 421.18 | 1404.80 | 4.8496 |
| 2006 | 310.79 | 310.79 | 868.92 | 3072.10 | 479.34 | 1694.71 | 5.4529 |
| 2007 | 333.33 | 333.33 | 988.91 | 3706.11 | 545.53 | 2044.46 | 6.1335 |
| 2008 | 357.43 | 357.43 | 1125.47 | 4470.96 | 620.86 | 2466.39 | 6.9004 |
| 2009 | 383.23 | 383.23 | 1280.88 | 5393.66 | 706.59 | 2975.39 | 7.7640 |
| 2010 | 410.78 | 410.78 | 1457.76 | 6506.78 | 804.17 | 3589.44 | 8.7381 |
| 2011 | 440.23 | 440.23 | 1659.06 | 7849.63 | 915.22 | 4330.22 | 9.8363 |
| 2012 | 471.72 | 471.72 | 1888.17 | 9469.60 | 1041.60 | 5223.87 | 11.0740 |
| 2013 | 505.32 | 505.32 | 2148.90 | 11423.90 | 1185.44 | 6301.96 | 12.4711 |
| 2014 | 541.29 | 541.29 | 2445.65 | 13781.52 | 1349.13 | 7602.53 | 14.0451 |
| 2015 | 579.70 | 579.70 | 2783.37 | 16625.70 | 1535.44 | 9171.51 | 15.8213 |
| 2016 | 620.80 | 620.80 | 3167.72 | 20056.84 | 1747.46 | 11064.29 | 17.8225 |
| 2017 | 664.59 | 664.59 | 3605.16 | 24196.10 | 1988.77 | 13347.69 | 20.0842 |
| 2018 | 713.97 | 713.97 | 4103.00 | 29189.59 | 2263.40 | 16102.34 | 22.5533 |
| 2019 | 769.34 | 769.34 | 4669.58 | 35213.62 | 2575.96 | 19425.48 | 25.2495 |
| 2020 | 831.61 | 831.61 | 5314.41 | 42480.88 | 2931.67 | 23434.43 | 28.1797 |
| 2021 | 901.24 | 901.24 | 6048.28 | 51247.91 | 3336.51 | 28270.74 | 31.3688 |
| 2022 | 482.31 | 482.31 | 6883.49 | 61824.26 | 3797.25 | 34105.14 | 70.7115 |

Notes:
[1] From: Set I, Q.4, Attachment 1, PUC Rate Case.
[2] MW = 1152, UNITS = 1, NE = 1.
[3] Assume 4% inflation in 1985, 6% thereafter.
[4] Two-unit case (MW = 1152, UNITS = 2, NE = 1) - [2]

TABLE 4.16: NUCLEAR CAPITAL ADDITIONS

| | Year | Average 1983$/kW-yr |
|---|---|---|
| All Years Before and Including: | 72 | 3.46 |
| | 73 | 11.82 |
| | 74 | 8.55 |
| | 75 | 8.71 |
| | 76 | 15.07 |
| | 77 | 21.06 |
| | 78 | 27.34 |
| | 79 | 14.62 |
| | 80 | 26.13 |
| | 81 | 30.97 |
| | 82 | 27.94 |
| | 83 | 31.57 |
| Overall Average: | | 19.41 |
| 1978-83 Average: | | 26.24 |
| Total # Observations: | | 477 |

TABLE 4.17: PROJECTIONS OF CAPITAL ADDITIONS COSTS FOR SSES ($million)

| Year | PP&L Capital Additions Budget | Extrapolation of (1978-1983) Average |
|---|---|---|
| | [1] | [2] |
| 1985 | 50 | 68.44 |
| 1986 | 45 | 73.50 |
| 1987 | 40 | 78.94 |
| 1988 | 35 | 84.78 |
| 1989 | 31 | 91.06 |
| 1990 | 33 | 97.79 |
| 1991 | 35 | 105.03 |
| 1992 | 38 | 112.80 |
| 1993 | 40 | 121.15 |
| 1994 | 43 | 130.12 |
| 1995 | 46 | 139.74 |
| 1996 | 48 | 150.09 |
| 1997 | 51 | 161.19 |
| 1998 | 54 | 173.12 |
| 1999 | 57 | 185.93 |
| 2000 | 60 | 199.69 |
| 2001 | 63 | 214.47 |
| 2002 | 67 | 230.34 |
| 2003 | 71 | 247.38 |
| 2004 | 75 | 265.69 |
| 2005 | 79 | 285.35 |
| 2006 | 84 | 306.47 |
| 2007 | 89 | 329.14 |
| 2008 | 94 | 353.50 |
| 2009 | 99 | 379.66 |
| 2010 | 105 | 407.75 |
| 2011 | 111 | 437.93 |
| 2012 | 117 | 470.33 |
| 2013 | 123 | 505.14 |
| 2014 | 131 | 542.52 |
| 2015 | 138 | 582.67 |
| 2016 | 146 | 625.78 |
| 2017 | 154 | 672.09 |
| 2018 | 130 | 721.83 |
| 2019 | 103 | 775.24 |
| 2020 | 73 | 832.61 |
| 2021 | 38 | 894.22 |
| 2022 | 10 | 960.39 |

Notes: [1] From IR I-4, Attachment 1.
[2] $ 26.24/kW x 2304 MW MGN, in 1983$, escalating at 5.4% in 1984, 7.4% thereafter.

# APPENDIX A

RESUME OF PAUL CHERNICK

## APPENDIX B

CAPACITY FACTOR DATA

| Unit | COD | Year | Age at 7/1 | Orig. DER | Annual GWH | CF@ original DER (Calculated) | Total Number of Refuelings |
|---|---|---|---|---|---|---|---|
| Nine Mi Pt | Dec-69 | 70 | 0.54 | 610 | | 0.0% | |
| Nine Mi Pt | Dec-69 | 71 | 1.54 | 610 | | 0.0% | |
| Nine Mi Pt | Dec-69 | 72 | 2.55 | 610 | | 0.0% | |
| Nine Mi Pt | Dec-69 | 73 | 3.55 | 610 | | 0.0% | |
| Nine Mi Pt | Dec-69 | 74 | 4.55 | 610 | 3296.7 | 61.7% | 1.000 |
| Nine Mi Pt | Dec-69 | 75 | 5.55 | 610 | 3044.9 | 57.0% | 1.000 |
| Nine Mi Pt | Dec-69 | 76 | 6.55 | 610 | 4112.8 | 76.8% | 0.000 |
| Nine Mi Pt | Dec-69 | 77 | 7.55 | 610 | 2946.0 | 55.1% | 1.000 |
| Nine Mi Pt | Dec-69 | 78 | 8.55 | 610 | 4467.5 | 83.6% | 0.000 |
| Nine Mi Pt | Dec-69 | 79 | 9.55 | 610 | 3005.4 | 56.2% | 1.000 |
| Nine Mi Pt | Dec-69 | 80 | 10.55 | 610 | 4537.8 | 84.7% | 0.000 |
| Nine Mi Pt | Dec-69 | 81 | 11.55 | 610 | 3270.3 | 61.2% | 1.000 |
| Nine Mi Pt | Dec-69 | 82 | 12.55 | 610 | 1134.8 | 21.2% | 0.000 |
| Nine Mi Pt | Dec-69 | 83 | 13.55 | 610 | 2802.1 | 52.4% | 0.000 |
| Oyster Creek | Dec-69 | 70 | 0.54 | 650 | | 0.0% | |
| Oyster Creek | Dec-69 | 71 | 1.54 | 650 | | 0.0% | |
| Oyster Creek | Dec-69 | 72 | 2.55 | 650 | | 0.0% | |
| Oyster Creek | Dec-69 | 73 | 3.55 | 650 | | 0.0% | |
| Oyster Creek | Dec-69 | 74 | 4.55 | 650 | 3673.5 | 64.5% | 1.000 |
| Oyster Creek | Dec-69 | 75 | 5.55 | 650 | 3145.8 | 55.2% | 1.064 |
| Oyster Creek | Dec-69 | 76 | 6.55 | 650 | 3860.3 | 67.6% | 0.936 |
| Oyster Creek | Dec-69 | 77 | 7.55 | 650 | 3248.3 | 57.0% | 1.000 |
| Oyster Creek | Dec-69 | 78 | 8.55 | 650 | 3645.7 | 64.0% | 1.000 |
| Oyster Creek | Dec-69 | 79 | 9.55 | 650 | 4563.2 | 80.1% | 0.000 |
| Oyster Creek | Dec-69 | 80 | 10.55 | 650 | 1957.6 | 34.3% | 1.000 |
| Oyster Creek | Dec-69 | 81 | 11.55 | 650 | 2628.3 | 46.2% | 0.000 |
| Oyster Creek | Dec-69 | 82 | 12.55 | 650 | 2013.1 | 35.4% | 0.000 |
| Oyster Creek | Dec-69 | 83 | 13.55 | 650 | 205.2 | 3.6% | 0.595 |
| Millstone 1 | Mar-71 | 72 | 1.30 | 690 | | 0.0% | |
| Millstone 1 | Mar-71 | 73 | 2.30 | 690 | | 0.0% | |
| Millstone 1 | Mar-71 | 74 | 3.30 | 690 | 3604.2 | 59.6% | 1.000 |
| Millstone 1 | Mar-71 | 75 | 4.30 | 690 | 3897.0 | 64.5% | 0.000 |
| Millstone 1 | Mar-71 | 76 | 5.30 | 690 | 3752.4 | 61.9% | 1.000 |
| Millstone 1 | Mar-71 | 77 | 6.30 | 690 | 4820.2 | 79.7% | 0.000 |
| Millstone 1 | Mar-71 | 78 | 7.30 | 690 | 4654.9 | 77.0% | 1.000 |
| Millstone 1 | Mar-71 | 79 | 8.30 | 690 | 4221.3 | 69.8% | 1.000 |
| Millstone 1 | Mar-71 | 80 | 9.30 | 690 | 3390.2 | 55.9% | 0.451 |
| Millstone 1 | Mar-71 | 81 | 10.30 | 690 | 2518.9 | 41.7% | 0.549 |
| Millstone 1 | Mar-71 | 82 | 11.30 | 690 | 4078.3 | 67.5% | 1.000 |
| Millstone 1 | Mar-71 | 83 | 12.30 | 690 | 5354.2 | 88.6% | 0.000 |
| Monticello | Jul-71 | 72 | 0.96 | 545 | | 0.0% | |
| Monticello | Jul-71 | 73 | 1.96 | 545 | | 0.0% | |
| Monticello | Jul-71 | 74 | 2.96 | 545 | 2923.8 | 61.2% | 1.000 |
| Monticello | Jul-71 | 75 | 3.96 | 545 | 2879.5 | 60.3% | 2.000 |
| Monticello | Jul-71 | 76 | 4.97 | 545 | 3986.4 | 83.3% | 0.000 |
| Monticello | Jul-71 | 77 | 5.97 | 545 | 3568.9 | 74.8% | 1.000 |
| Monticello | Jul-71 | 78 | 6.97 | 545 | 3856.3 | 80.8% | 1.000 |
| Monticello | Jul-71 | 79 | 7.97 | 545 | 4399.6 | 92.2% | 0.000 |
| Monticello | Jul-71 | 80 | 8.97 | 545 | 3453.8 | 72.1% | 1.000 |

| Unit | COD | Year | Age at 7/1 | Orig. DER | Annual GWH | CF@ original DER (Calculated) | Total Number of Refuelings |
|---|---|---|---|---|---|---|---|
| Monticello | Jul-71 | 81 | 9.97 | 545 | 3257.8 | 68.2% | 1.000 |
| Monticello | Jul-71 | 82 | 10.97 | 545 | 2420.8 | 50.7% | 1.000 |
| Monticello | Jul-71 | 83 | 11.97 | 545 | 4147.7 | 86.9% | 0.000 |
| Dresden 3 | Nov-71 | 72 | 0.63 | 809 | | 0.0% | |
| Dresden 3 | Nov-71 | 73 | 1.63 | 809 | | 0.0% | |
| Dresden 3 | Nov-71 | 74 | 2.63 | 809 | 3200.3 | 45.2% | 1.000 |
| Dresden 3 | Nov-71 | 75 | 3.63 | 809 | 2190.0 | 30.9% | 1.000 |
| Dresden 3 | Nov-71 | 76 | 4.63 | 809 | 4034.5 | 56.8% | 1.000 |
| Dresden 3 | Nov-71 | 77 | 5.63 | 809 | 5186.3 | 73.2% | 0.000 |
| Dresden 3 | Nov-71 | 78 | 6.63 | 809 | 3831.7 | 54.1% | 1.000 |
| Dresden 3 | Nov-71 | 79 | 7.63 | 809 | 3475.8 | 49.0% | 0.000 |
| Dresden 3 | Nov-71 | 80 | 8.63 | 809 | 4329.6 | 60.9% | 1.000 |
| Dresden 3 | Nov-71 | 81 | 9.63 | 809 | 5177.6 | 73.1% | 0.000 |
| Dresden 3 | Nov-71 | 82 | 10.63 | 809 | 3887.9 | 54.9% | 1.000 |
| Dresden 3 | Nov-71 | 83 | 11.63 | 809 | 4147.9 | 58.5% | 0.503 |
| Dresden 2 | Jun-72 | 73 | 1.04 | 809 | | 0.0% | |
| Dresden 2 | Jun-72 | 74 | 2.04 | 809 | 3379.6 | 47.7% | 0.301 |
| Dresden 2 | Jun-72 | 75 | 3.04 | 809 | 2966.1 | 41.9% | 0.699 |
| Dresden 2 | Jun-72 | 76 | 4.05 | 809 | 4371.6 | 61.5% | 1.000 |
| Dresden 2 | Jun-72 | 77 | 5.05 | 809 | 3532.5 | 49.8% | 1.000 |
| Dresden 2 | Jun-72 | 78 | 6.05 | 809 | 5704.4 | 80.5% | 0.000 |
| Dresden 2 | Jun-72 | 79 | 7.05 | 809 | 4939.6 | 69.7% | 1.000 |
| Dresden 2 | Jun-72 | 80 | 8.05 | 809 | 4580.9 | 64.5% | 0.000 |
| Dresden 2 | Jun-72 | 81 | 9.05 | 809 | 3407.9 | 48.1% | 1.000 |
| Dresden 2 | Jun-72 | 82 | 10.05 | 809 | 5123.0 | 72.3% | 0.000 |
| Dresden 2 | Jun-72 | 83 | 11.05 | 809 | 3397.5 | 47.9% | 1.000 |
| Vermont Yankee | Nov-72 | 73 | 0.62 | 514 | | 0.0% | |
| Vermont Yankee | Nov-72 | 74 | 1.62 | 514 | 2482.6 | 55.1% | 1.000 |
| Vermont Yankee | Nov-72 | 75 | 2.62 | 514 | 3561.2 | 79.1% | 0.000 |
| Vermont Yankee | Nov-72 | 76 | 3.63 | 514 | 3260.0 | 72.2% | 1.000 |
| Vermont Yankee | Nov-72 | 77 | 4.63 | 514 | 3537.7 | 78.6% | 1.000 |
| Vermont Yankee | Nov-72 | 78 | 5.63 | 514 | 3240.7 | 72.0% | 1.000 |
| Vermont Yankee | Nov-72 | 79 | 6.63 | 514 | 3448.8 | 76.6% | 1.000 |
| Vermont Yankee | Nov-72 | 80 | 7.63 | 514 | 2979.2 | 66.0% | 1.000 |
| Vermont Yankee | Nov-72 | 81 | 8.63 | 514 | 3568.7 | 79.3% | 1.000 |
| Vermont Yankee | Nov-72 | 82 | 9.63 | 514 | 4174.3 | 92.7% | 0.000 |
| Vermont Yankee | Nov-72 | 83 | 10.63 | 514 | 2874.5 | 63.8% | 1.000 |
| Pilgrim 1 | Dec-72 | 73 | 0.58 | 670 | | 0.0% | |
| Pilgrim 1 | Dec-72 | 74 | 1.58 | 670 | 1973.0 | 33.6% | 0.000 |
| Pilgrim 1 | Dec-72 | 75 | 2.58 | 670 | 2587.2 | 44.1% | 0.000 |
| Pilgrim 1 | Dec-72 | 76 | 3.58 | 670 | 2415.5 | 41.0% | 1.000 |
| Pilgrim 1 | Dec-72 | 77 | 4.58 | 670 | 2652.1 | 45.2% | 1.000 |
| Pilgrim 1 | Dec-72 | 78 | 5.58 | 670 | 4736.7 | 80.7% | 0.000 |
| Pilgrim 1 | Dec-72 | 79 | 6.58 | 670 | 4844.4 | 82.5% | 0.000 |
| Pilgrim 1 | Dec-72 | 80 | 7.59 | 670 | 3044.5 | 51.7% | 1.000 |
| Pilgrim 1 | Dec-72 | 81 | 8.59 | 670 | 3443.9 | 58.7% | 0.499 |
| Pilgrim 1 | Dec-72 | 82 | 9.59 | 670 | 3287.0 | 56.0% | 0.501 |
| Pilgrim 1 | Dec-72 | 83 | 10.59 | 670 | 4711.9 | 80.3% | 0.078 |
| Quad Cities 1 | Feb-73 | 74 | 1.37 | 809 | 3562.9 | 50.3% | 1.000 |
| Quad Cities 1 | Feb-73 | 75 | 2.37 | 809 | 4270.9 | 60.3% | 0.000 |

| Unit | COD | Year | Age at 7/1 | Orig. DER | Annual GWH | CF@ original DER (Calculated) | Total Number of Refuelings |
|---|---|---|---|---|---|---|---|
| Quad Cities 1 | Feb-73 | 76 | 3.38 | 809 | 3393.1 | 47.7% | 1.000 |
| Quad Cities 1 | Feb-73 | 77 | 4.38 | 809 | 3520.7 | 49.7% | 1.000 |
| Quad Cities 1 | Feb-73 | 78 | 5.38 | 809 | 4721.1 | 66.6% | 0.000 |
| Quad Cities 1 | Feb-73 | 79 | 6.38 | 809 | 4783.0 | 67.5% | 1.000 |
| Quad Cities 1 | Feb-73 | 80 | 7.38 | 809 | 3441.7 | 48.4% | 1.000 |
| Quad Cities 1 | Feb-73 | 81 | 8.38 | 809 | 5726.8 | 80.8% | 0.000 |
| Quad Cities 1 | Feb-73 | 82 | 9.38 | 809 | 3244.8 | 45.8% | 1.000 |
| Quad Cities 1 | Feb-73 | 83 | 10.38 | 809 | 5776.4 | 81.5% | 0.000 |
| Quad Cities 2 | Mar-73 | 74 | 1.30 | 809 | 4469.7 | 63.1% | 0.068 |
| Quad Cities 2 | Mar-73 | 75 | 2.30 | 809 | 2745.3 | 38.7% | 0.932 |
| Quad Cities 2 | Mar-73 | 76 | 3.30 | 809 | 4304.7 | 60.6% | 1.000 |
| Quad Cities 2 | Mar-73 | 77 | 4.30 | 809 | 4369.3 | 61.7% | 0.000 |
| Quad Cities 2 | Mar-73 | 78 | 5.30 | 809 | 4426.5 | 62.5% | 1.000 |
| Quad Cities 2 | Mar-73 | 79 | 6.30 | 809 | 3981.1 | 56.2% | 0.250 |
| Quad Cities 2 | Mar-73 | 80 | 7.30 | 809 | 3614.4 | 50.9% | 0.750 |
| Quad Cities 2 | Mar-73 | 81 | 8.30 | 809 | 3767.6 | 53.2% | 1.000 |
| Quad Cities 2 | Mar-73 | 82 | 9.30 | 809 | 5059.0 | 71.4% | 0.000 |
| Quad Cities 2 | Mar-73 | 83 | 10.30 | 809 | 3151.3 | 44.5% | 0.708 |
| Peach Bottom 2 | May-74 | 75 | 1.13 | 1065 | 5082.5 | 54.5% | 0.000 |
| Peach Bottom 2 | May-74 | 76 | 2.13 | 1065 | 5569.6 | 59.5% | 1.000 |
| Peach Bottom 2 | May-74 | 77 | 3.13 | 1065 | 4023.4 | 43.1% | 1.000 |
| Peach Bottom 2 | May-74 | 78 | 4.13 | 1065 | 6793.8 | 72.8% | 1.000 |
| Peach Bottom 2 | May-74 | 79 | 5.13 | 1065 | 8754.4 | 93.8% | 0.000 |
| Peach Bottom 2 | May-74 | 80 | 6.13 | 1065 | 4343.9 | 46.4% | 1.000 |
| Peach Bottom 2 | May-74 | 81 | 7.13 | 1065 | 6631.1 | 71.1% | 0.000 |
| Peach Bottom 2 | May-74 | 82 | 8.13 | 1065 | 4794.4 | 51.4% | 1.000 |
| Peach Bottom 2 | May-74 | 83 | 9.13 | 1065 | 4451.3 | 47.7% | 0.000 |
| Cooper | Jul-74 | 75 | 0.96 | 778 | 3853.6 | 56.5% | 0.000 |
| Cooper | Jul-74 | 76 | 1.96 | 778 | 3642.5 | 53.3% | 1.000 |
| Cooper | Jul-74 | 77 | 2.96 | 778 | 4540.1 | 66.6% | 1.000 |
| Cooper | Jul-74 | 78 | 3.96 | 778 | 4886.6 | 71.7% | 1.000 |
| Cooper | Jul-74 | 79 | 4.96 | 778 | 4994.9 | 73.3% | 1.000 |
| Cooper | Jul-74 | 80 | 5.97 | 778 | 3788.1 | 55.4% | 1.000 |
| Cooper | Jul-74 | 81 | 6.97 | 778 | 3851.0 | 56.5% | 1.000 |
| Cooper | Jul-74 | 82 | 7.97 | 778 | 5276.1 | 77.4% | 1.000 |
| Cooper | Jul-74 | 83 | 8.97 | 778 | 3343.2 | 49.1% | 1.000 |
| Browns Ferry 1 | Aug-74 | 75 | 0.88 | 1098 | 1347.9 | 14.0% | 0.000 |
| Browns Ferry 1 | Aug-74 | 76 | 1.88 | 1098 | 1301.2 | 13.5% | 0.000 |
| Browns Ferry 1 | Aug-74 | 77 | 2.88 | 1098 | 5043.3 | 52.4% | 0.862 |
| Browns Ferry 1 | Aug-74 | 78 | 3.88 | 1098 | 5817.9 | 60.5% | 0.138 |
| Browns Ferry 1 | Aug-74 | 79 | 4.88 | 1098 | 7495.7 | 77.9% | 0.358 |
| Browns Ferry 1 | Aug-74 | 80 | 5.88 | 1098 | 6061.8 | 62.9% | 1.000 |
| Browns Ferry 1 | Aug-74 | 81 | 6.88 | 1098 | 4405.1 | 45.8% | 1.000 |
| Browns Ferry 1 | Aug-74 | 82 | 7.88 | 1098 | 7880.9 | 81.9% | 0.000 |
| Browns Ferry 1 | Aug-74 | 83 | 8.88 | 1098 | 2175.5 | 22.6% | 0.995 |
| Peach Bottom 3 | Dec-74 | 75 | 0.54 | 1065 | 5282.3 | 56.6% | 0.000 |
| Peach Bottom 3 | Dec-74 | 76 | 1.55 | 1065 | 6049.6 | 64.7% | 0.436 |
| Peach Bottom 3 | Dec-74 | 77 | 2.55 | 1065 | 4773.9 | 51.2% | 0.564 |
| Peach Bottom 3 | Dec-74 | 78 | 3.55 | 1065 | 6966.1 | 74.7% | 1.000 |
| Peach Bottom 3 | Dec-74 | 79 | 4.55 | 1065 | 6101.7 | 65.4% | 1.000 |

| Unit | COD | Year | Age at 7/1 | Orig. DER | Annual GWH | CF@ original DER (Calculated) | Total Number of Refuelings |
|---|---|---|---|---|---|---|---|
| Peach Bottom 3 | Dec-74 | 80 | 5.55 | 1065 | 7233.8 | 77.3% | 0.000 |
| Peach Bottom 3 | Dec-74 | 81 | 6.55 | 1065 | 3131.8 | 33.6% | 1.000 |
| Peach Bottom 3 | Dec-74 | 82 | 7.55 | 1065 | 8532.3 | 91.5% | 0.000 |
| Peach Bottom 3 | Dec-74 | 83 | 8.55 | 1065 | 2421.0 | 26.0% | 1.000 |
| Duane Arnold | Feb-75 | 76 | 1.38 | 538 | 2489.3 | 52.7% | 1.000 |
| Duane Arnold | Feb-75 | 77 | 2.38 | 538 | 2899.8 | 61.5% | 1.000 |
| Duane Arnold | Feb-75 | 78 | 3.38 | 538 | 1227.6 | 26.0% | 1.000 |
| Duane Arnold | Feb-75 | 79 | 4.38 | 538 | 2898.8 | 61.5% | 0.000 |
| Duane Arnold | Feb-75 | 80 | 5.38 | 538 | 2770.0 | 58.6% | 1.000 |
| Duane Arnold | Feb-75 | 81 | 6.38 | 538 | 2219.5 | 47.1% | 1.000 |
| Duane Arnold | Feb-75 | 82 | 7.38 | 538 | 2280.5 | 48.4% | 0.000 |
| Duane Arnold | Feb-75 | 83 | 8.38 | 538 | 2324.3 | 49.3% | 1.000 |
| Browns Ferry 2 | Mar-75 | 76 | 1.30 | 1098 | 1567.2 | 16.2% | 0.000 |
| Browns Ferry 2 | Mar-75 | 77 | 2.30 | 1098 | 6225.0 | 64.7% | 0.000 |
| Browns Ferry 2 | Mar-75 | 78 | 3.30 | 1098 | 5547.4 | 57.7% | 1.000 |
| Browns Ferry 2 | Mar-75 | 79 | 4.30 | 1098 | 7441.3 | 77.4% | 1.000 |
| Browns Ferry 2 | Mar-75 | 80 | 5.30 | 1098 | 5618.8 | 58.3% | 1.000 |
| Browns Ferry 2 | Mar-75 | 81 | 6.30 | 1098 | 7471.8 | 77.7% | 0.000 |
| Browns Ferry 2 | Mar-75 | 82 | 7.30 | 1098 | 4450.9 | 46.3% | 0.664 |
| Browns Ferry 2 | Mar-75 | 83 | 8.30 | 1098 | 6385.5 | 66.4% | 0.336 |
| Fitzpatrick | Jul-75 | 76 | 0.96 | 821 | 4156.3 | 57.6% | 0.000 |
| Fitzpatrick | Jul-75 | 77 | 1.96 | 821 | 3893.3 | 54.1% | 1.000 |
| Fitzpatrick | Jul-75 | 78 | 2.96 | 821 | 4197.3 | 58.4% | 1.000 |
| Fitzpatrick | Jul-75 | 79 | 3.96 | 821 | 2964.6 | 41.2% | 0.000 |
| Fitzpatrick | Jul-75 | 80 | 4.97 | 821 | 4334.5 | 60.1% | 1.000 |
| Fitzpatrick | Jul-75 | 81 | 5.97 | 821 | 4779.7 | 66.5% | 0.477 |
| Fitzpatrick | Jul-75 | 82 | 6.97 | 821 | 4959.7 | 69.0% | 0.523 |
| Fitzpatrick | Jul-75 | 83 | 7.97 | 821 | 4634.3 | 64.4% | 1.000 |
| Brunswick 2 | Nov-75 | 76 | 0.63 | 821 | 2486.3 | 34.5% | 0.000 |
| Brunswick 2 | Nov-75 | 77 | 1.63 | 821 | 2436.6 | 33.9% | 1.000 |
| Brunswick 2 | Nov-75 | 78 | 2.63 | 821 | 4794.4 | 66.7% | 0.000 |
| Brunswick 2 | Nov-75 | 79 | 3.63 | 821 | 3652.3 | 50.8% | 1.000 |
| Brunswick 2 | Nov-75 | 80 | 4.63 | 821 | 1865.0 | 25.9% | 0.000 |
| Brunswick 2 | Nov-75 | 81 | 5.63 | 821 | 3284.0 | 45.7% | 0.000 |
| Brunswick 2 | Nov-75 | 82 | 6.63 | 821 | 1910.1 | 26.6% | 1.000 |
| Brunswick 2 | Nov-75 | 83 | 7.63 | 821 | 3935.7 | 54.7% | 0.000 |
| Hatch 1 | Dec-75 | 76 | 0.55 | 786 | 4133.8 | 59.9% | 0.000 |
| Hatch 1 | Dec-75 | 77 | 1.55 | 786 | 3713.0 | 53.9% | 1.000 |
| Hatch 1 | Dec-75 | 78 | 2.55 | 786 | 4227.3 | 61.4% | 1.000 |
| Hatch 1 | Dec-75 | 79 | 3.55 | 786 | 3337.9 | 48.5% | 1.000 |
| Hatch 1 | Dec-75 | 80 | 4.55 | 786 | 4790.5 | 69.4% | 0.000 |
| Hatch 1 | Dec-75 | 81 | 5.55 | 786 | 2756.3 | 40.0% | 1.000 |
| Hatch 1 | Dec-75 | 82 | 6.55 | 786 | 2877.6 | 41.8% | 0.615 |
| Hatch 1 | Dec-75 | 83 | 7.55 | 786 | 3964.1 | 57.6% | 0.385 |
| Browns Ferry 3 | Mar-77 | 78 | 1.33 | 1098 | 5554.3 | 57.7% | 1.000 |
| Browns Ferry 3 | Mar-77 | 79 | 2.33 | 1098 | 5482.6 | 57.0% | 1.000 |
| Browns Ferry 3 | Mar-77 | 80 | 3.34 | 1098 | 6936.6 | 71.9% | 0.684 |
| Browns Ferry 3 | Mar-77 | 81 | 4.34 | 1098 | 6246.6 | 64.9% | 0.695 |
| Browns Ferry 3 | Mar-77 | 82 | 5.34 | 1098 | 4892.9 | 50.9% | 0.532 |
| Browns Ferry 3 | Mar-77 | 83 | 6.34 | 1098 | 5394.4 | 56.1% | 0.332 |

| Unit | COD | Year | Age at 7/1 | Orig. DER | Annual GWH | CF@ original DER (Calculated) | Total Number of Refuelings |
|---|---|---|---|---|---|---|---|
| Brunswick 1 | Mar-77 | 78 | 1.29 | 821 | 5122.8 | 71.2% | 0.000 |
| Brunswick 1 | Mar-77 | 79 | 2.29 | 821 | 3169.2 | 44.1% | 1.000 |
| Brunswick 1 | Mar-77 | 80 | 3.29 | 821 | 3939.6 | 54.6% | 1.000 |
| Brunswick 1 | Mar-77 | 81 | 4.29 | 821 | 2556.1 | 35.5% | 0.000 |
| Brunswick 1 | Mar-77 | 82 | 5.29 | 821 | 2921.6 | 40.6% | 0.081 |
| Brunswick 1 | Mar-77 | 83 | 6.29 | 821 | 1388.7 | 19.3% | 0.919 |
| Hatch 2 | Sep-79 | 80 | 0.82 | 795 | 3645.0 | 52.2% | 0.539 |
| Hatch 2 | Sep-79 | 81 | 1.82 | 795 | 4478.4 | 64.3% | 0.461 |
| Hatch 2 | Sep-79 | 82 | 2.82 | 795 | 3728.3 | 53.5% | 1.000 |
| Hatch 2 | Sep-79 | 83 | 3.82 | 795 | 3809.5 | 54.7% | 1.000 |

OCA St. 3-A

COMMONWEALTH OF PENNSYLVANIA
BEFORE THE PUBLIC UTILITY COMMISSION

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THE PENNSYLVANIA
PUBLIC UTILITIES COMMISSION
v. PENNSYLVANIA POWER & LIGHT
COMPANY

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Docket No. R-842651

# SURREBUTTAL TESTIMONY OF PAUL CHERNICK
# ON BEHALF OF THE
# PENNSYLVANIA OFFICE OF CONSUMER ADVOCATE

## CONCERNING THE COSTS AND BENEFITS OF THE
## SUSQUEHANNA-2 NUCLEAR GENERATING STATION

December, 1984

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**Rebuttal Testimony of Paul Chernick**

**on Behalf of the Consumer Advocate**

Q: Are you the same Paul Chernick who testified previosly in this proceeding?

A: Yes.

Q: What is the purpose of your testimony?

A: I will respond to issues raised by various PP&L witnesses in their rebuttal testimony. The time available for preparation of this testimony precludes detailed responses to all of the points addressed by the PP&L witnesses, so I will concentrate on correcting major mischaracterizations of my testimony, and explaining the differences between my approaches and those of PP&L.

Q: How does your approach to assessing the economics of SSES 2, and evaluating the ratemaking options related to that unit, differ from the approach of the PP&L witnesses?

A: I believe that it is useful to focus on three major differences. First, the projections of SSES 2 costs which I present simply continue historical experience, measured in various ways, while the PP&L projections assume various improvements over that experience. Second, while my analyses rely almost entirely on publicly available data, the PP&L witnesses rely heavily on engineering judgement, which has been consistently incorrect and over-optimistic in projecting virtually all aspects of nuclear power costs. Third, I do not believe that it is fair to greatly increase the rates to today's PP&L customers to pay for SSES 2, even if the unit eventually provides considerable savings to customers in some other decade or century; the PP&L witnesses who address ratemaking claim that the mere demonstration of any net saving over the unit's life justifies charging current customers whatever the plant cost to construct.

Q: What kinds of improvements in the historical experience do the PP&L witnesses assume?

A: They generally claim that capital additions will be small, that O&M growth will be lower, and that capacity factors will be larger than observed in the past. These assertions are based on the assumptions that

- the experience of other plants was due to their immature design, and that those design problems have been solved at SSES,

- the pool of potential nuclear problems is relatively small and has been substantially depleted by the events of the last decade (i.e., most of the bad things which could happen to nuclear plants, have happened), and

- NRC regulatory actions, which contributed to all these costs, have now slowed down, and will fall off to a low and stable level, never again causing the kinds of problems seen in the past.

Q: Do you believe that these assumptions are correct?

A: I certainly hope that they are correct, but I suspect that all of these assumptions are (at best) overstated. However, the important question with regard to these issues is not "What is most likely to happen?", for we all know that there is tremendous uncertainty in any projection related to nuclear power, but "Who should bear the risk that these improvements will not occur?" PP&L claims to be confident that the future of nuclear power will be more favorable than the past, but it is adamant in insisting that today's ratepayers (rather than future ratepayers, or PP&L shareholders) assume the risk of the actual outcome, by paying much more for SSES 2 than it is worth to them, for each of the next several years.

Q: How do the PP&L witnesses rely on engineering judgement, as contrasted with published data?

A: There are several such examples, some of which I will touch on in subsequent sections. It is striking that, other than a couple of Mr. Koppe's calculations, the PP&L rebuttal testimony is almost devoid of data or calculations, even where very specific numerical assertions are made. In some cases, there is an implication that a specific computation has been carried out, but it is not provided. In other cases, the data is apparently proprietary, and its nature may not even be explicitly stated. One striking example of this sort is the repeated claim that NRC regulation has slowed down: no factual basis is offered for this assertions, despite the fact that it is a crucial element in the arguments of at least three witnesses.

The extreme example of resorting to engineering judgement lies in Mr. Curtis' conclusion that SSES will last 40 years **because GE and Bechtel say it will.**[1] Both GE and Bechtel have been so wrong so often about nuclear plant costs, that their opinions on this subject are virtually valueless. The limited data available (from the small plants of the early and middle 1960's) indicates that average nuclear unit life is running around 20 years: the oldest unit of more than 500 MW (Connecticut Yankee) will complete 17 years of commercial

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1. The fact that the letters presenting these opinions are the only attachments to the rebuttal of any of the witnesses on SSES issues, which are generally very quantitative, might cause one to wonder about how PP&L determines what sort of evidence is worth examining in detail. I, for one, would have been glad to accept Mr. Curtis' assertion that GE and Bechtel have promised (but not guaranteed) that SSES will run for 40 years, since both companies have promised other, even less likely things in the past. I would have been much more interested in how Mr. Curtis purports to measure the number and severity of new and outstanding nuclear safety issues.

operation on New Year's Day. Projecting nuclear power plant useful lives of more than 20 years requires some optimism, and projecting them to reach beyond 30 years seems to be little more than speculation, no matter how many testimonials PP&L collects from its vendors.

Q: What is the basic difference between your approach to ratemaking and that of PP&L?

A: PP&L's position, as expressed by Mr. Hecht, is that PP&L should be allowed to immediately charge ratepayers for whatever Susquehanna cost to build, provided that it will <u>someday</u> have positive present value benefits to customers as a whole. My position is that SSES should not greatly burden ratepayers in the 1980's to lower rates to customers in the next century: if customers are to pay for SSES 2, it should be the customers who will actually enjoy the benefits it may someday offer.

Q: How is the rest of your testimony organized?

A: I will briefly touch on some of the points raised by

- Mr. Curtis,
- Mr. Kenyon,
- Mr. Hecht, and
- and Mr. Koppe,

in that order.

## 3 - THE REBUTTAL TESTIMONY OF MR. CURTIS

Q: What responses do you have to Mr. Curtis' rebuttal?

A: Very few. Mr. Curtis basically repeats the assertions that things are getting better, and will be better still in the future, without any substantial documentation. He freely admits that his perceptions are based on little more than his "experience and knowledge" (page 1, line 26) of the nuclear industry. Hence, there is little that requires any response, other than to note that, if PP&L is as confident as Mr. Curtis claims to be, it should not object strongly to delaying its cost recovery for SSES 2 to match the benefits of the plant, since it would believe that the costs were small and that the benefits were large and close at hand. There are a few points which require some response, however.

Q: What are those points?

A: First, Mr. Curtis cites as evidence of the improved environment for nuclear power "the slowing down of reactor design development" and the assertion that "current regulatory levels are below past levels". He provides no evidence (or even an operational definition) for either of these statements. Reactor design development may well have slowed down, or even stopped, since there has been no new order for a nuclear unit in the US since 1978, and since there is no reasonable prospect of new orders in most of the next decade, but it is not clear how this improves the economics of SSES. I doubt that Mr. Curtis really means what he appears to be saying in the second quote, which is that the NRC will now tolerate designs and operating procedures which were not previously acceptable: in any case, Mr. Curtis has not demonstrated that either of these phenomena (whatever he means by these terms) have occurred or are relevant to SSES economics.

Q: Have you seen any evidence that NRC regulations have been decreased in number or severity, as they affect nuclear operating costs and capacity factors?

A: Not in this proceeding. The most recent tabulation of NRC regulations which I have seen is attached to this testimony as Attachment 1: it was provided by a consortium of Massachusetts utilities[2] in support of a contention similar to PP&L's in this case: that regulation had stabilized and that capacity factors would thus recover to levels better than any previously experienced. This document shows two things. First, while the number of some kinds of NRC documents is decreasing (some types have been phased out

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2. The New England Power Company, the Massachusetts Municipal Wholesale Electric Company, Canal Electric Company, and Fitchburg Gas and Electric, in the generic Seabrook 1 investigation, MDPU 84-152.

completely), others continue to rise, and it is difficult to determine how these changes may affect short-run and long-run cost and performance trends. Second, while the total number of new recent safety-related documents is slightly lower than that immediately following the TMI accident, it is still higher than the annual rates of new documents in the pre-TMI period, which was also characterized by high rates of O&M cost increases and capacity factors much lower than previously expected. This data runs through 1983; it is hard to imagine that the 1984 results could establish any trend, let alone a "clear downward trend."

Q: If the number of new regulatory actions fell to zero, would the effects of regulation on nuclear costs and performance stop?

A: Not immediately. A review by Northeast Utilities of the reasons for the 1982 increase in the cost estimate for its Millstone 3 nuclear plant, planned to go on line in 1986, found that regulatory actions from as far back as 1974 had resulted in increases in the 1982 cost estimate, despite the fact that there had been several other cost revisions in the interim, including one as recently as 1980. Since regulatory changes generally affect the design of new units before they affect capacity factors and capital additions of operating units (which requires that changes actually be made, rather than just planned), we must expect several more years of effects from regulatory changes which have already occurred. Of course, no one is projecting that the NRC will stop producing new regulations soon.

Q: To what other statements of Mr. Curtis do you wish to respond?

A: Mr. Curtis accuses me of being "inconsistent" in my application of recent capital additions, because he found an older piece of testimony in which I used all capital additions data, rather than the higher level of additions which has prevailed since 1977. This is a silly complaint: as I explain in my testimony, and as illustrated in Figure 4.2, the level of annual additions has clearly increased since the early 1970's. Since I performed the analysis described in my testimony, I have consistently used the results, rather than the simple cumulative average I used previously. I have attached the relevant portions of my most recent testimony on Seabrook (as Attachment 2), to illustrate this point.

Mr. Curtis also asserts that various other factors, such as multi-unit status and plant size, affect the level of capital additions per kW-year. These are interesting claims, and if properly supported by statistical analyses, would suggest improvements in my estimates. Unfortunately, while Mr. Curtis claims to have conducted a "careful analysis", he does not provide any analysis, but only a couple of summary results.[3] One of these results is an averge for a subset of

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3. Actually, both of his results refer to the effects of multi-unit plants, even though he claims to have found some economies

plants for a single year, 1983, without any tests of the significance of the difference between that year and other years. Mr. Curtis also is very selective in the issues he addresses: he does not consider whether the "multi-unit" effect is actually an "experienced nuclear utility" effect, related to the large number of multi-unit plants owned by the leading nuclear utilities, such as Commonwealth Edison, TVA, and Duke, nor does he attempt to correct for regional cost differences.

When I started to calculate capital additions for nuclear units, in 1979, I was (to my knowledge) the only analyst to be conducting such analyses. Until performing the study presented in my testimony, I used a simple average of all past capital additions in dollars/kW-year, since I recognized that the variability of annual additions would make it difficult to identify any trends in the data. For my direct testimony, I added an analysis of the trend of additions over time. If Mr. Curtis believes that a thorough, "careful" statistical analysis of capital additions over time will reveal significant economies of scale and economies of duplication, he is welcome to perform such an analysis, correcting for such other variables as location, and perhaps unit design (e.g., PWR versus BWR). The results, if

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of scale, as well.

presented in a reviewable form, could be a significant contribution to our understanding of patterns of capital additions. Mr. Curtis does nothing of the sort in his rebuttal.

Q: Do you have any other comments on Mr. Curtis' rebuttal?

A: I would just note that my introduction discussed Mr. Curtis' curious approach to estimating plant lifetime. In addition, his rebuttal asserts that previous licensing practice "resulted in only 30 years of actual operation", even though no domestic commercial reactors have operated nearly that long, and those which have been retired early have been retired for reasons unrelated to NRC licensing practice.

4 - THE REBUTTAL TESTIMONY OF MR. KENYON

Q: What responses do you have to Mr. Kenyon's rebuttal?

A: Mr. Kenyon, like Mr. Curtis, asserts that "the known causes of historical growth [in nuclear O&M] are on a clear downward trend", but provides no documentation to support this claim. He also cites Mr. Curtis' testimony as a basis for his position, even though Mr. Curtis also does not provide any evidence for this alleged trend.

Mr. Kenyon also suggests that I erred in not using capacity factor data from SSES (in projecting capacity factors for SSES 2: he rather testily claims that I "chose to ignore" SSES 1. Since my analysis used (and could use) only full calendar years of commercial operation data, SSES 1 data was not available, and will not be available until some time next year, when 1984 data is released. Mr. Kenyon does not indicate how he thinks this data could be incorporated into an analysis of national BWR data.

Q: Is the SSES 1 data very valuable in projecting SSES 2 capacity factors?

A: Not yet. SSES 1 has operated for a very short time, and many nuclear units have achieved high capacity factors initially, only to full to average performance (or worse) in later years. Furthermore, SSES 1 has not yet completed its first refueling, which generally brings down the average capacity factor substantially. In particular, Mr. Kenyon's suggestion that the SSES 2 tie-in outage be "excluded"[4] in calculating SSES 1 capacity factor must be rejected: we have no way of knowing what maintenance outages would have been required if not for the tie-in outage.

Q: What other problems are there in Mr. Kenyon's rebuttal?

A: Mr. Kenyon criticizes me for improving on earlier, more naive analyses of nuclear O&M in which I did not reflect the effect of size on O&M cost. He also makes some absurd calculations on the O&M costs which would result from the continuation of the historic O&M trends to the year 2022. As I note in my testimony, continuation of this trend would result in the retirement of the plant much earlier (sometime around 2010), when the O&M cost was only a tenth of the values Mr. Kenyon discusses. In addition, I recognize that projection of continued increases in O&M expenses (based on 15 years of data) for more than 15 years into the future is speculative, but even continuation of the trend through the end of the century would eliminate most or all of the projected benefits

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4. Mr. Kenyon does not explain how he performs this exclusion

of SSES 2. Furthermore, while projection of these high rates of O&M growth for very long periods are speculative, they are no more so than PP&L's projection of essentially no real growth.

Q: Does Mr. Kenyon make any useful suggestions?

A: Yes. He notes that O&M expenses vary with refueling schedules, which is probably true. It would be interesting to rerun the regressions with a refueling variable added, and I will do so when time allows. However, since O&M has increased rapidly for units which are more than two or three years old, we may reject Mr. Kenyon's suggestion that much of the time trend in the data is due to the first refueling effect. In addition, many PWR's and some BWR's do refuel in the first full year of commercial operation.

5 - THE REBUTTAL TESTIMONY OF MR. HECHT

Q: What responses do you have to Mr. Hecht's rebuttal?

A: There are nine topics I would like to address related to his testimony. These are

- his confusion of excess capacity and excess costs,
- his unsupported and misleading comments on inter-generational equity,
- his confusions about the time value of money,
- his confusion of unit lifetime cost-effectiveness with current benefits to ratepayers,
- his misrepresentations of my ratemaking recommendations,
- his misleading statements about the reliability value of SSES 2,
- his reliance on Mr. Curtis' unsupported testimony,
- his effective admission that PP&L has overstated the benefits of SSES 2 power, and
- his comments on the importance of other PJM nuclear plant capacity factors on SSES 2 operating savings.

Q: How does Mr. Hecht confuse excess capacity with excess costs?

A: Even if every MW of SSES were needed for reliability, its cost would be excessive unless it had some large economic benefits, and SSES would not be a problem at all if it produced benefits in the next few years comparable to its costs, even if PP&L had a large margin of excess reserves. Mr. Hecht repeatedly confuses excess MW's with excess dollars. This is the basis for his assertion that the system is the problem, not the unit, and that therefore any adjustment must be made on a system basis. The existing system (except for SSES 1) is not the problem: it is the high costs and low short-run benefits of SSES which are the problems, and to which ratemaking must be addressed. The Commission's slice-of-system adjustment for SSES 1 was exceedingly generous to PP&L, and resulted in higher rates for customers in this decade than if Unit 1 had never existed. I see no reason to repeat this treatment: if anything, the Commission's generosity in the SSES 1 case argues for a higher standard in this case.[5]

Q: What are Mr. Hecht's unsupported and misleading comments on inter-generational equity?

A: Mr. Hecht compares the situation of the customers whose rates will be raised for several years by SSES to the customers who paid for the early years of Brunner Island and Montour. However, he does not even claim that rates increased when those units entered service, compared to what rates would have been without the units, let alone demonstrate that the increases (assuming that there were any) were comparable to those caused by SSES. Since PP&L cross-examined me on the relevance of these plants, and their ratemaking, to the ratemaking for SSES 2, Mr. Hecht has had ample time to perform this comparison. It is highly unlikely tha the effect of any unit at either of these plants was comparable to that of SSES 2.

Even assuming that earlier generations of utility customers had suffered higher rates, to produce lower rates in the 1980's, it would not follow that this pattern makes sense or

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5. Mr. Hecht argues on page 4 that all PP&L capacity is equally excess, if any is, and that the system adjustment would therefore be fair. The gas turbines, which can be brought into service in a year or two, and even the fossil steam plants which required a several years from order to operation, would never have resulted in excess capacity on the scale that SSES has, with its long construction period.

is fair. If the sort of rate effects caused by SSES occurred in the past, there is now no way to compensate the customers who suffered in the 1960's (if they did) to produce lower rates in the 1980's, except for those customers who have remained on the system, and are now receiving the benefits of the older plants. Even those surviving customers would be denied full compensation if they were now compelled to pay for SSES 2, to provide lower rates in the next century. Charging much more for SSES 2 now than it is currently worth can only harm present customers for the benefit of future customers.

Mr. Hecht suggests that, if the costs of SSES 2 were spread out to fairly match the benefits from the unit, customers in the next century would have to pay both for SSES 2 and for the next set of units.[6] I see no reason why that should be the case. If and when other units enter service which are (at least for several years) uneconomical and unnecessary, they should be treated in much the same way as I have recommended that SSES 2 be treated. There is no reason for customers in the 1980's to pay higher bills to subsidize lower rates for customers in 2010, and there is no reason for

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6. Mr. Hecht apparently expects all future units to be as uneconomical as SSES when they enter service: this strikes me as an inordinately gloomy view of the world, from a person who is quite optimistic about the often disappointing economics of nuclear generating plants.

customers in 2010 to subsidize those in 2035.

Q: How is Mr. Hecht confused about the time value of money?

A: There are two basic problems. First, Mr. Hecht insists that the after-tax cost of capital is PP&L's cost of money, and that this rate should be used as PP&L's discount rate. As I carefully explained in my direct testimony, and illustrated in Table 4.11, if PP&L ratebases one dollar, rather than expensing it, the additional cost to the ratepayer's is the total cost of capital, plus taxes on the equity portion: the customers must pay both the cost of capital, and the associated taxes, in order to defer consumption by a year. Thus, as measured by Mr. Hecht's approach, the discount rate for PP&L is the total cost of money, plus taxes. Mr. Hecht adds no new analysis to his original incorrect assertion, and certainly does not perform a numerical analysis similar to my Table 4.11, so I can not determine why he is still confused about this point.

Second, Mr. Hecht agrees that consumers do not have the same discount rates as PP&L, and agrees that consumers may well use discount rates similar to those I discuss in determining whether to spend more money now so as to reduce energy costs later (page 19, lines 7 - 13). If the Commission also finds that I have properly estimated consumer discount rates, then the issue of what rates to use in discounting is solved, since PP&L is asking consumers to pay now, so as to save later. Since comparable choices are involved, for the same consumers, the same rates (at least 15%) should be used. Mr. Hecht rejects this suggestion without offerring any intelligible reason for doing so, and throws out the following <u>non sequiteur</u>

> PP&L has to make decisions that represent the balance of customers' interest over time, and in so doing, can't construct a number of small power plants and economically optimize each power plant for each customer that might have a different personal finance situation.

Of course, no one suggested any such thing. Some sort of average consumer discount rate must be used, and my 15% rate is as low as the average could possibly be expected to be. Mr. Hecht has not disputed the Hausman results for the discount rates for residential customers, nor has he suggested the many of PP&L's industrial or commercial customers would accept conservation investments with paybacks of more than six years, as implied by the 15% discount rate, let alone the 10 years suggested by PP&L's proposed 10% discount rate.

Q: How does Mr. Hecht confuse unit lifetime cost-effectiveness with current benefits to ratepayers?

A: Mr. Hecht repeatedly insists that there is no problem, and no special ratemaking is required, if SSES 2 is cost-effective over its lifetime. While that outcome is by no means as certain as Mr. Hecht would have us believe, it is not really the current issue. What the Commission must decide in this case is how much PP&L ratepayers will pay next year: whether or not SSES 2 is cost-effective in 1999, it will certainly not be cost-effective for customer in 1985 under PP&L's rate proposal.

Q: How does Mr. Hecht misrepresent your ratemaking recommendations?

A: First, he asserts that I fail "to recognize that SSES will provide real benefits to PP&L's customers", even though I explicitly recommend that PP&L be allowed to collect base rates equivalent to the current benefits to the customers. Second, as noted above, he claims that I equate excess capacity with the need for a ratemaking adjustment, which is simply untrue. Third, he describes my very modest and reasonable proposal for matching costs and benefits as "arbitrary", even though it addresses the most fundamental issues of equity. Fourth, he claims that I have proposed that "customers . . . receive the benefits of the plant without incurring the associated cost obligation", when I have clearly proposed that customers incur a cost obligation equivalent to the benefits they receive. Fourth, he nonsensically suggests that I have proposed penalizing PP&L "for superior construction and timely completion of SSES": while I have not reviewed SSES construction to determine whether it was in fact superior, it certainly was not timely. In any case, the "penalty" Mr. Hecht refers to would have been less if the plant were less expensive and greater if the plant had been more expensive, so I have proposed an approach which rewards PP&L for not having produced an even larger problem.[7] Finally, he notes that I have not proposed any method for dealing with the costs which PP&L does not recover in the short term, and then continues by alleging that he knows what I would have suggested, had I addressed that issue. Mr. Hecht's presumption is astounding: since I have not addressed this issue, and have not formulated a recommendation, I can not understand how Mr. Hecht supposes he know what I would propose. If he has a suggestion for the Commission, he should make it directly, rather than testifying as to what I would propose. In any case, whether or not the Commission allows subsequent recovery of some or all of the costs which are not collected under a ratemaking approach which matches current rates to current benefits, the rates allowed in this case (or in this decade) would not be affected, and there is no need for the Commission to address

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7. Mr. Hecht also notes that I have not challenged the prudence of PP&L's construction decisions. While he is correct in his observation, it results from the fact that I have not reviewed PP&L's decisions, which is a very time-consuming task if done properly, and should not be taken as an endorsement of PP&L's decisions. No party, including PP&L, has presented a comprehensive review of the construction and capacity planning decisions. I consider this to be an issue which has not been addressed in this case, rather than one which has been decided in favor of the company.

this issue in detail at this time.

Q: How are Mr. Hecht's statements about the reliability value of SSES 2 misleading?

A: Mr. Hecht presents the results of PJM member utility forecasts as the sole support of his contention that PJM will switch to a winter-peaking utility. I discuss in my testimony the reliability of PP&L's load forecasts, and I am sure that the Commission is familiar with the history of errors in other Pennsylvania utilities' load forecasts: Mr. Hect's confusion of these historically unreliable projections with real evidence of a shift to winter peak is inexplicable.

Mr. Hecht's response to my discussion of the reliability value of SSES to PJM is hard to follow, because he again appears to be arguing with statements I did not make. For example, he claims that I asserted that large nuclear units "do not provide meaningful reliability benefits", when I clearly indicated that I expected those benefits to be equivalent to the reliability provided by gas turbines with about 60% of the units' capacity. These are meaningful, and even substantial, benefits (although fairly small in dollar terms compared to the cost of SSES), once the unit is needed for reliability.

Mr. Hecht also appears to spend a lot of time arguing with himself. He first asserts that I am wrong in saying that the maintenance requirements of nuclear units reduce their value to the PJM pool, and then asserts that "all units provide reliability benefits directly in relation to the unit's availability factor," which means that maintenance requirements do matter. Mr. Hecht's assertion that only availability matters is clearly an oversimplification, since in the next paragraph he admits that unit size also matters. For some reason, he asserts that I am wrong in stating that large units provide less reliability to PJM than the level with which PJM credits them in setting utility required reserves. (PJM recognizes size differentials only for units over 1300 MW, which do not exist on the PJM system.) Everything he says on the subject supports the conclusion that large units provide less reliability than small units, per MW, although he is correct that this effect is less pronounced on a large system, such as PJM, than on a smaller system, such as an isolated PP&L.[8]

While Mr. Hecht asserts that the PP&L load forecast incorporates energy/demand relationships, he does not provide any detail about the role of SSES 2 in PP&L's projection of electric price or demand. He does not even provide the price forecast or the elasticities utilized in the load forecast, nor does the description of the forecast model included in the company's direct case (Exhibit JOB 1) provide such information, even though it discusses such less-relevant issues as trends in producer prices. In any case, it is my understanding that the results of PP&L's econometric model were only one input examined by PP&L in determining its "consensus" forecasts in 1984. The results of PP&L's consensus were then increased by 1190 GWH above the consensus to reflect PP&L's Marketing Plan goals for the period 1984-1987. Thus in reality PP&L's forecast is, as it is titled, a "Planned Objective" sales target and not really a forecast at all. Further, even if PP&L properly incorporated the effects of its projections of SSES 2 costs, I expect that traditional ratemaking would

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8. I noted the effect of system size in my testimony.

cause higher rates than PP&L forecasts, due to lower SSES 2 capacity factors and higher costs.

Mr. Hecht complains that, if my ratemaking recommendations are followed, load growth may be higher in the 1980's than PP&L has projected, and that this is somehow unfair to PP&L. Indeed, if load grows faster, PP&L should be entitled sooner to receive a credit for the limited reliability benefits of the plant (about $100 to $200/kW).

Q: How does Mr. Hecht admit that PP&L has overstated the benefits of SSES 2 power?

A: In response to my questions about the costs projected for SSES 2 operating benefits, Mr. Hecht defends those high projections by explaining that PP&L projects that its marginal source of power (if not for PJM interchange) will largely be combustion turbines by 1995. This is a remarkable admission, since these very expensive peakers are not likely to be the least expensive source of replacement power: if PP&L did not have SSES 2, it would probably be able to obtain power at a cost below that of the turbines, from cogenerators under long-term contracts, or from out-of-region purchases.[9]

Q. How are Mr. Hecht's comments on the importance of other PJM

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9. Mr. Hecht addresses this issue as if it indicated that I do not understand interchange pricing, when it really indicates that I was giving PP&L the benefit of the doubt concerning the level of its replacement power costs.

nuclear plant capacity factors on SSES 2 operating savings misleading?

A: First, he suggests that I should have run a two-system production costing model to correct PP&L's projections of capacity factors for other PJM nuclear units. That seems like an inordinate level of effort, considering the robustness of the basic result (SSES 2 will cost ratepayers much more than it saves them until well into the next decade) and the large uncertainties in all of the relevant projections. Second, he claims, without any specific documentation, that the present value of the operating savings from SSES (presumably referring to both units, and PP&L's very low discount rate) would increase by $600 million (since corrected to $900 million) if PP&L's projections of other units' capacity factors were reduced to the same extent that I suggest lowering PP&L's projections for SSES 2. Mr. Hecht does not present the initial or adjusted projections, nor does he explain how he determines the appropriate capacity factors for PWR's and for units much smaller than SSES. It is not clear that PP&L's projected capacity factors for Calvert Cliffs, for example, were even unreasonable. More importantly, the extra $900 million in operating savings would apparently assume even greater dependence on combustion turbines as major energy producers, and is therefore unrealistic. Even if Mr. Hecht was correct, his refinement would have no effect on my conclusions.

6 - THE REBUTTAL TESTIMONY OF MR. KOPPE

Q: What responses do you have to Mr. Koppe's rebuttal?

A: The basic issue here is simple. Mr. Koppe believes that most of the problems of the nuclear industry are behind us, while I am not convinced that this is the case. Mr. Koppe's "evidence" for future improvements lies primarily in his judgements that the basic problems have been solved, that there are not nearly as many problems left to find, and that the previously unreasonable NRC has become more tractable.[10] He may be correct, but many similar claims

about nuclear construction and operation made since the early 1970's (when it was already clear that the projections of the 1960's had been overoptimistic) have proven to be overstated. While the specific problems identified at any point in time may have been largely solved, new ones have repeatedly arisen. While

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10. The change in the NRC's attitude is attributed in part to a "recognition" that nuclear accidents are not as dangerous as previously thought. Mr. Koppe is not very specific about the source of this great revelation, but it appears to be the current industry line, replacing the low-probability argument of the Rasmussen report. It is my understanding that the industry had commissioned a series of studies to "prove" this point, since the low-probability arugment has not been supported by either engineering studies of actual plant operation or by analyses of insurers' implicit probability assessments. It remains to be seen whether this "recognition" does anything more to improve nuclear economics than did the Rasmussen report.

we may hope the Mr. Koppe is right this time, I do not believe that it is fair to expect the current ratepayers to assume all of the risks and costs which will airse if he is wrong.

Q: Are there any specific points to which you wish to respond?

A: Yes. Mr. Koppe describes my capacity factor projection as assuming that SSES 2 will have mature capacity factors equal to those of other large US BWR's in 1980-83. My analysis is much more complex than he suggests, and incorporates data on maturation and post-1980 effects from all US BWR's of more than 400 MW. He also mischaracterizes my description of the post-1980 decrease in nuclear capacity factor: Mr. Koppe suggests that I have attributed this effect to "regulatory requirements resulting from TMI", while I do not ascribe any particular cause to this decline (see pages 46 - 48 of my testimony).[11] He also suggests that I am predicting that exactly the same problems will occur in the future as occurred in the past, despite the fact that I specifically address that point on pages 51 and 52 of my testimony. Mr. Koppe, like the other PP&L witnesses, asserts the new NRC safety requirements have decreased, but offers no

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11. I refer on page 51 to "the regulatory effects of" TMI, but I intended that to mean the general climate of regulatory caution which resulted from the experience at TMI, rather than "lessons-learned" types of effects.

demonstration of such a phenomenon.[12] He suggests that only one serious nuclear accident has taken place (presumably TMI), even though Browns Ferry was also a major accident from a regulatory standpoint, as Mr. Curtis testifies in his rebuttal.[13]

Q: Are Mr. Koppe's criticisms of regression analysis approriate?

A: Not really. The Komanoff studies are very old, and the Rosen and Perl studies assume maturation effects which are not strongly demonstrated by the data. The Perl study also uses very small units and PWR's, and therefore is not comparable to the other analyses, or to mine. It is not suprising that these studies differ in their results, given the differences in their data bases, and in the specification of the maturation effects.

Q: Are Mr. Koppe's comments about the size effect you assume relevant?

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12. A slow-down in regulation has been predicted many times by the nuclear industry, and by the regulators themselves, but costs have continued to increase and capacity factors have continued to lag expectations.

13. Mr. Koppe's estimate of 800 unit-years of operation in the US apparently includes the experience of the very small demonstration reactors, pre-commercial operation, and periods of prolonged shutdown, such as of TMI 1. Observing two significant accidents in 800 reactor-years is consistent with a wide range of underlying probabilities.

A: No. First, he criticizes my use of the the term "strong" to describe size trends in fossil plants, but then reports that he found such trends. By "strong", I mean that a clear, non-random relationship exists, and Mr. Koppe appears to agree. Second, he asserts that I claim a 3% decrease in capacity factor per 100 MW of capacity, compared to the 1% or so that he thinks is reasonable. In fact, the effect of my size variable is swamped by the GT1000 variable, which increases the capacity factor projection for SSES 2 by 14.7%, raising it to about the same level as the projection for a 600 MW BWR. Thus, for the SSES units, my projection uses almost no size trend.

Q: Are Mr. Koppe's comments about the quality of the economic derating data correct?

A: No. Mr. Koppe relies on the representations of the utilities as to the potential ouput of their plants. He has no way of knowing whether the "economic" deratings were actually technical in nature. A good example of this problem is a situation which arose with Trojan (a PWR, and therefore not in my data set for SSES 2 capacity factor) in 1979. The plant shut down for "maintenance, surveillance, and containment leak rate testing" and returned to service 1608 hours later: however, exactly the last 1000 hours of the outage were classified as "economic". I know of no way to confirm that the plant was actually ready to operate in those last 1000 hours.

Q: Are there any other points you would like to emphasis with respect to Mr. Koppe's testimony?

A: He apparently believes that O&M "projections for 1985 and beyond" are inherently valid, despite the dismal record of the nuclear industry in projecting such costs

Q: Does this conclude your rebuttal testimony?

A: Yes.

Attachment 1

Re: Seabrook Unit I
DPU 84-152

AG Request 2-115

Date Received: September 17, 1984
Date Responded: September 26, 1984

AG 2-115 Q. Please provide and document the number of "new regulations requiring additional capital expenditures" (page 7), annually for 1970 to 1984. If this list does not include all AEC/NRC regulations, guides, interpretations, and other regulatory documents, please explain how the relevant documents were identified or selected.

AG 2-115 A. Please see response to CMRR 1-57. Also see the attached schedule for a testing of various NRC releases. This list was compiled by the Yankee Atomic Corporation.

Re: Seabrook Unit 1
DPU 84-152
September 26, 1984
AG Request 2-115
One Page Schedule

## GENERIC LETTERS

| 1977 1/ | 1978 | 1979 | 1980 | 1981 2/ | 1982 | 1983 |
|---|---|---|---|---|---|---|
| 4 | 28 | 56 | 58 | 40 | 39 | 44 |

1. From 12/77.
2. Includes one supplement, one draft, and one letter never issued.

## I&E DOCUMENTS 1/

| | 73 2/ | 74 2/ | 75 | 76 | 77 | 78 | 79 | 80 | 81 | 82 | 83 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Bulletins | 6 | 19 (16) | 11 (8) | 7 | 9 (8) | 15 (14) | 51 (28) | 32 (25) | 5 (3) | 6 (4) | 10 (8) |
| Circulars | | | | 7 | 17 | 19 | 25 | 25 | 15 | 0 | 0 |
| Info. Notices | | | | | | | 38 | 45 | 39 | 56 (3) | 84 |

1. Includes supplements and revisions, number in () indicates originals.
2. Issued as regulatory operations bulletins.

## REGULATORY GUIDES (Division 1) 1/

| 70 | 71 | 72 | 73 | 74 | 75 | 76 | 77 | 78 | 79 | 80 | 81 | 82 | 83 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 4 | 17 | 14 | 34 | 20 | 11 | 17 | 12 | 6 | 2 | 2 | 4 | -- | 1 |

1. Original guide issued calendar year.

Updated thru 1983

presents the least-squares estimates of annual linear growth (in 1983 dollars) and of annual geometric growth rates,[69] and the six-unit average of each parameter. Each unit is analyzed from its first full year of service through 1982.

Q: Have you similarly examined the national history of nuclear O&M?

A: Yes. Appendix C lists the non-fuel O&M for each full operating year from 1968 to the most recent data available. Years in which units were added have been eliminated. Table 3.24 presents the results of five regressions using the data for plants of more than 300 MW, from Appendix C, in 1983 dollars. A total of 413 observations were available. All five equations indicate that real O&M costs have increased at 13.6% to 13.8% annually, and that the economies-of-scale factor for nuclear O&M is about 0.50 to 0.57, so doubling the size of a plant (in Equations 1 and 2) or of a unit (in Equations 3 and 4) increases the O&M cost by about 42-48%. Equations 1 and 2 indicate that, once total plant size has been accounted for, the number of units is inconsequential, and the effect on O&M expense is statistically insignificant: indeed, the two equations disagree on the sign of the small effects they do detect. Equations 3 and 4 both measure size

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69. 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.

as MW per unit, and they both find that the effect of adding a second identical unit is just a little less than the effect of doubling the size of the first unit: 43% for Equation 3 and 39% for Equation 4.[70] Equation 5 tests for extra costs in the Northeast, which are commonly found in studies of nuclear plant construction and operating costs, but is otherwise identical to Equation 3. Indeed, there is a highly significant differential: Northeast plants cost 28% more to operate than other plants (using the definition of North Atlantic from the Handy-Whitman index). This Equation is the most satisfactory of the national regression results.

Q: What O&M cost projection do you use in your Seabrook cost analysis?

A: Table 3.25 extrapolates the New England linear and geometric average trends, and the national regression results evaluated for Seabrook, and displays the annual nominal O & M cost and the levelized O & M cost (in 1984$) for Seabrook over a 25 year life. Protracted geometric growth in real O & M cost would probably lead to retirement of all the nuclear units around the turn of the century, as they would then be prohibitively expensive to operate (unless the alternatives

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70. The two equations do treat extra units differently after the second: a third unit increases costs by another 39% (or 55% of the first-unit cost) in Equation 4, but only by 23% (or 33% of the first-unit cost) in Equation 3. The treatment of additional units in Equation 3 seems more plausible, in that each succeeding unit should be progressively less expensive to run.

managed to be even more expensive).

High costs of O & M and necessary capital additions were responsible for the retirement (formal or de facto) of Indian Point 1, Humboldt Bay, and Dresden 1, after only 12, 13, and 18 years of operation, respectively. Thus, rising costs caught up to most of the small pre-1965 reactors during the 1970's: only Big Rock Point and Yankee Rowe remain from that cohort. The operator of LaCrosse, a small reactor of 1969 vintage, has announced plans to retire it in the late 1980's. San Onofre 1, a 430-mw unit which entered service in 1968, has been shut down since February, 1982, and has no firm plans for restart. To be on the optimistic side, I have assumed a continuation of the linear trends in New England nuclear cost escalation; using the average experience of the existing units would produce 25-year real levelized O&M costs of about $71.8/kw in 1984 dollars. However, since the national regressions indicate clearly that larger units have higher O&M costs than small ones, it is appropriate to increase this cost by 31%, to $94.1/kw-yr to reflect the difference between Seabrook's size and that of the existing New England nuclear units.[71]

Q: Is it appropriate to include the period since 1979, when the

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71. This percentage is the average over the six existing units of the size effect, predicted by Equation 5, for an increase in size from the unit's MGN to the 1194 MGN of Seabrook.

TABLE 3.22: NEW ENGLAND NUCLEAR O & M HISTORIES

| Year | Conn. Yankee | Mill-stone 1 | Mill-stone 2 | Pilgrim | Vermont Yankee | Maine Yankee | GNP Deflator |
|---|---|---|---|---|---|---|---|
| | | | | ($ thousand) | | | |
| 1968 | 2,047 | | | | | | 82.54 |
| 1969 | 2,067 | | | | | | 86.79 |
| 1970 | 4,479 | | | | | | 91.45 |
| 1971 | 3,279 | | | | | | 96.01 |
| 1972 | 3,749 | 7,677 | | | | | 100.00 |
| 1973 | 6,352 | 7,635 | | 4,797 | 4,957 | 4,034 | 105.75 |
| 1974 | 4,935 | 9,808 | | 9,527 | 5,692 | 5,232 | 115.08 |
| 1975 | 9,381 | 12,065 | | 7,340 | 7,682 | 6,301 | 125.79 |
| 1976 | 9,419 | 14,040 | 10,929 | 16,633 | 7,912 | 5,261 | 132.34 |
| 1977 | 9,448 | 12,637 | 17,377 | 15,320 | 9,775 | 8,418 | 140.05 |
| 1978 | 8,736 | 16,448 | 22,288 | 14,187 | 11,191 | 10,817 | 150.42 |
| 1979 | 18,923 | 23,060 | 21,931 | 18,387 | 14,208 | 9,971 | 163.42 |
| 1980 | 35,155 | 24,784 | 30,163 | 27,785 | 22,586 | 14,028 | 178.42 |
| 1981 | 37,488 | 33,270 | 28,877 | 34,994 | 26,795 | 20,576 | 195.14 |
| 1982 | 35,722 | 33,463 | 45,247 | 42,437 | 33,764 | 28,556 | 206.88 |
| 1983 | 48,671 | 43,569 | 56,452 | 46,268 | 46,310 | 21,557 | 215.63 |

Annual Growth Rate to 1983:

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| Nominal: | 23.5% | 17.1% | 26.4% | 25.4% | 25.0% | 18.2% | 4.9% |
| Real: | 15.86% | 9.20% | 17.92% | 16.81% | 16.44% | 10.11% | |

TABLE 3.23: CALCULATION OF AVERAGE NEW ENGLAND EXPERIENCE
Non-Fuel Nuclear O & M Expense, Constant Dollars

| Unit | Period Analyzed | 1983 O & M | Least - Squares Annual Growth: Linear Increase | Least - Squares Annual Growth: Geometric Increase |
|---|---|---|---|---|
| | | (1000) | (1000 1983$) | |
| Conn. Yankee | 1968-83 | $48,671 | $2,726.4 | 15.6% |
| Millstone 1 | 1971-83 | $43,569 | $2,466.3 | 11.7% |
| Millstone 2 | 1976-83 | $56,452 | $4,523.1 | 14.2% |
| Pilgrim | 1973-83 | $46,268 | $3,453.2 | 14.8% |
| Vermont Yankee | 1973-83 | $46,310 | $3,281.3 | 16.2% |
| Maine Yankee | 1973-83 | $21,557 | $1,933.1 | 12.7% |
| AVERAGES: | | | | |
| 1983$ | | $43,805 | $3,063.9 | 14.2% |
| 1984$ [1] | | $45,557 | $3,186.5 | |

Notes: [1] 1984$=1983$*1.04

TABLE 3.24: RESULTS OF REGRESSION ON O&M DATA

| | Equation 1 | | Equation 2 | | Equation 3 | | Equation 4 | | Equation 5 | |
|---|---|---|---|---|---|---|---|---|---|---|
| | Coef | t-stat | Coef | t-stat | Coef | t-stat | Coef | t-stat | Coef | t-stat |
| CONSTANT | -3.76 | -6.88 | -3.48 | -6.92 | -3.76 | -6.88 | -4.14 | -7.77 | -3.90 | -7.49 |
| ln(MW) [2] | 0.56 | 7.86 | 0.50 | 7.33 | -- | -- | -- | -- | -- | -- |
| ln(UNITS) | -0.05 | -0.48 | -- | -- | 0.52 | 10.41 | -- | -- | 0.63 | 12.58 |
| YEAR [3] | 0.13 | 22.45 | 0.13 | 22.60 | 0.13 | 22.45 | 0.13 | 22.78 | 0.13 | 23.93 |
| UNITS | -- | -- | 0.03 | 0.54 | -- | -- | 0.33 | 10.98 | -- | -- |
| ln(MW/unit) | -- | -- | -- | -- | 0.56 | 7.86 | 0.57 | 8.04 | 0.54 | 7.95 |
| NE [4] | -- | -- | -- | -- | -- | -- | -- | -- | 0.25 | 6.69 |
| Adjusted R | | 0.71 | | 0.71 | | 0.71 | | 0.71 | | 0.73 |
| F statistic | | 329.2 | | 329.2 | | 329.2 | | 340.1 | | 284.4 |

Notes: [1] The dependent variable in each equation is ln(non-fuel O&M in 1983$)

[2] MW = number of MegaWatt in Design Electrical Rating (DER)

[3] YEAR = Calendar Year - 1900; e.g., 1985 = 85.

[4] NE is a dummy variable which measures whether the plant is located in the Northeast Region (defined as Handy Whitman's North Atlantic Region), where Susquehanna 2 is located. NE = 1 if located in Northeast Region, 0 if elsewhere.

TABLE 3.25: ANNUAL NON-FUEL O & M EXPENSE FOR SEABROOK ($thousand)
EXTRAPOLATED FROM NEW ENGLAND AND NATIONAL EXPERIENCE

| Year | Linear N.E. Experience | | Geometric N.E. Experience | | National Experience | |
|---|---|---|---|---|---|---|
| | 1984$ | Current$ | 1984$ | Current$ | 1984$ | Current$ |
| | [2] | [4] | [3] | [4] | | |
| 1987 | $58,303 | $69,439 | $77,510 | $92,316 | $75,867 | $88,654 |
| 1988 | $61,489 | $77,628 | $88,524 | $111,760 | $86,344 | $106,950 |
| 1989 | $64,675 | $86,550 | $101,103 | $135,298 | $98,267 | $129,023 |
| 1990 | $67,862 | $96,263 | $115,469 | $163,795 | $111,837 | $155,650 |
| 1991 | $71,048 | $106,830 | $131,877 | $198,294 | $127,281 | $187,772 |
| 1992 | $74,235 | $118,319 | $150,615 | $240,058 | $144,857 | $226,524 |
| 1993 | $77,421 | $130,802 | $172,017 | $290,619 | $164,860 | $273,273 |
| 1994 | $80,608 | $144,356 | $196,460 | $351,829 | $187,626 | $329,670 |
| 1995 | $83,794 | $159,066 | $224,375 | $425,931 | $213,535 | $397,706 |
| 1996 | $86,981 | $175,022 | $256,258 | $515,641 | $243,023 | $479,783 |
| 1997 | $90,167 | $192,320 | $292,671 | $624,245 | $276,582 | $578,798 |
| 1998 | $93,354 | $211,063 | $334,257 | $755,724 | $314,775 | $698,249 |
| 1999 | $96,540 | $231,364 | $381,753 | $914,894 | $358,243 | $842,350 |
| 2000 | $99,726 | $253,340 | $435,998 | $1,107,589 | $407,713 | $1,016,191 |
| 2001 | $102,913 | $277,121 | $497,951 | $1,340,869 | $464,014 | $1,225,909 |
| 2002 | $106,099 | $302,844 | $568,707 | $1,623,283 | $528,090 | $1,478,907 |
| 2003 | $109,286 | $330,655 | $649,517 | $1,965,179 | $601,014 | $1,784,118 |
| 2004 | $112,472 | $360,714 | $741,810 | $2,379,085 | $684,009 | $2,152,318 |
| 2005 | $115,659 | $393,189 | $847,217 | $2,880,167 | $778,464 | $2,596,505 |
| 2006 | $118,845 | $428,263 | $967,601 | $3,486,787 | $885,962 | $3,132,361 |
| 2007 | $122,032 | $466,130 | $1,105,092 | $4,221,174 | $1,008,306 | $3,778,806 |
| 2008 | $125,218 | $507,000 | $1,262,119 | $5,110,237 | $1,147,543 | $4,558,661 |
| 2009 | $128,405 | $551,096 | $1,441,459 | $6,186,555 | $1,306,008 | $5,499,459 |
| 2010 | $131,591 | $598,658 | $1,646,282 | $7,489,566 | $1,486,356 | $6,634,416 |
| 2011 | $134,777 | $649,944 | $1,880,209 | $9,067,017 | $1,691,608 | $8,003,601 |
| 2012 | $137,964 | $705,229 | $2,147,376 | $10,976,711 | $1,925,203 | $9,655,353 |

LEVELIZED

| | | | | | | |
|---|---|---|---|---|---|---|
| 1987-2012: [1] | $82,579 | $151,610 | $332,626 | $657,524 | $309,429 | $598,589 |
| $/kW-yr | $71.8 | $131.8 | $289.2 | $571.8 | $269.1 | $520.5 |

Notes: 1. Approximately the useful life of Seabrook 1.
2. Average New England 1983 nuclear O&M, plus (year-1984) times average annual increase, both in 1984$, from Table 3.23.
3. Average New England 1983 nuclear O&M, in 1984$, times (1 + average geometric increase) ^ (year-1984), from Table 3.23
4. At 6% inflation.