Executive Office of Energy Resources
DPU 89-100
Exhibit ER-PLC-1

COMMONWEALTH OF MASSACHUSETTS
BEFORE THE DEPARTMENT OF PUBLIC UTILITIES

DIRECT TESTIMONY OF

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and

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ON BEHALF OF THE

MASSACHUSETTS EXECUTIVE OFFICE OF ENERGY RESOURCES

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TABLE OF CONTENTS

1 EXECUTIVE SUMMARY AND QUALIFICATIONS 1
1.1 Qualifications 1
1.2 Executive Summary 4

2 STANDARDS AND TESTS 7
2.1 Prudence Standard 7
2.2 Hahn's Test 8
2.3 A Threshold Prudence Test 10

3 RESULTS AND CONCLUSIONS 13
3.1 What BECO Knew or Should Have Known 13
3.2 Economic Comparisons 15
3.2.1 Comparisons with 1989 Information 15
3.2.2 Comparisons with 1986 Information 18
3.2.3 The Effect of Pilgrim's Sunk Cost on the Analysis 21a
3.3 Conclusions 22

4 INPUTS TO PILGRIM PRUDENCE REVIEW 23
4.1 Capacity Factor 23
4.1.1 Capacity Factor Projections from Pilgrim Experience 23
4.1.2 Capacity Factor Projections from National Experience 24
4.1.3 Boston Edison's Capacity Factor Projections 26
4.2 Operation and Maintenance Expenses 35
4.2.1 O&M Projections from Pilgrim Experience 35
4.2.2 O&M Projections from National Experience 35
4.2.3 Boston Edison O&M Projections 37
4.3 Capital Additions 39
4.3.1 Capital Additions Projections from Pilgrim Experience 41
4.3.2 Capital Additions Projections from National Experience 43
4.3.3 Boston Edison Capital Addition Projections 44
4.4 Overheads and Insurance 45
4.4.1 BECO Estimates for this Case 45
4.4.2 Other Plant Experience 46
4.5 Decommissioning Costs 48
4.5.1 Manion Estimates 48
4.5.2 Analysis of Manion's Estimates 49
4.6 Useful Plant Life 65
4.7 Replacement Power Costs 68
4.8 Tax Effect of Abandonment 88
4.8.1 As of 1986 88
4.8.2 As of 1989 89

5 BIBLIOGRAPHY 91

1 EXECUTIVE SUMMARY AND QUALIFICATIONS

1.1 Qualifications

Q: Mr. Chernick, please state your name, occupation and business address.

A: My name is Paul L. Chernick. I am President of PLC, Inc., 18 Tremont Street, Suite 703, 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 the evaluation of power supply options.

As a Research Associate at Analysis and Inference, and in my current position, I have advised a variety of clients on utility matters. My work has considered, among other things, the need for, cost of, and cost-effectiveness of prospective new generation plants and transmission lines; retrospective review of generation planning decisions; ratemaking for plant under construction; and ratemaking for excess and/or uneconomical plant entering service. My resume is attached to this testimony as Exhibit ER-PLC-2.

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

A: Yes. I have testified approximately sixty times on utility issues before various regulatory, legislative, and judicial bodies, including the Massachusetts Department of Public Utilities, the Massachusetts Energy Facilities Siting Council, the Illinois Commerce Commission, the Texas Public Utilities Commission, the New Mexico Public Service Commission, the District of Columbia Public Service Commission, the New Hampshire Public Utilities Commission, the Connecticut Department of Public Utility Control, the Michigan Public Service Commission, the Maine Public Utilities Commission, the Vermont Public Service Board, the Minnesota Public Utilities Commission, the Federal Energy Regulatory Commission, and the Atomic Safety and Licensing Board of the U.S. Nuclear Regulatory Commission. A detailed list of my previous testimony is contained in my resume. Subjects I have testified on include nuclear power plant construction costs and schedules, nuclear power plant operating costs, power plant phase-in procedures, the funding of nuclear decommissioning, cost allocation, rate design, long range energy and demand forecasts, utility supply planning decisions, conservation costs and potential effectiveness, generation system reliability, fuel efficiency standards, and ratemaking for utility production investments and conservation programs.

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

A: Yes. I have authored a number of publications on rate design, cost allocations, power plant cost recovery, conservation program design and cost-benefit analysis, and other ratemaking issues. These publications are listed in my resume.

Q: Mr. Chernick, for which portions of this testimony are you primarily responsible?

A: I am primarily responsible for the conclusions presented in the text of the testimony. The underlying analyses were preformed by me, or under my direction and control.

Q: Mr. Wallach, please state your name, occupation and business address.

A: My name is Jonathan Wallach. I am a Senior Analyst at Komanoff Energy Associates, 270 Lafayette Street, Suite 400, New York, NY.

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

A: I received a B.A. degree from the University of California at Berkeley in January, 1981 from the Political Science Department.

As a research assistant at Energy Systems Research Group, an independent consultant, and in my current position at Komanoff Energy Associates (KEA), I have been responsible for a number of analyses of electric utility power supply planning. My work for the last eight years has included assessment of generating plant cost and performance, analysis of supply system excess capacity and reliability, and evaluation of required revenue impacts of, and ratemaking treatment for, completed and cancelled generating projects. My resume is attached to this testimony as Exhibit ER-PLC-3.

Q: Mr. Wallach, would you please briefly describe the services provided by KEA in the field of supply-side resource planning?

A: KEA consulting services employ comprehensive power-plant databases, sophisticated computer models, and strategic planning capability to quantitatively assess costs and benefits of supply-side utility resources. Since its founding in 1977, KEA has advised an array of governmental and private clients on the economic consequences of building, operating and refurbishing nuclear and fossil generating facilities.

KEA's nuclear and coal plant databases, comprising extensive annual cost and performance data for commercial nuclear and coal plants, are the foundation for much of KEA's research and consulting activities. The databases are updated annually and subject to comprehensive statistical analysis to evaluate industry-wide cost and performance trends.

My resume is attached to this testimony as Exhibit ER-PLC-3.

1.2 Executive Summary

Q: What is the purpose of this testimony?

A: The purpose of this testimony is to review the prudence of the actions of Boston Edison Company (BECO) in its decision to spend $300 to $400 million on returning the Pilgrim nuclear power plant to service, following the outage which started in April 1986 and continues (in most respects) to the current date.

Q: What are the major conclusions of your analysis?

A: Under all reasonable combinations of input assumptions, BECO's decision to return Pilgrim to service was not cost-effective for ratepayers. Ratepayers would have been better off if Pilgrim had been retired in 1986, even if they continued to pay for all the sunk costs of Pilgrim as of that time.

Under most of the range of reasonable assumptions, ratepayers would be better off if Pilgrim were retired today, even given the expenditures BECO has sunk into the plant over the last three years.

Given these facts, BECO's decisions to expend hundreds of millions of dollars on Pilgrim since 1986 were imprudent. BECO's failure to perform the analyses which would have identified the imprudence of continued Pilgrim investments was itself imprudent.

The margin by which Pilgrim operation is uneconomic is so large that it would have been imprudent to make a substantial investment in rehabilitating the plant, even if the amount spent was much smaller than the $350 million or so that BECO actually spent. Thus, BECO's imprudence is essentially independent of when and to what extent BECO should have foreseen the magnitude of the outage expenditures.

Q: How is the remainder of this testimony structured?

A: Section 2 of this testimony discusses the standards used in this analysis and in Mr. Hahn's analysis for BECO. Section 3 presents the results of our comparisons of the costs and benefits of continued Pilgrim operation. Section 4 explains the derivation of the input values used in the analyses in Section 3. The KEA estimates of nuclear performance from national experience are documented in Exhibit ER-PLC-4. The Tables referenced in this testimony are compiled in Exhibit ER-PLC-5.

In this testimony, we will refer to BECO's responses to Energy Office information requests as BECO IR EOER-xx, those to MASSPIRG information requests as BECO IR MP-xx-xx, those to Attorney General information requests as BECO IR AG-xx-xx, and those to DPU information requests as BECO IR DPU-xx, where the "xx" represents the number of the question and/or the set of questions.

2 STANDARDS AND TESTS

2.1 Prudence Standard

Q: What standard have you applied in analyzing BECO'S decision to make the expenditures necessary to return Pilgrim to service?

A: We have applied a prudence standard. The question we have asked is "Given the information which BECO knew or should have known at various times since April 1986, should BECO have made the expenditures necessary to return Pilgrim to service?" We have addressed this question in terms of whether the decision to continue investing in Pilgrim would have reasonably been expected to produce the lowest present value of revenue requirements for BECO ratepayers.

Q: Have you answered this question for each point in time from 1986 to the present?

A: No. To simplify the analysis, we have limited our perspectives to information available at two points in time: early 1986, and today. This approach allows us to ask whether BECO would have been prudent in:

- investing $300-400 million in Pilgrim, given what was known in 1986,
- investing $300-400 million in Pilgrim, if BECO could foresee the (sometimes more favorable, sometimes less favorable) information on nuclear power plant performance and replacement power costs available today, and
- starting up Pilgrim today, now that the $300-400 million has been invested.

We also examine the economics of Pilgrim operation under a variety of assumptions regarding Pilgrim's future operating characteristics, ranging from a continuation of Pilgrim's past behavior to performance typical of similar units nationally.

2.2 Hahn's Test

Q: What test does Mr. Hahn apply?

A: Mr. Hahn purports to apply a used-and-useful test to Pilgrim. However, Mr. Hahn does not include all of Pilgrim's costs in determining whether the plant is cost-effective, and hence economically useful. Instead, Mr. Hahn includes only a portion of the costs incurred during the outage, as well as operating costs from 1989 onward. He omits all sunk costs as of the beginning of the outage, as well as some costs incurred during the outage.

Q: Is this a meaningful used-and-useful test?

A: No. Consider how Mr. Hahn's economic usefulness test, which ignores all previously sunk Pilgrim costs and asks whether the plant would be cost-effective if investments in 1986 were the first investments, would translate into a test of physical usefulness, or capacity need. The physical usefulness version of Mr. Hahn's test would ignore all previously built (sunk and approved) capacity and simply ask whether this new unit would be needed in the absence of all other capacity. This is a pointless test, which would be difficult for any new plant to fail.

An economic used-and-useful analysis for a power plant <u>must</u> consider the entire cost of the plant. Mr. Hahn's approach tells us nothing about whether Pilgrim is cost-effective for the ratepayers. If Mr. Hahn wants to determine whether Pilgrim is worth what the ratepayers are being asked to pay for it, he must compare all of the benefits to all of the costs. If he were examining the economic usefulness of an incremental investment (such as a more efficient turbine), he could compare the incremental investment to the incremental benefits of the investment (such as the increased generation from the more efficient turbine). Mr. Hahn incorrectly includes all the benefits of Pilgrim, but only a portion of the costs.

Q: Does Mr. Hahn's test mean anything?

A: Mr. Hahn's test is a rough version of a prudence test. Essentially, Mr. Hahn asks whether the future benefits of Pilgrim operation are likely to exceed the costs of rehabilitating Pilgrim over the last three years, plus the costs of running the plant in the future. This would be an appropriate test of BECO's prudence in making the investment, if the assumptions used in the analysis were reasonable.

Mr. Hahn's test could also be seen as a used-and-useful test for a new plant, which we might call Pilgrim 1B. If the existing plant as of 1986 (Pilgrim 1A) were retired for ratemaking purposes, the usefulness of the investment and expenses related to the new plant could be evaluated with a test similar to the one Mr. Hahn proposed.[1] This test would only be relevant if BECO proposed (or were ordered) to write off all Pilgrim investments as of the time the outage started.

2.3 <u>A Threshold Prudence Test</u>

Q: Ideally, how would you set out to review the prudence of a utility's decision to make a major investment to keep a generating unit in service?

A: We would start by examining the decision-making process which led to the investment. We would examine the cost-effectiveness analyses the utility produced, to determine whether the conclusions of those analyses support the decision to make the investment. Assuming that the studies do support the investment, we would determine whether the basic form of those analyses was appropriate and whether they reflected the important choices faced by the utility. We would also review the important input values for the analyses and determine whether the results of the studies would change significantly under other reasonable assumptions.

Q: Have you performed these analyses for BECO's decision to bring Pilgrim back on line?

A: No. It is our understanding from BECO IR MP 3-1 that BECO did not perform any detailed, comprehensive study of this sort, to guide its decisions regarding the hundreds of millions of

[1]The treatment of decommissioning would have to be changed somewhat.

dollars it spent on Pilgrim from 1986 to 1989.[2] The closest BECO has come to preparing a study of Pilgrim's viability is the analysis contained in Mr. Hahn's testimony, which claims to be a used-and-useful analysis, rather than a decision tool. In fact, BECO seems to have never seriously considered whether continuing to spend money on Pilgrim was prudent or cost-effective. Therefore, we have no BECO decision documents to review.

Q: Was BECO prudent in proceeding with a project of this magnitude without performing any analysis of the economics of its decision?

A: We think the answer is clearly "No." The DPU has explicitly placed utilities under an obligation to perform these analyses, in Re Fitchburg Gas and Electric Light Company, DPU 1270/1414, pp. 107-108 (1983).[3] The DPU required that

> As a general matter, a utility company has a continuing obligation to monitor, review, and assess its participation in a specific power supply project. Such an evaluation should occur in within the context of the company's general power supply planning process. (Id.)

The DPU then specified five types of analyses that the utility is expected to perform. Slightly paraphrased, these include:

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[2]Indeed, BECO states that it had no projection of Pilgrim O&M, capital additions, or capacity factors as of January 1, 1986 (BECO IR EOER-28, 29, and 30). Hence, BECO was not even prepared to perform these analyses, as it headed into the outage.

[3]This language was cited with approval, and re-affirmed, in Re Western Massachusetts Electric Company, DPU 85-270, p. 22 (1986).

1. the likelihood of the project's coming on line on schedule and on budget,
2. the options available if the project does not operate as scheduled and as budgeted,
3. the feasibility and costs of alternatives,
4. the project's financial effect on the utility, and
5. the effect of the project on the utility's ratepayers.

Q: In your opinion, are these reasonable regulatory requirements?

A: Yes. They are required by common sense and good business practice, as well as by the utility's duties to its shareholders and ratepayers.

Q: Has BECO complied with any or all of these five requirements?

A: So far as we have been able to determine, BECO has not presented any evidence in this case which indicates compliance with any of these requirements.

3 RESULTS AND CONCLUSIONS

3.1 <u>What BECO Knew or Should Have Known</u>

Q: What should BECO have known about the economics of Pilgrim, before the outage?

A: BECO should have recognized that:

- O&M costs at Pilgrim and other nuclear units had been consistently rising faster than inflation over the entire history of the industry,
- capital additions at Pilgrim and other nuclear plants had been very high, especially in the 1980s,
- capacity factors for Pilgrim and other nuclear plants had consistently failed to reach original expectations, and that Pilgrim had been a particularly poor performer, and
- given recent levels and trends in Pilgrim performance, continued operation of Pilgrim was either already uneconomic, or could easily become uneconomic.

Q: What effect should this information have exerted on BECO, prior to the outage?

A: BECO should have been prepared to carefully assess the cost-effectiveness of any major investment in Pilgrim. BECO should have readied the necessary information-gathering and analytical support, so that such assessments could have been performed quickly and efficiently, when the need arose. Independent of specific decision points, BECO should periodically have conducted comprehensive assessments of Pilgrim economics.[4]

Q: How should BECO have acted at the beginning of the outage, in light of this knowledge, and with the preparation you have described?

A: BECO should have started critically assessing the cost-effectiveness of Pilgrim operation as soon as it had any indication that the outage might be lengthy and expensive. Such an analysis would have provided an upper bound, or a range, for the amount of money that might reasonably be spent on Pilgrim.

Q: What would such a study have determined?

A: Using reasonable assumptions, the study would have indicated that substantial investments in Pilgrim would not be cost-effective, and that closing the plant was preferable to any major effort to rehabilitate it.

Q: Would the results of the analysis have been very different if it were performed later in the outage?

A: The numerical results would be somewhat different. Assuming the use of reasonable inputs, the conclusion would have been the same: that no substantial investment in Pilgrim was likely

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[4]This is essentially the course of action urged by Mr. Skowronski of BECO in his 10/9/85 memo, provided as part of BECO IR MP 3-1. Had BECO taken Mr. Skowronski's advice, and also extended his analysis to reflect realistic capacity factors and replacement power sources, BECO would have been well positioned to make an intelligent decision regarding the fate of Pilgrim.

to be cost-effective, and that retirement was preferable to continued operation.

3.2 Economic Comparisons

Q: How did you reach your conclusions regarding the economics and prudence of continued Pilgrim operation?

A: We performed a number of economic comparisons of Pilgrim costs to replacement power costs, for a variety of assumptions. We performed some of these analyses with data available at or near the beginning of the outage (i.e., 1986-vintage data), and others with data available currently (i.e., 1989-vintage data).

3.2.1 Comparisons with 1989 Information

Q: How did you compare Pilgrim operation and retirement, for 1989 data?

A: We used Mr. Hahn's cost model for Pilgrim, as presented in Exhibit BE-RSH-4, BE-RSH-5, BE-RSH-7.[5]

Q: For what cases did you analyze the economics of Pilgrim, circa 1989?

A: Table 3.2.3 shows what we have called the "BECO" case, which reproduces the results Mr. Hahn presents in his testimony, except for a correction to the level of capital additions

[5] All references to Mr. Hahn's testimony are to the revised version filed on June 21, 1989.

during the outage.[6] Table 3.2.4 shows the "National" case, which is primarily based on projections from national experience. Table 3.2.5 shows the "Pilgrim" case, which assumes the continuation of Pilgrim historical performance. Both the National and Pilgrim cases use estimates of overhead expense, replacement power, and early decommissioning costs that differ from the estimates BECO uses.

Q: What was the source of inputs for your various 1989 cases?

A: The BECO case is taken directly from Mr. Hahn's testimony, except for a correction to the level of capital additions during the outage. The national projections of capacity factor, operations and maintenance expenses and capital additions come from Komanoff Energy Associates regressions on national data. These inputs are discussed in more detail in Section 4 of this testimony and in ER PLC-4. Projections of Pilgrim's historical experience in capacity factor, O&M and capital addition are performed in Tables 4.1.1, 4.2.2, and 4.3.2 respectively. In the national and the Pilgrim cases Administrative and General expenses are calculated by taking a percentage of O&M and subtracting insurance costs from the percentage. The percentage of O&M is based on an analysis of

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[6] In BE-RSH-7, Hahn calculates a present value benefit of continued Pilgrim operation of $402 million, when we perform the same analysis using Hahn's figure for the capital additions during the outage we calculate a present value benefit of continued operation of $408 million. The difference is less than 2% of the total figure and is probably the result of round-off. In any case, the direction of the change is in Pilgrim's favor.

the Yankee plant overheads which is performed in Table 4.4.1. Replacement power costs are assumed to be equal to the cents/kwh rate calculated in BECO's April 14, 1989 QF-RFP. We also assume that early decommissioning costs are the same as late decommissioning costs. The inputs are cited in more detail in the notes to the tables.

Q: What are the results of these 1989 cases?

A: In the BECO case, operating Pilgrim is $350 million less expensive in 1989 present-value terms than retiring the unit. In the Pilgrim case, operating Pilgrim costs $2,501 million <u>more</u> than retirement. In the more optimistic National case, Pilgrim operation still costs $1,127 million more than retirement.

Q: Have you determined how much each cost input or other parameter contributes to the cost-effectiveness results in your 1989 analyses?

A: Yes. This information is shown in Table 3.2.1.

Q: What are the critical assumptions which produce the net savings from Pilgrim operation in the BECO case?

A: The most important assumptions are (1) that early decommissioning will cost over three times as much as late decommissioning; (2) that Pilgrim can maintain low capital additions and a capacity factor of 68%, even as it ages; and (3) that Pilgrim would be replaced by an inefficient mix of power sources. The decommissioning assumption adds $207 million to the estimated present value benefits of Pilgrim operation. The capacity factor assumption adds another $330 million to the estimated savings from operation, compared to the most optimistic of the capacity factors we have derived from historical experience. The replacement power assumption increases estimated savings by $238 million in present value terms, compared to the replacement power costs used in both the national and the Pilgrim cases.

Q: What combinations of changes in those assumptions would cause the continued operation of Pilgrim to become uneconomical?

A: Pilgrim operation would no longer appear to be cost-effective, if BECO had made any of the following changes in its assumptions:

- used any one of the three alternative capital additions projections,
- used O&M based on Pilgrim's historical experience,
- used capacity factors based on Pilgrim's historical experience, or
- used optimistic national capacity factor projections in combination even a slight change in another assumption, such as early decommissioning costs.

3.2.2 Comparisons with 1986 Information

Q: How did you compare Pilgrim operation and retirement, for 1986 data?

A: We used Mr. Hahn's cost model for Pilgrim, as presented in Exhibits BE-RSH-4, BE-RSH-5, BE-RSH-6 and BE-RSH-7. We ignore all costs in 1986-88, except for the capital additions and the deferred O&M, both of which would be recovered in 1989 and beyond.

Q: Exhibit BE-RSH-7 uses 1989 assumptions for the cost of capital, discount rate, and tax rates and rules. Are these assumptions relevant to a 1986 analysis?

A: In principle, we should have redone the entire analysis with 1986 inputs. However, the differences between 1986 and 1989 are not generally material. In BECO IR EOER-82, BECO repeats the analysis in Exhibit BE-RSH-7 for the tax rates and rules in effect in 1986, and shows an increase in the present value of BECO's retail share of Pilgrim costs of $17.7 million, or 3.7% of the return and taxes on capital additions. This small effect can be added to the corresponding figures for all 1986-based runs, but it will not generally be crucial.

Costs of capital have also not changed radically since 1986. In a June 8, 1987 analysis of Pilgrim economics, BECO used a 10.33% cost of capital, while Mr. Hahn uses 10.88%. We use the 10.33% to calculate return and the present values in the 1986 cases.

Q: For what cases did you analyze the economics of Pilgrim, circa 1986?

A: Table 3.2.7 shows what we have called the "BECO" case, which attempts to reproduce the results BECO would have derived had it performed this analysis in 1986, given its assumptions at the time. Table 3.2.8 shows a "National Experience" case and

Table 3.2.9 shows a "Pilgrim" case which is based on Pilgrim's historical experience through the end of 1985.

Q: What was the source of inputs for your 1986 BECO case?

A: In the 1986 BECO case capital additions, materials and supplies, nuclear fuel inventory, operation and maintenance expenses, insurance, late decommissioning, capacity factors and Pilgrim fuel costs come from Carl Gustin's June 8, 1987 letter to Sharon Pollard (BECO IR MP-3-1). For replacement power costs we used the avoided costs from BECO's November 21, 1986 QF RFP. The inputs are cited in more detail in the notes to the tables.

Q: What were the sources of inputs for the other 1986 cases?

A: The inputs to the "Pilgrim" case are described in Section 4 of this testimony. They represent the historical experience of Pilgrim (for capacity factor, non-fuel O&M, and capital additions), historical values from the Yankee plants for overhead expenses, and replacement power costs from BECO's November 21, 1986 QF RFP. The inputs to the "KEA" cases represent KEA's projections of national experience for capacity factor, non-fuel O&M, and capital additions for a typical nuclear unit of Pilgrim's characteristics. We use KEA's optimistic projection of capacity factors. Other inputs are the same as in the "Pilgrim" cases.[7]

Q: What are the results of these 1986 cases?

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[7] We use BECO assumptions for financing costs, discount rates, and nuclear fuel throughout the analysis.

A: In the BECO case, operating Pilgrim is $355 million less expensive in 1989 present-value terms than retiring the unit. In the Pilgrim case, operating Pilgrim costs $1,381 million <u>more</u> than retirement. In the KEA case, Pilgrim operation costs $1544 million more than retirement.

Q: Is it possible to determine how much each cost input or other parameter contributes to the cost-effectiveness results in your analyses?

A: Yes. This information is shown in Table 3.2.2.

Q: What are the critical assumptions which produce the net savings from Pilgrim operation in the BECO case?

A: The most important assumptions are that Pilgrim's capacity factor will be 70% and that capital additions will decrease in constant dollar terms over the remaining life of the plant. The capacity factor assumption increases savings by $569 million in present value terms, compared to the most optimistic of the capacity factors we have derived from historical experience. The capital additions assumption increases savings by $598 million in present value terms, from projections based on Pilgrim's historical experience.

Pilgrim operation would no longer have appeared to be cost-effective, if BECO had used capital additions projections experience based on national experience or the more optimistic Pilgrim based projections; or if BECO had assumed capacity factor projections based on Pilgrim's historical or national experience.

3.2.3 The Effect of Pilgrim's Sunk Costs on the Analysis

Q: Are some of the Pilgrim costs you included in your analyses in the previous section now sunk and unavoidable?

A: Yes. The capital additions and deferred O&M from the outage are now sunk costs, as are a portion of costs for 1989. The decommissioning costs are also sunk, but our treatment of these costs recognizes that some form of decommissioning will be necessary regardless of when Pilgrim is retired.

Q: Do these sunk costs affect the prudence of any decisions?

A: Yes. The computations in the preceding two sections considered whether repairing Pilgrim over the last few years, so that it could be operated in the future, was cost-effective and prudent. Now that the repair process is largely complete, and Pilgrim is operating in a prolonged start-up process, BECO's choices are limited to running or retiring the plant. The sunk costs should be excluded from analyses of decisions to be made today or in the future.

Q: How large are these sunk costs?

A: Table 3.2.11 computes the $316 million present value of the revenue requirements from the sunk costs, defined as the O&M amortization and the capital additions during 1986-88. We have not included the operating expenses (O&M, overhead, insurance and fuel) in 1989, for three reasons:

1. it is not clear what portion of 1989 should be included,

2. the 1989 operating costs vary with the assumptions used, and

3. the 1989 operating costs are partially offset by the 1989 fuel savings, which are also sunk.[7]

The 1989 operating costs and savings (or any portion thereof) can be included, if a full accounting of sunk costs to a particular date is desired.

Q: How does the present value of the sunk costs affect the prudence of continued operation of Pilgrim, from today's perspective?

A: Now that the capital additions and O&M are sunk, Edison's potential savings from retiring Pilgrim are reduced by $316 million. If some combination of inputs in the preceding sections indicates a net present-value loss from Pilgrim of more than $316 million, that would imply that total costs from today forward would be lower if Pilgrim were not returned to service. This would also imply that none of the investments made in Pilgrim since 1986 were prudent or economically useful.

If another combination of inputs produces a present-value loss from Pilgrim operation of less than $316 million (but more than zero), continued operation from today forward would appear to be economically viable. However, the investments since 1986 would still be imprudent.

[7]For the most part, these savings never actually occurred, due to Pilgrim's failure to return to full commercial operation to date.

Depending on the magnitude of the net present-value loss, and the anticipated value of the annual losses in the next few years, the most reasonable course of future action with respect to Pilgrim operation might be to run the plant until (1) another major addition is required, or (2) increases in operating costs and development of alternatives renders further operation clearly uneconomic. If BECO does return Pilgrim to service, it should very carefully monitor and project Pilgrim's operating costs on a continuous basis, and should be prepared to abandon the plant expeditiously.

Q: How does the present value of the sunk costs affect the prudence of continued operation of Pilgrim, at various points during the outage?

A: The fact that the present value of the sunk costs is less than the present value of the loss from operating Pilgrim implies that BECO need not have anticipated the full eventual cost of returning Pilgrim to service, in order to decide that Pilgrim was not cost-effective. Had BECO anticipated only the $200 million in additions it projected in its 10/17/86 forecast for COMM/ELEC (O'Donnell letter, BECO IR MP 1-47), or even some much smaller number, it still would have been imprudent to proceed with those expenditures.

3.3 <u>Conclusions</u>

Q: Please summarize your conclusions regarding the economics and prudence of Pilgrim repair and restart in the period 1986-89.

A: Spending the $300-400 million BECO spent on Pilgrim repair and restart was uneconomical and imprudent. The same would be true of the bulk of O&M expenses in the outage period, continuing at least to the end of June 1989.

4 INPUTS TO PILGRIM PRUDENCE REVIEW

Q: What inputs did you project for your analyses?

A: The analyses required estimates of Pilgrim's

- capacity factor,
- non-fuel operation and maintenance (O&M) expenses,
- capital additions,
- overheads (BECO's categories of Administrative & General and Insurance),
- decommissioning, and
- useful life,

as well as replacement power costs and the tax effects of retiring Pilgrim. In addition to the inputs which we have estimated, we have used BECO assumptions regarding costs of capital, materials and supplies, discount rates, and nuclear fuel costs.

4.1 Capacity Factor

4.1.1 Capacity Factor Projections from Pilgrim Experience

Q: How did you project Pilgrim capacity factors from historical experience?

A: Table 4.1.1 shows Pilgrim's capacity factors in each year of operation, averages over various periods, as well as Pilgrim's cumulative lifetime capacity factor as of 12/31/85 and 12/31/88. Throughout this analysis, we use a 670 MW rating for Pilgrim. As of the end of March 1989 (the most recent data available from the NRC), Pilgrim's cumulative capacity factor was 45.7%. We use Pilgrim's capacity factor through the end of 1985 (55.6%) for the 1986 analysis and the capacity factor through the end of 1988 (46.3%) for the 1989 analysis.

Q: Has the DPU established any precedents on the use of historical nuclear capacity factors?

A: Yes. In DPU 88-83, on BECO's RFP #2 and QF bidding ceiling rates, the DPU rejected the 73.4% capacity factor proposed by BECO, ordered BECO to use a capacity factor of 54% as "consistent with the cumulative historical capacity factor of the plant," and described the historical evidence as "more compelling" than "what the Company predicts for the future." In DPU 88-19, reviewing a proposed WMECO contract with a QF, the DPU rejected the calculation of future nuclear capacity factors by reference to other plants, and selected the "actual historical performance" of the subject nuclear units as the most reasonable estimate of future performance by the units.[8]

Thus, DPU precedent appears to strongly favor, and perhaps to require, that nuclear power plant capacity factors be projected at historical values for the particular unit.

4.1.2 Capacity Factor Projections from National Experience

[8]The order in DPU 88-19 may also establish the precedent that the best predictor for a new nuclear unit is the historical capacity factor of the existing nuclear units operated by the utility.

Q: How did you project Pilgrim capacity factors from national experience?

A: This projection is based on a statistical analysis of national nuclear power plant operating experience. Various factors were identified which explain year-to-year and plant-to-plant variations in capacity factors. Performing a multi-variate linear regression on these explanatory variables and national capacity factor data yields an equation which, when specified for Pilgrim's characteristics, predicts annual capacity factors. The analysis was performed twice: once for the data available at the beginning of 1986 and again for the data available at the beginning of 1989. The calculation is explained in greater detail in Section 3 of ER PLC-4.

Q: What are the results of this analysis?

A: The results of this analysis are summarized in Table 4.1.2. We use the "optimistic" projections in our analysis of Pilgrim's economics based on national historical experience. These projections assume that Pilgrim is new as of 1989 but that BECO benefits from its 17 years of nuclear operating experience. Thus, all aging effects (including those related to salt-water cooling) are reset to age 1. In the 1989 case this capacity factor averages 55%. In the 1986 case it averages 49%.

Q: Do the capacity factor results have any bearing on the remaining useful life of Pilgrim, if it is returned to service?

A: Yes. The aging trends raise substantial questions regarding the ability of Pilgrim to function through 2012, as projected by BECO. If Pilgrim is returned to service this year, but continues the aging process experienced by older nuclear plants on a national level, it would be expected to reach 0 capacity factor in 1999 (for the 1986 equation) or 2002 (for the 1989 equation). Given the low capacity factors in its later years, and the gradually rising O&M and capital additions, even earlier retirement would be likely. If the aging clocks have been reset by the work done during the outage, but BECO retains the advantage of its experience in operating Pilgrim in its early years, expected capacity factors would stay above 0 throughout the remainder of the operating life BECO predicts for the plant (that is, to 2012). However, the low capacity factors in the last several years of its projected life, combined with increasing O&M and capital additions, could lead to an earlier shutdown.

4.1.3 Boston Edison's Capacity Factor Projections

Q: What is the basis of BECO's capacity factor projections?

A: BECO's capacity factor projections are taken from the testimony of Mr. Koppe.

Q: Have you reviewed Mr. Koppe's testimony with regard to his projection of Pilgrim capacity factor?

A: Yes.

Q: Please summarize your assessment of Mr. Koppe's analysis.

A: Mr. Koppe's analysis of historical U.S. nuclear plant capacity factor performance suffers from a reliance on limited comparisons of plant averages to assess industry experience. His use of group averages to evaluate performance trends fails to reveal the underlying factors affecting plant performance and thus lacks explanatory power. In addition, Mr. Koppe's projections of Pilgrim capacity factor reflect a very optimistic view of future plant performance which is inconsistent with historical performance. Overall, we do not feel that Mr. Koppe's analysis justifies an assumption of 68 percent long-term capacity factor for Pilgrim.

Q: How does Mr. Koppe use plant averages to evaluate industry capacity factor experience?

A: Mr. Koppe analyzes industry experience by compiling simple averages of plant performance for a subset of plants he designates as "peers" of the Pilgrim plant. His peer group encompasses performance experience for boiling-water reactors (BWR) completed before 1979 of similar size to the Pilgrim reactor. Koppe calculates the peer group's average capacity factor for the periods 1980-85 and 1986-88 and, with the aid of S.M. Stoller's OPEC-2 database, analyzes the sources of average capacity factor loss for the two time periods.

Mr. Koppe finds from his evaluation of peer group averages that performance appears to have dramatically improved during the 1980s, with average capacity factor increasing from 58 percent in the 1980-85 period to 67 percent in the 1986-88 period. In addition, he finds that average capacity factors for the peer group have been increasing steadily throughout the 1986-88 period, peaking at 70 percent in 1988.

Q: How does Mr. Koppe make use of his peer group averages to project Pilgrim capacity factors?

A: Mr. Koppe's estimate of future Pilgrim performance incorporates several findings and assumptions with regard to peer group average performance and the relationship between the peer group and Pilgrim. First, Koppe's analysis of the root causes of peer group plant outages and the industry's evolving regulatory environment leads him to estimate that the peer group will continue to operate with an average 67 percent capacity factor. Second, his comparison of Pilgrim and peer group outage and refurbishment experience leads him to assume the Pilgrim performance will equal or slightly exceed that of the peer group. As a result, Koppe estimates that Pilgrim capacity factor will be in the high end of the 65 to 70 percent range.

Q: Do you believe that Mr. Koppe's analysis of peer group averages justifies his capacity factor projection for Pilgrim?

A: No. Mr. Koppe's analysis of peer group averages, while illustrative of gross performance trends for plants sharing similar characteristics to Pilgrim, provides little explanatory power with regard to the <u>individual</u> effect of each plant characteristic on plant performance. If such characteristics as reactor type (BWR vs. PWR), unit size, and age are believed to have an impact on performance, as is implied by Koppe's use of "peers," then an analysis of performance trends should evaluate the effect of each characteristic in isolation from the others. Koppe's finding of an increase in capacity factor from the 1980-85 period to the 1986-88 period fails to unravel these overlapping trends and fails to address such issues as the relationship between plant aging and performance, the interaction of aging trends with regulatory or institutional trends, the effect of salt-water corrosion on general plant aging, among others.

In addition, Mr. Koppe's choice of plant characteristics to define his peers is admittedly arbitrary, as evidenced by his decision to exclude Nine Mile Point 1 and Oyster Creek from the peer group. More importantly, his choice of plant characteristics is seemingly capricious, in that he considers age, plant size, and reactor type, but does not evaluate salt-water cooling or other characteristics of Pilgrim.

Q: Using Mr. Koppe's methodology, what has been the capacity factor experience of salt-water peers?

A: Restricting the peer group to salt-water units, average capacity factor was 38 percent in the 1980-85 period, or 20 percentage points less than Koppe's peer group average.[9] Salt-water peer performance increased in the 1986-88 period to 57 percent, still 10 percentage points below Koppe's peer average

[9] All averages cited are compiled from KEA's capacity factor database and may therefore differ somewhat from averages compiled from Mr. Koppe's data.

performance.

Of course, salt-water peer experience is extremely limited, with only three units comprising the group. This reveals a problem inherent in Koppe's methodology; with each additional characteristic included in the definition of a "peer," the pool of experience drawn upon is further restricted. Eventually, the comparison group may be whittled down to the point where meaningful comparisons are no longer possible.

Q: Based on your analysis of salt-water peer experience, would it be reasonable to project future Pilgrim capacity factors at approximately 57 percent?

A: No. As we have indicated above, simple comparisons of peer plant averages lack explanatory power and hence also lack predictive power. It is not appropriate to apply peer experience to Pilgrim without first understanding the causal factors underlying peer performance trends and, thus, the relevance of these factors to Pilgrim.

Q: On what basis does Mr. Koppe justify a continuation of the peer group's 1986-88 period average capacity factor?

A: Mr. Koppe's assumption that the peer group's average 67 percent capacity factor is likely to continue into the future is based in part on his review of past engineering and regulatory causes of plant outages. Identifying some of the major design defects and regulatory restrictions that have led to plant outages, Mr. Koppe indicates that the defects have largely been corrected and that the regulatory environment has stabilized in the last few years. As a result, Mr. Koppe assumes that peer group performance should be constant or should improve in the future.

Q: If the design defects discussed by Mr. Koppe have been corrected and the regulatory environment appears to have stabilized, is it not reasonable to expect peer average performance to continue?

A: Not necessarily. While Mr. Koppe's analysis of the causes of past outages is relevant, his projection of past performance reflects an optimistic assessment of the state of the nuclear industry that may be unwarranted.

In large part, Mr. Koppe's assessment of future performance is based on three assumptions about plant design and the regulatory environment. First, because so many design defects and mechanical problems have been uncovered in the past, he assumes that the possibility for uncovering future defects is small. Second, because of extensive plant modifications, aged components have been replaced with new more-advanced equipment, which he claims would stabilize the component failure rate. Third, he believes that the regulatory environment has matured such that the likelihood of future backfits is reduced.

Q: Is it reasonable to assume that the bulk of plant design problems have been addressed?

A: No, it is not. That so many problems have been appearing in the past does not necessarily indicate that there are fewer problems to be uncovered in the future, as if there is a finite pool of possible defects that has been largely exposed. Mr.

Koppe seems to be claiming that the number of problems is bounded and that the bulk of these problems have been corrected. His testimony provides no basis for either of these assumptions.

The operating problems of the nuclear industry have largely been driven by issues which were not recognized until shortly before they started to affect plant performance. Classic examples include the role of fire protection and cable separation, which were not considered to be significant issues until the Brown's Ferry fire, and the accident sequence which destroyed Three Mile Island 2, which sequence only a few industry participants had heard of prior to the accident. Thus, the major nuclear problems of the mid-1990s may be unknown today, or considered to be only trivial concerns. Engineering estimates of the number and severity of remaining nuclear problems have been, and continue to be, highly unreliable.

Q: Would you agree that the failure rate of plant components should stabilize in the future?

A: Not necessarily. Although it is possible that extensive repairs may initially moderate aging, Mr. Koppe provides no basis for the assumptions (1) that the newer technology will not also age in the future and (2) that the failure rate will not rise again. In addition, some of the new technology is likely to increase the complexity of the plants, and thus the opportunities for future equipment failures.

Q: Has the regulatory environment stabilized, as Mr. Koppe claims?

A: In part. Mr. Koppe correctly points out that the rate of TMI-related NRC-mandated backfits appears to have decreased since the initial post-TMI years. However, while the rate of TMI-related outages has decreased, the possibility for other forms of NRC-mandated outages continues. A clear example is the emergence in the last few years of extended NRC-ordered shutdowns due to findings of utility mismanagement. The regulatory environment is not static; it continually evolves in response to newly discovered engineering and institutional problems. It would thus be short-sighted to claim that the extended regulatory outages that have plagued past industry performance are unlikely in the future.

Q: Has Mr. Koppe previously used a methodology similar to his analysis of the 1986-88 peer group performance?

A: Yes. In Koppe and Olson (1979), Mr. Koppe compared "early" nuclear capacity factor experience (through June 1976) to "recent" experience (June 1976 through June 1978), and found an improvement of 8.4 percentage points, to 64.2% (p. 6-3). He concluded that

> This substantial improvement in nuclear unit performance has resulted from extensive efforts to resolve may of the early design problems which affected units prior to 1976. The more recent experience appears to be typical of reasonable expectations for near-term performance of present day nuclear units. . .
>
> It is expected that continuing resolution of early design problems coupled with increased standardization will result in further improvements

in nuclear unit performance in the future. (p. S-3)

Q: Did Mr. Koppe's 1979 expectations prove to be accurate, at least in direction?

A: No. The performance of nuclear power plants has remained below the 1977 and 1978 levels ever since. More importantly, Mr. Koppe's expectation that nuclear power's operating problems had been substantially resolved by 1979 was patently incorrect. We have no reason to believe that he is any more correct today than he was in 1979.

Q: Have nuclear units which experienced long outages for major overhauls generally achieved superior performance following their return to service?

A: Not in general. While every situation is unique, there is no industry experience to suggest that poorly performing nuclear units can be made exceptional through long maintenance outages.

Q: How do BECO's capacity factors compare to those derived from historical data, either for Pilgrim or for the industry?

A: Table 4.1.2 summarizes and compares the projections. The 1986 BECO projection is 70% versus 49% for the optimistic national projection and 56% for the projection based on Pilgrim's past operating experience. BECO currently projects capacity factors which average 68% compared with 55% for the national projection and an average of 46% for the Pilgrim projection.

Q: Has BECO previously used less optimistic projections of Pilgrim capacity factors?

A: Yes. In its first QF RFP, in 1986, BECO voluntarily agreed to use a 54% capacity factor for Pilgrim. In DPU 88-83, the Department ordered BECO to use a 54% Pilgrim capacity factor in its second QF RFP.

4.2 <u>Operation and Maintenance Expenses</u>

4.2.1 O&M Projections from Pilgrim Experience

Q: How did you project Pilgrim non-fuel operation and maintenance (O&M) expenses from historical experience?

A: Table 4.2.1 shows annual O&M expenditures from 1974 through 1985, representing data which would have been available in early 1986. Table 4.2.1 repeats this analysis for data available in 1989.

It is clear that O&M expenses have been growing rapidly throughout Pilgrim's life. Hence, we project out Pilgrim's historical real O&M growth in linear terms in Tables 4.2.1 and 4.2.2. The regression in Table 4.2.1 fits quite well for the most recent years (1981-85). The regression in Table 4.2.2 underpredicts for the last few years, as well as for the early years, suggesting that the growth rate is more exponential than linear. Nonetheless, we use the more optimistic linear form for both analyses.

4.2.2 O&M Projections from National Experience

Q: How did you project Pilgrim capacity factors from national experience?

A: The national projections are based on a statistical analysis of U.S. nuclear power plant O&M expenditures for the years 1970 to 1987 for the 1989 projection. The 1986 projection uses data from 1970 to 1984. Performing a multi-variate linear regression on the relevant data yields an equation which, when specified for Pilgrim's characteristics, gives a year-by-year projection of O&M expenditures. This analysis is explained in more detail in Section 4 of ER PLC-4.

Q: What are the results of this analysis?

A: The results of the regression analysis are presented in Table 4.2.3. For 1986, O&M is expected to rise 2.65% annually above the general inflation rate. The 1989 "pessimistic" projection predicts a 2.85% growth rate above inflation. The impact on the economics of Pilgrim of the "optimistic" 1989 O&M projection is presented in Table 3.2.1.

Q: Do these data include all nuclear O&M costs?

A: No. These data include only the costs reported for individual plants. At least in some years, some owners of more than one nuclear power plant have apparently reported some nuclear O&M at the corporate level, but not at the individual plant level. Therefore, these nuclear O&M costs are understated to some extent.

Q: What is the effect on the O&M projections of the exclusion of these costs?

A: The under-reporting of plant specific O&M costs would make the national O&M projections more optimistic. The degree of the optimism depends on the extent to which O&M costs are not included in the individual plant accounts.

4.2.3 Boston Edison O&M Projections

Q: What are BECO's projections for Pilgrim O&M?

A: BECO's Pilgrim O&M projections are summarized in Table 4.2.3. BECO expects O&M to 2.51% annually above inflation in its 1989 in projection. In 1986, BECO expected O&M to rise only .76% above the general inflation rate.

Q: What support does BECO offer for its projections of Pilgrim O&M?

A: BECO offers Mr. Koppe's analysis of nuclear capacity factors in support of its projections.

Q: Have you reviewed Mr. Koppe's regression analyses of nuclear plant O&M costs?

A: Yes, we have. We find that Mr. Koppe's regression analyses of nuclear plant operating costs to be so fraught with methodological problems as to be without merit. Mr. Koppe needlessly restricts his analyses to a small subset of Pilgrim "peers," rather than employing the full range of industry experience in his regression analysis. He further restricts the range of experience by analyzing average annual 1980-87 costs rather than individual annual costs. This eliminates the ability to model time-related processes, such as aging, experience and regulatory change, and also greatly reduces the size of the dataset.

Mr. Koppe then performs a cursory regression analysis on this artificially limited data set. Not surprisingly, he finds no statistical relationship between variation in costs and variation in a small set of plant characteristics. By restricting his data set to peers, Mr. Koppe effectively minimizes variation in plant characteristics within the data set. In general, the smaller the range of an explanatory variable, the more difficult is the detection of a trend with respect to that data. Mr. Koppe has thus stacked the deck against finding any significant form of statistical relationship.[10] As a result, his conclusions regarding future Pilgrim O&M costs lack a sound empirical basis.

Q: Has BECO previously projected higher Pilgrim O&M costs than those used in this proceeding?

A: Yes. For example, the 1987 projections in the Gustin letter (in BECO IR MP 3-1) are higher than those Mr. Hahn sponsors. Also, BECO IR MP 1-47 provides a letter dated 10/17/86 from J. C. O'Donnell, providing BECO's projections of Pilgrim operating costs to its contract customer, Commonwealth Electric. This document projects O&M for 1989 of $99.2

[10] Although Mr. Koppe relaxes his restrictions on the data set in a secondary O&M analysis, allowing comparison over a subset of 43 plants, he continues to limit the database to plants completed before 1979 and to analyze average costs over the period of his data.

million, as opposed to the $83.6 million Mr. Hahn uses. For 1991, the last year of the projection, the 1986 projection is for $121.1 million, versus Mr. Hahn's $97.3 million, and the projected growth rate is 10% nominal, or 5% over general inflation.

Q: Is the amortization of excess O&M from 1986-88 included in the Boston Edison O&M projections?

A: No. BECO proposes to amortise this $101 million expense over the years 1988-93, at $20.2 million annually. This treatment amounts to less than full recovery of the excess costs; for a full prudence review, these costs should be recognized when they were incurred. However, since BECO has voluntarily assumed the cost of some of these excess O&M expenses, we have only included the portion which may be collected from ratepayers.

4.3 Capital Additions

Q: What group of capital additions have you included in your analysis?

A: We have included two groups of capital additions: the additions during the outage (or at least for the period through 1988), and projected future additions.[11]

Q: What were the additions during the outage?

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[11] Mr. Hahn uses the same sets of capital additions, although our estimates of the specific values differ.

A: Mr. Hahn states that BECO's FERC Form 1's report net capital additions of $295.8 million for the period 12/31/85 to 12/31/88. This period includes a few months prior to the beginning of the outage in April 1986, but since Pilgrim was operating at that time, additions were likely to have been quite small. The outage has not yet ended (in the sense that Pilgrim has not returned to what would usually be considered commercial operation, or received NRC permission for full-power operation), but additions during the 1989 portion of the outage are included in projected additions. While we accept this part of Mr. Hahn's approach, he has miscalculated the net capital additions. The FERC Forms give 1985 year-end Pilgrim investment of $663.1 million, and 1988 year-end investment of $955.6 million, giving a net increase of $292.5 million.

Of the $292.5 million, Mr. Hahn asserts that $42.1 million had already been spent as of 12/31/85, and was thus sunk. We accept this figure. Mr. Hahn also assumes that the $53.7 million authorized and projected to be spent as of 12/31/85 was sunk. We disagree. Most of these projects were not completed until well into the outage, and one has not yet been completed (BECO IR EOER-3).[12] Thus, net additions for 1986 through 1988

[12] Of the 21 projects listed in IR EOER-3 which were still under construction in 1986, only the "fuel pool filter system" was completed prior to the outage. Two other projects were completed in 1986, four in 1987, 13 in 1988, and one is projected for completion in 1991. For some reason, BECO also lists a project which was completed in 10/85 as comprising part of the $53.7 million in future costs on CWIP projects as of 12/85.

were closer to $250.4 million than to the $200 million used by Mr. Hahn.

Q: Are net additions the relevant value for this analysis?

A: No. The net capital additions are the difference between the gross additions (new equipment installed at the plant) and retirements (existing equipment removed from service).[13] Someone must pay for both the new equipment and the undepreciated portion of the investment in the old equipment: ratepayers usually pay for these interim retirements through adjustments to depreciation rates. Since we are concerned here with BECO's prudence in spending funds on returning Pilgrim to service, the relevant figure is the total amount invested.[14] The retirements during 1986 through 1988 totaled $9.5 million, bringing the gross additions to about $259.8 million.

4.3.1 Capital Additions Projections from Pilgrim Experience

Q: What has been Pilgrim's experience with capital additions?

A: Table 4.3.1 presents Pilgrim investment for the end of each year, from initial operation in 1972 through 1985. Table 4.3.2 extends the data through 1988. Except for 1974, when BECO reported $1.6 million of additions but $4.9 million of

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[13] Transfers and other adjustments also sometimes affect the net additions.

[14] In a used-and-useful analysis, the net additions might be relevant, if BECO were proposing to absorb the cost of the retirements, and not seek cost recovery either directly or through a higher depreciation rate.

retirements, the cost of Pilgrim has increased every year. At the end of 1972, BECO had invested only $232 million in Pilgrim; by the end of 1988, that had risen to $956 million, or 312% more. The largest increases occurred in 1984 and 1988, in connection with major outages.

Tables 4.3.1 and 4.3.2 also restate the net capital additions for each year in constant 1987 dollars, deflated by the Handy-Whitman index.[15] Annual additions vary considerably from year to year, depending on regulatory and technical requirements, aging, and the timing of maintenance and repair outages. For the plant's life up to the end of 1985, the average annual additions were $40 million annually in 1987 dollars. Through 1988, the lifetime average was $50 million per year.

The averages have been much higher in the 1980s: for 1980 through 1985, the annual average was $75 million, and for 1980-88, the average was $81 million, both in 1987 dollars.

Q: What value have you chosen to reflect the historical capital additions experience for Pilgrim?

A: We have used the 1980s averages: $75 million annually in 1987 dollars for the 1986 perspective and $81 million annually for the 1988 perspective.

Q: How have you projected this value into the future?

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[15]The gross additions would generally be somewhat higher than the net additions, as discussed above.

A: We have assumed that the average capital additions cost remains constant in Handy-Whitman nuclear construction dollars. We have used BECO's projection of the Handy-WHitman nuclear construction cost index.

4.3.2 Capital Additions Projections from National Experience

Q: How did you determine the national experience with capital additions, for purposes of extrapolating the results to Pilgrim?

A: The national experience with capital additions was determined by performing a statistical analysis of the KEA capital additions data base. Performing a multi-variate linear regression on the relevant data yielded an equation which, when specified for Pilgrim's characteristics, predicts capital additions expenditures. The data and process involved are described in more detail in Section 5 of ER-PLC-4.

Q: What are the results of this analysis?

A: The results of this analysis are presented in Table 4.3.3. The regression on national data available at the end of 1985, projects capital additions for Pilgrim which have an annual growth rate of 2% above general inflation. The 1989 "optimistic" equation predicts a growth rate of 2.5% above general inflation. The effect on Pilgrim economics of using KEA's "pessimistic" capital additions projection is presented in Table 3.2.1.

4.3.3 Boston Edison Capital Addition Projections

Q: What are BECO's projections of Pilgrim capital additions?

A: Table 4.3.3 compares BECO's projections of capital additions to those based on Pilgrim's experience and to those based on National experience. Beco projects capital additions expenditures which rise much more slowly than either of the other projections. BECO's 1989 projection has a growth rate of .69% above inflation for the years 1989 to 2007. After 2007, BECO predicts that capital additions expenditures will decrease in constant dollar terms. BECO's 1986 capital additions projection has a growth rate that is .5% <u>less</u> than the general inflation rate from 1989 to 2007.

Q: Have you reviewed Mr. Koppe's regression analysis of capital additions?

A: Yes. His analysis of capital additions is similar to that he performed for nuclear O&M, and is subject to the same criticisms.

Q: Has BECO previously projected capital additions which were higher than those projected in the current case?

A: Yes. BECO's 10/17/86 O'Donnell letter to COMM/ELEC in BECO IR MP-1-47 projects capital additions of $70 million annually in 1989-91, as compared to Mr. Hahn's projection of $33 to $51.9 million. The detail of the October 1985 study, provided in BECO IR MP-9-11, indicates that capital additions were then expected to be higher than Mr. Hahn now projects, averaging $70 million in 1990-91 and rising to $100 million annually for 1995-96.

4.4 Overheads and Insurance

Q: Are there operating costs for nuclear power plants, other than fuel and non-fuel O&M?

A: Yes. Not all of the costs associated with operating a nuclear power plant are listed by the utility as O&M costs for that plant. Some categories of costs are accounted for in other types of accounts, such as insurance, payroll taxes, and employee benefits.

4.4.1 BECO Estimates for this Case

Q: What overhead values does BECO assume for this case?

A: BECO splits overheads into two categories: nuclear insurance and administrative & general (A&G) expenses. BECO projects nuclear insurance costs to rise at nuclear construction inflation rates, from 1988. BECO computes 1988 A&G allocated to Pilgrim to be 20.1% of 1988 Pilgrim non-fuel O&M, and projects that relationship into the future.

Q: How did BECO derive the A&G ratio of 20.1%?

A: BECO added together specific nuclear-related costs (e.g., consultants, regulatory expenses), an allocated fraction of labor related costs (e.g., insurance, pensions, and payroll taxes), and 20% of the allocated fraction of all other A&G

expenses. BECO asserts that only 20% of these other expense items would be avoidable.

Q: Does this appear to be reasonable?

A: No. BECO offers no support for its assumption that only 20% of most overhead cost categories are avoidable. It is true that some small expenses, such as dispatching, are not much affected by the operation of Pilgrim. However, it is hardly plausible that a plant which represents about 40% of BECO net investment, and the same share of O&M, would contribute only 8% to the cost of running the company (administrative salaries, office expenses, rent, and the like), which comprise the bulk of the non-labor A&G. For many of these expenses, Pilgrim may contribute more than its allocated share of costs, due to its burden on BECO's officers, financial organization, public relations efforts, and the like.

If all the allocated costs are avoidable, BECO's computation of the A&G ratio would rise to about 32% of non-fuel O&M.

4.4.2 Other Plant Experience

Q: Is there any independent information on the extent of overhead costs from other plants?

A; Yes. Table 4.4.1 displays the overhead expenses for the three large Yankee plants between the years of 1984 and 1988.[16] Line 7 of this table shows the overhead expenses for each year expressed as a percentage of the total non-fuel station O&M. The percentages vary from 12% for Connecticut Yankee in 1984, to 96% for Maine Yankee in 1986. The overall trend in overhead expense ratios are decidedly upward for the Connecticut and Vermont units; the Maine Yankee overhead is consistently very high. It is possible that the trend evident at Connecticut Yankee and Vermont Yankee is likely to persist until they reach overhead ratios comparable to Maine Yankee, but it is difficult to determine whether this is likely to be the case. In calculating the overhead expense for Pilgrim in Section 3 of this report, we used an overhead ratio of 31.4% for the 1986 analysis, and 38.6% for the 1989 analysis. These are, respectively, the 1984-85 simple average and the 1984-88 simple average, over the three units.

In applying the overhead ratios to BECO's categories, we have set insurance equal to BECO's projection, and assigned the rest of the overhead loading to the administrative and general category.

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[16]Our data for Massachusetts Yankee is incomplete, and the unit is very small. BECO was unable to provide any data for Massachusetts Yankee, even though it is an equity owner in the plant. We find BECO's lack of curiosity regarding the cost structure of the other nuclear power plants in which it owns an interest to be most troubling.

4.5 Decommissioning Costs

4.5.1 Manion Estimates

Q: What decommissioning cost estimates does BECO use?

A: BECO's analysis relies on two decommissioning cost estimates prepared by Mr. Manion. These estimates are for:

(1) prompt dismantlement (DECON) of Pilgrim following the end of its BECO-projected useful life in 2012, and

(2) mothballing (SAFSTOR) of Pilgrim in 1989, followed by 21 years of fuel storage on site, and DECON of Pilgrim starting in 2013.

In the second option, the shipping of fuel to a Federal repository would start in mid-2011, and all fuel would be off of the site by the end of 2012.

Mr. Manion estimates the cost of the first option to be $174.3 million, or $217.8 million with a 25% contingency. He estimates the second option to cost $100.4 million for the mothballing, $11.8 million annually for 21 years of storage, and $153.1 million for dismantlement. The total cost of the second option, associated with early shutdown of Pilgrim, is thus $501 million, or $626 million with a 25% contingency.

Q: Is the difference between the two decommissioning options important to Mr. Hahn's analysis of the economics of Pilgrim operation?

A: Yes. The present value of the difference between the two decommissioning options is $279 million. Since the difference between the present values between Mr. Hahn's two cases (in his revised testimony) is only $402 million, decommissioning accounts for 69% of the difference.

4.5.2 Analysis of Manion's Estimates

Q: Do you consider the differences in Mr. Manion's estimates for the two decommissioning cases to be reliable?

A: No. Mr. Manion's estimates have at least six shortcomings for the purposes to which Mr. Hahn applies them:

- Mr. Manion's estimates are not intended to be accurate long-term forecasts of decommissioning costs, but only short-term guides for "financial planning."
- Nuclear decommissioning cost estimates are subject to tremendous escalation over time.
- Mr. Manion's analyses are poorly documented, and essentially unreviewable.
- Mr. Manion's treatment of contingency and escalation is illogical and inconsistent with
  - historical experience,
  - Mr. Hahn's treatment of O&M, and
  - expectations for radwaste disposal costs.
- Mr. Manion double-counts certain costs for the early decommissioning estimate, and ignores certain costs for the late decommissioning estimate.

- Mr. Manion and BECO have ignored options for resolving the spent fuel issue.

Q: What is your basis for saying that Mr. Manion's estimates are not intended to be accurate long-term forecasts of decommissioning costs, but only short-term guides for financial planning?

A: Mr. Manion makes this point very clearly. Mr. Manion acknowledges that the cost inputs to his estimates are subject to significant upward change. He therefore adds a 25% contingency factor to his engineering estimate. This contingency factor is based on cost trends over the last four years, projected for another four years, as discussed on page 71 of Exhibit BE-WJM-2. When asked why projected cost increases over only the next four years were included in his study, Mr. Manion replied that the four-year period was

> selected as being reasonably near term and reflective of a period of study applicability which would preclude the study becoming obsolete in one or two years. It should be noted that a three year period of historical trends of labor and burial cost escalation in excess of inflation would also support a 25% contingency factor. (BECO IR MP 7-22)

In other words, Mr. Manion expects his decommissioning study to be "applicable" for only three or four years, after which BECO would commission a new study.[17] Thus, his estimate is not intended to reflect the ultimate cost of decommissioning.

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[17] Indeed, Mr. Manion's previous Pilgrim study was performed three years prior to the current analysis.

Q: How large has the escalation been in nuclear decommissioning cost estimates over time?

A: We have performed two analyses of the trends in nuclear decommissioning costs. Table 4.5.1 shows the history of Mr. Manion's DECON decommissioning cost estimates.[18] Since 1979, his estimate of the cost of decommissioning a relatively small single BWR such as Monticello, Nine Mile Point 1, or Pilgrim, has increased from about $85 million to $206 million in 1987 dollars, or 142%. This amounts to an increase of about 12% annually. Given the limited and poorly presented information available from Mr. Manion,[19] we were unable to include the twin plants in a comprehensive analysis, or to perform any extensive analyses. Figure 4.5.1 shows the data for Mr. Manion's single-unit data, and the best-fit linear trend line. The trend line would almost certainly be higher if we compensated for the larger size of the units in some of the earlier estimates. In addition, the growth appears to be more exponential than linear.

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[18]Unfortunately, Mr. Manion did not respond fully to the request for this information in IR EOER-45. He failed to include his 1985 estimate for Pilgrim (even though the 1988 estimate was included), and we have no idea how many other estimates he neglected to mention. To judge from IR EOER-45, Mr. Manion has performed only three decommissioning estimates since 1982, and no utility has ever asked Mr. Manion to update any of his estimates. We know that the 1985 Pilgrim estimate is a counter-example for each of these generalizations.

[19]For example, in only one case does he indicate whether an estimate for a two-unit plant is for both units or for each unit.

Second, we have performed a similar analysis for a larger and better-documented data set of the decommissioning cost estimates of TLG Engineering. The data are shown in Table 4.5.2, and the results of a multiple regression analysis in Table 4.5.3. TLG's estimates, which seem to be relied on by more utilities than Mr. Manion's, but which are otherwise similar, have increased at an average of about 19% annually above inflation.

Q: How do these differences compare to the contingencies Mr. Manion builds into his analyses?

A: Mr. Manion allows for a 25% real increase in 3-4 years, as discussed above. This is an increase of only 5.7-7.7% annually, depending on whether he intends that the estimates be accurate for 3 or 4 years.

In fact, Mr. Manion's estimate of contingency for the period of his study is 31% (7-9.4% annually), but he uses only 25%. Also, his estimate of a 31% contingency is based on a two miscalculations. First, the 16-fold increase in radwaste disposal costs over the last 12 years is a 26% annual nominal increase (not 25%) and a 19% real increase, not the 15% Mr. Manion assumes. Second, averaging the escalation rates, as Mr. Manion does, understates the growth rates, since it ignores the fact that the fastest-growing costs become a larger portion of costs over time.

Q: Is the decommissioning cost estimate experience consistent with experience for other types of nuclear power plant costs?

A: Yes. Nuclear construction cost estimates for specific units have historically increased by about 25% annually. Nuclear O&M costs have increased at about 10% in real terms annually, depending on what factors are controlled for in the analysis.

Q: Please describe the inconsistencies in Mr. Manion's treatment of contingency and escalation.

A: Mr. Manion's contingency is basically an allowance for changing input prices (escalation), and changing physical requirements. Both of these factors would be expected to increase over time, and to vary with the type of activity. Mr. Manion treats all of his basic estimates as equally understated and subject to escalation/contingency, even though the estimates are for activities which vary widely by type and by time of performance.

Q: How is Mr. Manion's treatment of contingency and escalation inconsistent with historical experience?

A: Mr. Manion uses the same 25% contingency for placing Pilgrim in SAFSTOR in 1989, maintaining a spent-fuel storage pool in

1991-2011, and dismantlement in 2012-2015.[20] One would expect the first two activities to be subject to much less escalation than the last. The historical record supports this expectation.

As demonstrated by BECO IR EOER-44, near-term estimates for the cost of placing reactors in SAFSTOR are only very slightly understated. The most recent and relevant such activity, the SAFSTOR of Humboldt Bay with fuel on site, cost less than $12 million in 1984 dollars, with a cost overrun of only 5%.

Similarly, maintaining the spent fuel pool is an O&M expense. Historically, utilities generally have projected O&M expenses to rise at or near the rate of inflation. As shown in Section 4.2, these assumptions have been slightly wrong in the short term, and increasingly understated in the long term.

We discussed above the extraordinary rate of increase in projections for the cost of reactor dismantlement in the remote future.

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[20]Mr. Manion discusses the DECON option as through it would start with plant shutdown in 2012, but his DECON activity schedule shows final Pilgrim shutdown in January 2008, with fuel shipping starting immediately. Since Mr. Manion does not believe the fuel repository will be available to retired plants until 2011, his schedule would require three years of additional fuel-related costs, and the delay of dismantlement of some systems. Hence, the schedules in Section 5 of Exhibit BE-WJM-2 are inconsistent with either the cost estimates in Section 4 of that Exhibit, and in Exhibit BE-WJM-3. Perhaps Mr. Manion did not anticipate at the time that he prepared his DECON schedule that he would need to assume the unavailability of a fuel repository in preparing Exhibit BE-WJM-3.

Q: How is Mr. Manion's treatment of contingency and escalation inconsistent with Mr. Hahn's treatment of O&M?

A: There are two types of inconsistencies. First, Mr. Manion assumes that operating Pilgrim as a spent-fuel facility exposes BECO to contingencies and to an upward adjustment of costs, while Mr. Hahn assumes no such contingency for the larger and riskier activity of operating Pilgrim as a nuclear power plant. Mr. Manion assumes that cost of maintaining Pilgrim as a spent-fuel storage pool, a portion of the total cost of maintaining Pilgrim as an operating plant, in 1991-2011, is as subject to escalation as is dismantlement around 2012, and adds 25% to the projected cost. In contrast, Mr. Hahn adds no comparable contingency to the projection for Pilgrim operating O&M. If Mr. Hahn added 25% to his estimate of Pilgrim O&M, that would add $248 million to his estimate of the present value cost of keeping Pilgrim in service, eliminating 58% of his estimated net benefit of retaining Pilgrim. Since the difference in the two decommissioning estimates adds $207 million to the benefits of keeping Pilgrim open, treating operating O&M in the same fashion as Mr. Manion treats fuel-storage O&M would more than eliminate this benefit.

Second, Mr. Manion omits certain costs from the calculation of DECON costs, on the grounds that they would be incurred during a period of plant operation and would be recovered through O&M charges. Mr. Hahn does not appear to have increased his projection of Pilgrim operating costs in its later years to cover these added costs. Thus, costs which are charged to the early SAFSTOR case are omitted from the late DECON case.

Q: How is Mr. Manion's treatment of contingency and escalation inconsistent with expectations for radwaste disposal costs?

A: The most important portion of the cost escalation for nuclear decommissioning, as identified by Mr. Manion, is the escalation in radwaste disposal. Mr. Manion observes that the current cost of disposal is about $\$30/ft^3$.[21] He also discusses estimates of future disposal costs that range up to $\$300/ft^3$, computes that the costs have been rising at 25% annually for 12 years, and notes that costs following 1993 are very uncertain and subject to major upward adjustments. In 1993, or sooner, depending on the progress of Massachusetts in development of a radwaste disposal facility,[22] the existing radwaste facilities can refuse to take Pilgrim radwaste. At the least, a 400% penalty can be applied to the disposal charges levied on Pilgrim radwaste after 1992 (Exhibit BE-WJM-

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[21]Even in this specific level of detail, Mr. Manion's testimony is inconsistent. On page 65 of Exhibit BE-WJM-2, he states that the current cost is $\$29/ft^3$, while on page 71 he states that the current cost is $\$36/ft^3$.

[22]We understand that development of such a facility in Massachusetts would require voter approval, under the terms of a 1982 referendum. While the state government can eliminate this requirement, through an act of the Legislature or possibly legal action, the Commonwealth has generally been reluctant to override initiative referendum items. Siting of disposal facilities of any sort in Massachusetts has been difficult of late.

2, p. 66).[23] Mr. Manion nonetheless treats all radwaste disposal, regardless of when it occurs, as costing \$100/ft3, plus contingency (Exhibit BE-WJM-2, p. 71).

This value of \$100/ft3 is far too high a figure for the radwaste costs of SAFSTOR,[24] and probably far too low an estimate for the radwaste costs of DECON in 2012. The radwaste costs of SAFSTOR, incurred in roughly 1986-91, should be priced out at roughly \$30-40/ft^3, and the DECON option in the next century should be priced out at an escalated value of several hundred dollars per ft^3. Given the cost advantage of early shipment of radwaste, BECO would be well advised in the early shutdown case to dismantle and ship as much of the contaminated equipment as possible prior to 1993.

Q: Please describe the manner in which Mr. Manion's estimates are largely undocumented and unreviewable.

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[23]Mr. Manion assumes that a radwaste facility will be developed in Massachusetts. If Pilgrim radwaste is shipped out of state, perhaps to the Southwest, significant shipment costs must be added to the surcharge and/or whatever rate is negotiated with a host state in an excellent bargaining position. In IR AG 8-6, Mr. Manion estimates this cost as 9.6 cents per ft^3 per mile, or \$192/ft^3 for a 2000 mile haul.

[24] This statement assumes that Mr. Manion's estimates of current disposal costs are correct. His estimates of about \$30/ft^3 in 1988 appear to be out of step with BECO experience. BECO paid \$57/ft^3 in 1985, rising to \$156/ft^3 buried in 1988 (BECO IR MP 1-89). In 1988 (as in 1986 and 1987), BECO shipments exceeded burials, and it is not clear what activities the payments covered. Even calculating based on the amount of waste shipped, the 1988 rate was \$97/ft^3. Of Mr. Manion's many undocumented assumptions, this radwaste disposal price is one of the few which are subject to some simple empirical tests, and it does not appear that he has properly assessed this cost item.

A: From the materials provided in this case, Mr. Manion's estimates appear to be based on little more than his opinions. For example, in BECO IR EOER-19, Mr. Manion provides a fairly detailed rationale for $50,000 out of the $300 million (pre-contingency) difference between late and early SAFSTOR costs. Mr. Manion's justification for his cost estimates usually present only more disaggregated assertions, rather than references to data, posted rates, or specific regulations. This is true for insurance rates, required labor-hours for specific tasks, required staffing levels, and similar inputs.

One very good example of this tendency is Mr. Manion's rationale for the level of property taxes included in the early decommissioning case. Nearly $50 million of the $300 million increase in SAFSTOR costs from the standard case to the early case results from increases in local taxes. Mr. Manion's rationale for assuming that higher taxes would be charged on a larger liability (a retired plant with on-site fuel storage) than on a smaller liability (a retired plant without fuel) is presented in BECO IR EOER-92. No basis for the assumed tax level is provided, beyond the following statements:

> Several assumptions are made, including the Company's liability for taxes, in spite of a closed plant, negotiations with assessors on a level of tax payments, and the removal of all of the plant [in the DECON case]. In the event the station is closed and a spent nuclear fuel repository is maintained, it is expected that taxes will be incurred as the result for a certain amount of plant which would be required for the repository. If the plant is closed and there is not a spent nuclear fuel repository located at the plant, there

> would not be a need for the additional plant. A reduction in plant results in reduced taxes.

The additional plant to which Mr. Manion refers must be at least $80 million, to produce (at a 2.5% tax rate) the $2 million increase in annual taxes Mr. Manion estimates for early SAFSTOR. But Mr. Manion only projects that it will cost $53.2 million more to put Pilgrim in SAFSTOR early than late. Since virtually all ($47.5 million) of this added cost is due to two <u>expenses</u> -- utility staff and local taxes -- it is clear the amount of additional <u>plant</u> would not be substantial, even given Mr. Manion's estimates.

Clearly, the market value of Pilgrim (the price another utility would pay for the assets at Pilgrim) will be <u>lower</u> with fuel on site than without fuel. Mr. Manion offers no Massachusetts law, practice, or precedent to demonstrate that his assumptions regarding property tax liability make any sense whatsoever.[25]

Another example appears in Mr. Manion's estimate of the amount of radwaste disposal required in each dismantlement case. He simply asserts that 20% of the DECON cost is for radwaste disposal and refuses to document that assertion (BECO IR EOER-86).

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[25] BECO IR EOER-93 and BECO IR MP 7-018 provide more detail on Mr. Manion's assumptions, but no basis for any of those assumptions.

Q: How does Mr. Manion double-count certain costs for the early decommissioning estimate, and ignore certain costs for the late decommissioning estimate?

A: This occurs in several ways. First, Mr. Manion ignores all costs of late decommissioning which would occur prior to plant shutdown and could be charged off as O&M. The same costs are included in the early shutdown case. Obviously, these costs of decommissioning are real costs, regardless of whether they are rolled into operating plant O&M, or are identified as decommissioning costs.

Second, Mr. Manion assumes that the unplanned nature of the early shutdown would add $38 million in utility staff costs and $9.5 million in property taxes over a period of 30 months.[26] The property tax calculation is based on Mr. Manion's highly suspect and unsupported assumptions regarding the taxation of retired plant. In addition, both of these costs were paid in 1986-88; had BECO decided in 1986 (or even later) to retire Pilgrim, the staff costs and property taxes paid in this period could have been applied to the decommissioning costs, by using the 1986-88 period for decommissioning planning and staff ramp-down. Had Pilgrim been retired, the staff and tax costs would have been declining, rather than rising (as they actually did), in the 1986-88 period, and the savings would probably have

[26]The extra staff costs would apparently be incurred primarily over the first six months to a year (BECO IR MP 7-17).

exceeded the $47.5 million Mr. Manion adds in for these costs.[27] In other words, Pilgrim decommissioning in 1989 would only be unplanned because BECO imprudently failed to plan for decommissioning during the outage.

Third, of the $43.2 million in additional dismantlement costs due to early SAFSTOR, rather than late SAFSTOR, $25.9 million is for extra staff and $4.1 million is for extra security until the fuel is shipped off site. However, Mr. Manion includes these costs in the SAFSTOR annual costs until the fuel is all shipped. Thus, $30 million is simply double-counted.

Fourth, in the early decommissioning case, decontamination of concrete is included in both the preparation for SAFSTOR, and the later dismantlement phase. This appears to overstate the total cost of the early decommissioning case by $1.4 million. It also raises questions about the care Mr. Manion exercised in the preparation of his early decommissioning estimate.

Combined with the impossibility of reviewing the derivation of the estimates, and his inability to support his most important assumptions, these errors indicate that the Commission should give very little weight to Mr. Manion's estimate of the relative costs of early versus late

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[27] Of course, property tax payments would have almost certainly dropped much more sharply than Mr. Manion posits, so the $47.5 million figure is extremely hypothetical.

decommissioning.

Q: Please describe how Mr. Manion and BECO have ignored options for resolving the spent fuel issue.

A: Mr. Manion assumes that Pilgrim fuel must be stored on site until a Federal repository is ready. Neither Mr. Manion nor BECO appear to have investigated the feasibility of transferring the fuel to another facility, such as an operating or closed reactor which is already storing fuel (BECO IR EOER-42).[28] BECO has not even ascertained whether Seabrook, originally designed to be a twin-reactor plant, would have spent-fuel storage space for two reactors (BECO IR EOER-43).[29]

Another option would be for Pilgrim to store the spent fuel from Massachusetts Yankee, when it is shut down in 1997. Since the extra monitoring and security staff at Massachusetts Yankee could be eliminated, the net cost of the spent fuel storage at Pilgrim would be negligible.

Q: Are Mr. Manion's cost estimates for early decommissioning consistent with recent experience?

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[28]BECO's reasoning is remarkably circular. BECO's conclusion that Pilgrim operation remains economically viable is heavily dependent on the assumption that off-site fuel storage capacity is not available. But "BECO has not made any efforts to locate or establish such [fuel storage] capacity" (BECO IR EOER-42), because BECO expects to continue operating Pilgrim.

[29]Since Pilgrim is only about 60% the size of a Seabrook unit, and since Pilgrim has operated at 50% capacity factor, rather than Seabrook's planned 70-80% capacity factors, 16 years of Pilgrim operation would only produce about as much spent fuel as 6 years of a Seabrook unit's planned operation.

A: No. Humboldt Bay, a 65 MW BWR which operated for 13 years (about the same as Pilgrim's effective operating life, excluding its lengthy outages in 1984 and 1986-88), was retired in 1976 and placed in SAFSTOR in 1983, with fuel on site.[30] As noted previously, SAFSTOR cost less than $12 million in 1984 dollars, or $13.5 million in 1988 dollars, according to Mr. Manion (BECO IR EOER-44). Pacific Gas & Electric, the owner and operator of Humboldt, estimated that upgrading the spent-fuel pool cost $85,000 (1983$) and that keeping the fuel at the plant while it is in SAFSTOR will cost about $765,000 annually in 1985$, or $834,000 in 1988$ (Oden, 1985).[31] Mr. Manion's estimates (of $126 million to achieve SAFSTOR and $14.7 million annually for maintaining the plant in SAFSTOR) could only be reconciled with those from Humboldt if there are no economies of scale (actually, negative economies would be required). This is inconsistent with virtually all experience with nuclear plant operations.

Q: Does the useful operating life of Pilgrim affect the difference in the decommissioning cost estimates?

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[30] Other than Humboldt, LaCrosse is the only power reactor which has been retired with fuel on site and without any other reactor to bear the cost of security and fuel monitoring. We have not been successful in obtaining data on LaCrosse costs from the owner, Dairyland Power Coop. Indian Point 1 and Dresden 1 have fuel on site, but they each share their site with two other operating reactors.

[31] Based on conversations with Humboldt staff, this figure appears to include all of Mr. Manion's cost categories except for insurance.

A: Yes. For each year short of 2012 that Pilgrim operates, one year of spent fuel storage is required for the Pilgrim base case, adding about 7% to the cost of decommissioning by Mr. Manion's reckoning. If Pilgrim operates to age 30, in 2002, the spent-fuel storage would add about $96 million to the present value of keeping Pilgrim on line, given BECO's other assumptions.[32] Thus, the substantial difference between Mr. Manion's estimates of early and late decommissioning costs is largely an artifact of BECO's overly optimistic projection of Pilgrim's useful life.

Q: Could correction of the combination of problems you have identified in Mr. Manion's analysis reverse the economics of early versus late decommissioning?

A: Yes. As illustrated above, treating operating O&M in a manner analogous to the treatment of fuel-storage O&M eliminates the advantage of late decommissioning. Similar reversals could easily be accomplished by combinations of the continuation of historical escalation patterns (instead of Mr. Manion's simplistic contingency), the correction of errors identified above in the early SAFSTOR and subsequent dismantlement estimates, and the correction of the spent fuel maintenance

[32]This estimate is based on 10 years of fuel storage, at $14.7 million annually, including contingency. The present value of the late decommissioning is $408 million, based on a 1988$ cost of $625.7 million, or 65% of the 1988$ cost. The effect of 10 years of storage is thus 10*14.7*.65 = $96 million. The increase would be greater, due to the costs of initiating SAFSTOR in 2002, especially if the retirement in 2002 were "unplanned" in the sense used by Mr. Manion.

costs to reflect Humboldt experience, and earlier retirement of Pilgrim.

Q: What treatment do you recommend for decommissioning costs in the Pilgrim prudence analysis?

A: Considering the numerous errors and overstatements in the derivation of the early decommissioning estimate, and the understatement and risks of the late decommissioning estimate, we recommend that the cost of early decommissioning be assumed to be equivalent to the cost of late decommissioning, both stated in equivalent constant dollars. Thus, we set the annual decommissioning contribution for the early SAFSTOR case to equal BECO's estimated annual decommissioning contribution for the late DECON case.

4.6 <u>Useful Plant Life</u>

Q: What is BECO's current projection of Pilgrim's useful life?

A: BECO currently estimates that Pilgrim will remain in service until the year 2012, at which time it would be 40 years of age.

This lifetime is an extension of the 36 year useful life which seems to have been established at or near the time Pilgrim entered service, based on the experience of fossil-fired plants at that time.

Q: How does the 40-year projection compare with the experience of other nuclear units?

A: There is very little experience with the longevity of nuclear power plants. What little experience is available suggests that the useful lives of nuclear units is likely to be much shorter than 40 years.

The five small plants which entered commercial service in the early 1960s would be 20-26 years old today, if they had all survived.[33] Of this cohort, Indian Point 1, Humboldt Bay and Dresden 1 have been retired (formally or de facto), after only 12, 13, and 18 years of operation, respectively. Only Big Rock Point and Yankee Rowe remain in operation. The oldest and largest of the survivors, Yankee Rowe, has only been in service since 1961, and is thus just 28.

The first units of more than 300 MW began commercial operation in January 1968, and have 21 years of operating experience. The only clear retirement among this group is Three Mile Island 2, which operated for only a few months prior to its accident. Various nuclear units which are currently shutdown due to safety and design problems (such as Browns Ferry) may never reopen, but these units may be shut down for an extended period before it becomes clear that they have reached the end of their useful lives.

LaCrosse, a small commercial reactor of 1969 vintage, was retired in 1988 for economic reasons, after 19 years of operation.

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[33]This group excludes the exotic demonstration reactors, some of which used liquid metal coolant, organic moderation and other technologies very different than the light water reactors which have prevailed in US nuclear power plant design. Also excluded are some very small demonstration reactors which operated for only a few years.

Q: What are the implications of this analysis for BECO's projection of Pilgrim's useful life?

A: BECO is projecting that Pilgrim will survive almost twice as long as the oldest domestic unit over 300 MW and 40% longer than the oldest domestic commercial power reactor of any size. Meyer (1986) updates the analysis of the operating life of nuclear power plants contained in an earlier report to the NRC (Chernick, et al., 1981). Depending on the data set utilized, the data indicate a median useful life for nuclear power plants of anywhere from 20 to 35 years. Unfortunately, the data, no matter how defined, are quite sparse.

Q: Would your projections of capacity factor, O&M and capital additions have any effect on the useful life of Pilgrim?

A: Yes. Lower capacity factors and higher capital additions will make Pilgrim less cost-effective than BECO expects, so that continued operation at any given time is less likely. In addition, our projections of rising O&M and falling capacity factors would gradually make continued operation even less economical. As the capacity factor falls, the practical difference between operation and shutdown deteriorates.

Q: What is the impact of this assumption on BECO's analysis of the economics of the Pilgrim plant?

A: By assuming that Pilgrim will remain is service for an extraordinarily long time, BECO overstates the benefits of the Pilgrim investment and exaggerates the costs associated with replacing Pilgrim's power.

Q: How do BECO's estimates of replacement power costs for the Pilgrim Rate Case differ from the avoided cost estimates in its latest QF-RFP?

A: The difference in the two cost estimates is shown in Table 4.7.1. On a present value basis, the cost of replacement power BECO projects in this case is 10% higher than the avoided costs BECO used in its recent solicitation of QF bids.

Q: What is the basis for this difference in avoided costs?

A: The most important differences between the two estimates arise from the differences in the changes modelled. The QF avoided cost estimate is based on reducing loads by 200 MW at a 70% capacity factor, and removing a 200 MW combustion turbine in 1992. The replacement power estimate in this case is based on increasing the loads to be met by the non-Pilgrim system by 497.1 MW at a 68% capacity factor, and adding a 100 MW combustion turbine in 1992 and a 400 MW combined cycle plant in 1995. Thus, the direction of the effective load change is different and the size of the change is different. Additional differences, most of which are discussed in BECO IR EOER-80, include:

- several fossil units are rated slightly higher in the QF-RFP than in Mr. Hahn's testimony,
- BECO has assumed the addition of further purchases from NU, rising from 50 MW in 1989/90 to 300 MW in 1994, falling to 100 MW in 1995, and then disappearing,
- BECO has reduced its cogeneration and small power producer projections by 18 MW, and
- Pilgrim is assumed to be worth one MW of capability credit per MW of capacity, while the QFs are assumed to be worth .81 MW of capability credit per MW of capacity, even at a slightly higher reliability.[34]

[34] The 81% figure is the ratio of the QF capacity factor to the 86.5% assumed equivalent availability of the avoided combustion turbine.

Q: Is BECO's estimate of replacement power costs reasonably and appropriately derived for use in this case?

A: No. There are several problems with the replacement power cost assumptions, including:

- using higher projections of GNP inflation in projecting replacement fuel costs than in projecting Pilgrim capital additions and operating costs,
- using 1987 fuel price projections for a 1989 analysis,
- pessimistic assumptions on the availability of qualifying facilities, in both the base and no-Pilgrim cases,
- pessimistic assumptions regarding the cost of short-term power in the no-Pilgrim case,
- replacement of a base-load plant (Pilgrim) with peaking and intermediate capacity (Walpole and Edgar),
- overstatement of the carrying charges for Edgar and Walpole,
- failure to consider coal gasification at Edgar,
- assuming that the Edgar combined cycle plant would burn entirely #2 oil, rather than gas,
- failure to consider any out-of-region purchases, and
- failure to consider increased conservation and load management (C&LM) investments as part of the replacement for Pilgrim.

Q: Please describe BECO's use of higher projections of GNP inflation in projecting replacement fuel costs than in projecting Pilgrim capital additions and operating costs.

A: Table 4.7.2 compares the general inflation rates underlying BECO's cost projections. Construction and operating expenses, which dominate the cost of Pilgrim, are inflated based on a 1987 projection of the GNP inflation rate from Wharton Econometric Forecasting Associates (WEFA). Fossil fuel costs, which dominate the replacement power costs, are inflated based on a July 1987 projection of the GNP inflation rate from Data Resources, Inc. (DRI). The DRI forecast assumes higher general (GNP) inflation rates than does the WEFA forecast. In other words, the fuel cost projections assume a different (and more expensive) underlying world than do the Pilgrim-related escalation rates.

Q: What is the effect of this combination of assumptions?

A: The costs of replacement fuel are overstated compared to the cost of keeping Pilgrim on line. The present value of the GNP price index over the study period is 5.7% higher for the DRI forecast than for the WEFA forecast. Hence, the fuel prices would be overstated by 5.7% compared to the costs of Pilgrim, if each year's replacement fuel cost was equally important. In fact, the fuel costs are less important in the early years, when much of the replacement power is from the NU purchase, so the actual effect would probably be greater. Decreasing the fuel costs by just 5% would reduce total replacement power present-value costs by 3.5% (since fuel is about 70% of replacement power present value costs), or about $88 million.

Q: Would BECO have found it difficult to reconcile these two sets of forecasts?

A: Not at all. For example, BECO could have inflated DRI's real fuel prices projections by the WEFA GNP inflation rates.

Q: Please describe BECO's use of 1987 fuel price projections for a 1988/1989 analysis.

A: Mr. Hahn's analysis was originally performed late in 1988, and was corrected in June 1989. Nonetheless, BECO used DRI's July 1987 fuel price projections, even though it had fuel price forecasts from 5/88 and 2/89. The difference between the July 1987 forecast and the February 1989 forecast are illustrated in Table 4.7.3. In nominal dollars, the 1989 oil prices are 14-24% lower in the year 2000 (roughly the middle of the analysis period) and average 10-20% lower when present-valued over the period 1989-2012, compared to the 1987 projections.

The comparisons in Table 4.7.3 are in nominal dollars. The general inflation rate projection in the 1989 forecast is just a bit higher than that in the 1987 forecast, as shown in Table 4.7.2. Thus, the 1989 oil price forecast would be even lower if it were driven off the 1987 WEFA GNP price forecast, which drives the Pilgrim cost forecast. Correcting the difference in inflation rates would increase the difference between fuel price estimates to about 23% for 1%S #6 oil, and about 14% for #2 oil.

Q: How much would BECO's replacement power costs change with the current oil price forecasts?

A: As shown in Table 4.7.7, BECO projects that most of the replacement power from Pilgrim would come from 1% sulfur residual oil burned at Mystic and New Boston. On a present-value basis, corrected for different assumptions in general inflation rates, the new price projection for 1% sulfur residual oil is 23% less than the 1987 projection. Considering that portions of the replacement power are from distillate oil, coal, and NU nuclear fuel (all of which are less affected or unaffected by the change in the fuel price projection), balanced by some 0.5% and 2.2% sulfur oil (both of which decrease more in price than 1% sulfur oil), the overall reduction in replacement fuel cost might be about 20%.[35] Since the replacement fuel cost is 70% of the total replacement power cost, the reduction in replacement power cost would be about 14%.

Q: Was the reduction in fuel cost projections between 1987 and 1989 a sudden event in 1989?

A: No. The other fuel price forecasts provided to BECO since 1986 are summarized in Table 4.7.4. We included the prices for #2 oil and 1%S #6 oil, for each of the forecasts included in BECO IR AG 4-19 and BECO IR EOER-20, and have added the DRI forecast

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[35] In addition to the change in the price of the fuel supplying the replacement power in BECO's projections, the changing fuel prices would also change dispatch patterns, further reducing costs. Hence, we can not exactly determine the effect of a fuel price change without another production costing run.

for Spring 1988.[36] Oil price projections rose in the period from 1/86 to 7/87, and then fell in 1988 and 1989. The 7/87 forecast BECO used in this case is the highest of any of the seven forecasts in Table 4.7.4.

Q: How much would the use of 1989 oil price projections reduce BECO's projection of replacement power costs?

A: Reducing BECO's estimate of replacement fuel costs by 20% would reduce the present value of having Pilgrim on line by $246 million.

Q: Please describe BECO's pessimistic assumptions on the availability of qualifying facilities in both the base and no-Pilgrim cases.

A: BECO includes only half of the capacity of planned capacity additions, including qualifying facilities (QFs) currently under contract, as well as half of other new projects, such as HQ Phase 2, and Ocean State Power. This general approach of discounting planned additions is consistent with DPU precedent, as in DPU 88-83. However, the base case is understated in two ways.

First, the Peat Products project is in commercial start-up, and therefore should no longer be discounted. Second, DPU 88-83 specifies "that 50 percent of the output of all planned capacity additions" should be assumed to "contribute to BECO's

[36] While BECO generally subscribes to the DRI oil forecasts, BECO mysteriously failed to provide any 1988 DRI forecasts on discovery.

supply" (p. 11, emphasis added). BECO has sent out an RFP for 200 MW of additional QF capacity, which is now part of the "planned capacity additions," and should be included at the 50% level.

In addition, BECO does not include any QF capacity as part of the replacement power for Pilgrim. As noted above, BECO's replacement cost estimates are higher than its QF avoided-cost estimates. Virtually all New England utilities (including BECO) that have sought QF bids have received bids for more capacity than they were seeking, at prices below avoided cost. Thus, BECO would almost certainly be able to replace Pilgrim at a lower cost with QF purchases than with the mix of sources it selected.

Q: Please describe BECO's pessimistic assumptions regarding the cost of short-term power in the no-Pilgrim case.

A: In DPU 89-53, the DPU found that BECO had less expensive options than NU slice-of-system purchases. Mr. Hahn uses the slice-of-system purchases as the short-term replacement power supply in 1989-1995.

Q: Please explain how BECO's replacement of a base-load plant (Pilgrim) with peaking and intermediate capacity (Walpole and Edgar) affects the replacement power costs.

A: The replacement power costs for Pilgrim should be based on the lowest-cost alternative for replacing its baseload capacity. The cheapest replacement for baseload capacity is generally more baseload capacity.[37] With Pilgrim in service, BECO has determined that its least-cost construction plan consists of 200 MW of combustion turbines in 1997, and 400 MW integrated gasification combined cycle (IGCC) coal plants in 2001 and 2008 (BECO IR EOER-6). To replace Pilgrim, BECO adds the Walpole and Edgar units, and does not change the mix of units added in 1997-2007. Walpole would be a peaker, and Edgar (operating on #2 oil) would be a peaking/intermediate unit, operating at lower capacity factors than any of BECO existing oil-fired steam plants.

Q: Has BECO explained why it chose to replace Pilgrim with peaking and peaking/intermediate capacity?

A: Yes. In BECO IR EOER-7 and BECO IR EOER-8a, BECO asserts that replacing Pilgrim would require BECO to install whatever capacity would be available first. However, BECO does not appear to have performed any analysis of the alternatives available to delay the capacity need date until baseload capacity would be available, nor any analysis of the feasibility of converting the peaking or peaking/intermediate capacity to baseload capacity. For example, the additional

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[37]The exceptions to this rule occur when new baseload capacity is not economical due to its high cost, or when the system is long on baseload, even without the unit being replaces. However, BECO has generally found that baseload coal plants are its most cost-effective capacity additions for the bulk of its capacity needs, even with Pilgrim (Exhibit BE-WPK-3, Vol III, Section C; BECO IR EOER-6). Thus, BECO does not believe that baseload capacity is expensive, nor that BECO's existing baseload capacity is excessive, especially without Pilgrim.

purchases of NU capacity fall from 350 MW in 1993 to 0 MW in 1995. BECO has also not performed any analysis of the availability of baseload alternatives in the 1992-95 period.

Q: Has BECO explained why the addition of 500 MW of peak and peak/intermediate capacity does not change the optimal type of capacity for the 200 MW capacity addition in 1997?

A: No. In BECO IR EOER-8, BECO answers a question about the effect of the 500 MW of peak/intermediate capacity on the 1997 turbine by referring back to the base case expansion plan. In essence, BECO is assuming that it would build the same units after 1995, regardless of its capacity mix in 1995.

BECO's position on this point is just plain wrong. The choice of capacity to add in 1997 is clearly dependent on the mix of capacity existing prior to that date. If the optimal additions between 1997 and 2008 are 200 MW of peakers and 800 MW of IGCC <u>with</u> 500 MW of Pilgrim, the optimal additions <u>without</u> Pilgrim must be more heavily weighted toward baseload, and is probably all baseload.

Optimizing the post-1995 construction program in the without-Pilgrim case would reduce replacement power costs.

Q: Please describe BECO's failure to consider coal gasification at Edgar.

A: BECO IR EOER-8 asserts that:

- IGCC technology is immature,
- IGCCs are not available before 2000,

- phased IGCC construction (to convert Edgar to burn coal, after its original in-service date) is immature and uncertain, and
- BECO "has no real cost estimate for the retrofit gasifier on an existing large combined cycle unit."

These assertions are inconsistent with BECO's positions in other proceedings, and with data sources on which BECO claims to have relied. In its 1988 EFSC filing (Exhibit BE-WPK-3, Vol. III, Section C), BECO asserted that IGCC units would be available in 1995, when BECO is now projecting the construction of the Edgar combined cycle plant (p. C-4-2).[38]

Even if there were some timing difference, one of the reports relied on for its assumptions of the characteristics of new units finds that a phased IGCC would perform identically to a non-phased IGCC, and that the cost of the plant would rise by only $13/kW (Snyder, et al., 1986, p. S-2 in BECO IR EOER-4 Supplemental). This is only about $5 million for the 400 MW Edgar unit, not all of which would be recovered in the study period. By way of comparison, Figure C-4-8 of Vol. III, Exhibit BE-WPK-3, estimates that life-cycle cost difference between the IGCC and CC options at 50-70% capacity is $1500-2500/kW, or $600 million to $1 billion. In Exhibit BE-WPK-3

[38]The same BECO Exhibit indicates that pulverized coal plants could be on line in 1998 and are only marginally less cost-effective than the IGCCs.

(Vol. III, page C-4-7), BECO also praises the modular design (i.e., potential for phased construction) of IGCC plants.[39]

Thus, BECO's rationale for assuming that Edgar could not be built as an IGCC, either immediately or in a phased approach, is incorrect and inconsistent with BECO's position during the outage.

Q: Please describe how BECO's assumption that the Edgar combined cycle plant would burn entirely #2 oil, rather than gas, affects the replacement power costs.

A: Distillate or #2 fuel oil (essentially the same as home heating oil or diesel fuel) is currently much more expensive than natural gas for large users, and it is expected to stay that way. Oil-fired utility steam plants, such as Mystic and New Boston, generally use #6 residual oil, which is much less expensive than #2 oil. Only peaking plants, such as diesels and gas turbines, rely on #2 and other high-cost fuels. So far as we are aware, all the proposed combined cycle power plants in New England are proposed to burn natural gas (or gasified coal).[40] However, BECO chose to assume that Edgar, the major unit replacing Pilgrim, would burn expensive #2 oil.

Q: Does BECO offer a justification for the assumption that Edgar would burn oil, rather than gas?

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[39] That modular design starts with the construction of a gas turbine. Hence, the 1992 gas turbine might be the first stage of a combined cycle or IGCC plant.

[40] Some combined cycle units operate on #6 oil, but this requires pretreatment and presents some operational problems.

A: Yes, but not in the filing, which does not even mention this crucial fact. In BECO IR EOER-19, BECO asserts that the cost and availability of natural gas is too uncertain to use in this analysis. However, BECO has 1987-89 estimates of gas costs, provided by both WEFA and DRI (BECO IR AG 4-19, BECO IR EOER-20). The gas forecast materials provided by BECO do not indicate any special concern with gas availability (BECO IR AG 4-19). Future gas prices are uncertain, but so are oil price, nuclear power plant performance, and demand levels.[41] Both of the Open Season pipelines (Iroquois and Champlain) from Canada, as well as Boston Gas Company, have capacity available for 1995.

Perhaps more significantly, BECO seemed quite comfortable supplying annual natural gas escalation rates (from the Wharton third-quarter 1988 projections), for 1986-2011, in its QF RFP #2 package, issued April 14, 1989. These escalators would be used by BECO in evaluating QF pricing proposals. It is difficult to see why these escalation rates were adequate for projecting QF fuel costs and prices, but not for projecting Edgar fuel costs.

Table 4.7.5 compares the most current cost estimates for oil and firm gas provided by BECO (BECO IR AG 4-19). Gas prices stay at slightly over half of oil prices throughout the analysis period. Some transportation or margin charges

[41]BECO has no difficulty in selecting point values and/or ranges for these other inputs.

(probably on the order of 20-50 cents/MMBTU in 1989$) to Boston Gas would have to be added to these values, so the burner-tip cost of gas might be more like 60-65% (conservatively, as much as two-thirds) the cost of oil.[42]

Q: How much would BECO save by running Edgar on gas, rather than on #2 oil?

A: Table 4.7.6 lists the annual amounts and costs of Edgar generation projected by BECO. On the average, Edgar produces at a capacity factor of about 18%, due to its high assumed fuel cost. Even so, Edgar burns fuel costing $415 million in present value. Reducing that cost by a third by substituting gas for #2 oil would reduce the present value benefit of keeping Pilgrim on line by $138 million, or over a third of the net benefits BECO claims for Pilgrim operation.

In addition, Edgar on gas would be less expensive than Mystic and New Boston on oil.[43] As shown in Table 4.7.7, these two plants provide about half of the replacement power for Pilgrim, in the first couple years of the analysis, rising to two thirds in 1994. After the end of the NU purchase, Mystic and New Boston provide about 65-70% of the replacement power.[44] From Exhibit BE-RSH-14 for 2001 (for example), two-thirds of

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[42]BECO might also find it cost-effective to burn oil on peak heating days, to reduce its demand charges, and as a backup fuel.

[43]The advantage over Wyman 4 would be even greater, but BECO's entitlement in this unit is small. Canal would be more competitive with Edgar.

[44]Edgar provides another 25-30% of the power.

BECO's estimated cost of Edgar power would be 20% lower than Mystic 7 fuel costs. The differential would be higher for Mystic 4, 5, and 6, and lower for New Boston.

Many millions of additional dollars would be saved by a gas-fired Edgar backing out existing oil-fired capacity, although estimating these savings exactly would require a production costing run. However, we can estimate the effect. If operating on gas raises Edgar's capacity factor from the 18% average in Exhibit BE-RSH-14 to 75%, it would produce 1990 extra GWH annually, or two-thirds of the replacement energy for Pilgrim. Most of this added Edgar energy would back out Mystic and New Boston generation. If the extra Edgar energy is 20% less expensive than the energy it backs out, the change in dispatch would reduce the present value of Pilgrim fuel cost savings by 1,761 * .2 * .67 = $235 million.

Finally, it should be noted that New Boston and Mystic 7 currently burn natural gas on an interruptible basis. Once the Open Season supplies are in place, interruptible gas should be even more available. Given the large price differentials, firm or quasi-firm gas supplies may also be cost-effective. Thus, a more realistic estimate of Mystic 7 and New Boston fuel costs would further reduce replacement power costs.

Q: How has BECO overstated the carrying charges for Edgar and Walpole?

A: BECO has counted the carrying costs of Edgar and Walpole as they would be charged through ratemaking. As the DPU recognized in DPU 84-276, establishing the current QF bidding system, this overstates the cost of capacity which is included in the analysis for only the first part of its life. BECO completely ignores the value in 2012 of Walpole (which would be only 20 years old) and of Edgar (which would be only 17 years old). To correct these problems, the DPU requires for QF bidding purposes that the costs of avoided power plants be real-levelized, so that the benefit of avoiding a plant for a given period will be equal to the savings from delaying the plant's construction from the beginning of the period to the end of the period.[45]

Real-levelizing the carrying costs for Walpole and Edgar would reduce the estimated replacement capacity costs for Pilgrim.

Q: Please describe BECO's failure to consider any out-of-region purchases.

A: BECO simply ignores the possibility of replacing Pilgrim through firm purchases from Hydro Quebec (HQ), New Brunswick, Nova Scotia, or any other source outside the region. This replacement capacity might displace part of the NU purchases, Walpole, Edgar, or the 1997 gas turbine (which becomes redundant once Walpole and Edgar are on line).

In BECO IR EOER-12, BECO asserts that it did not examine the option of additional purchases from HQ because the

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[45] In the case of Edgar, the benefit is the delay in the unit from 1995 to 2012.

replacement power would have to be on line as soon as possible. This is obviously not a relevant consideration for replacing the 1997 gas turbine, which would be added 11 years after the start of the outage, and about 8 years from today. HQ could also have displaced some of the earlier replacements. During the outage, HQ offered, and signed a contract to sell, 500 MW of firm capacity to Vermont, with deliveries starting in 1991, at rates below BECO replacement power cost estimates.[46] An HQ offer to sell of up to 900 MW to Central Maine Power, starting in 1994, was rejected by the Maine PUC in 1989. The rates for the CMP purchase are below BECO's estimate of replacement power costs by 1997, even with a new transmission line. CMP offered shares of this purchase to other NEPOOL utilities. BECO has not even kept abreast of the rates HQ has offered to other New England utilities (BECO IR EOER-13), let alone approached HQ to explore options.

New Brunswick is currently selling BECO 100 MW of baseload nuclear capacity from the Pt. Lepreau nuclear plant, through 1991. In 1987 and 1988, the Pt. Lepreau purchase cost about 5 cents/kWh. BECO does not appear to have considered the option of extending the life of this contract, or of entering into any other contract when the existing contract ends. BECO IR MP 9-3 documents a series of offers from New Brunswick Power

[46] A portion of the Vermont purchase would utilize the NEPOOL/HQ Phase II transmission connection to carry firm capacity, rather than energy.

to BECO and NEPOOL in the period 1986-88, for at least 600 MW of long-term power sales. the 2/8/88 letter from New Brunswick Power to Mr. Hahn offers to extend the Pt. Lepreau sale through 1994 at rates which appear to be much lower than the NU purchase.

Nova Scotia has proposed building mine-mouth coal mines (the Bluenose Project) and transmitting power by an underwater cable to the Pilgrim site. The estimates BECO provided for this project's costs (in BECO RR MP-1) appear to be less expensive than IGCCs or system replacement power, and the project is expected to come on line in 1997.

Q: Please describe BECO's failure to consider increased QF purchases as part of the replacement for Pilgrim.

A: The experience of BECO and of other New England utilities indicates that QF power has generally been offered at prices lower than the utilities' posted avoided costs. Given BECO's high estimates for Pilgrim replacement power costs, it should find the procurement of QF power at prices lower than its replacement power cost estimates relatively easy.

Q: Please describe BECO's failure to consider increased conservation and load management (C&LM) investments as part of the replacement for Pilgrim.

A: Mr. Hahn, at page 16 of his testimony, asserts that the BECO base-case forecast includes the "maximum contribution from cost-effective C&LM," of nearly 1000 MW and that "it is not feasible or realistic to assume that Pilgrim can be replaced by additional C&LM." There are at least three errors in Mr. Hahn's reasoning:

- The "maximum contribution from cost-effective C&LM" is not a fixed number. If the retirement of Pilgrim would produce replacement power costs in excess of the avoided costs BECO used in estimating the amount of cost-effective C&LM, then the quantity of cost-effective C&LM would also rise.
- Mr. Hahn offers no demonstration that BECO has prepared an inventory of its C&LM potential, so BECO has no way of knowing whether its current forecast comes close to exhausting the cost-effective potential, at any avoided cost.
- Even if the studies Mr. Hahn cites to support the use of a 1000 MW maximum cost-effective C&LM potential were correct in the level of cost-effective BECO C&LM, they were referring to utility-sponsored C&LM, not natural "market-driven" C&LM. BECO projects only 513 MW of utility-sponsored C&LM, or half the targets.
- The studies Mr. Hahn cites were anticipating 1000 MW C&LM long before the end of BECO's study period in 2011. If 1000 MW is the right number for the year 2000 (the end date for the Boston Edison Review Panel) or 2005 (the end date for the analysis in **Power to Spare**), larger figures would be appropriate for 2011.
- One of the studies Mr. Hahn sites shows larger C&LM potential than his target. **Power to Spare** shows potential

savings in 2005 of 83,000 GWH. At a 60% load factor, this is equivalent to 9500 MW for New England. BECO is about 16% of NEPOOL, so its share would be about 1500 MW in 2005.

- Even if there were no more C&LM potential in total to be exploited by 2011, BECO could move up some programs, to realize savings earlier, particularly in the 1990s, when its replacement supply plan is so blatantly sub-optimal.[47]
- The reports on which Mr. Hahn relies were produced in 1987. Hence, they can not be used as a justification for failing to assemble a C&LM inventory and to consider C&LM as an alternative to Pilgrim in 1986. At that time, BECO projected only about 200 MW of C&LM by the year 2000.

While we have not produced the inventory of conservation potential which BECO should have already assembled, it is clear that adequate consideration of C&LM would reduce the cost of replacement power for Pilgrim.

Q: Given this long series of BECO errors, how have you corrected BECO's estimate of replacement power cost?

A: We have not been able to rerun the replacement power cost estimates to correct all of these problems. Instead, we have used BECO's QF avoided cost estimates as a proxy for the corrected replacement cost estimates. This approximation may

[47]In making this point, we would like to emphasize our reluctance to use whatever meager progress BECO may have made in the development of C&LM programs as evidence of earlier imprudence. Such an approach would penalize BECO for producing desirable results. BECO should be found imprudent for what it has not done with C&LM, not for the little it has done.

still overstate the best current estimate of replacement power costs.

Q: What replacement power costs have you used for the 1986 perspective?

A: Since BECO did not analyze the economics of Pilgrim operation at the beginning of the outage, we have no BECO replacement power cost estimate to review. We have used the 1986 avoided cost estimates from the first QF RFP as our estimate of replacement power costs. This appears to be a reasonable estimate of replacement power costs, as they would have been estimated by BECO in 1986. It is also very likely to be higher than the replacement power cost estimate which would have been produced by a comprehensive review of alternatives in 1986.

4.8 <u>Tax Effect of Abandonment</u>

4.8.1 As of 1986

Q: If BECO had retired Pilgrim in 1986, what would the tax effect have been?

A: BECO would have been able to deduct the undepreciated portion of Pilgrim from its Federal and state taxes at then-current rates of 46% and 6.5%, or a total of about 49.5%. At the beginning of 1986, BECO's depreciable investment in Pilgrim was $656 million, of which $131 million had been depreciated for book purposes. We do not have an exact deferred tax value for 1986, but from BECO IR MP 9-11, it appears that the value was about $98 million. Thus, the immediate write-off would be about

$$49.5\% * (656 - 131) - 98 = 162$$

or $162 million.

Q: What effect would this tax deduction have on the cost of Pilgrim retirement?

A: Table 4.8.1 displays the rate base effect of a tax credit of $162 million amortized over 24 years, starting in 1989. This treatment assumes that the ratepayers continue paying BECO for its entire investment in Pilgrim (presumably through a mechanism other than explicit ratebasing, since the plant would be retired) and that the ratepayers receive a deduction in rate base (or in the Pilgrim cost-recovery account) equal to the tax effect of the retirement.[48] The amortization of remaining Pilgrim costs would be taxable, since the investment would already have been deducted for tax purposes. The present value of the ratepayer benefit for the tax effect is $174 million in 1989 dollars.

4.8.2 As of 1989

Q: If BECO retired Pilgrim in 1989, what would the tax effect be?

A: The effect would have been similar to that for a 1986 retirement, except that the Federal tax rate is now 34%,

[48] If the shareholders absorb some or all of the sunk costs of Pilgrim, they should probably share proportionately in the tax benefits. In any case, the tax benefits are real savings from Pilgrim retirement.

bringing the total tax rate to about 38.3%. As of the end of 1988, BECO's depreciable investment in Pilgrim was $948 million, of which $208 million had been depreciated for book purposes. The letter in BECO IR MP 1-47 from BECO's J.C. O'Donnell to COMM/ELEC (dated 10/17/86) projects a deferred tax balance for 1988 of $102 million. Thus, the immediate write-off would be about

$$38.3\% * (948 - 208) - 102 = 181$$

or $181 million.

Q: What effect would this tax deduction have on the cost of Pilgrim retirement?

A: Table 4.8.2 repeats the computation in Table 4.8.1, but for the lower tax rate, 1989 finance costs, and the increased size of the write-off. The present value of the ratepayer benefit for the tax effect is about $175 million in 1989 dollars.

Q: Does this conclude your testimony?

A: Yes.

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EXHIBIT ER-PLC-2

RESUME OF PAUL L. CHERNICK

EXHIBIT ER-PLC-3

RESUME OF JONATHAN WALLACH

Executive Office of Energy Resources
DPU 89-100
Exhibit ER-PLC-3

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EXPERIENCE

1989-Present	Komanoff Energy Associates, New York, NY. Senior Analyst; responsible for comprehensive cost-benefit assessments of electric utility power supply options. Areas of specialization include: - Statistical analysis of nuclear and fossil fuel plant construction costs and operating costs and performance. - Computer modeling of electric utility required revenue impacts of power plant construction and operation. - Computer modeling of alternative ratemaking treatments of both completed and cancelled plant. - Critical evaluation of planning processes and decisions regarding large new baseload generating projects.
1987-1988	Independent Consultant; consulting services provided for Komanoff Energy Associates (New York, NY), Schlissel Engineering Associates (Belmont, MA), and Energy Systems Research Group (Boston, MA).
1981-1986	Energy Systems Research Group, Boston, MA. Research Associate; performed analyses of electric utility power supply planning scenarios. Also involved in analysis and design of utility conservation programs.
June 1979 - August 1979	Conservation Law Foundation, Boston, MA. Intern; analyzed scientific and technical data relating to proposed Georges Bank Marine Sanctuary, local toxic waste management issues, and prospective FERC regulations for non-utility producer access to grid.
Feb. 1979 - June 1979	Massachusetts Institute of Technology, Cambridge, MA. Researcher; involved in study of university-industry relationship in the recombinant-DNA controversy.

Nov. 1978 - Feb. 1979	Harvard Medical School, Boston, MA. Research Assistant; designed numerical analysis programs for computer analysis of nuclear magnetic resonance spectra.
Feb. 1978 - Aug. 1978	Massachusetts Institute of Technology, Cambridge, MA. Researcher; engaged in analysis of NRC construction permit hearings for Seabrook Nuclear Power Plant.

EDUCATION

B.A.	Political Science with honors and Phi Beta Kappa, University of California, Berkeley, 1980.
1976-1979	Massachusetts Institute of Technology, Cambridge, MA. Physics and Political Science.

AWARDS AND HONORS

Summer 1979	Summer internship funded by the Science, Technology, and Society Program at MIT.
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RESEARCH PUBLICATIONS

December 1985	*The Economics of Completing and Operating the Vogtle Generating Facility*, ESRG Study No. 85-51A. Co-author.
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EXHIBIT ER-PLC-4

STATISTICAL ANALYSIS OF U.S. NUCLEAR PLANT CAPACITY FACTORS, OPERATION AND MAINTENANCE COSTS, AND CAPITAL ADDITIONS

Executive Office of Energy Resources
DPU 89-100
Exhibit ER-PLC-4

STATISTICAL ANALYSIS OF U.S. NUCLEAR PLANT CAPACITY FACTORS, OPERATION AND MAINTENANCE COSTS, AND CAPITAL ADDITIONS

A REPORT TO THE
MASSACHUSETTS EXECUTIVE OFFICE OF ENERGY RESOURCES

JUNE 30, 1989

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TABLE OF CONTENTS

1. EXECUTIVE SUMMARY 1
   Capacity Factor 1
   O&M and Capital Additions 5
   1986 Retrospective 8

2. INTRODUCTION 11

3. CAPACITY FACTORS 14
   Regression Analysis 15
   Pilgrim Capacity Factor Projections 20

4. OPERATIONS AND MAINTENANCE COSTS 22
   Regression Analysis 24
   Pilgrim O&M Cost Projections 27

5. CAPITAL ADDITIONS 29
   Regression Analysis 31
   Pilgrim Capital Additions Projections 33

6. 1986 RETROSPECTIVE 35

1. EXECUTIVE SUMMARY

This report presents the results of statistical analyses of historical U.S. nuclear plant capacity factors, operation and maintenance costs (O&M), and capital additions costs carried out by Komanoff Energy Associates (KEA). The purpose of the analyses was to identify the salient engineering, institutional, and regulatory factors underlying the cost and performance experience of the U.S. nuclear industry. The results were then utilized to prepare projections of capacity factor, O&M, and capital additions for the Pilgrim nuclear plant.

The analyses of cost and performance experience employed multivariate linear regression analysis, a statistical technique that quantifies the variation in the cost or performance measure under question in relation to a set of explanatory factors or variables. Regression analysis measures the magnitude of the change in cost or performance as a function of the change in one explanatory variable, holding all other explanatory factors constant. In addition, it provides a measure of the statistical significance of the measured functional relation between cost/performance and an explanatory variable. The result is an equation that models the variation in cost or performance as a function of the set of causal factors that are found to be the statistically significant driving forces in cost or performance variation.

Capacity Factor

As a measure of nuclear plant operating performance, this study utilizes annual plant capacity factors, defined as the ratio of actual plant power generation to maximum possible generation based on design capacity. Equivalently, capacity factor equals the percentage of time in the year that the plant operated at full capacity. That nuclear plants do not operate at full capacity 100 percent of the time reflects the downtime associated with unscheduled or "forced" outages, as well as scheduled refueling and maintenance outages.

Based on capacity factor data collected by KEA for all commercial-size nuclear units during the years 1968 to 1988, which represent the entire history of commercial nuclear power in the U.S., the nuclear industry has operated at an average capacity factor of 59 percent. Although there has been little discernible industry-wide annual trend in operating performance, as illustrated in Figure 1.1, the 57 percent industry-wide average for the years 1979 to 1984 was significantly lower than the 61 percent average for all other years, indicative of the profound industry-wide impact of the TMI accident on operating performance.

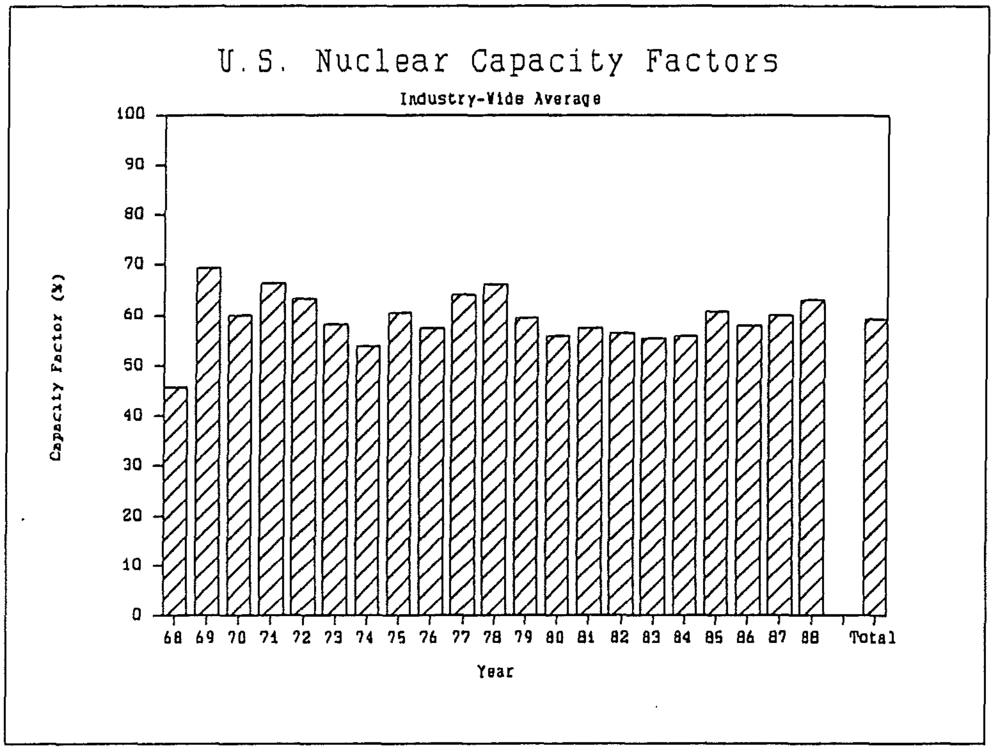

Figure 1.1

The KEA capacity factor database encompasses operating experience for all 100 nuclear units which reached commercial operation by the end of 1987. Cumulative lifetime capacity factor performance has varied widely over these plants, from a low (excluding TMI-2) of 32 percent for Seqouyah 1 to a high of 88 percent for St. Lucie 2. The Pilgrim plant has operated with an average 46 percent capacity factor over its lifetime, giving it the 12th lowest lifetime capacity factor among the 100 reactors.

The regression analysis of nuclear plant capacity factors explored a variety of potential explanatory factors. The variables found to be significantly correlated with *year-to-year* capacity factor variation include plant age -- reflecting plant maturation, long-term age-related decline, and enhanced decline associated with salt-water corrosion -- and utility reactor operating experience, reflecting an intra-utility learning curve.

Several variables were also identified which correlate with *plant-to-plant* capacity factor variation. Plant size was found to be negatively correlated with capacity factor, indicating a diseconomy of scale possibly resulting from increased design complexity. The second or third duplicate unit at a multiple-unit station were found to perform better than their commonly-sited partners or other single-site plants. NSSS vendor was also a significant factor, with Westinghouse, General Electric, and Babcock & Wilcox reactors all averaging progressively lower capacity factors than Combustion Engineering reactors. And plants whose construction began after the 1971-72 licensing hiatus that followed the *Calvert Cliffs* court decision were found to perform better on average than those started earlier.

Finally, several significant temporal variables were identified. A "post-TMI" effect was modelled which indicates an industry-wide decrease in capacity factor for the years 1979 to 1984. Furthermore, the impacts of outages for steam generator replacement in pressurized water reactors (PWR), primary and recirculation pipe replacement in boiling water reactors (BWR), and other major NRC-mandated plant modifications and shutdowns were isolated through the use of individual explanatory variables.

The resultant regression equation, correlating variations in plant capacity factor with a set of 20 explanatory variables, explains slightly more than half of all the year-to-year and plant-to-plant variation in U.S. nuclear capacity factors to date. It was utilized to project capacity factor performance for the Pilgrim plant for the years 1989 to 2012. The results are summarized in Table 1.1.

Two alternative capacity factor projections are presented in Table 1.1, representing, respectively, an "optimistic" and a "pessimistic" scenario. The "optimistic" projection assumes that plant modifications and improvements performed during Pilgrim's most recent outage have effectively rebuilt the plant. Pilgrim, therefore, is assumed to restart as a new unit. In this case, Pilgrim's capacity factor will mature to a peak of 65 percent in 1993 and then steadily decline thereafter. Although these results are possible, it should be noted that for industry experience to date there is no support for the proposition that plant refurbishment necessarily results in such dramatic performance improvement.

The "pessimistic" scenario, on the other hand, makes no such assumptions, projecting Pilgrim capacity factor based on its actual age. Under this scenario, Pilgrim's capacity factor is estimated to be 50 percent in 1989. Furthermore, at the rapid rate of decline anticipated, Pilgrim would be expected to operate for only 12 more years.

Table 1.1

PILGRIM CAPACITY FACTOR PROJECTIONS

(Percent)

Year	KEA 1989 Equation: Pessimistic Scenario	KEA 1989 Equation: Optimistic Scenario	Boston Edison
1989	50	61	56
1990	48	63	87
1991	45	63	66
1992	42	64	67
1993	39	65	69
1994	35	65	68
1995	32	65	68
1996	28	65	68
1997	24	64	68
1998	19	63	68
1999	14	62	68
2000	10	61	68
2001	4	60	68
2002		58	68
2003		56	68
2004		54	68
2005		52	68
2006		49	68
2007		46	68
2008		43	68
2009		40	68
2010		36	68
2011		33	68
2012		29	68
1989-98 Average:	36	64	68

Sources and Notes

(1) 1989 Equation results based on KEA regression equation on data through 1988.
(2) KEA pessimistic scenario assumes Pilgrim 1989 age equals actual age of 17. Optimistic scenario assumes 1989 age equals 1. Both scenarios assume 1989 utility experience is 16.
(3) Boston Edison data for 1989-93 from 5-Year Operating Plan. 68% CF assumption beyond 1993 from Hahn testimony.

Table 1.1 also includes Boston Edison's (BECo) estimates for Pilgrim capacity factor for 1989 and beyond. BECo projects Pilgrim capacity factor to plateau at 68 percent and to operate at the level throughout its remaining life. If industry-wide and Pilgrim past performance is any indication of the future, Boston Edison's projections are extremely optimistic and not supported by experience.

O&M and Capital Additions

Nuclear plant operating costs, exclusive of the cost of fuel, are largely expended on routine activities associated with operating and maintaining the plant and on intermittent large capital expenditures for plant modification (backfits) or refurbishment. The former costs are reported as O&M, while the latter are accounted for as capital additions.

The KEA nuclear O&M and capital additions database incorporates O&M and capital additions data for the years 1970 to 1987 (the last year for which such data are publicly available) as reported by utilities to the Federal Energy Regulatory Commission (FERC). All reported costs have been adjusted to 1987 dollars to analyze real dollar cost variation, net of general inflation. In addition, costs have been divided by plant capacity to express all costs on a normalized dollar-per-kilowatt (kW) basis.

Based on the data incorporated in the KEA database, industry-wide nuclear O&M has averaged $47 per kW for the years 1970 to 1987. Unlike industry-wide capacity factor performance, O&M costs exhibit a smooth upward trend. As indicated in Figure 1.2, annual average O&M expenditures grew from $10 per kW in 1970 to $78 per kW in 1987. The implied average annual growth rate is 12.5 percent.

Also provided in Figure 1.2 are annual industry-wide average capital additions for 1970 to 1987. Although such expenditures are by nature "lumpy," there is still concerted growth in average capital additions -- from $13 per kW in 1970 to $43 per kW in 1987. The average annual growth rate over this period is 11.1 percent.

KEA's regression analysis of O&M costs revealed several explanatory variables that were significantly correlated with the annual variation in O&M. Plant age is strongly correlated with O&M costs, probably indicating increasing expenditures as plant systems degrade over time. This aging trend was found to be

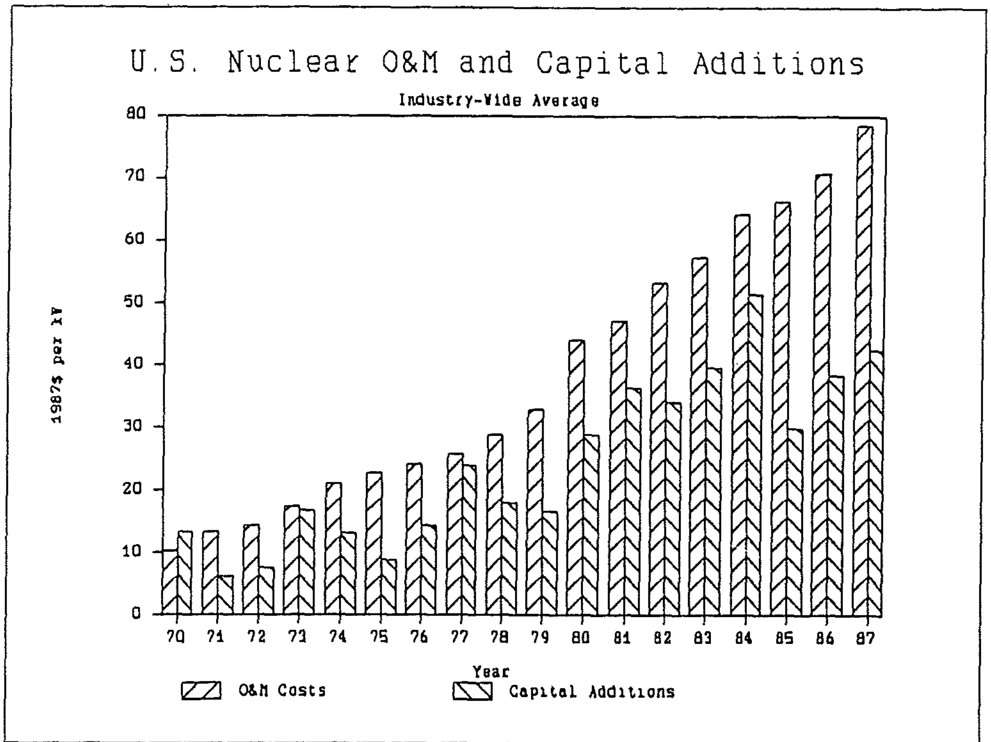

Figure 1.2

enhanced in salt-water cooled units. However, growth in utility reactor operating experience dampens the overall age effect; an ascent of the learning curve was correlated with reduced O&M expenditures.

Isolated from the overall age effect, costs were found to increase with a plant's commercial operation date. Newer plants, containing more equipment and employing more complex technologies, require higher expenditures for operation and repair. This vintage effect is partially offset by the negative correlation of O&M costs with increasing plant size -- a finding of economies of scale -- as newer-vintage plants tend to be larger than their older counterparts.

The evolving regulatory environment in the post-TMI era was modelled with two variables which together indicate that, after normalizing for plant age and vintage, O&M expenditures have increased significantly following the TMI accident. In addition, the gap between pre- and post-TMI expenditures continues to widen with each year beyond the TMI milestone.

The other plant characteristics found to correlate significantly with O&M costs were local wage rate, siting in the North Atlantic region, number of units on the plant site, and NSSS vendor.

The regression analysis of capital additions paralleled the O&M analysis in that capital additions were found to increase with both plant age -- a trend enhanced in salt-water cooled plants -- and vintage, and to decrease with increasing utility operating experience. However, there was no evidence of an economy of scale or North Atlantic siting effect. In addition, the post-TMI effect on capital expenditures was found to attenuate after 1984, indicating that the bulk of expenditures on post-TMI NRC-mandated backfits were made in the years 1980 to 1984. And, unlike the O&M analysis, the direct costs of PWR steam generator replacements and BWR pipe replacements were significant apart from the overall capital additions trends.

The O&M and capital additions regression equations have been applied to the Pilgrim plant to project expenditures over the remaining life of the plant. The O&M projections are provided in Table 1.2 for two different planning scenarios. The "optimistic" case assumes no further annual increase in the post-TMI effect beyond 1987, the last year for which empirical confirmation of the increased effect was available; this results in an average annual growth rate of 2.9 percent, with costs increasing from $120 per kW in 1989 to $236 per kW in 2012 (in 1987 dollars). The "pessimistic" scenario does not "cap" the post-TMI effect, and the outcome is a stronger growth rate of 3.5 percent.

Boston Edison's O&M projections are also included in Table 1.2 and, as indicated, assume a long-term average annual growth rate of 3.0 percent. Although this rate slightly exceeds that of the KEA "optimistic" projection, BECo's estimated annual costs are lower than KEA's in every year, because BECo has assumed relatively slow growth in the years 1989 to 1993.

Analogous "optimistic" and "pessimistic" capital additions projections for the Pilgrim plant are provided in Table 1.3. The "optimistic" scenario projections were derived by replacing the coefficient values for the plant age and salt-water age variables with their respective 95% lower-confidence limit values for all years after 1987. This results in an average annual growth rate of 2.6 percent, with costs increasing from $71 per kW in 1989 to $129 per kW in 2012. The "pessimistic" scenario does not incorporate any such adjustment and, as a result, costs are projected to increase from $74 per kW in 1989 to $168 per kW in 2012. The implied growth rate is 3.6 percent.

Boston Edison projections for Pilgrim capital additions, also provided in Table 1.3, increase costs from $42 per kW in 1989 to $62 per kW in 2012. The implied growth rate for these years is 1.2 percent.

1986 Retrospective

As part of its statistical analysis of nuclear plant cost and performance, KEA also projected Pilgrim capacity factor, O&M costs, and capital additions based on industry trends in evidence in early 1986, corresponding to the start of Pilgrim's recent extended outage. At the time, capacity factor data was available through 1985, and O&M and capital additions data was available through 1984.

The regression equations used to derive Pilgrim cost and performance projections from the perspective of early 1986 were those derived by KEA at the time for use in other proceedings. At the time, these equations were adopted by KEA as models that had the best "fit" of the available data.

In general, the early-1986 KEA regression equations project higher O&M costs and capital additions and lower capacity factor performance for Pilgrim than KEA's current equations. The only exception is the 1986 "optimistic" O&M projection for Pilgrim, which projects lower costs than the "optimistic" projection derived from current industry trends.

Table 1.2

PILGRIM O&M PROJECTIONS

(1987$ per kW)

	KEA 1989 Equation		
Year	Pessimistic Scenario	Optimistic Scenario	Boston Edison
1989	124	120	116
1990	130	125	113
1991	137	130	124
1992	144	135	113
1993	151	140	123
1994	157	145	127
1995	164	150	131
1996	171	155	135
1997	177	160	139
1998	184	165	144
1999	191	170	148
2000	198	175	152
2001	204	180	157
2002	211	185	162
2003	218	190	167
2004	225	195	172
2005	232	200	177
2006	238	205	183
2007	245	210	188
2008	252	215	194
2009	259	220	200
2010	265	225	206
2011	272	230	213
2012	279	236	219
Average Annual Growth:	3.53%	2.93%	2.98%

Sources and Notes

(1) 1989 Equation results based on KEA regression equation on data through 1987.

(2) KEA optimistic scenario caps value of Years-Past-TMI variable at the 1987 value of 8 years. Pessimistic scenario assumes continued Years-Past-TMI effect.

(3) Boston Edison costs for 1989-93 from 5-Year Operating Plan. 1989$ costs deflated to 1987$ using BECo estimates of GNP deflator, as provided in response to EOER-17. Beyond 1993, costs escalated at BECo estimates of real growth rate.

(4) Average annual growth rates derived from simple log-linear fit of data to time.

Table 1.3

PILGRIM CAPITAL ADDITIONS PROJECTIONS

(1987$ per kW)

Year	KEA 1989 Equation Pessimistic Scenario	KEA 1989 Equation Optimistic Scenario	Boston Edison
1989	74	71	42
1990	78	73	39
1991	82	75	58
1992	86	78	49
1993	90	80	56
1994	94	83	56
1995	98	85	56
1996	102	88	56
1997	106	90	56
1998	110	93	56
1999	114	95	56
2000	119	98	57
2001	123	100	57
2002	127	103	57
2003	131	105	58
2004	135	108	58
2005	139	111	59
2006	143	113	59
2007	148	116	60
2008	152	118	60
2009	156	121	61
2010	160	123	61
2011	164	126	62
2012	168	129	62
Average Annual Growth:	3.59%	2.62%	1.19%

Sources and Notes

(1) 1989 Equation results based on KEA regression equation on data through 1987.
(2) KEA optimistic scenario replaces value of plant age and salt-water age coefficients in regression equation with their respective 95% lower confidence limit values for all years after 1987. Pessimistic scenario projections make no such adjustment.
(3) Boston Edison costs for 1989-93 from 5-Year Operating Plan. 1989$ costs deflated to 1987$ using BECo estimates of GNP deflator, as provided in response to EOER-17. Beyond 1993, costs escalated at BECo estimates of real growth rate.
(4) Average annual growth rates derived from simple log-linear fit of data to time.

2. INTRODUCTION

The growth and maturation of the nuclear industry over the last 20 years has been accompanied by rapid escalation in the costs to operate, maintain, and refurbish nuclear power plants. Several factors appear to have driven this cost escalation. As plants that came on-line in the late-60's and early-70's have aged, expenditures on degrading components have multiplied. In addition, as the industry has matured and safety regulations have evolved, older plants have had to expend ever greater sums to revise operating procedures and replace functionally obsolete equipment.

Newer-vintage plants, while incorporating more-advanced technology in their original designs, have not been immune to the twin specters of component aging and maturation of the regulatory environment. Moreover, the newer-vintage units, larger and more complex than their earlier counterparts, have more (and more expensive) equipment to maintain, repair, and replace, as well as increased staffing requirements.

At the same time, the accretion of expenditures has not improved the overall operating performance of the industry. The average capacity factor has hovered around the 60 percent mark. Although these expenditures could conceivably lead to improved future performance, the current combination of steadily increasing costs and lackluster performance continues to erode any operating economic benefits (i.e., without regard to capital costs) that nuclear power currently offers.

While *on average* the industry has been plagued by escalating O&M and capital additions in combination with disappointing operating performance, there have been *individual* plants that have excelled in maintaining costs at a manageable level and/or performing at high capacity factors. The Point Beach 1 and 2 units are a notable example; they have achieved consistently high performance (72% and 81% lifetime average capacity factors, respectively, ranking 16th and 4th out of 100 reactors) while maintaining some of the lowest expenditures on O&M and capital additions in the industry.

The history of operating costs and performance at the Pilgrim nuclear plant, on the other hand, has not been inspiring in its ability to either manage costs or achieve notable performance. Over Pilgrim's lifetime, average annual expenditures for both O&M and capital additions, on a dollar per kilowatt of capacity basis, have been some of the highest in the industry. At the same time, its lifetime average capacity factor has been a disappointing 46 percent.

The current extended outage at Pilgrim, which began in 1986 and is only now in its final stage, is a major contributor (although, certainly not the only) to Pilgrim's sub-par cost and performance record. During this outage, Boston Edison has capitalized over $200 million of expenditures on an array of plant improvements such as fire protection backfits and Mark I containament modifications. In addition, approximately $100 million has been expended on inspection, maintenance, and repair duties. But despite $300 million dollars of plant refurbishment and maintenance work, Pilgrim's future cost and performance are highly uncertain.

As one approach in understanding Pilgrim's past cost and performance in relation to the rest of the nuclear industry, as well as predicting Pilgrim's future, this study examines the historical cost and performance trends of both Pilgrim and the industry as a whole. To do so, Komanoff Energy Associates (KEA) has compiled separate databases for plant capacity factor experience, O&M expenditures, and capital additions. Each database includes annual plant-specific information on the cost/performance measure in question, as well as information on plant characteristics (*e.g.*, plant capacity) and relevant institutional or regulatory factors (*e.g.*, utility operating experience, NRC-mandated outages).

Using a common statistical technique known as multivariate or multiple linear regression analysis, the variation in both *year-to-year* cost or performance -- across all plants -- and *plant-to-plant* cost or performance -- across all years -- is analyzed in relation to a set of engineering, institutional, and regulatory factors that are hypothesized to be causally related to the cost/performance measure in question. Regression analysis measures the *individual* correlation of the cost/performance measure (the "dependent variable") with each of the hypothesized explanatory factors (the "independent variables"), controlling for the effect of other factors. In so doing, regression analysis allows the user to isolate and quantify the impact of each causal factor.

It is this powerful ability to separate overlapping causal effects that makes the use of regression analyis superior to simple comparisons of average cost or performance. Although it is useful to survey, for example, industry-wide average annual capacity factors in search of gross performance trends, the outcome often lacks any true explanatory power. While trends may be identified with simple averages, the driving forces remain hidden in the data and undifferentiated from one another. Similarly, breaking the sample down into smaller subsets (e.g., boiling water vs. pressurized water reactors) may reveal the presence of a single causal factor, but it cannot isolate that causal effect from other synergistic forces.

Regression analysis provides several measures of correlation of the dependent variable under study with a set of independent variables. The *magnitude* of the correlation of the dependent variable with any one independent variable is measured by the "regression coefficient," which measures the amount of change in the dependent variable per unit of change in the independent variable. A measure of the *statistical significance* of the regression coefficient is also calculated which provides a level of confidence that the measured coefficient is not a product of random chance.

In addition, indicators of the overall *goodness of fit* of the regression equation are provided by the multiple coefficient of determination or "R^2" and the "F ratio." In essence, the R^2 measures the percentage of variation in the dependent variable that is explained by the set of independent variables in the equation. The F ratio provides a measure of the overall significance of the regression equation, indicating the probability that all of the regression coefficients are not simultaneously the result of random chance. Alternatively, the F ratio can be viewed as a measure of the statistical significance of the computed R^2.

The outcome of regression analysis is an equation that measures the historical variation in cost or performance as a function of a set of explanatory factors multiplied by their respective regression coefficients. The value of such an analysis of the historical data is that it provides a tool for predicting future performance, assuming historical trends continue. In this regard, the regression analyses performed on nuclear capacity factors, O&M, and capital additions have been used to project Pilgrim cost and performance over its remaining lifetime.

3. CAPACITY FACTORS

The KEA analysis of nuclear plant operating experience focuses on annual plant capacity factor as a measure of performance. Annual capacity factor is defined as the ratio of actual net generation to maximum possible generation based on plant capacity. Equivalently, capacity factor equals the fraction of the year that a plant is operating at full rated capacity. Mathematically, the calculation is as follows:

$$\text{Annual Capacity Factor} = \frac{\text{Net Generation}}{\text{Plant Capacity} * 8760 \text{ Hours}}$$

For the purposes of this study, a unit's net design electrical rating (DER) is used as the measure of plant capacity.

In any year, a plant's capacity factor is limited by "scheduled outages": downtime used to either refuel, maintain, or refurbish the plant. The majority of nuclear plants operate on a 12 or 18 month refueling cycle, at the end of which the reactor is shut down to replace the burned-up portion of the fuel core. Typically, the downtime during refueling is used to perform other maintenance and equipment replacement or modification work that cannot be carried out while the reactor is on-line. For more extensive modification work such as steam generator replacement, however, the refueling outage may be extended or a separate outage is scheduled.

Increased regulatory stringency following the 1979 accident at TMI-2 has led to increased prominence for that subset of scheduled outages classified as "NRC-mandated." In the years since TMI, these outages have largely involved work performed for TMI-related plant modifications (backfits). In addition, with growing awareness of the safety implications of lax management practices, there have been several notable examples of NRC-ordered shutdowns due to findings of utility mis-management.

In addition to scheduled outage time, a plant's capacity factor is limited by unscheduled or "forced" outages. With considerable complexity involved in nuclear technology, there are any number of chains of events that can force a reactor off-line. Moreover, equipment malfunction may compel a reactor operator to reduce plant output below full design capacity in order to meet safety criteria or simply to reflect equipment limitations. Extensive steam generator tube plugging -- necessary to prevent leakage of coolant water from corroded tubes -- has led to plant "deratings" in some instances.

Table 3.1, compiled from the KEA capacity factor database, indicates the combined magnitude of forced and scheduled outages experienced by the U.S. industry during its 21-year commercial history. For the years 1968 to 1988, the nuclear industry has operated on average at 59 percent capacity factor. There is little discernible long-term trend in the annual averages except for an industry-wide dip in performance for the years 1979 to 1984, apparently a result of TMI-related regulatory shutdowns. The upswing in capacity factor in 1988 is also notable; however, it is too early to tell whether this portends industry-wide improvement or is merely the result of a confluence of temporary factors.

Capacity factor experience for the Pilgrim plant is also summarized in Table 3.1. Over its 16-year lifetime, Pilgrim has operated at an average 46 percent capacity factor, or 89th out of 100 reactors. Pilgrim's lifetime performance has been abnormally low relative to industry experience, in large part due to its most recent extended outage. Yet, prior to the start of the this outage in 1986, Pilgrim averaged only 56 percent capacity factor.

Regression Analysis

As part of its analysis of U.S. nuclear plant capacity factor experience, KEA has compiled a database of plant performance and characteristics that spans the years 1968 to 1988 and includes operating data for 100 nuclear units. In all, the database encompasses 1026 reactor-years of experience, covering all U.S. commercial operating experience through 1988. In addition to annual capacity factor data, the database includes data on plant age, capacity, NSSS vendor, type of cooling water, and utility operating experience, as well as information on regulatory and other major plant modification outages.

The regression analysis of annual plant performance involved testing an extensive array of variables for correlation with annual capacity factor experience. Several hypotheses concerning the causal factors of capacity factor trends were investigated. These include:

Table 3.1

HISTORICAL CAPACITY FACTOR EXPERIENCE

(Percent)

	Industry Average	Pilgrim
1968	46	
1969	69	
1970	60	
1971	66	
1972	63	
1973	58	69
1974	54	34
1975	60	44
1976	57	41
1977	64	45
1978	66	75
1979	59	83
1980	56	52
1981	57	59
1982	56	56
1983	55	80
1984	56	0
1985	61	84
1986	58	18
1987	60	0
1988	63	0
1973-88 Average:	59	46

Sources and Notes

(1) Data compiled from KEA capacity factor database.
(2) Industry-wide and Pilgrim average annual capacity factors calculated for the years 1973-88. Industry-wide average for 1968-88 is also 59%.

(1) Plant age. The age of the plant was thought to be relevant to plant performance in three ways. First, plants exhibit capacity factor maturation as a result of the "shakedown" of plant systems in the early years of its life. Second, a long-term decline in performance is to be expected as components age and require greater outage time for maintenance and replacement. Third, it has been established empirically, both in the field and in other regression analyses, that salt-water corrosion intensifies the aging of plant components.

(2) Institutional learning. As utility management gains reactor operating experience, it seems logical to posit a learning curve leading to improved performance with time. This hypothesis was tested, allowing for experience gained not just at the instant plant, but at all plants owned by the utility.

(3) Regulatory or Major Plant Modification Outages. Enhanced regulatory stringency following the TMI accident has increased plant outage time to implement plant modifications (backfits), as well as to comply with revised operating procedures. In addition, considerable outage time has been expended to replace major components such as steam generators or large-diameter piping. Finally, increasing regulatory awareness of the safety implications of lax management practices has led to extended NRC-ordered outages. To the extent possible, such outages were isolated from the general performance trends as temporal incidents.

(4) Plant characteristics. Apart from the time-dependent causal relations tested, performance variation among plants was tested for correlation with key plant characteristics: plant capacity, NSSS vendor, construction permit date, and whether a plant was the second or third to be constructed at a multiple unit site.

The resultant equation, provided in Table 3.2, includes 20 explanatory variables, all of which are significant at greater than the 95% confidence level. The adjusted R^2 of the equation is 0.52, indicating that the explanatory variables together explain 52 percent of the variation in plant capacity factor. The overall fit of the equation, as indicated by the F ratio, is significant at greater than the 99.9% confidence level.

Plant aging was modelled with the combination of AGE and AGE^2 (the square of AGE), allowing for an initial maturation period followed by a steady long-term decline. For fresh-water cooled plants, peak performance is reached at around age 10. Salt-water cooled plants were found to peak much earlier, at age 6, with a steeper decline thereafter.

Table 3.2

ANNUAL PILGRIM CAPACITY FACTORS
1989 PERSPECTIVE
KEA REGRESSION EQUATION

Variable	Significance	Coefficient	1989 Value	1989 Product
Salt Water Cooling Times Age	0.0%	-0.842	17	-14.32
GE NSSS	0.0%	-10.709	1	-10.71
Westinghouse NSSS	0.0%	-7.240	0	0.00
B&W NSSS	0.0%	-12.677	0	0.00
Duplicate Unit	1.5%	2.845	0	0.00
Post-TMI 1979-84	0.0%	-6.856	0	0.00
PWR Steam Generator Replacement	0.0%	-35.167	0	0.00
BWR Large Pipe Replacement	0.0%	-43.491	0	0.00
BWR Small Pipe Replacement	3.8%	-6.821	0	0.00
Management Shutdown	0.0%	-59.094	0	0.00
Westinghouse Quake Mods.	0.0%	-33.572	0	0.00
Browns Ferry Fire	0.0%	-35.693	0	0.00
Westinghouse Fuel Failure	4.6%	-6.943	0	0.00
Palisades Plant	0.0%	-33.896	0	0.00
Post-1971 Construction Permit	0.1%	5.653	0	0.00
Log of Utility Experience	1.5%	1.925	2.83	5.45
Log of CECo Utility Experience	0.0%	-1.965	0.00	0.00
Log of Plant Size (MW)	0.0%	-13.531	6.51	-88.05
Age of Plant	0.0%	2.248	17	38.21
Age Squared	0.0%	-0.116	289	-33.48
Constant	0.0%	153.393	1	153.39
Adjustment for Major Outages				0.00
Predicted Annual Capacity Factor				50.50
Adjusted R-Square		0.519		
F-Statistic		56.302		
Standard Error of Estimate		14.918		

Sources and Notes

(1) Value of utility experience variable for Pilgrim in 1989 is 16. Calculation of log of utility experience adds 1 to utility experience variable to allow for zero experience in initial year.

(2) Plant age is set to 1 in a plant's first full year of operation and then increased by 1 each year thereafter. Pilgrim's age in 1989 is 17.

(3) Pilgrim capacity is 670 MW.

(4) Adjustment for major outages is the average annual percentage point reduction to capacity factor implied by historical effect of regulatory and other major plant modification outages. No adjustment is applied to estimated Pilgrim capacity factors.

Long-term aging appears to be moderated by learning associated with utility operating experience. Each doubling of utility experience -- total prior reactor-years -- increases capacity factor by 1.3 percentage points. However, for plants owned by Commonwealth Edison (CECo), the largest nuclear utility in the country, no such learning effect was in evidence. Two factors may be at work, however. First, CECo's plants are a mix of boiling water and pressurized water reactors and the experience gained at one may not be applicable to the other.[1] Second, as will be discussed in the following sections on O&M costs and capital additions, CECo spending for O&M and plant improvements has not kept up with industry trends. Perhaps as a result of this under-investement, CECo plant performance may not be improving at the rate apparent for non-CECo plants.

The post-TMI regulatory variable correlates significantly with capacity factor, indicating that the industry as a whole experienced an average 6.9 percentage point drop in capacity factor in the years following TMI. The post-TMI effect was not significant after 1984, apparently because the bulk of the TMI-related backfits was completed in this period and the pace of NRC-mandated modifications slackened. An alternative hypothesis is that the post-1984 TMI-related impact is being captured by the variable for NRC-mandated mismanagement shutdowns, all of which have occurred in 1985 or later. If so, it is a matter of interpretation as to whether shutdowns ordered over management concerns are a result of the post-TMI regulatory environment.

The other regulatory events or outages for major modifications found to correlate significantly with capacity factor were the Browns Ferry fire outage in 1975-76, the 1973-74 outages to remedy Westinghouse-reactor fuel failures, outages to repair or replace BWR small-diameter piping in 1974-75 and large diameter piping throughout the 1980's, outages since 1979 to replace Westinghouse steam generators, outages to re-analyze and correct seismic design factors at Westinghouse plants in 1976-79, and NRC-mandated shutdowns in response to utility mismanagement. Taken in combination, such outages have reduced industry-wide

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[1]Regression analysis conducted by Richard Lester and Mark McCabe of the MIT Energy Laboratory separated utility experience gained at PWRs from that gained at BWRs. Lester and McCabe, The Effect of Industrial Structure on Learning by Using in Nuclear Power Plant Operation, MIT-EL 88-024, November 1988.

average capacity factor by 3.9 percentage points.

A number of plant characteristics were also found to correlate significantly with capacity factor. Plant capacity is negatively correlated with capacity factor, indicating a diseconomy of scale possibly resulting from increased design complexity. The second or third duplicate reactor at a multiple-unit station performs better than their predecessors or other single-site plants, consistent with a supposition of intra-site learning. In addition, plants whose construction began after the 1971-72 licensing hiatus that followed the *Calvert Cliffs* court decision were found to perform better on average than those started earlier.

Average plant performance was also found to correlate significantly with the NSSS vendor. Westinghouse, General Electric and Babcock & Wilcox, reactor performance averaged 7.2, 10.7, and 12.7 percentage points, respectively, lower than average performance for Combustion Engineering reactors.

As informative as those variables that correlated significantly with capacity factor, are those that did not. In particular, variables were tested to measure performance improvement following either steam generator replacement or BWR pipe replacement. It was hypothesized that refurbishments of this magnitude would result in effectively "brand new" plants with less age-related decay. No such effect was apparent.

Pilgrim Capacity Factor Projections

The KEA capacity factor regression equation was used to project Pilgrim annual capacity factors for the years 1989 through 2012. As part of this analysis, the equation was also used to estimate Pilgrim historical capacity factor experience. Applying the appropriate Pilgrim plant characteristics, the KEA equation predicts an average annual capacity factor of 42 percent for the years 1973 to 1988. This estimate is 4 percentage points lower than actual average experience.

Although Pilgrim's historical capacity factor experience can be tracked moderately well with industry trends, there is still uncertainty involved with projecting past trends into the future. In Pilgrim's case, the uncertainty lies in estimating the impact of current plant modifications on future performance. Although there is little historical evidence that major renovations significantly improve performance, it is possible that Pilgrim may be an exception.

To allow for such uncertainty, two alternative projections of Pilgrim capacity factor performance were derived using the KEA regression equation. The "optimistic" projection posits a scenario whereby the plant modifications performed in the current outage have effectively rebuilt the plant. Pilgrim, therefore, is assumed to restart as a new unit. The "pessimistic" scenario, on the other hand, projects Pilgrim capacity factor based on its actual age.

In both scenarios, it is conservatively assumed that all outages isolated in the KEA regression equation as NRC-mandated or dedicated to major plant modifications are non-recurring and, therefore, do not affect future Pilgrim performance. This assumption is conservative in two regards. First, isolating such outages from the general population of industry experience in the KEA database results in a more optimistic industry trend than would be indicated by treating such outages as indistinct from others embodied in the database. Second, it is conservative to assume that the industry will not encounter another form of widespread problem leading to regulatory or other forms of extended outages.[2]

Table 1.1 details the capacity factor projections for both "optimistic" and "pessimistic" scenarios. The "optimistic" capacity factor estimate for 1989 is 61 percent. This is projected to mature to a maximum capacity factor of 65 percent in 1993 and then steadily decline thereafter. Under the "pessimistic" scenario, the 1989 capacity factor is estimated to be 50 percent. Capacity factors are projected to decline rapidly thereafter, with an expectation of complete shutdown by 2002.

BECo's estimates of Pilgrim capacity factor are also included in Table 1.1. BECo projects Pilgrim capacity factor to plateau at 68 percent in 1994 and to operate at that level thereafter. In comparison to past industry-wide and Pilgrim performance, as manifested in the KEA projections of Pilgrim capacity factor, BECo's projections are extremely optimistic unsupported by industry experience.

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[2]Recent industry problems with faulty steam generator tube plugs are an example of equipment malfunction that could lead to widespread extended outages. And recent threats by the NRC to shut down the Turkey Point units due to management deficiencies indicate the possibility for future NRC-mandated outages.

4. OPERATIONS AND MAINTENANCE COSTS

The costs to operate, maintain, and routinely repair a nuclear power plant, exclusive of the cost of fuel, are expensed as Operations and Maintenance (O&M) costs. O&M costs typically include staff salaries and other labor-related costs, as well as the costs of supplies and materials.

The KEA nuclear O&M database incorporates O&M cost data for the years 1970 to 1987 (the last year for which such data are publicly available). Costs are reported by utilities to the Federal Energy Regulatory Commission (FERC) each year as part of their annual Form 1 filing. In most cases where there is more than one *reactor* on the site, costs are reported for the *station* as a whole.

All reported costs incorporated in the KEA database have been adjusted for inflation in order to analyze real (1987) dollar cost variation. In addition, costs have been divided by plant capacity to express all costs on a normalized dollar per kilowatt (kW) basis. For multiple-unit *stations*, costs were divided by the *total* capacity of all units on the site.

Table 4.1, based on data compiled from the KEA O&M database, provides annual industry-wide average O&M costs for the years 1970 to 1987. As indicated, average industry costs grew steadily from $10 per kW in 1970 to $78 per kW in 1987. The implied annual growth rate for those years was 12.5 percent.

Aside from the steady growth in costs, of particular note in the industry-wide average cost data is the significant upward ratcheting of expenditures in the years 1980 and thereafter. It appears that the post-TMI regulatory environment has raised the level of expenditures required to meet increasingly stringent safety criteria. Perhaps also, utilities have recognized the fragility of nuclear plants and have actively stepped up their expenditures in order to safeguard their investment.

In addition to industry-wide data, Table 4.1 also summarizes O&M experience for the Pilgrim plant. As indicated in Table 4.1, Pilgrim O&M costs have been consistently higher than the industry average, with costs growing from $17 per kW in 1973 to $168 per kW in 1987. Over its lifetime, Pilgrim annual O&M costs averaged $65 per kW, the 13th highest average level of expenditure for the 63 plants included in the KEA database.

Table 4.1

HISTORICAL O&M EXPERIENCE

(1987$ per kW)

	Industry Average	Pilgrim
1970	10	
1971	13	
1972	14	
1973	17	17
1974	21	31
1975	23	22
1976	24	46
1977	26	40
1978	29	34
1979	33	41
1980	44	57
1981	47	65
1982	53	74
1983	57	80
1984	64	94
1985	66	97
1986	71	111
1987	78	168
1973-87 Average:	49	65
1973-87 Growth:	11.74%	14.57%

Sources and Notes

(1) Data compiled from KEA O&M database.
(2) Average annual growth rates derived from simple log-linear fit of data to time.
(3) Industry-wide 1970-87 average annual O&M is $47 per kW. 1970-87 average annual growth rate is 12.48%.

Regression Analysis

As noted above, the KEA O&M database incorporates U.S. nuclear industry O&M cost experience for the years 1970 to 1987, encompassing O&M cost experience for 63 commercial nuclear *stations*. The cost data provided to FERC were scrutinized carefully to correct inconsistencies in reported data (*e.g.*, reporting some costs for a utility's partial ownership share while reporting other costs for the whole plant). In several cases, inconsistent or implausible data were eliminated, yielding 648 station-years of experience.

In addition to O&M costs, the database includes annual data on station age, commercial operation date, capacity, NSSS vendor, type of cooling water, number of units on the plant site, local wage rates, utility operating experience, and information on regulatory outages. Because annual cost data for multiple-unit plant sites are reported for the station as a whole, the corresponding plant data are averaged over all units at the site. For example, if one reactor at a two-unit site starts up on January 1, 1985 and the second reactor starts one year later, plant vintage will be 85 in 1985 and 85.5 in 1986 and all years thereafter.

KEA's statistical analysis of O&M costs explored several hypotheses regarding the correlation of cost trends to engineering, institutional, and regulatory factors, including:

(1) Plant age. As plants age and components degrade, more labor and supplies must be allocated to equipment maintenance and repair, resulting in increased O&M expenditures. For salt-water cooled plants, salt-water corrosion is expected to add to the cost burden associated with general age-related wear-and-tear.

(2) Plant vintage. Newer-vintage plants are larger and more complex than their earlier counterparts. There is more equipment to maintain and repair and, therefore, more expenditures for O&M are required.

(3) Institutional learning. As a utility's operating experience increases, it is expected that operation, maintenance, and repair procedures would become more efficient, allowing for a reduction of expenditures with time. Analogous with the capacity factor analysis, this hypothesis was tested allowing for experience gained at all plants owned by the utility.

(4) Revised regulatory procedures. Although the nuclear regulatory environment has been evolving throughout time, the post-TMI era appears as a significant leap in the level of regulatory scrutiny and

the extent to which operation and maintenance procedures have been revised. It is anticipated that the combined effect of these regulatory changes on plant operations would translate into additional O&M expenditures.

(5) Plant characteristics. In addition to plant vintage, several plant characteristics were hypothesized to correlate with the *plant-to-plant* variation in O&M costs. These include: plant capacity, number of units on the plant site, local wage rate, NSSS vendor, and geographic location.

Table 4.2 details the regression equation derived from KEA's analysis of the variation in O&M costs. The equation models the variation in O&M costs as a function of 14 explanatory variables, all of which are significant at greater than the 95% confidence level. Taken together, the variables explain 68 percent of the variation in O&M costs at greater than the 99.9% confidence level, as indicated by the adjusted R^2 and F ratio, respectively.

Plant age is the predominant force driving O&M expenditures over time in the KEA regression equation. As indicated in Table 4.2, a one-year increase in age increases real (1987$) O&M costs per kW by $3.95. A salt-water plant's O&M increases an *additional* $1.21 dollars for every year increase in age.

The plant vintage variable correlates significantly with O&M costs, indicating that newer-vintage plants, without regard to the differential in age, spend more for O&M than older units. A plant completed in 1985, for example, will spend $37 dollars per kW more in its first year of operation than a comparable 1975-vintage plant in its first year of operation.

The effect of plant aging on O&M is moderated by the concomitant increase in utility operating experience. For plants owned by Commonwealth Edison, however, the impact of utility experience on costs appears to differ from that of the rest of the industry. Apparently, CECo O&M expenditures over time have been skewed in relation to industry trends. In the 1970's, CECo spent more for O&M than was typical for a utility with its level of operating experience at the time. In the 1980's, however, CECo has not kept up with industry expenditures on O&M. The latter period of under-investment could conceivably be a consequence of CECo's growing investment in new plant construction, as limited resources were diverted away from existing plant services to new plant construction. For the

Table 4.2

ANNUAL PILGRIM O&M COSTS
1989 PERSPECTIVE
KEA REGRESSION EQUATION

Variable	Significance	Coefficient	1989 Value	1989 Product
Salt Water Cooling Times Age	0.0%	1.214	16.58	20.13
GE NSSS	0.2%	4.753	1	4.75
CE NSSS	0.1%	-7.027	0	0.00
B&W NSSS	0.0%	11.455	0	0.00
Log of No. of Identical Units	0.0%	-13.044	0.00	0.00
Post-TMI	1.1%	6.419	1	6.42
Years Past TMI, Frozen at 8 Yrs	0.3%	1.742	8	13.94
Wage Rate (R.S. Means, 1/1/85)	2.7%	0.554	21.70	12.02
Vintage (CO Date)	0.0%	3.665	72.92	267.25
North Atlantic Location	0.2%	5.656	1	5.66
Log of Non-CECo Util Experience	0.0%	-3.954	2.83	-11.20
CECo Utility Experience	0.0%	-0.369	0.00	0.00
Log of Plant Size (MW)	0.1%	-12.598	6.51	-81.98
Age of Plant	0.0%	3.945	16.58	65.42
Constant	0.0%	-182.156	1	-182.16
Predicted Cost, 1987$/kW				$120.25
Adjusted R-Square		0.677		
F-Statistic		97.679		
Standard Error of Estimate		16.368		

Sources and Notes

(1) Value of utility experience variable for Pilgrim in 1989 is 16. Calculation of log of utility experience adds 1 to utility experience variable to allow for zero experience in initial year.
(2) Plant age is calculated as age at mid-point of calendar year (Age = Year + 0.5 - Vintage).
(3) Pilgrim capacity is 670 MW.

purposes of this analysis, CECo's unique cost experience was modelled with a separate operating experience variable.

Enhanced regulatory intervention in the post-TMI era appears to have raised the average level of O&M expenditures over the level experienced in prior years. The coefficient value for the Post-TMI variable indicates that the industry as a whole experienced an average $6.42 per kW *initial* increase in costs in 1980. In addition, the gap between pre- and post-TMI expenditures appears to be widening by $1.74 per kW (as indicated by the coefficient of the Years-Past-TMI variable) with each year following 1980. Taken in combination, these two variables model a substantial post-TMI effect that is growing in magnitude.

Of the plant characteristics tested for correlation with O&M costs, those found to be significant factors were the local wage rate, siting of the plant in the North Atlantic region, plant capacity, the number of units on the plant site, and NSSS vendor. As hypothesized, an increase in the local wage rate or siting in the North Atlantic increases plant O&M costs. A doubling of plant capacity decreases annual O&M by $8.73 per kW, indicating an economy-of-scale effect. In addition, a two-unit site will spend $9.04 per kW less per year than a single-unit site, indicating savings from sharing of site personnel and resources.

Of the four types of reactors, Combustion Engineering plants averaged the lowest O&M expenditures (holding all other factors constant). These were followed in order of increasing costs by Westinghouse reactors, General Electric reactors, and Babcock & Wilcox reactors. It is interesting to note that the level of average expenditures by reactor manufacturer correlates negatively with the finding of relative capacity factor performance discussed above. Combustion Engineering reactors have spent the least on O&M and performed the best while Babcock & Wilcox reactors have spent the most and had the worst performance.

Pilgrim O&M Cost Projections

The KEA regression equation provided in Table 4.2 was used to project Pilgrim annual O&M expenditures over the remaining life of the plant. The *predictive* accuracy of the regression equation -- its ability to track Pilgrim historical experience -- is illustrated by the fact that the equation predicts an average 1973-87 annual expenditure of $64.9 per kW for Pilgrim, which in actuality experienced an average expenditure of $65.1 per kW (1987 dollars). Assuming historical trends continue, the equation's predictive accuracy provides a measure of confidence that the equation can be used to derive Pilgrim *projections* for the future.

There is, of course, uncertainty in projecting future O&M based on past cost trends. Although causal factors such as plant aging -- inherent to the technology -- should continue unabated, there is the possibility that regulatory or institutional factors may diminish in the future. To allow for such uncertainty, two alternative projections of Pilgrim O&M were derived using the KEA regression equation. As indicated in Table 1.2, these are referred to as the "optimistic" and the "pessimistic" scenarios.

The "optimistic" projection "caps" the post-TMI effect at its 1987 average value by applying the 1987 value for the Years-Past-TMI variable to all years 1988 and beyond. This scenario posits a continuing cost impact of the post-TMI regulatory environment, as embodied in the revised operating and maintenance procedures currently in effect. However, it also assumes that the regulatory environment stabilizes such that there is no further growth in the cost impact after 1987. Although not supported by industry experience through 1987, it is feasible that a relaxation of regulatory scrutiny would diminish further growth in the post-TMI cost effect.[3]

Assuming no further annual increase in the post-TMI effect beyond 1987, the "optimistic" scenario projects an average annual growth rate of 2.9 percent for Pilgrim O&M expenditures. As detailed in Table 1.2, annual costs are projected to increase from $120 per kW in 1989 to $236 per kW in 2012. Alternatively, the "pessimistic" scenario places no restriction on the post-TMI effect, resulting in a 3.5 percent annual growth rate. In this scenario, costs are projected to grow from $124 per kW in 1989 to $279 per kW in 2012.

Boston Edison projections for Pilgrim O&M, also included in Table 1.2, posit an increase in costs from $116 per kW in 1989 to $219 per kW in 2012. Although BECo's annual cost estimates are lower in every year than KEA's "optimistic" estimates, BECo's implied average annual growth rate is slightly higher at 3.0 percent.

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[3]Attempts by the NRC within the last year to adopt a maintenance rule to standardize industry-wide maintenance practices provide one example of the continuing evolution of regulatory intervention.

5. CAPITAL ADDITIONS

In addition to expenditures for routine maintenance and repair activities, nuclear plant operating costs include intermittent expenditures to replace malfunctioning or obsolescent plant components and systems. Generally, such costs are capitalized as capital additions.

The KEA nuclear capital additions database includes *net* capital additions data for the years 1970 to 1987 (the last year for which such data are publicly available). Net capital additions reflect the cost of gross additions less retirements and other adjustments. As with O&M, capital additions are reported by utilities to FERC on an annual basis. For multiple-unit plant sites, costs are usually reported for the station as a whole.

All reported costs included in the KEA database have been adjusted for inflation in order to analyze real (1987) dollar cost variation. In addition, costs have been divided by plant capacity to express all costs on a normalized dollar per kilowatt (kW) basis. For multiple-unit stations, costs were divided by the total capacity of all units on the site.

Based on the data incorporated in the KEA capital additions database, industry-wide average capital additions averaged $30 per kW for the years 1970 to 1987. Annual costs have fluctuated widely, as would be expected for sporadic activities. Yet, as illustrated in Table 5.1, there has been a discernible growth trend in capital additions, with costs growing from $13 per kW in 1970 to $43 per kW in 1987, peaking at $51 per kW in 1984. The average annual growth rate over this period is 11.1 percent.

Apart from the overall growth trend, industry-wide capital additions, paralleling industry-wide O&M experience, show a significant increase in expenditures in the years following the 1979 accident at TMI. Unlike O&M experience, however, continued growth through 1984 was followed by a drop in 1985 costs to about the 1980 level. This drop, in turn was followed by resumed growth.

Table 5.1 also summarizes capital addition experience for the Pilgrim plant from 1973 to 1987. Pilgrim's cost history includes a number of years with extremely large expenditures, with expenditures in 1984 (the year in which Pilgrim's recirculating piping was replaced) being the largest. Over its lifetime, Pilgrim

Table 5.1

HISTORICAL CAPITAL ADDITIONS EXPERIENCE

(1987$ per kW)

	Industry Average	Pilgrim
1970	13	
1971	6	
1972	8	
1973	17	29
1974	13	2
1975	9	2
1976	14	14
1977	24	41
1978	18	10
1979	17	19
1980	29	138
1981	36	39
1982	34	124
1983	40	70
1984	51	265
1985	30	37
1986	38	51
1987	43	20
1973-87 Average:	30	57
1973-87 Growth:	10.42%	19.32%

Sources and Notes

(1) Data compiled from KEA capital additions database.
(2) Average annual growth rates derived from simple log-linear fit of data to time.
(3) Industry-wide 1970-87 average annual capital additions is also $30 per kW. 1970-87 average growth rate is 11.06%.

annual capital additions averaged $57 per kW, the sixth highest average level of expenditures for the 59 plants included in the KEA database.

Regression Analysis

The KEA capital additions database incorporates cost experience for 59 commercial nuclear stations for the years 1970 to 1987, a total of 567 station-years of experience. As with the development of the O&M cost database, the capital additions data provided to FERC was screened for inconsistencies and suspect data removed. In addition, all initial-year capital additions data was eliminated from the database, because original construction costs are included in the capital additions accounts in that year.

The KEA database also includes annual data on station age, commercial operation date, NSSS vendor, station capacity, type of cooling water, number of units on the plant site, local wage rates, utility operating experience, and information on regulatory and other major plant outages. For multiple-unit sites, annual plant data was recorded as the average value for all units.

KEA's regression analysis of historical capital additions trends closely paralleled the O&M analysis in exploring the correlation of costs to plant age, plant age in salt-water cooled plants, plant vintage, institutional learning, the changing regulatory environment, and key plant characteristics. In addition, KEA's analyis of capital additions isolated the cost impact of PWR steam generator replacement and BWR large-diameter pipe replacement.

The resultant regression equation, provided in Table 5.2, correlates the variation in capital additions with 11 explanatory variables, all of which are significant at greater than the 95% confidence level. The adjusted R^2 of .36 indicates that the explanatory variables together explain 36 percent of the cost variation. Although considerably less of the variation is explained than for O&M costs, this is to be expected due to the "lumpiness" of the capital additions data. The value of the F ratio implies that the overall fit of the equation is significant at greater than the 99.9% confidence level.

As with the O&M analysis, plant age is the major driving force in annual capital additions growth. A one-year increase in age increases real (1987$) capital additions by $3.45 per kW. For salt-water cooled plants, there is an additional $0.89 per kW increase for each year's increase in age.

Table 5.2

ANNUAL PILGRIM CAPITAL ADDITIONS
1989 PERSPECTIVE
KEA REGRESSION EQUATION

Variable	Significance	Coefficient	1989 Value	1989 Product
Salt Water Cooling Times Age	0.6%	0.889	16.58	14.75
GE NSSS	1.8%	6.292	1	6.29
Steam Generator Replacement	0.0%	106.731	0	0.00
BWR Pipe Replacement	0.0%	133.408	0	0.00
Log of No. of Identical Units	1.8%	-9.578	0.00	0.00
Post-TMI 1980-84	0.3%	7.743	0	0.00
Wage Rate (R.S. Means, 1/1/85)	1.8%	1.010	21.70	21.91
Vintage (CO Date)	0.0%	2.271	72.92	165.63
Log of Non-CECo Util Experience	0.3%	-6.087	2.83	-17.25
CECo Operating Experience	0.0%	-0.511	0.00	0.00
Age of Plant	0.0%	3.450	16.58	57.21
Constant	0.0%	-174.718	1	-174.72
Predicted Cost, 1987$/kW				$73.82
Adjusted R-Square		0.357		
F-Statistic		29.594		
Standard Error of Estimate		28.399		

Sources and Notes

(1) Value of utility experience variable for Pilgrim in 1989 is 16. Calculation of log of utility experience adds 1 to utility experience variable to allow for zero experience in initial year.
(2) Plant age is calculated as age at mid-point of calendar year (Age = Year + 0.5 - Vintage).

Utility operating experience moderates the age effect, with each doubling of experience for plants other than those owned by Commonwealth Edison reducing capital additions by $4.22 per kW. Commonwealth Edison capital additions exhibit skewing relative to industry trends analogous to that evidenced in the O&M analysis. Therefore, consistent with the O&M analysis, CECo's capital additions cost experience was modelled with a separate CECo operating experience variable.

The correlation of plant commercial operation date with the variation in capital additions is captured with the plant vintage variable. The positive value of the plant vintage coefficient indicates that newer-vintage plants spend more on plant refurbishment than comparable older units, holding age constant.

The post-TMI variable correlates significantly with capital additions, indicating that the years following the 1979 TMI accident were marked by an increased level of expenditures for capital additions. This effect was not found to be significant after 1984, consistent with the analogous finding for industry capacity factor experience. Apparently, the bulk of the TMI-related backfits was completed prior to 1985, reducing the subsequent level of expenditures dedicated to plant refurbishment and the amount of outage time necessary to perform such backfits. This finding contrasts to that for O&M, where the pace of operation and maintenance procedure revisions following TMI does not appear to be subsiding and the cost impact continues.

Plant characteristics significantly correlated with capital additions are local wage rate, number of units on the plant site, and whether the reactor is a boiling water or pressurized water reactor. In addition, significant correlation was found for steam generator replacement in PWRs and large-diameter pipe replacement for BWRs.

Pilgrim Capital Additions Projections

The KEA capital additions regression equation has been used both to estimate Pilgrim historical experience and to project Pilgrim capital additions over the remaining years of its life. The former application yields an estimate of average annual 1973-87 capital additions of $52 per kW, versus Pilgrim's actual average of $57 per kW (all costs in 1987 dollars). Given the amount of variation in capital additions experience, the $5 per kW difference between the estimate of average Pilgrim capital additions and actual experience is insignificant.

The "lumpiness" of capital additions data, as it translates into a relatively low adjusted R^2, introduces uncertainty when using the regression equation to project Pilgrim capital additions into the future. To account for this uncertainty, two alternative projections of Pilgrim capital additions were employed.

The "optimisitc" projection incorporates capital additions varability in the regression predictions by using lower values for the age terms, calculated as the lower bound of the 95% confidence interval around the age and salt-water age coefficients. The 95% confidence interval is defined such that there is 95% confidence that the coefficient estimate lies within the interval; it is thus a measure of the inherent uncertainty in the estimate of the coefficient value. And because the size of the interval is partially a function of the unexplained variation in capital additions, the interval is a reasonable proxy for the effect of data "noise" on the strength of the regression prediction.

The "optimistic" projection was thus derived by replacing the coefficient values for the age and salt-water age variables with their respective 95% lower-confidence limit values for all years after 1987. This reduces the age effect from $3.45 per kW per year to $2.49 per kW per year. The salt-water age effect is reduced from $0.89 per kW per year to $0.26 per kW per year.

As shown in Table 1.3, the "optimistic" scenario projects Pilgrim capital additions to grow from $71 per kW in 1989 to $129 per kW in 2012. The average annual growth rate is 2.6 percent. The "pessimistic" scenario, on the other hand, does not adjust the age variable coefficients, resulting in higher initial costs and a much stronger growth rate. Under the "pessimistic" scenario, Pilgrim capital additions grow from $74 per kW in 1989 to $168 per kW in 2012. The implied growth rate in this case is 3.6 percent.

Boston Edison's projections for Pilgrim capital additions, also shown in Table 1.3, are substantially lower than estimated under either of the KEA scenarios. BECo estimates capital additions to grow from $42 per kW in 1989 to $62 per kW in 2012, at an implied rate of 1.2 percent.

6. 1986 RETROSPECTIVE

As part of its statistical analysis of U.S. nuclear plant cost and performance, KEA projected Pilgrim capacity factors, O&M costs, and capital additions based on industry trends in evidence in early 1986. This time frame was chosen to correspond with the April 1986 start of Pilgrim's current extended outage so that cost and performance estimates could be made based on industry experience at that time.

In early 1986, capacity factor data through 1985 were available for analysis. O&M and capital additions data, on the other hand, were available only through 1984, as the 1985 FERC reports were not available to the public until mid-1986. The KEA databases at the time encompassed 732 reactor-years of capacity factor experience, 463 plant-years of O&M experience, and 416 plant-years of capital additions experience.

The regression equations used to project Pilgrim costs and performance from the perspective of 1986 were those derived by KEA at the time for use in other proceedings. At the time, these equations were adopted by KEA as the models that best "fit" the available data.

Tables 6.1, 6.3, and 6.5 detail the regression equations adopted by KEA in 1986 for modelling capacity factor, O&M costs, and capital additions, respectively. The projections of Pilgrim capacity factors, O&M costs, and capital additions for the years 1989 to 2012 are provided in Tables 6.2, 6.4, and 6.6, respectively.

Analogous to the projections made from the perspective of today's trends (1989 perspective), the 1986 retrospective equations were used to derive two alternative projections of Pilgrim costs and performance. For capacity factor, the "optimistic" and "pessimistic" scenarios are modelled using the same age assumptions as for the 1989 perspective projections. As indicated in Table 6.2, the "optimistic" scenario, assuming Pilgrim's age in 1989 equals 1, projects Pilgrim capacity factor to mature from 60 percent in 1989 to 63 percent in 1993 and to decline thereafter. The "pessimistic" scenario, on the other hand, projects a 44 percent capacity factor in 1989 and an eventual plant shutdown in 1999.

The 1986 retrospective O&M projections also parallel the 1989 perspective analysis with regard to modelling the post-TMI effect, although the 1986 "optimistic" scenario "freezes" the post-TMI effect at its peak 1984 value rather than the current peak value of 1987 adopted in the 1989 perspective. In this case, the "optimistic" scenario projections, provided in Table 6.4, grow from $115 per kW in 1989 to $216 per kW in 2012 at an implied growth rate of 2.7 percent. The "pessimistic" scenario projects much higher O&M expenditures, with costs growing from $132 per kW at an average rate of 3.7% to $309 per kW in 2012.

For capital additions, the methodology used to formulate the 1986 "optimistic" scenario differs from that adopted for the 1989 analysis. The post-TMI effect in KEA's 1986 equation was modelled as a continuing impact, as was indicated with data through 1984. From today's perspective, however, it is apparent that the impact diminished after 1984. Therefore, for the 1986 projections, the "optimistic" scenario holds the post-TMI effect at its 1984 value. This is consistent with KEA's convention for projecting capital additions at the time.

As indicated in Table 6.6, the capital additions 1986 "optimistic" scenario projects costs growing from $102 per kW in 1989 to $166 per kW in 2012. The average annual growth rate is 2.1 percent. The "pessimistic" scenario, with no cap placed on the post-TMI effect, projects costs to grow at a 3.8 percent annual rate. In this case, capital additions grow from $127 per kW in 1989 to $302 per kW in 2012. In both cases, projected costs are substantially higher than estimates derived from KEA's current equation. This results primarily from the inclusion of the BWR pipe replacement variable in the current equation, thereby isolating the substantial expenditures for pipe replacement from the general cost trend.

Table 6.1

ANNUAL PILGRIM CAPACITY FACTORS
1986 PERSPECTIVE
KEA REGRESSION EQUATION

Variable	Significance	Coefficient	1989 Value	1989 Product
Salt Water Cooling Times Age	0.0%	-1.022	17	-17.37
BWR Small Pipe Replacement	3.4%	-7.672	0	0.00
GE 800 MW Class	0.0%	-15.971	0	0.00
GE 1000 MW Class	0.0%	-14.458	0	0.00
B&W NSSS	0.0%	-11.394	0	0.00
Westinghouse Fuel Failure	4.1%	-7.876	0	0.00
Westinghouse 800 MW Class	0.7%	-5.860	0	0.00
Westinghouse 1000 MW Class	0.0%	-12.578	0	0.00
Westinghouse Quake Mods.	0.0%	-31.202	0	0.00
First of Identical Set	0.2%	5.148	0	0.00
Second of Identical Set	0.0%	7.326	0	0.00
Post-TMI	3.2%	-3.667	1	-3.67
PWR Steam Generator Replacement	0.0%	-34.934	0	0.00
Cooling Tower	0.4%	-4.716	0	0.00
Browns Ferry Fire	0.0%	-35.232	0	0.00
Age Squared	0.1%	-0.129	289	-37.20
Age of Plant	0.0%	2.337	17	39.72
Constant	0.0%	62.815	1	62.82
Adjustment for Major Outages				0.00
Predicted Annual Capacity Factor				44.30
Adjusted R-Square		0.224		
F-Statistic		12.1		

Sources and Notes

(1) Plant age is set to 1 in a plant's first full year of operation and then increased by 1 each year thereafter. Pilgrim's age in 1989 is 17.

(2) Adjustment for major outages is the average annual percentage point reduction to capacity factor implied by historical effect of regulatory and other major plant modification outages. No adjustment is applied to estimated Pilgrim capacity factors.

Table 6.2

PILGRIM CAPACITY FACTOR PROJECTIONS
1986 PERSPECTIVE

(Percent)

Year	Pessimistic Scenario	Optimistic Scenario
1989	44	60
1990	41	61
1991	38	62
1992	34	62
1993	30	63
1994	26	62
1995	21	62
1996	17	61
1997	12	61
1998	6	59
1999	1	58
2000		56
2001		54
2002		52
2003		50
2004		47
2005		44
2006		41
2007		38
2008		34
2009		30
2010		26
2011		21
2012		17
1989-98 Average:	27	61

Sources and Notes

(1) 1986 Perspective results based on KEA regression equation on data through 1985.

(2) Optimistic scenario assumes Pilgrim 1989 age equals 1. Pessimistic scenario assumes Pilgrim 1989 age equals actual age of 17.

Table 6.3

ANNUAL PILGRIM O&M COSTS
1986 PERSPECTIVE
KEA REGRESSION EQUATION

Variable	Significance	Coefficient	1989 Value	1989 Product
Salt Water Cooling Times Age	0.0%	0.967	16.58	16.03
Multiple-unit Station	0.0%	-7.036	0	0.00
Years Past TMI, Frozen at 5 Yrs	0.0%	3.040	5	15.20
Wage Rate (R.S. Means, 1/1/85)	0.2%	0.677	21.70	14.68
Vintage (CO Date - 1965)	0.0%	2.598	7.92	20.57
North Atlantic Location	0.4%	4.345	1	4.34
Age of Plant	0.0%	3.039	16.58	50.39
Constant	1.7%	-15.526	1	-15.53
Predicted Cost, 1984$/kW				$105.70
Adjusted R-Square		0.635		
F-Statistic		112.962		

Sources and Notes

(1) Plant age is calculated as age at mid-point of calendar year (Age = Year + 0.5 - Vintage).
(2) Pilgrim vintage is 72.92.

Table 6.4

PILGRIM O&M PROJECTIONS
1986 PERSPECTIVE

(1987$ per kW)

Year	Pessimistic Scenario	Optimistic Scenario
1989	132	115
1990	140	120
1991	147	124
1992	155	128
1993	163	133
1994	170	137
1995	178	142
1996	186	146
1997	193	150
1998	201	155
1999	209	159
2000	216	163
2001	224	168
2002	232	172
2003	240	177
2004	247	181
2005	255	185
2006	263	190
2007	270	194
2008	278	198
2009	286	203
2010	293	207
2011	301	211
2012	309	216
Average Annual Growth:	3.69%	2.73%

Sources and Notes

(1) 1986 Perspective results based on KEA regression equation on data through 1984. 1984$/kW results inflated to 1987$ with GNP 1984-87 6.8% inflator.
(2) Optimistic scenario caps value of Years-Past-TMI variable at the 1984 value of 5 years. Pessimistic scenario assumes continued Years-Past-TMI effect.
(3) Average annual growth rates derived from simple log-linear fit of data to time.

Table 6.5

ANNUAL PILGRIM CAPITAL ADDITIONS
1986 PERSPECTIVE
KEA REGRESSION EQUATION

Variable	Significance	Coefficient	1989 Value	1989 Product
Salt Water Cooling Times Age	0.2%	1.336	16.58	22.16
GE NSSS	0.1%	9.100	1	9.10
Steam Generator Replacement	0.0%	67.969	0	0.00
Multiple-unit Station	0.0%	-12.116	0	0.00
Years Past TMI, Frozen at 5 Yrs	8.0%	4.542	5	22.71
Age of Plant	0.0%	1.263	16.58	20.93
Constant	0.2%	20.893	1	20.89
Predicted Cost, 1984$/kW				$95.80
Adjusted R-Square		0.286		
F-Statistic		27.280		

Sources and Notes

(1) Plant age is calculated as age at mid-point of calendar year (Age = Year + 0.5 - Vintage).
(2) Pilgrim vintage is 72.92.

Table 6.6

PILGRIM CAPITAL ADDITIONS PROJECTIONS
1986 PERSPECTIVE

(1987$ per kW)

Year	Pessimistic Scenario	Optimistic Scenario
1989	127	102
1990	134	105
1991	142	108
1992	149	111
1993	157	113
1994	165	116
1995	172	119
1996	180	122
1997	188	125
1998	195	127
1999	203	130
2000	210	133
2001	218	136
2002	226	138
2003	233	141
2004	241	144
2005	249	147
2006	256	149
2007	264	152
2008	271	155
2009	279	158
2010	287	161
2011	294	163
2012	302	166
Average Annual Growth:	3.77%	2.12%

Sources and Notes

(1) 1986 Perspective results based on KEA regression equation on data through 1984. 1984$/kW results inflated to 1987$ with Handy-Whitman North Atlantic 1984-87 6.8% inflator.
(2) Optimistic scenario caps value of Years-Past-TMI variable at the 1984 value of 5 years. Pessimistic scenario assumes continued Years-Past-TMI effect.
(3) Average annual growth rates derived from simple log-linear fit of data to time.

EXHIBIT ER-PLC-5

TABLES TO ACCOMPANY EXHIBIT ER-PLC-1

TABLE OF CONTENTS

Table 3.2.1	1
Table 3.2.2	2
Table 3.2.3	3
Table 3.2.4	6
Table 3.2.5	9
Table 3.2.6	12
Table 3.2.7	15
Table 3.2.8	18
Table 3.2.9	21
Table 3.2.10	24
Notes to Tables 3.2.3 to 3.2.10	27
Table 3.2.11	29
Table 4.1.1	32
Table 4.1.2	33
Table 4.2.1	34
Table 4.2.2	35
Table 4.2.3	36
Table 4.3.1	37
Table 4.3.2	38
Table 4.3.3	39
Table 4.4.1	40
Table 4.5.1	41
Figure 4.5.1	42

Table 4.7.1	43
Table 4.7.2	44
Table 4.7.3	45
Table 4.7.4	46
Table 4.7.5	47
Table 4.7.6	48
Table 4.7.7	49
Table 4.8.1	51
Table 4.8.2	52

CORRECTED VERSION

TABLE 3.2.1: 1989 PRESENT VALUE COMPARISON OF PILGRIM ECONOMICS (BECO PORTION)

INPUTS	CASES				CHANGE FROM BECO CASE		
	BECO-89	NAT'L-89 OPTIMISTIC	NAT'L-89 PESSIMISTIC	PILGRIM-89	NAT'L-89 OPTIMISTIC	NAT'L-89 PESSIMISTIC	PILGRIM-89
	[1]	[2]	[3]	[4]	[5]	[6]	[7]
NET BENEFIT (COST) OF SHUTDOWN	(350)	1,127	NA	2,391	1,477	NA	2,741
A. CAPITAL ADDITIONS (RATE EFFECT)	837.9	1224.0	1382.7	1499.7	386.1	544.8	661.8
B. OPERATION AND MAINTENANCE	992.0	1145.2	1276.0	1623.3	153.2	284.1	631.4
C. ADMINISTRATIVE AND GENERAL	199.3	360.9	411.4	545.3	161.5	212.0	345.9
D. EARLY DECOMMISSIONING	-303.0	-96.0	-96.0	-96.0	207.1	207.1	207.1
E. NET REPLACEMENT POWER AT BECO CAPACITY FACTOR	-2314.3	-2076.1	NA	-2076.1	238.2	NA	238.2
F. NET REPLACEMENT POWER AT CASE CAPACITY FACTOR	-2314.3	-1745.9	NA	-1419.7	568.4	NA	894.6

NOTES:

A. [1]-[4]: 74.27% of PV to 1989 of (line 18 + line 19 + line 20 + line 25) from Table 3.2.X, depending on the case.

A - F [5]: (A-F)[2]-(A-F)[1].

A - F [6]: (A-F)[3]-(A-F)[1].

A - F [7]: (A-F)[4]-(A-F)[1].

B. [1]-[4]: 74.27% of the PV to 1989 of line 21 from Table 3.2.X, depending on the case.

C. [1]-[4]: 74.27% of the PV to 1989 of line 22 from Table 3.2.X, depending on the case.

D. [1]-[4]: 74.27% of the PV to 1989 of line 40 from Table 3.2.X, depending on the case.

E. [1]-[4]: 74.27% of the PV to 1989 of line 32 minus line 39 from Table 3.2.X, depending on the case; calculated with BECO's 1989 capacity factor projection.

F. [1]-[4]: 74.27% of the PV to 1989 of line 32 minus line 39 from Table 3.2.X, depending on the case; calculated with the capacity factor appropriate to the case.

[3], [6]: "NA" indicates that the calculations yield numbers which are not meaningful because the projections of pessimistic capacity factors suggest that Pilgrim would cease to produce power by 2001. See Table 4.1.2.

TABLE 3.2.2: 1986 PRESENT VALUE COMPARISON OF PILGRIM ECONOMICS (BECO PORTION)

INPUTS	----------CASES----------			-CHANGE FROM BECO CASE-	
	BECO-86	NAT'L-86	PILGRIM-86	NAT'L-86	PILGRIM-86
	[1]	[2]	[3]	[4]	[5]
NET BENEFIT (COST) OF SHUTDOWN	(355)	1,189	1,026	1,544	1,381
A. CAPITAL ADDITIONS (RATE EFFECT)	847.0	1583.4	1444.9	736.3	597.9
B. OPERATION AND MAINTENANCE	1207.1	1128.4	1306.0	-78.7	98.9
C. ADMINISTRATIVE AND GENERAL	242.6	301.3	357.1	58.7	114.5
D. EARLY DECOMMISSIONING	-57.6	-57.6	-57.6	0.0	0.0
E. NET REPLACEMENT POWER AT BECO CAPACITY FACTOR	-2766.8	-2766.8	-2766.8	0.0	0.0
F. NET REPLACEMENT POWER AT CASE CAPACITY FACTOR	-2766.8	-1939.1	-2197.6	827.7	569.1

NOTES:

A. [1]-[3]: 74.27% of PV to 1989 of (line 18 + line 19 + line 20 + line 25) from Table 3.2.X, depending on the case.

A - F [4]: (A-F)[2]-(A-F)[1].

A - F [5]: (A-F)[3]-(A-F)[1].

B. [1]-[3]: 74.27% of the PV to 1989 of line 21 from Table 3.2.X, depending on the case.

C. [1]-[3]: 74.27% of the PV to 1989 of line 22 from Table 3.2.X, depending on the case.

D. [1]-[3]: 74.27% of the PV to 1989 of line 40 from Table 3.2.X, depending on the case.

E. [1]-[3]: 74.27% of the PV to 1989 of line 32 minus line 39 from Table 3.2.X, depending on the case; calculated with BECO's 1986 capacity factor projection.

F. [1]-[3]: 74.27% of the PV to 1989 of line 32 minus line 39 from Table 3.2.X, depending on the case; calculated with the capacity factor appropriate to the case.

		SOURCE	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998
1	PLANT-IN-SERVICE											
2	BEGINNING OF YEAR		259.8	294.3	327.3	379.2	424.3	478.1	527.4	579.2	633.1	689.7
3	NET CAPITAL ADDITIONS	BECO-89	34.5	33.0	51.9	45.1	53.8	49.3	51.7	54.0	56.5	59.3
4	END OF YEAR		294.3	327.3	379.2	424.3	478.1	527.4	579.2	633.1	689.7	748.9
5	ACCUMULATED DEPRECIATION											
6	BEGINNING OF YEAR		0.0	12.3	26.0	42.0	60.2	81.1	104.6	131.0	160.5	193.6
7	ANNUAL DEPRECIATION		12.3	13.7	16.1	18.2	20.9	23.5	26.4	29.5	33.1	37.0
8	END OF YEAR		12.3	26.0	42.0	60.2	81.1	104.6	131.0	160.5	193.6	230.6
9	NET PLANT (YEAR END)		282.0	301.3	337.2	364.1	397.0	422.8	448.2	472.6	496.1	518.3
10	OTHER RATE BASE ITEMS											
11	DEFERRED TAXES		-0.9	-7.0	-12.7	-18.2	-23.4	-28.2	-32.8	-37.4	-42.0	-46.5
12	MATERIALS AND SUPPLIES	BECO-89	30.7	32.0	33.3	34.8	36.3	38.0	39.8	41.6	43.5	45.7
13	NUCLEAR FUEL INVENTORY	BECO-89	52.2	51.6	51.5	50.1	51.0	53.6	59.4	62.1	68.2	70.1
14	YEAR END RATE BASE		364.0	377.9	409.3	430.7	460.9	486.2	514.6	538.9	565.7	587.6
15												
16	COSTS											
17	-------											
18	RETURN ON RATE BASE		39.6	41.1	44.5	46.9	50.1	52.9	56.0	58.6	61.6	63.9
19	INCOME TAXES	BECO-89	14.4	14.9	16.1	17.0	18.2	19.2	20.3	21.3	22.3	23.2
20	DEPRECIATION (REMAINING LIFE)		12.3	13.7	16.1	18.2	20.9	23.5	26.4	29.5	33.1	37.0
21	ANNUAL O&M EXPENSES	BECO-89	83.6	85.1	97.3	92.1	105.3	108.5	116.7	125.9	135.5	145.8
22	ADMINISTRATIVE & GENERAL	BECO-89	16.8	17.1	19.6	18.5	21.2	21.8	23.5	25.3	27.2	29.3
23	OUTAGE AMORTIZATION		20.2	20.2	20.2	20.2	20.2	0.0	0.0	0.0	0.0	0.0
24	INSURANCE	BECO-89	8.1	8.4	8.8	9.2	9.6	10.0	10.5	11.0	11.5	12.1
25	LOCAL TAXES		4.5	4.8	5.4	5.8	6.4	6.8	7.2	7.6	7.9	8.3
26	DECOMMISSIONING ANNUAL CONTRIBUTION	BECO-89	8.3	8.6	9.0	9.4	9.8	10.6	11.4	12.3	13.2	14.2
27												
28	ANNUAL NON-FUEL COST		207.7	214.0	237.0	237.3	261.7	253.3	271.9	291.5	312.3	333.9
29												
30	CAPACITY FACTOR	BECO-89	65%	65%	68%	68%	68%	68%	68%	68%	68%	68%
31	PILGRIM FUEL IN CENTS/KWH	BECO-89	0.5894	0.5829	0.5812	0.5658	0.5758	0.6048	0.6702	0.7015	0.7705	0.7912
32	TOTAL FUEL COST		22.4	22.1	23.1	22.5	22.9	24.1	26.7	28.0	30.8	31.6
33	TOTAL PILGRIM COST		230.1	236.2	260.1	259.8	284.6	277.4	298.6	319.5	343.1	365.5
34	BECO'S SHARE		170.9	175.4	193.2	193.0	211.3	206.0	221.8	237.3	254.8	271.4
35												
36	SHUTDOWN COSTS											
37	--------------------------											
38	REPLACEMENT POWER IN CENTS/KWH	BECO-89	5.09	5.26	4.87	5.51	5.91	5.66	8.11	8.66	9.26	10.26
39	TOTAL REPLACEMENT POWER		193.3	199.7	193.9	219.1	234.9	225.7	323.9	345.6	369.7	409.5
40	EARLY DECOMMISSIONING	BECO-89	26.2	27.3	28.5	29.7	31.0	33.4	36.0	38.8	41.8	45.0
41	TOTAL SHUTDOWN COSTS		219.5	227.0	222.4	248.8	265.9	259.1	359.9	384.4	411.5	454.5
42	BECO'S SHARE		163.0	168.6	165.2	184.8	197.5	192.4	267.3	285.5	305.6	337.6
43												
44	NET BENEFIT (COST) OF SHUTDOWN		8	7	28	8	14	14	(45)	(48)	(51)	(66)

		SOURCE	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
1	PLANT-IN-SERVICE											
2	BEGINNING OF YEAR		748.9	811.1	876.5	945.4	1017.8	1094.1	1174.5	1259.2	1348.4	1442.5
3	NET CAPITAL ADDITIONS	BECO-89	62.2	65.4	68.8	72.4	76.3	80.4	84.7	89.3	94.1	79.3
4	END OF YEAR		811.1	876.5	945.4	1017.8	1094.1	1174.5	1259.2	1348.4	1442.5	1521.8
5	ACCUMULATED DEPRECIATION											
6	BEGINNING OF YEAR		230.6	272.1	318.6	370.8	429.6	496.1	571.4	657.4	756.1	870.5
7	ANNUAL DEPRECIATION		41.5	46.5	52.2	58.8	66.4	75.4	86.0	98.7	114.4	130.3
8	END OF YEAR		272.1	318.6	370.8	429.6	496.1	571.4	657.4	756.1	870.5	1000.8
9	NET PLANT (YEAR END)		539.1	558.0	574.6	588.2	598.0	603.0	601.8	592.3	572.0	521.0
10	OTHER RATE BASE ITEMS											
11	DEFERRED TAXES		-50.8	-54.7	-58.1	-60.7	-62.1	-58.8	-49.8	-37.0	-19.5	3.3
12	MATERIALS AND SUPPLIES	BECO-89	47.9	50.4	53.0	55.8	58.8	61.9	65.2	68.8	72.5	61.1
13	NUCLEAR FUEL INVENTORY	BECO-89	75.2	79.3	81.9	88.3	90.2	94.9	99.8	105.0	110.4	92.9
14	YEAR END RATE BASE		611.4	633.0	651.4	671.6	684.9	701.0	717.0	729.1	735.4	678.3
15												
16	COSTS											
17	-------											
18	RETURN ON RATE BASE		66.5	68.9	70.9	73.1	74.5	76.3	78.0	79.3	80.0	73.8
19	INCOME TAXES	BECO-89	24.1	25.0	25.7	26.5	27.0	27.7	28.3	28.8	29.0	26.8
20	DEPRECIATION (REMAINING LIFE)		41.5	46.5	52.2	58.8	66.4	75.4	86.0	98.7	114.4	130.3
21	ANNUAL O&M EXPENSES	BECO-89	157.1	169.1	182.1	196.2	211.5	227.8	245.4	264.4	284.9	307.0
22	ADMINISTRATIVE & GENERAL	BECO-89	31.6	34.0	36.6	39.4	42.5	45.8	49.3	53.2	57.3	61.7
23	OUTAGE AMORTIZATION		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
24	INSURANCE	BECO-89	12.7	13.3	14.0	14.7	15.5	16.3	17.2	18.1	19.1	20.2
25	LOCAL TAXES		8.6	8.9	9.2	9.4	9.6	9.6	9.6	9.5	9.2	8.3
26	DECOMMISSIONING ANNUAL CONTRIBUTION	BECO-89	15.3	16.5	17.8	19.2	20.7	22.2	24.0	25.8	27.8	30.0
27												
28	ANNUAL NON-FUEL COST		357.4	382.2	408.5	437.4	467.7	501.2	537.9	577.9	621.7	658.0
29												
30	CAPACITY FACTOR	BECO-89	68%	68%	68%	68%	68%	68%	68%	68%	68%	68%
31	PILGRIM FUEL IN CENTS/KWH	BECO-89	0.8496	0.8950	0.9245	0.9971	1.0177	1.0708	1.1263	1.1853	1.2467	1.3116
32	TOTAL FUEL COST		33.9	35.7	36.9	39.8	40.6	42.7	45.0	47.3	49.8	52.3
33	TOTAL PILGRIM COST		391.3	417.9	445.4	477.2	508.3	543.9	582.8	625.2	671.5	710.3
34	BECO'S SHARE		290.6	310.4	330.8	354.4	377.5	403.9	432.9	464.3	498.7	527.5
35												
36	SHUTDOWN COSTS											
37	--------------------------											
38	REPLACEMENT POWER IN CENTS/KWH	BECO-89	11.20	12.54	12.54	13.52	14.61	15.95	17.67	19.12	20.16	18.57
39	TOTAL REPLACEMENT POWER		446.9	500.5	500.4	539.6	583.2	636.6	705.4	763.0	804.5	741.0
40	EARLY DECOMMISSIONING	BECO-89	48.4	52.1	56.2	60.5	65.2	70.2	75.7	81.5	87.8	94.6
41	TOTAL SHUTDOWN COSTS		495.3	552.6	556.6	600.1	648.4	706.8	781.1	844.5	892.3	835.6
42	BECO'S SHARE		367.9	410.4	413.4	445.7	481.6	524.9	580.1	627.2	662.7	620.6
43												
44	NET BENEFIT (COST) OF SHUTDOWN		(77)	(100)	(83)	(91)	(104)	(121)	(147)	(163)	(164)	(93)

TABLE 3.2.3: PILGRIM ECONOMICS; BECO'S 1989 PROJECTIONS

		SOURCE	2009	2010	2011	2012	NPV TO 1989 10.88%
1	PLANT-IN-SERVICE						
2	BEGINNING OF YEAR		1521.8	1584.5	1628.6	1651.8	
3	NET CAPITAL ADDITIONS	BECO-89	62.7	44.1	23.2	0.0	
4	END OF YEAR		1584.5	1628.6	1651.8	1651.8	
5	ACCUMULATED DEPRECIATION						
6	BEGINNING OF YEAR		1000.8	1146.7	1307.3	1479.6	
7	ANNUAL DEPRECIATION		145.9	160.6	172.2	172.2	
8	END OF YEAR		1146.7	1307.3	1479.6	1651.8	
9	NET PLANT (YEAR END)		437.8	321.2	172.2	0.0	
10	OTHER RATE BASE ITEMS						
11	DEFERRED TAXES		31.8	66.4	106.5	0.0	
12	MATERIALS AND SUPPLIES	BECO-89	48.3	33.9	17.9	0.0	
13	NUCLEAR FUEL INVENTORY	BECO-89	73.3	51.4	27.1	0.0	
14	YEAR END RATE BASE		591.2	472.9	323.8	0.0	
15							
16	COSTS						
17	-------						
18	RETURN ON RATE BASE		64.3	51.5	35.2	0.0	511.1
19	INCOME TAXES	BECO-89	23.3	18.7	12.8	0.0	185.3
20	DEPRECIATION (REMAINING LIFE)		145.9	160.6	172.2	172.2	368.6
21	ANNUAL O&M EXPENSES	BECO-89	330.7	356.3	383.9	413.6	1335.6
22	ADMINISTRATIVE & GENERAL	BECO-89	66.5	71.6	77.2	83.1	268.4
23	OUTAGE AMORTIZATION		0.0	0.0	0.0	0.0	83.0
24	INSURANCE	BECO-89	21.2	22.4	23.6	24.9	108.8
25	LOCAL TAXES		7.0	5.1	2.8	0.0	63.2
26	DECOMMISSIONING ANNUAL CONTRIBUTION	BECO-89	32.3	34.8	37.5	26.9	129.2
27			-------	-------	-------	-------	
28	ANNUAL NON-FUEL COST		691.3	721.0	745.1	720.7	3053.3
29							
30	CAPACITY FACTOR	BECO-89	68%	68%	68%	68%	
31	PILGRIM FUEL IN CENTS/KWH	BECO-89	1.3800	1.4520	1.5275	1.6072	
32	TOTAL FUEL COST		55.1	58.0	61.0	64.1	282.2
33	TOTAL PILGRIM COST		746.4	779.0	806.1	784.9	3335.5
34	BECO'S SHARE		554.4	578.5	598.7	582.9	2477.3
35							
36	SHUTDOWN COSTS						
37	--------------------------						
38	REPLACEMENT POWER IN CENTS/KWH	BECO-89	19.49	21.14	22.39	23.97	
39	TOTAL REPLACEMENT POWER		778.0	843.7	893.4	956.7	3398.3
40	EARLY DECOMMISSIONING	BECO-89	102.0	109.9	118.4	85.0	408.0
41	TOTAL SHUTDOWN COSTS		880.0	953.6	1011.8	1041.7	3806.2
42	BECO'S SHARE		653.6	708.3	751.5	773.7	2826.9
43							
44	NET BENEFIT (COST) OF SHUTDOWN		(99)	(130)	(153)	(191)	(350)

		SOURCE	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998
1	PLANT-IN-SERVICE											
2	BEGINNING OF YEAR		259.8	311.2	366.8	427.0	492.0	562.1	637.7	719.4	807.1	901.5
3	NET CAPITAL ADDITIONS	KEA-89	51.4	55.6	60.1	65.0	70.1	75.6	81.6	87.7	94.4	101.8
4	END OF YEAR		311.2	366.8	427.0	492.0	562.1	637.7	719.4	807.1	901.5	1003.3
5	ACCUMULATED DEPRECIATION											
6	BEGINNING OF YEAR		0.0	13.0	28.4	46.5	67.7	92.4	121.1	154.3	192.7	237.0
7	ANNUAL DEPRECIATION		13.0	15.4	18.1	21.2	24.7	28.7	33.2	38.4	44.3	51.1
8	END OF YEAR		13.0	28.4	46.5	67.7	92.4	121.1	154.3	192.7	237.0	288.1
9	NET PLANT (YEAR END)		298.2	338.5	380.5	424.3	469.7	516.6	565.0	614.3	664.4	715.1
10	OTHER RATE BASE ITEMS											
11	DEFERRED TAXES		-1.0	-7.5	-13.9	-20.2	-26.3	-32.1	-37.9	-43.8	-49.8	-55.7
12	MATERIALS AND SUPPLIES	BECO-89	30.7	32.0	33.3	34.8	36.3	38.0	39.8	41.6	43.5	45.7
13	NUCLEAR FUEL INVENTORY	BECO-89	52.2	51.6	51.5	50.1	51.0	53.6	59.4	62.1	68.2	70.1
14	YEAR END RATE BASE		380.1	414.6	451.4	489.0	530.7	576.1	626.3	674.2	726.3	775.2
15												
16	COSTS											
17	-------											
18	RETURN ON RATE BASE		41.4	45.1	49.1	53.2	57.7	62.7	68.1	73.4	79.0	84.3
19	INCOME TAXES		15.0	16.4	17.8	19.3	20.9	22.7	24.7	26.6	28.7	30.6
20	DEPRECIATION (REMAINING LIFE)		13.0	15.4	18.1	21.2	24.7	28.7	33.2	38.4	44.3	51.1
21	ANNUAL O&M EXPENSES	KEA-89	89.1	97.7	107.0	117.0	127.9	139.5	151.9	165.3	179.5	194.7
22	ADMINISTRATIVE & GENERAL	KEA-89	26.3	29.2	32.5	35.9	39.7	43.8	48.1	52.8	57.7	63.0
23	OUTAGE AMORTIZATION		20.2	20.2	20.2	20.2	20.2	0.0	0.0	0.0	0.0	0.0
24	INSURANCE	BECO-89	8.1	8.4	8.8	9.2	9.6	10.0	10.5	11.0	11.5	12.1
25	LOCAL TAXES		4.8	5.4	6.1	6.8	7.5	8.3	9.0	9.8	10.6	11.4
26	DECOMMISSIONING ANNUAL CONTRIBUTION	BECO-89	8.3	8.6	9.0	9.4	9.8	10.6	11.4	12.3	13.2	14.2
27												
28	ANNUAL NON-FUEL COST		226.1	246.5	268.6	292.3	318.1	326.3	357.0	389.5	424.5	461.5
29												
30	CAPACITY FACTOR	KEA-89	61%	63%	63%	64%	65%	65%	65%	65%	64%	63%
31	PILGRIM FUEL IN CENTS/KWH	BECO-89	0.5894	0.5829	0.5812	0.5658	0.5758	0.6048	0.6702	0.7015	0.7705	0.7912
32	TOTAL FUEL COST		21.1	21.6	21.5	21.3	22.0	23.1	25.6	26.8	28.9	29.3
33	TOTAL PILGRIM COST		247.2	268.1	290.1	313.5	340.1	349.3	382.6	416.2	453.5	490.7
34	BECO'S SHARE		183.6	199.1	215.5	232.8	252.6	259.5	284.2	309.1	336.8	364.5
35												
36	SHUTDOWN COSTS											
37	--------------------------											
38	REPLACEMENT POWER IN CENTS/KWH	QF-RFP-89	3.39	3.76	3.87	5.38	5.93	6.12	7.19	7.72	8.73	9.98
39	TOTAL REPLACEMENT POWER		121.4	139.0	143.1	202.1	226.2	233.5	274.3	294.5	327.9	369.0
40	EARLY DECOMMISSIONING	PILG-89	8.3	8.6	9.0	9.4	9.8	10.6	11.4	12.3	13.2	14.2
41	TOTAL SHUTDOWN COSTS		129.7	147.7	152.1	211.5	236.1	244.1	285.7	306.8	341.2	383.3
42	BECO'S SHARE		96.3	109.7	113.0	157.1	175.3	181.3	212.2	227.9	253.4	284.7
43												
44	NET BENEFIT (COST) OF SHUTDOWN		87	89	103	76	77	78	72	81	83	80

		SOURCE	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
1	PLANT-IN-SERVICE											
2	BEGINNING OF YEAR		1003.3	1113.0	1231.4	1359.2	1497.2	1646.1	1806.8	1980.1	2167.0	2368.5
3	NET CAPITAL ADDITIONS	KEA-89	109.8	118.4	127.8	138.0	148.9	160.7	173.3	186.9	201.5	217.1
4	END OF YEAR		1113.0	1231.4	1359.2	1497.2	1646.1	1806.8	1980.1	2167.0	2368.5	2585.6
5	ACCUMULATED DEPRECIATION											
6	BEGINNING OF YEAR		288.1	347.0	415.1	493.7	585.0	691.1	815.0	960.7	1133.0	1338.9
7	ANNUAL DEPRECIATION		58.9	68.0	78.7	91.2	106.1	124.0	145.6	172.3	205.9	249.3
8	END OF YEAR		347.0	415.1	493.7	585.0	691.1	815.0	960.7	1133.0	1338.9	1588.3
9	NET PLANT (YEAR END)		766.0	816.4	865.5	912.2	955.0	991.7	1019.4	1034.0	1029.6	997.3
10	OTHER RATE BASE ITEMS											
11	DEFERRED TAXES		-61.3	-66.3	-70.4	-73.1	-73.7	-68.0	-54.0	-33.1	-2.9	40.1
12	MATERIALS AND SUPPLIES	BECO-89	47.9	50.4	53.0	55.8	58.8	61.9	65.2	68.8	72.5	61.1
13	NUCLEAR FUEL INVENTORY	BECO-89	75.2	79.3	81.9	88.3	90.2	94.9	99.8	105.0	110.4	92.9
14	YEAR END RATE BASE		827.7	879.7	930.0	983.2	1030.3	1080.5	1130.4	1174.7	1209.5	1191.4
15												
16	COSTS											
17	-------											
18	RETURN ON RATE BASE		90.1	95.7	101.2	107.0	112.1	117.6	123.0	127.8	131.6	129.6
19	INCOME TAXES		32.7	34.7	36.7	38.8	40.6	42.6	44.6	46.3	47.7	47.0
20	DEPRECIATION (REMAINING LIFE)		58.9	68.0	78.7	91.2	106.1	124.0	145.6	172.3	205.9	249.3
21	ANNUAL O&M EXPENSES	KEA-89	211.0	228.5	247.0	266.8	287.9	310.1	334.0	359.3	386.3	415.0
22	ADMINISTRATIVE & GENERAL	KEA-89	68.7	74.8	81.3	88.2	95.5	103.3	111.6	120.4	129.9	139.9
23	OUTAGE AMORTIZATION		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
24	INSURANCE	BECO-89	12.7	13.3	14.0	14.7	15.5	16.3	17.2	18.1	19.1	20.2
25	LOCAL TAXES		12.3	13.1	13.8	14.6	15.3	15.9	16.3	16.5	16.5	16.0
26	DECOMMISSIONING ANNUAL CONTRIBUTION	BECO-89	15.3	16.5	17.8	19.2	20.7	22.2	24.0	25.8	27.8	30.0
27												
28	ANNUAL NON-FUEL COST		501.6	544.6	590.5	640.4	693.7	752.0	816.4	886.7	964.8	1046.9
29												
30	CAPACITY FACTOR	KEA-89	62%	61%	60%	58%	56%	54%	52%	49%	46%	43%
31	PILGRIM FUEL IN CENTS/KWH	BECO-89	0.8496	0.8950	0.9245	0.9971	1.0177	1.0708	1.1263	1.1853	1.2467	1.3116
32	TOTAL FUEL COST		30.9	32.0	32.6	33.9	33.4	33.9	34.4	34.1	33.7	33.1
33	TOTAL PILGRIM COST		532.5	576.7	623.0	674.3	727.1	786.0	850.7	920.8	998.5	1080.0
34	BECO'S SHARE		395.5	428.3	462.7	500.8	540.0	583.3	631.8	683.9	741.6	802.1
35												
36	SHUTDOWN COSTS											
37	--------------------------											
38	REPLACEMENT POWER IN CENTS/KWH	QF-RFP-89	11.30	10.84	11.94	12.99	14.43	15.95	17.40	16.23	16.13	18.49
39	TOTAL REPLACEMENT POWER		411.2	388.1	420.5	442.2	474.3	505.5	531.0	466.8	435.5	466.6
40	EARLY DECOMMISSIONING	PILG-89	15.3	16.5	17.8	19.2	20.7	22.2	24.0	25.8	27.8	30.0
41	TOTAL SHUTDOWN COSTS		426.5	404.6	438.3	461.4	494.9	527.8	555.0	492.6	463.3	496.6
42	BECO'S SHARE		316.8	300.5	325.5	342.7	367.6	392.0	412.2	365.8	344.1	368.8
43												
44	NET BENEFIT (COST) OF SHUTDOWN		79	128	137	158	172	192	220	318	397	433

		SOURCE	2009	2010	2011	2012	NPV TO 1989 10.38%
1	PLANT-IN-SERVICE						
2	BEGINNING OF YEAR		2585.6	2819.3	3071.0	3341.7	
3	NET CAPITAL ADDITIONS	KEA-89	233.8	251.6	270.8	291.2	
4	END OF YEAR		2819.3	3071.0	3341.7	3632.9	
5	ACCUMULATED DEPRECIATION						
6	BEGINNING OF YEAR		1588.3	1896.0	2287.7	2814.7	
7	ANNUAL DEPRECIATION		307.8	391.6	527.0	818.3	
8	END OF YEAR		1896.0	2287.7	2814.7	3632.9	
9	NET PLANT (YEAR END)		923.3	783.3	527.0	0.0	
10	OTHER RATE BASE ITEMS						
11	DEFERRED TAXES		101.3	190.3	326.4	0.0	
12	MATERIALS AND SUPPLIES	BECO-89	48.3	33.9	17.9	0.0	
13	NUCLEAR FUEL INVENTORY	BECO-89	73.3	51.4	27.1	0.0	
14	YEAR END RATE BASE		1146.2	1058.9	898.5	0.0	
15							
16	COSTS						
17	-------						
18	RETURN ON RATE BASE		124.7	115.2	97.8	0.0	671.6
19	INCOME TAXES		45.2	41.8	35.4	0.0	243.5
20	DEPRECIATION (REMAINING LIFE)		307.8	391.6	527.0	818.3	646.4
21	ANNUAL O&M EXPENSES	KEA-89	445.3	477.6	512.1	548.6	1718.1
22	ADMINISTRATIVE & GENERAL	KEA-89	150.5	161.8	173.9	186.7	553.9
23	OUTAGE AMORTIZATION		0.0	0.0	0.0	0.0	83.0
24	INSURANCE	BECO-89	21.2	22.4	23.6	24.9	108.8
25	LOCAL TAXES		14.8	12.5	8.4	0.0	86.6
26	DECOMMISSIONING ANNUAL CONTRIBUTION	BECO-89	32.3	34.8	37.5	26.9	129.2
27							
28	ANNUAL NON-FUEL COST		1141.9	1257.8	1415.7	1605.3	4241.2
29							
30	CAPACITY FACTOR	KEA-89	40%	36%	33%	29%	
31	PILGRIM FUEL IN CENTS/KWH	BECO-89	1.3800	1.4520	1.5275	1.6072	
32	TOTAL FUEL COST		32.4	30.7	29.6	27.4	243.1
33	TOTAL PILGRIM COST		1174.3	1288.5	1445.3	1632.7	4484.3
34	BECO'S SHARE		872.1	957.0	1073.4	1212.6	3330.5
35							
36	SHUTDOWN COSTS						
37	--------------------------						
38	REPLACEMENT POWER IN CENTS/KWH	QF-RFP-89	21.04	16.64	20.84	16.55	
39	TOTAL REPLACEMENT POWER		494.0	351.6	403.6	281.7	2593.9
40	EARLY DECOMMISSIONING	PILG-89	32.3	34.8	37.5	26.9	129.2
41	TOTAL SHUTDOWN COSTS		526.3	386.4	441.1	308.6	2723.1
42	BECO'S SHARE		390.8	287.0	327.6	229.2	2022.5
43							
44	NET BENEFIT (COST) OF SHUTDOWN		481	670	746	983	1,308

TABLE 3.2.5: PILGRIM ECONOMICS; 1989 PILGRIM PROJECTIONS CORRECTED VERSION

		SOURCE	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998
1	PLANT-IN-SERVICE											
2	BEGINNING OF YEAR		259.8	349.2	442.3	539.5	640.9	746.8	857.6	973.7	1095.0	1221.8
3	NET CAPITAL ADDITIONS	PILG-89	89.4	93.1	97.2	101.4	105.9	110.8	116.1	121.2	126.9	133.1
4	END OF YEAR		349.2	442.3	539.5	640.9	746.8	857.6	973.7	1095.0	1221.8	1354.9
5	ACCUMULATED DEPRECIATION											
6	BEGINNING OF YEAR		0.0	14.5	33.1	56.2	84.0	117.2	156.1	201.5	254.1	314.6
7	ANNUAL DEPRECIATION		14.5	18.6	23.0	27.8	33.1	39.0	45.4	52.6	60.5	69.4
8	END OF YEAR		14.5	33.1	56.2	84.0	117.2	156.1	201.5	254.1	314.6	383.9
9	NET PLANT (YEAR END)		334.6	409.2	483.3	556.9	629.7	701.5	772.2	840.9	907.3	971.0
10	OTHER RATE BASE ITEMS											
11	DEFERRED TAXES		-1.1	-8.5	-16.3	-24.5	-32.7	-40.7	-48.8	-56.9	-65.1	-73.1
12	MATERIALS AND SUPPLIES	BECO-89	30.7	32.0	33.3	34.8	36.3	38.0	39.8	41.6	43.5	45.7
13	NUCLEAR FUEL INVENTORY	BECO-89	52.2	51.6	51.5	50.1	51.0	53.6	59.4	62.1	68.2	70.1
14	YEAR END RATE BASE		416.4	484.3	551.8	617.3	684.3	752.3	822.6	887.6	953.8	1013.7
15												
16	COSTS											
17	-------											
18	RETURN ON RATE BASE		45.3	52.7	60.0	67.2	74.4	81.9	89.5	96.6	103.8	110.3
19	INCOME TAXES		16.4	19.1	21.8	24.4	27.0	29.7	32.5	35.0	37.6	40.0
20	DEPRECIATION (REMAINING LIFE)		14.5	18.6	23.0	27.8	33.1	39.0	45.4	52.6	60.5	69.4
21	ANNUAL O&M EXPENSES	PILG-89	108.1	119.5	131.8	145.1	159.5	174.9	191.3	209.0	227.9	248.1
22	ADMINISTRATIVE & GENERAL	PILG-89	33.6	37.7	42.0	46.8	51.9	57.4	63.3	69.6	76.4	83.6
23	OUTAGE AMORTIZATION		20.2	20.2	20.2	20.2	20.2	0.0	0.0	0.0	0.0	0.0
24	INSURANCE	BECO-89	8.1	8.4	8.8	9.2	9.6	10.0	10.5	11.0	11.5	12.1
25	LOCAL TAXES		5.4	6.5	7.7	8.9	10.1	11.2	12.4	13.5	14.5	15.5
26	DECOMMISSIONING ANNUAL CONTRIBUTION	BECO-89	8.3	8.6	9.0	9.4	9.8	10.6	11.4	12.3	13.2	14.2
27												
28	ANNUAL NON-FUEL COST		259.9	291.4	324.5	358.9	395.6	414.6	456.2	499.5	545.4	593.2
29												
30	CAPACITY FACTOR	PILG-89	46%	46%	46%	46%	46%	46%	46%	46%	46%	46%
31	PILGRIM FUEL IN CENTS/KWH	BECO-89	0.5894	0.5829	0.5812	0.5658	0.5758	0.6048	0.6702	0.7015	0.7705	0.7912
32	TOTAL FUEL COST		16.0	15.8	15.8	15.4	15.6	16.4	18.2	19.1	20.9	21.5
33	TOTAL PILGRIM COST		275.9	307.2	340.3	374.3	411.3	431.1	474.4	518.6	566.3	614.7
34	BECO'S SHARE		204.9	228.2	252.7	278.0	305.5	320.1	352.4	385.1	420.6	456.5
35												
36	SHUTDOWN COSTS											
37	--------------------------											
38	REPLACEMENT POWER IN CENTS/KWH	QF-RFP-89	3.39	3.76	3.87	5.38	5.93	6.12	7.19	7.72	8.73	9.98
39	TOTAL REPLACEMENT POWER		92.1	102.2	105.2	146.2	161.1	166.3	195.4	209.8	237.2	271.2
40	EARLY DECOMMISSIONING	PILG-89	8.3	8.6	9.0	9.4	9.8	10.6	11.4	12.3	13.2	14.2
41	TOTAL SHUTDOWN COSTS		100.4	110.8	114.2	155.6	171.0	176.9	206.8	222.1	250.5	285.4
42	BECO'S SHARE		74.6	82.3	84.8	115.6	127.0	131.4	153.6	164.9	186.0	212.0
43												
44	NET BENEFIT (COST) OF SHUTDOWN		130	146	168	162	178	189	199	220	235	245

		SOURCE	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
1	PLANT-IN-SERVICE											
2	BEGINNING OF YEAR		1354.9	1494.6	1641.4	1795.9	1958.6	2129.9	2310.2	2500.3	2700.5	2911.6
3	NET CAPITAL ADDITIONS	PILG-89	139.7	146.8	154.5	162.6	171.3	180.4	190.0	200.3	211.1	222.4
4	END OF YEAR		1494.6	1641.4	1795.9	1958.6	2129.9	2310.2	2500.3	2700.5	2911.6	3134.1
5	ACCUMULATED DEPRECIATION											
6	BEGINNING OF YEAR		383.9	463.3	553.9	657.4	775.7	911.1	1066.6	1245.8	1453.6	1696.6
7	ANNUAL DEPRECIATION		79.3	90.6	103.5	118.3	135.4	155.5	179.2	207.8	243.0	287.5
8	END OF YEAR		463.3	553.9	657.4	775.7	911.1	1066.6	1245.8	1453.6	1696.6	1984.1
9	NET PLANT (YEAR END)		1031.3	1087.5	1138.5	1182.9	1218.8	1243.7	1254.5	1246.9	1215.0	1150.0
10	OTHER RATE BASE ITEMS											
11	DEFERRED TAXES		-80.5	-87.2	-92.6	-96.3	-97.5	-91.5	-75.9	-52.1	-17.6	31.0
12	MATERIALS AND SUPPLIES	BECO-89	47.9	50.4	53.0	55.8	58.8	61.9	65.2	68.8	72.5	61.1
13	NUCLEAR FUEL INVENTORY	BECO-89	75.2	79.3	81.9	88.3	90.2	94.9	99.8	105.0	110.4	92.9
14	YEAR END RATE BASE		1073.9	1130.0	1180.8	1230.7	1270.2	1309.0	1343.6	1368.7	1380.3	1334.9
15												
16	COSTS											
17	-------											
18	RETURN ON RATE BASE		116.8	122.9	128.5	133.9	138.2	142.4	146.2	148.9	150.2	145.2
19	INCOME TAXES		42.4	44.6	46.6	48.6	50.1	51.6	53.0	54.0	54.5	52.7
20	DEPRECIATION (REMAINING LIFE)		79.3	90.6	103.5	118.3	135.4	155.5	179.2	207.8	243.0	287.5
21	ANNUAL O&M EXPENSES	PILG-89	269.7	292.9	317.6	343.8	371.9	401.6	433.4	467.1	503.1	541.3
22	ADMINISTRATIVE & GENERAL	PILG-89	91.4	99.7	108.5	117.9	127.9	138.6	149.9	162.0	174.9	188.6
23	OUTAGE AMORTIZATION		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
24	INSURANCE	BECO-89	12.7	13.3	14.0	14.7	15.5	16.3	17.2	18.1	19.1	20.2
25	LOCAL TAXES		16.5	17.4	18.2	18.9	19.5	19.9	20.1	20.0	19.4	18.4
26	DECOMMISSIONING ANNUAL CONTRIBUTION	BECO-89	15.3	16.5	17.8	19.2	20.7	22.2	24.0	25.8	27.8	30.0
27												
28	ANNUAL NON-FUEL COST		644.1	698.0	754.7	815.3	879.3	948.2	1023.0	1103.8	1192.1	1283.9
29												
30	CAPACITY FACTOR	PILG-89	46%	46%	46%	46%	46%	46%	46%	46%	46%	46%
31	PILGRIM FUEL IN CENTS/KWH	BECO-89	0.8496	0.8950	0.9245	0.9971	1.0177	1.0708	1.1263	1.1853	1.2467	1.3116
32	TOTAL FUEL COST		23.1	24.3	25.1	27.1	27.7	29.1	30.6	32.2	33.9	35.6
33	TOTAL PILGRIM COST		667.2	722.3	779.8	842.4	906.9	977.3	1053.6	1136.0	1226.0	1319.6
34	BECO'S SHARE		495.5	536.5	579.1	625.6	673.6	725.8	782.5	843.7	910.5	980.0
35												
36	SHUTDOWN COSTS											
37	--------------------------											
38	REPLACEMENT POWER IN CENTS/KWH	QF-RFP-89	11.30	10.84	11.94	12.99	14.43	15.95	17.40	16.23	16.13	18.49
39	TOTAL REPLACEMENT POWER		307.1	294.6	324.5	353.0	392.1	433.4	472.8	441.0	438.3	502.5
40	EARLY DECOMMISSIONING	PILG-89	15.3	16.5	17.8	19.2	20.7	22.2	24.0	25.8	27.8	30.0
41	TOTAL SHUTDOWN COSTS		322.4	311.1	342.3	372.2	412.8	455.7	496.8	466.9	466.1	532.4
42	BECO'S SHARE		239.5	231.0	254.2	276.4	306.6	338.4	369.0	346.7	346.2	395.4
43												
44	NET BENEFIT (COST) OF SHUTDOWN		256	305	325	349	367	387	414	497	564	585

		SOURCE	2009	2010	2011	2012	NPV TO 1989 10.88%
1	PLANT-IN-SERVICE						
2	BEGINNING OF YEAR		3132.7	3367.0	3614.0	3874.3	
3	NET CAPITAL ADDITIONS	PILG-89	234.3	247	260.3	274.3	
4	END OF YEAR		3367.0	3614.0	3874.3	4148.6	
5	ACCUMULATED DEPRECIATION						
6	BEGINNING OF YEAR		1983.3	2329.2	2757.5	3315.9	
7	ANNUAL DEPRECIATION		345.9	428.3	558.4	832.7	
8	END OF YEAR		2329.2	2757.5	3315.9	4148.6	
9	NET PLANT (YEAR END)		1037.8	856.5	558.4	0.0	
10	OTHER RATE BASE ITEMS						
11	DEFERRED TAXES		98.7	194.6	336.7	0.0	
12	MATERIALS AND SUPPLIES	BECO-89	48.3	33.9	17.9	0.0	
13	NUCLEAR FUEL INVENTORY	BECO-89	73.3	51.4	27.1	0.0	
14	YEAR END RATE BASE		1258.1	1136.4	940.1	0.0	
15							
16	COSTS						
17	-------						
18	RETURN ON RATE BASE		136.9	123.6	102.3	0.0	828.4
19	INCOME TAXES		49.6	44.8	37.1	0.0	300.4
20	DEPRECIATION (REMAINING LIFE)		345.9	428.3	558.4	832.7	778.7
21	ANNUAL O&M EXPENSES	PILG-89	612.5	657.9	706.5	758.0	2292.7
22	ADMINISTRATIVE & GENERAL	PILG-89	215.0	231.3	248.9	267.5	775.5
23	OUTAGE AMORTIZATION		0.0	0.0	0.0	0.0	83.0
24	INSURANCE	BECO-89	21.2	22.4	23.6	24.9	108.8
25	LOCAL TAXES		16.6	13.7	8.9	0.0	111.1
26	DECOMMISSIONING ANNUAL CONTRIBUTION	BECO-89	32.3	34.8	37.5	26.9	129.2
27			-------	-------	-------	-------	
28	ANNUAL NON-FUEL COST		1430.1	1556.8	1723.2	1910.0	5407.8
29							
30	CAPACITY FACTOR	PILG-89	46%	46%	46%	46%	
31	PILGRIM FUEL IN CENTS/KWH	BECO-89	1.3800	1.4520	1.5275	1.6072	
32	TOTAL FUEL COST		37.5	39.5	41.5	43.7	193.7
33	TOTAL PILGRIM COST		1467.6	1596.3	1764.7	1953.7	5601.5
34	BECO'S SHARE		1090.0	1185.6	1310.6	1451.0	4160.2
35							
36	SHUTDOWN COSTS						
37	--------------------------						
38	REPLACEMENT POWER IN CENTS/KWH	QF-RFP-89	21.04	16.64	20.84	16.55	
39	TOTAL REPLACEMENT POWER		571.7	452.2	566.3	449.8	2105.3
40	EARLY DECOMMISSIONING	PILG-89	32.3	34.8	37.5	26.9	129.2
41	TOTAL SHUTDOWN COSTS		604.0	487.0	603.8	476.7	2234.5
42	BECO'S SHARE		448.6	361.7	448.4	354.1	1659.6
43							
44	NET BENEFIT (COST) OF SHUTDOWN		641	824	862	1,097	2,501

		SOURCE	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998
1	PLANT-IN-SERVICE											
2	BEGINNING OF YEAR		259.8	299.8	369.8	409.8	451.8	495.9	542.2	590.8	641.9	695.5
3	NET CAPITAL ADDITIONS	BECO-86	40.0	70.0	40.0	42.0	44.1	46.3	48.6	51.1	53.6	56.3
4	END OF YEAR		299.8	369.8	409.8	451.8	495.9	542.2	590.8	641.9	695.5	751.8
5	ACCUMULATED DEPRECIATION											
6	BEGINNING OF YEAR		0.0	12.5	28.0	45.4	64.7	86.3	110.3	137.0	166.7	199.7
7	ANNUAL DEPRECIATION		12.5	15.5	17.4	19.4	21.6	24.0	26.7	29.7	33.1	36.8
8	END OF YEAR		12.5	28.0	45.4	64.7	86.3	110.3	137.0	166.7	199.7	236.5
9	NET PLANT (YEAR END)		287.3	341.8	364.4	387.1	409.6	431.9	453.8	475.2	495.8	515.3
10	OTHER RATE BASE ITEMS											
11	DEFERRED TAXES		-1.0	-7.3	-13.7	-19.7	-25.1	-30.0	-34.6	-39.2	-43.8	-48.4
12	MATERIALS AND SUPPLIES	BECO-86	22.1	23.2	24.3	25.5	26.8	28.1	29.5	31.0	32.6	34.2
13	NUCLEAR FUEL INVENTORY	BECO-86	50.0	50.0	50.2	50.2	54.4	56.4	60.2	66.1	67.2	75.4
14	YEAR END RATE BASE		358.5	407.7	425.2	443.1	465.7	486.4	508.9	533.1	551.7	576.5
15												
16	COSTS											
17	-------											
18	RETURN ON RATE BASE	BECO-86	37.0	42.1	43.9	45.8	48.1	50.2	52.6	55.1	57.0	59.6
19	INCOME TAXES		13.4	15.3	15.9	16.6	17.4	18.2	19.1	20.0	20.7	21.6
20	DEPRECIATION (REMAINING LIFE)		12.5	15.5	17.4	19.4	21.6	24.0	26.7	29.7	33.1	36.8
21	ANNUAL O&M EXPENSES	BECO-86	106.5	119.5	125.0	131.3	137.8	144.7	151.9	159.5	167.5	175.9
22	ADMINISTRATIVE & GENERAL	BECO-86	21.4	24.0	25.1	26.4	27.7	29.1	30.5	32.1	33.7	35.4
23	OUTAGE AMORTIZATION		20.2	20.2	20.2	20.2	20.2	0.0	0.0	0.0	0.0	0.0
24	INSURANCE	BECO-86	5.0	5.2	5.5	5.7	6.0	6.3	6.6	7.0	7.3	7.7
25	LOCAL TAXES		4.6	5.5	5.8	6.2	6.6	6.9	7.3	7.6	7.9	8.2
26	DECOMMISSIONING ANNUAL CONTRIBUTION	BECO-86	4.8	5.1	5.4	5.7	6.1	6.5	6.9	7.3	7.8	8.3
27												
28	ANNUAL NON-FUEL COST		225.4	252.4	264.3	277.2	291.5	286.0	301.5	318.2	334.9	353.4
29												
30	CAPACITY FACTOR	BECO-86	70%	70%	70%	70%	70%	70%	70%	70%	70%	70%
31	PILGRIM FUEL IN CENTS/KWH	BECO-86	0.5793	0.5793	0.5793	0.5793	0.6280	0.6523	0.6961	0.7643	0.7765	0.8714
32	TOTAL FUEL COST		23.8	23.8	23.8	23.8	25.8	26.8	28.6	31.4	31.9	35.8
33	TOTAL PILGRIM COST		249.2	276.2	288.1	301.0	317.3	312.8	330.1	349.6	366.8	389.2
34	BECO'S SHARE		185.1	205.1	213.9	223.6	235.6	232.3	245.2	259.6	272.4	289.1
35												
36	SHUTDOWN COSTS											
37	--------------------------											
38	REPLACEMENT POWER IN CENTS/KWH	QF-RFP-86	3.26	3.39	3.89	5.58	6.23	6.89	7.58	8.46	9.54	10.50
39	TOTAL REPLACEMENT POWER		133.9	139.3	159.8	229.3	256.0	283.1	311.4	347.6	391.9	431.4
40	EARLY DECOMMISSIONING	BECO-86	4.8	5.1	5.4	5.7	6.1	6.5	6.9	7.3	7.8	8.3
41	TOTAL SHUTDOWN COSTS		138.7	144.4	165.2	235.0	262.1	289.6	318.3	354.9	399.7	439.7
42	BECO'S SHARE		103.0	107.2	122.7	174.5	194.6	215.1	236.4	263.6	296.9	326.6
43												
44	NET BENEFIT (COST) OF SHUTDOWN		82	98	91	49	41	17	9	(4)	(24)	(37)

		SOURCE	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
1	PLANT-IN-SERVICE											
2	BEGINNING OF YEAR		751.8	810.9	873.0	938.2	1006.6	1078.4	1153.8	1233.0	1316.2	1403.5
3	NET CAPITAL ADDITIONS	BECO-86	59.1	62.1	65.2	68.4	71.8	75.4	79.2	83.2	87.3	69.9
4	END OF YEAR		810.9	873.0	938.2	1006.6	1078.4	1153.8	1233.0	1316.2	1403.5	1473.4
5	ACCUMULATED DEPRECIATION											
6	BEGINNING OF YEAR		236.5	277.6	323.4	374.6	432.1	496.7	569.7	652.6	747.4	856.8
7	ANNUAL DEPRECIATION		41.0	45.8	51.2	57.5	64.6	73.0	82.9	94.8	109.3	123.3
8	END OF YEAR		277.6	323.4	374.6	432.1	496.7	569.7	652.6	747.4	856.8	980.1
9	NET PLANT (YEAR END)		533.3	549.6	563.6	574.5	581.7	584.1	580.4	568.8	546.7	493.3
10	OTHER RATE BASE ITEMS											
11	DEFERRED TAXES		-52.7	-56.7	-60.2	-62.9	-64.6	-61.6	-52.4	-39.5	-22.1	-0.2
12	MATERIALS AND SUPPLIES	BECO-86	35.9	37.7	39.6	41.6	43.7	45.8	48.1	50.5	53.1	42.5
13	NUCLEAR FUEL INVENTORY	BECO-86	75.4	84.2	84.2	92.2	93.9	99.3	105.1	111.3	117.9	124.9
14	YEAR END RATE BASE		591.9	614.8	627.2	645.4	654.7	667.6	681.2	691.1	695.6	660.5
15												
16	COSTS											
17	-------											
18	RETURN ON RATE BASE	BECO-86	61.1	63.5	64.8	66.7	67.6	69.0	70.4	71.4	71.9	68.2
19	INCOME TAXES		22.2	23.0	23.5	24.2	24.5	25.0	25.5	25.9	26.1	24.7
20	DEPRECIATION (REMAINING LIFE)		41.0	45.8	51.2	57.5	64.6	73.0	82.9	94.8	109.3	123.3
21	ANNUAL O&M EXPENSES	BECO-86	184.7	193.9	203.6	213.8	224.5	235.7	247.5	259.9	272.9	286.5
22	ADMINISTRATIVE & GENERAL	BECO-86	37.1	39.0	40.9	43.0	45.1	47.4	49.7	52.2	54.9	57.6
23	OUTAGE AMORTIZATION		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
24	INSURANCE	BECO-86	8.1	8.5	8.9	9.4	9.8	10.3	10.8	11.4	11.9	12.5
25	LOCAL TAXES		8.5	8.8	9.0	9.2	9.3	9.3	9.3	9.1	8.7	7.9
26	DECOMMISSIONING ANNUAL CONTRIBUTION	BECO-86	8.8	9.4	10.0	10.7	11.4	12.1	13.0	13.9	14.9	16.0
27												
28	ANNUAL NON-FUEL COST		371.6	391.9	412.0	434.4	456.9	481.8	509.1	538.6	570.6	596.8
29												
30	CAPACITY FACTOR	BECO-86	70%	70%	70%	70%	70%	70%	70%	70%	70%	70%
31	PILGRIM FUEL IN CENTS/KWH	BECO-86	0.8714	0.9736	0.9736	1.0661	1.0856	1.1489	1.2146	1.2876	1.3631	1.4434
32	TOTAL FUEL COST		35.8	40.0	40.0	43.8	44.6	47.2	49.9	52.9	56.0	59.3
33	TOTAL PILGRIM COST		407.4	431.9	452.0	478.2	501.5	529.0	559.0	591.5	626.6	656.1
34	BECO'S SHARE		302.6	320.8	335.7	355.1	372.5	392.9	415.2	439.3	465.3	487.3
35												
36	SHUTDOWN COSTS											
37	--------------------------											
38	REPLACEMENT POWER IN CENTS/KWH	QF-RFP-86	12.06	13.32	14.64	16.46	17.50	19.31	21.39	23.32	24.69	26.59
39	TOTAL REPLACEMENT POWER		495.5	547.2	601.5	676.2	719.0	793.3	878.8	958.1	1014.4	1092.4
40	EARLY DECOMMISSIONING	BECO-86	8.8	9.4	10.0	10.7	11.4	12.1	13.0	13.9	14.9	16.0
41	TOTAL SHUTDOWN COSTS		504.3	556.6	611.5	686.9	730.4	805.4	891.8	972.0	1029.3	1108.4
42	BECO'S SHARE		374.5	413.4	454.1	510.2	542.5	598.2	662.3	721.9	764.4	823.2
43												
44	NET BENEFIT (COST) OF SHUTDOWN		(72)	(93)	(118)	(155)	(170)	(205)	(247)	(283)	(299)	(336)

TABLE 3.2.6: PILGRIM ECONOMICS; 1986 BECO PROJECTIONS

		SOURCE	2009	2010	2011	2012	NPV TO 1989 10.33%
1	PLANT-IN-SERVICE						
2	BEGINNING OF YEAR		1473.4	1529.3	1574.0	1609.8	
3	NET CAPITAL ADDITIONS	BECO-86	55.9	44.7	35.8	28.6	
4	END OF YEAR		1529.3	1574.0	1609.8	1638.4	
5	ACCUMULATED DEPRECIATION						
6	BEGINNING OF YEAR		980.1	1117.4	1269.6	1439.7	
7	ANNUAL DEPRECIATION		137.3	152.2	170.1	198.7	
8	END OF YEAR		1117.4	1269.6	1439.7	1638.4	
9	NET PLANT (YEAR END)		411.9	304.4	170.1	0.0	
10	OTHER RATE BASE ITEMS						
11	DEFERRED TAXES		26.9	60.0	100.7	0.0	
12	MATERIALS AND SUPPLIES	BECO-86	34.0	27.2	21.7	17.4	
13	NUCLEAR FUEL INVENTORY	BECO-86	93.6	62.4	31.2	0.0	
14	YEAR END RATE BASE		566.4	454.0	323.7	17.4	
15							
16	COSTS						
17	-------						
18	RETURN ON RATE BASE	BECO-86	58.5	46.9	33.4	1.8	500.7
19	INCOME TAXES		21.2	17.0	12.1	0.7	181.5
20	DEPRECIATION (REMAINING LIFE)		137.3	152.2	170.1	198.7	391.6
21	ANNUAL O&M EXPENSES	BECO-86	300.8	315.9	331.7	348.2	1625.3
22	ADMINISTRATIVE & GENERAL	BECO-86	60.5	63.5	66.7	70.0	326.7
23	OUTAGE AMORTIZATION		0.0	0.0	0.0	0.0	83.8
24	INSURANCE	BECO-86	13.2	13.8	14.5	15.2	71.4
25	LOCAL TAXES		6.6	4.9	2.7	0.0	66.7
26	DECOMMISSIONING ANNUAL CONTRIBUTION	BECO-86	17.2	18.7	20.7	10.8	77.5
27							
28	ANNUAL NON-FUEL COST		615.3	632.9	652.0	645.3	3325.1
29							
30	CAPACITY FACTOR	BECO-86	70%	70%	70%	70%	
31	PILGRIM FUEL IN CENTS/KWH	BECO-86	1.5286	1.6211	1.7184	1.8231	
32	TOTAL FUEL COST		62.8	66.6	70.6	74.9	323.1
33	TOTAL PILGRIM COST		678.1	699.5	722.6	720.2	3648.2
34	BECO'S SHARE		503.6	519.5	536.6	534.9	2709.5
35							
36	SHUTDOWN COSTS						
37	--------------------------						
38	REPLACEMENT POWER IN CENTS/KWH	QF-RFP-86	28.38	30.13	32.72	35.04	
39	TOTAL REPLACEMENT POWER		1166.0	1237.9	1344.3	1439.6	4048.4
40	EARLY DECOMMISSIONING	BECO-86	17.2	18.7	20.7	10.8	77.5
41	TOTAL SHUTDOWN COSTS		1183.2	1256.6	1365.0	1450.4	4125.9
42	BECO'S SHARE		878.7	933.3	1013.8	1077.2	3064.3
43							
44	NET BENEFIT (COST) OF SHUTDOWN		(375)	(414)	(477)	(542)	(355)

		SOURCE	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998
1	PLANT-IN-SERVICE											
2	BEGINNING OF YEAR		259.8	334.3	414.3	500.2	592.6	691.5	797.6	911.5	1033.1	1163.3
3	NET CAPITAL ADDITIONS	KEA-86	74.5	80.0	85.9	92.3	99.0	106.1	113.9	121.6	130.2	139.6
4	END OF YEAR		334.3	414.3	500.2	592.6	691.5	797.6	911.5	1033.1	1163.3	1302.9
5	ACCUMULATED DEPRECIATION											
6	BEGINNING OF YEAR		0.0	13.9	31.3	52.6	78.4	109.0	145.3	187.8	237.5	295.4
7	ANNUAL DEPRECIATION		13.9	17.4	21.3	25.7	30.7	36.2	42.6	49.7	57.9	67.2
8	END OF YEAR		13.9	31.3	52.6	78.4	109.0	145.3	187.8	237.5	295.4	362.6
9	NET PLANT (YEAR END)		320.3	383.0	447.6	514.2	582.5	652.4	723.7	795.5	867.9	940.3
10	OTHER RATE BASE ITEMS											
11	DEFERRED TAXES		-1.1	-8.1	-15.4	-22.9	-30.5	-37.9	-45.4	-53.0	-60.8	-68.4
12	MATERIALS AND SUPPLIES	BECO-86	22.1	23.2	24.3	25.5	26.8	28.1	29.5	31.0	32.6	34.2
13	NUCLEAR FUEL INVENTORY	BECO-86	50.0	50.0	50.2	50.2	54.4	56.4	60.2	66.1	67.2	75.4
14	YEAR END RATE BASE		391.4	448.1	506.7	567.0	633.2	699.0	768.0	839.6	906.9	981.5
15												
16	COSTS											
17	-------											
18	RETURN ON RATE BASE	BECO-86	40.4	46.3	52.3	58.6	65.4	72.2	79.3	86.7	93.7	101.4
19	INCOME TAXES		14.7	16.8	19.0	21.2	23.7	26.2	28.8	31.4	34.0	36.8
20	DEPRECIATION (REMAINING LIFE)		13.9	17.4	21.3	25.7	30.7	36.2	42.6	49.7	57.9	67.2
21	ANNUAL O&M EXPENSES	KEA-86	83.1	89.7	96.8	104.5	112.8	121.7	131.2	141.3	152.0	163.5
22	ADMINISTRATIVE & GENERAL	KEA-86	21.1	23.0	24.9	27.1	29.4	31.9	34.6	37.4	40.4	43.6
23	OUTAGE AMORTIZATION		20.2	20.2	20.2	20.2	20.2	0.0	0.0	0.0	0.0	0.0
24	INSURANCE	BECO-86	5.0	5.2	5.5	5.7	6.0	6.3	6.6	7.0	7.3	7.7
25	LOCAL TAXES		5.1	6.1	7.2	8.2	9.3	10.4	11.6	12.7	13.9	15.0
26	DECOMMISSIONING ANNUAL CONTRIBUTION	BECO-86	4.8	5.1	5.4	5.7	6.1	6.5	6.9	7.3	7.8	8.3
27												
28	ANNUAL NON-FUEL COST		208.3	229.7	252.6	277.0	303.7	311.5	341.5	373.6	407.0	443.5
29												
30	CAPACITY FACTOR	KEA-86	60%	61%	62%	62%	63%	62%	62%	61%	61%	59%
31	PILGRIM FUEL IN CENTS/KWH	BECO-86	0.5793	0.5793	0.5793	0.5793	0.6280	0.6523	0.6961	0.7643	0.7765	0.8714
32	TOTAL FUEL COST		20.4	20.7	21.1	21.1	23.2	23.7	25.3	27.4	27.8	30.2
33	TOTAL PILGRIM COST		228.7	250.5	273.7	298.0	326.9	335.2	366.8	400.9	434.8	473.7
34	BECO'S SHARE		169.8	186.0	203.3	221.4	242.8	249.0	272.4	297.8	322.9	351.8
35												
36	SHUTDOWN COSTS											
37	---------------------------											
38	REPLACEMENT POWER IN CENTS/KWH	QF-RFP-86	3.26	3.39	3.89	5.58	6.23	6.89	7.58	8.46	9.54	10.50
39	TOTAL REPLACEMENT POWER		114.8	121.4	141.6	203.1	230.4	250.7	275.8	302.9	341.6	363.6
40	EARLY DECOMMISSIONING	BECO-86	4.8	5.1	5.4	5.7	6.1	6.5	6.9	7.3	7.8	8.3
41	TOTAL SHUTDOWN COSTS		119.6	126.5	147.0	208.8	236.5	257.2	282.7	310.2	349.4	371.9
42	BECO'S SHARE		88.8	93.9	109.1	155.0	175.6	191.0	210.0	230.4	259.5	276.2
43												
44	NET BENEFIT (COST) OF SHUTDOWN		81	92	94	66	67	58	62	67	63	76

		SOURCE	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
1	PLANT-IN-SERVICE											
2	BEGINNING OF YEAR		1302.9	1452.7	1613.4	1786.1	1971.6	2170.9	2385.0	2615.0	2861.9	3127.0
3	NET CAPITAL ADDITIONS	KEA-86	149.8	160.8	172.7	185.5	199.3	214.1	230.0	247.0	265.1	284.5
4	END OF YEAR		1452.7	1613.4	1786.1	1971.6	2170.9	2385.0	2615.0	2861.9	3127.0	3411.5
5	ACCUMULATED DEPRECIATION											
6	BEGINNING OF YEAR		362.6	440.4	530.7	635.3	756.8	898.2	1063.4	1257.3	1486.6	1760.0
7	ANNUAL DEPRECIATION		77.9	90.2	104.6	121.5	141.4	165.2	193.9	229.2	273.4	330.3
8	END OF YEAR		440.4	530.7	635.3	756.8	898.2	1063.4	1257.3	1486.6	1760.0	2090.3
9	NET PLANT (YEAR END)		1012.2	1082.8	1150.8	1214.8	1272.7	1321.6	1357.6	1375.3	1367.0	1321.2
10	OTHER RATE BASE ITEMS											
11	DEFERRED TAXES		-75.6	-81.9	-87.0	-90.2	-90.6	-83.3	-66.1	-39.4	-0.4	55.6
12	MATERIALS AND SUPPLIES	BECO-86	35.9	37.7	39.6	41.6	43.7	45.8	48.1	50.5	53.1	42.5
13	NUCLEAR FUEL INVENTORY	BECO-86	75.4	84.2	84.2	92.2	93.9	99.3	105.1	111.3	117.9	124.9
14	YEAR END RATE BASE		1048.0	1122.7	1187.6	1258.5	1319.8	1383.4	1444.8	1497.7	1537.6	1544.2
15												
16	COSTS											
17	-------											
18	RETURN ON RATE BASE	BECO-86	108.3	116.0	122.7	130.0	136.3	142.9	149.2	154.7	158.8	159.5
19	INCOME TAXES		39.3	42.1	44.5	47.1	49.4	51.8	54.1	56.1	57.6	57.8
20	DEPRECIATION (REMAINING LIFE)		77.9	90.2	104.6	121.5	141.4	165.2	193.9	229.2	273.4	330.3
21	ANNUAL O&M EXPENSES	KEA-86	175.7	188.9	202.7	217.4	233.1	249.6	267.2	285.9	305.7	326.8
22	ADMINISTRATIVE & GENERAL	KEA-86	47.1	50.8	54.8	58.9	63.4	68.1	73.1	78.4	84.1	90.1
23	OUTAGE AMORTIZATION		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
24	INSURANCE	BECO-86	8.1	8.5	8.9	9.4	9.8	10.3	10.8	11.4	11.9	12.5
25	LOCAL TAXES		16.2	17.3	18.4	19.4	20.4	21.1	21.7	22.0	21.9	21.1
26	DECOMMISSIONING ANNUAL CONTRIBUTION	BECO-86	8.8	9.4	10.0	10.7	11.4	12.1	13.0	13.9	14.9	16.0
27												
28	ANNUAL NON-FUEL COST		481.3	523.2	566.6	614.4	665.2	721.1	783.2	851.6	928.4	1014.2
29												
30	CAPACITY FACTOR	KEA-86	58%	56%	54%	52%	50%	47%	44%	41%	38%	34%
31	PILGRIM FUEL IN CENTS/KWH	BECO-86	0.8714	0.9736	0.9736	1.0661	1.0856	1.1489	1.2146	1.2876	1.3631	1.4434
32	TOTAL FUEL COST		29.7	32.0	30.9	32.5	31.9	31.7	31.4	31.0	30.4	28.8
33	TOTAL PILGRIM COST		511.0	555.2	597.4	647.0	697.1	752.8	814.6	882.6	958.8	1043.0
34	BECO'S SHARE		379.5	412.3	443.7	480.5	517.7	559.1	605.0	655.5	712.1	774.6
35												
36	SHUTDOWN COSTS											
37	--------------------------											
38	REPLACEMENT POWER IN CENTS/KWH	QF-RFP-86	12.06	13.32	14.64	16.46	17.50	19.31	21.39	23.32	24.69	26.59
39	TOTAL REPLACEMENT POWER		410.5	437.8	464.0	502.4	513.6	532.7	552.4	561.2	550.7	530.6
40	EARLY DECOMMISSIONING	BECO-86	8.8	9.4	10.0	10.7	11.4	12.1	13.0	13.9	14.9	16.0
41	TOTAL SHUTDOWN COSTS		419.3	447.2	474.0	513.1	525.0	544.8	565.4	575.1	565.6	546.6
42	BECO'S SHARE		311.4	332.1	352.0	381.0	389.9	404.6	419.9	427.1	420.0	406.0
43												
44	NET BENEFIT (COST) OF SHUTDOWN		68	80	92	99	128	155	185	228	292	369

		SOURCE	2009	2010	2011	2012	NPV TO 1989 10.33%
1	PLANT-IN-SERVICE						
2	BEGINNING OF YEAR		3411.5	3716.6	4043.9	4394.8	
3	NET CAPITAL ADDITIONS	KEA-86	305.2	327.3	350.9	376.1	
4	END OF YEAR		3716.6	4043.9	4394.8	4770.9	
5	ACCUMULATED DEPRECIATION						
6	BEGINNING OF YEAR		2090.3	2496.9	3012.5	3703.7	
7	ANNUAL DEPRECIATION		406.6	515.7	691.1	1067.2	
8	END OF YEAR		2496.9	3012.5	3703.7	4770.9	
9	NET PLANT (YEAR END)		1219.8	1031.4	691.1	0.0	
10	OTHER RATE BASE ITEMS						
11	DEFERRED TAXES		135.7	252.1	429.6	0.0	
12	MATERIALS AND SUPPLIES	BECO-86	34.0	27.2	21.7	17.4	
13	NUCLEAR FUEL INVENTORY	BECO-86	93.6	62.4	31.2	0.0	
14	YEAR END RATE BASE		1483.1	1373.0	1173.7	17.4	
15							
16	COSTS						
17	-------						
18	RETURN ON RATE BASE	BECO-86	153.2	141.8	121.2	1.8	815.6
19	INCOME TAXES		55.6	51.4	44.0	0.7	295.7
20	DEPRECIATION (REMAINING LIFE)		406.6	515.7	691.1	1067.2	905.2
21	ANNUAL O&M EXPENSES	KEA-86	349.0	372.6	397.7	424.2	1519.3
22	ADMINISTRATIVE & GENERAL	KEA-86	96.4	103.2	110.4	118.0	405.7
23	OUTAGE AMORTIZATION		0.0	0.0	0.0	0.0	83.8
24	INSURANCE	BECO-86	13.2	13.8	14.5	15.2	71.4
25	LOCAL TAXES		19.5	16.5	11.1	0.0	115.4
26	DECOMMISSIONING ANNUAL CONTRIBUTION	BECO-86	17.2	18.7	20.7	10.8	77.5
27							
28	ANNUAL NON-FUEL COST		1110.6	1233.7	1410.6	1637.9	4289.6
29							
30	CAPACITY FACTOR	KEA-86	30%	26%	21%	17%	
31	PILGRIM FUEL IN CENTS/KWH	BECO-86	1.5286	1.6211	1.7184	1.8231	
32	TOTAL FUEL COST		26.9	24.7	21.2	18.2	244.3
33	TOTAL PILGRIM COST		1137.6	1258.5	1431.8	1656.1	4533.9
34	BECO'S SHARE		844.9	934.7	1063.4	1230.0	3367.3
35							
36	SHUTDOWN COSTS						
37	--------------------------						
38	REPLACEMENT POWER IN CENTS/KWH	QF-RFP-86	28.38	30.13	32.72	35.04	
39	TOTAL REPLACEMENT POWER		499.7	459.8	403.3	349.6	2855.2
40	EARLY DECOMMISSIONING	BECO-86	17.2	18.7	20.7	10.8	77.5
41	TOTAL SHUTDOWN COSTS		516.9	478.5	424.0	360.4	2932.7
42	BECO'S SHARE		383.9	355.4	314.9	267.7	2178.1
43							
44	NET BENEFIT (COST) OF SHUTDOWN		461	579	749	962	1,189

TABLE 3.2.8: PILGRIM ECONOMICS; 1986 PILGRIM PROJECTIONS

		SOURCE	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998
1	PLANT-IN-SERVICE											
2	BEGINNING OF YEAR		259.8	342.7	429.0	519.1	613.1	711.3	814.0	921.6	1034.0	1151.6
3	NET CAPITAL ADDITIONS	PILG-86	82.9	86.3	90.1	94.0	98.2	102.7	107.6	112.4	117.6	123.3
4	END OF YEAR		342.7	429.0	519.1	613.1	711.3	814.0	921.6	1034.0	1151.6	1274.9
5	ACCUMULATED DEPRECIATION											
6	BEGINNING OF YEAR		0.0	14.3	32.3	54.4	81.0	112.6	149.5	192.4	241.9	298.7
7	ANNUAL DEPRECIATION		14.3	18.0	22.1	26.6	31.5	36.9	42.9	49.5	56.9	65.1
8	END OF YEAR		14.3	32.3	54.4	81.0	112.6	149.5	192.4	241.9	298.7	363.8
9	NET PLANT (YEAR END)		328.4	396.7	464.7	532.1	598.7	664.5	729.2	792.1	852.9	911.1
10	OTHER RATE BASE ITEMS											
11	DEFERRED TAXES		-1.1	-8.3	-15.9	-23.7	-31.5	-39.1	-46.7	-54.4	-62.1	-69.6
12	MATERIALS AND SUPPLIES	BECO-86	22.1	23.2	24.3	25.5	26.8	28.1	29.5	31.0	32.6	34.2
13	NUCLEAR FUEL INVENTORY	BECO-86	50.0	50.0	50.2	50.2	54.4	56.4	60.2	66.1	67.2	75.4
14	YEAR END RATE BASE		399.4	461.6	523.2	584.0	648.4	709.9	772.2	834.8	890.6	951.1
15												
16	COSTS											
17	-------											
18	RETURN ON RATE BASE	BECO-86	41.3	47.7	54.1	60.3	67.0	73.3	79.8	86.2	92.0	98.2
19	INCOME TAXES		15.0	17.3	19.6	21.9	24.3	26.6	28.9	31.3	33.4	35.6
20	DEPRECIATION (REMAINING LIFE)		14.3	18.0	22.1	26.6	31.5	36.9	42.9	49.5	56.9	65.1
21	ANNUAL O&M EXPENSES	PILG-86	86.1	94.5	103.7	113.4	124.0	135.5	147.6	160.6	174.4	189.3
22	ADMINISTRATIVE & GENERAL	PILG-86	22.0	24.5	27.1	29.9	32.9	36.2	39.7	43.4	47.5	51.8
23	OUTAGE AMORTIZATION		20.2	20.2	20.2	20.2	20.2	0.0	0.0	0.0	0.0	0.0
24	INSURANCE	BECO-86	5.0	5.2	5.5	5.7	6.0	6.3	6.6	7.0	7.3	7.7
25	LOCAL TAXES		5.3	6.3	7.4	8.5	9.6	10.6	11.7	12.7	13.6	14.6
26	DECOMMISSIONING ANNUAL CONTRIBUTION	BECO-86	4.8	5.1	5.4	5.7	6.1	6.5	6.9	7.3	7.8	8.3
27												
28	ANNUAL NON-FUEL COST		213.9	238.8	265.1	292.3	321.6	332.0	364.1	398.0	432.8	470.6
29												
30	CAPACITY FACTOR	PILG-86	56%	56%	56%	56%	56%	56%	56%	56%	56%	56%
31	PILGRIM FUEL IN CENTS/KWH	BECO-86	0.5793	0.5793	0.5793	0.5793	0.6280	0.6523	0.6961	0.7643	0.7765	0.8714
32	TOTAL FUEL COST		18.9	18.9	18.9	18.9	20.5	21.3	22.7	24.9	25.3	28.4
33	TOTAL PILGRIM COST		232.8	257.7	284.0	311.2	342.1	353.3	386.8	422.9	458.1	499.1
34	BECO'S SHARE		172.9	191.4	210.9	231.1	254.1	262.4	287.3	314.1	340.3	370.7
35												
36	SHUTDOWN COSTS											
37	--------------------------											
38	REPLACEMENT POWER IN CENTS/KWH	QF-RFP-86	3.26	3.39	3.89	5.58	6.23	6.89	7.58	8.46	9.54	10.50
39	TOTAL REPLACEMENT POWER		106.4	110.6	126.9	182.1	203.3	224.8	247.4	276.1	311.3	342.6
40	EARLY DECOMMISSIONING	BECO-86	4.8	5.1	5.4	5.7	6.1	6.5	6.9	7.3	7.8	8.3
41	TOTAL SHUTDOWN COSTS		111.2	115.7	132.3	187.8	209.4	231.3	254.3	283.4	319.1	350.9
42	BECO'S SHARE		82.6	85.9	98.3	139.5	155.5	171.8	188.8	210.5	237.0	260.6
43												
44	NET BENEFIT (COST) OF SHUTDOWN		90	105	113	92	99	91	98	104	103	110

		SOURCE	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
1	PLANT-IN-SERVICE											
2	BEGINNING OF YEAR		1274.9	1404.4	1540.5	1683.7	1834.5	1993.3	2160.5	2336.6	2522.2	2717.8
3	NET CAPITAL ADDITIONS	PILG-86	129.5	136.1	143.2	150.8	158.8	167.2	176.1	185.6	195.6	206.2
4	END OF YEAR		1404.4	1540.5	1683.7	1834.5	1993.3	2160.5	2336.6	2522.2	2717.8	2924.0
5	ACCUMULATED DEPRECIATION											
6	BEGINNING OF YEAR		363.8	438.1	522.9	619.7	730.1	856.4	1001.3	1168.2	1361.7	1587.7
7	ANNUAL DEPRECIATION		74.3	84.8	96.7	110.4	126.3	144.9	166.9	193.4	226.0	267.3
8	END OF YEAR		438.1	522.9	619.7	730.1	856.4	1001.3	1168.2	1361.7	1587.7	1854.9
9	NET PLANT (YEAR END)		966.3	1017.6	1064.0	1104.4	1136.9	1159.2	1168.4	1160.5	1130.1	1069.1
10	OTHER RATE BASE ITEMS											
11	DEFERRED TAXES		-76.7	-83.0	-88.1	-91.7	-92.9	-87.2	-72.5	-50.1	-17.8	27.5
12	MATERIALS AND SUPPLIES	BECO-86	35.9	37.7	39.6	41.6	43.7	45.8	48.1	50.5	53.1	42.5
13	NUCLEAR FUEL INVENTORY	BECO-86	75.4	84.2	84.2	92.2	93.9	99.3	105.1	111.3	117.9	124.9
14	YEAR END RATE BASE		1000.9	1056.5	1099.7	1146.5	1181.5	1217.0	1249.1	1272.3	1283.3	1263.9
15												
16	COSTS											
17	-------											
18	RETURN ON RATE BASE	BECO-86	103.4	109.1	113.6	118.4	122.1	125.7	129.0	131.4	132.6	130.6
19	INCOME TAXES		37.5	39.6	41.2	42.9	44.3	45.6	46.8	47.7	48.1	47.3
20	DEPRECIATION (REMAINING LIFE)		74.3	84.8	96.7	110.4	126.3	144.9	166.9	193.4	226.0	267.3
21	ANNUAL O&M EXPENSES	PILG-86	205.2	222.2	240.4	259.6	280.1	301.7	325.1	349.7	375.9	404.0
22	ADMINISTRATIVE & GENERAL	PILG-86	56.3	61.3	66.6	72.1	78.1	84.4	91.3	98.4	106.1	114.3
23	OUTAGE AMORTIZATION		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
24	INSURANCE	BECO-86	8.1	8.5	8.9	9.4	9.8	10.3	10.8	11.4	11.9	12.5
25	LOCAL TAXES		15.5	16.3	17.0	17.7	18.2	18.5	18.7	18.6	18.1	17.1
26	DECOMMISSIONING ANNUAL CONTRIBUTION	BECO-86	8.8	9.4	10.0	10.7	11.4	12.1	13.0	13.9	14.9	16.0
27												
28	ANNUAL NON-FUEL COST		509.1	551.2	594.4	641.3	690.3	743.3	801.6	864.5	933.6	1009.1
29												
30	CAPACITY FACTOR	PILG-86	56%	56%	56%	56%	56%	56%	56%	56%	56%	56%
31	PILGRIM FUEL IN CENTS/KWH	BECO-86	0.8714	0.9736	0.9736	1.0661	1.0856	1.1489	1.2146	1.2876	1.3631	1.4434
32	TOTAL FUEL COST		28.4	31.8	31.8	34.8	35.4	37.5	39.6	42.0	44.5	47.1
33	TOTAL PILGRIM COST		537.5	582.9	626.2	676.1	725.7	780.8	841.3	906.5	978.1	1056.2
34	BECO'S SHARE		399.2	432.9	465.1	502.1	539.0	579.9	624.8	673.2	726.4	784.4
35												
36	SHUTDOWN COSTS											
37	---------------------------											
38	REPLACEMENT POWER IN CENTS/KWH	QF-RFP-86	12.06	13.32	14.64	16.46	17.50	19.31	21.39	23.32	24.69	26.59
39	TOTAL REPLACEMENT POWER		393.6	434.7	477.7	537.1	571.1	630.1	698.0	761.0	805.7	867.7
40	EARLY DECOMMISSIONING	BECO-86	8.8	9.4	10.0	10.7	11.4	12.1	13.0	13.9	14.9	16.0
41	TOTAL SHUTDOWN COSTS		402.4	444.1	487.7	547.8	582.5	642.2	711.0	774.9	820.6	883.7
42	BECO'S SHARE		298.8	329.8	362.2	406.9	432.6	477.0	528.1	575.5	609.5	656.3
43												
44	NET BENEFIT (COST) OF SHUTDOWN		100	103	103	95	106	103	97	98	117	128

		SOURCE	2009	2010	2011	2012	NPV TO 1989 10.33%
1	PLANT-IN-SERVICE						
2	BEGINNING OF YEAR		2924.0	3141.3	3370.3	3611.7	
3	NET CAPITAL ADDITIONS	PILG-86	217.3	229.0	241.4	254.4	
4	END OF YEAR		3141.3	3370.3	3611.7	3866.1	
5	ACCUMULATED DEPRECIATION						
6	BEGINNING OF YEAR		1854.9	2176.5	2574.5	3093.1	
7	ANNUAL DEPRECIATION		321.6	397.9	518.6	773.0	
8	END OF YEAR		2176.5	2574.5	3093.1	3866.1	
9	NET PLANT (YEAR END)		964.8	795.8	518.6	0.0	
10	OTHER RATE BASE ITEMS						
11	DEFERRED TAXES		90.6	179.8	311.9	0.0	
12	MATERIALS AND SUPPLIES	BECO-86	34.0	27.2	21.7	17.4	
13	NUCLEAR FUEL INVENTORY	BECO-86	93.6	62.4	31.2	0.0	
14	YEAR END RATE BASE		1183.0	1065.3	883.4	17.4	
15							
16	COSTS						
17	-------						
18	RETURN ON RATE BASE	BECO-86	122.2	110.0	91.3	1.8	773.1
19	INCOME TAXES		44.3	39.9	33.1	0.7	280.3
20	DEPRECIATION (REMAINING LIFE)		321.6	397.9	518.6	773.0	782.5
21	ANNUAL O&M EXPENSES	PILG-86	433.5	464.8	498.5	533.9	1758.5
22	ADMINISTRATIVE & GENERAL	PILG-86	122.9	132.1	142.0	152.5	480.8
23	OUTAGE AMORTIZATION		0.0	0.0	0.0	0.0	83.8
24	INSURANCE	BECO-86	13.2	13.8	14.5	15.2	71.4
25	LOCAL TAXES		15.4	12.7	8.3	0.0	109.6
26	DECOMMISSIONING ANNUAL CONTRIBUTION	BECO-86	17.2	18.7	20.7	10.8	77.5
27			-------	-------	-------	-------	
28	ANNUAL NON-FUEL COST		1090.3	1190.0	1327.0	1487.8	4417.4
29							
30	CAPACITY FACTOR	PILG-86	56%	56%	56%	56%	
31	PILGRIM FUEL IN CENTS/KWH	BECO-86	1.5286	1.6211	1.7184	1.8231	
32	TOTAL FUEL COST		49.9	52.9	56.1	59.5	256.6
33	TOTAL PILGRIM COST		1140.2	1242.9	1383.1	1547.3	4674.0
34	BECO'S SHARE		846.8	923.1	1027.2	1149.2	3471.4
35							
36	SHUTDOWN COSTS						
37	--------------------------						
38	REPLACEMENT POWER IN CENTS/KWH	QF-RFP-86	28.38	30.13	32.72	35.04	
39	TOTAL REPLACEMENT POWER		926.1	983.2	1067.7	1143.5	3215.6
40	EARLY DECOMMISSIONING	BECO-86	17.2	18.7	20.7	10.8	77.5
41	TOTAL SHUTDOWN COSTS		943.3	1001.9	1088.4	1154.3	3293.0
42	BECO'S SHARE		700.6	744.1	808.4	857.3	2445.7
43							
44	NET BENEFIT (COST) OF SHUTDOWN		146	179	219	292	1,026

TABLE 3.2.9: PILGRIM ECONOMICS; 1989 OPTIMITSTIC NATIONAL PROJECTIONS

		SOURCE	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998
1	PLANT-IN-SERVICE											
2	BEGINNING OF YEAR		259.8	311.2	366.8	427.0	492.0	562.1	637.7	719.4	807.1	901.5
3	NET CAPITAL ADDITIONS	KEA-89 0	51.4	55.6	60.1	65.0	70.1	75.6	81.6	87.7	94.4	101.8
4	END OF YEAR		311.2	366.8	427.0	492.0	562.1	637.7	719.4	807.1	901.5	1003.3
5	ACCUMULATED DEPRECIATION											
6	BEGINNING OF YEAR		0.0	13.0	28.4	46.5	67.7	92.4	121.1	154.3	192.7	237.0
7	ANNUAL DEPRECIATION		13.0	15.4	18.1	21.2	24.7	28.7	33.2	38.4	44.3	51.1
8	END OF YEAR		13.0	28.4	46.5	67.7	92.4	121.1	154.3	192.7	237.0	288.1
9	NET PLANT (YEAR END)		298.2	338.5	380.5	424.3	469.7	516.6	565.0	614.3	664.4	715.1
10	OTHER RATE BASE ITEMS											
11	DEFERRED TAXES		-1.0	-7.5	-13.9	-20.2	-26.3	-32.1	-37.9	-43.8	-49.8	-55.7
12	MATERIALS AND SUPPLIES	BECO-89	30.7	32.0	33.3	34.8	36.3	38.0	39.8	41.6	43.5	45.7
13	NUCLEAR FUEL INVENTORY	BECO-89	52.2	51.6	51.5	50.1	51.0	53.6	59.4	62.1	68.2	70.1
14	YEAR END RATE BASE		380.1	414.6	451.4	489.0	530.7	576.1	626.3	674.2	726.3	775.2
15												
16	COSTS											
17	-------											
18	RETURN ON RATE BASE		41.4	45.1	49.1	53.2	57.7	62.7	68.1	73.4	79.0	84.3
19	INCOME TAXES		15.0	16.4	17.8	19.3	20.9	22.7	24.7	26.6	28.7	30.6
20	DEPRECIATION (REMAINING LIFE)		13.0	15.4	18.1	21.2	24.7	28.7	33.2	38.4	44.3	51.1
21	ANNUAL O&M EXPENSES	KEA-89 0	86.6	93.8	101.6	109.9	119.0	128.7	139.0	150.1	161.8	174.4
22	ADMINISTRATIVE & GENERAL	KEA-89 0	25.3	27.7	30.4	33.2	36.3	39.6	43.1	46.9	50.9	55.2
23	OUTAGE AMORTIZATION		20.2	20.2	20.2	20.2	20.2	0.0	0.0	0.0	0.0	0.0
24	INSURANCE	BECO-89	8.1	8.4	8.8	9.2	9.6	10.0	10.5	11.0	11.5	12.1
25	LOCAL TAXES		4.8	5.4	6.1	6.8	7.5	8.3	9.0	9.8	10.6	11.4
26	DECOMMISSIONING ANNUAL CONTRIBUTION	BECO-89	8.3	8.6	9.0	9.4	9.8	10.6	11.4	12.3	13.2	14.2
27												
28	ANNUAL NON-FUEL COST		222.6	241.1	261.1	282.4	305.8	311.3	339.1	368.4	400.1	433.4
29												
30	CAPACITY FACTOR	KEA-89 0	61%	63%	63%	64%	65%	65%	65%	65%	64%	63%
31	PILGRIM FUEL IN CENTS/KWH	BECO-89	0.5894	0.5829	0.5812	0.5658	0.5758	0.6048	0.6702	0.7015	0.7705	0.7912
32	TOTAL FUEL COST		21.1	21.6	21.5	21.3	22.0	23.1	25.6	26.8	28.9	29.3
33	TOTAL PILGRIM COST		243.7	262.6	282.6	303.7	327.8	334.4	364.7	395.2	429.1	462.7
34	BECO'S SHARE		181.0	195.1	209.9	225.5	243.4	248.3	270.9	293.5	318.7	343.6
35												
36	SHUTDOWN COSTS											
37	--------------------------											
38	REPLACEMENT POWER IN CENTS/KWH	QF-RFP-89	3.39	3.76	3.87	5.38	5.93	6.12	7.19	7.72	8.73	9.98
39	TOTAL REPLACEMENT POWER		121.4	139.0	143.1	202.1	226.2	233.5	274.3	294.5	327.9	369.0
40	EARLY DECOMMISSIONING	PILG-89	8.3	8.6	9.0	9.4	9.8	10.6	11.4	12.3	13.2	14.2
41	TOTAL SHUTDOWN COSTS		129.7	147.7	152.1	211.5	236.1	244.1	285.7	306.8	341.2	383.3
42	BECO'S SHARE		96.3	109.7	113.0	157.1	175.3	181.3	212.2	227.9	253.4	284.7
43												
44	NET BENEFIT (COST) OF SHUTDOWN		85	85	97	68	68	67	59	66	65	59

		SOURCE	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
1	PLANT-IN-SERVICE											
2	BEGINNING OF YEAR		1003.3	1113.0	1231.4	1359.2	1497.2	1646.1	1806.8	1980.1	2167.0	2368.5
3	NET CAPITAL ADDITIONS	KEA-89 O	109.8	118.4	127.8	138.0	148.9	160.7	173.3	186.9	201.5	217.1
4	END OF YEAR		1113.0	1231.4	1359.2	1497.2	1646.1	1806.8	1980.1	2167.0	2368.5	2585.6
5	ACCUMULATED DEPRECIATION											
6	BEGINNING OF YEAR		288.1	347.0	415.1	493.7	585.0	691.1	815.0	960.7	1133.0	1338.9
7	ANNUAL DEPRECIATION		58.9	68.0	78.7	91.2	106.1	124.0	145.6	172.3	205.9	249.3
8	END OF YEAR		347.0	415.1	493.7	585.0	691.1	815.0	960.7	1133.0	1338.9	1588.3
9	NET PLANT (YEAR END)		766.0	816.4	865.5	912.2	955.0	991.7	1019.4	1034.0	1029.6	997.3
10	OTHER RATE BASE ITEMS											
11	DEFERRED TAXES		-61.3	-66.3	-70.4	-73.1	-73.7	-68.0	-54.0	-33.1	-2.9	40.1
12	MATERIALS AND SUPPLIES	BECO-89	47.9	50.4	53.0	55.8	58.8	61.9	65.2	68.8	72.5	61.1
13	NUCLEAR FUEL INVENTORY	BECO-89	75.2	79.3	81.9	88.3	90.2	94.9	99.8	105.0	110.4	92.9
14	YEAR END RATE BASE		827.7	879.7	930.0	983.2	1030.3	1080.5	1130.4	1174.7	1209.5	1191.4
15												
16	COSTS											
17	-------											
18	RETURN ON RATE BASE		90.1	95.7	101.2	107.0	112.1	117.6	123.0	127.8	131.6	129.6
19	INCOME TAXES		32.7	34.7	36.7	38.8	40.6	42.6	44.6	46.3	47.7	47.0
20	DEPRECIATION (REMAINING LIFE)		58.9	68.0	78.7	91.2	106.1	124.0	145.6	172.3	205.9	249.3
21	ANNUAL O&M EXPENSES	KEA-89 O	187.9	202.3	217.6	233.7	251.0	269.3	288.8	309.4	331.4	354.7
22	ADMINISTRATIVE & GENERAL	KEA-89 O	59.8	64.7	69.9	75.4	81.3	87.5	94.2	101.2	108.7	116.6
23	OUTAGE AMORTIZATION		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
24	INSURANCE	BECO-89	12.7	13.3	14.0	14.7	15.5	16.3	17.2	18.1	19.1	20.2
25	LOCAL TAXES		12.3	13.1	13.8	14.6	15.3	15.9	16.3	16.5	16.5	16.0
26	DECOMMISSIONING ANNUAL CONTRIBUTION	BECO-89	15.3	16.5	17.8	19.2	20.7	22.2	24.0	25.8	27.8	30.0
27			------	------	------	------	------	------	------	------	------	------
28	ANNUAL NON-FUEL COST		469.6	508.4	549.6	594.7	642.7	695.4	753.7	817.6	888.7	963.4
29												
30	CAPACITY FACTOR	KEA-89 O	62%	61%	60%	58%	56%	54%	52%	49%	46%	43%
31	PILGRIM FUEL IN CENTS/KWH	BECO-89	0.8496	0.8950	0.9245	0.9971	1.0177	1.0708	1.1263	1.1853	1.2467	1.3116
32	TOTAL FUEL COST		30.9	32.0	32.6	33.9	33.4	33.9	34.4	34.1	33.7	33.1
33	TOTAL PILGRIM COST		500.5	540.4	582.2	628.6	676.1	729.3	788.0	851.7	922.4	996.5
34	BECO'S SHARE		371.7	401.4	432.4	466.9	502.1	541.7	585.3	632.5	685.1	740.1
35												
36	SHUTDOWN COSTS											
37	--------------------------											
38	REPLACEMENT POWER IN CENTS/KWH	QF-RFP-89	11.30	10.84	11.94	12.99	14.43	15.95	17.40	16.23	16.13	18.49
39	TOTAL REPLACEMENT POWER		411.2	388.1	420.5	442.2	474.3	505.5	531.0	466.8	435.5	466.6
40	EARLY DECOMMISSIONING	PILG-89	15.3	16.5	17.8	19.2	20.7	22.2	24.0	25.8	27.8	30.0
41	TOTAL SHUTDOWN COSTS		426.5	404.6	438.3	461.4	494.9	527.8	555.0	492.6	463.3	496.6
42	BECO'S SHARE		316.8	300.5	325.5	342.7	367.6	392.0	412.2	365.8	344.1	368.8
43												
44	NET BENEFIT (COST) OF SHUTDOWN		55	101	107	124	135	150	173	267	341	371

		SOURCE	2009	2010	2011	2012	NPV TO 1989 10.88%
1	PLANT-IN-SERVICE						
2	BEGINNING OF YEAR		2585.6	2819.3	3071.0	3341.7	
3	NET CAPITAL ADDITIONS	KEA-89 O	233.8	251.6	270.8	291.2	
4	END OF YEAR		2819.3	3071.0	3341.7	3632.9	
5	ACCUMULATED DEPRECIATION						
6	BEGINNING OF YEAR		1588.3	1896.0	2287.7	2814.7	
7	ANNUAL DEPRECIATION		307.8	391.6	527.0	818.3	
8	END OF YEAR		1896.0	2287.7	2814.7	3632.9	
9	NET PLANT (YEAR END)		923.3	783.3	527.0	0.0	
10	OTHER RATE BASE ITEMS						
11	DEFERRED TAXES		101.3	190.3	326.4	0.0	
12	MATERIALS AND SUPPLIES	BECO-89	48.3	33.9	17.9	0.0	
13	NUCLEAR FUEL INVENTORY	BECO-89	73.3	51.4	27.1	0.0	
14	YEAR END RATE BASE		1146.2	1058.9	898.5	0.0	
15							
16	COSTS						
17	-------						
18	RETURN ON RATE BASE		124.7	115.2	97.8	0.0	671.6
19	INCOME TAXES		45.2	41.8	35.4	0.0	243.5
20	DEPRECIATION (REMAINING LIFE)		307.8	391.6	527.0	818.3	646.4
21	ANNUAL O&M EXPENSES	KEA-89 O	379.3	405.5	433.4	462.9	1541.9
22	ADMINISTRATIVE & GENERAL	KEA-89 O	125.1	134.0	143.6	153.7	485.9
23	OUTAGE AMORTIZATION		0.0	0.0	0.0	0.0	83.0
24	INSURANCE	BECO-89	21.2	22.4	23.6	24.9	108.8
25	LOCAL TAXES		14.8	12.5	8.4	0.0	86.6
26	DECOMMISSIONING ANNUAL CONTRIBUTION	BECO-89	32.3	34.8	37.5	26.9	129.2
27							
28	ANNUAL NON-FUEL COST		1050.4	1157.9	1306.7	1486.7	3997.1
29							
30	CAPACITY FACTOR	KEA-89 O	40%	36%	33%	29%	
31	PILGRIM FUEL IN CENTS/KWH	BECO-89	1.3800	1.4520	1.5275	1.6072	
32	TOTAL FUEL COST		32.4	30.7	29.6	27.4	243.1
33	TOTAL PILGRIM COST		1082.8	1188.6	1336.3	1514.0	4240.2
34	BECO'S SHARE		804.2	882.7	992.5	1124.5	3149.2
35							
36	SHUTDOWN COSTS						
37	--------------------------						
38	REPLACEMENT POWER IN CENTS/KWH	QF-RFP-89	21.04	16.64	20.84	16.55	
39	TOTAL REPLACEMENT POWER		494.0	351.6	403.6	281.7	2593.9
40	EARLY DECOMMISSIONING	PILG-89	32.3	34.8	37.5	26.9	129.2
41	TOTAL SHUTDOWN COSTS		526.3	386.4	441.1	308.6	2723.1
42	BECO'S SHARE		390.8	287.0	327.6	229.2	2022.5
43							
44	NET BENEFIT (COST) OF SHUTDOWN		413	596	665	895	1,127

TABLE 3.2.10: PILGRIM ECONOMICS; 1989 PESSIMISTIC NATIONAL PROJECTIONS

		SOURCE	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998
1	PLANT-IN-SERVICE											
2	BEGINNING OF YEAR		259.8	313.5	372.8	438.0	509.6	588.1	673.9	767.7	869.7	980.7
3	NET CAPITAL ADDITIONS	KEA-89 P	53.7	59.3	65.2	71.6	78.5	85.8	93.8	102.0	111.0	120.9
4	END OF YEAR		313.5	372.8	438.0	509.6	588.1	673.9	767.7	869.7	980.7	1101.7
5	ACCUMULATED DEPRECIATION											
6	BEGINNING OF YEAR		0.0	13.1	28.7	47.3	69.3	95.3	125.7	161.4	203.0	251.6
7	ANNUAL DEPRECIATION		13.1	15.6	18.6	22.0	25.9	30.5	35.7	41.7	48.6	56.7
8	END OF YEAR		13.1	28.7	47.3	69.3	95.3	125.7	161.4	203.0	251.6	308.3
9	NET PLANT (YEAR END)		300.5	344.1	390.7	440.3	492.8	548.2	606.3	666.6	729.1	793.4
10	OTHER RATE BASE ITEMS											
11	DEFERRED TAXES		-1.0	-7.6	-14.1	-20.6	-27.0	-33.1	-39.3	-45.7	-52.2	-58.6
12	MATERIALS AND SUPPLIES	BECO-89	30.7	32.0	33.3	34.8	36.3	38.0	39.8	41.6	43.5	45.7
13	NUCLEAR FUEL INVENTORY	BECO-89	52.2	51.6	51.5	50.1	51.0	53.6	59.4	62.1	68.2	70.1
14	YEAR END RATE BASE		382.4	420.1	461.4	504.6	553.2	606.6	666.2	724.6	788.6	850.5
15												
16	COSTS											
17	-------											
18	RETURN ON RATE BASE		41.6	45.7	50.2	54.9	60.2	66.0	72.5	78.8	85.8	92.5
19	INCOME TAXES		15.1	16.6	18.2	19.9	21.8	23.9	26.3	28.6	31.1	33.6
20	DEPRECIATION (REMAINING LIFE)		13.1	15.6	18.6	22.0	25.9	30.5	35.7	41.7	48.6	56.7
21	ANNUAL O&M EXPENSES	KEA-89 P	89.1	97.7	107.0	117.0	127.9	139.5	151.9	165.3	179.5	194.7
22	ADMINISTRATIVE & GENERAL	KEA-89 P	26.3	29.2	32.5	35.9	39.7	43.8	48.1	52.8	57.7	63.0
23	OUTAGE AMORTIZATION		20.2	20.2	20.2	20.2	20.2	0.0	0.0	0.0	0.0	0.0
24	INSURANCE	BECO-89	8.1	8.4	8.8	9.2	9.6	10.0	10.5	11.0	11.5	12.1
25	LOCAL TAXES		4.8	5.5	6.3	7.0	7.9	8.8	9.7	10.7	11.7	12.7
26	DECOMMISSIONING ANNUAL CONTRIBUTION	BECO-89	8.3	8.6	9.0	9.4	9.8	10.6	11.4	12.3	13.2	14.2
27												
28	ANNUAL NON-FUEL COST		226.5	247.7	270.8	295.6	323.1	333.1	366.0	401.1	439.1	479.5
29												
30	CAPACITY FACTOR	KEA-89 P	50%	48%	45%	42%	39%	35%	32%	28%	24%	19%
31	PILGRIM FUEL IN CENTS/KWH	BECO-89	0.5894	0.5829	0.5812	0.5658	0.5758	0.6048	0.6702	0.7015	0.7705	0.7912
32	TOTAL FUEL COST		17.3	16.4	15.4	13.9	13.2	12.4	12.6	11.5	10.9	8.8
33	TOTAL PILGRIM COST		243.8	264.1	286.1	309.6	336.2	345.5	378.6	412.6	450.0	488.3
34	BECO'S SHARE		181.1	196.1	212.5	229.9	249.7	256.6	281.2	306.4	334.2	362.7
35												
36	SHUTDOWN COSTS											
37	--------------------------											
38	REPLACEMENT POWER IN CENTS/KWH	QF-RFP-89	3.39	3.76	3.87	5.38	5.93	6.12	7.19	7.72	8.73	9.98
39	TOTAL REPLACEMENT POWER		99.5	105.9	102.2	132.6	135.7	125.7	135.0	126.9	123.0	111.3
40	EARLY DECOMMISSIONING	PILG-89	8.3	8.6	9.0	9.4	9.8	10.6	11.4	12.3	13.2	14.2
41	TOTAL SHUTDOWN COSTS		107.8	114.6	111.2	142.0	145.6	136.3	146.4	139.2	136.2	125.5
42	BECO'S SHARE		80.1	85.1	82.6	105.5	108.1	101.2	108.8	103.4	101.2	93.2
43												
44	NET BENEFIT (COST) OF SHUTDOWN		101	111	130	124	142	155	172	203	233	269

		SOURCE	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
1	PLANT-IN-SERVICE											
2	BEGINNING OF YEAR		1101.7	1233.4	1376.8	1533.0	1702.9	1887.7	2088.6	2306.8	2543.6	2800.5
3	NET CAPITAL ADDITIONS	KEA-89 P	131.7	143.4	156.2	169.9	184.8	200.9	218.2	236.8	256.8	278.3
4	END OF YEAR		1233.4	1376.8	1533.0	1702.9	1887.7	2088.6	2306.8	2543.6	2800.5	3078.8
5	ACCUMULATED DEPRECIATION											
6	BEGINNING OF YEAR		308.3	374.4	451.5	541.6	647.2	771.3	917.6	1091.3	1298.8	1549.0
7	ANNUAL DEPRECIATION		66.1	77.1	90.1	105.6	124.1	146.4	173.6	207.5	250.3	306.0
8	END OF YEAR		374.4	451.5	541.6	647.2	771.3	917.6	1091.3	1298.8	1549.0	1855.0
9	NET PLANT (YEAR END)		859.0	925.3	991.4	1055.7	1116.5	1171.0	1215.5	1244.9	1251.4	1223.8
10	OTHER RATE BASE ITEMS											
11	DEFERRED TAXES		-64.7	-70.2	-74.5	-77.1	-77.2	-70.2	-53.9	-29.2	7.2	59.6
12	MATERIALS AND SUPPLIES	BECO-89	47.9	50.4	53.0	55.8	58.8	61.9	65.2	68.8	72.5	61.1
13	NUCLEAR FUEL INVENTORY	BECO-89	75.2	79.3	81.9	88.3	90.2	94.9	99.8	105.0	110.4	92.9
14	YEAR END RATE BASE		917.4	984.9	1051.8	1122.7	1188.3	1257.6	1326.6	1389.5	1441.5	1437.4
15												
16	COSTS											
17	-------											
18	RETURN ON RATE BASE		99.8	107.2	114.4	122.2	129.3	136.8	144.3	151.2	156.8	156.4
19	INCOME TAXES		36.2	38.9	41.5	44.3	46.9	49.6	52.3	54.8	56.9	56.7
20	DEPRECIATION (REMAINING LIFE)		66.1	77.1	90.1	105.6	124.1	146.4	173.6	207.5	250.3	306.0
21	ANNUAL O&M EXPENSES	KEA-89 P	211.0	228.5	247.0	266.8	287.9	310.1	334.0	359.3	386.3	415.0
22	ADMINISTRATIVE & GENERAL	KEA-89 P	68.7	74.8	81.3	88.2	95.5	103.3	111.6	120.4	129.9	139.9
23	OUTAGE AMORTIZATION		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
24	INSURANCE	BECO-89	12.7	13.3	14.0	14.7	15.5	16.3	17.2	18.1	19.1	20.2
25	LOCAL TAXES		13.7	14.8	15.9	16.9	17.9	18.7	19.4	19.9	20.0	19.6
26	DECOMMISSIONING ANNUAL CONTRIBUTION	BECO-89	15.3	16.5	17.8	19.2	20.7	22.2	24.0	25.8	27.8	30.0
27												
28	ANNUAL NON-FUEL COST		523.5	571.0	622.0	677.7	737.6	803.6	876.6	957.1	1047.1	1143.6
29												
30	CAPACITY FACTOR	KEA-89 P	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
31	PILGRIM FUEL IN CENTS/KWH	BECO-89	0.8496	0.8950	0.9245	0.9971	1.0177	1.0708	1.1263	1.1853	1.2467	1.3116
32	TOTAL FUEL COST		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
33	TOTAL PILGRIM COST		523.5	571.0	622.0	677.7	737.6	803.6	876.6	957.1	1047.1	1143.6
34	BECO'S SHARE		388.8	424.1	462.0	503.4	547.8	596.8	651.0	710.8	777.7	849.4
35												
36	SHUTDOWN COSTS											
37	---------------------------											
38	REPLACEMENT POWER IN CENTS/KWH	QF-RFP-89	11.30	10.84	11.94	12.99	14.43	15.95	17.40	16.23	16.13	18.49
39	TOTAL REPLACEMENT POWER		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
40	EARLY DECOMMISSIONING	PILG-89	15.3	16.5	17.8	19.2	20.7	22.2	24.0	25.8	27.8	30.0
41	TOTAL SHUTDOWN COSTS		15.3	16.5	17.8	19.2	20.7	22.2	24.0	25.8	27.8	30.0
42	BECO'S SHARE		11.4	12.3	13.2	14.2	15.3	16.5	17.8	19.2	20.7	22.3
43												
44	NET BENEFIT (COST) OF SHUTDOWN		377	412	449	489	533	580	633	692	757	827

		SOURCE	2009	2010	2011	2012	NPV TO 1989 10.38%
1	PLANT-IN-SERVICE						
2	BEGINNING OF YEAR		3078.8	3380.2	3706.3	4059.1	
3	NET CAPITAL ADDITIONS	KEA-89 P	301.4	326.2	352.7	381.2	
4	END OF YEAR		3380.2	3706.3	4059.1	4440.3	
5	ACCUMULATED DEPRECIATION						
6	BEGINNING OF YEAR		1855.0	2236.3	2726.3	3392.7	
7	ANNUAL DEPRECIATION		381.3	490.0	666.4	1047.6	
8	END OF YEAR		2236.3	2726.3	3392.7	4440.3	
9	NET PLANT (YEAR END)		1143.9	980.0	666.4	0.0	
10	OTHER RATE BASE ITEMS						
11	DEFERRED TAXES		135.3	246.7	419.0	0.0	
12	MATERIALS AND SUPPLIES	BECO-89	48.3	33.9	17.9	0.0	
13	NUCLEAR FUEL INVENTORY	BECO-89	73.3	51.4	27.1	0.0	
14	YEAR END RATE BASE		1400.8	1312.0	1130.4	0.0	
15							
16	COSTS						
17	-------						
18	RETURN ON RATE BASE		152.4	142.7	123.0	0.0	737.5
19	INCOME TAXES		55.3	51.8	44.6	0.0	267.4
20	DEPRECIATION (REMAINING LIFE)		381.3	490.0	666.4	1047.6	760.7
21	ANNUAL O&M EXPENSES	KEA-89 P	445.3	477.6	512.1	548.6	1718.1
22	ADMINISTRATIVE & GENERAL	KEA-89 P	150.5	161.8	173.9	186.7	553.9
23	OUTAGE AMORTIZATION		0.0	0.0	0.0	0.0	83.0
24	INSURANCE	BECO-89	21.2	22.4	23.6	24.9	108.8
25	LOCAL TAXES		18.3	15.7	10.7	0.0	96.1
26	DECOMMISSIONING ANNUAL CONTRIBUTION	BECO-89	32.3	34.8	37.5	26.9	129.2
27							
28	ANNUAL NON-FUEL COST		1256.7	1396.8	1591.7	1834.6	4454.7
29							
30	CAPACITY FACTOR	KEA-89 P	0%	0%	0%	0%	
31	PILGRIM FUEL IN CENTS/KWH	BECO-89	1.3800	1.4520	1.5275	1.6072	
32	TOTAL FUEL COST		0.0	0.0	0.0	0.0	91.6
33	TOTAL PILGRIM COST		1256.7	1396.8	1591.7	1834.6	4546.2
34	BECO'S SHARE		933.3	1037.4	1182.1	1362.6	3376.5
35							
36	SHUTDOWN COSTS						
37	---------------------------						
38	REPLACEMENT POWER IN CENTS/KWH	QF-RFP-89	21.04	16.64	20.84	16.55	
39	TOTAL REPLACEMENT POWER		0.0	0.0	0.0	0.0	772.2
40	EARLY DECOMMISSIONING	PILG-89	32.3	34.8	37.5	26.9	129.2
41	TOTAL SHUTDOWN COSTS		32.3	34.8	37.5	26.9	901.5
42	BECO'S SHARE		24.0	25.8	27.8	20.0	669.5
43							
44	NET BENEFIT (COST) OF SHUTDOWN		909	1,012	1,154	1,343	2,707

NOTES TO TABLES 3.2.3 TO 3.2.10

LINE 2: PLANT-IN-SERVICE AT BEGINNING OF 1989 IS EQUAL TO \$301.9 MILLION (GROSS CAPITAL ADDITIONS 1986-88 FROM FERC RETURNS) LESS \$42.1 MILLION WHICH WAS IN CWIP IN 1985. AFTER 1989, THE PLANT-IN-SERVICE AT THE BEGINNING OF THE YEAR IS EQUAL TO THE PLANT-IN-SERVICE AT THE END OF THE PREVIOUS YEAR.

LINE 3: NET CAPITAL ADDITIONS FOR BECO, NATIONAL AND PILGRIM BASED PROJECTIONS ARE SUMMARIZED IN TABLE 4.3.3.

LINE 4: LINE 2 + LINE 3.

LINE 6: ACCUMULATED DEPRECIATION IS EQUAL TO THE END OF YEAR DEPRECIATION IN THE PREVIOUS YEAR.

LINE 7: ANNUAL DEPRECIATION EQUALS END OF YEAR PLANT-IN-SERVICE LESS ACCUMULATED DEPRECIATION DIVIDED BY THE PLANT'S REMAINING LIFE IN YEARS.

LINE 8: LINE 5 + LINE 6.

LINE 9: LINE 4 - LINE 8.

LINE 11: DEFERRED TAXES ARE BASED ON 150% DOUBLE-DECLINING BALANCE DEPRECIATION.

LINE 12: 13 IN THE 1989 CASES FROM REVISED BE-RSH-7, IN THE 1986 CASES FROM CARL GUSTIN'S 6/8/87 LETTER TO SHARON POLLARD (BECO IR MP-3-1).

LINE 14: LINE 9 + LINE 11 + LINE 12 + LINE 13.

LINE 18: 10.88% OF LINE 14, 1989 CASES; 10.33% OF LINE 14, 1986 CASES.

LINE 19: 36.26% OF LINE 18.

LINE 20: SAME AS LINE 7.

LINE 21: OPERATION AND MAINTENANCE EXPENSE FOR BECO, NATIONAL AND PILGRIM BASED EXPENSES ARE SUMMARIZED IN TABLE 4.2.3.

LINE 22: IN THE BECO CASES, A + G EQUALS 20.1% OF LINE 21. IN THE PILGRIM AND NATIONAL 1989 CASES, A + G EQUALS 38.57% OF LINE 21, MINUS LINE 24. FOR THE 1986 PILGRIM AND NATIONAL CASES, A + G EQUALS 31.40% OF LINE 21, MINUS LINE 24. THESE PERCENTAGES ARE CALCULATED IN TABLE 4.4.1.

LINE 23: FROM REVISED BE-RSH-7.

LINE 24: IN THE 1989 CASES FROM REVISED BE-RSH-7; IN THE 1986
26 CASES FROM CARL GUSTIN'S 6/8/87 LETTER TO SHARON POLLARD (BECO IR MP-3-1).

LINE 25: 1.6% OF LINE 9.

LINE 28: LINE 18 + LINE 19 + LINE 20 + LINE 21 + LINE 22 + LINE 23 + LINE 24 + LINE 25 + LINE 26.

LINE 30: CAPACITY FACTOR PROJECTIONS FOR BECO, NATIONAL AND PILGRIM BASED PROJECTIONS ARE SUMMARIZED IN TABLE 4.1.2.

LINE 31: FOR THE 1989 CASES THIS FIGURE IS CALCULATED FROM BE-RSH-13. FOR THE 1986 CASES THIS FIGURE IS CALCULATED FROM CARL GUSTIN'S 6/8/87 LETTER TO SHARON POLLARD (BECO IR MP-3-1).

LINE 32: 670 MW * LINE 30 * 8760 HOURS * LINE 31/100,000.

LINE 33: LINE 28 + LINE 32.

LINE 34: 74.27% OF LINE 33.

LINE 38: FOR BECO'S 1989 CASES CALCULATED IN TABLE 4.7.1 FROM BE-RSH-5 AND BE-RSH-6. FOR THE OTHER 1989 CASES FROM BECO'S 4/14/89 QF RFP. FOR ALL OF THE 1986 CASES FROM BECO'S 11/21/86 QF RFP.

LINE 39: 670 MW * LINE 30 * 8760 HOURS * LINE 38/100,000.

LINE 40: IN BECO'S 1989 CASE FROM REVISED BE-RSH-7. IN ALL OTHER CASES IT IS EQUAL TO LINE 26.

LINE 41: LINE 39 + LINE 40.

LINE 42: 74.27% OF LINE 41.

LINE 44: LINE 34 - LINE 42.

TABLE 3.2.11: THE ECONOMICS OF PILGRIM SUNK COSTS

		SOURCE	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998
1	PLANT-IN-SERVICE											
2	BEGINNING OF YEAR		259.8	259.8	259.8	259.8	259.8	259.8	259.8	259.8	259.8	259.8
3	NET CAPITAL ADDITIONS		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
4	END OF YEAR		259.8	259.8	259.8	259.8	259.8	259.8	259.8	259.8	259.8	259.8
5	ACCUMULATED DEPRECIATION											
6	BEGINNING OF YEAR		0.0	10.8	21.7	32.5	43.3	54.1	65.0	75.8	86.6	97.4
7	ANNUAL DEPRECIATION		10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8
8	END OF YEAR		10.8	21.7	32.5	43.3	54.1	65.0	75.8	86.6	97.4	108.3
9	NET PLANT (YEAR END)		249.0	238.2	227.3	216.5	205.7	194.9	184.0	173.2	162.4	151.6
10	OTHER RATE BASE ITEMS											
11	DEFERRED TAXES		-0.8	-6.1	-10.5	-14.0	-16.7	-18.8	-20.5	-22.3	-24.0	-25.7
12	MATERIALS AND SUPPLIES		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
13	NUCLEAR FUEL INVENTORY		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
14	YEAR END RATE BASE		248.1	232.0	216.8	202.5	188.9	176.0	163.5	150.9	138.4	125.8
15												
16	COSTS											
17	-------											
18	RETURN ON RATE BASE		27.0	25.2	23.6	22.0	20.6	19.2	17.8	16.4	15.1	13.7
19	INCOME TAXES		9.8	9.2	8.6	8.0	7.5	6.9	6.4	6.0	5.5	5.0
20	DEPRECIATION (REMAINING LIFE)		10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8
21	ANNUAL O&M EXPENSES		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
22	ADMINISTRATIVE & GENERAL		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
23	OUTAGE AMORTIZATION		20.2	20.2	20.2	20.2	20.2	0.0	0.0	0.0	0.0	0.0
24	INSURANCE		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
25	LOCAL TAXES		4.0	3.8	3.6	3.5	3.3	3.1	2.9	2.8	2.6	2.4
26	DECOMMISSIONING ANNUAL CONTRIBUTION		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
27												
28	ANNUAL SUNK COSTS		71.8	69.2	66.8	64.5	62.3	40.0	38.0	36.0	33.9	31.9
29												
30	BECO'S PORTION OF SUNK COSTS		53.3	51.4	49.6	47.9	46.3	29.7	28.2	26.7	25.2	23.7

		SOURCE	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008
1	PLANT-IN-SERVICE											
2	BEGINNING OF YEAR		259.8	259.8	259.8	259.8	259.8	259.8	259.8	259.8	259.8	259.8
3	NET CAPITAL ADDITIONS		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
4	END OF YEAR		259.8	259.8	259.8	259.8	259.8	259.8	259.8	259.8	259.8	259.8
5	ACCUMULATED DEPRECIATION											
6	BEGINNING OF YEAR		108.3	119.1	129.9	140.7	151.6	162.4	173.2	184.0	194.9	205.7
7	ANNUAL DEPRECIATION		10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8
8	END OF YEAR		119.1	129.9	140.7	151.6	162.4	173.2	184.0	194.9	205.7	216.5
9	NET PLANT (YEAR END)		140.7	129.9	119.1	108.3	97.4	86.6	75.8	65.0	54.1	43.3
10	OTHER RATE BASE ITEMS											
11	DEFERRED TAXES		-27.5	-29.2	-30.9	-32.6	-34.4	-33.2	-29.0	-24.9	-20.7	-16.6
12	MATERIALS AND SUPPLIES		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
13	NUCLEAR FUEL INVENTORY		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
14	YEAR END RATE BASE		113.3	100.7	88.2	75.6	63.1	53.4	46.8	40.1	33.4	26.7
15												
16	COSTS											
17	-------											
18	RETURN ON RATE BASE		12.3	11.0	9.6	8.2	6.9	5.8	5.1	4.4	3.6	2.9
19	INCOME TAXES		4.5	4.0	3.5	3.0	2.5	2.1	1.8	1.6	1.3	1.1
20	DEPRECIATION (REMAINING LIFE)		10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8	10.8
21	ANNUAL O&M EXPENSES		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
22	ADMINISTRATIVE & GENERAL		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
23	OUTAGE AMORTIZATION		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
24	INSURANCE		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
25	LOCAL TAXES		2.3	2.1	1.9	1.7	1.6	1.4	1.2	1.0	0.9	0.7
26	DECOMMISSIONING ANNUAL CONTRIBUTION		0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
27												
28	ANNUAL SUNK COSTS		29.9	27.8	25.8	23.8	21.7	20.1	19.0	17.8	16.6	15.5
29												
30	BECO'S PORTION OF SUNK COSTS		22.2	20.7	19.2	17.7	16.1	15.0	14.1	13.2	12.4	11.5

		SOURCE	2009	2010	2011	2012	NPV TO 1989 10.88%
1	PLANT-IN-SERVICE						
2	BEGINNING OF YEAR		259.8	259.8	259.8	259.8	
3	NET CAPITAL ADDITIONS		0.0	0.0	0.0	0.0	
4	END OF YEAR		259.8	259.8	259.8	259.8	
5	ACCUMULATED DEPRECIATION						
6	BEGINNING OF YEAR		216.5	227.3	238.2	249.0	
7	ANNUAL DEPRECIATION		10.8	10.8	10.8	10.8	
8	END OF YEAR		227.3	238.2	249.0	259.8	
9	NET PLANT (YEAR END)		32.5	21.7	10.8	0.0	
10	OTHER RATE BASE ITEMS						
11	DEFERRED TAXES		-12.4	-8.3	-4.1	0.0	
12	MATERIALS AND SUPPLIES		0.0	0.0	0.0	0.0	
13	NUCLEAR FUEL INVENTORY		0.0	0.0	0.0	0.0	
14	YEAR END RATE BASE		20.0	13.4	6.7	0.0	
15							
16	COSTS						
17	-------						
18	RETURN ON RATE BASE		2.2	1.5	0.7	0.0	158.6
19	INCOME TAXES		0.8	0.5	0.3	0.0	57.5
20	DEPRECIATION (REMAINING LIFE)		10.8	10.8	10.8	10.8	101.1
21	ANNUAL O&M EXPENSES		0.0	0.0	0.0	0.0	0.0
22	ADMINISTRATIVE & GENERAL		0.0	0.0	0.0	0.0	0.0
23	OUTAGE AMORTIZATION		0.0	0.0	0.0	0.0	83.0
24	INSURANCE		0.0	0.0	0.0	0.0	0.0
25	LOCAL TAXES		0.5	0.3	0.2	0.0	25.9
26	DECOMMISSIONING ANNUAL CONTRIBUTION		0.0	0.0	0.0	0.0	0.0
27							
28	ANNUAL SUNK COSTS		14.3	13.2	12.0	10.8	426.1
29							
30	BECO'S PORTION OF SUNK COSTS		10.6	9.8	8.9	8.0	316.4

TABLE 4.1.1: CAPACITY FACTORS BASED ON PILGRIM'S EXPERIENCE

YEAR	CAPACITY FACTOR	NUMBER OF REFUELINGS	
1972	56.7%	0.00	BEGAN OPERATION 12/1/72
1973	69.4%	0.00	
1974	33.6%	1.00	
1975	44.1%	0.00	
1976	41.0%	1.00	
1977	45.2%	1.00	
1978	74.6%	0.00	
1979	82.5%	0.00	
1980	51.7%	1.00	
1981	58.7%	0.50	
1982	56.0%	0.50	
1983	80.3%	0.06	
1984	0.1%	0.94	
1985	84.4%	0.00	
1986	17.5%	1.00	OUTAGE BEGINS 07/25/86
1987	0.0%	0.00	OUTAGE CONTINUES
1988	0.0%	0.00	OUTAGE CONTINUES
1989	3.7%	0.00	OUTAGE ENDS 03/11/89

AVERAGE:	1978-1985	61.0%
AVERAGE:	1978-1986	56.2%
AVERAGE:	1978-1987	50.6%
AVERAGE:	1978-1988	46.0%
AVERAGE:	1973-1985	55.5%
AVERAGE:	1973-1988	46.2%
CUMMULATIVE CAPACITY FACTOR TO 12/31/85:		55.6%
CUMMULATIVE CAPACITY FACTOR TO 12/31/88:		46.3%

SOURCE: NRC GREY BOOKS OR EQUIVALENT. ASSUMES 670 MW RATING.
1989 CAPACITY FACTOR CALCULATED THROUGH 03/31/89.

TABLE 4.1.2: SUMMARY OF CAPACITY FACTOR PROJECTIONS

	NATIONAL EXPERIENCE				PILGRIM EXPERIENCE		BECO PROJECTIONS	
	OPTIMISTIC	PESSIMISTIC	OPTIMISTIC	PESSIMISTIC				
YEAR	1986	1986	1989	1989	1986	1989	1986	1989
1989	60%	44%	61%	50%	56%	46%	70%	65%
1990	61%	41%	63%	48%	56%	46%	70%	65%
1991	62%	38%	63%	45%	56%	46%	70%	68%
1992	62%	34%	64%	42%	56%	46%	70%	68%
1993	63%	30%	65%	39%	56%	46%	70%	68%
1994	62%	26%	65%	35%	56%	46%	70%	68%
1995	62%	21%	65%	32%	56%	46%	70%	68%
1996	61%	17%	65%	28%	56%	46%	70%	68%
1997	61%	12%	64%	24%	56%	46%	70%	68%
1998	59%	6%	63%	19%	56%	46%	70%	68%
1999	58%	0%	62%	14%	56%	46%	70%	68%
2000	56%	0%	61%	10%	56%	46%	70%	68%
2001	54%	0%	60%	4%	56%	46%	70%	68%
2002	52%	0%	58%	0%	56%	46%	70%	68%
2003	50%	0%	56%	0%	56%	46%	70%	68%
2004	47%	0%	54%	0%	56%	46%	70%	68%
2005	44%	0%	52%	0%	56%	46%	70%	68%
2006	41%	0%	49%	0%	56%	46%	70%	68%
2007	38%	0%	46%	0%	56%	46%	70%	68%
2008	34%	0%	43%	0%	56%	46%	70%	68%
2009	30%	0%	40%	0%	56%	46%	70%	68%
2010	26%	0%	36%	0%	56%	46%	70%	68%
2011	21%	0%	33%	0%	56%	46%	70%	68%
2012	17%	0%	29%	0%	56%	46%	70%	68%
AVERAGE:	49%	11%	55%	16%	56%	46%	70%	68%

TABLE 4.2.1: OPERATIONS AND MAINTENANCE PROJECTIONS BASED ON PILGRIM EXPERIENCE THROUGH 1985

RESULTS OF REGRESSION ON PILGRIM O&M DATA

CONSTANT	(8,728,469)
YEAR	4429
R SQUARED	0.90

YEAR	ACTUAL O&M DATA FOR PILGRIM ($ NOMINAL)	ACTUAL O&M DATA FOR PILGRIM ($1987)	PROJECTION FROM REGRESSION ($1987)	BECO'S SHARE ($1987)	BECO'S SHARE ($ NOMINAL)
	[1]	[2]	[3]	[4]	[5]
1974	9,527	20,730	13,690		
1975	7,340	14,544	18,118		
1976	16,633	30,973	22,547		
1977	15,320	26,747	26,976		
1978	14,187	23,088	31,404		
1979	18,387	27,487	35,833		
1980	27,785	38,095	40,262		
1981	34,994	43,743	44,690		
1982	42,437	49,863	49,119		
1983	47,276	53,464	53,548		
1984	57,854	63,118	57,976		
1985	61,245	64,715	62,405		
1986			66,834	49,637	51,116
1987			71,262	52,926	52,926
1988			75,691	56,216	58,129
1989			80,119	59,505	63,961
1990			84,548	62,794	70,222
1991			88,977	66,083	76,994
1992			93,405	69,372	84,250
1993			97,834	72,661	92,141
1994			102,263	75,951	100,578
1995			106,691	79,240	109,587
1996			111,120	82,529	119,263
1997			115,549	85,818	129,567
1998			119,977	89,107	140,600
1999			124,406	92,396	152,395
2000			128,835	95,685	165,068
2001			133,263	98,975	178,491
2002			137,692	102,264	192,778
2003			142,121	105,553	208,052
2004			146,549	108,842	224,168
2005			150,978	112,131	241,440
2006			155,407	115,420	259,721
2007			159,835	118,710	279,245
2008			164,264	121,999	299,961
2009			168,693	125,288	321,910
2010			173,121	128,577	345,243
2011			177,550	131,866	370,123
2012			181,978	135,155	396,494

NOTES:
[1]: FROM FERC FORM 1, OR EQUIVALENT.
[2]: ESCALATED USING GNP DEFLATOR.
[3]: PROJECTED FROM LINEAR REGRESSION.
[4]: 74.27% OF [3].
[5]: ESCALATED USING BECO'S GNP INFLATION.

CORRECTED VERSION

TABLE 4.2.2: OPERATIONS AND MAINTENANCE PROJECTIONS BASED ON PILGRIM EXPERIENCE THROUGH 1988

RESULTS OF REGRESSION ON PILGRIM O&M DATA	
CONSTANT	(12,420,835)
YEAR	6295
R SQUARED	0.86

YEAR	ACTUAL O&M DATA FOR PILGRIM ($ NOMINAL)	ACTUAL O&M DATA FOR PILGRIM ($1987)	PROJECTION FROM REGRESSION ($1987)	BECO'S SHARE ($1987)	BECO'S SHARE ($ NOMINAL)
	[1]	[2]	[3]	[4]	[5]
1974	9,527	20,730	6,133		
1975	7,340	14,544	12,429		
1976	16,633	30,973	18,724		
1977	15,320	26,747	25,019		
1978	14,187	23,088	31,315		
1979	18,387	27,487	37,610		
1980	27,785	38,095	43,905		
1981	34,994	43,743	50,201		
1982	42,437	49,863	56,496		
1983	47,276	53,464	62,791		
1984	57,854	63,118	69,086		
1985	61,245	64,715	75,382		
1986	72,031	74,177	81,677		
1987	112,482	112,482	87,972		
1988	113,518	109,781	94,268		
1989			100,563	74,688	80,282
1990			106,858	79,364	88,752
1991			113,154	84,039	97,915
1992			119,449	88,715	107,741
1993			125,744	93,390	118,427
1994			132,040	98,066	129,864
1995			138,335	102,741	142,089
1996			144,630	107,417	155,229
1997			150,926	112,093	169,236
1998			157,221	116,768	184,245
1999			163,516	121,444	200,304
2000			169,812	126,119	217,569
2001			176,107	130,795	235,876
2002			182,402	135,470	255,376
2003			188,698	140,146	276,236
2004			194,993	144,821	298,270
2005			201,288	149,497	321,895
2006			207,584	154,172	346,921
2007			213,879	158,848	373,664
2008			220,174	163,523	402,059
2009			226,470	168,199	432,164
2010			232,765	172,874	464,186
2011			239,060	177,550	498,349
2012			245,356	182,226	534,580

NOTES:

[1]: FROM FERC FORM 1, OR EQUIVALENT.
[2]: ESCALATED USING GNP DEFLATOR.
[3]: PROJECTED FROM LINEAR REGRESSION.
[4]: 74.27% OF [3].
[5]: ESCALATED USING BECO'S GNP INFLATION.

CORRECTED VERSION

TABLE 4.2.3: SUMMARY OF PILGRIM OPERATION AND MAINTENANCE PROJECTIONS, $ MILLION

	KEA -1986 PROJECTION-		KEA -1989 PROJECTION-		PLC -1986 PROJECTION-		PLC -1989 PROJECTION-		BECO -1986 PROJECTION-		BECO -1989 PROJECTION	
YEAR	1987 DOLLARS	NOMINAL DOLLARS	1987 DOLLARS	NOMINAL DOLLARS	1987 DOLLARS	NOMINAL DOLLARS	1987 DOLLARS	NOMINAL DOLLARS	1987 DOLLARS	NOMINAL DOLLARS	1987 DOLLARS	NOMINAL DOLLARS
	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]
1989	77.3	83.1	82.9	89.1	80.1	86.1	100.6	108.1	99.1	106.5	77.8	83.6
1990	80.2	89.7	87.4	97.7	84.5	94.5	106.9	119.5	106.9	119.5	76.1	85.1
1991	83.1	96.8	91.9	107.0	89.0	103.7	113.2	131.8	107.3	125.0	83.5	97.3
1992	86.0	104.5	96.3	117.0	93.4	113.4	119.4	145.1	108.1	131.3	75.8	92.1
1993	89.0	112.8	100.8	127.9	97.8	124.0	125.7	159.5	108.7	137.8	83.0	105.3
1994	91.9	121.7	105.3	139.5	102.3	135.5	132.0	174.9	109.3	144.7	81.9	108.5
1995	94.8	131.2	109.8	151.9	106.7	147.6	138.3	191.3	109.8	151.9	84.3	116.6
1996	97.8	141.3	114.4	165.3	111.1	160.6	144.6	209.0	110.4	159.5	87.1	125.9
1997	100.7	152.0	118.9	179.5	115.5	174.4	150.9	227.9	110.9	167.5	89.7	135.4
1998	103.6	163.5	123.4	194.7	120.0	189.3	157.2	248.1	111.5	175.9	92.4	145.8
1999	106.6	175.7	127.9	211.0	124.4	205.2	163.5	269.7	112.0	184.7	95.2	157.0
2000	109.5	188.9	132.4	228.5	128.8	222.2	169.8	292.9	112.4	193.9	98.0	169.1
2001	112.4	202.7	137.0	247.0	133.3	240.4	176.1	317.6	112.9	203.6	101.0	182.1
2002	115.3	217.4	141.5	266.8	137.7	259.6	182.4	343.8	113.4	213.8	104.1	196.2
2003	118.3	233.1	146.0	287.9	142.1	280.1	188.7	371.9	113.9	224.5	107.3	211.4
2004	121.2	249.6	150.6	310.1	146.5	301.7	195.0	401.6	114.4	235.7	110.6	227.8
2005	124.1	267.2	155.1	334.0	151.0	325.1	201.3	433.4	114.9	247.5	114.0	245.4
2006	127.0	285.9	159.7	359.3	155.4	349.7	207.6	467.1	115.5	259.9	117.5	264.4
2007	130.0	305.7	164.2	386.3	159.8	375.9	213.9	503.1	116.0	272.9	121.1	284.9
2008	132.9	326.8	168.8	415.0	164.3	404.0	220.2	541.3	116.5	286.5	124.8	306.9
2009	135.8	349.0	173.3	445.3	168.7	433.5	226.5	581.9	117.1	300.8	128.7	330.7
2010	138.8	372.6	177.9	477.6	173.1	464.8	232.8	625.0	117.6	315.9	132.7	356.2
2011	141.7	397.7	182.4	512.1	177.6	498.5	239.1	671.0	118.2	331.7	136.7	383.8
2012	144.6	424.2	187.0	548.6	182.0	533.9	245.4	719.8	118.7	348.2	141.0	413.5
AVERAGE ANNUAL GROWTH RATE	2.65%	7.03%	2.85%	7.87%	3.48%	7.90%	3.79%	8.22%	0.76%	5.06%	2.51%	6.89%

NOTES:

[1]: FROM KOMANOFF ENERGY ASSOCIATES 1986 EQUATION, FOR 670 MW PLANT.
[2],[4]: INFLATED WITH BECO'S GNP INFLATION PROJECTION.
[3]: FROM KOMANOFF ENERGY ASSOCIATES 1989 EQUATION, PESSIMISTIC SCENARIO FOR 670 MW PLANT.
[5]: FROM PLC, INC. 1986 REGRESSION, TABLE 4.2.1, COLUMN 3.
[6],[8]: INFLATED WITH BECO'S GNP INFLATION PROJECTION.
[7]: FROM PLC, INC. 1989 REGRESSION, TABLE 4.2.2, COLUMN 3.
[9],[11]: DEFLATED WITH BECO'S GNP INFLATION PROJECTION.
[10]: FROM 6/8/87 LETTER TO SHARON POLLARD FROM CARL GUSTIN, EXHIBIT 1.
[12]: FROM EXHIBIT BE-RSH-7.

TABLE 4.3.1: PROJECTED CAPITAL ADDITIONS IN 1,000'S OF $, BASED ON PILGRIM'S EXPERIENCE THROUGH 1985

YEAR	PLANT COST	----NET CAPITAL ADDITIONS---- $ NOMINAL	$1987	$/KW	PROJECTED ADDITIONS ($ NOMINAL)	BECO'S SHARE ($ NOMINAL)	BECO'S SHARE ($ 1987)
	[1]	[2]	[3]	[4]	[5]	[6]	[7]
1972	231,540	--	--	--			
1973	239,329	7,789	19,161	28.60			
1974	235,982	(3,347)	(7,994)	-11.93			
1975	236,464	482	980	1.46			
1976	241,440	4,976	9,273	13.84			
1977	257,579	16,139	28,157	42.03			
1978	261,758	4,179	6,900	10.30			
1979	270,428	8,670	13,166	19.65			
1980	337,986	67,558	93,894	140.14			
1981	358,680	20,694	26,377	39.37			
1982	430,711	72,031	83,583	124.75			
1983	472,831	42,120	46,674	69.66			
1984	639,225	166,394	177,199	264.48			
1985	663,099	23,874	24,573	36.68			
1986					74,464	55,304	56,798
1987					75,383	55,987	55,987
1988					79,673	59,173	57,225
1989					82,860	61,540	57,253
1990					86,340	64,125	57,342
1991					90,053	66,882	57,405
1992					94,015	69,825	57,495
1993					98,152	72,898	57,486
1994					102,697	76,273	57,597
1995					107,647	79,949	57,809
1996					112,351	83,443	57,742
1997					117,609	87,348	57,854
1998					123,336	91,602	58,054
1999					129,491	96,173	58,309
2000					136,108	101,087	58,598
2001					143,213	106,364	58,980
2002					150,760	111,969	59,397
2003					158,765	117,915	59,823
2004					167,196	124,176	60,292
2005					176,141	130,820	60,756
2006					185,635	137,871	61,270
2007					195,640	145,302	61,769
2008					206,185	153,134	62,282
2009					217,299	161,388	62,812
2010					229,011	170,086	63,344
2011					241,355	179,254	63,864
2012					254,364	188,916	64,397
AVERAGE 1973-85:		33,197	40,149	59.92			
AVERAGE 1980-85:		65,445	75,383	112.51			

NOTES:

[1]: FROM FERC FORM 1, OR EQUIVALENT.

[2]: [1(t)] - [1(t-1)].

[3]: DEFLATED USING THE HANDY-WHITMAN INDEX FOR TOTAL NUCLEAR PRODUCTION PLANT IN THE NORTH ATLANTIC REGION, JANUARY FIGURES.

[4]: [3]/670 MW.

[5]: AVERAGE $/KW FIGURE FOR THE 1980'S ($113/KW*670MW). INFLATED USING HANDY-WHITMAN INDEX 1986-88, 1989-2012 WITH BECO'S CAPITAL ADDITIONS ESCALATOR.

[6]: 74.27% OF [3].

[7]: DEFLATED USING BECO'S GNP INFLATION ASSUMPTIONS.

CORRECTED VERSION

TABLE 4.3.2: PROJECTED CAPITAL ADDITIONS IN 1,000'S OF $, BASED ON PILGRIM'S EXPERIENCE THROUGH 1988

YEAR	PLANT COST	----NET CAPITAL ADDITIONS---- $ NOMINAL	$1987	$/KW	PROJECTED ADDITIONS ($ NOMINAL)	BECO'S SHARE ($ NOMINAL)	BECO'S SHARE ($ 1987)
	[1]	[2]	[3]	[4]	[5]	[6]	[7]
1972	231,540	--	--	--			
1973	239,329	7,789	19,161	28.60			
1974	235,982	(3,347)	(7,994)	-11.93			
1975	236,464	482	980	1.46			
1976	241,440	4,976	9,273	13.84			
1977	257,579	16,139	28,157	42.03			
1978	261,758	4,179	6,900	10.30			
1979	270,428	8,670	13,166	19.65			
1980	337,986	67,558	93,894	140.14			
1981	358,680	20,694	26,377	39.37			
1982	430,711	72,031	83,583	124.75			
1983	472,831	42,120	46,674	69.66			
1984	639,225	166,394	177,199	264.48			
1985	663,099	23,874	24,573	36.68			
1986	696,062	32,963	33,370	49.81			
1987	709,579	13,517	13,517	20.17			
1988	955,581	246,002	232,756	347.40			
1989					89,394	66,393	61,767
1990					93,148	69,181	61,863
1991					97,153	72,156	61,931
1992					101,428	75,331	62,028
1993					105,891	78,645	62,019
1994					110,794	82,287	62,138
1995					116,134	86,253	62,367
1996					121,209	90,022	62,294
1997					126,882	94,235	62,416
1998					133,061	98,824	62,631
1999					139,701	103,756	62,906
2000					146,839	109,057	63,218
2001					154,504	114,750	63,630
2002					162,647	120,798	64,080
2003					171,283	127,212	64,540
2004					180,378	133,967	65,046
2005					190,028	141,134	65,546
2006					200,271	148,741	66,101
2007					211,066	156,758	66,639
2008					222,442	165,208	67,192
2009					234,432	174,112	67,765
2010					247,068	183,497	68,339
2011					260,384	193,388	68,899
2012					274,419	203,811	69,474
AVERAGE 1973-88:		45,253	50,099	74.77			
AVERAGE 1980-88:		76,128	81,327	121.38			

CORRECTED VERSION

TABLE 4.3.3: SUMMARY OF PILGRIM CAPITAL ADDITIONS PROJECTIONS, $ MILLION

	KEA -1986 PROJECTION-		KEA -1989 PROJECTION-		PLC -1986 PROJECTION-		PLC -1989 PROJECTION-		BECO -1986 PROJECTION-		BECO -1989 PROJECTION	
YEAR	1987 DOLLARS	NOMINAL DOLLARS	1987 DOLLARS	NOMINAL DOLLARS	1987 DOLLARS	NOMINAL DOLLARS	1987 DOLLARS	NOMINAL DOLLARS	1987 DOLLARS	NOMINAL DOLLARS	1987 DOLLARS	NOMINAL DOLLARS
	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]
1989	68.5	74.5	47.3	51.4	76.3	82.9	82.3	89.4	36.8	40.0	31.8	34.5
1990	70.4	80.0	48.9	55.6	75.9	86.3	81.9	93.1	61.6	70.0	29.0	33.0
1991	72.3	85.9	50.6	60.1	75.8	90.1	81.7	97.2	33.6	40.0	43.6	51.9
1992	74.1	92.3	52.2	65.0	75.5	94.0	81.4	101.4	33.7	42.0	36.2	45.1
1993	76.0	99.0	53.8	70.1	75.4	98.2	81.3	105.9	33.9	44.1	41.3	53.8
1994	77.8	106.1	55.5	75.6	75.4	102.7	81.3	110.8	34.0	46.3	36.2	49.3
1995	79.7	113.9	57.2	81.6	75.3	107.6	81.3	116.1	34.0	48.6	36.2	51.7
1996	81.6	121.6	58.8	87.7	75.4	112.4	81.3	121.2	34.3	51.1	36.2	54.0
1997	83.4	130.2	60.5	94.4	75.3	117.6	81.3	126.9	34.3	53.6	36.2	56.5
1998	85.3	139.6	62.2	101.8	75.3	123.3	81.3	133.1	34.4	56.3	36.2	59.3
1999	87.1	149.8	63.9	109.8	75.4	129.5	81.3	139.7	34.4	59.1	36.2	62.2
2000	89.0	160.8	65.6	118.4	75.3	136.1	81.3	146.8	34.4	62.1	36.2	65.4
2001	90.9	172.7	67.3	127.8	75.3	143.2	81.3	154.5	34.3	65.2	36.2	68.8
2002	92.7	185.5	69.0	138.0	75.4	150.8	81.3	162.6	34.2	68.4	36.2	72.4
2003	94.6	199.3	70.7	148.9	75.4	158.8	81.3	171.3	34.1	71.8	36.2	76.3
2004	96.4	214.1	72.4	160.7	75.3	167.2	81.3	180.4	34.0	75.4	36.2	80.4
2005	98.3	230.0	74.1	173.3	75.3	176.1	81.2	190.0	33.9	79.2	36.2	84.7
2006	100.2	247.0	75.8	186.9	75.3	185.6	81.2	200.3	33.7	83.2	36.2	89.3
2007	102.0	265.1	77.5	201.5	75.3	195.6	81.2	211.1	33.6	87.3	36.2	94.1
2008	103.9	284.5	79.3	217.1	75.3	206.2	81.2	222.4	25.5	69.9	29.0	79.3
2009	105.7	305.2	81.0	233.8	75.3	217.3	81.2	234.4	19.4	55.9	21.7	62.7
2010	107.6	327.3	82.7	251.6	75.3	229.0	81.2	247.1	14.7	44.7	14.5	44.1
2011	109.5	350.9	84.5	270.8	75.3	241.4	81.2	260.4	11.2	35.8	7.2	23.2
2012	111.3	376.1	86.2	291.2	75.3	254.4	81.2	274.4	8.5	28.6	0.0	0.0
AVERAGE ANNUAL GROWTH RATE												
1989-2012:	2.04%	6.98%	2.53%	7.49%	-0.06%	4.78%	-0.05%	4.78%	-5.94%	-1.39%		
1989-2007:	2.11%	6.91%	2.63%	7.45%	-0.07%	4.62%	-0.07%	4.63%	-0.48%	4.19%	0.69%	5.42%

NOTES:

[1]: FROM KOMANOFF ENERGY ASSOCIATES 1986 EQUATION, FOR 670 MW PLANT.
[2],[4]: INFLATED USING BECO'S PROJECTION OF NUCLEAR CONSTRUCTION ESCALATION.
[3]: FROM KOMANOFF ENERGY ASSOCIATES 1989 "OPTIMISTIC" EQUATION. FOR 670 MW PLANT.
[5],[7],
[9], [11]: DEFLATED USING BECO'S PROJECTION OF NUCLEAR CONSTRUCTION INFLATION.
[6]: FROM PLC, INC. 1986 PROJECTION, TABLE 4.3.1, COLUMN 5.
[8]: FROM PLC, INC. 1989 PROJECTION, TABLE 4.3.2, COLUMN 5.
[10]: FROM 6/8/87 LETTER TO SHARON POLLARD ROM CARL GUSTIN, EXHIBIT 1.
[12]: FROM EXHIBIT BE-RSH-7.

TABLE 4.4.1: YANKEE PLANT OVERHEADS 1984-88

	VERMONT YANKEE						MAINE YANKEE					
	1984	1985	1986	1987	1988		1984	1985	1986	1987	1988	
1. Other O&M	9,021	10,267	12,593	15,129	18,271		17,934	19,290	19,804	23,140	28,127	
2. Employment Taxes												
FICA	620	723	840	919	968		656	703	738	875	1,055	
Fed Unemp.	16	45	20	23	21		20	19	19	21	23	
State Unemp.	44	40	52	46	35		83	63	51	51	52	
3. Total Other	9,701	11,075	13,505	16,117	19,295		18,693	20,075	20,612	24,087	29,257	
4. Station O&M	64,652	67,187	67,491	76,067	73,536		67,574	71,454	60,329	74,259	80,717	
5. Fuel	21,449	20,771	15,465	26,306	31,347		35,079	35,694	38,890	25,935	34,246	
6. Non-Fuel Station O&M	43,203	46,416	52,026	49,761	42,189		32,495	35,760	21,439	48,324	46,471	
7. Other as a % of Non-fuel Station O&M	22.45%	23.86%	25.96%	32.39%	45.73%	AVERAGE 30.08%	57.53%	56.14%	96.14%	49.84%	62.96%	AVERAGE 64.52%

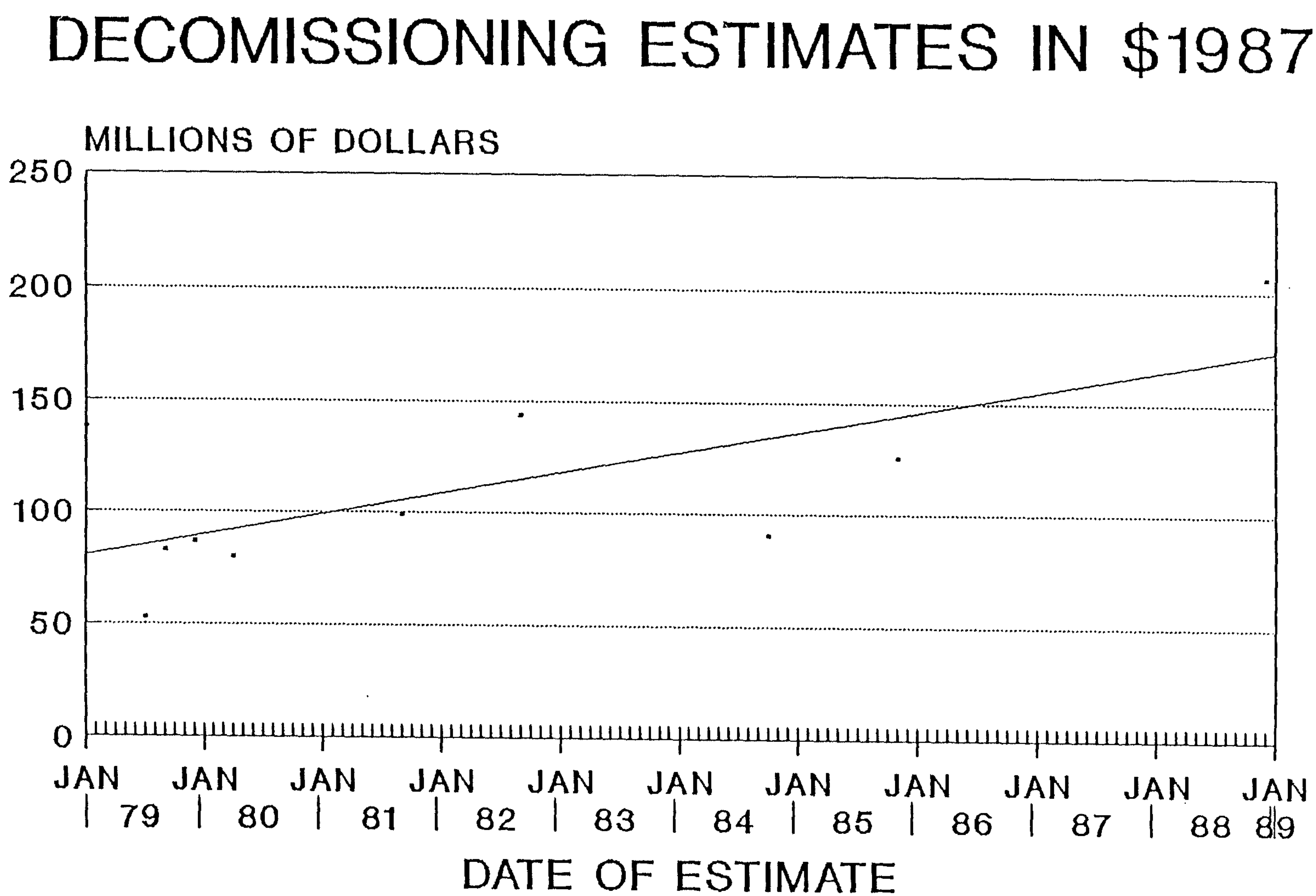
	CT YANKEE					
	1984	1985	1986	1987	1988	
1. Other O&M	6,382	6,780	11,898	19,696	21,788	
2. Employment Taxes						
FICA	690	686	1,046	1,623	1,819	
Fed Unemp.	30	16	30	31	36	
State Unemp.	30	33	27	51	54	
3. Total Other	7,132	7,515	13,001	21,401	23,697	
4. Station O&M	86,320	86,492	103,490	115,284	97,389	
5. Fuel	26,432	40,941	21,777	26,612	33,535	
6. Non-Fuel Station O&M	59,888	45,551	81,713	88,672	63,854	
7. Other as a % of Non-fuel Station O&M	11.91%	16.50%	15.91%	24.14%	37.11%	AVERAGE 21.11%

TOTAL AVERAGE	
1984-88:	38.57%
1984-85:	31.40%

TABLE 4.5.1: MANION'S DECOMMISSIONING ESTIMATES IN $ MILLIONS, FROM BECO IR EOER-45

PLANT NAME	# OF UNITS	MW	DATE OF ESTIMATE	DECOM. ESTIMATE	YEAR'S DOLLARS	DECOMMISSIONING ESTIMATE 1987 DOLLARS
1. FERMI 2	1	1150	01/26/79	83.4	1978	137.7
2. ROBINSON 2	1	665	07/23/79	34.7	1979	52.8
3. MONTICELLO	1	536	09/28/79	54.6	1979	82.9
4. NINE MILE POINT	1	610	12/14/79	57.1	1979	86.7
5. MAINE YANKEE	1	790	04/25/80	57.6	1980	80.0
6. VERMONT YANKEE	1	514	09/02/81	77.9	1981	99.3
7. SHOREHAM	1	820	09/08/82	123.9	1982	143.8
8. INDIAN POINT	1	265	10/01/84	65.1	1980	90.5
9. PILGRIM	1	670	11/27/85	121.7	1985	125.3
10. PILGRIM	1	670	12/20/88	217.8	1988	206.1
11. SUNDESERT	2	950	01/13/78	38.9	1977	67.9
12. NYSE&G	2	1250	06/30/78	122.2	1978	201.8
13. GREENWOOD	2	1208	03/23/79	110.5	1979	167.8
14. BRUNSWICK	2	790	07/20/79	85.2	1979	129.4
15. PRAIRIE ISLAND	2	520	09/28/79	66.5	1979	101.0
16. COOK	2	1060	06/27/86	283.9	1986	287.4

FIGURE 4.5.1



BECO IR-EOER-45, SINGLE UNITS ONLY

TABLE 4.7.1: COMPARISON OF PILGRIM REPLACEMENT POWER COSTS AND BECO QF RATES

YEAR	------BECO'S SHARE OF------ PILGRIM REPLACEMENT COSTS	PILGRIM GENERATION GWH	REPLACEMENT COSTS IN CENTS/KWH	QF RATES IN CENTS/KWH	REPLACEMENT POWER AS A % OF QF RATES
	[1]	[2]	[3]	[4]	[5]
1989	143.5	2822.1	5.09	3.39	150.04%
1990	148.3	2822.1	5.26	3.76	139.78%
1991	144.0	2954.6	4.87	3.87	125.97%
1992	162.7	2954.6	5.51	5.38	102.38%
1993	174.5	2954.6	5.91	5.93	99.58%
1994	167.1	2954.6	5.66	6.12	92.41%
1995	239.8	2954.6	8.11	7.19	112.86%
1996	255.9	2954.6	8.66	7.72	112.18%
1997	273.7	2954.6	9.26	8.73	106.09%
1998	303.2	2954.6	10.26	9.98	102.82%
1999	330.9	2954.6	11.20	11.30	99.10%
2000	370.5	2954.6	12.54	10.84	115.68%
2001	370.1	2951.3	12.54	11.94	105.02%
2002	398.7	2948.7	13.52	12.99	104.08%
2003	431.6	2953.4	14.61	14.43	101.27%
2004	470.8	2951.4	15.95	15.95	100.00%
2005	522.2	2954.6	17.67	17.40	101.57%
2006	564.9	2954.6	19.12	16.23	117.80%
2007	595.4	2953.6	20.16	16.13	124.97%
2008	546.7	2944.6	18.57	18.49	100.42%
2009	574.2	2945.7	19.49	21.04	92.65%
2010	623.9	2951.1	21.14	16.64	127.05%
2011	660.9	2952.1	22.39	20.84	107.42%
2012	708.3	2954.6	23.97	16.55	144.82%
P.V. 1989-2012 AT 10.88%			77.25	69.87	110.56%
P.V. 1992-2012 AT 10.88%			88.35	83.04	106.40%

NOTES

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[1]: CALCULATED FROM REVISED EXHIBITS BE-RSH-5 AND BE-RSH-6.
[2]: FROM BE-RSH-13.
[3]: ([1]/[2])*100.
[4]: FROM BECO QF RFP, APRIL 14, 1989, EXHIBIT A, TABLE 1A, COLUMN K.
2012 FIGURE IS THE AVERAGE OF THE PREVIOUS TEN YEARS.
[5]: [3]/[4].

TABLE 4.7.2: COMPARISON OF BECO'S INFLATION ASSUMPTIONS

YEAR	1982=100 PILGRIM WEFA-87	OIL DRI-87	PERCENT CHANGE [1] TO [2]	CURRENT DRI-89	PERCENT CHANGE [2] TO [5]
	[1]	[2]	[4]	[5]	[6]
1989	126.3	126.5	0.16%	126.5	0.00%
1990	131.4	131.5	0.08%	131.3	-0.15%
1991	136.9	137.4	0.37%	136.8	-0.44%
1992	142.7	144.3	1.12%	143.6	-0.49%
1993	149.0	151.7	1.81%	150.8	-0.59%
1994	155.6	159.7	2.63%	158.4	-0.81%
1995	162.5	168.4	3.63%	166.6	-1.07%
1996	169.8	177.6	4.59%	175.5	-1.18%
1997	177.4	187.2	5.52%	185.2	-1.07%
1998	185.4	197.4	6.47%	195.6	-0.91%
1999	193.8	207.9	7.28%	206.6	-0.63%
2000	202.7	218.7	7.89%	218.3	-0.18%
2001	211.9	229.7	8.40%	230.3	0.26%
2002	221.5	241.4	8.98%	242.9	0.62%
2003	231.6	253.7	9.54%	255.9	0.87%
2004	242.0	266.5	10.12%	269.5	1.13%
2005	253.0	280.1	10.71%	283.6	1.25%
2006	264.4	294.5	11.38%	298.5	1.36%
2007	276.4	309.6	12.01%	314.2	1.49%
2008	288.9	325.7	12.74%	330.5	1.47%
2009	301.9	342.5	13.45%	347.6	1.49%
2010	315.5	360.0	14.10%	365.6	1.56%
2011	329.8	378.3	14.71%	384.7	1.69%
2012	344.7	397.1	15.20%	404.8	1.94%
PRESENT VALUE @10.88%	1488.4	1573.1	5.69%	1573.5	0.02%
AVERAGE ANNUAL GROWTH RATE	4.27%	4.88%		4.97%	

NOTES:
[1]: FROM BECO IR EOER-17.
[2]: FROM BECO IR EOER-20.
[5]: FROM BECO IR EOER-19.

TABLE 4.7.3: COMPARISON OF 1987 AND 1989 DRI BASE CASE NY-HARBOR OIL PRICE FORECASTS IN NOMINAL $/BARREL

	DISTILLATE			0.5% SULFUR			1% SULFUR			2.2% SULFUR		
YEAR	1987	1989	% CHANGE	1987	1989	% CHANGE	1987	1989	% CHANGE	1987	1989	% CHANGE
	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]
1989	23.48	23.83	1.49%	19.68	18.57	-5.64%	18.26	17.49	-4.22%	17.08	15.71	-8.02%
1990	24.56	25.85	5.25%	20.78	19.73	-5.05%	19.35	18.56	-4.08%	18.09	16.89	-6.63%
1991	26.72	27.96	4.64%	22.90	21.38	-6.64%	21.40	20.10	-6.07%	20.01	18.30	-8.55%
1992	28.97	29.80	2.87%	24.98	23.06	-7.69%	23.35	21.67	-7.19%	21.83	19.72	-9.67%
1993	31.17	31.65	1.54%	27.06	24.74	-8.57%	25.29	23.24	-8.11%	23.65	21.15	-10.57%
1994	34.35	33.69	-1.92%	30.19	26.55	-12.06%	28.21	24.95	-11.56%	26.38	22.71	-13.91%
1995	38.08	36.26	-4.78%	33.83	28.83	-14.78%	31.62	27.08	-14.36%	29.56	24.65	-16.61%
1996	42.33	39.33	-7.09%	37.99	31.55	-16.95%	35.51	29.64	-16.53%	33.20	26.98	-18.73%
1997	47.53	43.47	-8.54%	43.20	35.18	-18.56%	40.37	33.05	-18.13%	37.75	30.08	-20.32%
1998	53.89	48.10	-10.74%	49.44	39.27	-20.57%	46.21	36.89	-20.17%	43.20	33.58	-22.27%
1999	61.50	54.02	-12.16%	56.73	44.48	-21.59%	53.02	41.80	-21.16%	49.57	38.04	-23.26%
2000	70.53	60.41	-14.35%	65.05	50.16	-22.89%	60.80	47.13	-22.48%	56.85	42.90	-24.54%
2001	78.99	67.77	-14.20%	72.86	56.53	-22.41%	68.09	53.12	-21.99%	63.67	48.34	-24.08%
2002	88.58	75.64	-14.61%	81.71	63.36	-22.46%	76.36	59.54	-22.03%	71.40	54.18	-24.12%
2003	97.61	84.01	-13.93%	90.04	70.66	-21.52%	84.15	66.39	-21.11%	78.68	60.42	-23.21%
2004	108.33	91.56	-15.48%	99.92	77.29	-22.65%	93.39	72.62	-22.24%	87.32	66.09	-24.31%
2005	119.61	99.08	-17.16%	110.33	83.94	-23.92%	103.11	78.86	-23.52%	96.41	71.77	-25.56%
2006	130.33	106.83	-18.03%	120.22	90.82	-24.46%	112.36	85.33	-24.06%	105.05	77.66	-26.07%
2007	141.05	115.09	-18.40%	130.11	98.17	-24.55%	121.60	92.24	-24.14%	113.69	83.94	-26.17%
2008	150.64	122.79	-18.49%	138.96	105.08	-24.38%	129.87	98.73	-23.98%	121.42	89.85	-26.00%
2009	160.24	130.46	-18.58%	147.80	112.00	-24.22%	138.13	105.24	-23.81%	129.16	95.77	-25.85%
2010	169.26	138.09	-18.42%	156.13	118.94	-23.82%	145.92	111.75	-23.42%	136.43	101.70	-25.46%
2011	179.42	146.38	-18.41%	165.50	126.44	-23.60%	154.67	118.80	-23.19%	144.62	108.11	-25.25%
2012	189.58	154.66	-18.42%	174.87	134.96	-22.82%	163.43	126.81	-22.41%	152.80	115.40	-24.48%
AVERAGE:	87.36	74.45	-14.79%	80.01	62.57	-21.80%	74.77	58.79	-21.37%	69.91	53.50	-23.48%
PV AT 10.88%	463.35	415.82	-10.26%	418.40	340.67	-18.58%	390.86	320.15	-18.09%	365.45	291.18	-20.32%

SOURCES: BECO IR EOER-20 AND BECO IR AG 4-19.

TABLE 4.7.4: SUMMARY OF BASE CASE OIL FORECASTS IN BECO'S IR-EOER-20

NEW YORK HARBOR PRICES IN NOMINAL DOLLARS/BARREL

	DISTILLATE #2 OIL							1% SULFUR #6 OIL						
YEAR	DRI-1/86	DRI-7/86	DRI-1/87	DRI-7/87	DRI-SP-88	WEFA-5/88	DRI-2/89	DRI-1/86	DRI-7/86	DRI-1/87	DRI-7/87	DRI-SP-88	WEFA-5/88	DRI-2/89
	[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]	[13]	[14]
1989	30.02	22.53	22.57	23.48	24.60	23.60	23.83	23.61	17.86	17.85	18.26	18.90	18.80	17.49
1990	31.26	24.25	24.42	24.56	27.70	24.30	25.85	24.58	19.30	19.30	19.35	20.72	19.40	18.56
1991	33.02	26.35	26.53	26.72	30.45	25.80	27.96	26.02	21.23	21.23	21.40	22.81	20.50	20.10
1992	34.90	28.50	28.76	28.97	32.89	27.60	29.80	27.47	23.16	23.16	23.35	24.99	21.80	21.67
1993	37.27	30.66	30.94	31.17	34.95	29.10	31.65	29.39	25.09	25.09	25.29	26.68	22.90	23.24
1994	40.18	33.82	34.11	34.35	37.23	34.40	33.69	31.80	27.99	27.99	28.21	28.55	26.80	24.95
1995	43.61	37.42	37.77	38.08	40.89	38.20	36.26	34.69	31.37	31.37	31.62	30.89	29.70	27.08
1996	47.90	41.56	41.97	42.33	45.53	43.70	39.33	38.55	35.23	35.23	35.51	33.70	33.70	29.64
1997	53.69	46.58	47.11	47.53	48.13	45.80	43.47	43.85	40.05	40.05	40.37	37.44	35.30	33.05
1998	60.93	52.54	53.20	53.89	53.30	48.70	48.10	50.60	45.84	45.84	46.21	41.66	37.50	36.89
1999	69.18	59.43	61.01	61.50	59.89	53.00	54.02	58.31	52.60	52.60	53.02	47.04	40.80	41.80
2000	78.47	67.29	69.97	70.53	67.01	57.40	60.41	66.98	60.32	60.32	60.80	52.89	44.20	47.13
2001	88.27	74.59	78.37	78.99	75.19	61.30	67.77	76.13	67.56	67.56	68.09	59.44	47.20	53.12
2002	97.65	82.89	87.88	88.58	83.92	65.20	75.64	84.81	75.76	75.76	76.36	66.46	50.20	59.54
2003	107.01	90.85	96.84	97.61	93.22	70.30	84.01	93.48	83.48	83.48	84.15	73.95	54.20	66.39
2004	116.37	100.26	107.48	108.33	101.60	76.70	91.56	102.16	92.65	92.65	93.39	80.74	59.10	72.62
2005	128.96	110.16	118.67	119.61	109.93	81.50	99.08	110.83	102.30	102.30	103.11	87.52	62.80	78.86
2006	140.66	119.64	129.31	130.33	118.55	90.00	106.83	121.43	111.47	111.47	112.36	94.55	69.30	85.33
2007	153.53	129.14	139.94	141.05	127.72	98.50	115.09	133.00	120.64	120.64	121.60	102.03	75.90	92.24
2008	167.43	137.76	149.46	150.64	136.27	108.20	122.79	145.52	128.84	128.84	129.87	109.05	83.30	98.73
2009	181.41	146.39	158.97	160.24	144.79	116.60	130.46	158.05	137.05	137.05	138.13	116.08	89.80	105.24
2010	193.52	154.62	167.93	169.26	153.27	125.00	138.09	168.65	144.77	144.77	145.92	123.10	96.30	111.75
2011	206.79	163.89	178.01	179.42	162.47	137.10	146.38	180.22	153.45	153.45	154.67	130.48	105.60	118.80
2012		173.17	188.08	189.58		150.30	154.66		162.14	162.14	163.43		115.80	126.81
AVERAGE GROWTH 1989-2011 RATE:	8.8%	9.0%	9.4%	9.2%	8.6%	8.0%	8.2%	9.2%	9.8%	9.8%	9.7%	8.8%	7.8%	8.7%
PV 1989-2011 AT 10.88%	511.61	425.44	443.24	447.45	444.90	376.45	402.86	427.05	374.03	374.01	377.15	346.68	292.50	309.52

SOURCES: BECO IR EOER-20
BECO IR AG 4-19
Connecticut Light & Power: Third Annual Cogeneration Filing, April 11, 1988 (DRI Spring '88 Forecast).

TABLE 4.7.5: COMPARISON OF BECO 1989 OIL AND GAS PRICE FORECASTS

YEAR	DISTILLATE OIL	NATURAL GAS	GAS AS A % OF OIL
	[1]	[2]	[3]
1989	4.24	2.35	55.42%
1990	4.60	2.48	53.91%
1991	4.97	2.59	52.11%
1992	5.30	2.80	52.83%
1993	5.63	3.01	53.46%
1994	5.99	3.25	54.26%
1995	6.45	3.53	54.73%
1996	7.00	3.85	55.00%
1997	7.73	4.26	55.11%
1998	8.56	4.73	55.26%
1999	9.61	5.33	55.46%
2000	10.74	5.99	55.77%
2001	12.05	6.73	55.85%
2002	13.45	7.54	56.06%
2003	14.94	8.36	55.96%
2004	16.28	9.12	56.02%
2005	17.62	9.89	56.13%
2006	19.00	10.69	56.26%
2007	20.47	11.54	56.38%
2008	21.84	12.36	56.59%
2009	23.20	13.19	56.85%
2010	24.56	14.02	57.08%
2011	26.03	14.94	57.40%
2012	27.51	15.94	57.94%
AVERAGE 1989-2012:			55.49%
1995-2012:			56.10%

SOURCE: BECO IR AG 4-19.

TABLE 4.7.6: EDGAR (CC4) GENERATION, FROM EX. BE-RSH-14

YEAR	GWH	FUEL COST $ THOUSAND	FUEL COST $/MWH
1995	789.7	49,516	62.70
1996	833.4	57,915	69.49
1997	747.2	58,871	78.79
1998	980.5	86,098	87.81
1999	877.1	88,651	101.07
2000	1023.1	117,404	114.75
2001	464.7	62,153	133.75
2002	382.7	57,991	151.53
2003	632.1	107,257	169.68
2004	435.8	80,330	184.33
2005	534.1	107,398	201.08
2006	532.5	117,427	220.52
2007	454.3	109,353	240.71
2008	465.7	131,009	281.32
2009	446.3	133,801	299.80
2010	532.9	165,661	310.87
2011	680.0	222,066	326.57
2012	652.8	222,339	340.59
AVERAGE	636.9		
NPV AT 10.88% TO 1989		415,012	

TABLE 4.7.7: CHANGES IN GENERATION: WITH-PILGRIM CASE TO WITHOUT-PILGRIM CASE

	PILGRIM	------NEW BOSTON 1------			------NEW BOSTON 2------			------EDGAR (CC4)------			---------MYSTIC 4--------		
YEAR	GWH	W/P	W/O P	CHANGE	W/P	W/O P	CHANGE	W/P	W/O P	CHANGE	W/P	W/O P	CHANGE
1989	2822.1	2381.5	2461.8	80.3	1776.3	1996.2	219.9	0.0		0.0	584.3	742.6	158.3
1990	2822.1	2012.8	2053.2	40.4	1901.3	2133.2	231.9	0.0		0.0	640.7	828.2	187.5
1991	2954.6	2451.0	2563.0	112.0	1479.3	1740.7	261.4	0.0		0.0	531.7	725.5	193.8
1992	2954.6	2328.5	2458.7	130.2	1768.0	2080.1	312.1	0.0		0.0	558.2	790.7	232.5
1993	2954.6	2318.3	2411.3	93.0	1802.1	2205.0	402.9	0.0		0.0	602.6	832.0	229.4
1994	2954.6	2353.2	2506.4	153.2	1616.4	1963.2	346.8	0.0		0.0	480.2	721.5	241.3
1995	2954.6	1959.7	2052.0	92.3	1815.9	2236.1	420.2	0.0	789.7	789.7	601.2	862.4	261.2
1996	2954.6	2439.2	2564.0	124.8	1491.3	1833.0	341.7	0.0	833.4	833.4	486.4	695.9	209.5
1997	2954.6	2339.9	2461.0	121.1	1839.9	2254.8	414.9	0.0	747.2	747.2	603.7	864.4	260.7
1998	2954.6	2318.2	2412.5	94.3	1860.7	2255.5	394.8	0.0	980.5	980.5	641.4	881.1	239.7
1999	2954.6	2417.4	2515.2	97.8	1790.2	2178.6	388.4	0.0	877.1	877.1	593.9	829.4	235.5
2000	2954.6	1996.9	2053.2	56.3	1946.1	2341.0	394.9	0.0	1023.1	1023.1	683.9	920.7	236.8
2001	2951.3	2234.4	2513.3	278.9	1297.9	1601.0	303.1	0.0	464.7	464.7	356.8	556.9	200.1
2002	2948.7	2134.3	2407.1	272.8	1586.6	1952.4	365.8	0.0	382.7	382.7	431.2	678.6	247.4
2003	2953.4	2127.6	2375.2	247.6	1574.3	1934.6	360.3	0.0	632.1	632.1	447.9	694.7	246.8
2004	2951.4	2195.1	2464.0	268.9	1517.0	1866.6	349.6	0.0	435.8	435.8	412.8	643.4	230.6
2005	2954.6	1832.5	2029.6	197.1	1649.1	2031.9	382.8	0.0	534.1	534.1	486.2	739.3	253.1
2006	2954.6	2284.8	2531.9	247.1	1349.0	1656.8	307.8	0.0	532.5	532.5	390.6	590.9	200.3
2007	2953.6	2181.4	2424.0	242.6	1654.2	2023.7	369.5	0.0	454.3	454.3	476.1	722.5	246.4
2008	2944.6	1922.8	2222.7	299.9	1397.7	1659.2	261.5	0.0	465.7	465.7	318.0	505.9	187.9
2009	2945.7	2021.3	2322.4	301.1	1355.2	1617.9	262.7	0.0	446.3	446.3	302.6	477.8	175.2
2010	2951.1	1690.8	1925.8	235.0	1482.2	1766.2	284.0	0.0	532.9	532.9	361.3	561.0	199.7
2011	2952.1	2156.0	2427.0	271.0	1235.5	1494.9	259.4	0.0	680.0	680.0	317.3	483.3	166.0
2012	2954.6	2120.3	2365.7	245.4	1581.1	1901.3	320.2	0.0	652.8	652.8	426.9	637.2	210.3

SOURCE: EX. RSH-13 AND 14

	MYSTIC 5			MYSTIC 6			MYSTIC 7			TOTAL	CHANGE AS %
YEAR	W/P	W/O P	CHANGE	W/P	W/O P	CHANGE	W/P	W/O P	CHANGE	CHANGE	OF PILGRIM GWH
1989	462.5	566.1	103.6	593.7	746.7	153.0	2374.8	2924.2	549.4	1264.5	44.81%
1990	633.4	788.9	155.5	540.4	713.0	172.6	2475.8	2977.2	501.4	1289.3	45.69%
1991	595.5	786.8	191.3	584.4	822.6	238.2	2324.1	2953.9	629.8	1626.5	55.05%
1992	515.4	687.5	172.1	520.9	750.4	229.5	2254.1	2943.6	689.5	1765.9	59.77%
1993	610.0	833.0	223.0	564.8	796.8	232.0	2017.5	2550.9	533.4	1713.7	58.00%
1994	415.4	601.9	186.5	497.1	762.7	265.6	2205.0	2976.8	771.8	1965.2	66.51%
1995	611.0	863.0	252.0	470.7	692.7	222.0	2311.3	3063.1	751.8	2789.2	94.40%
1996	593.7	836.6	242.9	607.7	891.8	284.1	2323.8	3093.5	769.7	2806.1	94.97%
1997	554.0	779.9	225.9	566.8	831.3	264.5	2356.9	3143.2	786.3	2820.6	95.46%
1998	646.8	883.8	237.0	603.1	840.6	237.5	2055.8	2713.9	658.1	2841.9	96.19%
1999	502.4	693.8	191.4	621.4	889.0	267.6	2532.3	3324.7	792.4	2850.2	96.47%
2000	688.9	925.2	236.3	539.8	744.6	204.8	2530.9	3243.0	712.1	2864.3	96.94%
2001	453.6	672.0	218.4	440.3	700.4	260.1	1789.0	2574.2	785.2	2510.5	85.06%
2002	414.0	615.5	201.5	399.2	640.1	240.9	1815.7	2595.1	779.4	2490.5	84.46%
2003	465.5	686.3	220.8	412.5	657.3	244.8	1586.1	2279.4	693.3	2645.7	89.58%
2004	365.4	540.2	174.8	425.2	675.3	250.1	1899.7	2712.3	812.6	2522.4	85.46%
2005	507.8	740.6	232.8	377.6	585.7	208.1	1926.4	2709.9	783.5	2591.5	87.71%
2006	490.3	711.9	221.6	484.2	747.0	262.8	1907.0	2709.0	802.0	2574.1	87.12%
2007	451.1	654.7	203.6	443.3	685.7	242.4	1940.4	2734.1	793.7	2552.5	86.42%
2008	358.1	523.5	165.4	295.6	472.0	176.4	1258.2	1831.9	573.7	2130.5	72.35%
2009	279.3	415.4	136.1	308.7	495.9	187.2	1576.1	2270.6	694.5	2203.1	74.79%
2010	398.7	578.1	179.4	281.7	440.3	158.6	1610.5	2302.0	691.5	2281.1	77.30%
2011	403.0	595.0	192.0	390.6	607.9	217.3	1680.2	2381.9	701.7	2487.4	84.26%
2012	404.3	587.0	182.7	395.7	603.8	208.1	1874.1	2614.6	740.5	2560.0	86.64%

TABLE 4.3.1: TAX EFFECT OF PILGRIM WRITE-OFF, 1986

	Reduction In Rate Base	Reduction In Return & Taxes
1989	162.0	26.1
1990	155.3	25.0
1991	148.2	23.9
1992	141.2	22.7
1993	134.1	21.6
1994	127.1	20.5
1995	120.0	19.3
1996	113.0	18.2
1997	105.9	17.1
1998	98.9	15.9
1999	91.9	14.8
2000	84.8	13.7
2001	77.8	12.5
2002	70.7	11.4
2003	63.7	10.3
2004	56.6	9.1
2005	49.6	8.0
2006	42.6	6.9
2007	35.5	5.7
2008	28.5	4.6
2009	21.4	3.5
2010	14.4	2.3
2011	7.3	1.2
2012	0.3	0.0
PV @	10.33%	174.1

Write-off =	$162 million
Tax Rate =	49.5%
% of Return Taxable	57.1%
Tax plus Return =	16.1%

TABLE 4.8.2: TAX EFFECT OF PILGRIM WRITE-OFF, 1989

	Reduction In Rate Base	Reduction In Return & Taxes
1989	181.0	26.9
1990	173.5	25.7
1991	165.6	24.6
1992	157.7	23.4
1993	149.8	22.2
1994	142.0	21.1
1995	134.1	19.9
1996	126.2	18.7
1997	118.4	17.6
1998	110.5	16.4
1999	102.6	15.2
2000	94.8	14.1
2001	86.9	12.9
2002	79.0	11.7
2003	71.2	10.6
2004	63.3	9.4
2005	55.4	8.2
2006	47.5	7.1
2007	39.7	5.9
2008	31.8	4.7
2009	23.9	3.6
2010	16.1	2.4
2011	8.2	1.2
2012	0.3	0.0
PV @	10.88%	174.9

Write-off =	$181 million
Tax Rate =	38.3%
% of Return Taxable	58.6%
Tax plus Return =	14.8%

#77R

Executive Office of Energy Resources
DPU 89-100
Exhibit ER-PLC-7

COMMONWEALTH OF MASSACHUSETTS
BEFORE THE DEPARTMENT OF PUBLIC UTILITIES

REBUTTAL TESTIMONY OF

PAUL CHERNICK
PLC, Inc.

ON BEHALF OF THE

MASSACHUSETTS EXECUTIVE OFFICE OF ENERGY RESOURCES

August 7, 1989

1 EXECUTIVE SUMMARY AND QUALIFICATIONS

1.1 Qualifications

Q: Mr. Chernick, please state your name, occupation and business address.

A: My name is Paul L. Chernick. I am President of PLC, Inc., 18 Tremont Street, Suite 703, Boston, Massachusetts.

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

A: Yes.

Q: What is the purpose of your surrebuttal testimony?

A: My primary purpose is to respond to the rebuttal testimony of Mr. Manion, which addresses the direct testimony I filed jointly with Mr. Wallach. Due to the length of his rebuttal, I will respond in detail to only a few points to illustrate general problems with Mr. Manion's approach.

Q: What is Mr. Manion's principal criticism of your direct testimony?

A: While Mr. Manion raises a number of issues, his basic argument appears to be that he is a professional in nuclear decommissioning cost estimation, while Mr. Wallach and I are amateurs. From this assertion, he concludes that his engineering estimates of nuclear decommissioning costs must be correct, and that our criticisms are unreliable.

Q: Have Mr. Manion's nuclear decommissioning cost estimates proven to be correct?

A: No. As shown in our Table 4.5.1, his estimates have escalated rapidly over the last decade.

Q: Mr. Manion asserts that his estimates have not grown at 12% in real terms, as suggested by your testimony, but at 8% in nominal terms. Is he correct?

A: No. Mr. Manion alleges that a regression analysis, which he does not document or otherwise describe, shows that his estimates of the cost of decommissioning single units have risen at 8% in nominal terms, which would be roughly 2% in real terms. I have attached a copy of a revised Table 4.5.1, showing just the single units to which Mr. Manion referred, along with a regression comparable to the one I presented in my testimony using Mr. LaGuardia's estimates. The average growth rate in Mr. Manion's single-unit estimates has been about 9% in real terms, not the 2% he alleges. While this growth rate is somewhat lower than the examples we discussed in our testimony, the difference is not material to the point we were making. Mr. Manion's cost estimates have increased rapidly in the past, and there is no reason to believe that his estimation procedure has suddenly become more reliable.[1]

Q: Does Mr. Manion's error regarding the growth rate in his own estimates illustrate any other important points?

A: Yes. As noted in our direct testimony, Mr. Manion repeatedly makes allegations without any support other than his opinion.

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[1]This problem is not limited to Mr. Manion, but is endemic to engineering estimates of nuclear costs. Mr. Manion describes his current estimate for Pilgrim DECON as "definitive," a term used for many nuclear construction cost estimates which subsequently proved to be a small fraction of the actual cost.

He does not seem to feel any obligation to demonstrate that his assertions are correct. As he argues in his rebuttal, he is a professional decommissioning-cost estimator, and only his opinion (and those of his rather small fraternity) is of any significance. Failing to provide his putative "regression analysis" is the most blatant example of Mr. Manion's reluctance to document his work.

This same error also illustrates that Mr. Manion's undocumented assertions can be just plain wrong. The DPU should avoid relying on his poorly documented allegations and analyses, at least until they can be reviewed in greater detail.

Finally, it is clear from this error that Mr. Manion does not understand, or will not acknowledge, how much his cost estimates have increased over the last decade. This detachment from the reality of his own work, in an area in which he claims to be a peculiarly qualified professional, must cast a pall over all of Mr. Manion's opinions.

Q: Did Mr. Manion's errors in decommissioning cost estimation start with the 1979 estimates, the earliest estimates shown in Table 4.5.1?

A: No. In November 1976, Mr. Manion co-authored (with Mr. LaGuardia) the Atomic Industrial Forum decommissioning cost estimates. In that document, Mr. Manion estimated that decommissioning a large (1178 MW) BWR would cost $31 million in 1975 dollars, which would be $61 million in the 1987 dollars of Table 4.5.1. At the economies-of-scale factor estimated in Table 4.5.1.1, this would be $51 million for a 670 MW unit, such as Pilgrim.[2] By 1979, Mr. Manion's cost estimates for small PWR's had increased 70% from the 1976 level. Mr. Manion's current estimate for Pilgrim decommissioning is $218 million in 1988 dollars, or $206 million in 1987 dollars, or 4 times the 1976 estimate. Interestingly, Mr. Manion's estimate of the uncertainty in the 1976 estimate was only 17%, much less than the 25% contingency he uses today.[3]

Q: Does Mr. Manion's discussion of the regression issues offer any correct insights?

A: Yes. On page 3, Mr. Manion agrees with us, and disagrees with Mr. Koppe, when he says that

> When dealing with statistics, utilization of the largest available and pertinent data base is always the preferred approach rather than selective exclusion of data entries. . .

While Mr. Manion rather unfairly accuses us of this "selective exclusion," his description fits Mr. Koppe's approach quite well.

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[2]By way of comparison, Manion and LaGuardia estimate that a 550 MW BWR would cost 80% as much to decommission as would a 1178 MW BWR. The regression in Table 5.4.1.1 would predict that the smaller unit would have a decommissioning cost of 78% that of the larger unit, so our regression appears consistent with their estimates of scale effects. The Manion-LaGuardia estimates do not appear to include an explicit contingency allowance.

[3]Adding the 17% to the 1976 estimate would decrease the escalation to subsequent estimates. With this revision, the increase to 1979 would be 45%, and the 1987 estimate would be 3.4 times the 1976 estimate. In any case, the real-dollar escalation in Mr. Manion's estimates has been very high.

Q: Are there other problems with Mr. Manion's rebuttal testimony?

A: Yes. Given the time constraints, I will not respond to all of his incorrect issues. I will concentrate of a few points which are particularly noteworthy.

First, Mr. Manion faults us for taking him at his word in his testimony, exhibits, and information responses.

- On page 5, Mr. Manion argues that we should not have paid any attention to his decommissioning schedules, because those schedules were wrong.
- On pages 12-13, Mr. Manion asserts that we should have known that he did not mean what he said about transportation costs in BECO IR AG 8-6, and that we should have known that by regional he meant "within Massachusetts."[4]
- On page 2, Mr. Manion argues that his prior statements that the cost estimate was intended to survive for 3-4 years should be ignored, and that it was actually intended (unlike all of his previous estimates) to be correct for the life of the plant.
- On page 3, Mr. Manion criticizes us for believing his explanation (in BECO IR EOER-86 and in Exhibit BE-WJM-2) that his contingency factor was derived from the data he presented.

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[4]Since proposals for regional waste compacts include states as far apart as North Dakota and California, the term "regional" in this context has come to refer to areas larger than traditional terminology would suggest.

- On page 4, Mr. Manion misquotes our description of his contingency factor, and attacks us for daring to assert that he included contingency for "changing physical requirements." In fact, we said that the contingency was intended to cover changes in input prices and in physical requirements, based on our understanding of Mr. Manion's definition of contingency, which includes (from Exhibits BE-WJM-1, page 14, and BE-WJM-2, page 68):
  - "unknowns,"
  - "unplanned occurrences,"
  - variations in "actual radioactive waste volumes,"
  - "degree of activation and contamination,"
  - "adverse weather impacts,"
  - "equipment breakdown," and
  - "labor strikes."

  If Mr. Manion did not include these factors, and other changes in physical requirements, in his analysis of contingency, he could not properly reflect the nature of the uncertainties and historical cost escalation in decommissioning cost estimates. In any case, Mr. Manion's testimony is now internally inconsistent.[5]
- On pages 9-10, Mr. Manion criticizes us for not knowing that the actual disposal cost for Pilgrim waste (\$76.87/ft^3) is more than twice as high as the figure he

[5] It is surprising that Mr. Manion made such a fuss about our rather neutral description of his contingency factor.

quotes in Exhibit BE-WJM-2 ($36.87). However, in Exhibit BE-WJM-2, and at page 3 of his rebuttal, Mr. Manion represents that his use of $100 for disposal costs is very conservative, since it is much higher than the $36.87 value, which he claims is typical of today's prices. Mr. Manion tries to claim that current disposal charges are both high and low, and succeeds only in demonstrating that his calculations and comparisons are of very limited value.

- On pages 18-20 (and again on page 31), Mr. Manion criticizes us for not understanding the (previously undocumented) detail of his local tax calculation. Our point was that the tax calculation rests on undocumented assumptions. On page 19, Mr. Manion acknowledges that all of his tax figures are simply assumptions.[6]

Second, Mr. Manion faults us for not believing his assumptions, even though he offers no further explanation for those assumptions. This is true for local taxes, for the level and stability of contingency, and for the assumption that Massachusetts will have a low-level nuclear waste disposal facility in operation in the state by 1993.

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[6] Mr. Manion's initial criticism of our review of his tax assumption was that we had misquoted his assumption for annual taxes in the early SAFSTOR case. We used a value of $2.4 million annually, while he claimed he actually assumed $2 million. Page 9 of Exhibit BE-WJM-3 shows a total tax cost over 21 years of $50,850,000, or an average of $2,421,000 annually. The $2 million value appears to be the final value, rather than the average.

Third, Mr. Manion engages in a number of arguments which are not so much with us as with algebra, arithmetic, and the English language. In various ways, Mr. Manion presents his "professional" expertise as if it took precedence over all other aspects of reality.

- On page 4, Mr. Manion repeats his claim that he derives his contingency factor from a quantitative analysis, but on page 3 he argues that we are wrong in pointing out that his quantitative analysis is inconsistent with the data he claims supports it. Either Mr. Manion quantitatively but incorrectly derived a 15% real escalation rate from a 25% nominal rate (as he asserts in BECO IR EOER-86), or he did not rely on the data. Again, he tries to have it both ways: to rely on data, but not to actually have to use them.
- On the top of page 4, he asserts that a rapidly-escalating cost component will not become a larger share of the total cost. This is a basic arithmetic issue, and Mr. Manion is simply incorrect.
- At the bottom of page 4 and at the top of page 5, Mr. Manion claims that we were incorrect in stating that he used the same 25% contingency for all decommissioning costs. He argues that he actually used one 25% contingency for the late DECON and a <u>different</u> 25% factor for the early SAFSTOR. This is an interesting semantic point, but not a practical issue. In any case, 25% is equal to 25%, and

all our criticisms of the contingency survive Mr. Manion's quibbling.

- On page 6, Mr. Manion argues that the cost of operating Pilgrim with fuel stored on site is somehow less uncertain than the cost of simply storing the fuel. This is a totally illogical position, and Mr. Manion makes no attempt to justify it.

Fourth, Mr. Manion attacks us for statements we did not make. These are generally not worth responses, beyond a single example. On page 27, Mr. Manion claims that we incorrectly stated that Humboldt is not onsite with two fossil units. In fact, the footnote to which he refers says that Humboldt is not sited with another reactor, which would require nuclear-quality security and nuclear fuel monitoring.[7]

Fifth, Mr. Manion says things which are simply not true, or at least misleading.

- He claims on page 26 that the NRC "precludes utilities from shipping nuclear spent fuel from one site to another for purposes of storage." Like most major nuclear operating actions, fuel shipping would require licensing, but this is not the same as "precluding" shipments starting in 1997, which was the issue in question. In fact, the NRC Grey Book lists Robinson spent fuel stored at Brunswick, and

[7] Mr. Manion does not attempt to demonstrate that the presence of the fossil units on the site affects the costs of nuclear fuel storage.

states that McGuire is authorized to accept spent fuel from Oconee. Relevant pages of the Grey Book are attached.

- He asserts on page 26, note 5, that a PWR fuel element can not be stored in a BWR "storage location," which might be taken as referring to a BWR storage pool. The actual meaning of "storage location" to which this statement applies is "a space in the storage rack." The Robinson PWR fuel assemblies are stored in the Brunswick BWR pool.
- Mr. Manion's estimates on pages 22-25 of the costs of "planning" for decommissioning are actually dominated by activities which (according to his direct testimony, especially Exhibit BE-WJM-2) would not be performed until after plant shutdown, or even after the end of the SAFSTOR period, such as waste processing, and the decontamination of systems and concrete. We suggested that the three-year outage should have been used for planning of decommissioning, and Mr. Manion estimated the cost of that planning by including numerous irrelevant items.

Q: How does Mr. Manion's rebuttal testimony affect the weight which should be given to his estimate of the difference between the cost of early SAFSTOR and the cost of late DECON?

A: If anything, the inconsistencies, confusion, and dogmatism displayed in Mr. Manion's rebuttal should decrease the weight given to his largely undocumented opinions.

Q: Does this conclude your surrebuttal testimony?
A: Yes.