UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

ATOMIC SAFETY AND LICENSING BOARD

Before Administrative Judges:
James P. Gleason, Chairman
Frederic J. Shon
Dr. Oscar H. Paris

In the Matter of	)	
	)	
CONSOLIDATED EDISON COMPANY OF NEW YORK, INC. (Indian Point, Unit No. 2)	)	Docket Nos. 50-247 SP 50-286 SP
	)	
POWER AUTHORITY OF THE STATE OF NEW YORK (Indian Point, Unit No. 3)	)	April 12, 1983

TESTIMONY OF GREATER NEW YORK COUNCIL ON ENERGY WITNESS RICHARD A. ROSEN ON COMMISSION QUESTION 6.3

April 12, 1983

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Richard A. Rosen. My business address is Energy Systems Research Group, Inc., 120 Milk Street, Boston, Massachusetts 02109.

Q. DR. ROSEN, PLEASE DESCRIBE YOUR BACKGROUND AND QUALIFICATIONS.

A. I am a senior research scientist at Energy Systems Research Group, Inc., as well as Executive Vice-President of the firm. ESRG is a non-profit organization specializing in research on energy-related issues, particularly research related to electric utilities. Among the issues addressed by ESRG research are demand forecasting, conservation program analysis, electric utility dispatch and reliability modeling, generation planning, avoided cost analysis, financial analysis, demand curtailment modeling, rate design, cost of capital analysis, and district heating.

In May, 1979, I completed directing my extensive critique of the New England Power Pool Electric Demand Forecasting Model under contract to the New England Conference of Public Utility Commissioners. I have also testified on demand forecasting in Case #19494 before the Massachusetts Department of Public Utilities, in *Pennsylvania PUC v. Philadelphia Electric Company*, RID #438 (the 1978 rate case), before the Pennsylvania Public Utility Commission, and before the Michigan Public Service Commission in Case #U-5979. During 1979, I was project director of a study that led to Dr. D. Shakow's testimony on behalf of our firm regarding "Generation Planning and Reliability" in *Pennsylvania PUC v. Philadelphia Electric Company*, R-79060865 (the

1979 rate case), before the Pennsylvania Public Utility Commission. During 1980 I was project director of a study that culminated in further testimony by Dr. D. Shakow regarding "Generation Planning and Reliability" in Case #EO-80-57 before the Missouri Public Service Commission.

I have submitted extensive direct and sur-rebuttal testimony in Case No. I-79070315 and 317 (CAPCO Investigation) before the Pennsylvania Public Utility Commission on generation planning and reliability, in Case No. I-80100341 (the Limerick Investigation), and on excess capacity in Case #R-822169. I have testified on "Generation Expansion Planning Re: Consumers Power Company" in Case No. U-6360 before the Michigan Public Service Commission, and on generation planning in cases before the Alabama Public Service Commission, Ohio Public Utility Commission (80-141-EL-AIR and 79-427-EL-AIR), and before the Maine PUC in Dockets #80-180 and #81-114. I have also testified before the North Carolina Utilities Commission in Docket No. E-100, Sub 47 on principles of risk sharing between ratepayers and utility investors as applied to the structure of fuel adjustment clauses and the role of power plant performance.

Other generation planning studies at ESRG that I have directed include analyses of proposed power plants in the American Electric Power system, and the Consolidated Edison service territory. That work, as well as prior research, led to the development of the ESRG Electric System Generation Planning Model (ESGEM) under Dr. Shakow's and my direction, and the introduction and revision of the SYSGEN electric system production costing

model at ESRG. I was also principal investigator for a project which expanded the capabilities of the ESGEM model, which was funded by the U.S. Department of Energy, Office of Utility Systems.

In a number of generation planning studies that I have conducted, the ESRG staff has applied the ELFIN electric utility corporate financial model to estimate the financial impacts of alternative construction programs.

I received my Bachelor of Science degree from M.I.T. in 1966 and my Master's degree and Ph.D. in physics from Columbia University in 1970 and 1974, respectively. Before joining ESRG, I did research at the National Center for the Analysis of Energy Systems at Brookhaven National Laboratory on industrial energy conservation. In that capacity, I served as Principal Investigator on two projects involving industrial process energy modeling for the U.S. Department of Energy.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY TODAY?

A. My testimony is comprised of seven pages of questions and answers and an 83-page document entitled, "The Economics of Closing the Indian Point Nuclear Power Plants," and the appendices thereto which together form a comprehensive study that Energy Systems Research Group, Inc. has performed with respect to contention 6.3 in these dockets. The basic motivation behind performing this study was to improve on the methodology and consistency of the earlier similar studies that had been performed by the General Accounting Office, the Congressional Research Service, and the Rand Corp. Further

background on the report is discussed in the report itself. The study is done solely from the point of view of required revenues, i.e. from the point of view of costs to the downstate PASNY and Con Edison ratepayers. Put simply, it examines the net impact over the 15 year period 1983-1997 on these ratepayers of permanently shutting down the Indian Point Units #2 and #3 versus keeping them operating.

Q. WHAT ARE YOUR MAJOR FINDINGS?

A. Three "early retirement" scenarios for the fifteen year period 1983-1997 were developed and employed in this study. These are the High Impact scenario, the Low Impact scenario, and the Mid-Range scenario. The High and Low Impact scenarios are comprised of assumption sets which consistently bias the results of the analysis toward higher or lower cost effects from closing the units. As a group, the assumptions in either of these scenarios would therefore occur only if a set of conditions, each of which may individually be considered improbable, should prevail. Thus, the High Impact scenario assumes no deterioration in plant performance from aging effects, no benefits from reductions in spent fuel and decommissioning costs, no readjustment of import power availability or system fuel mix in the absence of the plants, rapidly escalating make-up fuel costs, and so on. The Low Impact scenario is, by contrast, consistently pessimistic on nuclear plant performance and optimistic on make-up power economics. Each extreme may be considered unlikely. Together they place wide boundaries on plausible future conditions.

The Mid-Range results are offered as our best estimates of the direct cost effects of early retirement of IP-2 and IP-3. The overall effect of closing the plants by 1983 is about $746 million (discounted 1981 dollars) or, on a percentage basis, approximately two percent. This is the cumulative impact for the entire 1983-1997 period. The annual impacts are relatively more severe in the early years and then moderate substantially over time, as will be discussed further below.

The results of our analysis for each of the three early retirement scenarios are summarized in Table 1. The results for each scenario are presented in terms of total additional revenues required from ratepayers during the period 1983-1997. The results are also expressed as a percentage increase or decrease from the revenues that would be required assuming continued plant operation during the period.

TABLE 1

REQUIRED REVENUE IMPACT OF INDIAN POINT RETIREMENTS: SUMMARY RESULTS FOR NEW YORK RATEPAYERS*, 1983-1997

Scenario	Cumulative Total (Millions of 1981 Discounted $)	Average Percentage Change in Discounted Revenue Requirements
1. High Impact	$3,656	9.2
2. Mid-Range	746	1.9
3. Low Impact	- 1,337	-3.5

*"New York ratepayers" are Con Ed's retail customers and PASNY's downstate customers.

A number of sensitivity tests were also performed to investigate the responsiveness of these results to changes in key variables. These results are detailed in Section 4.2. Relative to the Mid-Range average cumulative impact of 1.9 percent, we performed four sensitivity tests. First, increasing the length of the time period for analysis (from a final year of 1997 to one of 2000) decreases average impacts to 1.2 percent. Second, delaying the times of the retirement from 1983 to 1985 decreases average impacts to 0.8 percent. Third, increasing the assumed discount rate (from 12 to 14 percent) increases the impacts to 2.0 percent. Finally, assuming that capacity factors (a measure of plant availability at full capacity) do not deteriorate over time increases the net impacts to 3.9 percent.

The ratepayers cost impacts, then, are likely to average about two percent over the next fifteen years with the major effects in the earlier years. This small but measurable negative impact would have to be weighed against the perceived benefits in avoided nuclear risks in deliberating the fate of the Indian Point units.

Q. ARE THERE ANY IMPORTANT EVENTS THAT HAVE TAKEN PLACE SINCE OCTOBER, 1982 THAT WOULD TEND TO ALTER YOUR CONCLUSIONS?

A. Yes. The key change that has occurred since October, 1982 is that oil prices have fallen and not risen as we had projected. In fact in the study we find that by April, 1983 we had overpredicted oil prices by about 17 percent for Con Edison. If only this change were made for 1983 in our oil price assumptions (leaving the

price escalation assumptions as they were), the rate impact of early retirement in the Mid-Range case would be reduced from about 2 percent over the next 15 years, to about 0.2 percent. Thus we see that this single event has tended to almost completely eliminate any average 15 year impact on ratepayers of closing the Indian Point units now. I believe that this economic result, which is quite contrary to utility claims, is extremely important for the Licensing Board to take into account when deciding whether or not to order the closing of the Indian Point units.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

THE ECONOMICS OF CLOSING THE INDIAN POINT NUCLEAR POWER PLANTS

The Direct Effects Upon Ratepayers of Early Retirement of Units 2 and 3

Prepared by

Energy Systems Research Group, Inc.
120 Milk Street
Boston, Massachusetts 02109

ESRG Study No. 82-40

Principal Investigators

Paul D. Raskin and Richard A. Rosen

Project Team

Thomas Austin, Stephen S. Bernow, Bruce Biewald, Barry Feldman, and David Nichols

E S R G

For ordering information concerning this report,

see last page.

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1. INTRODUCTION

1.1 The Issues

The research described in this report undertook to develop a systematic framework for assessing the direct economic effects upon ratepayers of a decision to retire a nuclear power plant that has already commenced commercial operation. This cost assessment system, consisting of conceptual analyses, computer models, and associated databases, has been applied to two case studies. The first case study was an assessment of the direct economic effects of retiring the Maine Yankee Atomic power plant in 1988. The second case study, reported on in detail here, was an assessment of the direct costs to ratepayers of retiring units 2 and 3 of the Indian Point nuclear generating station in New York in 1983. In both cases, these retirement years are well in advance of the retirement dates currently planned by the operators of the power plants.

Public concern about the health and safety implications of continued operation of existing nuclear power stations has increased in the aftermath of the Three Mile Island accident of 1979. One regulatory expression of this concern is the intensification of programs for safety-related plant modifications and post-accident emergency planning as promulgated by the U.S. Nuclear Regulatory Commission. However, recent regulatory pressures for upgraded plant

operation measures have not comforted that segment of the public that has continued to advocate the closing of nuclear power plants.

Problems related to the aging of nuclear power plants, such as corrosion in steam generators, have begun to appear with increasing frequency. These problems have reinforced skepticism concerning the advisability of continuing to operate maturing nuclear plants.

One premise of the nuclear shutdown argument appears to be that avoiding the health and safety risks of continued nuclear plant operations, especially where such plants are in close proximity to population centers, is more important than securing whatever benefits can be derived from continued operation. But this premise is challenged by the proponents of continued nuclear plant operations, who have argued both that the risks of continued operation (while tangible) are relatively modest, and that the power system reliability impacts and the economic costs of premature retirement would be unacceptably severe.

On the one side of the debate, then, are those who emphasize the risks and uncertainties of the continued operation of nuclear power plants. But it is difficult to persuasively quantify both the probabilities of occurrence of, and the human and economic effects of, catastrophic events.

On the other side of the debate are those who emphasize the economic consequences of substituting more

expensive electricity generation alternatives for nuclear power. Yet previous studies of this complex economic trade-off problem have not produced clear, complete, and methodologically sound evaluations. They have often raised more questions than they have answered.(1)

This study was initiated to develop a systematic basis for assessing the economic impacts of nuclear plant retirement.* The computer models and data bases were designed as a flexible framework for specific applications.

The consideration of cost impacts in this study is limited to those which have a direct economic effect upon ratepayers. These direct economic impacts do not include such consequences of nuclear plant retirement as, for example, health and safety trade-offs. Indeed, it is important to acknowledge that the two sides of the ledger -- nuclear risk versus nuclear substitution economics -- cannot at this time be cast into a common measure and compared with one another in a noncontroversial social cost/benefit assessment. In defining positions on the plant shutown issue, quantitative analysis will continue to be supplemented by subjective perceptions and normative judgments on such concerns as the likelihood and impact of nuclear accidents, long-term radioactive waste disposal problems, and nuclear fuel security breaches.

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*Funding for this ongoing effort has been provided by foundations and private contributions through ESRG's Energy Alternatives Research Fund.

However, it is possible to systematically evaluate some of the direct cost repercussions of early nuclear plant retirement. Assumptions, methods, and planning scenarios for such cost evaluations can be clearly and consistently treated and documented. Below we present -- and apply to the case of the Indian Point units -- a systematic framework for computing the major quantifiable cost effects that would be felt by ratepayers as a result of a decision to shut down a nuclear power plant. This study is intended to offer useful information to decision-making bodies and to the general public as they deliberate on the issue of the magnitude of the direct cost penalties they are willing to bear in order to avoid nuclear risk.

The Indian Point generating station is located some thirty miles north of New York City. At this writing there are two operating units, units 2 and 3. Unit 2 is operated by the Consolidated Edison Company of New York (Con Ed), and unit 3 is operated by the Power Authority of the State of New York (PASNY). Unit 2 is rated as capable of meeting 864 megawatts (thousand kilowatts, or MW) of demand; unit 3 can meet 965 MW of demand.

1.2 Study Approach

In this study we have had two principal objectives. First, we have developed a flexible computer-based cost assessment system for estimating the direct impacts of a

nuclear plant closing upon ratepayers. Second, we have applied this assessment system to the case of a shutdown of Indian Point unit 2 (IP-2) and Indian Point unit 3 (IP-3) after 1982.

The cost assessment system is designed to simulate the increments in ratepayer costs -- or in utility finance parlance, the increased "required revenues" -- over a planning time frame. The streams of required revenues are disaggregated into the major categories of costs that would be affected by a nuclear plant closing. These include generation of replacement power; the recovery of, and return on, invested capital; nuclear fuel costs; nuclear operations and maintenance; plant decommissioning and radioactive waste disposal; and expenditures on power plant modifications.

There is considerable uncertainty with respect to the future behavior of the variables that influence future costs. Consequently, there is no substitute for developing scenarios comprised of clusters of variable assumptions to establish a range of plausible effects. Important variables included in our scenario analyses are: (1) the composition of make-up generation; (2) plant performance characteristics; (3) nuclear fuel and operation and maintenance (O&M) escalation rates; (4) electric energy conservation levels; and (5) decommissioning and waste disposal costs.

Once the scenarios were developed, the Cost Assessment of Nuclear Substitution (CANS) Model was run. The results of the application of the CANS system to the case of early

retirement of IP-2 and IP-3 are reported on next. Following this summary of major findings are sections of the report and appendices to the report designed to provide a full explication of methodology, data development, detailed results, and implications of the analysis.

The "ratepayers" with respect to whom this assessment was conducted are those located within the service area of the Consolidated Edison Company of New York. Tnere are two sets of such electric ratepayers. First there are the retail customers of Con Ed itself. Second, there are the downstate customers of PASNY, such as the Metropolitan Transit Authority, the Triborough Bridge Authority, the New York City Housing Authority, and other public agencies.

1.3 Major Findings

Three "early retirement" scenarios for the fifteen year period 1983-1997 were developed and employed in this study. These are the High Impact scenario, the Low Impact scenario, and the Mid-Range scenario. The High and Low Impact scenarios are comprised of assumption sets which consistently bias the results of the analysis toward higher or lower cost effects from closing the units. As a group, the assumptions in either of these scenarios would therefore occur only if a set of conditions, each of which may individually be considered improbable, should prevail. Thus, the High Impact scenario assumes no deterioration in plant performance from

aging effects, no benefits from reductions in spent fuel and decommissioning costs, no readjustment of import power availability or system fuel mix in the absence of the plants, rapidly escalating make-up fuel costs, and so on. The Low Impact scenario is, by contrast, consistently pessimistic on nuclear plant performance and optimistic on make-up power economics. Each extreme may be considered unlikely. Together they place wide boundaries on plausible future conditions.

The Mid-Range results are offered as our best estimates of the direct cost effects of early retirement of IP-2 and IP-3. The overall effect of closing the plants by 1983 is about $746 million (discounted 1981 dollars) or, on a percentage basis, approximately two percent. This is the cumulative impact for the entire 1983-1997 period. The annual impacts are relatively more severe in the early years and then moderate substantially over time, as will be discussed further below.

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The ratepayers cost impacts, then, are likely to average about two percent over the next fifteen years with the major effects in the earlier years. This small but

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measurable negative impact would have to be weighed against the perceived benefits in avoided nuclear risks in deliberating the fate of the Indian Point units.

1.4 Report Plan

The remaining sections of this report explain and discuss the methodological strategy used to derive cost impacts (Section 2); the central components of the cost assessment model and the basis for quantitative input assumptions used (Section 3); the scenario specifications, basic findings, and related issues (Section 4); and the indirect impacts of a plant closing (Section 5). While a complete summary of methods and findings is presented in these sections, detailed technical explications of the computer models and databases have been deferred to a series of appendices for the more technically inclined reader.

2. METHOD OF ANALYSIS

The aim is to develop realistic estimates of the direct impacts on ratepayers of closing the two Indian Point nuclear units. Concretely, the analytical problem is to quantify the resulting changes in required revenues over a planning period. The required revenues consist of the amount utilities need to collect from their customers to cover operating expenses, taxes, capital amortization, and return on investment. As an appropriate overall measure of ratepayer costs, required revenues constitute the measure to be employed in the cost impact assessments performed here.

2.1 Impacts Considered

The required revenues for a given year are composed of many elements reflecting the operations of the entire electric system under consideration. However, the ratepayer impacts of a plant closing is the difference of two required revenue streams: one with the plant included and the other with it nonoperational. Consequently, costs common to both cases cancel in computing the incremental impacts of a plant closing and need not be considered further.

There remain seven significant components of the required revenue that would be affected by a plant retirement. These are:

Make-up Generation. In the absence of the nuclear plant, the electricity generation requirements must be

provided by the existing system, by purchased power, by new plant construction, or by conservation. The costs of these make-up power alternatives constitute the major penalty of early power plant retirement. To analyze them, it is necessary to carefully specify the possible economic system responses to the loss of the facility. Projections of nuclear plant generation (capacity factors) to determine how much generation must be replaced are an important ingredient in this analysis. Independent projections of possible future capacity factors for the Indian Point units have been performed for this study and will be detailed below.

Direct Capital Related Costs. These include recovery of the sunk capital, return on investment, taxes and insurance. In an early retirement scenario, a number of adjustments must be considered in, e.g., tax write-off schedules, insurance and property tax requirements, and regulatory treatment of customer responsibility for providing full capital recovery and return in the event the plant is no longer providing service.

Nuclear Fuel. This is an avoided cost (i.e., a benefit) of early retirement. As with make-up generation its value is dependent on assumptions on likely future plant capacity factors.

Nuclear Operation and Maintenance. This is another avoided cost of early retirement and, as we shall report, there is statistical evidence for projecting rapidly escalating

nuclear O&M costs related in part to the aging-related equipment problem.

Radioactive Waste Storage and Disposal. In both cases, early and mature retirement, it is necessary to find temporary off-site storage for, and then, to finally dispose of highly radioactive spent fuel. However, the early retirement scenario has two advantages here. First, the storage ponds used for on-site storage until off-site temporary and permanent repositories become available will be filled to capacity in the next few years if the plants continue running, and this problem is ameliorated by early retirement. Second, the magnitude of waste requiring ultimate disposal is a direct function of cumulative plant generation, so early retirement reduces the total amount of waste that must be disposed of.

Decommissioning. In either case, expenses will be incurred in dismantling or encapsulating the radioactive facility after its useful life has ended. The relative costs may differ here primarily if the decommissioning expenses are greater for older, more irradiated units, as we discuss further below.

Other Expenses. Certain costs for major plant repairs and safety modifications are avoidable if the plant is to be closed. Furthermore, if the closing date is set for after the planned maintenance period during which these improvements will be made, then there is the extra benefit of

having greater plant availability in the short run by not having to make these improvements.

2.2 Cost Accounting System

The complexity of these issues -- as well as the desire to have a flexible capability for developing scenarios, performing sensitivity analyses, and synthesizing results -- warranted the development of a computer-based costing model. The resultant model, the Cost Assessment of Nuclear Substitution (CANS) System used to compute the required revenue impact, is documented in Appendix A.

The CANS system is designed to simulate the required revenue impacts in both current and discounted dollars and over variable time periods. It provides a flexible framework for testing the effects for various scenarios and parameter ranges so that uncertainty in both technology variables (e.g., future plant performances) and policy or economic variables (e.g., conservation activity) may be adequately explored. In addition, several ancillary computer models were employed for developing inputs on make-up generation, capacity factors, and O&M costs. These will be identified and discussed in Section 3.

2.3 Scenario Design

Three scenarios were developed to estimate the ratepayer impacts of early retirement. In all three scenarios the retirement date is taken as January 1, 1983. In a separate

sensitivity exercise, we report impacts based on a 1985 retirement date. The three scenarios incorporate a range of planning assumptions affecting the level of impact on ratepayers.

The High Impact scenario consistently incorporates those plausible assumptions on capital costing, load growth, make-up generation sources, nuclear O&M, capacity factors, waste disposal, and decommissioning that would be most unfavorable from the ratepayers' point of view. In the Low Impact scenario, on the other hand, the incremental costs are computed on the basis of inputs that are the most favorable to the ratepayer. The Mid-Range scenario reflects compromise assumptions between these extremes. Again, the High and Low Impact cases were developed to function as extreme and unlikely cases, based on the simultaneous bias of probablistic input variables in the same impact direction. In principle, the convolution of a number of stochastic, statistical, and uncertain policy variables should lead to a strong centering tendency around mid-range values. The Mid-Range scenario result therefore represent our best estimate figures. The other two scenarios' results and the supplemental sensitivity analyses serve to quantify the implications of alternative assumptions or sets of assumptions. A qualitative characterization of the scenarios is presented in Table 2. The details of the scenario analysis are the subject of the next section.

TABLE 2

QUALITATIVE SUMMARY OF SCENARIOS EMPLOYED

Scenario	Sunk Cost Treatment	Make-up Generation	Load Growth	Nuclear O&M	Nuclear Fuel	Nuclear Capacity Factors	Spent Fuel Disposal	Decommis-sioning
1. High Impact	Full Rate Base	Existing Systems High fossil fuel cost escalation, little additional imports	Base (0.5%/ year Growth Rate	Low	Low	High	Low	No aging effect/ Low Cost Escalation
2. Mid-Range	Full Rate Base	Additional coal conver-sion, addi-tional hydro imports, lower fuel escalation, moderate additional imports	50% Conser-vation Target (no growth)	Mid	Mid	Mid	Mid	Mid
3. Low Impact	Full Capital Recovery	Additional conversion, low hydro, low fuel escalation, high additional imports.	Conser-vation Target (-0.7%/ year growth rate)	High	High	Low	High	Aging Effect/ High Cost Escalation

3. COSTS BY MAJOR CATEGORY

3.1 Introduction

This section describes our assumptions and results for each of the major cost categories considered. In all cases, the results are generated by the CANS system as documented in Appendix A. Supplementary modeling and analysis were performed in developing various input values. These efforts are identified below where reference is made to supporting technical appendices and documents.

The costs are consistently reported in discounted (or "present worth") 1981 dollars. This is the conventional approach to comparing dollar outlays (or savings) that occur at different points over a given time interval. A dollar today is worth more than a future dollar because of its earning power in the intervening years. Future impacts are brought back to a common year's currency in this study by discounting future nominal cost estimates ("current" dollars) at 12 percent per year. The average rate of inflation is taken at 8 percent per year, so the "real" discount rate is four percent above inflation. We analyze the effects of other discount rate assumptions in Section 4. It should be further noted that the dollar impact estimates consistently reflect an allowance for Con Ed revenue taxes taken at 4 percent overall (PASNY as a public authority pays no such taxes).

3.2 Make-Up Generation

3.2.1 Scenario Definitions

In the event of an early retirement, other power sources must supply the electrical energy that would have been produced by the Indian Point units. These sources could include running less economical units in the system more than they otherwise would have been run; importing more energy from outside the system; or investing in new generation facilities. In principle, it could also include utility investment in conservation and improved end-use equipment efficiency, though we have not considered this option for substitute power in the scenarios in the Indian Point case study. Make-up generation costs, then, are the costs of substitute power caused by the need to adjust and to re-dispatch the downstate Con Edison/PASNY generation system if the Indian Point units are not present. It is generally agreed that these costs are likely to be substantial in calculating the economic impact on utility ratepayers of an Indian Point closing.

3.2.2 Demand Growth

Demand growth scenarios were based upon our June, 1981, study for the New York City Energy Office.(7) This was a detailed study of the Con Ed and downstate PASNY generation system. The study developed a long-range Base Case forecast of electric energy and peak demand for the Con Ed region.

This long-range planning forecast is the one connoted by the term "Base Case" in Table 3 and used as the demand forecast in the High Impact scenario generation analyses.

Our June, 1981 study also developed a conservation scenario consisting of conservation measures and levels that were technically feasible and cost-effective compared to energy supply. A Conservation Case load forecast was prepared to calculate the year-by-year electric energy consumption and peak demand for the Con Ed region assuming implementation of the conservation scenario. In the Low Impact scenarios, we assumed full implementation of this conservation scenario, independently of whether or not the Indian Point units are retired early.

A systematic generation dispatch study was performed to develop make-up power cost scenarios for input to the CANS nuclear retirement cost assessment system. An economic dispatch model, SYGEN, was used to perform six generation system dispatch runs.* The six dispatch runs consist of High-Impact, Mid-Range, and Low-Impact Cases, each with and

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*A dispatch model provides a computer simulation of the operation of an electric generation system as a function of demand, based on specified economic and operating characteristics for each available type of generating station. Plants with the lowest unit variable cost run first, with higher cost units being added as needed to meet demand. SYGEN documentation is provided in our June, 1981 study for the New York City Energy Office.

ESRG

TABLE 3

MAKE-UP GENERATION SCENARIO DEFINITIONS

Scenario:	Demand Level	Ravenswood 1&2 Coal Conversion	Oil Price Escalation Rate (Real)*	Coal Price Escalation Rate (Real)	Availability of Canadian Imports to Con Ed Region**	Indian Point Capacity Factors
1. High-Impact						
a. Indian Point On	Base Case	No	4%	2%	42%	High
b. Indian Point Shut-down	Base Case	No	4%	2%	47%	--
2. Mid-Range						
a. Indian Point On	50% Conservation	No	2%	1%	42%	Mid-Range
b. Indian Point Shut-down	50% Conservation	Yes, in 1990,91	2%	1%	52%	--
3. Low-Impact						
a. Indian Point On	100% Conservation	No	0%	0%	42%	Low
b. Indian Point Shutdown	100% Conservation	Yes, in 1987	0%	0%	57%	--

* To these fuel prime escalation rates, 8 percent general inflation must be added.

** Measured as percentage of the non-firm Canadian power expected to come to the entire New York State Power Pool, which is 8,000 GWH for 1982-83, and 15,000 GWH for 1984-2000. Extra New York Power Pool imports are also available at higher cost according to dispatch requirements.

without the Indian Point units.[10] The annual replacement power costs for any single scenario were then obtained by subtracting the dispatch for the results with Indian Point from the results without the units operating. The specific assumptions that were employed in creating the six generation system dispatch runs are detailed in Table 3. Let us review these assumptions -- on demand growth, coal conversion, fossil fuel escalation rates, the availability of Canadian power, and Indian Point capacity factors -- in turn.

In the Mid-Range scenario, fifty percent implementation of the conservation scenario was used. Thus, demand levels in the Mid-Range scenario are precisely halfway between the demand levels of the bracketing scenarios.

3.2.3 Coal Conversion

With regard to coal conversion, the Mid-Range scenario reflects the fact that an Indian Point shutdown should make the coal conversion options more attractive to NYS regulators and to Con Edison, so that the conversion of Ravenswood #1 and #2 is assumed to be added to their present conversion program. Such conversions would improve the downstate security of the transmission system. The 1990 and 1991 conversion dates for these units are Con Edison assumptions on the feasible conversion dates.[11] The conversion of these units was also included in the 1981 State Energy Master

Planning report "Full Implementation Scenario" for conversion, though not in the basic "Electricity Supply Plan".[12] This conversion is presently supported by the New York City Office as an important oil replacement option.

It is possible, though not likely, that these conversions would not occur in the event of an Indian Point shutdown. In the High Impact scenario, the conversions are assumed not to take place.

In our June, 1981 study we made independent estimates for cost and operating characteristics relevant to the conversion of Ravenswood 1 and 2. Our study found that even with scrubbers included in the cost of conversion to coal, it is cost-effective to convert the units from oil. Our analysis found that it was feasible to convert them by 1987.[7] These results informed development of our Low Impact scenario, where we assumed that early retirement would cause the Ravenswood conversions to occur in 1987, as shown in Table 3.

3.2.4 Fuel Cost Escalation

The scenario fuel price assumptions reflect the uncertainty surrounding likely future oil and coal prices. We have assumed that in real terms (above an overall 8 percent inflation rate) oil price escalation rates would range between 0 and 4 percent, and that real coal price escalation rates would range between 0 and 2 percent over the next 20

years. These price assumptions bracket the fuel price assumptions that Con Edison recently used to calculate the costs of replacement power for the Indian Point units.(14)

3.2.5 Canadian Power Availability

The three basic make-up generation scenarios are distinguished by differing assumptions on the future availability of Canadian power imports into the downstate Con Edison/PASNY system. Canadian imports are projected by the NYPP to come from both Hydro Quebec (HQ) and Ontario Hydro (ONHY) in the following amounts at the statewide level:(15)

NYPP Canadian Import Assumptions
(GWH)

Years	HQ	ONHY	Total Statewide
1982-83	8,000	3,000	11,000
1984-96	12,000	6,000	18,000

It was necessary to project the portion of these projected imports that would be available to the Con Ed and downstate PASNY systems. Based on a firm power contract of 780 MW, Con Ed is already entitled to some 3,000 GWH throughout the period. The question is thus what portion of the remaining 8,000 (1982-3) and 15,000 (1984-96) GWH to allocate the downstate systems in the various cases and scenarios. In the no-shutdown case, we assumed that 42 percent of the non-firm import power would be available. (This is

approximately the portion of the non-firm power that went to Con Ed in 1981.)

In the shutdown scenario dispatch runs it was assumed that 5, 10, and 15 percent more Canadian power would be available downstate to both Con Edison and PASNY, in the High, Mid-Range, and Low Impact cases, respectively. These values derive from the assumption that some redistribution of PASNY Canadian power would occur throughout NYPP due to: (1) a reallocation of Canadian power between upstate and downstate, (2) the change in the dispatch of the NYS Power Pool and (3) the role of state regulators in allocating power to alleviate the impacts of an Indian Point shutdown. The average price for the Canadian imports in the base year 1981 was taken from Con Edison data to be $36.40 per MWH.(16)

In addition to Canadian power, higher priced NYPP power would be available to the downstate region if needed.(17) When Indian Point is assumed closed in 1983, then, some of the replacement generation comes from NYPP members, some from Con Edison's and PASNY's own plants, and some from Canadian imports. The more technically inclined reader may find it instructive to compare the sample Mid-Range Case dispatch model output given for 1990 for both the shutdown (MR1) and no shutdown (MKL) cases provided in Appendix F below.

One important consideration in modeling the costs of make-up generation is the extent to which transmission

constraints exist from the upstate region (including Canada) to the downstate Con Edison/PASNY service territory. This is a complex subject with little published analytic material. However, several points can be made. First, transmission line improvements in 1984 and 1986 are currently scheduled. This will so significantly improve the capacity of the downstate interconnection, as well as the upstate NYPP interconnection to Canada, that after 1986 transmission constraints will be minimal. Second, if the Indian Point units are no longer operational, some additional capacity on the interconnection to upstate from New York City will be available prior to 1986. Indeed, Con Edison's dispatch analysis of the transmission constraints to the upstate region and their impact on the sources of energy to replace Indian Point indicates that there is considerable additional capability on these lines even in 1983.(19)

3.2.6 Power Plant Capacity Factor Assumptions

The quantity of replacement power required is directly proportional to the capacity factors of IP-2 and IP-3. The capacity factor scenario assumptions for the Indian Point units for each year of planned operation were developed on the basis of the units' historical experience, a review of the literature on nuclear plant capacity factors, and independent analyses conducted during the course of this investigation. The capacity factor represents the fraction

of time a unit is available at equivalent full rated capacity. Three capacity factor scenarios were employed -- High Impact, Mid-Range, and Low Impact cases, embodying high, medium, and low predicted future performance of each of the two Indian Point units.

The multivariate regression analysis presented in Appendix C provides a model of nuclear power plant performance (capacity factor) as measured by a number of explanatory variables. Among these variables are the unit's size (maximum dependable capability), type [pressurized water reactor (PWR) or boiling water reactor (BWR)], age (years of commercial operation), and whether or not cooling towers or salt-water cooling are used.

One significant implication of that analysis is that large salt-water cooled PWR nuclear units like the Indian Point units can be expected to exhibit strongly deteriorating performance after their first several years of operation. Application of the regression equation developed in our capacity factor analysis to the Indian Point units clearly shows this same general trend. We did not, however, directly apply the regression equation in developing our scenarios for future capacity factors, for the application of statistical results describing the historical experience of essentially all operating nuclear units in the U.S. to a particular unit must be made with caution. It is nonetheless obligatory, in an economic evaluation such as the

present one or, for that matter, in any utility capacity planning analysis, to make estimates of the future capacity factors. The regression analysis presented in Appendix C certainly did provide an important guideline in our development of capacity factor scenarios for the Indian Point units.

Figures 1 and 2 show the High Impact, Mid-Range, and Low Impact capacity factor scenarios that were summarized in Table 3 for each of the Indian Point units. For comparison, the results of the regression equation as well as actual experienced capacity factors are also shown on the graph. All three of the scenarios chosen for this study assume better future performance than the regression analysis would indicate. Each scenario takes the actual operating experience for the units as a point of departure. The High Impact and Mid-Range cases assume that each unit's capacity factor for 1982 will be equal to its historic average, thus smoothing out the quite substantial fluctuations evidenced by the data points on the graphs. These initial values are 55 percent and 53 percent for IP-2 and IP-3, respectively. In the Low Impact case, the 1982 capacity factor values are those predicted for that year by the ESRG regression analysis. These results are 45 percent and 50 percent, respectively, for Indian Point units #2 and #3.*

*The 1980-81 average capacity factors for these units is 48 percent and 36 percent, respectively.

Figure 1

INDIAN POINT 2
CAPACITY FACTOR SCENARIOS

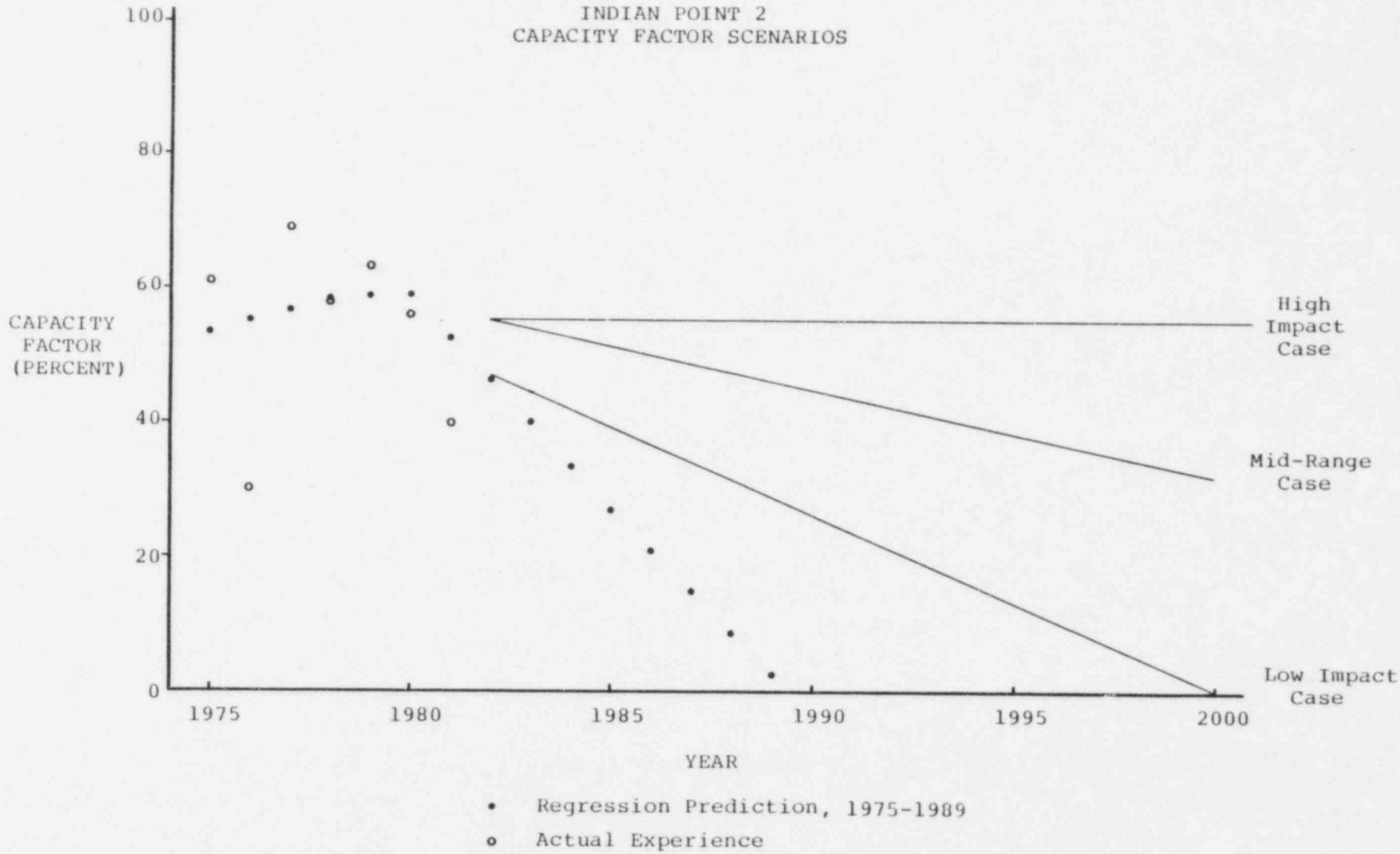
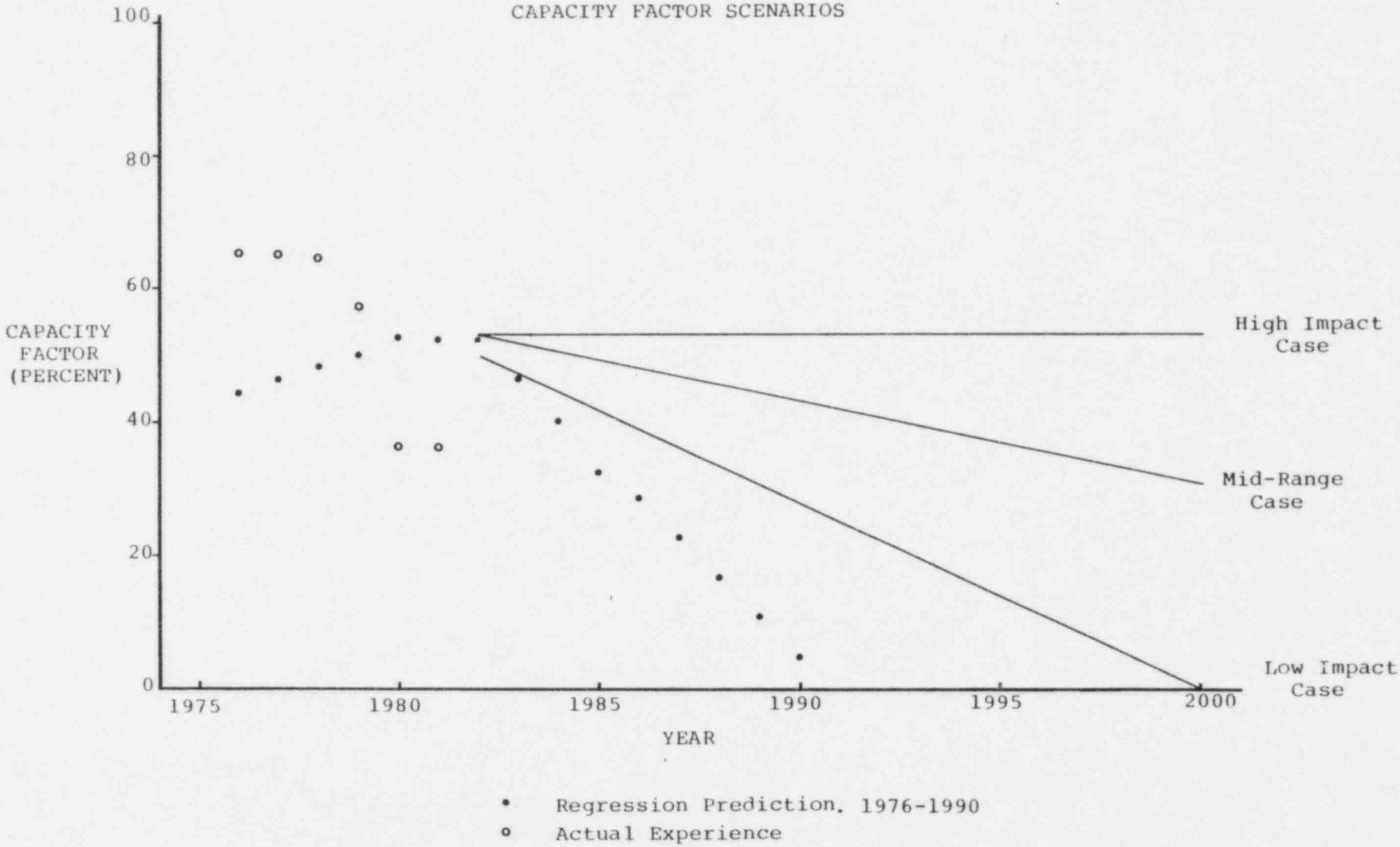


Figure 2

INDIAN POINT 3
CAPACITY FACTOR SCENARIOS



In the High Impact case no aging effect is assumed for either of the Indian Point units. The units are assumed to maintain their historic average capacity factors of 55 percent and 53 percent, respectively. Given our statistial results showing declining capacity factors for salt-water cooled PWRs, this scenario, while quite possible, does not appear to be likely. Con Edison and PASNY have assumed that both units will achieve 69 percent capacity factors for their remaining years of planned operation, but our studies lead to the conclusion that this assumption is too optimistic (even as a High Impact input).

In the Mid-Range case we have assumed that beginning in 1982 the capacity factors for the Indian Point units will decline linearly with age. Rather than the very rapid decline indicated by the results of our regression analysis of nuclear plant operating experience, we have assumed a more cautious rate of deterioration in performance, with capacity factors reaching 20 percent by the 35th year of operation.(21)

Finally, in the Low Impact case we have followed the regression analysis results somewhat more closely. We have assumed that the capacity factors will reach zero by the year 2000. This is less than half the rate of drop-off predicted by the regression equation. In the year 2000, the average age of the two Indian Point units will be twenty-five years. Of course, thus far there has been no

experience of nuclear units remaining in operation for 25 years. In contrast, some reactors have been shut down before 15 years of operation. Given this history of actual early shutdowns and the strong results of the regression analysis, the capacity factor assumptions in the Low Impact case appear to be quite possible on an average basis (where some reactors may last for 30 to 35 years, while others may last only 15 to 20 years).

3.2.7 Make-Up Power Cost Summaries

The cost components of the make-up generation are presented in current dollars for the three scenarios in Tables 4, 5, and 6. The column labeled "Fuel Cost" represents the differential fuel costs for the Con Edison/PASNY system between the shutdown and no shutdown cases. The column labelled "O&M Cost" represents the differential variable O&M and purchased power costs again due to re-dispatch of the generation system in case of an Indian Point shutdown in 1983. The "Working Capital" values represent the additional working capital changes to ratepayers due to the increased level of fuel usage. The average rate appropriate to Con Edison and PASNY was assumed to be 2 percent of fuel costs annually. The "New Capital" column takes account of the annualized charges to ratepayers of the capital costs required to convert Ravenswood #1 and #2 to coal in the Mid-Range and Low Impact scenarios. The O&M cost column

TABLE 4

MAKE-UP POWER REPORT -- MID-RANGE
(Millions of Current Dollars)

Year	Fuel Cost	O&M* Cost	Working Capital	New Capital	Total Cost
1983	359.365	174.969	7.187	0.0	541.520
1984	338.594	189.656	6.772	0.0	535.021
1985	356.177	211.021	7.124	0.0	574.321
1986	134.427	160.229	2.689	0.0	297.344
1987	349.594	285.760	6.992	0.0	642.345
1988	364.562	303.552	7.291	0.0	675.405
1989	391.146	329.104	7.823	0.0	728.073
1990	321.094	390.677	6.422	194.524	912.716
1991	-79.000	247.125	-1.580	217.777	384.322
1992	215.583	387.500	4.312	222.167	829.561
1993	210.052	413.917	4.201	226.945	855.114
1994	202.135	442.292	4.043	232.136	880.606
1995	199.594	476.625	3.992	237.843	918.053
1996	194.583	513.198	3.892	244.037	955.710
1997	184.417	554.510	3.688	250.842	993.456

*Includes purchased power.

TABLE 4

MAKE-UP POWER REPORT -- MID-RANGE
(Millions of Current Dollars)

Year	Fuel Cost	O&M* Cost	Working Capital	New** Capital	Total*** Cost
1983	359.365	174.969	7.187	0.0	541.520
1984	338.594	189.656	6.772	0.0	535.021
1985	356.177	211.021	7.124	0.0	574.321
1986	134.427	160.229	2.689	0.0	297.344
1987	349.594	285.760	6.992	0.0	642.345
1988	364.562	303.552	7.291	0.0	675.405
1989	391.146	329.104	7.823	0.0	728.073
1990	321.094	390.677	6.422	194.524	912.716
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1992	215.583	387.500	4.312	222.167	829.561
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1994	202.135	442.292	4.043	232.136	880.606
1995	199.594	476.625	3.992	237.843	918.053
1996	194.583	513.198	3.892	244.037	955.710
1997	184.417	554.510	3.688	250.842	993.456

*Includes purchased power.

**Composed of capital costs and incremental fixed O&M costs of coal conversion.

***All costs include revenue taxes at 4%.

TABLE 5

MAKEUP POWER REPORT -- HIGH IMPACT
(Millions of Current Dollars)

Year	Fuel Cost	O&M* Cost	Working Capital	Total** Cost
1983	394.187	175.021	7.884	577.092
1984	412.844	190.573	8.257	611.673
1985	451.927	227.166	9.039	688.132
1986	437.281	315.510	8.746	761.537
1937	490.271	348.323	9.805	848.399
1988	539.104	392.406	10.782	942.292
1989	603.448	442.635	12.069	1,058.152
1990	675.219	498.073	13.504	1,186.795
1991	755.437	560.500	15.109	1,331.046
1992	845.156	630.771	16.903	1,492.829
1993	945.489	709.865	18.910	1,674.263
1994	1,057.604	797.865	21.152	1,876.620
1995	1,183.000	896.719	23.660	2,103.378
1996	1,323.532	1,007.469	26.471	2,357.471
1997	1,464.167	1,150.104	29.283	2,643.554

*Includes purchased power.

**All costs include revenue taxes at 4%.

TABLE 6

MAKEUP POWER REPORT -- LOW IMPACT
(Millions of Current Dollars)

Year	Fuel Cost	O&M* Cost	Working Capital	New** Capital	Total*** Cost
1983	275.240	158.938	5.505	0.0	439.682
1984	217.698	173.771	4.354	0.0	395.823
1985	214.604	182.552	4.292	0.0	401.448
1986	55.271	138.198	1.105	0.0	194.574
1987	97.208	235.198	1.944	167.647	501.997
1988	-111.604	96.562	-2.232	170.683	153.409
1989	22.615	184.979	0.452	174.033	382.078
1990	-6.656	184.667	-0.133	177.687	355.564
1991	-35.719	185.552	-0.714	181.672	330.791
1992	-75.146	182.000	-1.503	186.062	291.413
1993	-114.823	179.719	-2.296	190.840	253.439
1994	-159.781	175.990	-3.196	196.032	209.044
1995	-211.406	169.198	-4.228	201.738	155.301
1996	-278.083	155.281	-5.562	207.933	79.569
1997	-345.562	142.135	-6.911	214.737	4.399

*Includes purchased power.

**Composed of capital costs and fixed O&M costs of coal conversion.

***All costs include revenue taxes at 4%.

also includes the increase in fixed O&M that results from coal burning at Ravenswood when compared to oil burning.*

The total annual make-up generation costs from 1983-1997 in discounted 1981 dollars for all three scenarios are presented in Table 6. The sum for the Mid-Range Impact scenario is $3.91 billion, with the High Impact value at $6.49 billion and the Low Impact value at $1.95 billion. Thus these costs are both quite substantial and quite sensitive to the assumptions listed in Table 3.

3.3 Direct Capital-Related Costs

In this section, we will discuss the effect of past investments in the Indian Point units on future revenue requirements. As always, our attention will be focused on differential costs, that is, the change in costs that can be attributed to early retirements.

For PASNY, the primary capital cost component is the interest and principal payments on the bonds issued to finance IP-3. But because PASNY electric revenues will invariably be used to service the bonds, we assumed no differential costs or benefits from retirement. One differential cost factor considered was nuclear liability

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* We remind the reader that make-up generation costs generally reported in other studies subtract out the appropriate savings for nuclear fuel, nuclear O&M, and spent nuclear fuel disposal.(20) However, in this study these items (and their costs) are treated separately.

insurance, which we assumed was not to be incurred after the retirement date. Based on information supplied by PASNY, this insurance cost was taken to be $453,000 in 1981 and was assumed to increase at a rate of 9 percent per year.

The capital cost module described in Appendix A section A3 was employed in developing differential capital costs for Con Ed's IP-2. The major data items employed in this analysis are shown in Table 7. Estimates for original cost and tax credits were supplied by Con Ed. AFDC was assumed to be 20 percent of original cost.

Under retirement, it is assumed in the Mid-Range and High Impact cases that Con Ed will be allowed to amortize its remaining Indian Point investment over a twenty year period and to earn its average rate of return on the unamortized balance. In the Low Impact case, it is assumed that the plant will be more quickly amortized, over ten years, but that no return will be earned.

In Table 8, sample computer output of the capital cost module for Con Ed under "Keep" assumptions is shown. In Table 9, output of costs under retirement is shown. Table 10 displays the complete 1983-1997 time stream of relative impacts for the three scenarios in discounted dollars. Beyond the nuclear liability insurance adjustments, the major impacts result from the earlier tax write-off schedule of plant costs when a plant is retired.

TABLE 7

DATA USED IN DEVELOPING CAPITAL-RELATED COSTS
FOR CON ED INDIAN POINT 2

Data Item	Value
Original Cost (including AFDC)	\$363,741,000
AFDC	\$ 72,748,000
Tax Credits	\$ 15,657,000
Book Life	33 years
Tax Life	16 years
Tax Depreciation Method	Sum of Years' Digits
Income Tax Rate	46%
Other Annual Cost	\$2,619,000 in 1981 escalating at 9% per year

TABLE 8

CAPITAL COSTS OF CONTINUED OPERATION

CON ED

(MILLIONS OF DOLLARS)

YEARS ---	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990
ANNUAL BOOK DEPR.	11.022	11.022	11.022	11.022	11.022	11.022	11.022	11.022	11.022	11.022
NET VALUE (BOOK DEPR.)	308.629	297.606	286.583	275.561	264.539	253.516	242.494	231.471	220.449	209.427
ANNUAL TAX DEPR.	23.536	21.397	19.257	17.117	14.978	12.838	10.698	8.559	6.419	4.279
NET VALUE (TAX DEPR.)	141.217	117.681	96.284	77.028	59.910	44.933	32.095	21.397	12.838	6.419
S.L. DEPR. FOR NORM. TA	8.818	8.818	8.818	8.818	8.818	8.818	8.818	8.818	8.818	8.818
OTHER COSTS	2.619	2.855	3.112	3.392	3.697	4.030	4.392	4.788	5.219	5.688
REVENUE TAX	2.428	2.333	2.244	2.157	2.075	2.002	1.934	1.871	1.816	1.767
TAX CREDIT ANN. AMORT.	0.474	0.474	0.474	0.474	0.474	0.474	0.474	0.474	0.474	0.474
TAX CREDIT RESERVE	13.285	12.810	12.336	11.861	11.387	10.912	10.438	9.964	9.489	9.015
DEFFERED TAXES	6.770	5.786	4.802	3.818	2.833	1.849	0.865	-0.119	-1.104	-2.088
AFDC-DEBT TAX AMORT.	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DEFFERED TAX RESERVE	48.616	55.386	61.172	65.974	69.792	72.625	74.474	75.339	75.220	74.116
RATE BASE	251.117	233.816	217.499	202.167	187.819	174.456	162.076	150.681	140.270	130.843
RETURN TO EQUITY	18.080	16.835	15.660	14.556	13.523	12.561	11.669	10.849	10.099	9.421
RETURN TO PREFERRED	1.657	1.595	1.531	1.468	1.405	1.362	1.301	1.243	1.188	1.123
RETURN TO BONDS	7.071	6.996	6.890	6.672	6.446	6.218	5.990	5.702	5.431	5.181
TAXABLE INCOME	25.037	24.754	24.600	24.578	24.688	24.968	25.344	25.856	26.506	27.267
INCOME TAX	11.517	11.387	11.316	11.306	11.357	11.485	11.658	11.894	12.193	12.543
REQUIRED REVENUES	60.691	58.334	56.104	53.915	51.884	50.055	48.359	46.775	45.390	44.183
P.V. FACTOR TO 1981	1.000	0.893	0.797	0.712	0.636	0.567	0.507	0.452	0.404	0.361
P.V. OF REQ. REVENUES	60.691	52.084	44.725	38.376	32.973	28.403	24.500	21.159	18.332	15.933

TABLE 9

CAPITAL COSTS AFTER RETIREMENT

CON ED

(MILLIONS OF DOLLARS)

YEARS ---	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992
ANNUAL BOOK DEPR.	8.439	8.439	8.439	8.439	8.439	8.439	8.439	8.439	8.439	8.439
NET VALUE (BOOK DEPR.)	168.785	160.346	151.906	143.467	135.028	126.589	118.149	109.710	101.271	92.832
ANNUAL TAX DEPR.	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NET VALUE (TAX DEPR.)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
S.L. DEPR. FOR NORM. TA	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
OTHER COSTS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
REVENUE TAX	1.872	1.821	1.768	1.715	1.660	1.602	1.542	1.481	1.420	1.359
TAX CREDIT ANN. AMORT.	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
TAX CREDIT RESERVE	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DEFFERED TAXES	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
AFDC-DEBT TAX AMORT.	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DEFFERED TAX RESERVE	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
RATE BASE	164.565	156.126	147.687	139.247	130.808	122.369	113.930	105.491	97.051	88.612
RETURN TO EQUITY	11.849	11.241	10.633	10.026	9.418	8.811	8.203	7.595	6.988	6.380
RETURN TO PREFERRED	1.159	1.133	1.105	1.088	1.050	1.010	0.965	0.905	0.854	0.790
RETURN TO BONDS	5.213	5.152	5.069	4.963	4.835	4.630	4.411	4.177	3.929	3.704
TAXABLE INCOME	39.716	38.544	37.365	36.208	35.014	33.814	32.606	31.370	30.150	28.905
INCOME TAX	18.269	17.730	17.188	16.656	16.107	15.554	14.999	14.430	13.869	13.296
REQUIRED REVENUES	46.801	45.517	44.202	42.887	41.509	40.046	38.560	37.028	35.499	33.968
P.V. FACTOR TO 1981	0.797	0.712	0.636	0.567	0.507	0.452	0.404	0.361	0.322	0.287
P.V. OF REQ. REVENUES	37.310	32.398	28.091	24.335	21.030	18.115	15.574	13.353	11.430	9.765

TABLE 10

CAPITAL COSTS IMPACTS
(Million 1981 Discounted Dollars)

Year	Scenario: High Impact	Mid-Range	Low Impact
1983	-7.8	-7.8	-19.2
1984	-6.4	-6.4	-15.6
1985	-5.3	-5.3	-12.7
1986	-4.5	-4.5	-10.3
1987	-3.9	-3.9	-8.4
1988	-3.4	-3.4	-6.8
1989	-3.2	-3.2	-5.6
1990	-3.0	-3.0	-4.5
1991	-2.9	-2.9	-3.7
1992	-2.9	-2.9	-3.2
1993	-2.7	-2.7	-11.1
1994	-2.7	-2.7	-9.8
1995	-2.7	-2.7	-8.7
1996	-2.6	-2.6	-7.7
1997	-2.6	-2.6	-6.8
TOTAL	-56.6	-56.6	-134.0

3.4 Nuclear Fuel

As described in Section 3.2, an early shutdown would incur the costs of substitute power. On the other hand, savings would result from avoiding expenditures for nuclear power production. One such avoided expenditure consists of nuclear fuel costs.

Nuclear fuel expenditures can be treated simply on a cost-per-KWH basis. The 1981 nuclear fuel costs were taken at 4.9 and 5.4 mills per KWH for IP-2 and IP-3, respectively. These are based on gross values provided by Con Ed and PASNY from which were deducted the costs collected for waste storage (about 2.1 mills per kwh). Waste storage costs were treated separately in this study.

For the High Impact, Mid-Range, and Low Impact scenarios, these 1981 nuclear fuel costs per KWH were increased by real escalation rates of 0 percent, 1 percent, and 2 percent, respectively.(23) In addition, a nuclear fuel "working capital" charge was included because nuclear fuel is capitalized by utilities. This capital charge amounts to 34 percent of the fuel costs so capitalized.(24) Table 11 shows the running costs for the Mid-Range case. Table 12 gives the discounted cost impacts for the three scenarios.

3.5 Operation and Maintenance Costs

Annual operation and maintenance (O&M) costs for the two Indian Point nuclear units were estimated for each of their

TABLE 11

NUCLEAR FUEL COST -- MID-RANGE CASE
(Current Dollars)

Year	Unit 1 Generation (GWH)	Unit 1 Unit Cost (Mills/KWH)	Unit 1 Total Cost ($ Millions)	Unit 2 Generation (GWH)	Unit 2 Unit Cost (Mills/KWH)	Unit 2 Total Cost ($ Millions)	Combined Total Cost ($ Millions)
1981	4,162.75	6.84	28.471	4,480.30	7.54	33.770	62.242
1982	4,162.75	7.46	31.034	4,480.30	8.22	36.810	67.843
1983	4,087.06	8.13	33.212	4,395.77	8.96	39.365	72.577
1984	3,935.69	8.86	34.860	4,311.23	9.76	42.083	76.943
1985	3,860.01	9.65	37.267	4,226.70	10.64	44.971	82.238
1986	3,784.32	10.52	39.824	0.0	11.60	0.0	39.824
1987	3,708.63	11.47	42.540	3,973.10	12.64	50.224	92.764
1988	3,557.26	12.50	44.476	3,888.56	13.78	53.579	98.056
1989	3,481.57	13.63	47.447	3,804.03	15.02	57.132	104.579
1990	3,405.89	14.85	50.593	3,719.49	16.37	60.890	111.483
1991	0,.0	16.19	0.0	3,634.96	17.84	64.861	64.861
1992	3,178.83	17.65	56.103	3,550.43	19.45	69.055	125.157
1993	3,103.14	19.24	59.696	3,381.36	21.20	71.685	131.381
1994	2,951.77	20.97	61.894	3,296.82	23.11	76.183	138.078
1995	2,876.08	22.86	65.735	3,212.29	25.19	80.911	146.646
1996	2,800.40	24.91	69.765	3,127.76	27.45	85.872	155.637
1997	2,724.71	27.15	73.989	3,043.22	29.93	91.070	165.059
1998	2,573.34	29.60	76.167	2,958.69	32.62	96.509	172.677
1999	2,497.65	32.26	80.580	2,874.15	35.55	102.189	182.770
2000	2,421.96	35.17	85.171	2,705.09	38.75	104.834	190.005
TOTAL	63,273.76		1,018.824	69,486.87		1,261.994	2280.819

TABLE 12

NUCLEAR FUEL IMPACTS
(Million 1981 Discounted Dollars)

Year	Scenario: High Impact	Mid-Range	Low Impact
1983	-57.9	-57.9	-50.4
1984	-55.8	-54.8	-46.2
1985	-53.8	-52.3	-43.2
1986	-51.9	-22.6	-16.6
1987	-50.0	-47.0	-35.9
1988	-48.3	-44.4	-19.1
1989	-46.5	-42.2	-29.6
1990	-44.9	-40.2	-26.2
1991	-43.3	-20.9	-23.2
1992	-41.7	-36.0	-20.0
1993	-40.2	-33.7	-17.3
1994	-38.8	-31.6	-14.7
1995	-37.4	-30.0	-12.2
1996	-36.1	-28.4	-9.3
1997	-34.8	-26.9	-6.9
TOTAL	-681.3	-568.9	-370.7

future years of planned commercial operation. Historical data on the units' O&M cost experience were used in developing the estimates.

These data on IP-2 and IP-3 were complemented by an independent analysis of the O&M costs experienced by 49 commercially operating nuclear power plants during and before 1979 (described fully in Appendix B).

Actual experience shows that O&M costs for nuclear units have been increasing at rates generally far in excess of the rate of inflation. A simple exponential fit to the historical O&M cost experience of each of 49 nuclear units shows that more than 60 percent have incurred costs escalating at rates between 10 and 30 percent above inflation over their years of commercial operation (see Table B-19).

A regression analysis was performed to relate historical O&M costs for commercially operating nuclear generating stations to a number of explanatory variables. The explanatory factors include unit size, age, and in-service date, as well as several variables expressing the type of units (BWR or PWR) and whether they have cooling towers, use salt water for cooling, are located in the Northeast, are demonstration plants, or have two or more units at the station. This regression analysis is detailed in Appendix B.

In the regression analysis, two types of specification in the age (years of operation) variables were explored, linear and exponential. They were found to have comparable

explanatory power for the historical data. Given these results one would expect that a plausible choice for nuclear O&M cost escalation would lie somewhere between the linear and exponential predictions. However, since the exponential form predicts a much more rapid escalation in the future, diverging strongly from the linear result, it was not used in the present study (as an exercise of caution).

The O&M cost scenarios developed for the present study begin with 1981 costs for the Indian Point generating station derived from a simple linear least squares fit to their historically experienced costs. This procedure ensures that any fluctuations in this experience are smoothed out so that a suitable starting point from which future escalation begins is established. The station 1981 O&M costs thus derived are $58.66 per KW or $107.3 million (in 1981 dollars). A similar estimate of the O&M costs based upon historical experience was made by the General Accounting Office (25). The GAO estimate, when corrected for inflation from 1979 to 1981, becomes about $71 million. By contrast, Con Edison has estimated 1983 O&M costs for the station to be about $41 million.

O&M costs for the remaining years of planned commercial operation of the Indian Point generating units were obtained by using the linear regression equation (Appendix B, Table B-11), applied to Indian Point, to obtain the ratios of future years' real-dollar O&M costs per KW to the base

year (1981) value given above. These ratios provide real dollar O&M costs for all subsequent operating years. This procedure is employed in both the Mid-Range and Low Impact cases. For the High Impact case the real O&M cost escalation is taken to be 75 percent of that given by the linear regression equation. Thus, in the present study, three O&M cost scenarios are employed -- High Impact, Mid-Range, and Low Impact -- embodying low, medium, and high escalation rates, respectively.

The O&M cost projections for the Indian Point generating station are presented in Table 13 in constant dollars for the three scenarios. It can be seen in these tables that while per KW costs escalate smoothly, there are some years in which total station costs drop sharply. This occurs because in the Mid-Range and Low Impact cases, where it is assumed that steam generators are replaced once during each of the units' planned operating lives, no O&M costs are incurred during the period when replacement is being effected.

3.6 Radioactive Waste Disposal

The several year stay of nuclear fuel assemblies in the nuclear reactors themselves is but one phase in the "nuclear fuel cycle." The preparatory phases include mining and milling of uranium, conversion of uranium oxide into gaseous uranium hexafluoride, enrichment (increasing the concentra-

TABLE 13

NUCLEAR O&M IMPACTS
(Million 1981 Discounted Dollars)

	Scenario		
Year	High Impact	Mid-Range	Low Impact
1983	-109.9	-113.4	113.4
1984	-110.8	-115.9	-115.9
1985	-111.3	-118.1	-118.1
1986	-111.6	-56.6	-56.6
1987	-111.6	-121.4	-121.4
1988	-111.5	-122.6	-64.7
1989	-111.2	-123.6	-123.6
1990	-110.6	-124.3	-124.3
1991	-110.0	-65.8	-124.8
1992	-109.2	-125.1	-125.1
1993	-108.3	-125.2	-125.2
1994	-107.3	-125.1	-125.1
1995	-106.1	-124.8	-124.8
1996	-104.9	-124.4	-124.4
1997	-103.7	-123.9	-123.9

tion of the fissionable U-235 isotope of uranium), and fabrication of reactor-ready fuel elements consisting of zirconium tubes containing pellets of uranium dioxide. A portion of the "front-end" costs are reflected in rates through the nuclear fuel charges discussed in Section 3.4 above. Other social costs related to federal subsidies of nuclear fuel technologies and environmental impacts are beyond the scope of the quantitative analysis in this investigation. (See Section 5 for more discussion of indirect costs.)

In this subsection, costs associated with the "back-end" of the nuclear fuel cycle concern us. Until several years ago, it was assumed that spent fuel rods would, after several months in temporary storage to undergo initial radioactive decay, be reprocessed with uranium and plutonium extracted for re-use in conventional or breeder reactors. This "ideal" scheme is depicted in Figure 3(a). Spent fuel discharged from reactors contains substantial quantities of unburned uranium and plutonium. In the conventional judgment, it would be uneconomical not to recover these fuels. However, reprocessing of spent fuel has proved to be more technically complex and costly than anticipated by the nuclear industry. In addition, sensitivity to the dangers of nuclear weapons proliferation through use of reactor grade plutonium has raised further doubts about the reprocessing option and it has been indefinitely deferred.

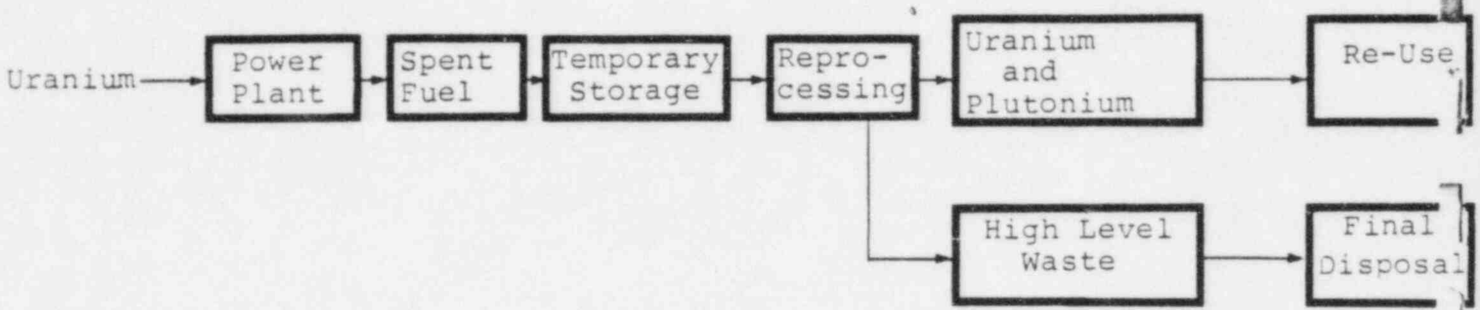
Until the last few years, research and development efforts assumed that highly radioactive wastes would be reprocessed. But in the absence of reprocessing, the spent fuel itself must be treated as the ultimate waste product. Not surprisingly, there is currently a good deal of uncertainty on the technologies, timing, and costs facing utilities over the next several decades as waste disposal burdens mount.

A detailed technical discussion on waste disposal alternatives is the subject of Appendix D. A schematic of the back-end of the nuclear fuel cycle that appears to be actually in the offing is presented in Figure 3(b). The temporary on-site storage pools have indefinitely become repositories for virtually all discharged fuel produced by commercial reactors. But the limited capacity of these pools allows them to accept only a fraction of spent fuel produced over the life of a reactor. The space available can be increased through fuel assembly "reracking" procedures, but this at best extends the time until existing pools are filled to capacity (until the late 1980's and early 1990's for most reactors).

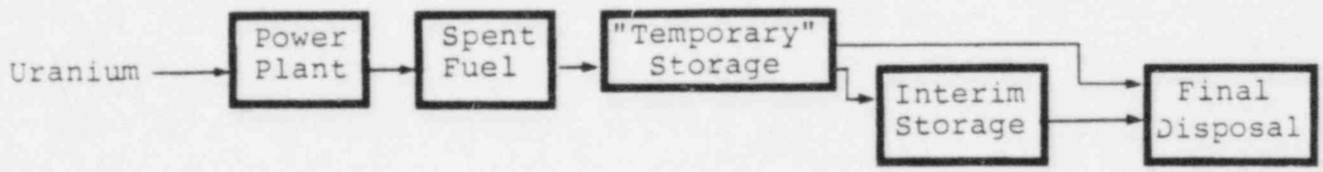
On the other hand, a workable solution to the "permanent" disposal of irradiated nuclear fuel is not in sight. Substantial problems remain regarding the selection of a viable storage technology which satisfactorily addresses environmental, social, and political concerns in an economi-

Figure 3

BACK-END OF NUCLEAR FUEL CYCLE



a) "Ideal"



b) Actual

cally acceptable manner. A federal disposal site cannot realistically be expected to be in operation until some time after the turn of the century.[26]

Therefore, a time gap can be anticipated between the filling of storage pools and the availability of an ultimate disposal facility. If a nuclear plant is to continue operating it must use some type of interim storage system. The costs for disposal are comprised of three components beyond temporary on-site storage: interim storage costs (either away from reactor or on-site), transportation costs, and permanent disposal fees.

The options, cost estimates, and methods for estimating waste disposal costs for Indian Point are detailed in Appendix D. A summary of total cost estimates, expressed in terms of 1981 dollars per kilogram of uranium waste, is presented in Table D-9. These costs can be converted to costs per KWH generated, as shown on page D-28, which led to the following estimates having been employed in the scenario analysis.

TABLE 14

SPENT FUEL DISPOSAL COSTS
(1981 Mills per KWH)

	Scenario		
	High Impact	Mid-Range	Low Impact
Planned Retirement	1.1	2.2	3.6
Early Retirement	0.9	1.7	2.8

Applying these figures to the lifetime generation in the respective scenarios yields incremental costs of $247, $322, and $222 million 1981 dollars for the Low Impact, Mid-Range, and High Impact scenarios. These are the estimated savings in fuel disposal resulting from a shutdown. In the planned retirement case, the extra costs are spread from 1985 to 2006.

3.7 Decommissioning

No large commercial nuclear power plant has yet been decommissioned in the United States. The largest nuclear reactor that has previously been decommissioned was the 22 MW experimental Elk River reactor in Minnesota, and that facility had only operated for 4 years. Decommissioning is the process whereby all components of the power plant and site are made secure from radiological contamination. Options include encasing the plant in an impermeable shell (entombment), and cutting up the plant, restoring the site, and shipping the radioactive parts of the plant to a permanent nuclear waste storage facility (dismantlement). A brief overview of decommissioning methods and their potential cost can be found in Appendix E.

There are two areas of concern in this study regarding the decommissioning of the Indian Point units. The first concerns the total ultimate cost of decommissioning. The second is the issue of the relationship between decommis-

sioning costs for Indian Point and the length of time the units will have operated. The major fact relevant to this second issue is that the longer a nuclear reactor operates, the more highly radioactive it becomes, especially with respect to the longer lived radioisotopes induced in the plant structure itself. These radioactive parts become the major contributor to the radioactive inventory of the plant.(27)

However, the degree to which early retirement will affect decommissioning costs is difficult to estimate. Since there are currently no permanent nuclear waste storage sites we have assumed in this report that IP-2 and IP-3 will be decommissioned after their normal retirement dates in both the early shutdown or normal retirement scenarios. We also assume that the decommissioning technique used will be complete dismantlement and permanent disposal of the radioactive components. However, as Con Edison's own dismantlement cost analysis for Indian Point #2 indicates, "the costs to cut, remove, ship, and bury the reactor vessel and internals are dependent on the segment curie [measure of radioactivity] content and weight...." For reactors that operated for less than their design lifetime, there is a corresponding reduction in total curies, and a potential for reduction in disposal cost for segments that are curie limited.

Nuclear Energy Services, Inc. estimated that there would be 10 million curies in Indian Point #2 at the end of

its normal lifetime.[28] To put this number in perspective, there is presently a 50 thousand curie per shipment burial limit at the Hanford burial site. Given this assumed level of radioactivity, NES estimates that it will cost about 90 million (1980 dollars) to dismantle the Indian Point Unit 2. For comparative purposes, in 1977, an even higher estimate of about $124 million (1980 dollars) was made for decommissioning Three Mile Island #1.[29]

While great uncertainty exists with respect to both total decommissioning costs and differential decommissioning costs as a function of plant lifetime, estimates must be made whenever an important public policy decision is pending, as one is at Indian Point. Inaccuracy in estimating the costs of constructing nuclear power plants has been widespread in the nuclear industry. Actual costs have been as much as four or more times originally planned costs, even after inflation has been accounted for. We have assumed similar potential inaccuracy in designing our decommissioning cost scenarios. Much of the industry's inaccuracy in construction estimates was due to the changing regulatory environment as safety standards were upgraded, but we believe that similar regulatory changes are likely in the decommissioning area as well. This is especially so since it is an area that has not yet received as much attention at the Nuclear Regulatory Commission as other areas of nuclear regulation.

For our High Impact case we assumed that both IP-2 and IP-3 would cost Con Edison's estimate of $90 million in 1980 dollars to decommission. We further assumed that there would be no cost differential between early and normal retirement. This is a fairly extreme assumption. In the Mid-Range case we assumed that each Indian Point unit would cost two times the Con Edison estimate to decommission at the normal retirement date, and that early retirement would reduce this cost by 25 percent, resulting in a savings for both plants of $90 million out of $360 million (1980 dollars). Finally, in the Low Impact case we assume that allowing the radioactivity in the plant to decay for an extra 20 years or so prior to decommissioning in the early retirement situation would have a major impact on decommissioning costs and reduce them by 50 percent. The baseline cost for normal retirement was taken as four times the Con Edison estimate in the Low Impact case. This results in the early retirement savings for decommissioning in the Low Impact scenario being $360 million out of $720 million (1980 dollars). The annual scenario dependent required revenue impacts of these assumptions can be found in Tables 16, 17, and 18 below. Comparing these results with the aggregate scenario findings (Table 1), we see that even in the Low Impact case the differential discounted required revenue impact of decommissioning is only about $240 million out of a total scenario impact of about $1330 million, or less than 20 percent. In

the Mid-Range case the differential decommissioning impact was only 8 percent of the total scenario impact. In the High Case, decommissioning has zero impact. Thus, decommissioning cost assumptions, while important, are not major determinants of the overall scenario results in this study.

The incremental costs of 0, $90, and $360 million (1981) dollars for the High, Mid-Range, and Low Impact cases, respectively, are assumed spread over the 1985-2006 time frame.

3.8 Costs of Capitalized Expenses

During the normal course of operating and maintaining a power station, various capital costs must be regularly incurred for replacement components and equipment as well as for new equipment required. These costs are in addition to the original capital investment in the plant (discussed in Section 3.3) and in addition to the expensed operations and maintenance costs (discussed above in Section 3.5). These expenditures have particularly affected nuclear stations because extensive retrofitting of many technological improvements has been required. These capital costs, which are added to the rate base and thus charged to ratepayers in the same manner as the original capital cost of the plant, can amount to a substantial economic deficit of trying to keep a nuclear station such as those at Indian Point functioning.

Examining the record of capital cost increases for the Consolidated Edison portion of the Indian Point station (units #1 and #2), one finds that the total capital cost for these units has increased from about $335 million in 1973 to about $422 million in 1981.[30] This represents an average annual increase of about 3 percent per year. However, at the end of this period the increase for Indian Point #2 alone has been almost 11 percent from 1980 to 1981. Unfortunately, data for Indian Point #3, owned by PASNY, are not reported.

The key question in the current context is how can these additional capital costs for Indian Point #2 and #3 be reasonably projected. Con Edison anticipates that over the period 1983-1986 capital expenditures for Indian Point #2 will amount to $131 million.[31] This implies that from 1981 to 1986 the total capitalized cost for Indian Point #2 will increase by at least 6.8 percent per year. Con Edison lists a variety of items that these expenses will cover including: vendor retubing, NUREG-0737 modifications, cooling tower settlement modifications and "numerous other improvement projects." PASNY lists similar items in stating that Indian Point #3 will need $80 million worth of capital improvements in the foreseeable future.[32] These estimates do not cover the replacement of the steam generator, if this is needed.

In designing the three basic cost scenarios analyzed in this study, the following assumptions were made based on the

information discussed above. For the <u>High Impact</u> case it is assumed that the rate of increase in the total capitalized costs for both Indian Point #2 and #3 returns for the period 1987-2000 to the lower rate of 3 percent per year that obtained from 1973-81 for Indian Point #2. In the <u>Low Impact</u> case we assume that the rate of increase in capitalized costs during 1987-2000 continues at 6.8 percent, the rate projected for IP-2 for the 1981-1986 period. For the Mid-Range case, an intermediate growth rate of 4.9 percent is used.

However, in addition, the GAO report states that serious corrosion problems were beginning to develop by 1979 in the IP-2 steam generators, and that similar problems have occurred at IP-3.[33] The report goes on to suggest that Con Edison will have to replace or retube the steam generator some time after 1983, requiring that IP-2 be out of service for up to one year. On the other hand, the Companies have stated that steam generator replacement will not be necessary at least until 1986.[34]

It appears that steam generator problems, as experienced in other aging nuclear units, are likely to occur at the Indian Point Station. However, recent experience indicates that the IP-3 unit has more severe problems with its steam generator than does IP-2.[35] In light of this, it is assumed in the Mid-Range scenario that replacement of this key component will be required during 1991 and 1986, for the IP-2 and IP-3 units, respectively. For comparison, the Rand

Report assumes that the IP-2 and IP-3 steam generator expenditures are made in 1985.[36] In this Mid-Range case the need for replacement of the steam generator is delayed for Indian Point #2, since its problems appear less severe to date. In contrast, in the Low Impact scenario it is assumed that the IP-2 steam generator will have to be replaced three years earlier, in 1988. Since both Con Edison and PASNY state that it is possible that steam generator replacement may not be necesary at all, this is assumed in the High Impact scenario. In all cases where the steam generator is replaced the cost is assumed to be capitalized at a level of $130 million and $132 million (in 1982 dollars), respectively, for IP-2 and IP-3, and depreciated over the remaining lifetime of the unit.[37] The replacement is assumed to take a period of one year to accomplish, during which the unit affected cannot operate. During this year, other expensed and capitalized operations and maintenance costs are not charged to those scenarios that assume Indian Point is not retired.

The resulting stream of these capitalized expenses from 1983 - 1997 can be found in Table 15 below for each of the three main scenarios.

TABLE 15

CAPITALIZED EXPENSES
(Million 1981 Discounted Dollars)

	Scenario		
Year	High Impact	Mid-Range	Low Impact
1983	-8.3	-8.3	-8.3
1984	-17.0	-17.0	-17.0
1985	-20.5	-20.5	-20.5
1986	-23.7	-34.8	-34.8
1987	-24.1	-35.8	-37.7
1988	-24.2	-36.5	-59.3
1989	-24.1	-36.8	-59.1
1990	-23.8	-36.9	-58.6
1991	-23.5	-55.3	-58.0
1992	-23.0	-53.0	-57.3
1993	-22.4	-50.8	-56.6
1994	-21.8	-48.7	-55.8
1995	-21.2	-46.7	-54.9
1996	-20.5	-44.8	-54.0
1997	-19.8	-43.0	-53.2
TOTAL	-317.9	-569.1	-685.0

4. IMPACT ON RATEPAYERS

4.1 Introduction

In the previous section, the findings for each of the major components of revenue impact were presented. Here, we synthesize these component results into integrated estimates of overall impacts on ratepayers.

The "basic results" for the three scenarios -- High Impact, Mid-Range, and Low Impact as described in Section 2.3 -- are the subject of the first subsection. Annual and cumulative cost impacts are reported over a fifteen year time frame. We then go on to explore the sensitivity of the results to variations in certain input assumptions such as the assumed year of retirement of the Indian Point units.

4.2 Basic Results

Summary results for the Mid-Range, High and Low Impact scenarios are given, respectively, in Table 16, 17, and 18. Each table shows the impact of closing the Indian Point facilities over our fifteen year horizon on both an annual and a cumulative basis. Also displayed is the annual percentage impact on required revenue.[38] This provides a measure of the relative magnitude of the repercussions on the price of power. In the lower right corner is the cumulative impact as a percentage of the cumulative required revenues, a useful figure in evaluating the overall impacts of closing the

Table 16

INDIAN POINT RETIREMENT STUDY -- MID-RANGE IMPACT

Differential Required Revenues by Cost Category

(millions of 1981 discounted dollars)

YEAR	CAPITAL CON ED	CAPITAL PASNY	NUCLEAR O&M	MAKEUP GENERATN	SPENT FUEL	DECOMMIS COST	NUCLEAR FUEL	OTHER COST	ANNUAL TOTAL	CUM. TOTAL	ANNUAL % IMPACT
1983	-7.4	-0.4	-113.4	431.7	0.0	0.0	-57.9	-8.3	244.2	244.2	7.1
1984	-6.0	-0.4	-115.9	380.8	0.0	0.0	-54.8	-17.0	186.7	430.9	5.7
1985	-4.9	-0.4	-118.1	365.0	-15.2	-4.6	-52.3	-20.5	149.1	580.0	4.7
1986	-4.1	-0.4	-56.6	168.7	-15.2	-4.6	-22.6	-34.8	30.4	610.3	1.0
1987	-3.5	-0.4	-121.4	325.4	-15.2	-4.6	-47.0	-35.8	97.5	707.9	3.4
1988	-3.0	-0.4	-122.6	305.5	-15.2	-4.6	-44.4	-36.5	78.8	786.6	2.9
1989	-2.8	-0.4	-123.6	294.1	-15.2	-4.6	-42.2	-36.8	68.4	855.1	2.6
1990	-2.6	-0.4	-124.3	329.1	-15.2	-4.6	-40.2	-36.9	104.9	960.0	4.2
1991	-2.5	-0.4	-65.8	123.7	-15.2	-4.6	-20.9	-55.3	-41.0	919.0	-1.6
1992	-2.5	-0.4	-125.1	238.5	-15.2	-4.6	-36.0	-53.0	1.8	920.8	0.1
1993	-2.4	-0.3	-125.2	219.5	-15.2	-4.6	-33.7	-50.8	-12.9	907.9	-0.5
1994	-2.4	-0.3	-125.1	201.8	-15.2	-4.6	-31.6	-48.7	-26.2	881.7	-1.2
1995	-2.4	-0.3	-124.8	187.9	-15.2	-4.6	-30.0	-46.7	-36.2	845.4	-1.7
1996	-2.3	-0.3	-124.4	174.6	-15.2	-4.6	-28.4	-44.8	-45.5	799.9	-2.3
1997	-2.3	-0.3	-123.9	162.1	-15.2	-4.6	-26.9	-43.0	-54.1	745.8	-2.9
TOTAL	-51.0	-5.6	-1710.1	3908.4	-198.2	-59.8	-568.9	-569.1	745.8	745.8	1.9

Table 17

INDIAN POINT RETIREMENT STUDY -- HIGH IMPACT

Differential Required Revenues by Cost Category

(millions of 1981 discounted dollars)

YEAR	CAPITAL CON ED	CAPITAL PASNY	NUCLEAR O&M	MAKEUP GENERATN	SPENT FUEL	DECOMMIS COST	NUCLEAR FUEL	OTHER COST	ANNUAL TOTAL	CUM. TOTAL	ANNUAL % IMPACT
1983	-7.4	-0.4	-109.9	460.1	0.0	0.0	-57.9	-8.3	276.0	276.0	7.9
1984	-6.0	-0.4	-110.8	435.4	0.0	0.0	-55.8	-17.0	245.4	521.4	7.3
1985	-4.9	-0.4	-111.3	437.3	-10.5	0.0	-53.8	-20.5	235.9	757.3	7.4
1986	-4.1	-0.4	-111.6	432.1	-10.5	0.0	-51.9	-23.7	230.0	987.3	7.5
1987	-3.5	-0.4	-111.6	429.8	-10.5	0.0	-50.0	-24.1	229.7	1217.0	7.8
1988	-3.0	-0.4	-111.5	426.2	-10.5	0.0	-48.3	-24.2	228.4	1445.4	8.1
1989	-2.8	-0.4	-111.2	427.4	-10.5	0.0	-46.5	-24.1	232.0	1677.4	8.5
1990	-2.5	-0.4	-110.6	428.0	-10.5	0.0	-44.9	-23.8	235.1	1912.5	9.0
1991	-2.5	-0.4	-110.0	428.5	-10.5	0.0	-43.3	-23.5	238.5	2151.0	9.5
1992	-2.5	-0.4	-109.2	429.1	-10.5	0.0	-41.7	-23.0	241.9	2392.9	10.1
1993	-2.4	-0.3	-108.3	429.8	-10.5	0.0	-40.2	-22.4	245.5	2638.4	10.6
1994	-2.4	-0.3	-107.3	430.1	-10.5	0.0	-38.8	-21.8	248.9	2887.4	11.2
1995	-2.4	-0.3	-106.1	430.4	-10.5	0.0	-37.4	-21.2	252.5	3139.8	11.9
1996	-2.3	-0.3	-104.9	430.7	-10.5	0.0	-36.1	-20.5	256.0	3395.9	12.5
1997	-2.3	-0.3	-103.7	431.2	-10.5	0.0	-34.8	-19.8	259.9	3655.7	13.3
TOTAL	-51.0	-5.6	-1638.0	6486.2	-136.6	0.0	-681.3	-317.9	3655.7	3655.7	9.2

Table 18

INDIAN POINT RETIREMENT STUDY -- LOW IMPACT

Differential Required Revenues by Cost Category

(millions of 1981 discounted dollars)

YEAR	CAPITAL CON ED	CAPITAL PASNY	NUCLEAR O&M	MAKEUP GENERATN	SPENT FUEL	DECOMMIS COST	NUCLEAR FUEL	OTHER COST	ANNUAL TOTAL	CUM. TOTAL	ANNUAL % IMPACT
1983	-18.8	-0.4	-113.4	350.5	0.0	0.0	-50.4	-8.3	159.2	159.2	4.7
1984	-15.2	-0.4	-115.9	281.7	0.0	0.0	-46.2	-17.0	87.0	246.2	2.7
1985	-12.3	-0.4	-118.1	255.1	-11.7	-18.4	-43.2	-20.5	30.7	276.8	1.0
1986	-9.9	-0.4	-56.6	110.4	-11.7	-18.4	-16.6	-34.8	-38.0	238.9	-1.2
1987	-8.0	-0.4	-121.4	254.3	-11.7	-18.4	-35.9	-37.7	20.9	259.8	0.7
1988	-6.4	-0.4	-64.7	69.4	-11.7	-18.4	-19.1	-59.3	-110.5	149.2	-4.1
1989	-5.2	-0.4	-123.6	154.3	-11.7	-18.4	-29.6	-59.1	-93.6	55.7	-3.6
1990	-4.2	-0.3	-124.3	128.2	-11.7	-18.4	-26.2	-58.6	-115.5	-59.8	-4.7
1991	-3.4	-0.3	-124.8	106.5	-11.7	-18.4	-23.2	-58.0	-133.3	-193.1	-5.7
1992	-2.9	-0.3	-125.1	83.8	-11.7	-18.4	-20.0	-57.3	-151.8	-345.0	-6.9
1993	-10.8	-0.3	-125.2	65.1	-11.7	-18.4	-17.3	-56.6	-175.1	-520.0	-8.4
1994	-9.5	-0.3	-125.1	47.9	-11.7	-18.4	-14.7	-55.8	-187.5	-707.5	-9.4
1995	-8.4	-0.3	-124.8	31.8	-11.7	-18.4	-12.2	-54.9	-198.8	-906.3	-10.5
1996	-7.4	-0.3	-124.4	14.5	-11.7	-18.4	-9.3	-54.0	-210.9	-1117.2	-11.8
1997	-6.5	-0.3	-123.9	0.7	-11.7	-18.4	-6.9	-53.2	-220.1	-1337.3	-12.9
TOTAL	-128.8	-5.2	-1711.1	1954.3	-152.0	-238.8	-370.7	-685.0	-1337.3	-1337.3	-3.5

E S R G

plants. Cumulative results for the scenarios have been grouped in Table 1.

The High and Low Impact scenarios are, it will be recalled, developed by consistently biasing uncertain statistical and policy variables toward those future values which create the greatest and least ratepayer impact, respectively. The scenario likelihood is related in these cases to the joint probability of a set of unlikely events. For example, the High Impact scenario represents a case of no aging-related deterioration of capacity factors, no conservation effort beyond current levels, no electric system readjustment to the loss of the Indian Point units, high make-up fuel costs, no aging effect on decommissioning cost and so on. Likewise, the Low Impact scenario incorporates assumptions at the opposite end of the uncertainty band, those that are most pessimistic about the nuclear option. For these reasons, we consider the High and Low scenarios to bracket the range of plausible impact. Their average impact on electricity costs (9.2 percent and -3.5 percent, respectively) represent unlikely extreme cases.(39) We shall thus focus henceforth on the Mid-Range scenario.

Table 16 presents the breakdown by cost impact category as discussed in Section 3. The estimated average impact on required revenue over the period considered is 1.9 percent (a cumulative absolute total of $745.8 million discounted 1981 dollars). As expected the primary penalty of nuclear

retirement is the cost of make-up power ($3.91 billion cumulatively). On the other hand, there are major benefits in avoiding the costs of nuclear O&M, fuel and additional capital investments. Additional savings result from decreased spent fuel disposal and decommissioning burdens. Minor savings result also from early tax write-offs and lower nuclear insurance costs. After 1990, the annual avoided costs (i.e., the benefits) of not having the units exceeds the extra costs incurred. These savings are reflected as negative annual impact in the output.

4.3 Sensitivity to Scenario Assumptions

Comparison of the disaggregated output across the scenarios reported earlier will reveal the variation of results with respect to the range of inputs characterizing each scenario. Here, we wish to explore the sensitivity of our basic results to four variables which cannot be gleaned from the earlier results. These are the length of the study period, the timing of the retirement of the Indian Point units, the discount rate, and nuclear capacity factors. These will be discussed in turn below. These sensivitity tests have been performed against Mid-Range scenario results.

Length of Period. The impacts were computed to the year 2000 or three years longer than in our basic runs. The effect is to decrease the impacts by $215 million discounted

dollars and the average percent impact on required revenues from 1.9 percent to 1.2 percent. This is traced to the projection that nuclear related costs will escalate more rapidly than substitute power costs.

Timing of Retirement. Here, the Indian Point units are assumed to be retired in 1985 rather than in 1983 as was forecast in the basic runs, since impacts are most severe in the early years. Cumulative costs decrease from $746 million to $290 million 1981 discounted dollars while the percentage impact decreases from 1.9 percent to 0.8 percent.

Discount Rate. The impacts were recomputed using a 14-percent annual discount rate rather than the 12 percent employed in the basic results. This has the effect of weighting the early years more heavily in the cumulative impacts while decreasing the absolute levels of discounted costs. Specifically, the cumulative costs decrease by $70 million while the percentage impact increases to 2.0 percent from 1.9 percent.

Nuclear Capacity Factor. In this test the Mid-Range capacity factor assumptions were replaced by the High Impact case non-deteriorating capacity factor assumptions (see Section 3.1). Make-up generation costs were recomputed using the power plant dispatch model as described in Section 3.1. This raises the estimated impacts by $751 million (discounted to 1981) and the average percentage impact from 1.9 percent to 3.9 percent. This estimate does not reflect

the increased fuel disposal costs which would result from additional generation.

5. INDIRECT REPERCUSSIONS OF PLANT CLOSINGS

5.1 The Limits of Direct Cost Impact Analysis

The foregoing discussion has developed the estimates of the impacts on ratepayers of the early retirement of the Indian Point facilities. The annual changes in required revenues (customer payments) were approximated over a future planning period for each of the major components of the cost structure likely to be reflected in electricity bills. These are the direct economic repercussions.

Such direct cost trade-offs do not, however, exhaust the impacts on society of a plant closing. There are a number of indirect consequences that are not incorporated into the required revenue analysis presented above. While there is at this time considerable controversy on methods and assumptions appropriate for quantifying indirect (or "external") costs and benefits of plant closings, there are four broad categories of indirect repercussions which deserve brief qualitative identification here. These are: health and safety issues, behavioral response to price increments, financial repercussions on utilities, and secondary impacts on economic activity. We shall discuss these below, in turn.

5.2 Health and Safety Issues

A full social cost/benefit treatment would attempt to monetarize and incorporate some measure of the health and

safety trade-offs which would result from a nuclear plant closure. To date, there has been no attempt to include these in assessments of plant closing economic impacts. The reason is easily discovered: high-confidence techniques for estimating and costing the relevant factors do not currently exist. Of course, such methodological underdevelopment does not make the effects any less real.

What then are the main issues? On the nuclear side, the costs of continued operation would be identified with the extra risks incurred at all phases of the nuclear fuel cycle. The problems include (1) the mining and milling of uranium with danger of release of radioactive material (e.g., thorium, radium) from tailing heaps into soil and water systems, (2) low-level toxic releases during normal plant operations, (3) the risk of a major accident at a nuclear plant,[40] (4) protection against release of highly toxic spent fuel over unprecedented, long planning periods (say, ten half-lives or about 250,000 years for the case of Plutonium-239), and (5) avoiding proliferation of nuclear weapons fashioned from power plant plutonium. On the other side, the environmental cost of early closure would include increased air pollution from fossil fuel generated make-up power and perhaps increased dependency on uncertain foreign sources.

Full explication of these complex health and safety issues would, of course, require volumes. Some would argue

that the risks are too serious to justify continued nuclear plant operation; others that they are comparatively negligible or easily manageable.[41] The exercise performed in this study -- the computation of required revenue under risk-free conditions -- can play a role here. It can help the public and their decision-makers in deciding whether the direct cost impacts are a tolerable investment for avoiding health and safety risks as they perceive them.

5.3 Behavioral Response to Price Increments

In theory, a change in electricity price will cause a change in the demand for electricity. This relationship is often expressed in the so-called "price elasticity of demand": the percentage change of consumption divided by the percentage change of price. Two time periods are generally distinguished. The "short run" elasticity represents the immediate response to price changes due presumably to adjustments in usage (e.g., changing thermostat settings), while the generaly larger "long run" elasticities should reflect the lagged response to price changes due to equipment choice (e.g., more efficient devices).

Clearly, these price elasticity effects would have a moderating influence on the direct cost impacts of a plant closing. This is shown mathematically in Table 19. The final equation presents a correction factor, which would scale down our earlier cost impacts. Indeed, if the elasti-

TABLE 19

PRICE ELASTICITY EFFECTS ON REQUIRED REVENUE IMPACTS

With the definitions:

	No Retirement	Retirement ($\varepsilon = 0$)	Retirement ($\varepsilon \neq 0$)
Required Revenue	R	$R + \Delta R_o$	$R + \Delta R$
Electricity Consumption	E	E	$E + \Delta E$
Average rate	r	-	$r + \Delta r$
Marginal generation cost	p		
Elasticity	$-\varepsilon$		
Correction factor	f		

We have:

$$\Delta R = \Delta R_o - p\Delta E$$

From $r \equiv R/E$, we have

$$\frac{\Delta r}{r} = \frac{\Delta R}{R} - \frac{\Delta E}{E}$$

Substituting $\frac{(\Delta E/E)}{(\Delta r/r)} \equiv \varepsilon$ yields:

$$\Delta E/E = \frac{\varepsilon}{1+\varepsilon} \left(\frac{\varepsilon}{1+\varepsilon}\right) \cdot \frac{\Delta R}{R} \text{ or } \Delta E = \left[\frac{\varepsilon}{1+\varepsilon}\right] \cdot \frac{\Delta R}{r}$$

Substituting in defined equation and simplifying:

$$\Delta R = f \cdot \Delta R_o$$

Where the elasticity correction factor is

$$f = \left[1 + \frac{p}{r} \cdot \left(\frac{\varepsilon}{1-\varepsilon}\right) \right]^{-1}$$

city were minus one, the required revenue impact would be zero. The problem, however, is that in the words of a recent review monograph, there is a "startling lack of consensus on price elasticities."[42] Representative price elasticity spreads are shown in Table 20.

The uncertainty of these estimates makes specific applications problematic and we have not reported elasticity adjustments in our quantitative results. If, for the sake of illustration, one makes the not unreasonable assumption that marginal generation costs roughly equal average rates ($P/r \approx 1$) and the price elasticity is approximately -0.4, then the correction factor (f in Table 19) is 0.6. This would imply an overestimate in the earlier required revenue impacts of the order of 40 percent.

5.4 Financial Repercussions on Utilities

The central issue here is the possible impact on investor confidence in the event of a nuclear plant closing. The perception of risk by the financial community is reflected most directly in the level of return and annual cash flow required to attract an adequate level of investment. The determinants of that perception are multiple but probably include such factors as regulatory policy on rates and sunk cost recovery, market-to-book ratios, coverage ratios (earnings divided by debt service burdens), and, in the case at hand, confidence in nuclear plant performance.

TABLE 20

PRICE ELASTICITY ESTIMATES IN THE LITERATURE[43]

	Short-Run	Long-Run
Residential	-.08 to -.45	-.45 to -2.10
Commercial	-.17 to 1.18	-.56 to -1.60
Industrial	-.04 to -1.36	-.51 to -1.82

These, in turn, depend on utility management performance, construction plans, and on the performance of nuclear facilities over time.

Clearly, any quantification of investor response to a plant closing must first develop scenarios for these conditioning variables and then link them to estimated changes in the cost of capital and cash flow requirements. This is necessarily a complex and judgmental task.

However, the scenarios developed here assume full flow through of incremental costs of plant closing to the ratepayers (only the return portion of the unamortized part of the initial capital expenses is treated as a scenario variable). The working assumption for the High Impact and Mid-Range cases is that stockholders and investors will be "kept whole" in that the regulatory treatment will allow all utility costs to be reflected in rates. Under these conditions, there is no basis for assuming any additional expenses to maintain investor confidence. Furthermore, cash flow problems will not emerge with passthrough ratemaking as a result of a plant closing.[44]

There is, on the other hand, the possibility that performance by maturing nuclear power plants will not live up to industry expectations. In this event (our Mid-Range and Low Impact cases), investor confidence would presumably be sufficiently enhanced by the early retirement of such a facility that the loss of the return on the unamortized balance, as assumed in the Low-Impact case, will not

negate this increased confidence. Additionally, in a full asessment, one would need to weight in the small probability of an unplanned plant shutdown (as occurred at Three Mile Island) which, of course, would be seriously detrimental to a utility's financial condition. These would be avoided costs -- that is, benefits -- to early retirement.

Each of the elements that constitute the indirect financial repercussions seems to satisfy at least one of these characteristics -- small, improbable, and speculative. Thus, we have not attempted to include them in our numerical results.

5.5 Secondary Economic Activity

The analysis of required revenue impacts is restricted to estimates of the direct out-of-pocket expenditures required to support an early plant closing. But will the ensuing change in business and household expenditure patterns -- more spending for electricity, less for other commodities in the case where the closing increases costs -- have significant indirect repercussions on employment, economic output, and household income?

The indirect impacts of changes in energy expenditure patterns are complex. Alternative patterns may alter the economic activity in the energy supply industry itself and in equipment supply sectors, in business costs and location

decisions, in the suppliers of the suppliers, etc. There could be distributional impacts between household type and industrial sectors, between regions, and over time.[45] There have been no attempts to assess such secondary effects for a nuclear plant closing. In perhaps the most closely allied study, the impacts of a phase-out of nuclear power in California was analyzed with no significant secondary economic impacts found.[46]

One of the main complications, is that increases in electricity prices stimulate conservation and conservation dollar-for-dollar is thought to be more economically stimulative of a region than supply side alternatives. For example, a study of electric price increases in the Buffalo area concluded that the indirect effects actually were beneficial.[47] Similarly, two recent investigations of conservation impacts find substantial economic benefits in switching from energy investment to conservation investment.[48]

However, for the case of a plant closing the conservation induced is not easily specified (see the discussion of behavioral responses above). Against this effect will be the economically negative impact (if elasticities are less than one) of transferring household expenditures to electricity from other commodities. This is likely to decrease employment, especially in the case where the conservation expenditures stimulate local economic activitiy while ıe

expenditures for make-up generation go in part to foreign coffers.

What are the changes in expenditures patterns implied by a plant closing? What are the economic repercussions locally and nationally? Will induced conservation and health and safety benefits counteract the negative repercussion of higher electricity costs? These are significant questions that cannot be answered today.

FOOTNOTES

1. The basic documents on the cost impacts of closing the Indian Point facility are listed in References 2 through 5 below. Together, they present a remarkable spectrum of assumptions, methods, and not surprisingly, results. None present a documented and systematic framework for scenario explication, sensitivity analysis, and output evaluation.

2. Economic Impact of Closing the Indian Point Nuclear Facility, Report by the Comptroller General of the United States, U.S. Government Accounting Office, EMD-81-3, Washington, D.C., November 7, 1980.

3. Costs of Closing the Indian Point Nuclear Power Plant, prepared for Power Authority of the State of New York, Rand Corporation, R-2857-NYO, Santa Monica, California, November, 1981.

4. Taylor, Vince and Komanoff, Charles, An Evaluation of "Economic Impact of Closing the Indian Point Nuclear Facility" A Report of the General Accounting Office, Union of Concerned Scientists, December 3, 1980.

5. Brancato, Carolyn Kay, "The Indian Point No. 2 Nuclear Facility," Congressional Research Service, Washington D.C., December 5, 1980.

6. The IP-1 unit has been shut down since 1974; the NRC revoked Con Ed's operating license in 1980. We shall not consider this unit further in this study.

7. An Analysis of the Need for and Alternatives to the Proposed Coal Plant at Arthur Kill, a report to the New York City Energy Office and the Corporation Counsel of New York, ESRG Study No. 81-21, June, 1981.

8. Referenced in Note 7. This study was also presented as part of testimony in the 1981 New York State Energy Master Planning hearings by Dr. Richard A. Rosen. The focus of the study was the economics of the proposed Arthur Kill plant, but the work has general applicability to generation planning and demand related issues in the region.

9. Documented in Note 7 reference.

FOOTNOTES
(Continued)

10. Note that neither the proposed 700-MW Arthur Kill unit on Staten Island nor the proposed Prattsville pumped storage facility has been included in these generation dispatch runs. Had they been, the replacement power for Indian Point would have derived from more efficient back-up units than we have assumed, thus lowering make-up power costs.

11. Con Edison response to NRC Staff interrogatory #24, NRC Docket #50-247SP, #50-286SP.

12. Vol. II, p. 433.

13. In the Low Impact case one could conceivably assume the additional coal conversions of the Astoria #3, #4, and #5 units, but due to unresolved controversy surrounding the feasibility of such conversions we did not.

14. Con Edison response to NRC Staff interrogatory #1, p. 7-8, NRC Docket #50-247SP, #50-286SP. Indeed, Con Edison's oil price assumptions are somewhat below the Mid-Range case assumption.

15. 1982 NYPP Report, p. 12.

16. Con Edison FERC Form #1, pp. 326-27.

17. The following amounts of power were assumed available for dispatch at the listed prices:

Power Line	Years	Megawattage Maximum	Cost (1981 $/MWH)
NYPP#1	1981-2000	300	49.60
LLLCO#1	1981-2000	500	65.00
NYPP#2	1981-2000	800	70.00
NYPP#3	1986-2000	1000	65.00

Generally these lines will dispatch only a fraction of the time.

18. Con Edison response to NRC Staff interrogatory #1, p. 9.

19. This analysis shows that about 36% or about 3000 GWH of the make-up power would come from upstate NYPP companies. This is the equivalent of about a 800 MW line with a capacity factor about 40%.

FOOTNOTES
(Continued)

20. In current dollars, in 1983, the make-up power costs for the Mid-Range scenario would be about $542 million. To compare with the Con Edison calculations provided on discovery for that year, however, the nuclear fuel, nuclear operations and maintenance costs (O&M) and nuclear spent fuel disposal costs would have to be subtracted, yielding a total Mid-Range impact of $327 million, or 3.8 cents per KWH. (See Table 2 referenced in note #14.) The comparable High-Impact value will be about $367 million, and the Low-Impact value is $235 million. In contrast, the RAND report claims that a reasonable upper and lower limit of $455 million and $425 million, respectively, is appropriate, which can be compared to the Con Edison value of $506 million. The largest single cost item that separates the Con Edison and Rand Estimates from the High-Impact or Mid-Range Impact cases here is a roughly $50-100 million differential for nuclear O&M. The justification for the ESRG assumptions on O&M can be found in Section 3.4 below. Secondly, different capacity factor assumptions among all parties account almost completely for the remainder of this cost differential.

21. The 20% figure was estimated by Dr. Lewis Perl of NERA, a consultant to Con Edison and other utility companies in Revised Direct Testimony, Pennsylvania Public Utility Commission Docket #I-80100341.

22. Response to Greater New York Council on Energy, interrogatory #23 (Con Ed), Table 6B, p.8, and #4 (PASNY).

23. The New York utilities appear to assume a 0% real escalation rate. Other observers assume rates above our High Impact case assumption (e.g., Lewis Perl, _op. cit._, Table 11 testified to over 5% real escalation rates).

24. Based on a reloading cycle of 18 months with one-third assembly replacement (implying an average age of 27 months) and a fixed charge rate of 15% (Con Ed & PASNY average): 27/12 x .15 = .34 .

25. Cited in Note 2.

26. See, _e.g._, App. D, Refs. D-4 and D-8.

27. NES, Inc., "Decommissioning Study of Prompt Dismantlement of Indian Point Unit 2", April, 1982, p. 9.

FOOTNOTES
(Continued)

28. Reference cited in Note 27.

29. Cited in California Energy Commission, "Nuclear Economics", November, 1980, p. 56.

30. Steam-Electric Plant Construction Cost and Annual Production Expenses, USDOE, various years esp. 1973 and 1979.

31. Con Ed response to interrogatory #2 of GNYCE's First Set.

32. PASNY response to interrogatory #2 of GNYCE's First Set.

33. Cited in Note 2, pp. 20-21.

34. Con Ed response to interrogatory #11 of GNYCE's First Set.

35. New York Times, March 31, 1982, p.A25. "Tubes at 40 A-Plants Assailed". Steam-generator replacement has already occurred at the Surry #1 and #2 units in Virginia. Similar replacements are underway or planned at Turkey Point and Palisades nuclear stations.

36. Cited in Note 3, Table 10.

37. PASNY response to interrogatory #11 of GNYCE's Furst Set.

38. Annual required revenue in constant dollars is assumed to decrease at an annual raate of -1.5%, -1.0%, and -0.5% for the Low, Mid, and High Impact scenarios, respectively, based on scenario load growth assumptions and a decrease in the unit cost of electricity in the Con Ed service area of 0.7%/year (Energy Master Plan II, State Energy Office of New York, August 1981, p. 170).

39. Indeed, in the later years of the Low Impact case the costs of generating power from the nuclear stations exceeds the make-up costs. In this case, on economic grounds, the plant would be voluntarily retired sometime after 1990.

FOOTNOTES
(Continued)

40. The required revenue simulation used in this study employs statistically estimated measures of normal plant operation. Abnormal events of low probability such as a catastrophic accident are, of course, not reflected. Cost estimates here would be related to such imponderables as the worth of human lives (a moral as well as economic concept), probability of losing lives, psychological costs, etc.

41. There is abundant popular literature on nuclear risks (see, e.g., Countdown to a Nuclear Moratorium, Environmental Action Foundation, 1976). On the other hand, most economic impact assessments are silent on the question of nuclear hazards (e.g., Refs. 2 and 3).

42. Bohi, Douglas R., Analyzing Demand Behavior: A Study of Energy Elasticities, John Hopkins, Baltimore, 1981, p. 1.

43. Ibid., p. 57 ff.

44. This is apparently confirmed in Ref. 2, Table 3-13, p.58, where satisfactory interest ratios are found under passthrough ratemaking. The caveat "apparently" is necessary due to a lack of documentation on data, assumptions, and methodology in that study. Ref. 3 refers to that exercise as a "black box" (p. 35) but nevertheless manipulates various Ref. 2 tables in an attempt to cull out "business costs" (everything but fuel-related cost it appears). This exercise cannot be considered scientifically interesting.

45. The issues are reviewed in Ref. 3 (pp. 38-45) and in J. Stutz and P. Raskin, Electricity Requirements in New York State. Volume III: Employment Impacts of the Conservation Policy Base Case Alternative, Energy Systems Research Group, Inc., ESRG 79-12/3, July, 1979. The latter offers a concrete quantitative assesment of the secondary effects of conservation in New York utilizing a regional model based on input/output techniques.

46. Martin L. Baughman et al., Direct and Indirect Economic, Social,and Environmental Impacts of the Passage of the California Nuclear Power Plant Initiative, Center for Energy Studies, University of Texas at Austin, FEA/G-7612661, April 1976. However, as pointed out in Ref. 3 (p.40), there are questions about the validity of this report and its relevance to an Indian Point closing.

FOOTNOTES
(Continued)

47. J.H. Savitt, Electric Energy Usage and Regional Economic Redevelopment, Final Report, EPRI, ES-187, Palo Alto, California, August, 1976.

48. These are the ESRG study cited in Ref. 6 and the New York State Energy Office's State Energy Master Plan and Long-Range Electric and Gas Report, Albany, 1980.

APPENDIX A

COST ASSESSMENT OF NUCLEAR SUBSTITUTION (CANS) MODEL:

A MATHEMATICAL DESCRIPTION

ESRG

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APPENDIX A

COST ASSESSMENT OF NUCLEAR SUBSTITUTION (CANS) MODEL: A MATHEMATICAL DESCRIPTION

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In this appendix, the calculation procedures employed by the Cost Assessment of Nuclear Substitution (CANS) model are described. The appendix is divided into eleven sections. The first (section A-1) will describe the general organization of the CANS model and introduce seven modules used to calculate eight different components of costs.[1] Section A-2 describes the data requirements and conventions shared among the modules. Sections A-3 through A-10 describe the individual modules and the data requirements specific to each module. Finally, in Section A-11, we discuss the CANs report and comparison module.

A-1 An Overview of CANS

The CANS system consists of two separate FORTRAN programs. The first is the cost estimation program which estimates the required revenue impacts of a particular user defined scenario. The second is the report and comparison program which compares the revenue impacts of two scenarios.

The simulation program consists of seven independent modules that calculate the following cost impacts:

1. Nuclear plant capital costs, assuming the plant remains on line for its full expected lifetime.
2. Nuclear plant capital costs, assuming the plant is retired from service before its full lifetime.

[1] Since capital costs assuming the plant remains in service and capital costs assuming it is retired are separate modules, only seven modules are actually employed in any given simulation.

3. Nuclear plant operations and maintenance costs
4. Makeup power costs when the plant has been retired early
5. Spent nuclear fuel disposal costs
6. Nuclear plant decommissioning costs
7. Nuclear fuel costs
8. Extraordinary costs.

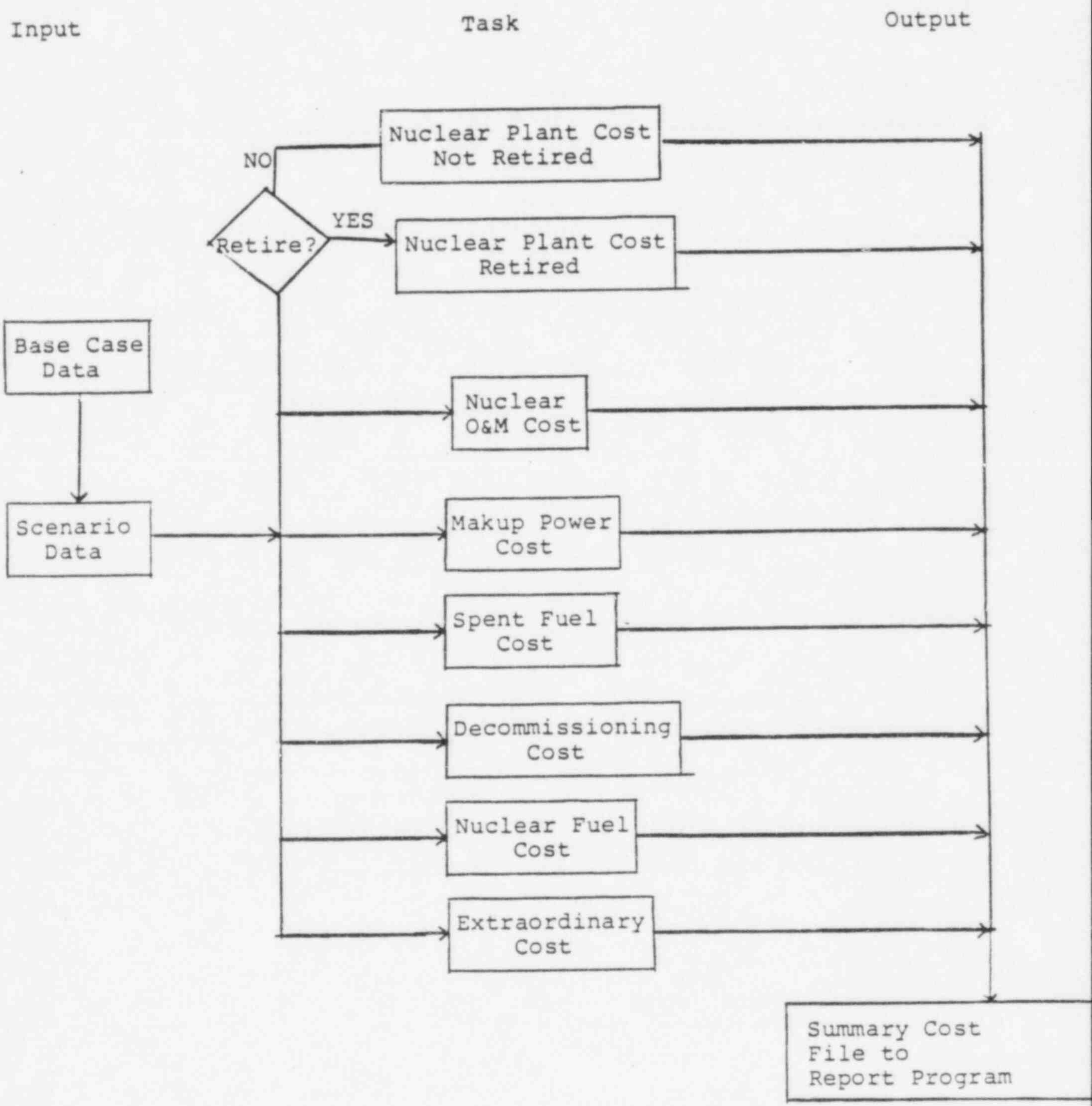
Since CANS was designed to estimate the costs of replacing nuclear plant with one or more alternatives, the modules were primarily designed to consider incremental required revenue impacts. For instance, the model makes no attempt to estimate the capital related costs of existing generators because these are independent of the decision on retiring nuclear plants. Similarly, no attempt is made to estimate the costs of current spent nuclear fuel.

An overview of CANS is provided in Figure A-1. The model reads the base case data, accepts or replaces values of inputs required for the particular scenario to be simulated, and calls the individual modules in turn. At this point it produces a file which summarizes the total revenue requirement impact as estimated by each module for the years in the study period. In addition, the user may request a more detailed report on the calculations performed by any of the individual modules.

When two scenarios have been simulated, the report program is used to generate a report comparing the results of the simulations.

Figure 1

Outline of the CANS Model



A-2. The Conventions of the CANS Model

In this section, we describe the handling of data common to more than one CANS module. In addition, we describe the conversion between cost estimates denominated in current dollars and present value estimates since this conversion is common to the reporting program (described in Section A-11) and the modules.

The data common to all CANs modules is entered through the BKGD data set. This data set is described in Table A-1. When CANS reports present values of various cost items, it does so based on the values of IPVYR and PVRATE from the BKGD data set. If PVRATE is not entered, present value calculations are based on the weighted cost of capital.

In the remainder of this appendix, we will make use of two conventions which the reader should note. First, variables which are inputs to CANS are denoted with an asterisk to distinguish them from variables which are internally calculated. Second, a number of variables are, in part, functions of time. These are denoted with the time subscript t. By convention, t is one in the base year; two in the second, and so on.

TABLE A-1

BKGD Data Set

Background Data Common to the CANS Program

$BNDCST_t$	Bond cost (as a fraction) in year t
$BNDSTR_t$	Bonds as a fraction of total capitalization in year t
CAPMW	Capacity of the nuclear generating unit in megawatts
COMP2	Logical variable. If true, the capital cost calculations are performed separately for two companies.
CONVRT	Factor to convert the dollars in which data is input to dollars of the base year of the study. Default value is 1.0.
$EQCST_t$	Common equity cost (as a fraction) in year t.
$EQSTR_r$	Common equity as a fraction of total capitalization in year t.
$ESCRAT_t$	The escalation rate to convert the year t-1 price level to the year t price level.
IBASE	Base year of the study
INDOL	Year in which input dollars are denominated
INYR	Year in which plant came on line
IPVYR	The year to which present values will be taken
IYRREP	The last year on which costs will be reported (Default value is LYSTUD)
LYSTUD	The last year of the study period
MECHO	Logical variable. If true the data sets are printed to a separate output file.
OWNSHR	The fraction of the nuclear generating unit owned by the utility being considered

$PRFCST_t$	Preferred stock cost (as a fraction) in year t
$PRFSTR_t$	Preferred stock as a fraction of total capitalizatior
PRTALL	If true, all modules print detailed reports on their estimations.
PVRATE	Rate for calculating present values (as a fraction). Default, weighted cost of capital is used.
REVTXR	Revenue tax rate, as a fraction
RRBAS	Total company required revenues in the base year
RRGR	Real escalation rate for required revenues.

A-3 Capital Costs of Nuclear Plant in Service

In this section, we describe the methodology employed to estimate the annual revenue requirement impact of the fixed charges associated with a nuclear plant. No allowance is made for fixed charges associated with nuclear fuel since these are estimated in the nuclear fuel cost module (see section A-6). The calculations described below are performed for every year in a "keep" scenario and for years prior to retirement in a "retire" scenario.

Like the other modules of CANS, this module employs both the background data set listed in Table A-1 and a module-specific data set, in this case CPTL. A description of the module specific data is presented in Table A-2.

As indicated in the table, the user can request employment of either normalized or flow-through accounting conventions. In the body of this section, we will assume normalized accounting. Subsequently, we describe the changes necessitated by a switch to the flow-through variant.

Required Revenues

The total annual revenue requirement impact is defined

$$REQREV_t = BKDEP_t + RETEQ_t + RETPRF_t + RETBND_t + TAX_t + DEFTAX_t - TXCRDA_t + OTHTOT_t - AFDCDA_t + REVTAX_t$$

TABLE A-2

CPTL Data Set

Used in Developing Annual Nuclear Capital Cost Estimates

Data Item	Description
AFDC	The allowance for funds used during construction (AFDC) component of original plant capital cost.
AFDCD	The income tax reduction resulting from the deduction of debt AFDC from taxable income which is flowed through to ratepayers.
BKLIFE	The total book life of the plant.
IDTXDP	Switch determining tax depreciation method if IDTXDP = 1, sum of the years' digits depreciation employed = 2, double declining balance depreciation employed If this variable is not specified, the default value is 1.
NRMDEP	Logical variable. If true, normalized accounting is employed. If false, flow-through accounting is used. The default value is true.
NYRDDB	When using the double declining balance method of calculating tax depreciation, NYRDDB controls the number of years during which that method will be used prior to switching over to straightline depreciation. The default value is one-half of the tax life.
OTHGRS	The fraction of original plant cost to be included as miscellaneous plant related expenses.
$OTHINP_t$	Annual miscellaneous expenses directly added to the revenue requirement.
OTHNET	Similar to OTHGRS except that the fraction is applied to the original cost net of book depreciation.
ORGCST	Original cost of the plant (in millions of dollars) including AFDC.
PRTFIX	Logical switch to prompt a report on the details of the fixed charge calculation. The default value is false.

TABLE A-2
(Continued)

RESCAP	The fraction of accumulated deferred taxes to be netted from the rate base. The default value is 1.
TXCRD	Total investment tax credit originally claimed for the plant.
TXLIFE	Tax life of the plant.
TXRATE	The composite (including federal and state) income tax rate.

where $REQREV_t$ - Required revenues in year t

$BKDEP_t$ - Book depreciation for revenue requirement purposes in year t

$RETEQ_t$ - Return to common stockholders in year t

$RETPRF_t$ - Return to preferred stockholders in year t

$RETBND_t$ - Return to bond holders in year t

TAX_t - Actual income taxes paid in year t

$DEFTAX_t$ - The difference between taxes charged to ratepayers and actual taxes (TAX_t) in year t

$TXCRDA_t$ - Amortization of the tax credit in year t

$OTHTOT_t$ - Other fixed charges in year t

$AFDCDA_t$ - Amortization of tax reduction from the interest component of AFDC in year t

$REVTAX_t$ - Revenue or gross receipts tax in year t

In the remainder of this section, each component of required revenues is described. An asterisk indicates those variables which are input items.

<u>$BKDEP_t$</u> - Annual book depreciation for rate purposes. Unless explicitly input, book depreciation for rate purposes is calculated under straight line depreciation.

$$BKDEP_t = ORGCST^*/BKLIFE^*$$

where ORGCST - Value of asset, including AFDC, when it comes on line

BKLIFE - The book life of the asset.

$\underline{RETEQ_t}$, $\underline{RETPFR_t}$, $\underline{RETBND_t}$ - Return to capital

The return to each type of capital is calculated as

$$\text{Equity cost, year } t = EQCST^*_t \times EQSTR^*_t$$

$$\text{Preferred cost, year } t = PRFCST^*_t \times PRFSTR^*_t$$

$$\text{Bond cost, year } t = BNDCST^*_t \times BNDSTR^*_t$$

where $XXXCST_t$ - the cost of capital source XXX in year t (expressed as a decimal)

$XXXSTR_t$ - the proportion of capital source XXX as a fraction of total capital in year t.

Since returns to each type of capital are calculated symmetrically, only the derivation of RETEQ, the return to equity capital, will be described in detail

$$RETEQ_t = EQCST^*_t \times EQSTR^*_t \times RATBAS_t$$

where $RATBAS_t$ is the mid-year rate base in year t.

The rate base is defined as

$$RATBAS_t = ((BKVAL_t + BKVAL_{t+1})/2 - RESCAP^* \times (DTXRES_t + DTXRES_{c+1})/2)$$

where $BKVAL_t$ is the book value of the plant at the beginning of year t

RESCAP* is the fraction of the deferred tax reserve fund to be netted from the rate base

DTXRES is the deferred tax reserve balance in year t

RESCAP* is input data. $DTXRES_t$ is described below. The book value of the plant is

$$BKVAL_t = ORGCST - \sum_{i=1}^{t-1} BKDEP_i = ORGCST^* \frac{BKLIFE^* - t+1}{BKLIFE^*}$$

where ORGCST, $BKDEP_t$ and BKLIFE retain their definitions given above.

TAX_t - Actual Income taxes paid

CANS does not distinguish between Federal and state income taxes. Therefore

$$TAX_t = TAXINC_t \times TXRATE^*$$

where $TAXINC_t$ - taxable income for Federal tax purpose excluding any deductible state or local income taxes in year t

TXRATE - the composite state and Federal income tax rate

$TXCRD_t$ is described below. TXRATE is input data. When state taxes are deducted from income in determining taxes, the composite rate must be calculated as follows.

State Tax = State tax rate x Income

Federal Tax = Federal tax rate x (Income-State tax)

Total Income Tax = Federal Tax + State Tax

= Federal tax rate x (Income - State tax rate x Income)

\+ State tax rate x Income

Therefore, the proper value of TXRATE for input is

TXRATE* = Federal rate + State rate - Federal rate x State rate

Taxable income must be calculated with reference to the fact that many components of income are after-tax

requirements. Taxable income must be sufficient to fulfill these requirements.[1]

$$TAXINC_t = \frac{1}{1\text{-}TXRATE^*} (BKDEP_t - TXDEP_t + DEFTAX_t - TXCRDA_t + RETEQ_t + RETPRF_t - AFDCDA_t)$$

where $BKDEP_t$ - Straight line depreciation for book purposes in year t

$TXDEP_t$ - Accelerated depreciation for tax purposes in year t

$DEFTAX_t$ - Deferred taxes due to normalizing accelerated depreciation in year t

$TXCRDA_t$ - Investment tax credit amortized in year t

$RETEQ_t$ - Return to common stockholders in year t

$RETPRF_t$ - Return to preferred stockholders in year t

$AFDCDA_t$ - Amortization of tax savings from AFDC

The depreciation terms are conveniently considered together. Another depreciation item which requires introduction is $BKDEPT_t$, depreciation for book taxes. $BKDEPT_t$ is similar to $BKDEP_t$ with one significant difference. Since only direct construction expenditures can be depreciated for tax purposes, depreciation was calculated

$$BKDEPT_t = (ORGCST^* - AFDC^*)/BKLIFE^*$$

where AFDC* - total AFDC during construction.

Other variables are defined above.

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[1]This equation is derived as follows

$$ATI_t = TAXINC_t - TXRATE \times TAXINC_t$$

where ATI - after tax income

rearranging terms yields:

$$TAXINC_t = \frac{1}{1\text{-}TXRATE} \cdot ATI_t$$

Unless input, accelerated tax depreciation is calculated by sum of the years' digits if IDTXDP = 1 or by double declining balance when IDTXDP = 2. Under sum of the years' digits,

$$TXDEP_t = (ORGCST^* - AFDC^*) \times (TXLIFE^* + 1-t)/SYD$$

$$SYD = \sum_{i=1}^{TXLIFE^*} i = TXLIFE^* \times (TXLIFE^*+1)/2$$

where $TXDEP_t$ - Accelerated depreciation for tax purposes in year 5

ORGCST - Cost of plant, including AFDC in rate base

AFDC - Total allowance for funds used during construction

SYD - Sum of the years' digits

Under double declining balance, tax depreciation in the early years is

$$TXDEP_t = (ORGCST^* - AFDC^*) \times (1-2/TXLIFE^*)^{t-1} \times (2/TXLIFE^*)$$

where all variables retain their previous definitions.

After one half of the tax life or at a user specified time, the double declining depreciation method reverts to straight-line depreciation to allow a complete write-off.

Deferred taxes resulting from accelerated depreciation under normalized accounting are calculated as

$$DEFTAX_t = (TXDEP_t - BKDEP_t) \times TXRATE^*$$

For ease in understanding, the first terms in the taxable income equation can be rewritten

$$\frac{1}{1\text{-TXRATE}}(BKDEP_t - TXDEP_t + DEFTAX_t)$$

$$= \frac{BKDEP_t - TXDEP_t + (TXDEP_t - BKDEPT_t)TXRATE}{1 - TXRATE}$$

$$= \frac{BKDEP_t - TXRATE \times BKDEPT_t + (1\text{-TXRATE})TXDEP_t}{1 - TXRATE}$$

$$= \frac{BKDEP_t - TXRATE \times BKDEPT_t}{1 - TXRATE} + TXDEP_t$$

<u>TXCRDA</u>$_t$ - Investment tax credit amortization

Total investment tax credits taken during construction are entered as data. Once construction expenditures are over, no further tax credits are generated.

Credits are amortized over the book life so that

$$TXCRDA_t = TXCRD^*/BKLIFE^*$$

<u>OTHTOT</u>$_t$ - Other Fixed Charges

Conceptually, these costs may represent insurance, property taxes or other miscellaneous items. To allow flexibility,

$$OTHTOT_t = OTHGR^* \times ORGCST^* + OTHNET^* \times BKVAL_t + OTHINP^*_t$$

where OTHGR* - Other costs incurred as a fraction of original cost.

OTHNET* - Other costs incurred as a fraction of net plant

$OTHINP^*_t$ - Other costs in dollar terms exogenously supplied by the user.

$BKVAL_t$ is described above in the discussion of $RETEQ_t$.

$\underline{AFDCDA}_t$ - Amortization of deferred taxes from debt portion of AFDC.

When AFDC is partially debt related, the interest expense during the construction period results in a tax reduction during those years. Under normalized accounting, these are flowed through to ratepayers at a constant rate over the service life.

$\underline{DTXRES}_t$ - Deferred Tax Reserve

Deferred taxes result from two sources: 1) accelerated depreciation under normalized accounting, and 2) normalization of the tax savings from debt portion of AFDC. The investment tax credit component is not considered. The deferred tax reserve is the sum of these components not yet passed to ratepayers. In some jurisdictions, this account is netted against the rate base or, equivalently, considered as part of the capital structure at zero return.

$$DTXRES_t = \sum_{i=1}^{t} DEFTAX_i + (AFDCD^* - \sum_{i=1}^{t-1} AFDCDA_i)$$

where $DEFTAX_t$ - Current deferred taxes in year t

$AFDCD^*$ - Tax savings from debt portion of AFDC

AFDCDA - Amortization of AFDC tax savings in year t

$DEFTAX_t$, AFDCD and AFDCDA are described above.

$$AFDCDA_t = AFDCD^*/BKLIFE^*$$

where $AFDCD^*$ - Total tax reduction during contruction period

$BKLIFE^*$ - Asset life for book purposes.

Both $AFDCD^*$ and $BKLIFE^*$ are data inputs.

$\underline{REVTAX_t}$ - Revenue

Revenue taxes are calculated after all other components of required revenues have been computed. For didactic purposes, we will refer to this total revenue requirement, net of revenue taxes, as RR′.

Revenue taxes are then defined

$$REVTAX_t = \frac{REVTXR^* \times RR'}{1-REVTXR^*}$$

where REVTXR* is the revenue tax rate.

Flow-Through Accounting

Under flow-through accounting, various tax savings are used to reduce required revenues immediately. The computation is simpler since there is no need to differentiate between actual and book taxes. The required revenue function is

$$REQREV_t = BKDEP_t - TXCRDA_t + RETEQ_t + RETPRF_t + RETBND_t + TAX_t + OTHTOT_t + TXCRD_t + REVTAX$$

Variables retain their definitions from section 1. Note this formulation differs in that the elements relating to normalization of accelerated depreciation and the debt portion of AFDC do not appear. Other required changes are similarly straightforward. DTXRES, the deferred tax reserve fund, is no longer relevant. The taxable income calculation is the same, but some terms cancel.

$$TAXINC_t = \frac{1}{TXRATE} (BKDEP_t - TXDEP_t + RETEQ_t + RETPRF_t - TXCRDA_t)$$

Otherwise, the same equations employed under normalized accounting continue to apply.

A-4 Capital Cost Recovery for Retired Plant

In many respects, recovery of the capital of retired plants is similar to recovery of the costs of plants that remain in service. The most important change is that in the year of retirement, the focus shifts from the recovery of undepreciated plant costs to the recovery of that portion of plant costs charged to ratepayers. I a given situation, it is possible that these two items will be ‹ qual. A second potential difference is that the costs of retired plants may be amortized over a different time period. Finally, there is an important tax effect since upon retirement, the remaining value of the plant is written off for tax purposes rather than being recovered over the remaining tax life.

When estimating plant capital costs under a retirement scenario, CANS first calculates the capital costs of maintaining the plant in service during the years prior to retirement. This serves two purposes. First, the costs for those years are required directly. Second, the simulation serves to provide estimates of the levels of the reserve accounts, e.g. depreciation, deferred taxes, unamortized investment tax credits.

The module employs three data sets: the background data set, the capital cost data set (see Table A-2), and a new data set, CPRT, shown in Table A-3.

TABLE A-3

CPRT Data Set

Used In Developing the Annual Capital Costs

Of Retired or Cancelled Nuclear Plant

Data Item	Description
AMLIFE	Amortization period (in years) over which the ratepayers will be assessed for their share of retired or cancelled plant costs.
DEPNET	Fraction of deferred tax reserves which is credited to ratepayers in determining the value of plant to be recovered from ratepayers. The default value is 1.
OTHGRS	Fraction of original plant cost incurred as an annual miscellaneous expense (Values for OTHGRS, OTHINP, and OTHNET over-ride values in CPTL data set).
OTHINP	Input annual miscellaneous expense.
OTHNET	Fraction of unamortized unused plant incurred as an annual miscellaneous expense.
RETURN	Fraction of unamortized unused plant included in the rate base.
RPSHAR	Fraction of plant cost recovered from ratepayers.
TXCNET	Fraction of unamortized investment tax credit reserve credited to ratepayers in determining the value of plant to be recovered from ratepayers. Default value is 1.
TXWNET	Fraction of tax savings from write-off off plant costs which is credited to ratepayers in determining the value of plant. Default value is 1.

Required Revenues

The required revenues component is defined by the same equation described in Section A-3. The reader should note, however, that the definitions of individual items may change somewhat. In particular, $BKDEP_t$ refers to current book depreciation when referring to plant in service and current amortization of unused plant cost for plant not in service.

The total annual revenue requirement impact is defined

$$REQREV_t = BKDEP_t + RETEQ_t + RETPFR_t + RETBND_t + TAX_t + DEFTAX_t - TXCRDA_t + OTHTOT_t - AFDCDA_t + REVTAX_t$$

where $REQREV_t$ - Required revenues in year t

$BKDEP_t$ - Amortization of unused plant in year t

$RETEQ_t$ - Return to common stockholders in year t

$RETPRF_t$ - Return to preferred stockholders in year t

$RETBND_t$ - Return to bond holders in year t

TAX_t - Actual income taxes paid in year t

$DEFTAX_t$ - The difference between taxes charged to ratepayers and actual taxes (TAX_t) in year t

$TXCRDA_t$ - Amortization of the tax credit in year t

$OTHTOT_t$ - Other fixed charges in year t

$AFDCDA_t$ - Amortization of tax reduction from the interest component of AFDC in year t

$REVTAX_t$ - Revenue or gross receipts tax in year t

The methodology employed in calculating these elements is extremely similar to that described in the previous section. That earlier development will be redrawn here only to the extent that it is modified. The subscript r will refer to the year of retirement.

$\underline{BKDEP_t}$ - Amortization of unused plant

$$BKDEP_t = RPPLNT / AMLIFE^*$$

where RPPLNT - the value of the plant net of tax write-off charged to rate payers at time of retirement

$AMLIFE^*$ - the amortization period

The total plant cost to be recovered from ratepayers is developed from the net value of the plant prior to retirement. This can be adjusted to reflect

1) The tax reduction which results from writing the plant off as a loss for income tax purposes

2) (Optionally) The netting out of the value of the associated deferred tax accounts

3) (Optionally) A reduction of the ratepayers liability to some fraction of the original plant cost

Adopting the convention that the subscript r refers to a variable value on January first of the retirement year, RPPLNT is defined:

$$RPPLNT = BKVAL_r - TXRATE * BKVALT_r - DTXRES_r X\ DEPNET^*$$

$$- TXCRDR_r \times TXCNET^*) \times RPSHAR^*$$

where $BKVAL_r$ - Book value of plant immediately prior to retirement

$BKVALT_r$ - Tax value of plant immediately prior to retirement

TXRATE* - Composite income tax rate

$DTXRES_r$ - Deferred tax reserve from depreciation and AFDC sources prior to retirement

DEPNET* - Portion of DTXRES netted from rate payers liability for plant

$TXCRDR_r$ - Deferred tax reserve from investment tax credit

TXCNET* - Portion of $AFDCDR_r$ netted from ratepayers liability for plant

RPSHAR* - Fraction of original plant cost to be recovered from ratepayers

ORGCST* - Original plant cost (including AFDC).

<u>$RETEQ_t$</u>, <u>$RETPRF_t$</u>, <u>$RETBND_t$</u> - Return to capital

The changes outlined above affect the return on capital through its effect on the rate base. The rate base calculation must be modified to reflect both the new asset valuation and the possibility that the deferred tax reserve accounts may have been netted out.

$$RATBAS_t = ((BKVAL_t + BKVAL_{t+1})/2 - RESCAP^* \times (DTXRES_t + DTXRES_{t+1})/2) \times RETURN^*$$

where $RATBAS_t$ - mid-year rate base in year t

RESCAP* - Fraction of deferred tax reserve netted from rate base

$DTXRES_t$ - Deferred tax reserve at the beginning of year t

RETURN* - Fraction of plant allowed in the rate base

$DTXRES_t$ is calculated as shown in section A-3, but its components are reduced by the multiplication factor (1-DEPNET*) to reflect the possibility that the reserve has been wholly or partly netted against the plant value.

The returns to capital, $RETEQ_t$, $RETPRF_t$, and $RETBND_t$ are calculated as before by using the weighted cost of each capital component.

$\underline{TAX}_t$

Income taxes are calculated as before. The full remaining value of the plant is assumed written off for tax purposes in the first year.

$\underline{DEFTAX}_t$

Deferred tax expense is zero under flow-through accounting when the full tax benefits of write-off have not been immediately credited to ratepayers (e.g. TXWNET $\neq$ 1). In this case, deferred taxes are

$$DEFTAX_t = -TXRATE^* * (1-DEPNET) \times BKVALT_r/AMLIFE$$

$\underline{TXCRDA}_t$, $\underline{AFDCDA}_t$

Investment tax credits and the tax savings from debt AFDC are amortized over the amortization period with adjustments to recognize cases in which they have been netted against the ratepayer plant liability.

$\underline{OTHTOT}_t$

Other costs are calculated as shown in A-3. The reader should note, however, that new values of the inputs OTHGRS*, $OTHIMP_t$, and OTHNET* are read from the CPRT data set.

$\underline{REVTXR}_t$

Revenue taxes are calculated as before.

A-5 Calculation of Nuclear Plant Operation and Maintenance Costs

The development of the statistical forecasts for operation and maintenance expenses is described in detail in Appendix B. Here we will simply report the manner in which those forecasts are employed by CANS to produce required revenue impacts. In general, one cf the two forecasting equations is employed in each simulation to derive an estimated real (net of general inflation) escalation rate for nuclear O+M costs for each year in the study period and prior to retirement. These escalation rates are then employed in concert with input values for base year nuclear O+M costs and a general inflation rate to produce estimated current dollar costs estimates for each year. In addition, the user is allowed to specify a scaling factor (OMSCAL) which is used to adjust the estimated real escalation rates.

This module requires the OM data set in addition to the general data. The OM data set is described in Table A-4.

Given the data inputs, nuclear O+M costs are calculated recurseively beginning in the first year.

$$OMCOST_t = OMNET_t + REVTX_t$$

where $OMCOST_t$ - Total O+M cost in year t including an allowance for revenue taxes.

$OMNET_t$ - O+M cost net of revenue taxes in year t

$REVTX_t$ - Revenue taxes associated with O+M costs in year t.

Revenue taxes are calculated in the manner described in A-3 and can be quickly dismissed.

$$REVTX_t = REVTXR^* \times OMNET_t/(1-REVTXR^*)$$

where REVTXR - revenue tax rate

TABLE A-4

O&M Data Set

Data Requirements for Calculating
Nuclear Operations and Maintenance Costs

Variable	Description
BASEOM	Nuclear operations and maintenance expense in the base year (millions of dollars)
$BIRTH_t$	Year unit first came on line relative to 1970. Since there may be if multiple units are at a site, this must be input as a vector of length 50 since other units on the site could be retired.
DEMO	A value of 1 indicates a demonstration unit. Otherwise zero.
LOG	Logical variable. If true, log-linear specification is employed. Otherwise, linear model used. Default value is false.
NEMASK	A value of one indicates the plant is in the Northeast. Otherwise zero.
OMSCAL	Scaling factor applied to the calcualted real escalation rate. See text. Default valve is one.
PRTOM	Logical variable. If true, a separate report on operations and maintenance costs is produced.
SALT	A value of one indicates a salt water cooling system. Otherwise zero.
SECOND	A value of one indicates unit is one of two or more at the site. For the reason noted in the discussion of BIRTH, above, this must be input as a vector.
TOWERS	A value of one indicates cooling towers are used. Otherwise zero.
TYPE	A value of one indicates unit is a pressurized water reactor (PWR). A value of zero indicates a boiling water reactor (BWR).

Operations and maintenance expenses net of revenue taxes is calculated

$$OMNET_t = BASEOM^* \text{ for } t = 1$$

$$= OMNET_{t-1}\ (1 + OMSCAL^*(\frac{OMEQ_t}{OMEQ_{t-1}} -1) + ESCRAT^*_{t-1})$$

$$\text{for } t > 1$$

where BASEOM* - Input operations and maintenance cost in the first year of the study (millions of dollars)

$OMEQ_t$ - Predicted operations and maintenance costs from linear or log-linear statistical model

OMSCAL* - Input scali factor to adjust real escalation rate

$ESCRAT^*_{t-1}$ - General inflation rate from year t-1 to year t.

The values of $OMEQ_t$ are developed from either the linear or log-linear forecasting equation, depending on the value of the logical variable LOG*. If LOG is false the linear equation is employed. If true, the log-linear version is used. Using the linear equation,

$$\begin{aligned} OMEQ_t = \ & 23.1426 \\ & +4.000111 \times NEMASK^* \\ & +4.64958 \times SALT^* \\ & +2.75956 \times TOWERS^* \\ & +15.2714 \times DEMO^* \\ & +1.18159 \times TYPE^* \\ & -0.00372 \times CAPMW^* \\ & +1.94284 \times (IYEAR_t-1980) \\ & +0.89526 \times DEMO^* \times (IYEAR_t-1980) \\ & -3.17592 \times SECOND^*_t \\ & -0.38098 \times BIRTH^*_t \end{aligned}$$

where CAPMW - Plant capacity (in megawatts)

$IYEAR_t$ - Calendar year associated with year index t

All other variables as shown in Table A-5.

Using the log-linear specification,

$$
\begin{aligned}
OMEQ_t = \exp\ (3.01852 \\
& +0.270349 \times NEMASK* \\
& +0.280196 \times SALT* \\
& +0.109606 \times TOWERS* \\
& +0.546909 \times DEMO* \\
& +0.075949 \times (IYEAR_t - 1980) \\
& +0.000102 \times CAPMW*_t (ITIME-1980) \\
& -0.201635 \times SECOND_t \\
& -0.013045 \times TYPE* \times (ITIME-1980)
\end{aligned}
$$

where all variables retain their previous definitions.

A-6. Makeup Energy and Power Costs

The Makeup Energy and Power Costs module is employed to estimate the sources of energy which will replace nuclear generation and to calculate their costs. For this reason, it does not calculate costs when CANS is simulating a keep case.[1] Total makeup costs are calculated as the sum of five components:

1) Conservation costs when additional conservation is assumed to replace nuclear generation.
2) Energy costs (fuel and O&M) of replacement electricity
3) Capacity costs
4) Costs of fuel switching or similar investments
5) Revenue taxes.

As will be described below, energy costs can be developed in either of two ways. The total energy costs of a "KEEP" and a "RETIRE" case may be independently estimated (typically using a separate production costing model) or CANS will develop the cost estimate internally based on a user specified mix of replacement energy sources. Makeup power costs are calculated based upon data in the MKUP data set, described in Table A-5.

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[1] Strictly, the subroutine is called in such cases, but it assigns a zero cost.

TABLE A-5

MKUP Data Set

Data Used to Calculate Makeup Power Costs

Variable	Description
$CAPCST_j$	The capital cost of fuel switching investment j ($j \leq 50$) (in millions of IYRCAP dollars)
$CAPFCF_j$	The levelized fixed charge factor associated with investment j
CONB$	Base year capital cost of conservation (in dollars per killowatt hour)
CONFCF	Fixed charge factor to derive annualized cost of conservation
CONPEN	Ultimate conservation penetration ratio. Fraction of total energy demand met by conservation after the conservation plan is fully implemented
$FGWHKP_t$	When GWHINP is true, $FGWHKP_t$ is the total nonnuclear fuel cost in the reference case, year t. (Millions of current dollars)
$FGWHRT_t$	Counterpart of $FGWHKP_t$ current for the retirement case
$FSOM_t$	Differential operation and maintenance expenses resulting from fuel switching investment in year t
$FUEL_i$	Base year fuel cost of generation option i ($i \leq 5$) in dollars per million Btu
FWKCAP	Fuel working capital contribution to required revenues as a fraction of fuel expense
$GFRAC_{t,i}$	Fraction of replacement generation from source i in year t
GWHINP	Logical variable. If true, replacement energy costs are calculated based on the results of an independent analysis. The fault value is false
$HTRATE_i$	Average heat rate of generation option i, BTU per kilowatt hour

TABLE A-5

Continued

Variable	Description
$ICLIFE_j$	Book life of fuel switching investment j.
ILYCON	Year in which conservation achieves full penetration (CONPEN)
ISTCON	Year in which conservation program begins
$IYRCAP_j$	The year in which fuel switching investment j first is reflected in required revenues
$IYRNRG_j$	List of 3 future years in which forecast energy demand is available (See REFNRG)
NFUELS	Number of fuels used to provide replacement power ($NFUELS \leq 5$)
OMGEN	Operations and maintenance expense for replacement--power source λ ($\lambda \leq 5$)
$OGWHKP_t$	When GWHINP is true, $OTWHKP_t$ is the total non-nuclear operations and maintenance cost in the reference case, year t (millions of year t dollars).
$OGWHRT_t$	Counterpart of $OTWHKP_t$ for the retirement case.
PRTMUP	Logical variable. If true, a report on makeup power costs is printed.
RCESC	Real escalation rate for conservation costs
$REFNRG_j$	Forecast gigawatt hour demand for each of the three years specified by $IYRNRG_j$
$RFESC_j$	Real escalation rate for fuel costs of replacement power source j
$ROMESC_j$	Real escalation rate for operations and maintenance costs of replacement source j
RMWESC	Real escalation rate of peak capacity shortage costs

TABLE A-5

Continued

Variable	Description
$SHRTMW_t$	Megawatts of peak capacity shortage in year t
$MW	Base year peak capacity shortage cost (in dollars per megawatt)

Total makeup costs are calculated

$$TOTAL_t = \$CON_t + GWHDIF_t + \$SHRTP + TCAP_t + REVTAX_t$$

where $TOTAL_t$ - Total makeup costs (in millions of dollars) in year t

$\$CON_t$ - Total cost, as reflected in required revenues, of additional conservation

$GWHDIF_t$ - Total differential energy cost of generation and/or imports

$\$SHRTP_t$ - Total differential peak cost of generation and/or imports

$TCAP_t$ - Total cost of fuel conversion or similar investments

$REVTX_t$ - Annual revenue taxes associated with makeup power

Revenue taxes are calculated in the same manner described in section A- . The other four components of makeup costs are discussed below.

<u>$\$CON_t$ - Conservation Costs</u>

If additional conservation efforts are undertaken in response to plant retirement, the resulting reduction in demand can be considered as a source of makeup power, de facto. Similarly, the costs of these efforts, to the extent they are reflected in required revenues, are a cost of makeup power. Conservation costs are calculated (in millions of dollars)

$$\$CON_t = CONB\$^* \times TCESC_t \times CONFCF^* \times CONGWH_t$$

where $CONB\$^*$ - Base year capital cost of conservation per KWH

$TCESC_t$ - Total escalation factor to convert base year conservation costs to costs in year t

$CONFCF^*$ - Fixed charge factor to annualize conservation capital costs

$CONGWH_t$ - Reduction in energy demand due to conservation

CONB$* and CONFLF* are input data items. Escalation factors similar to $TCEFC_t$ are also calculated for the other makeup costs. Discussion of these three elements is reserved for the end of the section. $CONGWH_t$ is calculated as a fraction of total systemwide energy demand, the fraction being determined by an ultimate conservation penetration and by a phase-in period for the conservation measures.

$$CONGWH_t = CONPEN^* \times FRCON_t \times DEMNRG_t$$

where CONPEN* - Conservation penetration fraction

$FRCON_t$ - Fraction representing the position of year t to the phase-in period

$DEMNRG_t$ - Base case customer energy demand in year t

CONPEN* is an input data item. $FRCON_t$ is determined by a user supplied phase-in period.

$$FRCON_t = 0 \quad \text{if } IYEAR_t < ISTCON^*$$

$$= \frac{IYEAR_t - ISTCON^* + 1}{ILYCON^* - ISTCON^* + 1} \quad \text{if } IYEAR_t \geq ISTCON^* \text{ and } IYEAR_t < ILYCON^*$$

$$= 1 \text{ if } IYEAR_t \geq ILYCON^*$$

where $IYEAR_t$ - Calendar year corresponding to year index t

ISTCON* - Year in which conservation effort produces its first effects

ILYCON* - Year in which conservation effort reaches full effect.

Base case energy demand, $DEMNRG_t$, is calculated based on forecasts of energy demands ($REFNRG_j^*$) in each of three years ($IYRNRG_t^*$). For other years, demand is assumed to be a piece-wise linear function of time.

$$DEMNRG_t = REFNRG_2 + \frac{REFNRG_2 - REFNRG_1}{IYRNRG_2 - IYRNRG_1} \times (IYEAR_t - IYRNRG_2)$$

For $IYEAR_t \leq IYRNRG_2$

$$= REFNRG_2 + \frac{REFNRG_3 - REFNRG_2}{IYRNRG_3 - IYRNRG_2} \times (IYEAR_t - IYRNRG_2)$$

For $IYEAR_t > IYRNRG_2$

where $IYRNRG_j^*$ - Is the calendar year of energy forecast j

$REFNRG_j^*$ - Energy demand (in GWH) of energy forecast j

<u>$GWHDIF_t$ - Energy Cost of Makeup Power</u>

As noted earlier in this section, energy costs can be separately estimated or calculated by the CANS model. In the former case, energy costs are the difference between two vectors of annual costs.

$$GWHDIF_t = (1 + FWRKLP^*)\ (FGWHRT_t^* - FGWHRP_t^*) + (OGWHRT_t^* - OGWI$$

where * - Fractional working capital allowance

$FGWHRT_t$ - Non-nuclear fuel cost in the retirement case, year t

$FGWHKP_t$ - Non-nuclear fuel cost in the reference case, year t

$OGWHRT_t$ - Non-nuclear operations and maintenance cost in the retirement case, year t

$OGWHKP_t$ - Non-nuclear operations and maintenance cost in the reference case, year t.

If estimates of energy costs are not available from outside sources, they are calculated by CANS based upon the amount of energy required, the costs of energy from various sources, and user supplied estimates of the fraction of the

total energy which will be provided by each source. Total costs are:

$$GWHDIF_t = \sum_{i=1}^{NFUELS} GWHSUP_{t,i} \times (HTRATE_i \times FUEL_i \times (1 + FWRKCP) \times TFESC_{t,i}/1{,}000{,}000) + OMGEN_i \times TOMESC_{t,i})$$

where NFUELS* - Number of sources of energy considered (NFUELS $\leq$ 5

$GWHSUP_{t,i}$ - Energy production (in GWH) from source i in year t

FWRKCP* - Working capital fractional allowance

$HTRATE_i^*$ - Heat rate of source i (in BTU per kilowatt hour)

$FUEL_i^*$ - Base year fuel cost of source i (in dollars per million BTU)

$TFESC_{i,t}$ - Total escalation factor for fuel i in time period t

$OMGEN_i^*$ - Base year variable operations and maintenance cost of source i

$TOMESC_{t,i}$ - Total escalation factor for fuel i in time period t.

As indicated, NFUELS, FWKLAP, $HTRATE_i$, $FUEL_i$, and $OMGEN_i$ are data items. The escalation factor derivation is at the end of this section. Energy production is calculated

$$GHWSUP_{t,i} = GFRAC^*_{t,i} \times (BSHWH1_t + BSGWH2_t) - (SCGWH1_t + SCGWH2_t) - CONGWH_t)$$

where $GFRAC^*_{t,i}$ - the fraction of energy supplied by source i in year t

$BSGWH1_t$ - Nuclear plant output (in GWH) from unit 1 in the reference case in year t

$SCGWH1_t$ - Nuclear plant output (in GWH) from unit 1 in the current scenario in year t

$CONGWH_t$ - Conservation makeup energy in year t

Conservation energy ($CONGWH_t$) is derived above. Nuclear output is calculated based on capacity factors input in the CPFC data set shown in Table A-6. Reference case nuclear output from generating unit one is

$$BASWH1_t = 8.760 \times UN1MW \times BCPFC1$$

where UN1MW* - unit one capacity (in MW)

$BCPFC1_t$ - Reference case capacity factor of unit one in year t.

Each of these items is input data. The other plant outputs are similarly calculated. $SCGWH1_t$ is defined to be zero after plant retirement.

The reader should note that energy makeup costs may be negative under some circumstances. In the years immediately prior to retirement, the user may wish to specify that an increased nuclear capacity factor, due perhaps to a modified refueling or maintenance schedule, or an early conservation program will cause a reduction in the energy supplied from non-nuclear sources. The Makeup module calcuates this as a credit using exactly the algorithms described above.

Peak Costs of Generation and/or Imports

Under retirement, peak costs may be incurred when construction of additional peaking units is necessary or when increased electricity importation requires a payment based upon the level of peak purchases. The revenue requirement impact of these costs is calculated

TABLE A-6

CPFL Data Set

Data Used to Determine Nuclear Generation

$BCPFC1_t$	-	Annual capacity factor of nuclear generating unit one in the reference case (year t)
$BCPFC2_t$	-	As above for unit 2
PRTFAC	-	Logical variable. If true, a report on capacity factors and nuclear generation is printed.
$SCPFC1_t$	-	Annual capacity factors of nuclear generating unit one in the retirement case (year t)
$SCPFC2_t$	-	As above for unit 2
UN1MW	-	Capacity (in megawatts) of unit one. (Default valve is CAPMW x OWNSHR from BKGD data set).
UN2MW	-	As above for unit 2.

$$\$SHRTP_t = SHRTMW_t^* \times \$MW^* \times TMWESC_t/1{,}000{,}000$$

where $SHRTMW_t^*$ - Number of megawatts of on-peak shortage

$\$MW^*$ - Base year cost of onpeak shortage (in dollars per megawatt)

$TMWESC_t$ - Total escalation factor for peak costs in time period t.

The items $SHRTMW_t$, and \$MW are from data. $TMWESC_t$ and the escalation factors employed earlier are described below.

TCAP--Fuel Switching Investments

The impact of fuel switching investments on required revenues is simulated through a fixed charge factor technique.

$$TCAP_t = FSOM_t + \sum_{i=1}^{50} \Psi_{\gamma,t} \times CAPCST_i \times CAPFLF_i$$

$$\Psi_{i,t} = 1 \quad \text{if } IYRCAP_i - IBASE + 1 \leq t \leq IYRCAP_i - IBASE + ICLIFE_i$$

$$= 0 \quad \text{Otherwise}$$

where $TCAP_t$ -- Revenue requirement impact of all fuel switching investments in year t

$FSOM_t^*$ -- O&M expenses of fuel switching investments in year

$CAPCST_i^*$ -- Current dollar cost of investment i

$CAPFLF_i^*$ -- Levelized fixed charge factor of investment i

$IYRCAP_i^*$ -- Year in which investment i is first reflected in required revenues

$ILLIFE_i^*$ - Book life of investment i

Escalation Factors

Individual escalation factors are employed for each of the components of makeup costs except for revenue taxes. The

method of calculation for all is very similar. For this reason, only $TCESC_t$, the escalation factor for conservation costs will be developed in detail.

$$TCESC_t = CONVRT^* \quad \text{when } t=1$$

$$TCESC_t = TCESC_{t-1} \times (1+ESCRAT^*_{t-1} + RCESC^*)$$

$$\text{when } t > 1$$

Where CONVRT* - conversion factors from input to base year dollars

$ESCRAT^*_{t-1}$ - nominal escalation factor to convert year t-1 dollars to year t dollars

RCESC* - Real escalation rate for conservation costs.

With the exception of the recursive term, $TCESC_{t-1}$, all elements are data items. (CONVRT and ESCRAT are from the BKGD data set.) It should be noted that when data is input in base year dollars, the value of CONVRT defaults to one.

A-7. Spent Fuel Costs

CANS does not produce an independent estimate of spent fuel costs. This analysis is separately performed and is described in Appendix D. CANS does, however, take the results of that analysis and estimate its impact on required revenues. This is done by spreading the costs over a user specified period of years under the assumption that recovery is equal in present value terms in each year.

The spent fuel module requires data set SFCT which is described in Table A-7. Using this data, it calculates the annual revenue requirement impacts in present value terms

$$SFRRPV_t = 0 \quad \text{if } IYEAR_t < IYRSTF^* \text{ or } IYEAR_t > IYRFNF^*$$

$$= \frac{TOTSF}{IYRFNF-IYRSTF + 1} \quad \text{if } IYRSTF^* \leq IYEAR_t \leq IYRFNF^*$$

where

- $SFRRPV_t$ - Spent fuel revenue requirement impact in present value terms in year t
- IYRSTF - First year in which spent fuel costs will be collected through the revenue requirement
- $IYEAR_t$ - Calendar year corresponding to index year t
- IYRFNF - Last year in which spent fuel costs will be collected through the revenue requirement

The revenue requirement impact in current dollar terms is then calculated through application of the present value multiplier (see section A-2).

$$SFRR_t = SFRRPV_t / PVVECT_t$$

TABLE A-7

SFCT Data Set

Data for Calculating Spent Fuel Costs

Variable	Description
IYRFNF	Last year in which spent fuel costs will be recovered through required revenues
IYRSTF	First year in which spent fuel costs will be recovered through required revenues
PRTSFC	Logical variable. If true, a report on spent fuel revenue requirement impacts is produced
TOTSF	Present value of total spent fuel costs (in millions of dollars).

where $SFRR_t$ - Spent fuel revenue requirement impacts in current dollar terms in year t

$PVVECT_t$ - Present value factor which, muliplicatively, converts current dollar costs to their present value equivalents in year t.

An allowance for revenue taxes is also made.

A-8 Decommissioning Costs

Like spent fuel costs described previously, an independent estimate of decommissioning costs is developed off line (see Appendix E) and the results are used by CANS to develop annual revenue requirements in the same manner used for spent fuel costs.

The decommission'ng cost module uses the DCCT data set described in Table A-8. It calculates the annual revenue requirements in present value terms

$$DCRRPV_t = 0 \quad \text{if} \quad IYEAR_t < IYRSTD \quad \text{or} \quad IYEAR > IYRFND$$

$$= \frac{TOTDC}{IYRFND-IYRSTD+1} \quad \text{If } IYRSTD \leq IYEAR_t \leq IYRFND$$

where $DCRRPV_t$ - Decommissioning revenue requirement impact in present value terms in year t

IYRSTD - First year in which decommissioning costs will be reflected through rates

IYEAR - Calendar year corresponding to index year t

IYRFND - Last year in which decommissioning costs will be reflected through rates.

The revenue requirement impact in current dollar terms is

$$DCRR_t = DCRRPV_t/PVVECT_t$$

where $DCRR_t$ - Decommissioning revenue requirement impacts in current dollar terms

$PVVECT_t$ - Present value factor which, multiplicatively, converts current dollar costs to their present value equivalents in year t.

An allowance for revenue taxes is also made.

TABLE A-8

DCCT Data Set

Data for Calculating Decommissioning Costs

Variable	Description
IYRFND	Last year in which decommissioning costs will be recovered through required revenues
IYRSTD	First year in which decommissioning costs will be recovered through required revenues
PRTDC	Logical variable. If true, a report on decommissioning revenue requirement impacts is produced.
TOTDC	Present value of total decommissioning costs (millions of dollars)

A-9. Nuclear Fuel Costs

Nuclear Fuel costs are calculated based upon user supplied data defining the capacity of each generating unit, its capacity factor, and its cost per kilowatt-hour of electricity generated. The first two items are described above in Section A-6 on makeup power costs. The last is calculated based upon data from the MFUL data set described in Table A-9. In the remainder of this Section, we describe the development of nuclear fuel costs for the first nuclear unit. When a second unit is also present, precisely symmetric calculations are performed for it.

The revenue requirement contribution of nuclear fuel by the first generating unit is

$$FLNRR_{1,t} = FLNKWH_{1,t} \times SCHWH1_{i}/1000.0$$

where $FLNRR_{1,t}$ - Revenue requirement of unit 1 Fuel in in year t (millions of dollars)

$FLNKWH_{1,t}$ - Fuel cost per kilowatt hour of unit 1 in year t (mils per kilowatt hour)

$SCLWH1_{t}$ - Generation of unit 1 in year t (gigawatt-hours).

$FLNKWH_{1,t}$ is the new element. It reflects allowances for return on nuclear fuel investment and revenue taxes.

$$FLNKWH_{1,t} = \frac{(1 + FULNWC^{*}) \times FULNBS^{*}_{1} \times TFESC_{t}}{(1 - REVTXR^{*})}$$

$TFESC_{t}$ is the nuclear fuel escalation factor in this module. It is calculated similarly to its counterparts in other modules.

$$TFESC_{t} = CONVRT^{*} \quad \text{when } t = 1$$

$$= TFESC_{t-1} \times (1 + ESCRAT_{t-1} + FULMGR^{*}) \quad \text{when } t > 1$$

TABLE A-9

NFUL Data Set

Data for Calculating Nuclear Fuel Costs

Variable	Description
$FULNBS_i$	Base year fuel cost of nuclear unit i ($i \leq 2$) in Mils per Kilowatt-hour.
FULNGR	Real escalation rate for nuclear fuel
FULNWC	Working capital multiplier for nuclear fuel
PRTNFL	Logical variable. If true, a report on nuclear fuel costs is generated.

A-10. Other Costs

As defined here, other costs represent one time costs required to maintain a nuclear plant in operation. CANS allows the user to separate these costs into those that will be capitalized and those that will be directly reflected in required revenues as expense items. In the former case, costs are reflected in required revenues by reference to a levelized fixed charge factor and an asset book life.

This module employs the XTRA data set detailed in Table A-10. The required revenue impact is the sum of the impacts of the expensed and the capitalized items.

$$XTRR_t = XEXPRR_t + XCAPRR_t$$

where $XTRR_t$ - Total revenue impact in year t

$XEXPRR_t$ - Revenue impact of capitalized items in year t

$XCAPRR_t$ - Revenue impact of capitalized items in year t

The revenue effect of expenses items is

$$XEXPRR_t = \sum_{i=1}^{50} \Psi_{i,t} \times XTLAP_i^* \times XTCFCF_i^*/(1-REVTXR^*)$$

$$\Psi_{i,t} = 1 \text{ if } IXTCAP_i^* - IBASE^{*+1} \leq t \leq IXTCAP_i^* + IXLIFE_i^* - IBASE^*$$

$$= 0 \text{ Otherwise}$$

TABLE A-10

XTRA Data Set

Data for Calculating Extraordinary Costs

Variable	Description
$IXLIFE_i$	Book life of capitalized expenditure i ($i \leq 50$)
$IXTCAP_i$	Year in which capitalized expenditure i is first reflected in required revenues
$IXTEXP_j$	Year in which non-capitalized expenditure j ($j \leq 50$) is made
PRTXTR	Logical variable. If true, a report on extraordinary costs is generated
$XTCAP_i$	Capitalized expenditure i (millions of $IXTCAP_i$ dollars)
$XTCFCF_i$	Levelized fixed charge factor associated with capitalized expenditure i
$XTEXP_j$	Non-capitalized expenditure i (millions of $IXTEXP_j$ dollars)

A-11. Cost Comparison Report

In addition to the cost estimation program, the CANS system includes a separate program (RETREP) which compares the costs of any two user specified scenarios. The logic of the program is very simple and intuitively straightforward. Each module of the cost estimation program writes an alpha-numeric identifier and the estimated annual costs to an intermediate file where it is saved. RETREP reads intermediate files for each of two cases and writes four reports.

1,2. For each case, a summary of the annual costs by component as well as aggregations over components and over years.

3. The differential cost of the second scenario relative to the first expressed in mixed current dollars.

4. The differential costs cited above but expressed in present value terms.

The RETREP program requires no new data, relying on the intermediate files just described and the BKGD data set described in Section A-2.

With one minor exception, the calculations performed by RETREP are limited to simple summing and subtracting and therefore will not be described in detail. The single exception is the column of the differential cost reports entitled "Annual % Impact." This column is calculated as the annual differential cost of scenario 2 as a percentage of total company required revenues. The latter is calculated as base year required revenues (RRBAS* in Table A-1) escalated according to both nominal and real inflation rates (ESCRAT* and RRGR*, respectively in the same table).

APPENDIX B

NUCLEAR POWER PLANT

OPERATION AND MAINTENANCE

COSTS

ESRG

August 1982

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B-1 NUCLEAR O&M DATABASE PREPARATION

O&M Costs

Operations and maintenance (O&M) cost data was collected from government documents and utility filings with government agencies. For the years preceeding 1978, the annual editions of the FERC survey of utility reports, "Steam Electric Plant Construction Costs and Annual Production Expenses" were utilized. For the year 1978 a proof of the 1978 edition of the steam survey was used in conjunction with the utilities' 1978 FERC Form 1 filings. The 1979 costs are based exclusively on Form 1 filings except for costs for the Cooper and Fort Calhoun stations which were obtained directly from the utilities.*

All data from the years 1970 through 1979 were included in this survey except the following: Humboldt station was not in operation during the years 1978 and 1979; the O&M costs for these years were excluded from this survey. Three Mile Island 2 was not included. Three Mile Island 1 was included, but data for the year 1979 was excluded because it was not in operation. Some further exclusions, mostly of abnormal partial years, will be described later.**

Table B-1 presents the annual O&M costs as reported. Table B-2 presents these costs in constant 1978 dollars by multiplying costs in Table B-1 by the GNP inflator, Table B-3.

Analysis of nuclear plant costs as presented in Tables B-1 or B-2 is difficult primarily because many stations are composed of more than one unit. Since utilities with multiple unit stations do not have to report O&M cost data on FERC forms separately by unit, the present analysis does not separate the cost data by unit.

---

* Private communication, Verdel Goldberg at Omaha Public Power and Bob Buntain at Nebraska Public Power.

** In addition, Shippingport and LaCross were not included because data could not be obtained for years prior to 1978.

TABLE B-1

OPERATIONS AND MAINTENANCE COSTS IN MIXED CURRENT DOLLARS

	1970	1971	1972	1973	1974	1975	1976	1977	1978	1979
DUANE ARNOLD	-	-	-	-	6.29	7.68	14.10	15.02	23.83	19.06
BEAVER VALLEY	-	-	-	-	-	-	8.80	18.36	28.35	28.63
BIG ROCK POINT	16.86	20.10	22.41	25.17	35.92	41.02	50.52	81.35	57.86	146.56
BROWNS FERRY	-	-	-	-	-	4.96	7.55	[illegible]	14.35	17.37
BRUNSWICK	-	-	-	-	-	35.50	13.31	17.96	16.86	21.65
CALVERT CLIFFS	-	-	-	-	-	8.06	11.09	13.75	15.52	21.73
DONALD C. COOK	-	-	-	-	-	4.44	6.71	9.54	9.68	12.44
COOPER	-	-	-	-	7.50	9.49	[illegible]	13.13	10.68	13.15
CONNECTICUT YANKEE	7.79	5.70	6.52	11.05	8.58	16.31	16.38	16.43	15.19	32.91
CRYSTAL RIVER	-	-	-	-	-	-	-	11.66	19.23	29.54
DAVIS BESSE	-	-	-	-	-	-	-	122.92	15.56	22.69
DRESDEN	4.58	3.31	5.09	5.04	9.32	18.33	16.76	15.04	18.90	24.84
JOSEPH M. FARLEY	-	-	-	-	-	-	-	7.11	15.45	28.53
JAMES A. FITZPATRICK	-	-	-	-	-	18.70	13.37	21.73	23.81	31.41
FORT CALHOUN	-	-	-	4.07	7.67	13.40	16.74	19.09	18.24	19.11
ROBERT E. GINNA	-	5.82	7.90	6.84	10.43	12.76	14.23	15.36	18.99	24.79
EDWIN I. HATCH	-	-	-	-	-	-	6.90	11.53	31.87	12.07
HUMBOLDT BAY	9.83	14.70	14.24	14.52	16.98	19.22	31.43	48.90	25.95	23.52
INDIAN POINT 1	13.20	14.95	26.23	-	-	-	-	-	-	-
INDIAN POINT 2	-	-	-	45.70	14.74	15.27	21.16	19.13	32.60	37.78
INDIAN POINT 3	-	-	-	-	-	-	7.50	13.11	24.16	29.93
KEWAUNEE	-	-	-	-	24.90	11.51	20.05	20.42	19.50	21.16
MAINE YANKEE	-	-	-	5.04	6.54	7.88	6.58	10.52	13.52	12.47
MILLSTONE 1	-	4.93	11.63	11.57	14.86	18.28	21.27	19.15	24.92	34.94
MILLSTONE 2	-	-	-	-	-	.54	13.46	21.40	27.45	27.01
MONTICELLO	-	5.56	4.61	8.99	9.30	15.67	11.87	19.94	16.40	19.00
NORTH ANNA	-	-	-	-	-	-	-	-	13.17	21.52
NUCLEAR ONE	-	-	-	-	-	4.92	7.19	10.02	14.50	22.64
NINE MILE POINT	2.81	4.52	5.86	7.42	10.25	9.52	8.74	15.97	11.20	19.12
OCONEE	-	-	-	2.91	6.85	4.83	6.49	9.70	11.47	15.57
OYSTER CREEK	3.00	4.76	5.96	9.71	16.43	18.94	16.00	22.82	24.46	20.08
PALISADES	-	-	-	4.27	15.92	12.97	13.31	8.88	20.80	35.60
PEACH BOTTOM	-	-	-	-	3.35	6.04	14.64	22.33	18.81	21.59
PILGRIM	-	-	2.85	7.16	14.22	10.96	24.83	22.87	21.17	27.44
POINT BEACH	-	-	9.22	3.68	5.28	6.22	6.66	8.09	7.47	12.59
PRARIE ISLAND	-	-	-	4.81	7.85	6.94	14.89	16.34	13.59	14.67
QUAD CITIES	-	-	3.46	3.99	5.84	9.36	10.60	11.25	14.05	19.79
RANCHO SECO	-	-	-	-	-	17.75	7.84	8.85	12.89	14.95
H.B. ROBINSON	-	3.44	2.54	6.58	6.83	9.09	8.43	9.41	20.51	21.63
ST. LUCIE	-	-	-	-	-	-	42.19	9.47	19.89	18.10
SALEM	-	-	-	-	-	-	-	23.15	20.49	43.63
SAN ONOFRE	5.13	5.53	8.07	13.39	12.75	19.88	24.06	18.63	33.30	26.76
SURRY	-	-	31.95	3.95	6.37	9.85	9.55	10.31	12.47	15.04
THREE MILE ISLAND 1	-	-	-	-	12.65	17.78	22.30	16.61	22.44	-
TROJAN	-	-	-	-	-	-	8.89	12.62	14.08	15.70
TURKEY POINT	-	-	4.84	4.44	6.94	10.41	13.36	10.85	13.36	16.17
VERMONT YANKEE	-	-	9.00	9.18	10.54	14.23	14.65	18.10	20.72	26.31
YANKEE ROWE	8.90	9.97	16.64	13.93	22.57	26.15	28.43	39.81	43.73	57.99
ZION	-	-	-	1.02	6.87	6.12	8.78	8.70	9.80	13.00

TABLE B-2

OPERATIONS AND MAINTENANCE COSTS IN CONSTANT 1978 DOLLARS

	1970	1971	1972	1973	1974	1975	1976	1977	1978	1979
DUANE ARNOLD	-	-	-	-	8.25	9.18	16.03	16.11	23.[illegible]3	17.80
BEAVER VALLEY	-	-	-	-	-	-	10.00	19.71	28.35	26.75
BIG ROCK POINT	28.06	31.82	34.08	36.18	47.08	49.05	57.45	87.29	57.86	136.90
BROWNS FERRY	-	-	-	-	-	5.93	8.58	6.85	14.35	16.22
BRUNSWICK	-	-	-	-	-	4[illegible].45	15.14	19.27	16.86	20.22
CALVERT CLIFFS	-	-	-	-	-	9.64	12.61	14.75	15.52	20.30
DONALD C. COOK	-	-	-	-	-	5.31	7.63	10.23	9.68	11.62
COOPER	-	-	-	-	9.82	11.35	14.92	14.09	10.68	12.29
CONNECTICUT YANKEE	12.96	9.03	9.91	15.88	11.25	19.51	18.63	17.63	15.19	30.74
CRYSTAL RIVER	-	-	-	-	-	-	-	12.51	19.23	27.60
DAVIS BESSE	-	-	-	-	-	-	-	131.89	15.56	21.20
DRESDEN	7.62	5.23	7.74	7.25	12.22	21.91	19.06	16.14	18.90	23.20
JOSEPH M. FARLEY	-	-	-	-	-	-	-	7.63	15.45	26.65
JAMES A. FITZPATRICK	-	-	-	-	-	22.37	15.21	23.32	23.81	29.35
FORT CALHOUN	-	-	-	5.85	10.05	16.02	19.04	20.48	18.24	17.85
ROBERT E. GINNA	-	9.21	12.01	9.83	13.67	15.26	16.18	16.48	18.99	23.16
EDWIN I. HATCH	-	-	-	-	-	-	7.85	12.37	31.87	11.27
HUMBOLDT BAY	16.35	23.28	21.65	20.87	22.26	22.99	35.74	52.48	25.95	21.97
INDIAN POINT 1	21.97	23.68	39.88	-	-	-	-	-	-	-
INDIAN POINT 2	-	-	-	65.68	19.32	18.26	24.07	20.52	[illegible]2.60	35.29
INDIAN POINT 3	-	-	-	-	-	-	8.53	14.07	24.16	27.96
KEWAUNEE	-	-	-	-	32.64	13.77	22.80	21.91	19.50	19.77
MAINE YANKEE	-	-	-	7.25	8.57	9.42	7.48	11.29	13.52	11.65
MILLSTONE 1	-	7.81	17.69	16.63	19.48	21.86	24.19	20.55	24.92	32.64
MILLSTONE 2	-	-	-	-	-	.64	15.31	22.96	27.45	25.23
MONTICELLO	-	8.80	7.01	12.92	12.19	18.74	13.49	21.40	16.40	17.75
NORTH ANNA	-	-	-	-	-	-	-	-	13.17	20.10
NUCLEAR ONE	-	-	-	-	-	5.88	8.18	10.75	14.50	21.15
NINE MILE POINT	4.68	7.16	8.91	10.66	13.43	11.39	9.94	17.14	11.20	17.86
OCONEE	-	-	-	4.18	8.97	5.77	7.38	10.41	11.47	14.55
OYSTER CREEK	5.00	7.54	9.07	13.95	21.53	22.65	18.19	24.49	24.46	18.76
PALISADES	-	-	-	6.14	20.86	15.52	15.13	9.53	20.80	33.26
PEACH BOTTOM	-	-	-	-	4.39	7.22	16.65	23.96	18.81	20.17
PILGRIM	-	-	4.33	10.29	18.64	13.10	28.23	24.54	21.17	25.63
POINT BEACH	-	-	14.02	5.29	6.92	7.44	7.57	8.69	7.47	11.76
PRARIE ISLAND	-	-	-	6.91	10.29	8.30	16.93	17.53	13.59	13.70
QUAD CITIES	-	-	5.26	5.73	7.65	11.20	12.05	12.07	14.05	18.49
RANCHO SECO	-	-	-	-	-	21.22	8.91	9.49	12.89	13.96
H.B. ROBINSON	-	5.45	3.87	9.46	8.95	10.86	9.59	10.10	20.51	20.21
ST. LUCIE	-	-	-	-	-	-	47.98	10.16	19.89	16.91
SALEM	-	-	-	-	-	-	-	24.84	20.49	40.75
SAN ONOFRE	8.54	8.76	12.27	19.25	16.71	23.77	27.36	19.99	33.30	25.00
SURRY	-	-	48.56	5.67	8.35	11.78	10.86	11.06	12.47	14.05
THREE MILE ISLAND 1	-	-	-	-	16.57	21.[illegible]6	25.36	17.82	22.44	-
TROJAN	-	-	-	-	-	-	10.11	13.54	14.08	14.67
TURKEY POINT	-	-	7.36	6.38	9.09	12.45	15.20	11.65	13.36	15.11
VERMONT YANKEE	-	-	13.68	13.19	13.81	17.01	16.66	19.42	20.72	24.58
YANKEE ROWE	14.82	15.79	25.30	20.01	29.58	31.28	32.33	42.71	43.73	54.17
ZION	-	-	-	1.46	9.00	7.32	9.99	9.34	9.80	12.15

TABLE B-3

GNP DEFLATORS

(Used to Compute 1978 Constant Dollars)

Years	Deflators
1970	1.66429
1971	1.58352
1972	1.5205
1973	1.43715
1974	1.31055
1975	1.19583
1976	1.13716
1977	1.07304
1978	1.
1979	0.918731

Based on 1980 Report of the President's Council of Economic Advisors

The present study deals with this problem by dividing total annual O&M costs by the station's capacity in megawatt-years for the respective year. This complication is necessary because new capacity does not materialize for commercial operation on the first day of the year. For example, we might have a 1000 MW unit on-line for a whole year, and another 1000 MW unit that comes into service at the same station on July 1st. The first unit contributes a full year of operation or 1000 MW-years, while the second one, only on-line for half a year, contributes 500 MW-years of capacity in that year. The station as a whole, then had 1500 MW-years of capacity for the year.

Standardizing costs on the basis of a unit of capacity per operating year basis also has the following advantages: it enables easy comparison of O&M costs on a cost per unit of capacity basis and it enables first years of operation of stations with single units to be included in the data base even when the unit went on-line during the calendar year.* Table B-4 presents the estimated megawatt-years of capacity for each station for each year of the survey. Each unit's in-service date was taken from the FERC steam station cost survey. In situations where only the first month of operation was reported, rather than an exact date, the in-service date was taken to be the mid-point of the month. A unit's capacity was taken to be its FERC reported net continuous capability.

As can be seen from Table B-4, operating time for units in their first year of operation was frequently very small. It was found that cost fluctuated widely for units with less than 10% of a year's operation. This may be a result of inaccurate reporting of the exact on-line data or possibly inaccurate expensing of O&M costs for the first year. At any rate, operation for less

* Analysis of costs on a kilowatt-hour basis would have also eliminated these problems. This option was rejected because it is generally believed that nuclear O&M costs are not proportional, or even strongly related to a plant's capacity factor. Even so, uncertainty about future capacity factors would make cost projection difficult.

TABLE B-4

ANNUAL MEGAWATT-YEARS
OF CAPACITY FOR EACH STATION

	1970	1971	1972	1973	1974	1975	1976	1977	1978	1979
DUANE ARNOLD	NA	NA	NA	NA	236.	500.	500.	500.	500.	500.
BEAVER VALLEY	NA	NA	NA	NA	NA	NA	202.	806.	800.	900.
BIG ROCK	63.	63.	63.	63.	63.	63.	63.	63.	63.	63.
BROWNS FERRY	NA	NA	NA	NA	NA	1336.	2134.	3026.	3201.	[illegible]
BRUNSWICK	NA	NA	NA	NA	NA	124.	790.	1413.	1580.	[illegible]
CALVERT CLIFFS	NA	NA	NA	NA	NA	526.	810.	1466.	1675.	1675.
DONALD C COOK	NA	NA	NA	NA	NA	374.	1050.	1050.	1622.	2150.
COOPER	NA	NA	NA	NA	257.	778.	778.	778.	778.	[illegible]
CONNECTICUT YANKEE	575.	575.	575.	575.	575.	575.	575.	575.	575.	575.
CRYSTAL RIVER	NA	NA	NA	NA	NA	NA	NA	452.	812.	812.
DAVIS BESSE	NA	NA	NA	NA	NA	NA	NA	[illegible]	906.	906.
DRESDEN	501.	1101.	1795.	1795.	1795.	1795.	1795.	1795.	1795.	1795.
JOSEPH M FARLEY	NA	NA	NA	NA	NA	NA	NA	65.	790.	[illegible]
JAMES A FITZPATRICK	NA	NA	NA	NA	NA	369.	800.	800.	800.	[illegible]
FORT CALHOUN	NA	NA	NA	130.	445.	445.	445.	445.	445.	445.
ROBERT E GINNA	NA	411.	517.	517.	517.	517.	517.	517.	517.	517.
HATCH	NA	NA	NA	NA	NA	[illegible]	850.	850.	850.	[illegible]
HUMBOLDT BAY	63.	63.	63.	63.	63.	63.	63.	63.	63.	63.
INDIAN POINT 1	265.	265.	265.	NA	NA	NA	NA	NA	NA	NA
INDIAN POINT 2	NA	NA	NA	325.	864.	864.	864.	864.	864.	864.
INDIAN POINT 3	NA	NA	NA	NA	NA	NA	[illegible]	965.	965.	965.
KEWANEE	NA	NA	NA	NA	290.	535.	535.	535.	535.	535.
MAINE YANKEE	NA	NA	NA	800.	900.	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
MILLSTONE 1	NA	660.	660.	660.	660.	660.	660.	660.	660.	[illegible]
MILLSTONE 2	NA	NA	NA	NA	NA	13.	812.	812.	812.	812.
MONTICELLO	NA	257.	557.	557.	557.	557.	557.	557.	557.	557.
NORTH ANNA	NA	NA	NA	NA	NA	NA	NA	NA	495.	[illegible]
NUCLEAR ONE	NA	NA	NA	NA	NA	836.	876.	836.	836.	836.
NINE MILE POINT	610.	610.	610.	610.	610.	610.	610.	610.	610.	610.
OCONEE	NA	NA	NA	313.	1022.	2580.	2580.	2580.	2580.	[illegible]
OYSTER CREEK	650.	650.	650.	650.	650.	650.	650.	650.	650.	650.
PALISADES	NA	NA	NA	740.	740.	740.	740.	740.	740.	740.
PEACH BOTTOM	NA	NA	NA	NA	535.	2093.	2090.	2090.	2090.	2090.
PILGRIM	NA	NA	40.	670.	670.	670.	670.	670.	670.	670.
POINT BEACH	NA	NA	250.	990.	995.	990.	990.	990.	990.	990.
PRARIE ISLAND	NA	NA	NA	[illegible]	[illegible]	1046.	1046.	1046.	1046.	1046.
QUAD CITIES	NA	NA	388.	1578.	1579.	1578.	1573.	1578.	1578.	1578.
RANCHO SECO	NA	NA	NA	NA	NA	654.	918.	918.	918.	918.
H B ROBINSON	[illegible]	[illegible]	700.	700.	700.	700.	700.	730.	700.	700.
ST LUCIE	NA	NA	NA	NA	NA	NA	[illegible]	795.	795.	795.
SALEM	NA		NA	NA	NA	NA	NA	549.	1089.	1559.
SAN ONOFRE	436.	436.	436.	436.	436.	436.	436.	436.	436.	436.
SURRY	NA	NA	[illegible]	1293.	1550.	1550.	1550.	1550.	1550.	1550.
THREE MILE ISLAND 1	NA	NA	NA	NA	265.	302.	800.	800.	800.	NA
TROJAN	NA	NA	NA	NA	NA	NA	666.	1040.	1080.	1080.
TURKEY POINT 3 AND 4	NA	NA	51.	715.	1392.	1392.	1392.	1392.	1392.	1392.
VERMONT YANKEE	NA	NA	46.	540.	540.	540.	540.	540.	540.	540.
YANKEE ROWE	175.	175.	175.	[illegible]	175.	175.	175.	175.	175.	175.
ZION	NA	NA	NA	436	1345.	2080.	2080.	2080.	2080.	2080.

than a month appeared to be highly unrepresentative of normal operation. Therefore, single units with less than 10% of a year's operation were dropped from analysis. Additionally, several years' costs were dropped because of other first-year abnormalities.* Table B-5 summarizes the excluded first year costs. Once abnormal first years of operation were excluded, the final data base could be prepared by dividing real annual costs (in constant 1978 dollars) by the station capacity for that year. Table B-6 presents the final data base used in this study. Table B-7 presents costs per kilowatt-year in mixed current dollars for reference. Kilowatt-years were found to be a more convenient unit of analysis than megawatt-y ars for the purposes of this report. O&M costs per kilowatt-year are megawatt-year costs divided by 1000.

Other Variables

Data on plant characteristics were used in addition to O&M costs. Tables B-8, B-9, and B-10 present these data in summary form. The column titles are the variable names used in the study. Plant characteristic data is taken from the NUS publication, "Commercial Nuclear Power Plants."

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* (1) Brunswick first year costs in 1975 were excluded because reported costs were more than twice the next year's costs on a per KW-year basis. (2) Cost data for Indian Point 2 was excluded for the years 1973 and 1974 because Indian Point 1 was in operation then and they were reported on the same account. Indian Point 1 was subsequently shut down. (3) Kewanee, Point Beach, and Rancho Seco also ad their first year's data excluded on the basis of having abnormally high reported costs. (4) Palisades was excluded for its first two years of operation because it was not in full power operation and had abnormally low reported costs compared to subsequent years. These data were excluded because the regression procedures would give them equal weight with other full year reported costs which have a much higher degree of certainty associated with them. Statistical weighting, called heteroskedastic correction could be attempted, but is beyond the scope of this study.

TABLE B-5

POWER PLANTS WITH FIRST YEAR OPERATION EXCLUDED FROM DATA BASE

			Fraction of Year	First Year Costs STAN(t)	Second Year Costs STAN(t+1)
#1	5:	Brunswick	.1589	35.5	13.31
#2	11:	Davis-Besse	.0027	122.91	16.45
#3	18:	Hatch	.0027	NR	
#4	21:	Indian Point 2	.3767	Indian Pt. #1 incl. in 1st 2 years	
#5	23:	Kewanee	.5425	24.90	11.51
#6	27:	Millstone 2	.01644	.523	13.46
#7	34:	Palisades*	1.00	1.0176	4.27
#8	36:	Pilgrim	.0603	2.85	7.1597
#9	37:	Point Beach	.2521	9.22	3.68
#10	38:	Prarie Island	.0411	4.8095	7.80
#11	40:	Rancho Seco	.7123	17.75	7.83
#12	42:	St. Lucie	.0968	42.19**	9.4
#13	46:	Surry	.0247	31.94	3.94
#14	50:	Turkey Point	.0739	5.04	4.63
#15	51:	Vt. Yankee	.0849	9.	9.1
#16	53:	Zion	.2096	1.01	4.44
#17	13:	Farley	.08		

TOTALS:

CAUSE ≡ { NON STAN or FRAC RELATED: 2; FRAC TOO SMALL: 9; $STAN_{(t)}$ TOO HIGH: 4; $STAN_{(t)}$ TOO LOW: 2 }

COSTS HIGH: 8
COSTS LOW: 7
NA: 2

* Not in full power operation during 1st full year.

** Per KWH basis.

TABLE B-6

NUCLEAR STATION COSTS PER KILOWATT-YEAR
IN CONSTANT 1978 DOLLARS

[illegible]	1970	1971	1972	1973	1974	1975	1976	1977	1978	1979
DUANE ARNOLD	0.	0.	0.	0.	8.24	9.18	16.03	16.31	23.83	17.51
BEAVER VALLEY	0.	0.	0.	0.	0.	0.	16.	19.7	28.35	26.3
BIG ROCK	28.05	31.82	34.07	36.17	47.02	49.04	57.45	87.29	57.85	134.64
BROWNS FERRY	0.	0.	0.	0.	0.	5.93	8.58	6.84	14.34	15.95
BRUNSWICK	0.	0.	0.	0.	0.	0.	15.14	19.27	14.85	19.88
CALVERT CLIFFS	0.	0.	0.	0.	0.	9.64	12.61	14.75	15.52	19.96
DONALD C COOK	0.	0.	0.	0.	0.	5.31	7.63	10.22	9.68	11.43
COOPER	0.	0.	0.	0.	9.82	11.35	14.92	14.09	10.67	12.08
CONNECTICUT YANKEE	12.96	9.03	9.91	15.87	11.24	19.5	18.62	17.62	15.19	30.23
CRYSTAL RIVER	0.	0.	0.	0.	0.	0.	0.	12.5	19.22	27.14
DAVIS BESSE	0.	0.	0.	0.	0.	0.	0.	0.	15.55	20.84
DRESDEN	7.62	5.23	7.74	7.24	12.21	21.91	19.06	16.12	18.9	22.81
JOSEPH M FARLEY	0.	0.	0.	0.	0.	0.	0.	0.	15.45	26.21
JAMES A FITZPATRICK	0.	0.	0.	0.	0.	0.	15.2	23.31	23.8	28.86
FORT CALHOUN	0.	0.	0.	5.84	10.05	16.02	19.03	20.47	18.23	17.55
ROBERT E GINNA	0.	[illegible]	[illegible]	9.82	11.66	15.25	16.17	16.41	18.99	22.77
HATCH	0.	0.	0.	0.	0.	0.	7.84	12.37	14.42	14.67
HUMBOLDT BAY	14.35	23.27	21.44	20.87	22.25	22.98	35.73	52.47	0.	0.
INDIAN POINT 1	21.97	23.4	39.8	0.	0.	0.	0.	0.	0.	0.
INDIAN POINT 2	0.	0.	0.	0.	0.	10.26	24.06	20.52	32.6	34.71
INDIAN POINT 3	0.	0.	0.	0.	0.	0.	8.52	14.07	20.16	27.5
KEWAUNEE	0.	0.	0.	0.	0.	13.76	22.8	21.91	19.49	19.44
MAINE YANKEE	0.	0.	0.	7.24	8.57	9.41	7.47	11.29	13.52	11.45
MILLSTONE 1	0.	7.81	17.68	14.62	19.47	21.86	24.19	20.54	24.92	32.09
MILLSTONE 2	0.	0.	0.	0.	0.	0.	15.3	22.96	27.44	24.81
MONTICELLO	0.	8.8	0.	12.91	12.18	10.74	13.49	21.4	16.9	17.45
NORTH ANNA	0.	0.	0.	0.	0.	0.	0.	0.	13.17	19.77
NUCLEAR ONE	0.	0.	0.	0.	0.	3.07	8.18	10.75	14.5	20.79
NINE MILE POINT	4.68	7.14	8.91	10.65	13.42	11.38	9.93	17.13	11.19	17.26
OCONEE	0.	0.	0.	4.18	8.97	5.77	7.37	10.41	11.67	14.3
OYSTER CREEK	5.	7.54	9.06	13.95	21.52	22.64	18.19	24.48	24.45	18.45
PALISADES	0.	0.	0.	4.17	20.85	15.51	15.13	9.52	20.8	32.7
PEACH BOTTOM	0.	0.	0.	0.	4.38	7.22	16.64	23.96	18.8	19.82
PILGRIM	0.	0.	0.	10.28	10.63	13.1	28.23	24.53	21.17	25.21
POINT BEACH	0.	0.	0.	5.2	6.92	7.43	7.57	8.65	7.4	11.56
PRAIRIE ISLAND	0.	0.	0.	0.	16.[illegible]	8.3	16.93	17.53	13.58	13.4
QUAD CITIES	0.	0.	5.25	5.77	7.64	11.19	12.05	12.07	14.04	18.18
RANCHO SECO	0.	0.	0.	0.	0.	0.	8.91	9.49	12.09	13.73
H B ROBINSON	0.	5.45	3.86	9.46	8.94	10.86	9.58	10.1	26.5	19.8
ST LUCIE	0.	0.	0.	0.	0.	0.	0.	10.16	19.89	16.63
SALEM	0.	0.	0.	0.	0.	0.	0.	24.83	20.48	40.06
SAN ONOFRE	8.53	8.76	12.26	19.24	16.[illegible]	23.77	27.35	19.99	33.29	24.58
SURRY	0.	0.	0.	5.4	8.35	11.76	10.85	11.06	[illegible]	13.81
THREE MILE ISLAND 1	0.	0.	0.	0.	16.57	21.26	25.35	17.82	22.44	0.
TROJAN	0.	0.	0.	0.	0.	0.	10.1	13.54	14.07	14.42
TURKEY POINT 3 AND 4	0.	0.	0.	6.37	9.09	12.45	15.19	11.64	13.36	14.85
VERMONT YANKEE	0.	0.	0.	13.19	13.81	17.01	16.66	19.42	20.[illegible]	24.17
YANKEE ROWE	14.81	15.78	25.3	20.01	29.58	31.27	32.33	42.71	43.73	53.28
ZION	0.	0.	0.	0.	8.99	7.32	9.98	9.33	9.79	11.94

TABLE B-6

NUCLEAR STATION COSTS PER KILOWATT-YEAR
IN CONSTANT 1978 DOLLARS

	1970	1971	1972	1973	1974	1975	1976	1977	1978	1979
DUANE ARNOLD	0.	0.	0.	0.	8.24	9.18	16.03	16.11	23.83	17.53
BEAVER VALLEY	0.	0.	0.	0.	0.	0.	10.	19.7	28.35	26.3
BIG ROCK	28.05	31.82	34.07	36.17	47.07	49.04	57.45	87.29	57.85	134.69
BROWNS FERRY	0.	0.	0.	0.	0.	5.93	8.58	6.84	14.34	13.95
BRUNSWICK	0.	0.	0.	0.	0.	0.	15.14	19.27	14.85	19.88
CALVERT CLIFFS	0.	0.	0.	0.	0.	9.64	12.41	14.75	15.52	19.96
DONALD C COOK	0.	0.	0.	0.	0.	5.31	7.63	10.22	9.66	11.43
COOPER	0.	0.	0.	0.	9.82	11.35	14.92	16.09	10.67	12.08
CONNECTICUT YANKEE	12.96	9.03	9.93	15.87	11.24	19.5	18.62	17.62	15.19	30.23
CRYSTAL RIVER	0.	0.	0.	0.	0.	0.	0.	12.5	19.22	27.14
DAVIS BESSE	0.	0.	0.	0.	0.	0.	0.	0.	15.55	20.84
DRESDEN	7.42	5.23	7.74	7.24	12.21	21.91	19.06	14.13	18.9	22.81
JOSEPH M FARLEY	0.	0.	0.	0.	0.	0.	0.	0.	15.45	26.21
JAMES A FITZPATRICK	0.	0.	0.	0.	0.	0.	15.2	23.31	23.8	28.86
FORT CALHOUN	0.	0.	0.	5.84	10.05	14.02	19.03	20.47	18.23	17.55
ROBERT E GINNA	0.	[illegible]	[illegible]	9.82	13.66	15.25	16.17	16.41	18.99	22.77
HATCH	0.	0.	0.	0.	0.	0.	7.84	12.37	14.93	14.67
HUMBOLDT BAY	14.35	23.27	21.64	20.87	22.25	22.98	35.73	52.47	0.	0.
INDIAN POINT 1	21.92	23.67	39.87	0.	0.	0.	0.	0.	0.	0.
INDIAN POINT 2	0.	0.	0.	0.	0.	18.26	24.06	20.52	32.6	34.71
INDIAN POINT 3	0.	0.	0.	0.	0.	0.	8.52	14.07	24.16	27.5
KEWAUNEE	0.	0.	0.	0.	0.	11.76	22.8	21.91	19.49	19.44
MAINE YANKEE	0.	0.	0.	7.24	8.57	9.41	7.47	11.29	13.52	11.45
MILLSTONE 1	0.	7.81	17.68	16.62	19.47	21.86	24.19	20.54	24.92	32.09
MILLSTONE 2	0.	0.	0.	0.	0.	0.	15.3	22.96	27.44	24.81
MONTICELLO	0.	8.8	0.	12.91	12.18	18.74	13.49	21.4	16.4	17.45
NORTH ANNA	0.	0.	0.	0.	0.	0.	0.	0.	13.17	19.77
NUCLEAR ONE	0.	0.	0.	0.	0.	5.87	8.18	10.75	14.5	20.79
NINE MILE POINT	4.68	7.16	8.91	10.65	13.42	11.38	9.93	17.13	11.19	17.26
OCONEE	0.	0.	0.	4.18	8.97	5.77	7.37	10.41	11.47	14.3
OYSTER CREEK	5.	7.54	9.06	13.95	21.57	22.64	18.19	24.48	24.45	58.45
PALISADES	0.	0.	0.	6.17	20.85	15.51	15.13	9.52	20.8	32.7
PEACH BOTTOM	0.	0.	0.	0.	4.38	7.22	14.64	23.96	18.8	19.82
PILGRIM	0.	0.	0.	10.28	18.61	13.1	28.23	24.53	21.17	25.21
POINT BEACH	0.	0.	0.	5.27	6.92	7.43	7.57	8.68	7.4	11.56
PRAIRIE ISLAND	0.	0.	0.	0.	16.8	8.3	16.93	17.53	13.58	13.47
QUAD CITIES	0.	0.	5.25	5.72	7.64	11.19	12.05	12.07	14.04	10.18
RANCHO SECO	0.	0.	0.	0.	0.	0.	8.91	9.49	12.89	13.73
H B ROBINSON	0.	5.45	3.86	9.46	8.94	10.86	9.58	10.1	26.5	19.8
ST LUCIE	0.	0.	0.	0.	0.	0.	0.	10.16	19.89	16.63
SALEM	0.	0.	0.	0.	0.	0.	0.	24.83	20.48	40.06
SAN ONOFRE	8.53	8.76	12.26	19.24	16.	23.77	27.35	19.99	33.29	24.58
SURRY	0.	0.	0.	5.6	8.35	11.76	10.85	11.06	12.96	13.81
THREE MILE ISLAND 1	0.	0.	0.	0.	14.57	21.26	25.35	17.82	22.44	0.
TROJAN	0.	0.	0.	0.	0.	0.	10.3	13.54	14.07	14.42
TURKEY POINT 3 AND 4	0.	0.	0.	6.37	9.09	12.45	15.19	11.64	13.36	14.85
VERMONT YANKEE	0.	0.	0.	13.19	13.81	17.01	16.66	19.42	20.72	24.17
YANKEE ROWE	14.81	15.78	25.3	20.01	29.58	31.27	32.33	42.71	43.73	53.28
ZION	0.	0.	0.	0.	8.99	7.32	9.98	9.33	9.79	11.94

TABLE B-7

NUCLEAR STATION COSTS PER KILOWATT-YEAR
IN MIXED CURRENT DOLLAR

	1970	1971	1972	1973	[illegible]	1975	[illegible]	[illegible]	[illegible]	[illegible]
DUANE ARNOLD	0.	0.	0.	0.	[illegible]	7.6	14.09	15.01	23.83	[illegible]
BEAVER VALLEY	0.	0.	0.	0.	0.	0.	8.79	[illegible]	[illegible]	[illegible]
BIG ROCK	16.85	20.09	22.41	25.17	35.9	41.01	50.52	81.39	[illegible]	[illegible]
BROWNS FERRY	0.	0.	0.	0.	0.	4.95	7.54	[illegible]	14.2	[illegible]
BRUNSWICK	0.	0.	0.	0.	0.	0.	13.31	17.97	[illegible]	[illegible]
CALVERT CLIFFS	0.	0.	0.	0.	0.	8.06	11.09	13.75	[illegible]	[illegible]
DONALD C COOK	0.	0.	0.	0.	0.	4.44	6.71	[illegible]	9.68	[illegible]
COOPER	0.	0.	0.	0.	7.49	7.49	13.12	13.17	[illegible]	[illegible]
CONNECTICUT YANKEE	7.78	5.7	6.51	11.04	8.59	16.31	16.36	[illegible]	15.19	[illegible]
CRYSTAL RIVER	0.	0.	0.	0.	0.	0.	0.	11.65	[illegible]	29.54
DAVIS BESSE #	0.	0.	0.	0.	0.	0.	0.	0.	[illegible]	[illegible]
DRESDEN	4.57	3.3	5.09	5.04	9.32	10.32	14.76	15.04	16.	[illegible]
JOSEPH M FARLEY	0.	0.	0.	0.	0.	0.	0.	0.	15.45	28.53
JAMES A FITZPATRICK	0.	0.	0.	0.	0.	0.	13.37	21.72	[illegible]	[illegible]
FORT CALHOUN	0.	0.	0.	4.06	7.66	13.39	16.73	[illegible]	14.23	[illegible]
ROBERT E GINNA	0.	5.81	7.09	4.83	19.4	[illegible]	14.22	15.36	[illegible]	[illegible]
HATCH	0.	0.	0.	0.	[illegible]	0.	6.7	[illegible]	[illegible]	[illegible]
HUMBOLDT BAY	[illegible]	14.69	14.23	[illegible]	16.50	19.27	31.42	[illegible]	[illegible]	[illegible]
INDIAN POINT 1	13.15	14.95	[illegible]	0.	[illegible]	0.	0.	[illegible]	[illegible]	[illegible]
INDIAN POINT 2	0.	0.	0.	0.	0.	15.27	21.16	19.12	[illegible]	[illegible]
INDIAN POINT 3	0.	0.	0.	0.	0.	[illegible]	[illegible]	13.11	[illegible]	29.93
KEWAUNEE	0.	0.	0.	[illegible]	[illegible]	11.51	[illegible]	20.41	[illegible]	21.16
MAINE YANKEE	0.	0.	0.	5.04	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	12.46
MILLSTONE 1	0.	4.93	11.63	11.56	14.86	14.20	[illegible]	17.19	[illegible]	[illegible]
MILLSTONE 2	0.	0.	0.	0.	[illegible]	[illegible]	[illegible]	21.4	27.44	[illegible]
MONTICELLO	0.	5.54	4.6	8.98	9.79	[illegible]	11.87	19.94	16.4	15.
NORTH ANNA	0.	0.	0.	0.	[illegible]	[illegible]	[illegible]	[illegible]	13.17	[illegible]
NUCLEAR ONE	0.	0.	0.	0.	[illegible]	[illegible]	[illegible]	13.62	[illegible]	[illegible]
NINE MILE POINT	2.81	4.52	5.87	7.41	[illegible]	[illegible]	[illegible]	[illegible]	11.19	19.12
OCONEE	0.	0	0.	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	11.47	[illegible]
OYSTER CREEK	3.	4.72	5.96	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	24.45	20.06
PALISADES	0.	0	0.	4.27	[illegible]	[illegible]	[illegible]	[illegible]	20.8	[illegible]
PEACH BOTTOM	0.	0.	0.	0.	3.34	[illegible]	[illegible]	[illegible]	10.8	21.58
PILGRIM	0.	0	0.	7.15	14.21	17.95	[illegible]	[illegible]	21.17	[illegible]
POINT BEACH	0.	0.	0.	[illegible]	5.21	[illegible]	[illegible]	[illegible]	7.46	[illegible]
PRAIRIE ISLAND	0.	0.	0.	0.	[illegible]	6.94	[illegible]	16.23	13.58	[illegible]
QUAD CITIES	0.	0.	3.45	3.98	[illegible]	[illegible]	10.5	[illegible]	[illegible]	19.78
RANCHO SECO	0.	0.	0.	0.	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
H B ROBINSON	0.	3.44	2.54	6.58	6.8	[illegible]	6.4	[illegible]	20.5	21.63
ST LUCIE	0.	0.	0.	0	[illegible]			[illegible]	19.85	10.1
SALEM	0.	0.	0.	0.	[illegible]	[illegible]	[illegible]	27.14	20.48	43.42
SAN ONOFRE	[illegible]	5.53	8.06	13.39	[illegible]	[illegible]	[illegible]	12.47	33.25	26.76
SURRY	0.	0.	0.	3.94	[illegible]	[illegible]	[illegible]	[illegible]	12.46	15.04
THREE MILE ISLAND 1	0.	0	0.	0.	[illegible]	[illegible]	[illegible]	[illegible]	22.44	0.
TROJAN	0.	0.	0.	0.	[illegible]	[illegible]	8.8	[illegible]	14.07	15.7
TURKEY POINT 3 AND 4	0.	0.	0.	4.43	[illegible]	17.41	[illegible]	16.85	13.36	[illegible]
VERMONT YANKEE	0.	0.	0.	9.17	[illegible]	[illegible]	[illegible]	10.1	20.72	[illegible]
YANKEE ROWE	8.9	9.97	16.63	13.92	[illegible]	[illegible]	[illegible]	25.6	43.73	57.9
ZION	0.	0.	0.	0.	6.6	[illegible]	[illegible]	[illegible]	9.79	[illegible]

TABLE B-8

NUCLEAR UNIT CHARACTERISTICS

STATION	UNITSIZE (MW)	REACTOR TYPE (1 = PWR)	COOLING TOWERS (1 MEANS USED)	SALT WATER COOLING (1 MEANS USED)
DUANE ARNOLD	500.	0.	1.	0.
BEAVER VALLEY	800.	1.	1.	0.
BIG ROCK	63.	0.	0.	0.
BROWNS FERRY	1067.	0.	1.	0.
BRUNSWICK	790.	0.	0.	1.
CALVERT CLIFFS	840.	1.	0.	1.
DONALD C COOK	1060.	1.	0.	0.
COOPER	778.	0.	0.	0.
CONNECTICUT YANKEE	575.	1.	0.	0.
CRYSTAL RIVER	812.	1.	0.	1.
DAVIS BESSE	906.	1.	1.	0.
DRESDEN	800.	0.	0.	0.
JOSEPH M FARLEY	790.	1.	1.	0.
JAMES A FITZPATRICK	800.	0.	0.	0.
FORT CALHOUN	445.	1.	0.	0.
ROBERT E GINNA	517.	1.	0.	0.
HATCH	850.	0.	1.	0.
HUMBOLDT BAY	63.	0.	0.	1.
INDIAN POINT 1	265.	1.		
INDIAN POINT 2	864.	1.	0.	1.
INDIAN POINT 3	965.	1.	0.	1.
KEWANEE	535.	1.	0.	0.
MAINE YANKEE	800.	1.	0.	1.
MILLSTONE 1	660.	0.	0.	1.
MILLSTONE 2	812.	1.	0.	1.
MONTICELLO	557.	0.	1.	0.
NORTH ANNA	907.	1.	0.	0.
NUCLEAR ONE	836.	1.		
NINE MILE POINT	610.	0.	0.	0.
OCONEE	860.	1.	0.	0.
OYSTER CREEK	650.	0.	0.	1.
PALISADES	740.	1.	1.	0.
PEACH BOTTOM	1045.	0.	1.	0.
PILGRIM	670.	0.	0.	1.
POINT BEACH	445.	1.	0.	0.
PRARIE ISLAND	523.	1.	1.	0.
QUAD CITIES	789.	0.	0.	0.
RANCHO SECO	918.	1.	1.	0.
H B ROBINSON	700.	1.	0.	0.
ST LUCIE	795.	1.	0.	1.
SALEM	1089.	1.	0.	1.
SAN ONOFRE	436.	1.	0.	1.
SURRY	775.	1.	0.	1.
THREE MILE ISLAND I	800.	1.	1.	0.
TROJAN	1080.	1.	1.	0.
TURKEY POINT 3 AND 4	693.	1.	0.	1.
VERMONT YANKEE	540.	0.	1.	0.
YANKEE ROWE	175.	1.	0.	0.
ZION	1040.	1.	0.	0.

TABLE B-9

NUCLEAR UNIT CHARACTERISTICS

STATION	SECOND (1 IF MORE THAN ONE UNIT)	WESTING 1 IF WESTINGHOUSE DESIGN	CE 1 IF COMBUSTION ENGINEERING DESIGN
DUANE ARNOLD	0.	0.	0.
BEAVER VALLEY	0.	1.	0.
BIG ROCK	0.	0.	0.
BROWNS FERRY	1.	0.	0.
BRUNSWICK	1.	0.	0.
CALVERT CLIFFS	1.	0.	1.
DONALD C COOK	1.	1.	0.
COOPER	0.	0.	0.
CONNECTICUT YANKEE	0.	1.	0.
CRYSTAL RIVER	0.	0.	0.
DAVIS BESSE	0.	0.	0.
DRESDEN	1.	0.	0.
JOSEPH M FARLEY	0.	1.	0.
JAMES A FITZPATRICK	0.	0.	0.
FORT CALHOUN	0.	0.	1.
ROBERT E GINNA	0.	1.	0.
HATCH	0.	0.	0.
HUMBOLDT BAY	0.	0.	0.
INDIAN POINT 1	0.	1.	0.
INDIAN POINT 2	0.	1.	0.
INDIAN POINT 3	0.	1.	0.
KEWANEE	0.	1.	0.
MAINE YANKEE	0.	0.	1.
MILLSTONE 1	0.	0.	0.
MILLSTONE 2	0.	0.	1.
MONTICELLO	0.	0.	0.
NORTH ANNA	0.	1.	0.
NUCLEAR ONE	0.	0.	0.
NINE MILE POINT	0.	0.	0.
OCONEE	1.	0.	0.
OYSTER CREEK	0.	0.	0.
PALISADES	0.	0.	1.
PEACH BOTTOM	1.	0.	0.
PILGRIM	0.	0.	0.
POINT BEACH	1.	1.	0.
PRARIE ISLAND	1.	1.	0.
QUAD CITIES	1.	0.	0.
RANCHO SECO	0.	0.	0.
H B ROBINSON	0.	1.	0.
ST LUCIE	0.	0.	1.
SALEM	0.	1.	0.
SAN ONOFRE	0.	1.	0.
SURRY	1.	1.	0.
THREE MILE ISLAND I	0.	0.	0.
TROJAN	0.	1.	0.
TURKEY POINT 3 AND 4	1.	1.	0.
VERMONT YANKEE	0.	0.	0.
YANKEE ROWE	0.	1.	0.
ZION	1.	1.	0.

TABLE B-10

NUCLEAR UNIT CHARACTERISTICS

STATION	AVERAGE UNIT YEAR OF FIRST OPERATION (1970 = 0)	TURNKEY (1=TURNKEY)	DEMONSTRATION UNIT (1 = DEMO)	NE (1 = LOCATION IN THE NORTH EAST)
DUANE ARNOLD	4.474	0.	0.	0.
BEAVER VALLEY	6.74789	0.	0.	1.
BIG ROCK	-7.	0.	1.	0.
BROWNS FERRY	5.97079	0.	0.	0.
BRUNSWICK	6.18359	0.	0.	0.
CALVERT CLIFFS	6.3	0.	0.	0.
DONALD C COOK	6.9028	0.	0.	0.
COOPER	4.53841	0.	0.	0.
CONNECTICUT YANKEE	-2.	0.	0.	1.
CRYSTAL RIVER	7.1973	0.	0.	0.
DAVIS BESSE	7.9973	0.	0.	0.
DRESDEN	0.	0.	1.	0.
JOSEPH M FARLEY	7.9178	0.	0.	0.
JAMES A FITZPATRICK	5.5834	0.	0.	1.
FORT CALHOUN	3.7068	0.	0.	0.
ROBERT E GINNA	0.204102	1.	0.	1.
HATCH	5.9973	0.	0.	0.
HUMBOLDT BAY	-8.	0.	1.	0.
INDIAN POINT 1	-8.	0.	1.	1.
INDIAN POINT 2	3.62331	0.	0.	1.
INDIAN POINT 3	6.66029	0.	0.	1.
KEWANEE	4.4575	0.	0.	0.
MAINE YANKEE	3.	0.	0.	1.
MILLSTONE 1	1.	1.	0.	1.
MILLSTONE 2	5.98357	0.	0.	1.
MONTICELLO	1.53841	1.	0.	0.
NORTH ANNA	8.4548	0.	0.	0.
NUCLEAR ONE	4.96712	0.	0.	0.
NINE MILE POINT	0.	0.	0.	1.
OCONEE	4.3967	0.	0.	0.
OYSTER CREEK	0.	1.	0.	1.
PALISADES	1.9575	0.	0.	0.
PEACH BOTTOM	4.7438	0.	0.	1.
PILGRIM	2.9397	0.	0.	1.
POINT BEACH	2.25211	1.	0.	0.
PRARIE ISLAND	4.465	0.	0.	0.
QUAD CITIES	2.6274	1.	0.	0.
RANCHO SECO	5.2877	0.	0.	0.
H B ROBINSON	1.2041	1.	0.	0.
ST LUCIE	6.9032	0.	0.	0.
SALEM	6.4959	0.	0.	1.
SAN ONOFRE	-1.9575	1.	0.	0.
SURRY	3.1534	0.	0.	0.
THREE MILE ISLAND I	4.6685	0.	0.	1.
TROJAN	6.38361	0.	0.	0.
TURKEY POINT 3 AND 4	3.2849	0.	0.	0.
VERMONT YANKEE	2.9151	0.	0.	1.
YANKEE ROWE	-8.	0.	1.	1.
ZION	4.2487	0.	0.	0.

B-2 ANALYTIC METHOD

General Methodology

The data base for this study is substantial; included are 300 plant-years of power plant O&M cost observations cross-referenced with the characteristics of these plants. The problem is to draw meaningful conclusions regarding O&M cost trends on the basis of this data. To that end, the tools of statistical analysis are used. The principal approach and conclusions embodied in this appendix rely on the use of linear regression analysis, particularly the use of pooled regression and analysis of variance techniques. The aim of this section is twofold: to provide a general introduction to these techniques for those who are unfamiliar with them, and to describe their use in the analysis of nuclear plant O&M costs in particular.

Linear regression is generally used to build one kind of model of a particular process and to identify significant causal or associated factors that seem to explain the outcome of that process. The outcome of the process is represented by a so-called dependent variable and the causal factors are represented by the independent or explanatory variables. Statistical tests have been developed which give some idea of how important a given explanatory variable is and how precisely we can estimate its effect on the dependent variable. In our study, for example, annual nuclear plant O&M costs (represented as the dependent variable) can be considered to be the outcome of a process, and plant size and/or year of operation can be considered to be among the candidates for causal or associated factors (i.e. as independent or explanatory variables).

Regression works by assuming that the dependent variable to be analyzed, in this case annual O&M costs, is a linear function of other factors which we can measure, that is, that

the effect of each factor is independent from the effects of other factors.* In this appendix we try to see how much we can learn by assuming that O&M costs are a function of intrinsic variables describing a power plant which are known before it is even built, such as whether it uses cooling towers, what its size is, and so forth. Thus, we are really concerned with examining the <u>differences</u> between O&M costs for different types of plants rather than developing a detailed model for any single unit.

Pooled analysis is a regression technique for simultaneously analyzing time related processes in different analytical units. In this study it will be used to study plant characteristics associated with different O&M cost levels or growth rates at different nuclear power stations.

When regression analysis is used to examine variation caused by qualitative explanatory variables it is called analysis of variance.** In this study we shall be interested in determining whether qualitative variables such as whether a given reactor is of boiling water or pressurized design has a significant impact on O&M costs for that unit.

The combined use of these techniques will enable determination of not only whether a variable is significantly associated with costs, but also what the form of that association is. For example, some variables may actually be associated with an increase of the <u>rate</u> of cost escalation while others might only be associated with the general level of costs.

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* Interactions between characteristics can themselves be identified as new characteristics. Several good texts about linear regression exist. The interested reader is directed to Kementa (1972) or Goldberg (1969).

** For a discussion of analysis of variance as a kind of linear regression analysis, see Hoel, et al. (1971), page 127, ff.

Description of Variables

The dependent variable in all cases is the annual non-fuel O&M costs for all plants in 1978 dollars and standardized on a per kilowatt-year basis, as presented in Table B-6. The natural logarithms of these costs were used when exponential growth rates were estimated. The name REALSTAN was chosen to represent O&M costs and REALPOOL was chosen to represent the logs of O&M costs.

The constant term used in all regressions has been called MASKS.* Time was represented by TIME, which was chosen as a sequentially increasing series of negative numbers which reached 0 in the year 1980. This particular way to represent time was chosen to facilitate comparison of expected 1980 costs and has no effect of the estimated costs in either the linear or log-linear models.

As discussed earlier, plant characteristics can affect the general level of costs uniformly or affect the rate of growth over time. For example, the variable SIZEM is the term which measures the uniform level effect of average unit size over time. The variable SIZET measures the effect of station unit size on the rate of cost escalation (SIZET is SIZEM x TIME). This pattern is repeated for other characteristics examined in this study. The suffix M refers to the variable's effect on costs uniformly and the suffix T refers to the effect on the rate of escalation. The following additional variables were tested or are in one of the final models:

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*This name evolved because of the procedure which had to be developed to cope with the fact that data for all plants was not available for all years of the survey and the computer routines used had no provision for the use of pooled data with missing observations.

variable	description
BIRTHM BIRTHT	The time a unit first came on line. Multiple unit stations have their birth dates averaged. Birth includes the actual date of commercial operation through the use of fractional years.
DEMOM DEMOT	It was found quickly that the earliest plants, which were built as demonstration projects, had normalized costs that were much higher than other stations and that other variables could not adequately account for this difference. Thus it was decided to add a dummy variable which could isolate the effect imputed to being early demonstration projects.
NEMASK NET	It was similarly found that units in the North East had abnormally higher costs, and this dummy variable was created to isolate the effect.
SALTM SALTT	SALT is 0 unless the station is cooled by salt water.
SECONDM SECONDT	SECOND is 0 unless there is two or more units at the station.
TOWERSM TOWERST	TOWERS is 0 unless the station is cooled with cooling towers, either mechanical or natural draft.
TURNKEYM TURNKEYT	TURNKEY is 0 unless the unit was completed as one of the original turnkey contracts.
TYPEM TYPET	TYPE is 0 unless the unit is a Pressurized Water Reactor design.

A complete listing of the values of these variables for every station can be found in Tables B-8 to B-10. In the actual computer runs an X will be found before all variables for cases when the Big Rock station is excluded.*

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* In the original runs of the linear model, it was found that the Big Rock nuclear unit contributed almost a third of the total sum of squared errors. The reason for this is easy to locate in Table B-6 in which it can be seen that Big Rock's normalized costs were much higher than any other unit. This cost level was so much above the cost level for the other demonstration units that it proved impossible to adequately explain Big Rock's cost behavior through the fact that it was a demonstration unit, at least in the linear model. For these reasons, the work in this study was conducted without data for Big Rock station. There is an additional econometric reason for excluding Big Rock. Ordinary least square regression, described earlier, assumes that the size of the error term is randomly distributed. Therefore, the sum of squared error for any single plant should be within a certain range. If it is known that the sum of squared error of a given plant is outside of this normal distribution, then a heteroskedastic correction should be made to the data in order to normalize the effect that the abnormal data has on the regression process of minimizing the total sum of squared error (see for example, Kmenta (1972), p. 510). Heteroskedastic correction is difficult in this case because there are not enough observations of Big Rock's performance to accurately estimate the sample variance. The correction procedure then becomes totally arbitrary and it makes more sense to simply leave the unit out. Runs of the linear model with and without Big Rock can be found in the appendix. It can quickly be seen that the run without Big Rock had much more precision in its estimated coefficients (lower standard errors) and that the T-values were correspondingly higher. Most importantly, the standard error of the equation, which is the best overall indicator of the "resolving power" of the regression decreased from 7.76 to about 4.6, indicating a marked improvement in explanatory performance.

Other variables such as forced outage rate, capacity factor, reported radiation exposures, and person-hours of maintenance per year could also have been used in this study. They have not been included in the present research principally due to the limited time available. A more complete investigation would examine the correlations between such variables and O&M costs and thus give a more complete understanding of what is causing O&M cost increases. Instead of asking will O&M costs continue to rise, the question would be, will labor requirements, forced outage rates, and so forth continue to rise?

B-3 PRESENTATION OF RESULTS

Linear Models: Results

Table B-11 presents the basic linear model judged to best project future O&M costs. It shows an expected cost of 23.14 - (1000X.00372) = 19.42 dollars per KW (in 1978 dollars) for a non-duplicate 1000 MW reactor in 1980 (year 0) without cooling tower, etc. This cost is expected to grow at an average of $1.94 a year or just over 10% in real dollars in the first year. Other factors that would affect the base year (1980) cost include salt water cooling (+ $4.65), the use of cooling towers (+ $2.79) and PWR (TYPEM) design (+ $1.18). Co-location of the unit would reduce its expected 1980 cost by $3.18 and location in the North East is expected to add $4.00 to the costs. These figures can be read in millions of dollars if we consider a 1000 MW unit instead of a per KW cost.

TABLE B-11

REFERENCE LINEAR MODEL

Dependent Variable: REALSTAN

Independent Variable	Coefficient Value	Standard Error	t-Statistic	Confidence Level
TIME	1.94284	0.13734	14.14600	99.9%
MASKS	23.14260	1.58885	14.56560	99.9%
NEMASK	4.00011	0.66366	6.02732	99.9%
SIZEM	-0.00372	0.00220	-1.69181	97.5%
SALTM	4.64958	0.67700	6.86794	99.9%
TOWERSM	2.75956	0.76679	3.59883	99.5%
DEMOT	0.89526	0.32423	2.76116	99.5%
DEMOM	15.27140	2.38542	6.40196	99.9%
SECONDM	-3.17592	0.74950	-4.23739	99.9%
BIRTHM	-0.38098	0.17049	-2.23464	99.5%
TYPEM	1.18159	0.59233	-1.99481	99.5%

R^2 = .6802

Standard Error of the Equation: 4.5731

Sum of Squared Error: 5834.91

TABLE B-12

REFERENCE LINEAR CASE
BUT WITHOUT BIRTHM

Dependent Variable: REALSTAN

Independent Variable	Coefficient Value	Standard Error	t-Statistic	Confidence Level
TIME	1.85205	0.12995	14.25210	99.9%
MASKS	24.03200	1.53674	15.63830	99.9%
NEMASK	4.66269	0.62948	7.40723	99.9%
SIZEM	-0.00721	0.00158	-4.57198	99.9%
SALTM	4.42078	0.74543	5.93049	99.9%
TOWERSM	1.76842	0.72280	2.44661	97.5%
DEMOT	0.93647	0.32106	2.91684	99.9%
DEMOM	16.85320	2.17890	7.73472	99.9%
SECONDM	-2.95573	0.74865	-3.94805	99.9%
TYPEM	1.66645	0.61121	2.72649	99.5%

$R^2 = .6776$

Standard Error of the Regression: 4.5836

Sum of Squared Error: 5882.73

F-test for the significance of BIRTHM:

$$A(1,279) = \frac{5882.73 - 5834.91}{5834.91} \times \frac{290 - 11}{11 - 10} = 2.28654$$

The threshold value for 95% significance for F(1,200+) is 3.89, therefore BIRTHM is not statistically significant in the reference equation.

SIZET in the Linear Model

A natural question is whether the size of the units has any effect on the rate of cost increase in addition to its effect on the absolute level of costs. Using the linear model, a significant relationship between size of the units and a linear rate of cost increase was not found.* The details of this investigation will be presente' here because the use of the log-linear model results in very significant estimates for the effect of size on the escalation rate.

Table B-13 shows the results of a regression with SIZET added to the reference linear model. The coefficient of SIZET has a positive value of .00021, indicating that a 1000 MW unit increases in cost at a rate of 10¢ a year (per KW and in 1978 dollars) faster than a 500 MW unit. This corresponds to an additional rate of increase of $100,000 per year for the whole unit. This statistic, however, has a t-value below .5, and cannot be seriously considered as a significant variable in this equation. In order to examine this conclusion further, a F-test was performed, with the same result.

If, however, SIZET is used in the linear model without SIZEM, the results become quite significant. Table B-14 presents the results. The question might arise as to whether it might be preferable to use SIZET instead of SIZEM in the reference linear model. The answer is that statistical practice gives no absolute guidelines in such a situation--where one model is not a "subset" of another. However, in this case the reference run without SIZET but with SIZEM produced a lower sum of squared error, and absent any compelling reasons otherwise, such a model should be preferred. Thus, for the linear "equation specification" SIZEM has been chosen as the best measure of the effect of unit size on O&M costs. The use of the log-linear specification will lead to the opposite.

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*However, the linear model infers higher percentage escalation rates for larger plants because of lower base costs with the same annual cost increase (KW costs).

TABLE B-13

SIZET ADDED TO REFERENCE LINEAR MODEL

Dependent Variable: REALSTAN

Independent Variable	Coefficient Value	Standard Error	t-Statistic	Confidence Level
TIME	1.77361	.41431	4.2808	99.9%
MASKS	22.9578	1.28129	10.643327	99.9%
NEMASK	4.36153	.66142	6.59415	99.9%
SALTM	4.41715	.75306	5.86553	99.9%
TOWERSM	1.99068	.74436	2.67434	99.5%
DEMOT	.954623	.36916	2.58588	99.5%
DEMOM	15.6776	2.47989	6.32185	99.9%
SECONDM	12.91793	.75415	3.87059	99.9%
BIRTHM	-.249541	.16849	1.48103	90%
TYPEM	1.66079	.61813	2.68680	99.5%
SIZEM	-.004176	.00304	1.37412	90%
SIZET	.00021	.00057738	.362826	

$R^2 = .6804$

Standard Error of the Equation: 4.58027

Sum of Squared Error: 5832.14

TABLE B-14

SIZET REPLACING SIZEM IN REFERENCE LINEAR MODEL

Dependent Variable: REALSTAN

Independent Variable	Coefficient Value	Standard Error	t-Statistic	Confidence Level
TIME	1.40359	0.31538	4.45050	99.9%
MASKS	20.46110	1.16436	17.57270	99.9%
NEMASK	4.18621	0.65003	6.43999	99.9%
SALTM	4.40306	0.75420	5.83809	99.9%
TOWERSM	2.00292	0.74549	2.68671	99.5%
DEMOM	16.16540	2.45826	6.57597	99.9%
DEMOT	1.11972	0.34962	3.20265	99.9%
SECONDM	-3.04031	0.75007	-4.05335	99.9%
BIRTHM	-0.35215	0.15128	-2.32775	97.5%
TYPEM	1.60776	0.61791	2.60195	99.5%
SIZET	7.64203E-04	4.13596E-04	1.84770	95%

R^2 = .6782

Standard Error of Regression: 4.5876

Sum of Squared Error: 5871.76

The Log-Linear Model

The reference log-linear model results are presented in Table B-15. In this model SIZET is a significant term and so to compute estimated escalation rates, the size of the unit must also be known. Figure B-1 shows the estimated relationship between estimated escalation rate and size. The equation predicts that a 500 MW unit experienced, on the average a 13.5% escalation rate for O&M costs, in constant 1978 dollars. The value for a 1000 MW unit would be 19.48%.

In the log-linear model, constant terms enter into the costs in a uniformly multiplicative way rather than being uniformly additive. In order to derive the actual multiplier, the estimated coefficient must be exponentiated according to the formula:

$$\text{multiplier} = e^{[\text{log-linear coefficient}]}$$

Thus, from Table B-16 the multiplier for location in the North East can be constructed. It is $e^{.256199}$, which is equal to 1.29. Thus, location in the North East is expected to increase O&M costs by almost 30% over what they would be otherwise, for every year of operation. Table B-16 presents multipliers for all variables in the reference model, along with 95% confidence intervals.

If one compares these results with those of the reference linear model the general pattern is rougly similar in the near term. In the linear model a nonduplicate PWR with cooling tower would have (1978 dollar) O&M costs of $22.25 per KW in year 1980. Increasing at $1.91 per year, real O&M costs would reach $41.35 by the tenth year, and $60.45 by the 20th year. The log-linear model result would start at $22.61, reach $53.13 by the 10th year and $124.64 by the twentieth year. Clearly the log-linear model gives a more pronounced long-term cost escalation effect, although both model types have comparable explanatory power with respect to the historical experience.

TABLE B-15

REFERENCE LOG-LINEAR RESULTS

Dependent Variable: REALPOOL

Independent Variable	Coefficient Value	Standard Error	t-Statistic	Confidence Level
TIME	.075949	.0139914	5.42807	99.9%
MASKS	3.01852	.0434089	66.022425	99.9%
NEMASK	.270349	.0370223	7.30240	99.9%
SIZET	.000102	.00001937	5.28214	99.9%
SALTM	.280196	.045016	6.236224	99.9%
TOWERSM	.109606	.042258	2.5949963	99.5%
DEMOM	.546909	.067134	8.1524508	99.9%
SECONDM	-0.201635	.044147	4.56739	99.9%
TYPET	-0.013045	.0072153	1.75816	95%

R^2 = .6993

Sum of Squared Error: 20.8558

Standard Error of Regression: .2724

(e.g., 95% of estimates are within ± 70% of actual cost: $e^{(1.96 \times .2724)} = 1.70568$)

FIGURE B-1

LOG-LINEAR MODEL O&M COST ESCALATION RATE

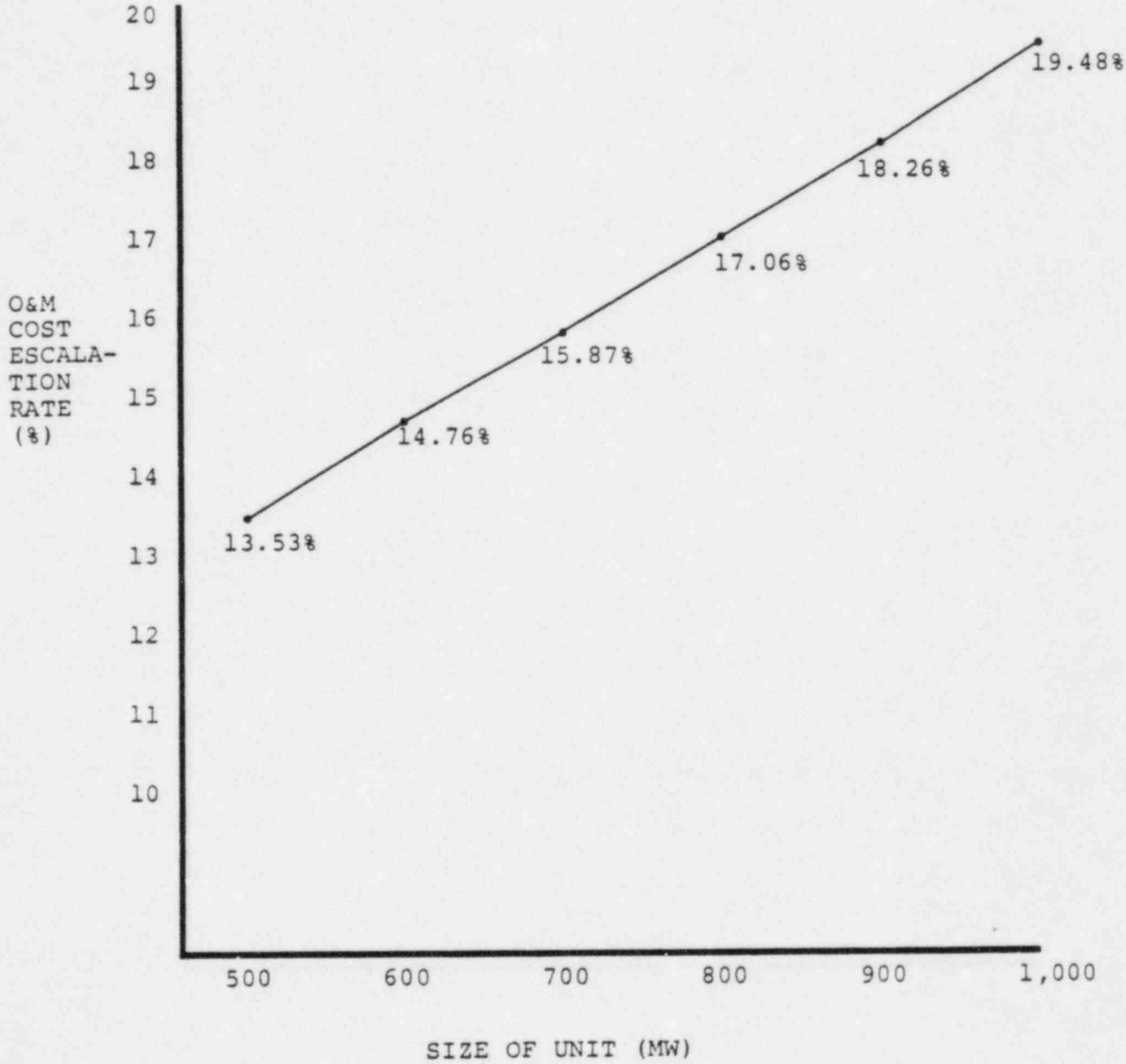

TABLE B-16

CONFIDENCE INTERVALS ON MULTIPLIERS IN THE REFERENCE LOG-LINEAR MODEL

	Estimated	Confidence Interval* 95% Lower Bound	95% Upper Bound
MASKS	20.46	18.79	22.28
NEMASK	1.31	1.22	1.41
SALTM	1.32	1.21	1.45
TOWERSM	1.12	1.03	1.21
DEMOM	1.73	1.51	1.97
SECONDM	.82	.75	.89
TYPET (differential escalation rate for PWRs)	.987	.973	1.001
TIME (base escalation rate above inflation)	7.89%	4.97%	10.89%
SIZET (incremental escalation rate per 1000 mw of capacity)	1.03%	.64%	1.41%

*95% probability that true coefficient value lies between lower and upper bounds.

SIZET in the Log-Linear Model

The log-linear model is different from the linear model in that it is more sensitive to quantities which behave exponentially, and "reacts" more strongly to such variables than does the linear model, which alternately is more sensitive to variables which increase in fixed absolute increments or in a fixed increment over the whole range of observations.

These factors must be kept in mind when examining why the SIZET term was chosen over SIZEM in the log-linear model. Consider Table B-17 where the SIZEM variable has been added to the reference log-linear model. The coefficient for SIZEM has a t-value of less than 1.3 while SIZET has a coefficient with a t-value of over 2.4 in this augmented model. The F-test shows that SIZEM does not approach contributing enough explanatory power to the regression to deserve inclusion. On the other hand, if one tests whether SIZET adds sufficient explanatory power to a model without it, but with SIZEM, the result is that SIZET is significant at the 95% level. Table B-18 shows the results of a regression on the log-linear model without SIZET and with SIZEM and the results of an F-test based on this regression and the regression presented in Table B-17.

This result thus supports the notion that larger units are associated with higher escalation rates in a stronger way than indicated by the linear reference model. Not only does it appear that larger units have higher escalation rates due to lower absolute costs, but the actual percentage annual increment of cost increase is identified as being larger for larger units by the log-linear model.

One might wonder why the "strength" of this interaction effect between size and escalation rate was not identified by the linear model. The simplest explanation is, of course, that the annual increase is not constant over time, but is itself increasing. The simplest approximation of this state of affairs is to assume that the annual increase itself increases a fixed amount every year, i.e., that the fractional or percentage increase is constant over time.

TABLE B-17

SIZEM ADDED TO REFERENCE LOG-LINEAR MODEL

Dependent Variable: REALPOOL

Independent Variable	Coefficient Value	Standard Error	t-Statistic	Confidence Level
TIME	0.09549	0.02112	4.52032	99.9%
MASKS	3.13857	0.10988	28.62530	99.9%
NEMASK	0.27287	0.03704	7.36619	99.9%
SIZEM	-1.80551E-04	1.46339E-04	-1.23379	90%
SALTM	0.28128	0.04490	6.26494	99.9%
TOWERSM	0.11535	0.04245	2.71695	99.5%
DEMOM	0.54261	0.06716	8.07908	99.9%
SECONDM	-0.19340	0.04461	-4.33546	99.9%
TYPET	-0.01374	0.00743	-1.84879	95%
SIZET	7.88549E-05	3.01396E-05	2.45043	97.5%

R^2 = .70053

Standard Error of the Regression: 0.2722

Sum of Squared Error: 20.743

F-test for significance of SIZEM:

$$F(1,280) = \frac{20.8588 - 20.743}{20.743} \times \frac{280}{1} = 1.52263$$

Critical value at 95% F(1,200+) = 3.89,
SIZEM "not significant."

TABLE B-18

SIZEM REPLACES SIZET IN REFERENCE LOG-LINEAR MODEL

Dependent Variable: REALPOOL

Independent Variable	Coefficient Value	Standard Error	t-Statistic	Confidence Level
TIME	0.14354	0.00793	18.10340	99.9%
MASKS	3.31636	0.08334	39.79200	99.9%
NEMASK	0.27044	0.03736	7.23882	99.9%
SIZEM	-4.55387E-04	9.48315E-05	-4.80207	99.9%
SALTM	0.29857	0.04473	6.67468	99.9%
TOWERSM	0.12622	0.04260	2.96309	99.9%
DEMOM	0.59802	0.06409	9.29956	99.9%
SECONDM	-0.20852	0.04457	-4.67838	99.9%
TYPET	-0.01735	0.00735	-2.35956	97.5%

R^2 = .69411

Standard Error of Regression: 0.2746

Sum of Squared Error: 21.188

F-test for the significance of SIZET:

$$F(1,280) = \frac{21.188 - 20.743}{20.743} \times \frac{280}{1} = 6.6068,$$

SIZET is a "significant at the 95% confidence level" addition to the reference log-linear model with SIZEM but without SIZET.

This is, in fact, the basic assumption of the log-linear model. The greater sensitivity to cost increases related to size in the log-linear model is also reflected in the greater precision of the SIZET variable in the log-linear model as opposed to SIZEM in the linear model (a higher t-statistic correlates with precision).

In other respects, the results of the log-linear model are similar to those of the linear model. Salt water cooling is expected to increase O&M costs about 33%, towers are expected to increase costs about 11%, co-location of units is expected to reduce costs about 22%, and PWR design is expected to reduce costs over time at the rate of about 1.31% a year relative to other designs.

The result that the linear model predicts uniformly higher costs for PWRs and the log-linear predicts a lower escalation rate is not necessarily contradictory for the same reason that lower uniform costs for larger units in the linear model are properly associated with higher escalation rates in the log-linear model, though the behavior of the TYPE variables is the converse of that of the SIZE variables. If linear base level costs are higher, the log-linear escalation rate associated with that cost can be expected to be lower.

Other Variables

Besides the variables considered here, others have been tested for significant association with O&M cost increases. These give however, negative results since these plant characteristics have not been found to have a significant association with O&M costs. They do not demonstrate that the characteristics under consideration have no impact on O&M costs, but merely that this impact cannot be identified as statistically significant at this time.

BIRTHM and BIRTHT were not found to be statistically significant under any conditions. This means that the in-service date of a nuclear station was not found to have a significant effect on the level of O&M costs or their rate of increase. This result creates the impression that new stations will start off being as expensive as those which have already been on-line for some time, a disconcerting possibility.

TURNKEYM and TURNKEYT were also statistically not significant in all tests, meaning that the study could not identify and O&M cost trends associated with the early turnkey construction projects.

Tests were also conducted to find out if significant O&M cost variations could be found between stations from different PWR reactor manufacturers. No significant variations could be identified.

In the future, more significant variables may be identified through the use of more years of plant data and through the study of particular components of O&M cost.

Existing Plants

For comparison, with the regression results, B-19, provides the results of a simple exponential regression fit to the historic real dollar O&M costs of each nuclear plant separately are presented. Similarly, Table B-20 provides the results of performing a simple linear fit to this data.

TABLE B-19

ESTIMATED SINGLE EQUATIONS EXPONENTIAL GROWTH

($ 1978 per KW)

STATION	ESTIMATED 1980 COST	ESCALATION RATE % = X100	R - SQUARED
DUANE ARNOLD	27.5414	0.208614	0.758553
BEAVER VALLEY	44.2886	0.386037	0.789055
BIG ROCK	113.081	0.159601	0.850822
BROWNS FERRY	20.191	0.283134	0.798695
BRUNSWICK	20.987	0.070865	0.491901
CALVERT CLIFFS	23.2092	0.18092	0.956787
DONALD C COOK	14.5562	0.193639	0.84417
COOPER	13.0195	0.022923	0.068849
CONNECTICUT YANKEE	25.0135	0.096313	0.596402
CRYSTAL RIVER	40.5553	0.473095	0.995978
DAVIS BESSE	27.9301	0.339837	1.
DRESDEN	29.2878	0.170795	0.78314
JOSEPH M FARLEY	44.476	0.696569	1.
JAMES A FITZPATRICK	36.1087	0.214414	0.860922
FORT CALHOUN	27.9667	0.184237	0.641283
ROBERT E GINNA	24.0944	0.108888	0.911037
HATCH	19.8936	0.22514	0.806661
HUMBOLDT BAY	57.1158	0.133829	0.708008
INDIAN POINT 1	401.872	0.347289	0.84244
INDIAN POINT 2	40.6132	0.172093	0.796063
INDIAN POINT 3	46.2901	0.499768	0.948436
KEWANEE	22.5322	0.054853	0.180298
MAINE YANKEE	13.6894	0.092073	0.659367
MILLSTONE 1	35.7053	0.129788	0.719221
MILLSTONE 2	33.228	0.17678	0.673199
MONTICELLO	23.0413	0.112589	0.651068
NORTH ANNA	29.6734	0.500823	1.
NUCLEAR ONE	27.7017	0.363408	0.997967
NINE MILE POINT	17.0889	0.114762	0.692972
OCONEE	16.4245	0.185799	0.756824
OYSTER CREEK	34.711	0.169225	0.722094
PALISADES	29.1781	0.17546	0.400511
PEACH BOTTOM	38.0517	0.360675	0.729415
PILGRIM	31.8214	0.136046	0.549913
POINT BEACH	11.1888	0.099317	0.751948
PRARIE ISLAND	17.1992	0.085258	0.280132
QUAD CITIES	21.7625	0.190023	0.940578
RANCHO SECO	16.5158	0.173879	0.916173
H B ROBINSON	23.052	0.188826	0.789214
ST LUCIE	24.5205	0.279402	0.501633
SALEM	44.094	0.270382	0.479566
SAN ONOFRE	37.894	0.147612	0.793882
SURRY	16.6132	0.129512	0.757544
THREE MILE ISLAND I	24.2832	0.043919	0.154385
TROJAN	17.0229	0.116889	0.746287
TURKEY POINT 3 AND 4	18.1482	0.122716	0.652427
VERMONT YANKEE	25.9601	0.103615	0.962388
YANKEE ROWE	60.85	0.147923	0.934457
ZION	11.8235	0.065612	0.556827

TABLE B-20

ESTIMATED SINGLE EQUATIONS LINEAR GROWTH

($ 1978 per KW)

STATION	ESTIMATED 1980 COST	ANNUAL ESCALATION (1978 DOLLARS)	R - SQUARED
DUANE ARNOLD	24.1582	2.58151	0.702003
BEAVER VALLEY	35.46.3	5.75575	0.808512
BIG ROCK	105.434	8.92881	0.38882
BROWNS FERRY	18.0754	2.58123	0.800415
BRUNSWICK	20.748	1.18303	0.430885
CALVERT CLIFFS	21.5800	2.35485	0.854334
DONALD C COOK	13.1443	1.42839	0.877258
COOPER	13.0023	0.240878	0.081303
CONNECTICUT YANKEE	24.479	1.33747	0.530222
CRYSTAL RIVER	34.2303	7.31715	0.227785
DAVIS BESSE	28..332	5.28733	1.
DRESDEN	24.5427	1.20385	0.773743
JOSEPH M FARLEY	36.9786	10.7333	1.
JAMES A FITZPATRICK	33.1803	4.14473	0.898104
FORT CALHOUN	23.3116	1.88803	0.330423
ROBERT E GINNA	22.5213	1.3173	0.814791
HATCH	17.8324	2.25008	0.843024
HUMBOLDT BAY	51.7585	3.81305	0.308038
INDIAN POINT 1	109.083	6.85428	0.820707
INDIAN POINT 2	38.4319	4.14028	0.80571
INDIAN POINT 3	35.3185	3.70088	0.837027
KEWANEE	21.8995	0.805041	0.130724
MAINE YANKEE	13.0389	0.87114	0.023675
MILLSTONE 1	31.5306	2.1800	0.811802
MILLSTONE 2	30.8839	3.30031	0.833304
MONTICELLO	21.0243	1.35131	0.823255
NORTH ANNA	23.3391	6.3877	1.
NUCLEAR ONE	22.8719	3.81321	0.852583
NINE MILE POINT	17.2464	1.02727	0.677783
OCONEE	14.6447	1.42227	0.788783
OYSTER CREEK	27.5433	2.00233	0.702232
PALISADES	27.7534	2.32887	0.425032
PEACH BOTTOM	27.0733	3.40800	0.881727
PILGRIM	28.8228	2.18808	0.517015
POINT BEACH	10.8718	0.753427	0.717212
PRARIE ISLAND	16.3847	0.023037	0.221122
QUAD CITIES	18.3054	1.74043	0.844142
RANCHO SECO	15.7012	1.78782	0.8.323.
H B ROBINSON	20.1827	1.80325	0.735402
ST LUCIE	22.0023	3.20335	0.423731
SALEM	43.7.3	7.323.1	0.5488.2
SAN ONOFRE	32.3271	2.34178	0.773338
SURRY	15.1330	1.14112	0.812788
THREE MILE ISLAND I	24.011	0.808742	0.13331
TROJAN	18.4027	1.24877	0.73E-24
TURKEY POINT 3 AND 4	13.3247	1.18494	0.248872
VERMONT YANKEE	[illegible]	1.77318	[illegible]
YANKEE ROWE	[illegible]	[illegible]	[illegible]
ZION	[illegible]	.314030	[illegible]

APPENDIX C

Nuclear Capacity Factors

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C-1 Introduction and Summary

The capacity factor of a power plant is the ratio of actual electricity generation to the maximum potential generation over some time period.* Annual capacity factors are a key measure of plant performance. The present study was a statistical analysis of the determinants of nuclear power plant capacity factors. Its data base consisted of operating information and data on other plant characteristics for 68 commercially operating nuclear units in the U.S., representing almost all such units.

The multiple regression analysis that was performed for this study focussed on the question of how and why capacity factors change over time. An equation was specified that explained historical capacity factors (and had test statistics sufficient to merit serious consideration to predicting nuclear power plant performance).

Among the variables found to have explanatory power were the size of the unit, its reactor type (pressurized water vs. boiling water), whether or not its cooling system used salt water or fresh water, and its age. Of the several interesting results obtained by applying the regression eqation, perhaps the most important was the effect upon

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* Capacity factors as reported in this text are defined as:

$$\frac{\text{Net electrical energy generated} \times 100}{\text{Period hours} \times \text{maximum dependable capacity}}$$

Maximum dependable capacity is defined in Table C-2 below.

capacity factors of a nuclear unit's using salt water for cooling. After a period of maturation during which capacity factors increase from their initial level, the capacity factors for units using salt water cooling decline significantly. The capacity factors of salt water cooled pressurized water reactor (PWR) units were found to decline much more rapidly than those of salt water cooled boiling water reactor (BWR) units. For non salt water cooled BWRs the general aging trend was a long term increase in adjusted capacity factors. For similar PWRs this was balanced by a long term trend towards declining performance, which was more pronounced for smaller units.

In the balance of this technical report, the present research is situated in the context of previous studies; the study methodology and data base are described, the modelling approach is discussed; the resulting analysis of capacity factors is detailed; and the use of the results in the Maine Yankee nuclear retirement study is described.

Statistical Analyses of Nuclear Capacity Factors

The several capacity factor studies that have been completed heretofore have attempted to provide an analytical basis for understanding nuclear power plant performance. Thus far, there have not been many years of capacity factor data for nuclear units. The investigations heretofore conducted on the subject of nuclear capacity factors have addressed the hypothesis of a "maturation" effect, a hypothesis which implies increasing capacity factors (after relatively low initial values) for the first few years of commercial operation. On the basis of the limited operating experience upon which previous studies have been carried out, there is some evidence for maturation.

The principal question left unanswered by these previous studies is whether nuclear units can be expected to perform at the levels they reach after approximately five years of capacity factor maturation for the remaining twenty five years of planned operating life, or whether shortly after attaining this "mature" level an aging effect will set in, causing capacity factors to decline. The available data base spans such a relatively short time that it is difficult to provide a conclusive answer to this question. It is obligatory, however, to provide analyses which may give indicative, if only tentative, results.

This study addresses the issue of nuclear power plant performance generally, the maturation effect, and capacity factor behavior after the maturation period. One conclusion that has been reached is that significantly decreased performance can be expected from pressurized water reactor (PWR) units and reactors cooled by salt water after a maturation period of about six years. These findings extend and are consistent with earlier analyses, and provide a basis for more extensive work in the future.

Charles Komanoff pioneered capacity factor analysis (Ref. C-1). His work revealed poor performance of large boiling water reactor (BWR) units and indicated that maturation effects for large PWRs were limited. Komanoff is continuing to perform research in this field.

Robert Easterling found a strong maturation effect for nuclear units up to the fifth year of operation; significantly poorer than average overall performance by large units; and differential levels of performance of PWR and BWR units over time (Ref. C-2). His predictions of large PWR unit performance -- an average capacity factor of 57 percent over the second to tenth years of operation -- were much

lower than estimates generally made by the industry and government. Easterling considered age, size, and reactor type as independent or explanatory variables in his statistical analyses of nuclear plant capacity factors.

A more comprehensive study by Lucas and Hall (Ref. C-3), based upon an international cross-section of nuclear reactors, shows a probable decline in BWR capacity factors after the fourth year of operation.

Generally, previous work has indicated that industry expectations of post-maturation capacity factors of 70 percent or higher may be too optimistic. However, the question of long-term nuclear power plant performance has been left open, due to the limitations of this work. It is only in the last few years that significant numbers of nuclear power plants have entered what may prove to be their post-maturation phase. This may be one of the factors accounting for the low degree of explanatory power characteristically found in past statistical analyses of power plant capacity factors, which in turn made it difficult to predict long term trends with any degree of precision.

The present study attempts to go beyond previous work methodologically in two important ways. It includes more explanatory variables in the statistical analysis. Additionally it uses an adjusted capacicity factor as the measure of power plant performance to be investigated, explained, and predicted. The methodological innovation used to develop the adjusted capacity factor is conceptually straightforward. It was decided to subtract planned refueling outages and outages mandated by the Nuclear Regulatory Commission (NRC) from the total of planned and forced outages for each unit. This had not been done in previous capacity factor studies, but it permitted us to focus more narrowly on the issue of past and future technical performances _per se._

Methodology and Data Base

The basic procedure employed in this study, as in the previous efforts referred to above, was multivariate regression analysis by the method of least squares. This statistical technique for the analysis of variance estimates coefficients in an equation in which several independent variables are believed to collectively "explain" the observer variation in the dependent variable. In this case the dependent variable is the key component of the capacity factor, namely, the adjusted capacity factor based on forced outages and scheduled equipment and maintenance. One can express the dependent variable as a linear combination of the independent or explanatory variables chosen. For the variable of primary interest, CF, a multiple regression equation is

$$CF = \sum_i a_i X_i$$

For a set of observations of CF and values of the explanatory variables (X_i) the values of the coefficients (a_i) are estimated. That is, the dependence of the dependent variable upon each of a set of explanatory variables (and the set as a whole) is statistically established.

Regression analysis provides methods by which the accuracy of the estimated coefficient for each independent variable may be evaluated. Moreover, regression analysis provides means by which the explanatory power of a particular set of independent variables may be measured. Alternative equations or models, embodying different sets of independent variables, may be compared.

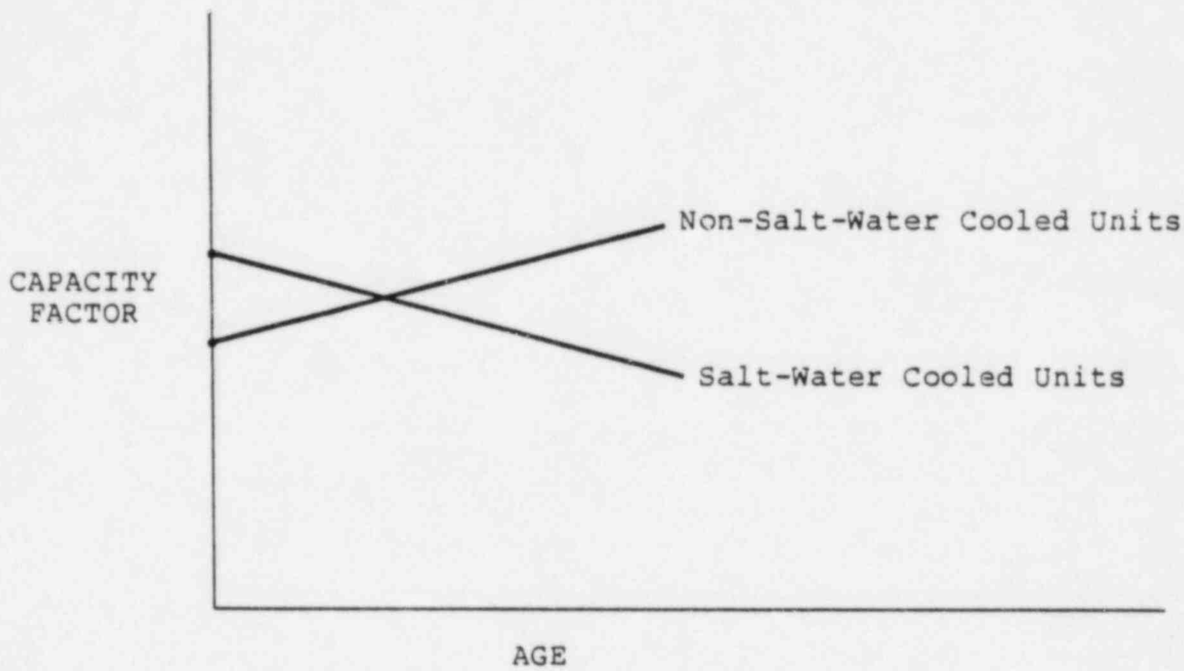
The basic set of independent variables (the X_i) used in the capacity factor analysis in this study are the unit's maximum dependable capacity (MDCU), use of cooling towers (TOWERSU=1 if they are used,

0 otherwise), use of salt water in the cooling system (SALTU=1 if it is used, 0 otherwise), the type of unit (PWRU=1 if it is a PWR, 0 otherwise), and a variable (AGE) which identifies the year of plant operation with which each capacity factor observation is associated. These are not an exhaustive set of potential explanatory variables, and indeed they do not <u>prima facie</u> provide significant explanatory power. Some of them, however, have already been used rather successfully in previous analyses, and the group as a whole represents a real expansion of the information considered to date.

Moreover, extensive use has been made of product terms, which entail new independent variables created as the product of two or more of the basic set of variables given above. The interpretation of these terms is straightforward. For example, if AGE, SALTU, and AGE x SALTU are among the variables in an equation (or model) under consideration, then a statistically significant value for the coefficient of the product term AGE x SALTU indicates differential capacity factor aging behavior for salt-water cooled nuclear power plants when compared with other types of plants. The coefficient of the SALTU term itself thus can be taken as providing an intercept value that estimates a baseline difference that is modified by the product term. These three terms together can characterize a general aging effect for all nuclear units (the AGE term) starting from a common baseline, a differential baseline effect for salt-water cooled units (the SALTU term), and a differential aging effect for salt-water cooled units (the SALTU x AGE term). Figure C-1 below illustrates this possibility.

Figure C-1

Hypothetical Effect of a Simple Product Term for Aging



The accuracy of regression analysis is predicated upon the assumption that all available information relevant to the explanation of the dependent variables (in this case the capacity factor) is incorporated into the model. Two sources of outage that contribute to the total outage data from which the capacity factor is formed are particularly troublesome in this regard. Plant outages for nuclear refueling and NRD-mandated shutdowns cause a significant and apparently random variation in observed capacity factors that has not been separately analyzed in previous research. If one is attempting principally to explain forced outage rates for nuclear units, inclusion of these outages in the capacity factor observation would in

theory lead to biased results. This should thus be corrected if credibility is to be achieved for the regression analysis.

If refuelling and NRC mandated outages are not related to the independent variables selected for a model of equipment and maintenance related outages the explanatory power of a model for the total or unadjusted capacity factor (incorporating all outages) may be found to be unnecessarily poor. Removal of this "noise" could lead to statistical results which are much improved over those found for the unadjusted capacity factor. This is especially likely in the case of capacity factors calculated, as is usually done, on an annual basis, since refuelling cycles generally do not occur on a regular yearly basis, but often each 14 to 18 months, thus affecting plant outages in different calendar years quite differently. Randomness can also be introduced by NRC related outages. As a consequence, an adjusted capacity factor resulting from the subtraction of refuelling and NRC-mandated outages was chosen as the dependent variable in this study. Since training and licensing outages, while not lengthy, introduce similar randomness, they too were subtracted. Adjustment is according to the formula:

NCAPFAC2 = Electric Generation/[8760 x FRAC-OUTAGE] x MDC

where "MDC is the maximum dependable capacity of the plant, "FRAC" is the fraction of the year it was in commercial operation, and "OUTAGE" is the total outage hours for the categories for which adjustment is made.

This adjustment to the nuclear capacity factors analyzed is one of the important advances that the present study offers.

Data on nuclear unit outages for the years 1975 through 1981 were obtained from the NRC "grey book" data base on computer tape.* This data was processed by computer into outage hours for 16 categories of outage causes. The basic categories were equipment failure, maintenance, refueling, NRC mandated shutdown, training and examination, administrative causes, operator error, and "other" causes. Table C-1 provides capacity factors expressed as ratios and adjusted by subtracting outages due to refueling, NRC orders, and training and licensing.

Table C-2 provides some of the characteristics of the existing nuclear units whose operating experience has been used as the basis for the present study.

The use of adjusted capacity factors requires further correction of the regression analysis because the significance of each observation is no longer equal. For example, a 20 percent capacity factor for 600 hours of operation should not carry as much weight as one of 60 percent for a whole year (8760 hours). Also, the expected variance of observations on shorter periods is higher. The way to correct for this bias is to weight the estimates through the use of the generalized least squares (GLS) techniques. The weights are proportional to expected variance, which in this case was taken to be a linear function of the square of the inverse of the on-line hours (Ref. C-4).

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* The "grey book" is the Licensed Operating Reactors Status Summary Report (NUREG-0020) issued periodically by the NRC. The data base underlying this report was obtained on computer tape from NRC for use in this analysis.

TABLE C-1

ADJUSTED CAPACITY FACTORS

	1970	1971	1972	1973	1974	1975	1976	1977	1978	1979	1980	1981
1. ARKANSAS 1	-	-	-	-	-	0.669	0.531	0.854	0.849	0.546	0.579	0.842
2. ARKANSAS 2	-	-	-	-	-	0.	0.	0.	0.	0.	0.633	0.788
3. DUANE ARNOLD	-	-	-	-	-	0.453	0.664	0.785	0.306	0.643	0.778	0.668
4. BEAVER VALLEY 1	-	-	-	-	-	0.	0.173	0.405	0.35	0.526	0.372	0.657
5. BIG ROCK POINT	-	-	-	-	-	0.518	0.654	0.804	0.715	0.233	0.912	0.919
6. BROWNS FERRY 1	-	-	-	-	-	0.151	0.148	0.771	0.707	0.849	0.829	0.898
7. BROWNS FERRY 2	-	-	-	-	-	0.071	0.195	0.667	0.784	0.872	0.77	0.801
8. BROWNS FERRY 3	-	-	-	-	-	0.	0.	0.751	0.757	0.83	0.859	0.856
9. BRUNSWICK 1	-	-	-	-	-	0.	0.	0.461	0.753	0.704	0.757	0.369
10. BRUNSWICK 2	-	-	-	-	-	0.61	0.359	0.499	0.693	0.746	0.557	0.475
11. CALVERT CLIFFS 1	-	-	-	-	-	0.766	0.873	0.875	0.8	0.74	0.82	0.845
12. CALVERT CLIFFS 2	-	-	-	-	-	0.	0.	0.837	0.783	0.865	0.911	0.882
13. CONNECTICUT YANKEE	-	-	-	-	-	0.967	0.953	0.899	0.968	0.994	0.955	0.961
14. D. C. COOK 1	-	-	-	-	-	0.626	0.761	0.646	0.878	0.73	0.918	0.821
15. D. C. COOK 2	-	-	-	-	-	0.	0.	0.	0.657	0.754	0.746	0.829
16. COOPER STATION	-	-	-	-	-	0.51	0.646	0.715	0.8	0.812	0.77	0.654
17. CRYSTAL RIVER 3	-	-	-	-	-	0.	0.	0.666	0.38	0.756	0.855	0.757
18. DAVIS-BESSE 1	-	-	-	-	-	0.	0.	0.	0.34	0.567	0.654	0.57
19. DRESDEN 1	-	-	-	-	-	-	-	-	-	-	-	-
20. DRESDEN 2	-	-	-	-	-	0.7	0.806	0.612	0.844	0.84	0.682	0.775
21. DRESDEN 3	-	-	-	-	-	0.547	0.691	0.766	0.674	0.513	0.778	0.769
22. FARLEY 1	-	-	-	-	-	0.	0.	0.684	0.841	0.703	0.807	0.482
23. J. A. FITZPATRICK	-	-	-	-	-	0.501	0.612	0.741	0.726	0.806	0.83	0.811
24. FORT CALHOUN	-	-	-	-	-	0.66	0.656	0.859	0.846	0.876	0.793	0.69
25. GINNA	-	-	-	-	-	0.805	0.618	0.819	0.928	0.84	0.887	0.977
26. HATCH 1	-	-	-	-	-	0.	0.624	0.624	0.729	0.779	0.722	0.695
27. HATCH 2	-	-	-	-	-	0.	0.	0.	0.	0.812	0.597	0.773
28. HUMBOLDT BAY	-	-	-	-	-	0.697	0.348	0.	0.	0.004	0.	0.
29. INDIAN POINT 2	-	-	-	-	-	0.614	0.598	0.76	0.8	0.846	0.666	0.663
30. INDIAN POINT 3	-	-	-	-	-	0.	0.657	0.653	0.826	0.806	0.41	0.359
31. KEWAUNEE	-	-	-	-	-	0.745	0.894	0.918	0.964	0.841	0.925	0.962
32. LA CROSS	-	-	-	-	-	0.821	0.779	0.534	0.52	0.542	0.597	0.626
33. MAINE YANKEE	-	-	-	-	-	0.751	0.836	0.875	0.857	0.923	0.747	0.845
34. MILLSTONE 1	-	-	-	-	-	0.721	0.786	0.841	0.902	0.885	0.782	[illegible]
35. MILLSTONE 2	-	-	-	-	-	0.	0.6	0.627	0.777	0.722	0.925	0.869
36. MONTICELLO	-	-	-	-	-	0.781	0.849	0.928	0.857	0.937	0.84	0.741
37. NINE MILE POINT	-	-	-	-	-	0.57	0.77	0.879	0.836	0.809	0.852	0.906
38. NORTH ANNA 1	-	-	-	-	-	0.	0.	0.	0.849	0.755	0.796	0.839
39. NORTH ANNA 2	-	-	-	-	-	0.	0.	0.	0.	0.	1.024	0.725
40. OCONEE 1	-	-	-	-	-	0.703	0.632	0.595	0.78	0.77	0.791	0.61
41. OCONEE 2	-	-	-	-	-	0.66	0.633	0.588	0.73	0.836	0.681	0.695
42. OCONEE 3	-	-	-	-	-	0.669	0.713	0.77	0.902	0.847	0.741	0.793
43. OYSTER CREEK	-	-	-	-	-	0.676	0.774	0.836	0.826	0.84	0.767	0.526
44. PALISADES	-	-	-	-	-	0.451	0.792	0.914	0.66	0.9	0.718	0.946
45. PEACH BOTTOM 2	-	-	-	-	-	0.567	0.801	0.705	0.828	0.931	0.75	0.72
46. PEACH BOTTOM 3	-	-	-	-	-	0.586	0.682	0.734	0.891	0.787	0.799	0.712
47. PILGRIM	-	-	-	-	-	0.441	0.62	0.63	0.746	0.825	0.826	0.799
48. POINT BEACH 1	-	-	-	-	-	0.739	0.944	0.929	0.911	0.836	0.74	0.727
49. POINT BEACH 2	-	-	-	-	-	0.863	0.928	0.961	0.963	0.907	0.911	0.955
50. PRARIE ISLAND 1	-	-	-	-	-	0.838	0.815	0.927	0.924	0.72	0.827	0.972
51. PRARIE ISLAND 2	-	-	-	-	-	0.725	0.698	0.982	0.946	0.957	0.912	0.808
52. QUAD CITIES 1	-	-	-	-	-	0.634	0.627	0.611	0.71	0.767	0.734	0.85
53. QUAD CITIES 2	-	-	-	-	-	0.54	0.738	0.649	0.773	0.658	0.771	0.803
54. RANCHO SECO	-	-	-	-	-	0.245	0.288	0.977	0.724	0.904	0.859	0.472

TABLE C-1
ADJUSTED CAPACITY FACTORS
(Continued)

55. H. B. ROBINSON 2	-	-	-	-	-	0.804	1.059	0.711	0.801	0.886	0.7	0.649
56. SALEM 1	-	-	-	-	-	0.	0.	0.379	0.479	0.427	0.74	0.655
57. SAN ONOFRE 1	-	-	-	-	-	0.892	0.871	0.612	0.872	0.879	0.294	0.204
58. ST. LUCIE 1	-	-	-	-	-	0.	0.531	0.785	0.894	0.912	0.902	0.94
59. SURRY 1	-	-	-	-	-	0.786	0.678	0.875	0.893	0.871	0.483	0.35
60. SURRY 2	-	-	-	-	-	0.855	0.569	0.72	0.813	0.964	0.899	0.922
61. THREE MILE ISLAND 1	-	-	-	-	-	0.815	0.867	0.956	0.954	0.33	0.	0.
62. TROJAN	-	-	-	-	-	0.	0.345	0.689	0.79	0.714	0.88	0.837
63. TURKEY POINT 3	-	-	-	-	-	0.843	0.879	0.935	0.916	0.81	0.862	0.188
64. TURKEY POINT 4	-	-	-	-	-	0.915	0.782	0.786	0.774	0.863	0.797	0.968
65. VERMONT YANKEE	-	-	-	-	-	0.872	0.824	0.927	0.794	0.893	0.814	0.929
66. YANKEE ROWE	-	-	-	-	-	0.937	0.817	0.874	0.938	0.857	0.215	0.764
67. ZION 1	-	-	-	-	-	0.539	0.677	0.663	0.857	0.77	0.757	0.914
68. ZION 2	-	-	-	-	-	0.53	0.513	0.882	0.912	0.678	0.579	0.693

TABLE C-2

NUCLEAR UNIT CHARACTERISTICS

	PWR	SALT WATER	MDC	TOWERS	STEAM SYSTEM	C. O. DATE
1. ARKANSAS 1.............	1	0	836	0	1	74.97
2. ARKANSAS 2.............	1	0	858	1	2	80.23
3. DUANE ARNOLD...........	0	0	515	1	4	75.09
4. BEAVER VALLEY 1........	1	0	810	1	3	70.75
5. BIG ROCK POINT.........	C	0	64	0	4	63.24
6. BROWNS FERRY 1.........	0	0	1065	1	4	74.58
7. BROWNS FERRY 2.........	0	0	1065	1	4	75.16
8. BROWNS FERRY 3.........	0	0	1065	1	4	77.16
9. BRUNSWICK 1............	0	1	790	0	4	77.21
10. BRUNSWICK 2...........	0	1	790	0	4	75.84
11. CALVERT CLIFFS 1......	1	1	825	0	2	75.35
12. CALVERT CLIFFS 2......	1	1	825	0	2	77.25
13. CONNECTICUT YANKEE....	1	0	555	0	3	68.00
14. D. C. COOK 1..........	1	0	1044	0	3	75.65
15. D. C. COOK 2..........	1	0	1082	0	3	78.50
16. COOPER STATION........	0	0	764	0	4	74.50
17. CRYSTAL RIVER 3.......	1	1	782	0	1	77.12
18. DAVIS-BESSE 1.........	1	0	874	1	1	78.50
19. DRESDEN 1.............	0	0	200	0	4	60.00
20. DRESDEN 2.............	0	0	772	0	4	70.44
21. DRESDEN 3.............	0	0	773	0	4	71.88
22. FARLEY 1..............	1	0	804	1	3	77.92
23. J. A. FITZPATRICK.....	0	0	810	0	4	75.57
24. FORT CALHOUN..........	1	0	478	0	2	74.47
25. GINNA.................	1	0	470	0	3	70.46
26. HATCH 1...............	0	0	757	1	4	76.00
27. HATCH 2...............	0	0	771	1	4	79.68
28. HUMBOLDT BAY..........	0	1	65	0	4	60.00
29. INDIAN POINT 2........	1	1	864	0	3	74.58
30. INDIAN POINT 3........	1	1	965	0	3	76.66
31. KEWAUNEE..............	1	0	512	0	3	74.42
32. LA CROSS..............	0	0	48	0	-	69.84
33. MAINE YANKEE..........	1	1	810	0	2	74.99
34. MILLSTONE 1...........	0	1	654	0	4	71.16
35. MILLSTONE 2...........	1	1	864	0	2	75.99
36. MONTICELLO............	0	0	536	1	4	71.41
37. NINE MILE POINT.......	0	0	610	0	4	69.92
38. NORTH ANNA 1..........	1	0	865	0	3	78.43
39. NORTH ANNA 2..........	1	0	890	0	3	80.96
40. OCONEE 1..............	1	0	860	0	1	73.54
41. OCONEE 2..............	1	0	860	0	1	74.69
42. OCONEE 3..............	1	0	860	0	1	74.96
43. OYSTER CREEK..........	0	1	620	0	4	69.92
44. PALISADES.............	1	0	635	1	2	71.92
45. PEACH BOTTOM 2........	0	0	1051	1	4	74.51
46. PEACH BOTTOM 3........	0	0	1035	1	4	74.99
47. PILGRIM...............	0	1	670	0	4	72.92
48. POINT BEACH 1.........	1	0	495	0	3	70.97
49. POINT BEACH 2.........	1	0	495	0	3	72.75
50. PRARIE ISLAND 1.......	1	0	503	1	3	73.96
51. PRARIE ISLAND 2.......	1	0	500	1	3	74.97
52. QUAD CITIES 1.........	0	0	769	0	4	73.13
53. QUAD CITIES 2.........	0	0	769	0	4	73.19
54. RANCHO SECO...........	1	0	873	1	1	75.29

TABLE C-2

NUCLEAR UNIT CHARACTERISTICS
(Continued)

55. [illegible] B. ROBINSON 2......	1	0	665	0	3	71.18
56. SALEM 1................	1	1	1079	0	3	77.4[illegible]
57. SAN ONOFRE 1..........	1	1	436	0	3	68.[illegible]
58. ST. LUCIE 1...........	1	1	777	0	2	76.[illegible]
59. SURRY 1................	1	1	775	0	3	72.97
60. SURRY 2................	1	1	775	0	3	73.33
61. THREE MILE ISLAND 1...	1	0	776	1	1	74.[illegible]
62. TROJAN................	1	0	1080	1	3	76.[illegible]
63. TURKEY POINT 3........	1	1	646	0	3	72.[illegible]
64. TURKEY POINT 4........	1	1	646	0	3	73.47
65. VERMONT YANKEE........	0	0	504	1	4	72.[illegible]
66. YANKEE ROWE...........	1	0	175	0	3	61[illegible]
67. ZION 1................	1	0	1040	0	3	74[illegible]
68. ZION 2................	1	0	1040	0	3	74.7[illegible]

Notes

PWR: PWR Unit if 1; BWR if 0

Salt Water: Salt water used for cooling if 1; fresh water if 0

MDC: Maximum dependable capacity net MW (maximum electrical output during the most restrictive seasonal conditions, less the normal station service loads)

Towers: Cooling towers if 1; none if 0

Steam System: Supplier of steam system (Babcock and Wilcox, 1; Combustion Engineering, 2; Westinghouse, 3; or General Electric, 4)

C.O. Date: Date of initial commercial operation (year, followed by the fraction of the year that had passed by the point of commercial opeation. Thus, Yankee Rowe started commercial operation at 61.50, or July 1, 1961).

First years of operation are included among the capacity factor observations, and thereby in these analyses, since the GLS estimation procedure weights their significance appropriately.

Outage data for the Dresden #1 unit is not presently available in the NRC data base, and hence this unit was not included in the analysis. Exclusion of this unit's experience tends to bias the capacity factor results of this study on the high side. Similarly, Three Mile Island #2 was excluded, as were Indian Point #1 and Humboldt Bay after 1978. Year 1980 data for Arkansas #2 was unintentionally excluded. Moreover, no operating experience prior to 1975 has been analyzed since the unit-specific (as opposed to station-specific) outage data were not available on the NRC tape.

Modelling Considerations

Simple linear regression using the basic set of independent variables -- MDCU, PWRU, SALTU, TOWERSU, and AGE -- produced rather weak results. The model employed and the regression results are given explicitly in Table C-3 below.

Note the only term here with strong statistical significance is the PWRU term, while the SALTU and AGE terms are only found to be significant at 90+ percent. Note, also, the poor R-SQUARED (.07).

Addition of various cross product terms to the regression equation (e.g. AGE x MDCU, AGE x SALTU, PWRU x MDCU, SALTU x PWRU) yielded significantly improved results, and this modelling direction was pursued on a systematic basis. Moreover, in an attempt to capture long term trends two methods were explored; the addition of quadratic age terms (e.g. AGE^2 x MDCU; etc.), and the use of broken linear terms. These approaches were taken in order to examine whether the

TABLE C-3

INITIAL REGRESSION ON BASIC SET OF VARIABLES

Term in Equation	Coefficient of Term	t-Statistic
1	.717	13.7
MDCU	-5.77×10^{-5}	-1.23
PWRU	.071	4.20
SALTU	-.034	-1.75
AGE	.005	1.76
TOWERSU	3.73×10^{-4}	.016

Number of Variables = 6
R-Squared = .069
Corrected R^2 = .058

Standard Error of Regression = .140
F(5/414) = 6.18
COND(X) = 15.5

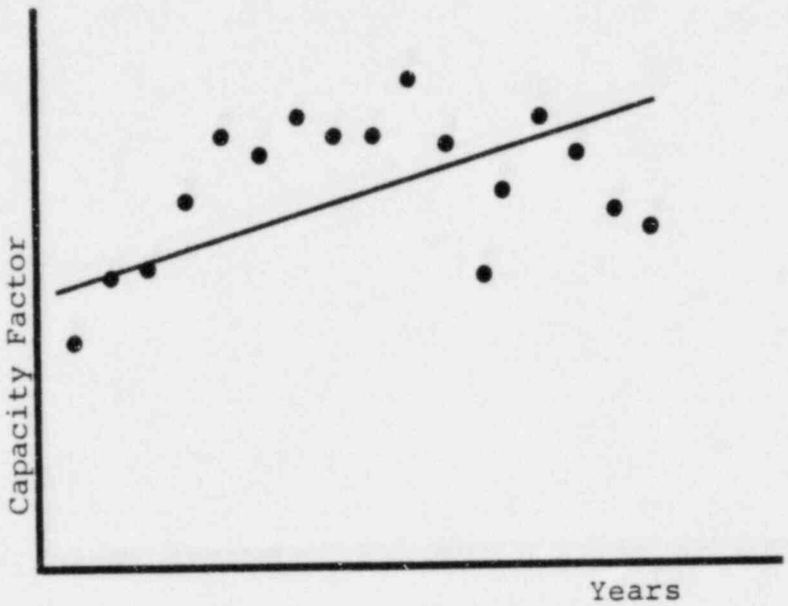
basic age results, for example maturation in early years, could be expected to continue beyond those years or whether a change in the capacity factor aging behavior would be found. If such additional (i.e. quadratic or broken linear age) terms proved to be statistically significant then the latter conclusion would be indicated.

Illustration of the use of quadratic and broken linear approaches can be found in Figures C-2, C-3, and C-4. Figure C-2 shows how a hypothetical set of observations could be explained by a simple linear term (e.g. in any one of the age variables; AGE or AGE x SALTU). Quadratic terms start out small and become rapidly larger. If a quadratic term is added to the linear and found to be statistically significant, it means that the long term behavior of the same set of observations (the dependent variable capacity factor) is better estimated by the sum of linear and quadratic terms than by the linear alone. This can be seen by comparing Figure C-3 to Figure C-2. In Figure C-3 the resulting estimation is the solid line which is the sum of the linear and quadratic (dashed) lines.

Broken linear age terms can be used to estimate the behavior of the capacity factors over limited segments of time within the operating experience of the nuclear units. Consider Figure C-4. In this illustration example line A (beginning as a broken line and continuing as solid) represents an overall long-term aging trend, while line B is added to account for early year (i.e. maturation) behavior. The actual estimate is the sum of these two lines, i.e. the solid line beginning with line segment C (early maturation). If the coefficients of both lines (A and B) are found to be statistically significant, it means that actual capacity factor behavior is better

FIGURE C-2

Illustration of a Simple Linear Specification



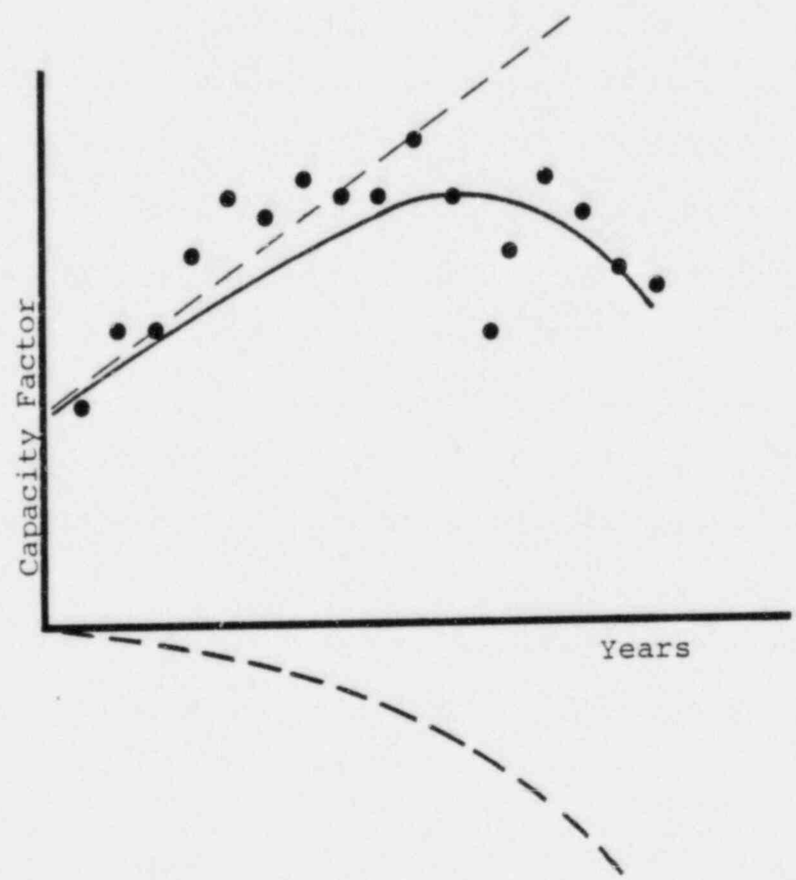


FIGURE C-3

Illustration of a Linear Plus Quadratic Specification

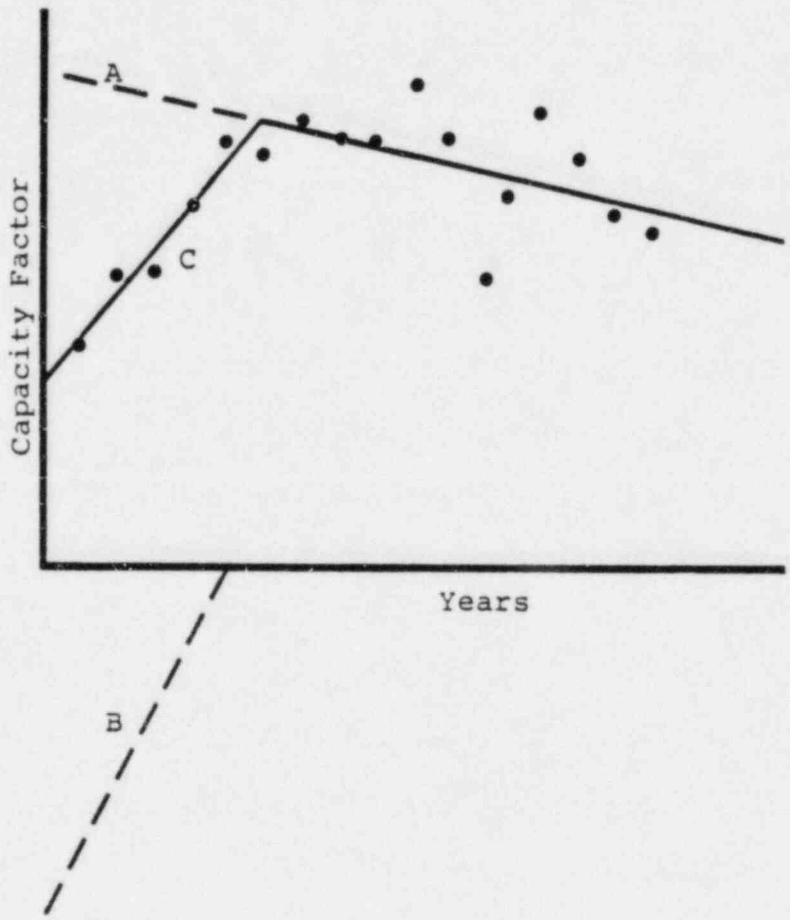


FIGURE C-4

Illustration of a Broken Linear Specification

described by the broken linear than by a simple linear age term (compare Figures C-2 and C-4). Note, finally, that while both the quadratic (Figure C-3) and broken linear Figure C-4) estimations have comparable explanatory power with regard to the observations, they have quite different long term behavior. In either case statistically signficant results for this illustrative example would indicate that capacity factors experienced early maturation followed by long-term decline.

The broken linear method was ultimately selected over the quadratic approach. The basic reasons for this choice was that the results of the broken linear approach were easier to interpret, more conservative with regard to long term capacity factor prediction, and potentially much more accurate given the greater number of functions of age used (four). Given the limited number of operating years within the existing nuclear plant data base, a finding of a slow down or leveling of capacity factor maturation by use of a quadratic age term (i.e., a negative coefficient for this term) provide serious problems for prediction of long term behavior. While a leveling off of maturation could be embodied in the data base a quadratic term which explains this could misleadingly indicate an extremely rapid decline in just a few years thereafter. The long term aging effects could be further explored by adding higher order (e.g., cubic) terms. The introduction of such terms could have a moderating effect on the rapid capacity factor decline associated with the quadratic model, but would be difficult to justify statistically at this point.

While the broken linear approach was chosen here, it is interesting to note that the general results were similar for both broken linear and quadratic models. That is, they have comparable

explanatory power with respect to the observations embodied in actual operating experience.

In addition to a general age term, four broken linear terms were tested for significance both alone and in product terms containing AGE. These were called AGE2, AGE4, AGE6, and AGE8. The values for these terms were established by subtraction of 2, 4, 6, and 8, respectively, from a nuclear unit's age in a given year of its operation and setting to zero all of the resulting values that were greater than zero. Each of these variables has a sequence of negative values whose absolute magnitude decreases by 1 each year until zero is reached.

This technique produces four line segments in the first eight years of operation, similar to the simple broken linear illustration discussed earlier. It is employed in an attempt to capture the shape and duration of early maturation effects, while the simple AGE terms capture long-term behavior. The procedure for choosing which broken linear age terms to include in the model was to begin by including all of them and to follow this by eliminating those which contributed insufficiently to the explanatory power of the equation. With this procedure AGE8 was not found to be significant in any of the models examined.

Analysis of Adjusted Capacity Factors

The model selected and the linear regression results are given in Table C-4. The terms in the equation for the adjusted nuclear capacity factor (NCAPFAC2) are defined in Table C-5. Some terms not introduced in the earlier discussion of the basic independent variables were incorporated in the model to explore additional relationships.

TABLE C-4

FINAL REGRESSION RESULTS FOR ADJUSTED CAPACITY FACTORS

Name of Coefficient	Term in Equation	Coefficient of Term	t-Statistic
A	1	.625	6.10
B	MDCU	-7.53×10^{-5}	- .528
Z	MDCU x PWRU	-3.44×10^{-4}	-3.73
C	PWRU	.527	5.01
G	SALTU	.723	4.33
E	AGE	1.35×10^{-4}	.013
X1	MDCU x SALTU	-5.35×10^{-4}	-3.73
K	PWRU x TOWERSU	- .143	-3.30
W	AGE x PWRU	- .021	-3.32
D	AGE x MDCU	3.29×10^{-5}	2.31
L	TOWERSU	.101	2.84
S	SALTU x AGE	-.050	-4.29
F	SALTU x PWRU	.133	1.78
H	SALTU x PWRU x AGE	-.028	-2.82
L3	AGE6	.036	1.52
M2	AGE4 x MDCU	1.07×10^{-4}	3.55
M3	AGE6 x MDCU	-7.75×10^{-5}	-1.95
N2	AGE4 x SALTU	-.079	-1.87
N3	AGE6 x SALTU	.105	3.24
X2	BWSTM	-.089	-2.30
X3	WESTM	-.035	-1.30
X4	TMI	.002	.131
X5	TMI x BWSTM	-.025	-.543

Number of Variables = 23
R-Squared = .362
Corrected R^2 = .327

Standard Error of Regression = .118
F(22/397) = 10.2
COND(X) = 81.4

TABLE C-5

INDEPENDENT VARIABLE DEFINITIONS

Variable Name	Definition
MDCU	Unit size in megawatts
PWRU	1 if unit is pwr 0 otherwise
SALTU	1 if unit is salt water cooled 0 if otherwise
AGE	Years of commercial operation according to calendar years. The first calendar year of operation averages only one-half a year of plant operation.
TOWERSU	1 if unit has cooling tower 0 otherwise
AGE4	AGE-4 for Age $\leq$ 4 0 otherwise
AGE6	Age-6 for Age $\leq$ 6 0 otherwise
BWSTM	Babcock and Wilcox Steam System
WESTM	Westinghouse Steam System
TMI	1 if year of operation is 1980, 1981 0 otherwise (This is to estimate the effect of the Three Mile Island event.)

The regression summarized in Table C-4 has an R-SQUARED of 0.36, which is much higher than the results heretofore reported in the literature. The standard error is about 0.12, which means that 68 percent of the adjusted capacity factors estimated by this equation will fall within 12 percent of the actual observations. Its value of 81 for COND(X) indicates that collinearity is not a serious problem.

The F-statistic indicates more than sufficient explanatory power for all 23 variables collectively at the 99%+ confidence level.

Table C-4 also presents the values, standard errors, and t-statistics for each of the coefficients in the regression. The interpretation of these results is straightforward. The estimated value for a coefficient is its most likely value. The standard error is a probability measure of the difference between actual and predicted values. There is a 68 percent probability that the estimate will be within one standard error of the actual value. The t-statistic measures the likelihood that the coefficient is significantly different from zero, that is, whether the independent variable is statistically significant. A t-statistic of absolute value equal to or greater than 1.645 indicates that the probability is 90 percent that the coefficient differs from zero. A value greater than 1.96 indicates a 95 percent probability, and one of 2.57 or greater indicates a 98 percent probability.

The most important terms in the regression are those related to capacity factor aging effects. The coefficients of these terms will be reviewed first. Reference can be made to Table C-4.

General aging effect: Coefficient E has the estimated value of .000135. If accurate this would mean that the average adjusted capacity factor for nuclear units increases almost not at all, other factors equal. In fact, the rather high standard error and near zero t-statistic found here indicate that there is no significant general aging effect. Rather one must look to other more complex terms in the regression equation (with AGE) to see whether they can capture or explain general aging behavior.

The only other general age term in the model is AGE6. Its coefficient L3 indicates an average general capacity factor maturation rate of [illegible].6 percent per year for the first six years of operation. However, this coefficient is found to be significant only at the 80 percent confidence level.

PWR aging effect: The value of coefficient W for the product term AGE x PWRU suggests a 2 percent annual decline in the adjusted capacity factor for PWR units after their 6th year of operation. Unlike the E coefficient for aging in general, W is estimated to be significant at the 99.8 percent level. Broken linear terms were not found to be significant in the case of PWR-specific aging effects.

Size related aging effects: The value of coefficient D for the product term AGE x MDCU estimates the effect of a nuclear unit's size on the general long-term variation of its capacity factor. In order to obtain the estimated annual effect this coefficient must be multiplied by the unit's size (MDCU). For a 1000 MW plant of any type this general long-term size related aging effect is estimated to embody a 3.2 percent annual increase, as opposed to 1.6 percent for a 500 MW unit. This coefficient is found to be significant at the 95 percent confidence level.

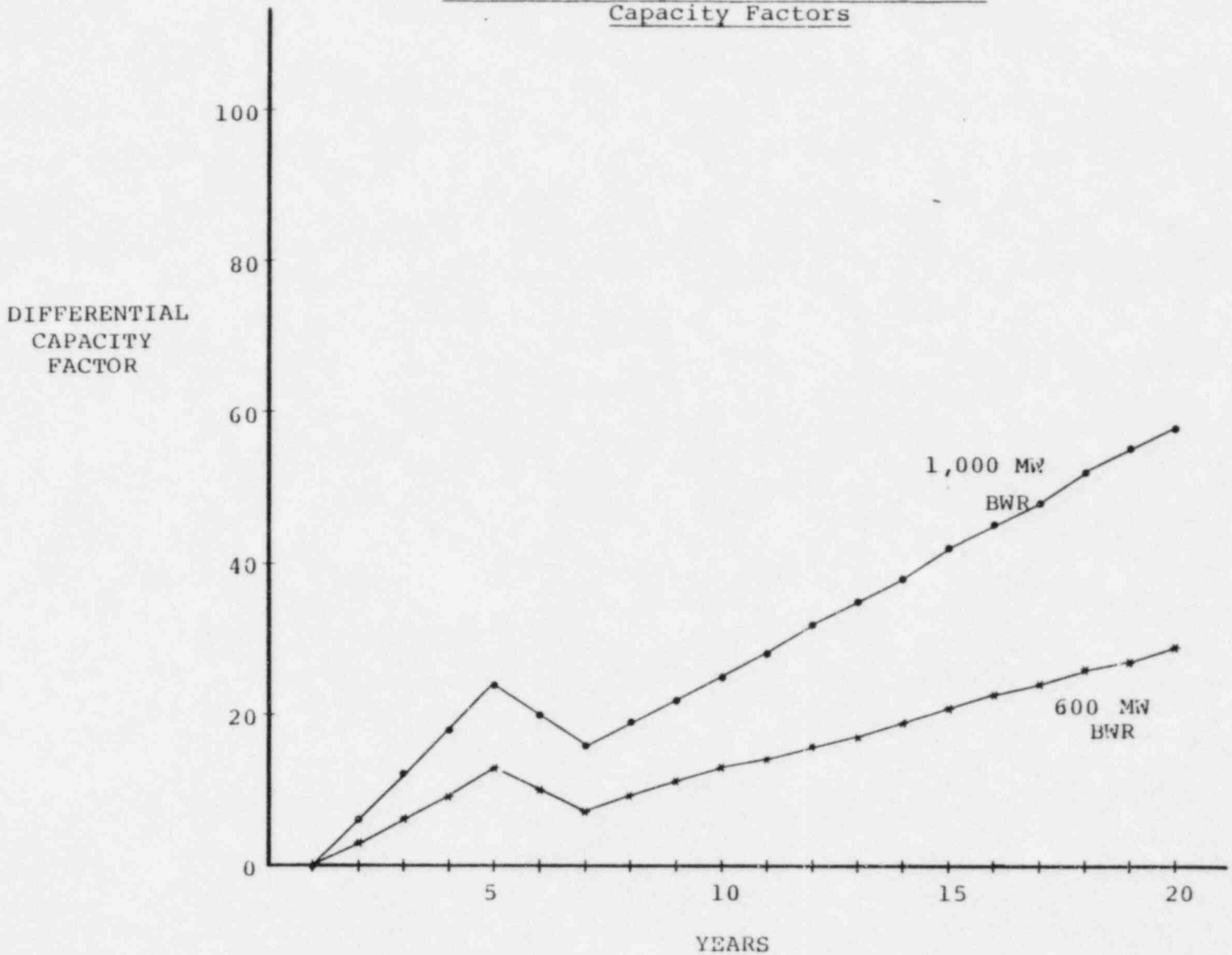
Since AGE, AGE x MDCU, and AGE x PWR are the only non salt-water cooling related age variables representing long-term adjusted factor behavior, it can be seen that a net long-term growth in capacity factors of BWR units which are not salt-water cooled has been estimated. This result will be reviewed later.

The broken linear age coefficients M2 and M3 for the variables AGE4 x MDCU and AGE6 x MDCU, respectively, are both found to be significant at the 95+ percent confidence level. These imply early maturation effects, which are greater for larger units, followed by a decline in the years 5-7, followed by continued maturation. The decline and subsequent maturation are both greater for larger units. Figure C-5 shows the estimated magnitude of these effects for 600 MW and 1000 MW BWR units not cooled by salt-water. The peak could be real, but sharpened by the regression specification, or it could be an artifact of the data base. Since performance data prior to 1975 were not available, the data base could be comprised mostly of units with data for the pre-maturity years and others for the post-maturity years but not the first 4-6 years.

Salt-water cooling-related effects: Salt or brackish water is used in the cooling systems of 20 nuclear units, 14 PWRs and 6 BWRs (see Table C-2). These are cooled by oceans, bays, or rivers with tidal flows. The regression analysis summarized in Table C-3 indicates that salt-water cooled nuclear plants have sharply reduced performance over time. The salt-water related aging effects are represented by the terms SALTU x AGE (a general long-term effect for these units), SALTU x AGE4 and SALTU x AGE6 (a general early year effect for these units), and SALTU x PWR x AGE (a differential long-term effect

FIGURE C.5

Size Related Age Trends for Adjusted Capacity Factors



for PWR units). In addition, a SALTU x MDCU term accounts for a differential effect for salt-water units related to their size. Finally, two other salt-water cooling terms, SALTU (general effect) and SALTU x PWR (PWR effect) provide the intercepts for the aging effect product terms given above. Two of these estimations (coefficients N2 and F) were found to be significant at about the 95 percent confidence level and the other five are significant at greater than the 99 percent level.

Coefficient S of the SALTU x AGE term measures the differential average annual long-term percentage decline of capacity factors associated with salt-water cooled nuclear units at about 5 percent per year. The coefficients of the broken linear terms AGE4 x SALTU and AGE6 x SALTU indicate a different behavior over the first six years for such units. Taken together, these coefficients (N2 and N3) imply aging behavior that is opposite to that reported earlier for the size related aging effects. In this case performance first declines, then improves sharply, and then declines again.

Coefficient H for the SALTU x PWRU x AGE term estimates a further negative age effect for salt-water cooled units of the PWR type, a decline of almost 3 percent per year. No significant early operating year effects were found. This effect is likely due to the well-noted faster deterioration of steam generators in salt-water cooling environments (Ref. C-5).

Coefficient X1 estimates an across-the-board decline in adjusted capacity factors of salt-water cooled plants with increasing size. This differential amounts to a 26 percent lower base line performance for a 600 MW unit.

Remaining terms in the equation: Coefficients X2 and X3 measure differential performance for reactors with Babcock & Wilcox and Westinghouse steam systems, respectively. It can be seen that Babcock & Wilcox reactors are expected to have a capacity factor 9 percent lower than other non-Westinghouse reactors. All other things equal, Westinghouse reactors are expected to have a 3.5 percent lower performance, but the low t-statistic for X3 indicates uncertainty regarding this estimate.

Coefficients X4 and X5 are present in the equation to capture any "post-TMI" effects on nuclear unit performance. "TMI" is a dummy variable which is 1 for the years 1979, 1980 and 1981. The near 0 t-statistic for coefficients X4 and X5 shows that all general post-TMI effects have been corrected for by the previously discussed adjustment of capacity factors for refueling and NRC mandated shut-downs.

The remaining coefficients are intercept terms for the various related coefficients. The exceptions are K and L which estimate the impact of cooling towers on plant performance. Coefficient L estimates that cooling towers improve reactor performance by an average of 10 percent for BWR units. Coefficient K estimates that PWR units with cooling towers show a differential negative performance of about 14 percent, for a net negative effect of about a 4 percent reduction in capacity factor.

Coefficient F is the salt-water cooled PWR intercept, G is the general salt-water plant intercept, C is the PWR unit intercept term, and Z is the size of PWR intercept term.

The model as a whole: The previous discussion has focused attention upon the specific effects of each term in the equation specified. Summary statistics, presented at the beginning of this section show that the specification has relatively good explanatory power for the observed variations in capacity factors. However, because of the rather complex nature of this equation, involving the superposition of many terms, it is difficult to see by cursory inspection how the various terms contribute together to estimate yearly capacity factors for nuclear units with various reactor tyupes, sizes, cooling systems, ages, etc. It is therefore useful to apply the equation to several generic cases to illustrate the overall results of the regression analysis.

Table C-6 shows the adjusted capacity factors expressed as ratios and estimated by the equation for each year of operation for each of eight composite nuclear power plant types: BWRs and PWRs of 600 and 1000 MW, with and without salt-water cooling systems. Figures C-6 through C-9 illustrate the general results graphically.

Inspection of these results shows that salt-water related effects dominate all others, causing adjusted capacity factors for both BWR and PWR units of either size to decline rapidly after several years of maturation. Capacity factors of salt-water cooled PWRs are found to decline much faster than those of salt-water cooled BWRs. Moreover, large salt-water cooled PWRs are found to have much poorer initial performance and even more rapid decline than smaller such units.

TABLE C - 6

Adjusted Capacity Factors
(BWR)

600 MW BWR
No Salt

Age*				
1	0.404022	0.478342	0.552662	0.626982
5	0.701301	0.710044	0.718787	0.73959
9	0.760394	0.781197	0.802	0.822804
13	0.843607	0.864411	0.885214	0.906017
17	0.926821	0.947624	0.968427	0.989231
21	1.01003	1.03084	1.05164	1.07244
25	1.09325	1.11405	1.13485	1.15566
29	1.17646	1.19726		

600 MW BWR
Salt

Age				
1	0.460154	0.510611	0.561067	0.611525
5	0.661982	0.727597	0.793214	0.763837
9	0.73446	0.705085	0.675708	0.646332
13	0.616956	0.58758	0.558204	0.528828
17	0.499452	0.470075	0.440699	0.411325
21	0.381948	0.352571	0.323195	0.293818
25	0.264442	0.235066	0.20569	0.176313
29	0.146938	0.117562		

1000 MW BWR
No Salt

Age				
	0.404613	0.503889	0.603166	0.702443
5	0.801719	0.791701	0.781683	0.815921
9	0.850158	0.884396	0.918633	0.952871
13	0.987109	1.02135	1.05558	1.08982
17	1.12406	1.1583	1.19253	1.22677
21	1.26101	1.29525	1.32948	1.36372
25	1.39796	1.4322	1.46644	1.50067
29	1.53491	1.56915		

1000 MW BWR
Salt

Age				
1	0.249287	0.3247	0.400113	0.475527
5	0.550941	0.597796	0.644651	0.628708
9	0.612766	0.596825	0.580883	0.564941
13	0.548998	0.533057	0.517116	0.501173
17	0.485232	0.469289	0.453347	0.437407
21	0.421465	0.405523	0.389581	0.373639
25	0.357697	0.341755	0.325813	0.309871
29	0.293929	0.277987		

* The capacity factors for each age category are to be read across in groups of four years beginning with the year indicated in the "Age" column.

TABLE C-6(cont.)

Adjusted Capacity Factors
(PWR)

600 MW PWR
No Salt

Age				
1	0.708445	0.760637	0.812829	0.865021
5	0.917213	0.903828	0.890444	0.889119
9	0.887795	0.886471	0.885147	0.883823
13	0.882498	0.881174	0.87985	0.878526
17	0.877201	0.875877	0.874553	0.873229
21	0.871905	0.87058	0.869256	0.867932
25	0.866608	0.865284	0.863959	0.862635
29	0.861311	0.859987		

600 MW PWR
Salt

Age				
1	0.86533	0.865767	0.866203	0.866643
5	0.867081	0.882679	0.898276	0.818881
9	0.739486	0.660092	0.580697	0.501301
13	0.421907	0.342511	0.263117	0.183721
17	0.104327	0.024931	-0.054464	-0.133857
21	-0.213253	-0.292648	-0.372044	-0.451439
25	-0.530834	-0.610229	-0.689624	-0.769019
29	-0.848414	-0.927809		

1000 MW PWR
No Salt

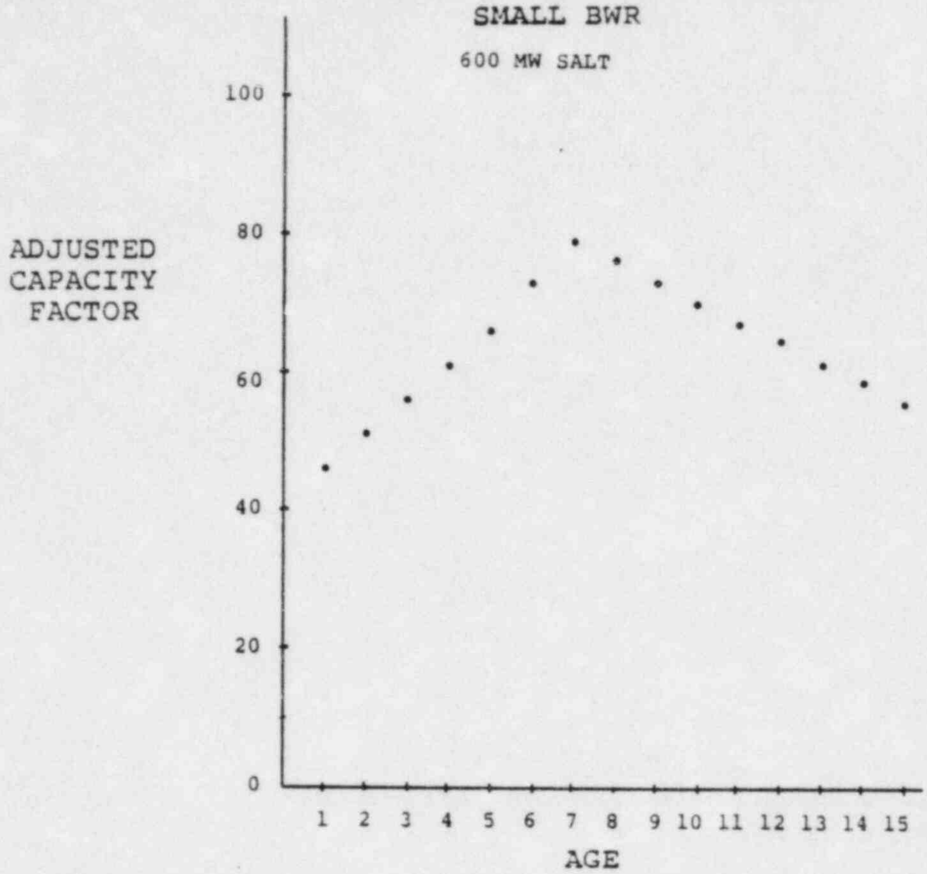
Age				
1	0.568561	0.64571	0.722859	0.800008
5	0.877157	0.845011	0.812865	0.824976
9	0.837086	0.849196	0.861306	0.873416
13	0.885526	0.897636	0.909746	0.921856
17	0.933966	0.946076	0.958186	0.970297
21	0.982407	0.994517	1.00663	1.01874
25	1.03085	1.04296	1.05507	1.06718
29	1.07929	1.0914		

1000 MW PWR
Salt

Age				
1	0.513989	0.539384	0.564779	0.590174
5	0.615569	0.612403	0.60924	0.543279
9	0.477318	0.411358	0.345397	0.279436
13	0.213474	0.147514	0.081554	0.015593
17	-0.050368	-0.116329	-0.182289	-0.248249
21	-0.314211	-0.380171	-0.446132	-0.512093
25	-0.578054	-0.644015	-0.709975	-0.775937
29	-0.841897	-0.907858		

Figure C-6

ADJUSTED CAPACITY FACTORS
SMALL BWR



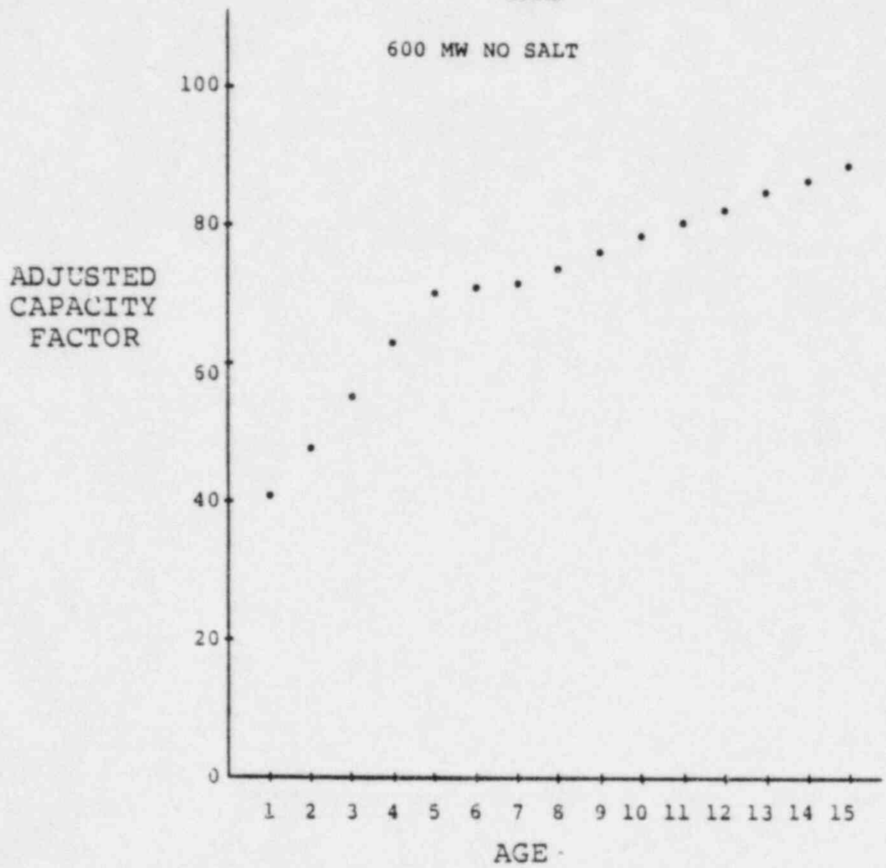
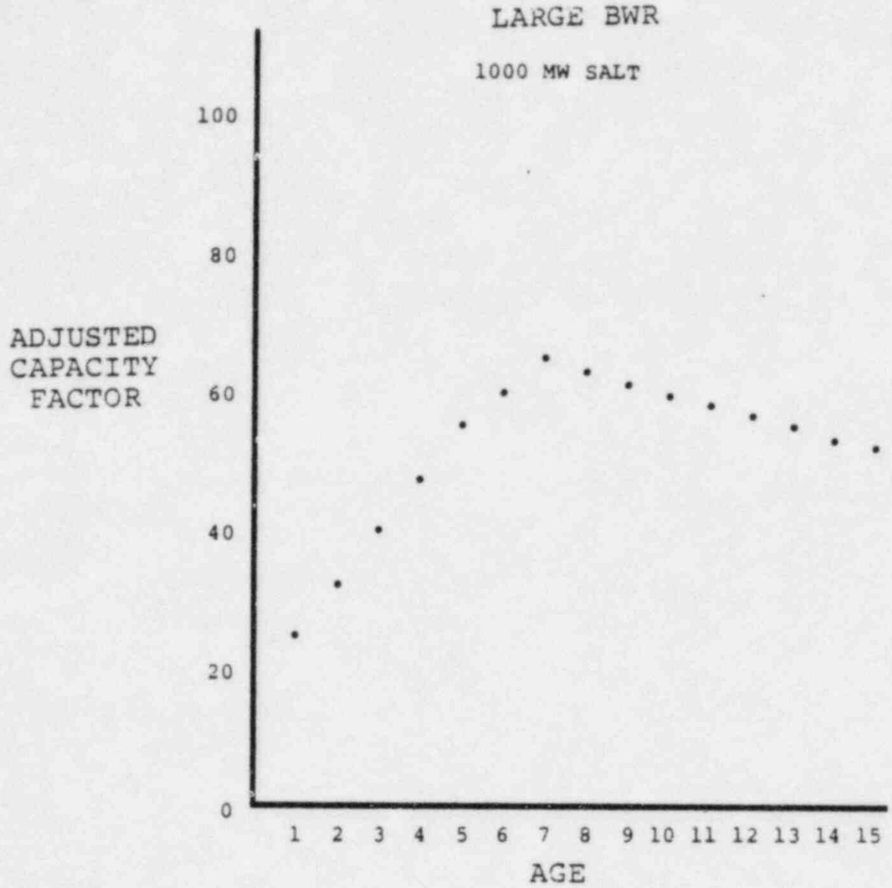


Figure C-7

ADJUSTED CAPACITY FACTORS

LARGE BWR



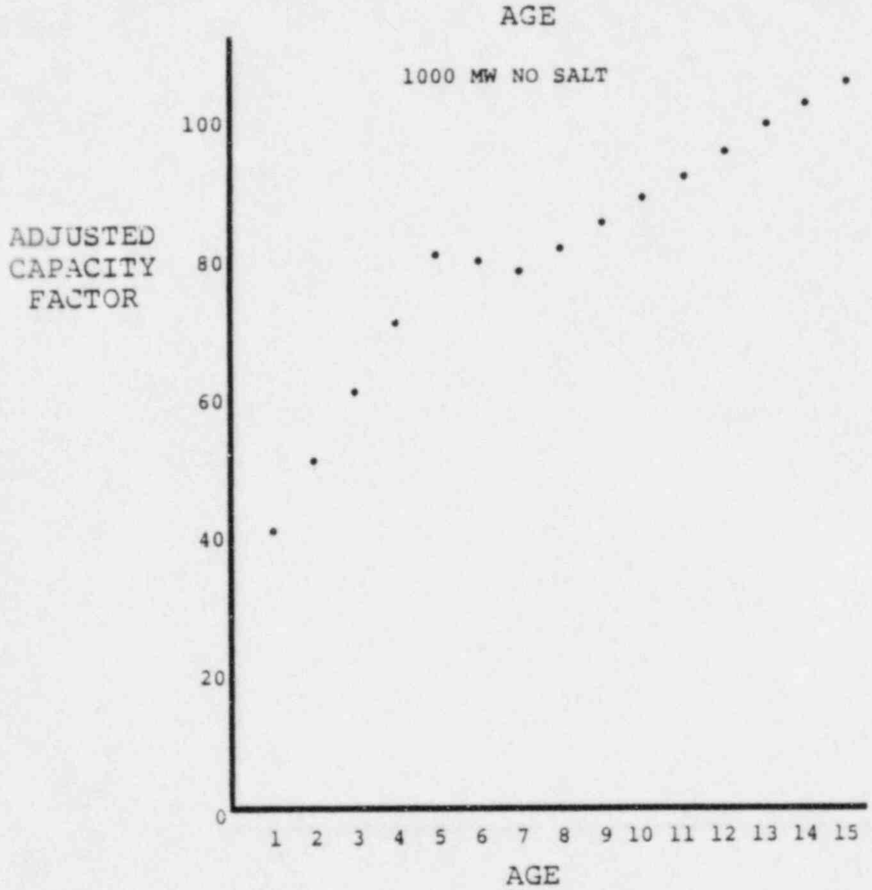
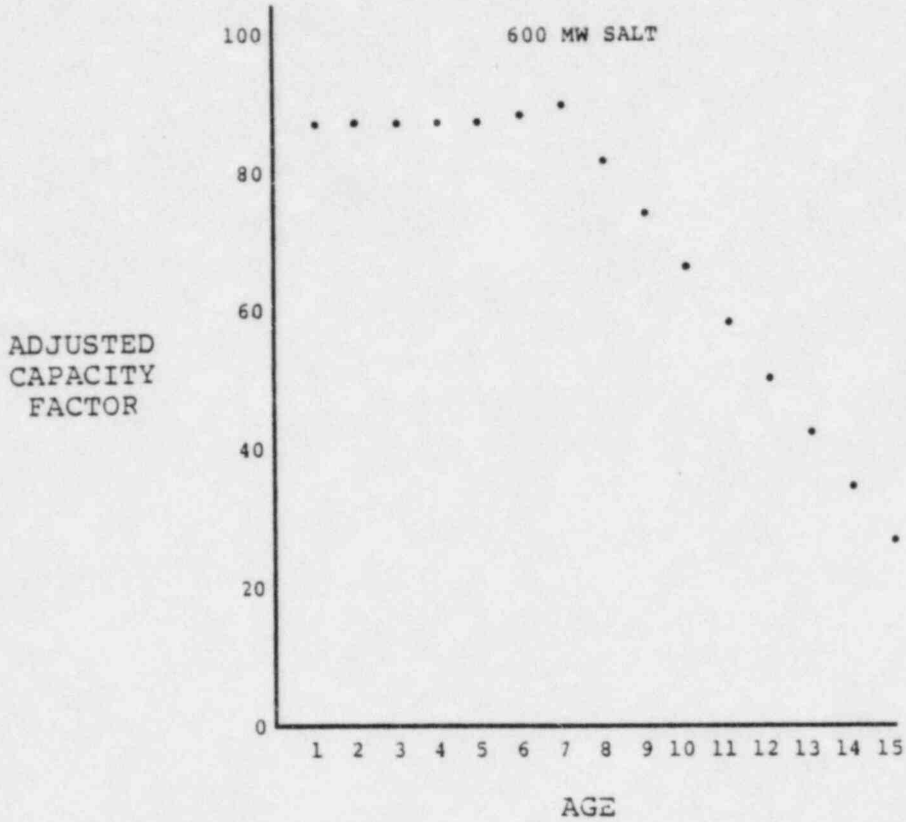


Figure C-8

ADJUSTED CAPACITY FACTORS
SMALL PWR



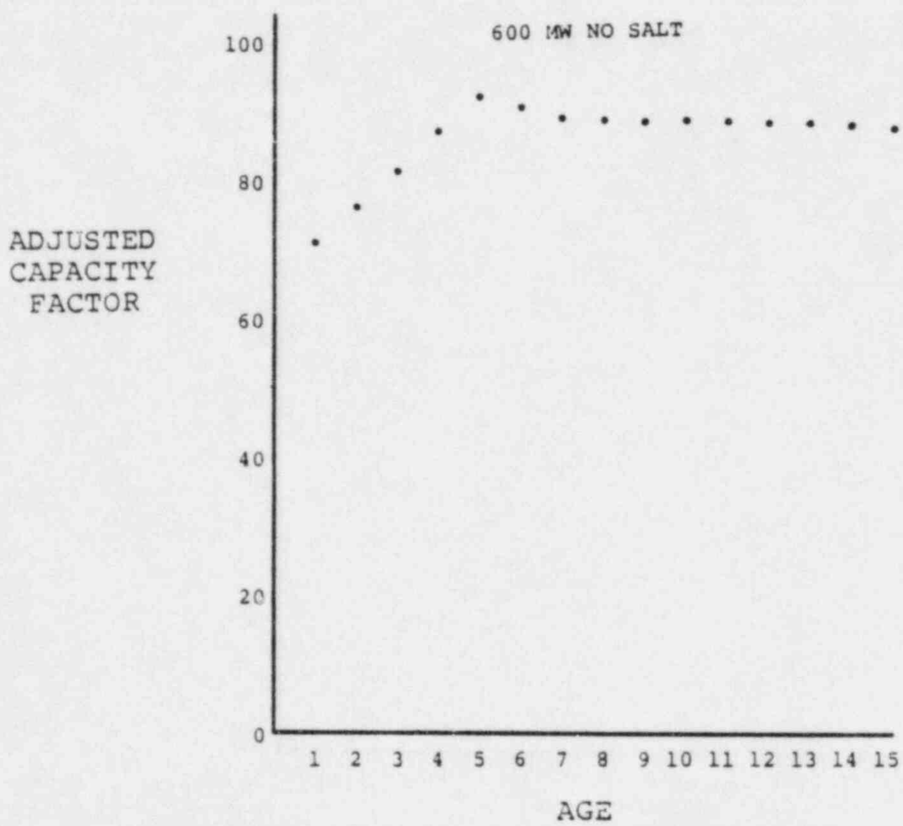
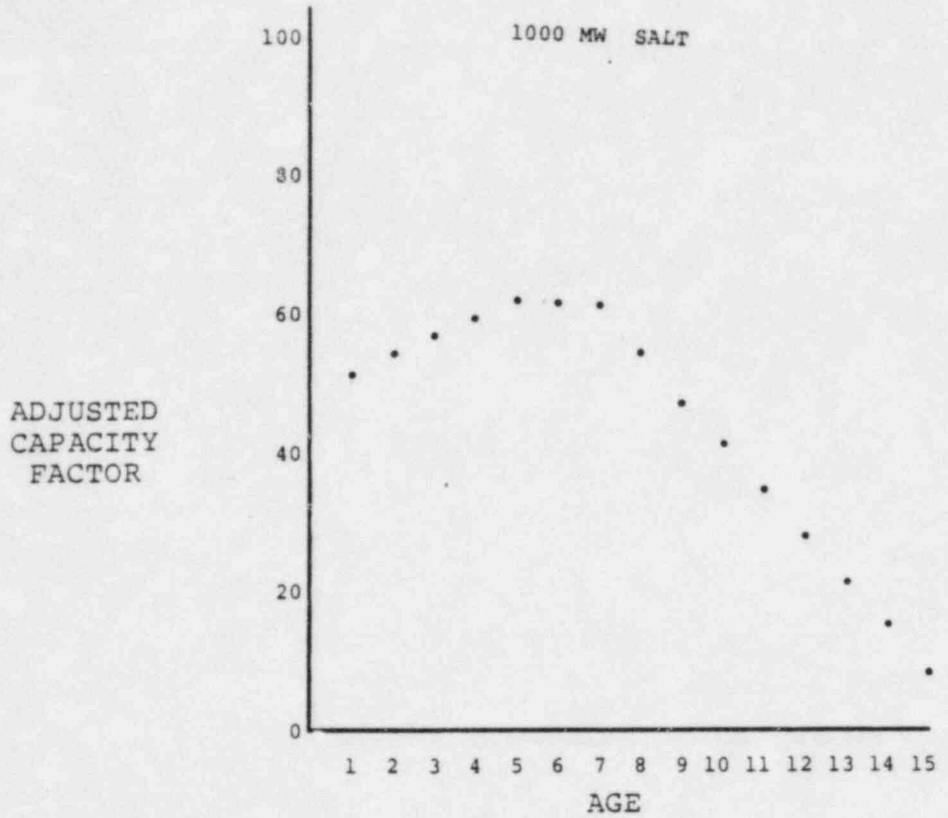
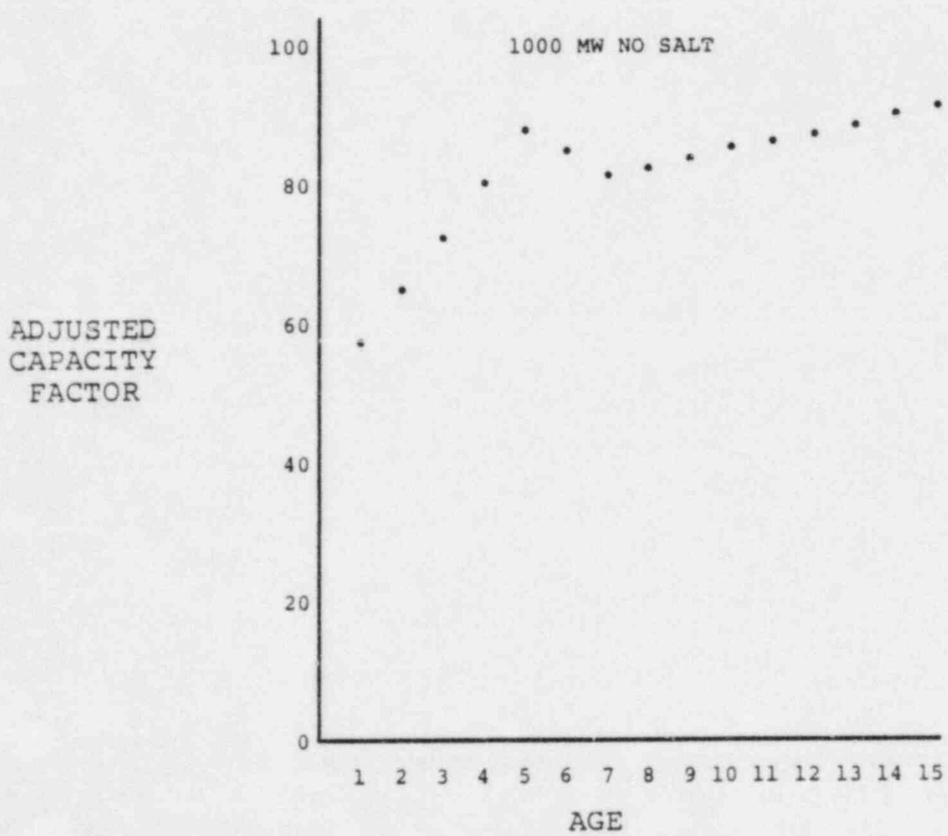


Figure C-9

ADJUSTED CAPACITY FACTORS
LARGE PWR





Among non-salt-water cooled units, BWRs are shown to have continued maturation (out to the limits of the data), with larger units approaching 100 percent adjusted capacity factor more rapidly than smaller units. For all but non-salt-water cooled BWRs larger units perform more poorly. PWR units that are not salt-water cooled show middle ground performance. For these PWRs smaller units perform somewhat better than larger ones in the early years, while the larger units "catch up" after maturation. On the other hand, PWRs of this type are found to perform better in their early years than their BWR counterparts. After maturation, however, PWR performance is overtaken by BWR performance.

The general aging trend for non-salt-water cooled BWRs shows a long term increase in adjusted capacity factors. For similar PWRs this is balanced by a long term trend towards declining performance, which is more pronounced for smaller units. Further exploration of these long term general aging effects is essential as more years of data become available. Even after taking account of refueling outages in preparing the data base, the above results would show total capacity factors of non-salt-water cooled BWRs approach 100 percent. This is not plausible, since refueling alone would keep these at about 85 percent as an upper limit. Further statistical analyses of an exploratory nature provided preliminary indications that this long term increase may abate within the time periods under investigation.

Given the limitations of the data base, the aging effects found in this study are more accurate for the first 10-12 years or so of unit operation. The key finding that emerges is that salt-water cooled reactors of all types may be running into serious operating

problems as they age. We believe that this is the first time such a finding has been reported.

The graphs presented in Figures C-6 through C-9 illustrate the general results for adjusted capacity factors for the eight generic nuclear units. These results are in broad agreement with those reported in the less detailed earlier studies. For example, BWRs in general are found to achieve capacity factors of about 60 percent on average during their first 10 years of operation, with little difference between large and small units. Large PWRs have comparable performance, while small PWRs perform substantially better (capacity factors over 70 percent). The significant advance embodied in these results are the clear maturation effects and the differential aging trends for different types of units, especially the sharp decline found for salt-water cooled nuclear units.

<u>Total or unadjusted capacity factors:</u> In order to estimate values for the total or unadjusted nuclear capacity factors that are generally discussed in the literature, three alternative procedures could be followed. First, one could simply revert to explanation of the observed values of these capacity factors by regression analysis similar to that performed for the adjusted capacity factors. This would depart from one of the major methodological objectives of this study, the removal of bias or "noise" associated with refueling outages and NRC mandated outages (<u>e.g.</u> events like the post-TMI shutdowns of certain units) from unadjusted capacity factors.

To illustrate this first alternative we can examine a regression using the model, discussed earlier, that was developed for the adjusted capacity factors. Applying this to the unadjusted capacity

factors (Table C-7) it is found that there is a general continuity of many of the results. However, the R-SQUARED for this equation is substantially lower and the standard error is higher, reflecting both greater variation in the data and lower explanatory power when refueling and NRC outages are included. This size maturation effect (coefficient D) is insignificant, and the general aging effect (coefficient E) is barely significant (at the 60 percent level). The post-TMI variables (coefficients X4 and X5), on the other hand, become significant in this regression whereas they were not in the case of the adjusted capacity factors. They reflect the shut-downs for NRC mandated modifications. It appears that the change in the significance of the age and age-size variables is due to the variations in refueling outages.

Second, regression analysis could be applied to the refueling and NRC outage observations alone. The results could then be used (in conjunction with the independently developed adjusted capacity factor estimations) to develop total capacity factor estimations. However, preliminary regression analyses of the refueling and NRC outages did not produce satisfactory results. It would be important to explore this approach further in future work.

The final, and at this time most straightforward, procedure for readjusting the adjusted capacity factor results to account for refueling outages is to obtain the average values of these outages for the two reactor types, PWRs and BWRs. The information in the data base yields:

BWR Refueling Outage Rate: 14%

PWR Refueling Outage Rate: 12.5%

TABLE C-7

FINAL REGRESSION MODEL APPLIED TO UNADJUSTED CAPACITY FACTORS

Name of Coefficient	Term in Equation	Coefficient of Term	t-Statistic
A	1	.413	4.04
B	MDCU	1.43×10^{-4}	.981
Z	MDCU x PWRU	-4.32×10^{-4}	-4.51
C	PWRU	.608	5.54
G	SALTU	.538	2.90
E	AGE	.010	1.23
X_1	MDCU x SALTU	-4.05×10^{-4}	-2.61
K	PWRU x TOWERSU	-.214	-4.65
W	AGE x PWRU	-.026	-3.80
D	AGE x MDCU	1.33	.878
L	TOWERSU	.132	3.49
S	SALTU x AGE	-.036	-2.78
F	SALTU x PWRU	.057	.686
H	SALTU x PWRU x AGE	-.020	-1.77
L3	AGE6	.019	.722
M2	AGE4 x MDCU	1.17	.361
M3	AGE6 x MDCU	2.00	.005
N2	AGE4 x SALTU	-.035	-.767
N3	AGE6 x SALTU	.054	1.56
X2	BWSTM	-.035	-.821
X3	WESTM	-.017	-.605
X4	TMI	-.045	-2.23
X5	TMI x BWSTM	-.074	-1.51

Number of Variables = 23
R-Squared = .263
Corrected R^2 = .222

Standard Error of Regression = .149
F(22/397) = 6.45
COND(X) = 77.0

While actual refueling outage time may be typically somewhat smaller than these averages, it should be borne in mind that refueling outages reported to the NRC can often contain outage hours for other of the outage modes since certain kinds of equipment, maintenance, and even NRC related outage activities may be performed while the plant is shut down for refueling.

The net or readjusted capacity factor can be obtained as:

$$CAPFAC = (1-\beta) \times NCAPFAC2$$

Where NCAPFAC2 is the adjusted capacity factor, and β is the average fraction of a year during which refueling outages occur.

Note here, that no adjustment is made for outages resulting from explicit NRC mandates. This tacitly assumes that, unlike past experience, no NRC-mandated outages will occur in the future. This assumption yields higher capacity factor estimates than would be obtained if average NRC related outages of the past were assumed for the future.

We developed total capacity factor estimations for the two Indian Point units for use as guidance in establishing the High Impact, Mid-Range, and Low-Impact scenarios for capacity factors. We began by applying the regression model described in Table C-4 to each Indian Point unit. We adjusted the resulting stream of adjusted capacity factor estimations to simulate total capacity factors according to the third method described in the preceding section. In other words, for each year from 1974 (for IP 2)

or 1976 (for IP 3), we applied the following formula for estimated total capacity factor:

$$\frac{\text{Adjusted Capacity Factor} \times (100 - 12.5)}{100} = \text{Total Capacity Factor}$$

The resulting estimated total capacity factors were then used as guidance in establishing the scenarios, as described in the text of section 3.3 of the report. The total capacity factors are plotted in Figure 1 and 2 of the report for the years during which they are greater than zero.

REFERENCES

C-1 Charles Komanoff, "Nuclear Plant Performance Update 2," Komanoff Energy Associates, 475 Park Avenue South, N.Y. 10016.

C-2 R.G. Easterling, "Statistical Analysis of Power Plant Capacity Factors Through 1979," NUREG CR-1881 (April 1981), Division 1223, Sandia National Laboratories, Alburquerque, NM 87185.

C-3 N.J.D. Lucas and P.J. Thompson, "Age, Size, and Learning Effects in Light Water Reactors," Dept. of Mech. Eng., Imperial College, London SW7 England.

C-4 See, for example, Elements of Econometrics, Jan Kementa, MacMillan, 1971, pp. 317-321 and 499-508.

C-5 See, for example, "Workshop Proceedings: Outage Planning & Maintenance Management," WS-78-94 EPRI, June 1979, especially section F-8.

APPENDIX D

Irradiated Fuel Storage Costs

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D-1 General Issues

With the exception of a small amount of irradiated fuel which was sent to reprocessing plants, all of the irradiated fuel discharged from commercial nuclear reactors is being stored in onsite storage pools. These pools, which were designed to serve as temporary, short-term storage, have limited capacity.

As the available space in existing storage pools decreases, reactor operators have taken steps to increase the capacity of their pools by packing the irradiated fuel rods closer together. The procedure generally used is called "reracking." The assemblies of spent fuel rods are moved close together and separated by boron metal plates. While there is some concern regarding the safety of storing increased quantities of fuel in existing pools (Ref. D-1), the NRC has approved the reracking of most storage pools (Ref. D-2). Even if reracking is used to the full extent allowable under current licensing requirements, the storage pools at most reactors will be filled to capacity by the late 1980's and early 1990's.

While the Federal government has shown fairly clearly its intent to take responsibility for the ultimate disposal of irradiated nuclear fuel, progress toward a detailed solution faces a "formidable array of social, economic, and political problems" (Ref. D-3). It is estimated that the opening of a federal "permanent" disposal facility will take place some time after 1997 (Refs. D-4 and D-8).

If a nuclear power plant is to continue operating between the time that its storage pool fills and the time that a permanent disposal facility becomes available, then some type of interim system must be used to store the irradiated fuel. Current possibilities for interim storage fall into two categories: federally operated away from reactor storage facilities (AFRs)* and onsite storage.

Federally operated AFRs, if available, are likely to be the preferred option from the point of view of the utility which would pay a one-time fee and then be free of responsibility for the irradiated fuel. The availability of AFRs is uncertain, however, so utilities must consider the options for on-site storage: water pools, storage casks, drywells, concrete silos, and air cooled vaults (Ref. D-5).

The total cost for the disposal of irradiated fuel can be considered in three parts:

1. interim storage cost (away from reactor or onsite)
2. transportation cost
3. permanent disposal fee

The next section of this appendix will discuss these costs in a general sense, then the derivation of the costs used in our analysis of Indian Point will be described.

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*These were previously referred to as Independent Spent Fuel Storage Facilities (ISFS).

D-2 Cask Storage Costs

Our cost estimates for onsite storage of irradiated fuel in casks are based on the procedure used in A Preliminary Assessment of Alternative Dry Storage Methods for the Storage of Commercial Spent Nuclear Fuel (Ref. D-5). In that study, a cost per kilogram of waste was calculated for Virginia Electric Power and Light Co.'s Surry Station by assuming normal plant operation until 2009. The 967 MTU* of irradiated fuel was assumed to require storage between 1985, when the onsite pool will run out of room, and 2009, the scheduled retirement date.

Based upon the above assumptions a unit cost of $117/KgU (1981) was calculated for the storage of unconsolidated fuel in casks. This cost is not much greater than the $110/KgU (1981) calculated for the storage of consolidated fuel in casks, the least expensive of the options for onsite storage (according to the study). Although consolidating the fuel results in a slightly lower cost, the procedure involves greater technical uncertainties.

The various components of the cost of storing unconsolidated irradiated fuel onsite in casks are listed in Table D-1. Note that the casks used for storage are larger than typical transportation casks. The cask assumed in our cost estimates is designed to hold up to 24 PWR assemblies, or about 10 MTU of irradiated fuel.

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* Metric tonne (1000 Kg.) uranium.

The tax and insurance costs are based upon \$.45 per \$100 of investment for taxes and \$.48 per \$100 of investment for insurance. At an investment of \$600,000 per cask the annual taxes and insurance will be about \$6000 per cask per year. The cost of constructing warehouse space for each cask was calculated by multiplying the cost per square foot (\$75/sq. ft.) by the floorspace required for a cask (850 sq. ft./cask). The costs listed in the table for the operation of the cask storage facility were derived by plotting the costs listed in Reference D-5 as a function of the warehouse size in casks. This procedure resulted in a linear fit which implied the fixed and variable operating costs listed in the table.

The costs listed in Table D-1 can be expressed in units of \$/cask-year by assuming that the cask purchase and warehouse construction costs are capitalized at a certain fixed charge rate, and by spreading the fixed operating costs over the average number of casks being stored. At a fixed charge rate of 18 percent and 50 casks on average per warehouse, the cost simplifies to \$135,000/cask-year (1981). At a cask capacity of about 10 MTU this cost converts to \$14/KgU-year (1981).

TABLE D-1

Cask Storage Costs[1]
(1981 $)

	Cost
Cask Purchase	600,000/cask
Maintenance Supplies	1,000/cask
Taxes and Insurance	6,000/cask-year
Warehouse Construction[2]	64,000/cask
Fixed Operating Cost[3]	190,000/year
Variable Operating Cost[3]	5,000/cask-year

1) Source: Reference D-5.

2) This includes the cost of the warehouse, pad, and approach roads.

3) The operating cost of the cask storage warehouse is broken into two components, the part which is attributable to operation of the facility itself (fixed), and the part which can be allocated to each cask (variable).

D-3 Costs of Other Onsite Storage Technologies

There are a variety of alternatives to storage casks for onsite storage of irradiated fuel. Unit cost estimates for these were developed by E.R. Johnson Associates for DOE (Ref. D-5). These estimates are expressed in dollars per kilogram.* In order to recast these estimates in dollars per kilogram per year to better represent the utilities' cash flow, (the costs of storing irradiated fuel onsite are likely to be capitalized), the cost relationships between the alternative technologies analyzed in Reference D-5 were applied to our cost estimate for casks of $14 per KgU-year to derive the costs listed in Table D-2.

Drywells are steel storage cylinders placed in the ground just below grade and covered with concrete plugs. Silos are similar to drywells, except that they are made of large amounts of concrete, and that they stand above grade on concrete pads. An air cooled vault is a massive two-level concrete structure in which the fuel would be stored in steel cavities on the lower level. Water pool storage is the method currently in use at reactor sites. Of these methods, casks, drywells, and silos can be built in increments, while air cooled vaults and water pools to be economical must be built in entirety. In this sense, the incremental methods offer less risk of unnecessary spending.

As the table shows, for the technologies which require canning, the costs are significantly less if the fuel can be canned in the existing storage pool rather than in a separate canning facility. At this point, it is not clear whether or not existing pools will be acceptable as the location for the canning process.

---

* Quantities of irradiated fuel are measured in kilograms of uranium (KgU) or kilograms of heavy metal (KgHM). The term heavy metal refe to all metals with atomic numbers of 90 or greater. Because nearly all of the heavy metal content of irradiated fuel is uranium, KgU and KgHM are considered to be equivalent for the purposes of this st

TABLE D-2

Cost Estimates for Onsite Storage Technologies

of Unconsolidated Fuel[1]

(1981 $ per KgU-year)

	Cost
Cask Storage	14
Drywell Storage	
Canned in Reactor Pool	16
Canned in Separate Facility	31
Silo Storage	
Canned in Reactor Pool	19
Canned in Separate Facility	30
Vault Storage	
Canned in Reactor Pool	50
Canned in Separate Facility	60
Water Pool Storage	41

1) Source: Reference D-5.

AFR Storage Costs

The total cost of storing irradiated fuel at an away from reactor storage facility includes the fee paid to the operator of the facility (the U.S. government) and the cost of transporting the fuel from the reactor site to the AFR site. A federally operated facility will presumably be run on a full cost recovery basis, that is, the utility will pay a one-time fee when the irradiated fuel is delivered to the AFR. The fee would be designed to totally recover the cost of constructing and operating the facility. The costs of transporting the irradiated fuel to the AFR will most likely be paid by the utility.

DOE estimates the unit cost for storage in a 3000 MTHM away from reactor storage pool at $117/KgHM(1978) (Ref. D-7, Volume 1, page 4.105). This cost will decrease for AFR pools with greater capacity. However, it will increase if the capacity is underutilized. For example, DOE estimates that using storage pools of 5000 MTHM capacity will reduce the unit cost by about 30%. They also state that "if a facility utilized only 50 percent of its capacity, unit costs would be almost doubled. In the study which reports these estimates (Ref. D-7) the cost of $117/KgHM(1978) is used in reference calculations.

A study by MHB Technical Associates (Ref. D-12) calculates a unit cost for disposal which includes AFR and permanent disposal costs. The MHB cost estimates which apply to AFR operation are listed in Table D-3. The unit costs at the bottom

of the table are the costs to the government in constant 1978 dollars. They do not include the effects of possible real cost escalation (above or below inflation), the time value of money, and interest compensation for money spent by the government before the fee is collected. (These factors are apparently included in the DOE estimates referred to above, but it is not obvious how.) Depending upon the assumptions made for these financial parameters and the time schedule of costs and payments received, Table D-3 unit cost estimates will adjust accordingly. Generally, the fee will be significantly higher than the costs listed here because the Government must spend a great deal of money on construction before any fees are collected.

The basis for each of the "uncertainty factors" listed in the table is described in Reference D-12. These are included here as a reminder that there is a wide range of uncertainty in cost estimates for undeveloped technologies.

TABLE D-3

MHB AFR Cost Estimates[1]
(Millions of 1978 $)

Task	REFERENCE CASE COST	Uncertainty Factor	Cost	Uncertainty Factor	Cost
Research and Development	40	4	160	1/2	20
NEPA/Site	75	2	150	1	75
Licensing	75	2	150	1	75
Construction[2]	750	4	3000	1/3	250
AFR Operation	450	4	1800	1/3	150
Decommissioning of AFR	75	2	150	1/2	38
Totals	1465		5410		608
Unit Costs (1978 $/KgU)	98		361		41

1) Source: Reference D-12.

2) Cost is based upon construction of 3 5000 MTU AFRs.

D-5 Transportation Costs

The primary modes of transportation for irradiated nuclear fuel are truck and rail. In either case, some type of shipping cask must be used. The primary factors affecting transportation cost are the distance to be covered, the mode of transportation chosen, and the leasing rate paid for the casks.

As no site has been designated for away from reactor storage or permanent disposal of spent fuel, transporation cost estimates cannot be based upon a specific route. Also, it is unclear in many cases whether or not transportation by rail will be a viable option.

Furthermore, it is possible but far from certain that casks used to store spent fuel onsite will be acceptable for transportation. Cask leasing comprises about 73 percent of transportation cost (Ref. D-6, Vol. 4, p. II-15). Therefore, if casks which were purchased for onsite storage can be used for transportation, the transportation cost estimate will be dramatically reduced. In a preliminary assessment done for DOE (Ref. D-5) it is stated that "none of the casks currently under consideration as storage vessels are considered capable, under current regulations, of being licensed in the U.S. as a transportation cask, although at least one of them has been licensed in the Federal Republic of Germany."

DOE's Final Environmental Impact Statement Management of Commercially Generated Radioactive Waste estimates the transportation cost for a 1,500 mile delivery by truck to be $26.4/KgHM (1978) (Ref. D-7, Vol. 2, p. A.103). This figure adjusted

by the GNP price deflators to 1981 dollars is about \$34/KgHM. This is consistent with a range of \$21 to \$29 per KgHM (1978) for a 1,500 mile delivery by truck used in a slightly more recent DOE report (Ref. D-6, Volume 4, page II-14). In one of these reports (Ref. D-7) it appears that rail transportation would cost about 15 percent less than truck. This disagrees with the other report (Ref. D-6) and a recent telephone conversation with DOE (Ref. D-8), both of which indicate a higher cost for rail transportation.

The cost estimates reported above can be compared to a figure of \$30/KgU (1980?) used in two recent studies of various aspects of the economics of nuclear fuel cycles (Refs. D-9 and D-10). They also fall generally within the range reported by the American Physical Society in 1978 (page S64, Ref. D-11) of \$15 to \$30 per KgHM (1976). Also notable is a 1978 report by MHB Technical Associates which uses a price of \$30/KgU (1978). All of the cost estimates referred to above for transportation of irradiated fuel are listed in Table D-4.

TABLE D-4

Summary of Cost Estimates for Transportation

of Irradiated Nuclear Fuel

	Year in Which Cost Reported	Dollars in Which Cost Reported	Reported Cost ($/Kg)	Escalated[1] Cost (1981 $/kg)
DOE (Ref. D-6)[2]	1980	1978	21-29	27-37
DOE (Ref. D-7)[2]	1980	1978	26	34
DOE (Ref. D-6)[3]	1980	1978	10-45	13-58
DOE (Ref. D-7)	1980	1978	16-32	21-41
TRCF (Ref. D-9)	1980	1980?	30	33
GIT (Ref. D-10)	1981	1980?	30	33
APS (Ref. D-11)	1978	1976	15-30	22-44
MHB (Ref. D-12)	1978	1978	30	39

1) Escalated according to the GNP price deflators listed in the Economic Report of the President, February 1982.

2) These costs are explicitly for transportation 1,500 miles by truck. The other costs in this table are not as specific.

3) The range of costs here is especially wide due to a wide range of distance assumptions (500 miles to 1,500 miles) and lease rates.

Permanent Storage Costs

Whether the irradiated fuel is temporarily stored onsite or at AFRs, at some point the problem of long-term storage, or disposal, must be addressed. Many schemes have been proposed for the disposal of high level radioactive waste. These include placing the waste into space, into the ocean, into continental ice sheets, and into geologic formations of the earth's crust. Of these, the last seems to entail the least technical and political difficulty. Of the possibilities for geologic disposal, the only option which is based upon available technology is storage in the mined vaults of a deep geologic repository.

While the mined deep geologic repository is currently considered the most viable option for disposal of spent nuclear fuel, it is not without technical difficulties. Some of the uncertainties which could effect the cost and effectiveness of this technology are listed and discussed in a recent report of the Union of Concerned Scientists (Ref. D-3). These include uncertainties regarding the effects upon the geological stability of the host rock due to mechanical disturbances during mining, heat released by the radioactive wastes, changes in ground water flows, and possible future seismatic activity. Also, the chemical processes involved in the decay of the storage containers are not well understood. These are some of the issues which must be adequately addressed before the disposal of permanent high level waste in geologic formations can be considered safe.

The responsibility for the research and development of a viable waste disposal method and ultimately the construction and operation of waste disposal facility appears to rest upon the federal government. It is intended that any government operated facility for permanent waste disposal be run on a "full cost recovery" basis (Ref. D-13). The specific design of the fee remains to be worked out. The details which are of the most importance to this study are: 1) when is the fee paid by the utility and how is it collected from the utility's customers, and 2) does the fee distinguish between spent fuel which requires temporary (AFR) storage and that which goes directly to permanent storage?

We chose to assume a one-time fee for permanent storage which would be paid by the utility at the time of delivery to the permanent disposal site. This fee would be designed to recover the full cost of storage including regulation, research and development, licensing, and decommissioning as well as the costs of actually constructing and operating the facility. Utility costs are assumed to be collected from the utility's customers.

The fee assumed in this study corresponds to the "dual cost center pricing philosophy" used by DOE in their <u>Final Environmental Impact Statement U.S. Spent Fuel Policy</u> (Ref. D-6). That is, if AFRs are built and operated by the government, fuel sent to an AFR will be charged a higher fee than fuel sent

directly to permanent storage. The higher fee would reflect the cost of supplying the interim storage.

DOE estimates the fee for disposal only (as opposed to interim storage and disposal) at $114/KgU (1978) for a case in which domestic and foreign irradiated fuel is stored in a geologic repository (Page II-5, Volume 4, Ref. D-6). This fee is listed in components as follows:

Encapsulation	$33/KgU
Geologic Repository (construction and operation)	$50/KgU
R&D and Gov't. Overhead	$31/KgU
Total	$114/KgU

The same DOE study estimates a slightly higher unit cost for a case in which foreign irradiated fuel is not stored in the U.S. Also, calculations for a "low demand case" yield a significantly higher unit cost of $234/KgU.

The above estimate of the fee for disposal in a geologic repository seems to agree with another DOE estimate of the unit cost for constructing, operating, and decommissioning a repository sited in salt of $52/KgHm (1978) (Ref. D-7, Vol. 1, p. 5.95). According to other estimates in the same report, salt is the least expensive media in which to situate a repository. However, technical uncertainties of salt disposal could force another, more expensive, geologic media (with its own technical uncertainties) to be used. A Union of Concerned Scientists report (Ref. D-3) cites the following

technical uncertainties associated with repositories sited in salt:

1. problems of brine-induced corrosion
2. effects of heat on salt geologic integrity
3. problems due to plasticity of salt.

These (or other problems) could easily increase costs by requiring additional research on equipment, by necessitating the use of another disposal technology, or by requiring that the deposited fuel be recovered and shipped to another disposal site.

A recent GAO study, Economic Impact of Closing Zion Nuclear Facility (Ref. D-18), uses a fee of $339/kg (1981) for irradiated fuel disposal. While this figure is "based upon DOE estimates," it is significantly higher than the DOE estimates discussed above.

An MHB study of waste disposal costs (Ref. D-12) addresses the uncertainties necessarily present in cost estimates for untested technologies. We adjusted the MHB figures such that they apply to permanent disposal only (not AFR storage). The figures, thus derived, are listed in Table D-5. Note that, as for the MHB estimates for AFRs discussed earlier, the costs are in constant 1978 dollars -- unadjusted for real cost escalation, the time value of money, and interest compensation.

The range indicated by the uncertainty factors implies that in the reference and high cases the waste put into one of the two repositories must be retrieved and reburied. This is an expensive procedure, but given the uncertainties in the technology of deep geologic disposal, it is certainly possible if not likely.

TABLE D-5

Irradiated Fuel Permanent Disposal Costs[1]
(Millions of 1978 $)

TASK	REFERENCE CASE Cost	HIGH CASE Uncertainty Factor	HIGH CASE Cost	LOW CASE Uncertainty Factor[2]	LOW CASE Cost
I. FIXED COST					
1. Regulatory	285	3	858	1	286
2. APR R&D	-				
3. Repository R&D	660	2	1320	1	660
4. Alternative R&D	600	2	1200	0	0
II. VARIABLE COSTS					
1. NEPA/Site	571	2	1142	1	571
2. Licensing	371	4	1484	1/3	124
3. AFR Const.	-				
4. AFR Oper.	-				
5. Repos. Const.	3150	2	6300	1/3	1050
6. Transport	-				
7. Repos. Oper.	750	2	1500	1/3	250
8. Repos. Monit.	390	4	1560	1/2	195
9. Retrieval	1566	2	3132	0	
10. Alt. Const.	1575	2	3150	0	
11. Alt. Transp.	900	2	1800	0	
12. Alt. Oper.	375	2	750	0	
13. Alt. Monit.	125	2	250	0	
14. Decommissioning	70	2	140	1/2	35
TOTALS (10^6, 1978 $):	11,389		24,586		3,171
UNIT COSTS (1978$/KgU):	$190/KgU		$410/KgU		$53/KgU

1. This table is based upon Table 5-3 in Spent Fuel Disposal Costs (Ref. D-12).

2. An uncertainty factor of zero means that the task is not performed.

D-7 Summary of Cost Estimates

Table D-6 summarizes our unit cost assumptions for disposal of irradiated fuel. Low, reference, and high costs are listed. The range of uncertainty in current cost estimates is represented by, but in no way limited to the range of costs listed here. Note that the low disposal cost will later be applied in our High Impact case. Likewise, the high disposal cost listed here will be applied in our Low Impact case. This somewhat confusing procedure is necessary because higher disposal costs will result in lower costs for plant shutdown.

The low cost assumption of $15/KgU-yr. for onsite storage is based on the current estimate for casks. (See Table D-2.) The reference cost assumption of $30/KgU-yr. is roughly the estimate for storage in dry wells or silos of fuel canned at a separate facility. The high cost assumption of $50/KgU-yr. can be thought of as representing vault or water pool storage. Of course, even cask storage could cost as much as the reference or high cost figures if current estimates prove to be low.

The costs listed in the table for transportation, either to an AFR or to the permanent storage site, are all within the range of current estimates (see Table D-4). These could be decreased to about one-quarter of the prices listed here if one assumes that storage casks purchased for onsite storage can be used for transportation.

The low fee for AFR storage is based upon the DOE figure of $117/KgHM (1978) cited earlier (Ref. D-7, Vol. 1, page 4.105). This figure escalated by 29 percent for three years of inflation yields the low cost figure in the table.

The reference cost estimate for AFR storage, double the low cost estimate, is more likely than the current DOE estimate. It reflects a cost increase that could occur with the use of much smaller AFRs than those upon which the original cost estimates were made. At present it seems that if an AFR is built at all, it will be much smaller than originally planned. However, current cost estimates for AFR storage are not available. Also, some cost overrun is certainly likely given the preliminary nature of the DOE estimates, and the problems which have historically plagued the storage of other radioactive materials.

The high AFR fee of $500/KgU (1981) represents a case in which the relationship between the preliminary cost estimates and the actual implementation costs is similar to that seen historically for other untested technologies. The difference here of about a factor of three is roughly the difference between preliminary estimates and actual costs for the construction of nuclear plants. A recent study by the RAND Corporation (Ref. D-20) concludes that "significant underestimation of future costs by several orders of magnitude is a general rule for new technologies" (Ref. D-19, page 56). The storage of large quantities of irradiated fuel by any method other than the onsite storage pool is a problem with more than its share of unresolved details, and is certainly classifiable as a "new technology." There is at the very least, a significant probability that current cost estimates will prove to be low by a factor of three or more.

For permanent disposal, the low fee listed in the table is based upon the DOE figure of $114/KgU (1978) (Ref. D-6, Vol. 4, page III-5) escalated to 1981 dollars. The reference and high cost estimates are increased similarly to those for AFR storage, for basically the same reasons.

Here, there are also potential problems with geological instability and long term chemical corrosion which could require very expensive repairs or possibly the retrieval of deposited waste which would then have to be re-deposited. Problems of this magnitude could easily result in costs much greater than those assumed in our high case.

TABLE D-6

Low, Reference, and High Case Unit Cost Assumptions
(1981 $)

	Low Case	Ref. Case	High Case
Onsite Storage Cost ($/KgU-year)	15	30	50
Transport to AFR ($/KgU)	20	30	40
AFR Storage Fee[1] ($/KgU)	150	300	500
Transport to Permanent Storage ($/KgU)	20	30	40
Permanent Disposal Fee[1] ($/KgU)	150	300	500

1) Note that the AFR storage fee and permanent disposal fee are treated separately here. In some of the DOE cost estimates (consistent with stated DOE policy) it is assumed that utilities using the AFR storage pay a fee at the time of delivery to the AFR which covers the costs of AFR storage, transportation, and permanent disposal. Because the utility is prepaying many of the costs to the government, the fee is lower (in constant dollars), reflecting the time value of money over the prepayment period. In our analysis we assume the fees associated with permanent disposal are paid at the time of permanent disposal, even for fuel which is stored temporarily in an AFR. This allows comparison between options for interim storage.

D-8 Application to Indian Point

The storage pool at Indian Point 2 originally designed to hold 482 assemblies, has the potential, through reracking, to hold 980 (Ref. D-14). Work on reracking the pool is currently under way (Ref. D-15). With 344 assemblies scheduled to be in the pool during 1982, and 72 more at each refueling, the pool will require alternative storage in 1993 in order to maintain full core reserve (Ref. D-14). Table D-7 shows the scheduled storage requirements by year.

In addition to the technical uncertainties faced by federally operated AFRs, there is considerable political uncertainty. In fact the AFR concept was discarded by DOE in March 1981 because of "lower than projected requirements for AFR storage, and lack of Congressional authority to implement the establishment of federal spent fuel storage facilities" (Ref. D-5). Recently the Senate passed a bill (S.1662) which includes a provision for building a small AFR.* However, this bill (and especially the part supporting AFRs) is the target of significant political opposition (Refs. D-13 and D-16). The siting of radioactive waste storage facilities is particularly troublesome. Construction plans have a tendancy to be delayed. At this point we do not know whether or not away from reactor storage will be available by 1993.

In the absence of an AFR, Con Ed would have to consider onsite storage. The large storage casks described earlier are not a feasible option because the Indian Point 2 fuel pool crane was not designed for

* The small AFR would take up to 2800 MTU of irradiated fuel. This is a much smaller quantity than that proposed by the Carter administration for AFR storage. The cost estimates discussed above all assumed the larger AFRs and are probably significantly low. Studies of cost more recent than those discussed above are not currently available.

the 100 ton loads typical of storage casks (Ref. D-17). If storage casks cannot be used, then drywells or silos are likely to be the preferable technology. The cost of drywells or silos will be greater than casks, especially if the irradiated fuel cannot be canned in the reactor pool.

Table D-7 shows the annual costs for storage of irradiated fuel at Indian Point 2 assuming the fuel reloading schedule listed in Reference D-14, and that an AFR is available by 1993. The fuel discharged between 2000 and 2005 goes directly to permanent disposal. In 2010, after the most recently irradiated fuel has had five years to "cool," all of the fuel remaining in the pool and all of the fuel at the AFR goes to permanent disposal. The total cost of this scenario is about $430/KgU (1981).

Table D-8 is similar to Table D-7, but here onsite storage replaces the AFR. The total cost for this scenario is $480/KgU (1981), 12% higher than the AFR case price. Of course, the relative economics of onsite interim storage vs. AFR interim storage will vary depending upon what assumptions are made regarding the timing and quantities of waste storage requirements.

Note that our calculations of unit disposal costs are based upon Indian Point unit 2. For Indian Point unit 3 the onsite storage pool is expected to reach capacity earlier, therefore, the disposal costs can be expected to be higher due to the larger quantity of fuel requiring interim storage. This effect is not accounted for here.

TABLE D-7

Indian Point 2 Irradiated Fuel Disposal Costs with AFR Interim Storage[1]
(All costs in thousands of 1981 $)

	Cumulative[2] Irradiated Fuel Discharges (MTU)	Fuel[2] Requiring Interim Storage (MTU)	Transport to AFR Cost	AFR Fee	Transport To Permanent Disposal Cost	Permanent Disposal Fee	Total Cost
1980	91	0					
1981	124	0					
1982	157	0					
1983	157	0					
1984	190	0					
1985	233	0					
1986	233	0					
1987	255	0					
1988	288	0					
1989	288	0					
1990	321	0					
1991	354	0					
1992	354	0					
1993	387	28	840	8400			9240
1994	420	33	990	9900			10890
1995	420	0					
1996	452	33	990	9900			10890
1997	485	33	990	9900			10890
1998	485	0					
1999	518	33	990	9900			10890
2000	551	33	990	9900			10890
2001	551	0					
2002	584	33			990	9900	10890
2003	617	33			990	9900	10890
2004	617	0					
2005	650	33			990	9900	10890
2006	650	0					
2007	650	0					
2008	650	0					
2009	650	0					
2010[3]	650	0			16,530	165,300	181,830
Total	650	292	5790	57,900	19,500	195,000	278,190

1. Costs are based on reference case costs in Table D-6.
2. Source: Reference D-14.
3. In 2010, 551 MTU is shipped to permanent disposal, 193 MTU from the AFR and 358 MTU from the onsite pool.

TABLE D-8

Indian Point 2 Irradiated Fuel Disposal Costs
With Onsite Interim Storage[1]

	Cumulative Irradiated Fuel Discharges (MTU)[2]	Fuel Requiring Interim Storage (MTU)[2]	Cumulative Fuel Requiring Interim Storage	Onsite Storage Cost	Transport to Permanent Disposal Cost	Permanent Disposal Fee	Total Cost
1980	91	0	0				
1981	124	0	0				
1982	157	0	0				
1983	157	0	0				
1984	190	0	0				
1985	233	0	0				
1986	233	0	0				
1987	255	0	0				
1988	288	0	0				
1989	288	0	0				
1990	321	0	0				
1991	354	0	0				
1992	354	0	0				
1993	387	28	28	840			84
1994	420	33	61	1830			1830
1995	420	0	61	1830			183
1996	452	33	94	2820			28
1997	485	33	127	3810			381
1998	485	0	127	3810			3810
1999	518	33	160	4800			48
2000	551	33	193	5790			579
2001	551	0	193	5790			5790
2002	584	33	226	6780			678
2003	617	33	259	7770			77
2004	617	0	259	7770			7770
2005	650	33	292	8760			876
2006	650	0	292	8760			876
2007	650	0	292	8760			876
2008	650	0	292	8760			8760
2009	650	0	292	8760			876
2010[3]	650	0	292	0	19,500	195,000	214,5
Total	650	292	292	97,440	19,500	195,000	311,94

1. Same as 1 above.
2. Same as 2 above.
3. In 2010 all 650 MTU is shipped to permanent disposal.

Table D-9 shows total costs per unit of waste calculated according to the unit costs for interim storage, transportation, and disposal listed in Table D-6. For the AFR case the storage requirements assumed in Table D-7 are used. For the onsite interim storage case the storage requirements are taken from Table D-8. The lower of the two sets of costs, those which assume AFR storage is available, are used for our continuation scenario.

The costs in Table D-9 for "no interim storage required" include the permanent disposal fee and the cost of transportation. These are the disposal costs used in our early retirement scenario. The costs of interim storage are excluded becasue it is assumed that if the plant is shut down before the existing pool is full, then the irradiated fuel can remain in the existing pool until a permanent geologic repository is available. This may require that the plant not be dismantled until the next century. Actually, it is not likely that the plant would be dismantled any sooner anyway due to the inavailability of a disposal site for large quantities of low level waste, and the general tendency of utilities to avoid dismantling.

Also shown in Table D-9 are cost estimates for irradiated fuel disposal from two other sources. The first is a study by Lewis Perl of NERA (Ref. D-21). Note that these estimates, while lower than ours, show a wide margin of uncertainty and imply a significant increase beyond the initial DOE estimates. The other source is a California Energy Commission report (Ref. D-19) which

TABLE D-9

Sample Total Costs for Storage, Transportation, and Disposal of Irradiated Fuel[1]
(All costs in 1981 dollars per KgU)

Case	Low	Reference	High
ESRG[1]			
With AFR interim storage	220	428	700
With onsite interim storage	245	480	790
With no interim storage required (i.e., early retirement scenario)	170	330	540
NERA/Lewis Perl[2]	170	294	434
CEC/Duane Chapman[3]	300	-	3000

1. ESRG cost estimates are based upon the low, reference, and high case prices in Table D-6, and the scenarios outlined in Table D-7 for the AFR case and in Table D-8 for the onsite storage case.

2. Table 12 of Lewis Perl's Revised Testimony, April 9, 1981 (Ref. D-21). Prices originally in 1979 dollars were escalated to 1981 by the GNP price deflators.

3. Page 73 of Nuclear Economics: Taxation, Fuel Cost, and Decommissioning by Duane Chapman for The California Energy Commission, November 1980 (Ref. D-19). Prices originally in 1979 dollars were escalated and rounded.

uses a price of about $300/KgU in its reference calculations. This report goes on to state that a cost higher by a factor of 10 is "equally likely."

For our reference case model runs, a cost for fuel disposal of $430/KgU (1981) was used in the continuation scenario and $330/KgU (1981) was used in the retirement scenario. The total incremental cost difference between the two scenarios is attributable to two separate effects. The first is that in the retirement scenario much less waste is produced. The second effect is that because the capacity of the existing storage pool is never exceeded, costs of onsite or AFR interim storage are avoided.

Cost per KgU can be converted to cost per Kwh if the number of Kwh generated per unit of fuel is known. The conversion factor can be estimated as follows:

$$\text{Kwh/KgU} = \frac{\text{B} \times \text{N} \times 24\ \text{hrs/day} \times 1000\ \text{KW/MW}}{1000\ \text{KgU/MTU}}$$

where:

B = burnup (MWtd/MTU)

N = plant thermal efficiency.

Assuming a burnup of 25,000 MWtd/MTU and a thermal efficiency of .32 (Ref. D-12), we calculate a factor of 192,000 Kwh/KgU. Using this number, our cost estimates in Table D-9 translate to 1981 mills per kwh as follows:

	Low	Ref.	High
Continuation Scenario	1.1	2.2	3.6
Retirement Scenario	0.9	1.7	2.8

The costs per kwh listed above were used to calculate the total costs for disposal of irradiated fuel in our Low, Mid-Range and High Impact cases. The low disposal cost listed above was used in our High Impact case, because a lower disposal cost will result in a larger difference between the keep and retirement cases. Likewise, the high disposal cost was used in our Low Impact case.

The total lifetime energy generation from the Indian Point units were calculated based upon the Low, Mid-Range, and High Impact scenario capacity factors as discussed in the text. These energy totals were multiplied by the costs per kwh listed above to derive the total irradiated fuel disposal cost for each scenario. These are listed in Table D-10. Note that the different capacity factors used in the Low, Mid-Range and High Impact scenarios ser-e to offset most of the disposal price variation.

Table D-10

Total Irradiated Fuel Disposal Costs
for Indian Point Units 1 and 2
(millions of 1981 $)

Indian Point Retirement Scenario	Keep	Retire	Increment
Low Impact	422	175	247
Mid-Range Impact	429	107	322
High Impact	279	57	222

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APPENDIX E

Decommissioning Options

and Costs

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APPENDIX E

E-1 Decommissioning Options

Whether or not a nuclear reactor continues to operate until the date of its planned retirement, the problem of decommissioning must eventually be addressed. Cost estimates for the various decommissioning options vary widely, even within the nuclear industry. Critics outside of the industry predict that even the highest utility estimates are much too low.

The three decommissioning options generally considered are entombment, mothballing and immediate dismantlement. Entombment involves removing the fuel and radioactive liquids, and then encasing the radioactive components of the reactor within a concrete structure (entombment barrier).

Mothballing is essentially entombment with decreased physical barrier and greater security requirements. Mothballing is lower cost than entombment initially, but the increased annual cost of guarding the site will generally make entombment the less expensive option over a long time period.

Immediate dismantlement entails clearing the radioactive components to the extent that decontamination is practical, and then cutting the radioactive structures into pieces which can be transported to a permanent radioactive waste disposal site. This option requires the highest initial investment, but if the site can be restored to unrestricted use, thereafter, the land use benefits as well as the saving in the direct

costs of guarding the site will generally make immediate dismantlement the most economically attractive option.

It was once believed that a retired reactor could simply be entombed until the radioactivity decayed to the point at which the structure could be demolished by the same methods used to demolish a conventional building. However, due to the discovery of some extremely longlived radioactive isotopes, ^{94}Nb and ^{59}Ni, which were originally overlooked, it is now believed that entombment is not a permanent solution. Design and construction of a structure which would survive the hundreds of thousands of years required for these isotopes to decay to acceptable levels is beyond present capabilities. Therefore, entombment and mothballing are now considered the only means of postponing dismantlement.

Delaying dismantlement would allow some of the radionuclides with short half-lives to decay, reducing the overall internal radioactivity level, thereby somewhat decreasing dismantling cost and worker exposure. In spite of this, immediate dismantlement,with its advantages of lower overall cost and allowing earlier use of the site, is currently the preferred option (Ref. E-1, p. 54, and Ref. E-2, p. 376). However, immediate dismantlement may not be a viable option for a reactor retired in the near future due to waste storage requirements:

> "The large quantities of low-level wastes generaged in the decommissioning process may exceed the existing quantity limits on operating burial grounds and so cannot be buried. Because of the present waste disposal problem, it may not be possible to conduct a total decommissioning today." (page 4, ref. E-3)

It is not clear how or when storage of huge quantities of low-level radioactive waste will cease being a problem.

E-2 Cost Estimates

With nuclear reactor dismantling experience limited to a number of very small military or research reactors and one 22 MW demonstration plant, cost estimates are necessarily approximate.

The 22 MW Elk River reactor is hardly comparable to the large commercial reactors in operation today since Elk River was only in operation for about four years. Elk River was dismantled between June 1972 and November 1974 at a cost of over $6 million. This was roughly equal to the original construction cost (Ref E-4).

There may be some factors which lead to relatively higher costs for larger reactors:

> "When dismantling larger reactors, workers would have to be protected with more effective--and isolating--shielding; the isolation will require both remote operation and monitoring of the cutting torches. In addition, the thicker, heavier fragments from commercial reactors will be more expensive to handle: additional manipulators will be needed, and current to the plasma torch would have to be higher to cut through the thicker metal. A particularly cumbersome problem would arise if the nuclear facility is a great distance away from a convenient nuclear waste disposal site. (Ref. E-5)

On the other hand, large scale dismantling projects would tend to enjoy certain economies of scale as they do at the construction phase.

The radioactive waste from Elk River was shipped from Minnesota to a burial site in Illinois. This distance is much shorter than can be expected on average for future decommissionings though the current shortage (indeed non-existance) of sites for the disposal of large quantities of radioactive waste makes detailed estimates impossible. The Elk River costs for dismantlement simply scaled by MW size, in 1982 dollars, the cost of dismantling a 1,000 MW power plant would be about $600 million. Further, if the decommissioning costs for a large reactor scaled from the Elk River costs according to MW years of operation, then the cost would be much higher. But clearly either scaling approach is too simplistic.

A recent survey of decommissioning cost estimates was done by Stone Webster Engineering Corp. for NESP (Ref. E-3). This survey selected and compared some of the current industry estimates of decommissioning costs for large reactors of approximately 1,000 MW. The conclusions of the survey are summarized briefly in Table E-1. Many of the studies surveyed estimated costs by adjusting the figures in a 1976 Atomic Industrial Forum/NESP study, An Engineering Evaluation of Nuclear Power Reactor Decommissioning Alternatives.

TABLE E-1

Summary of AIF/NESP Survey of Decommissioning Cost Estimates[1]

	Low	Average	High
Mothballing	3	6	13
Entombment	7	16	45
Immediate Dismantling	26	59	111
Annual Costs[3]	0.18	--	0.34

[1]Source: Reference E-3.

[2]Costs are escalated to 1981 $ according to the GNP price deflators.

[3]Components of annual cost include a full-time security guard force, surveillance, and radiological monitoring.

The wide range, to some extent, indicates differences in local labor rates and characteristics specific to individual plants. However, most of the disagreement is ultimately attributable to the judgement of the estimators. The low estimates are Arkansas Power and Light Co's estimates for the ANO-1 plant. These were made by scaling the original AIF/NESP estimates to account for the smaller size of ANO-1 and then reducing the estimate further to account for several factors which include the lack of cooling towers and an accelerated work schedule. The high estimates in Table E-1 were made in a 1977 study for TMI-1 by the Jersey Central Power and Light Co. and the Pennsylvania Electric Co. The judgement in the TMI-1 study is that "the NESP study estimated certain items too optimistically." These utilities then made estimates that more than doubled the total cost relative to the original AIF/NESP estimates.

A 1978 Battelle study done for the NRC (Ref. E-6) is the most detailed engineering analysis of decommissioning costs presently available. The Battelle estimates (which were included in the AIF/NESP survey) are just slightly higher than the original AIF/NESP estimates, and fall roughly in the middle of the range reported in the AIF/NESP survey. The final estimates from the Battelle report are summarized in Table E-2. A breakdown of the Battelle estimate for immediate dismantlement is listed in Table E-3.

TABLE E-2

Battelle Cost Estimates for PWR Decommissioning[1]

(All costs in millions of 1981 $)[2]

	Cost
Immediate Dismantlement	54
Safe Storage	
Initial Cost	16
Annual Cost (million $/yr)	0.10
Deferred Dismantlement	
10 years deferred	48
30 years deferred	48
50 years deferred	39
100 years deferred	39

[1]Source: Reference E-6

[2]Costs are escalated from 1978 dollars to 1981 using the factor of 1.29 indicated by the GNP price deflators.

TABLE E-3

Battelle Cost Estimate for Immediate Dismantlement of a Reference Pressurized Water Reactor[1]

(all costs in millions of 1981$)[2]

Category	Cost
Spent Fuel Disposal	3.2
Activated Materials Disposal	3.5
Containment Internals Disposal	1.2
Other Building Internals Disposal	5.4
Waste Disposal	0.9
Staff Labor	11.6
Electrical Power	4.5
Special Equipment	1.1
Miscellaneous Supplies	2.0
Facility Demolition (non-radioactive)	8.3
Specialty Contractors	0.5
Nuclear Insurance	1.0
Environmental Surveillance	0.2
SUBTOTAL	43.4
25% Contingency	10.9
TOTAL DISMANTLING COSTS (ROUNDED)	54.3

[1]Source: Reference E-6

[2]Costs are escalated from 1978 dollars to 1981 using the factor of 1.29 indicated by the GNP price deflators.

An alternative estimate for large reactor decommissioning costs has been made by a consultant to the California Energy Commission (Ref. E-1). Their report concludes that 24% of the original plant cost is a reasonable assumption.

The quantitative estimates in the decommissioning literature must be considered speculative. Indeed, if the comparison of initial industry estimates for nuclear power plant construction costs to final actual costs can be taken as any guide, then it will not be surprising if the NESP cost assumptions prove too low by factors of 4-5 or more. Such a possibility is also supported by a Rand Corp. report which concludes that "significant underestimation of future costs by several orders of magnitude is a general rule for new technologies." (Cited in Ref. E-1, p. 56)

References

E-1 Nuclear Economics: Taxation, Fuel Cost, and Decommissioning, P 300-80-038 by Duane Chapman of Cornell University for California Energy Commission, November 1980.

E-2 "A Long Tērm Problem for the Nuclear Industry," Colin Normin, Science, Volume 215, January 22, 1982.

E-3 Analysis of Nuclear Power Reactor Decommissioning Costs, AIF/NESP-021 SR, by Greenwood, Rymsha, Tondu, and Westfahl of Stone & Webster Engineering Corp. for the National Environmental Studies Project, Atomic Industrial Forum, Inc., May 1981.

E-4 "A Landscape of Nuclear Tombs," Alexis Parks, The Progressive, December 1977.

E-5 "Decommissioning Commercial Nuclear Reactors," Joseph Sefcik, Technology Review, Volume 81, Number 7, June 1979.

E-6 Technology, Safety and Costs of Decommissioning a Reference Pressurized Water Reactor Power Station, NUREG/CR-0130, Battelle Pacific Northwest Labs, June 1978.

E-7 A Review of Cost Estimation in New Technologies: Implications for Energy Process Plants, Ed Merrow, Rand Corporation, R-2481, July 1979.

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APPENDIX F

Sample Dispatch Runs
Output for Mid-Range Case
with and without
Indian Point
(1983, 1990, 1997)

Continued operation: Case MK1

Plant retirement: Case MR-2

UNIT TOTALS FOR 1983

UNIT INDEX	UNIT NAME	UNIT NAME	TOTAL CAPACITY	TOTAL EXPECTED ENERGY (MWHS)	FUEL COST ($M)	VARIABLE O&M COST ($MW)	TOTAL COST ($M)	TOTAL CAPACITY FACTOR	ENERGY TO STORAGE AND SALES (MWH)	CAPACITY FACTOR AFTER STORAGE AND SALES	EFFECTIVE CAPACITY MW	%
1	INDPNT 2	NUC INTR	864.0	4087061.0	0.0	0.0	0.0	0.540				
3	INDPNT 3	NUC INTR	965.0	4395763.0	0.0	0.0	0.0	0.520				
4	INDPCT	DIST PEAK	72.0	0.8	0.0	0.0	0.0	0.000				
5	RVNSWD 1	RSID INTR	390.0	931328.4	56.1	0.9	57.0	0.273				
8	RVNSWD 2	RSID INTR	390.0	1304269.0	77.7	1.3	79.0	0.382				
11	RVNSWD 3	RSID INTR	928.0	377094.4	23.0	0.4	23.4	0.046				
12	RVNSWD 3	COL1 INTR	928.0	4396491.0	136.3	13.7	150.0	0.541				
14	RAVCT2	DIST PEAK	239.0	20.5	0.0	0.0	0.0	0.000				
15	RAVCT3	DIST PEAK	126.0	8.0	0.0	0.0	0.0	0.000				
16	RVCT4-11	DIST PEAK	142.0	6.9	0.0	0.0	0.0	0.000				
17	ASTORIA1	RSID INTR	149.0	67869.9	5.1	0.1	5.2	0.052				
18	ASTORIA2	RSID INTR	164.0	71338.7	5.4	0.1	5.5	0.050				
19	ASTORIA3	RSID INTR	387.0	473495.8	30.7	1.0	31.7	0.140				
22	ASTORIA4	RSID INTR	387.0	452537.7	29.5	0.9	30.4	0.133				
25	ASTORIA5	RSID INTR	395.0	331291.2	23.0	0.7	23.7	0.096				
28	ASTORIA6	RSID INTR	825.0	1291460.0	77.1	2.7	79.8	0.179				
29	ASTCT1	DIST PEAK	18.0	15.0	0.0	0.0	0.0	0.000				
30	ASTCT2	DIST PEAK	184.0	122.6	0.0	0.0	0.0	0.000				
31	ASTCT3	DIST PEAK	184.0	87.8	0.0	0.0	0.0	0.000				
32	ASTCT4	DIST PEAK	184.0	63.7	0.0	0.0	0.0	0.000				
33	ASCT5-13	DIST PEAK	172.0	38.7	0.0	0.0	0.0	0.000				
34	BOWLINE1	RSID INTR	401.0	1900675.0	102.8	0.9	103.7	0.541				
35	BOWLINE2	RSID INTR	400.0	2129195.0	115.1	1.0	116.1	0.608				
36	ROSETON1	RSD2 INTR	240.0	1423496.0	60.2	0.5	60.6	0.677				
37	ROSETON2	RSD2 INTR	237.0	1400688.0	59.3	0.4	59.8	0.675				
41	FITZPATK	NUC INTR	123.0	726900.3	0.0	8.4	8.4	0.675				
47	WATRSID4	RSID INTR	20.0	431.9	0.0	0.0	0.0	0.002				
49	WATRSID6	RSID INTR	14.0	296.6	0.0	0.0	0.0	0.002				
50	WATR5,7	RSID INTR	74.0	1552.2	0.2	0.0	0.2	0.002				
51	WTR8,9	RSID INTR	72.0	1305.4	0.1	0.0	0.1	0.002				
52	WTR14,15	RSID INTR	116.0	2540.9	0.2	0.0	0.3	0.003				
53	E RIV5	RSID INTR	134.0	4594.8	0.4	0.0	0.4	0.004				
54	E RIV6	RSID INTR	134.0	3991.7	0.4	0.0	0.4	0.003				
55	E RIV7	RSID INTR	170.0	82068.3	5.9	0.4	6.3	0.055				
56	NARROWS1	DIST PEAK	184.0	29.6	0.0	0.0	0.0	0.000				
57	NARROWS2	DIST PEAK	184.0	21.6	0.0	0.0	0.0	0.000				
58	GWNUSCT1	DIST PEAK	174.0	5.4	0.0	0.0	0.0	0.000				

UNIT TOTALS FOR 1983

UNIT INDEX	UNIT NAME	UNIT NAME	TOTAL CAPACITY	TOTAL EXPECTED ENERGY (MWHS)	FUEL COST ($M)	VARIABLE O&M COST ($MW)	TOTAL COST ($M)	TOTAL CAPACITY FACTOR	ENERGY TO STORAGE AND SALES (MWH)	CAPACITY FACTOR AFTER STORAGE AND SALES	EFFECTIVE CAPACITY MW %
59	GWNUSCT2	DIST PEAK	186.0	4.2	0.0	0.0	0.0	0.000			
60	GWNUSCT3	DIST PEAK	167.0	2.8	0.0	0.0	0.0	0.000			
61	GWNISCT4	DIST PEAK	142.0	1.8	0.0	0.0	0.0	0.000			
62	HUDCT1-5	DIST PEAK	83.0	0.8	0.0	0.0	0.0	0.000			
63	HUDSN2,3	RESD PEAK	34.0	0.2	0.0	0.0	0.0	0.000			
65	HUDSON6	RESD PEAK	17.0	0.1	0.0	0.0	0.0	0.000			
66	HUDSON7	RESD PEAK	101.0	0.0	0.0	0.0	0.0	0.000			
67	HUDSON7	RESD PEAK	126.0	0.6	0.0	0.0	0.0	0.000			
68	HUDSON8	RESD PEAK	151.0	0.6	0.0	0.0	0.0	0.000			
69	HUDSON10	RESD PEAK	40.0	0.2	0.0	0.0	0.0	0.000			
70	74TH-9	RSID INTR	58.0	63.1	0.0	0.0	0.0	0.000			
71	74TH-10	RSID INTR	58.0	55.5	0.0	0.0	0.0	0.000			
72	74TH-11	RSID INTR	31.0	29.6	0.0	0.0	0.0	0.000			
73	74TH CT	DIST PEAK	34.0	0.2	0.0	0.0	0.0	0.000			
74	59TH-13	RSID INTR	53.0	45.2	0.0	0.0	0.0	0.000			
75	59TH-14	RSID INTR	19.0	16.2	0.0	0.0	0.0	0.000			
76	59TH-15	RSID INTR	20.0	16.2	0.0	0.0	0.0	0.000			
77	59TH CT	DIST PEAK	40.0	0.4	0.0	0.0	0.0	0.000			
78	BUCHANAN	DIST PEAK	20.0	0.1	0.0	0.0	0.0	0.000			
79	KENT CT	DIST PEAK	12.0	0.1	0.0	0.0	0.0	0.000			
80	ARTKILL2	RSID INTR	350.0	1150794.0	67.5	1.6	69.2	0.375			
83	ARTKILL3	RSID INTR	501.0	1978568.0	112.4	2.8	115.2	0.451			
87	ARKLCT	DIST PEAK	18.0	0.9	0.0	0.0	0.0	0.000			
98	HYDQ1S	PRCH BASE	780.0	3003518.0	0.0	64.4	64.4	0.440			
99	HYDQ2S	PRCH INTR	168.0	747645.6	0.0	29.8	29.8	0.508			
100	HYDQ2W	PRCH INTR	343.0	1230600.0	0.0	49.0	49.0	0.410			
101	ONHY1	PRCH BASE	161.0	1150500.0	0.0	45.9	45.9	0.816			
104	NYPP1	PRCH INTR	300.0	1616547.0	0.0	88.2	88.2	0.615			
105	LILCO	PRCH INTR	500.0	493525.4	0.0	35.3	35.3	0.113			
106	NYPP2	PRCH INTR	800.0	182672.9	0.0	14.1	14.1	0.026			
108	PSEG1	PRCH INTR	600.0	10133.0	0.0	1.1	1.1	0.002			
109	PSEG2	PRCH INTR	800.0	2941.1	0.0	0.3	C.3	0.000			
SYSTEM TOTALS				37425744.0	988.7	366.1	1354.7	0.294			

UNIT TOTALS FOR 1990

UNIT INDEX	UNIT NAME	UNIT NAME	TOTAL CAPACITY	TOTAL EXPECTED ENERGY (MWHS)	FUEL COST ($M)	VARIABLE O&M COST ($MW)	TOTAL COST ($M)	TOT/ CAPACITY FACTOR	ENERGY TO STORAGE AND SALES (MWH)	CAPACITY FACTOR AFTER STORAGE AND SALES	EFFECTIVE CAPACITY MW %
1	INDPNT 2	NUC INTR	864.0	3405883.0	0.0	0.0	0.0	0.450			
3	INDPNT 3	NUC INTR	965.0	3719492.0	0.0	0.0	0.0	0.440			
4	INDPCT	DIST PEAK	72.0	0.0	0.0	0.0	0.0	0.000			
5	RVNSWD 1	RSID INTR	390.0	898763.6	105.4	1.6	107.0	0.263			
8	RVNSWD 2	RSID INTR	390.0	1259707.0	146.3	2.2	148.5	0.369			
13	RVNSWD 3	COL2 INTR	922.0	4089910.0	203.2	17.4	220.7	0.506			
14	RAVCT2	DIST PEAK	239.0	0.2	0.0	0.0	0.0	0.000			
15	RAVCT3	DIST PEAK	126.0	0.1	0.0	0.0	0.0	0.000			
16	RVCT4-11	DIST PEAK	142.0	0.1	0.0	0.0	0.0	0.000			
17	ASTORIA1	RSID INTR	149.0	8139.9	1.2	0.0	1.2	0.006			
18	ASTORIA2	RSID INTR	164.0	7171.6	1.1	0.0	1.1	0.005			
19	ASTORIA3	RSID INTR	387.0	439552.2	55.6	1.6	57.2	0.130			
22	ASTORIA4	RSID INTR	387.0	474005.2	60.2	1.7	61.9	0.140			
25	ASTORIA5	RSID INTR	395.0	303024.1	41.0	1.1	42.1	0.088			
28	ASTORIA6	RSID INTR	825.0	1165089.0	135.7	4.2	139.8	0.161			
29	ASTCT1	DIST PEAK	18.0	0.3	0.0	0.0	0.0	0.000			
30	ASTCT2	DIST PEAK	184.0	2.0	0.0	0.0	0.0	0.000			
31	ASTCT3	DIST PEAK	184.0	1.3	0.0	0.0	0.0	0.000			
32	ASTCT4	DIST PEAK	184.0	0.9	0.0	0.0	0.0	0.000			
33	ASCT5-13	DIST PEAK	172.0	0.5	0.0	0.0	0.0	0.000			
34	BOWLINE1	RSID INTR	401.0	1465419.0	154.7	1.1	155.9	0.417			
35	BOWLINE2	RSID INTR	400.0	1702068.0	179.6	1.3	180.9	0.486			
36	ROSETON1	RSD2 INTR	240.0	1243701.0	102.5	0.7	103.2	0.592			
37	ROSETON2	RSD2 INTR	237.0	1173616.0	97.0	0.6	97.6	0.565			
51	WTR8,9	RSID INTR	72.0	49.9	0.0	0.0	0.0	0.000			
52	WTR14,15	RSID INTR	116.0	89.8	0.0	0.0	0.0	0.000			
53	E RIV5	RSID INTR	134.0	171.0	0.0	0.0	0.0	0.000			
54	E RIV6	RSID INTR	134.0	141.1	0.0	0.0	0.0	0.000			
55	E RIV7	RSID INTR	170.0	11326.4	1.6	0.1	1.7	0.008			
56	NARROWS1	DIST PEAK	184.0	0.3	0.0	0.0	0.0	0.000			
57	NARROWS2	DIST PEAK	184.0	0.2	0.0	0.0	0.0	0.000			
58	GWNUSCT1	DIST PEAK	174.0	0.0	0.0	0.0	0.0	0.000			
59	GWNUSCT2	DIST PEAK	186.0	0.0	0.0	0.0	0.0	0.000			
60	GWNUSCT3	DIST PEAK	167.0	0.0	0.0	0.0	0.0	0.000			
61	GWNISCT4	DIST PEAK	142.0	0.0	0.0	0.0	0.0	0.000			
62	HUDCT1-5	DIST PEAK	83.0	0.0	0.0	0.0	0.0	0.000			
65	HUDSON6	RESD PEAK	17.0	0.0	0.0	0.0	0.0	0.000			

UNIT TOTALS FOR 1990

UNIT INDEX	UNIT NAME	UNIT NAME	TOTAL CAPACITY	TOTAL EXPECTED ENERGY (MWHS)	FUEL COST ($M)	VARIABLE O&M COST ($MW)	TOTAL COST ($M)	TOTAL CAPACITY FACTOR	ENERGY TO STORAGE AND SALES (MWH)	CAPACITY FACTOR AFTER STORAGE AND SALES	EFFECTIVE CAPACITY MW	%
67	HUDSON7	RESD PEAK	126.0	0.0	0.0	0.0	0.0	0.000				
69	HUDSON10	RESD PEAK	40.0	0.0	0.0	0.0	0.0	0.000				
70	74TH-9	RSID INTR	58.0	1.2	0.0	0.0	0.0	0.000				
71	74TH-10	RSID INTR	58.0	1.0	0.0	0.0	0.0	0.000				
72	74TH-11	RSID INTR	31.0	0.5	0.0	0.0	0.0	0.000				
73	74TH CT	DIST PEAK	34.0	0.0	0.0	0.0	0.0	0.000				
74	59TH-13	RSID INTR	53.0	0.8	0.0	0.0	0.0	0.000				
75	59TH-14	RSID INTR	19.0	0.3	0.0	0.0	0.0	0.000				
76	59TH-15	RSID INTR	20.0	0.3	0.0	0.0	0.0	0.000				
77	59TH CT	DIST PEAK	40.0	0.0	0.0	0.0	0.0	0.000				
78	BUCHANAN	DIST PEAK	20.0	0.0	0.0	0.0	0.0	0.000				
79	KENT CT	DIST PEAK	12.0	0.0	0.0	0.0	0.0	0.000				
82	ARTKILL2	COL2 INTR	335.0	1663075.0	72.1	21.3	93.4	0.567				
85	ARTKILL3	COL2 INTR	461.0	2121399.0	89.1	27.1	116.3	0.525				
87	ARKLCT	DIST PEAK	18.0	0.0	0.0	0.0	0.0	0.000				
88	PEEKSKIL	SLWT INTR	50.0	315309.7	17.3	0.0	17.3	0.720				
98	HYDQ1S	PRCH BASE	780.0	3004559.0	0.0	125.6	125.6	0.440				
99	HYDQ2S	PRCH INTR	168.0	705865.4	0.0	53.1	53.1	0.480				
100	HYDQ2W	PRCH INTR	343.0	1227819.0	0.0	92.4	92.4	0.409				
101	ONHY1	PRCH BASE	161.0	1104748.0	0.0	83.1	83.1	0.783				
102	HYDQ3	PRCH BASE	194.0	1416482.0	0.0	106.6	106.6	0.833				
103	ONHY2	PRCH BASE	160.0	1019822.2	0.0	76.7	76.7	0.728				
104	NYPP1	PRCH INTR	300.0	1254184.0	0.0	133.3	133.3	0.477				
105	LILCO	PRCH INTR	500.0	513350.9	0.0	71.5	71.5	0.117				
106	NYPP2	PRCH INTR	800.0	12183.8	0.0	1.8	1.8	0.002				
107	NYPP3	PRCH INTR	1000.0	449272.7	0.0	62.6	62.6	0.051				
108	PSEG1	PRCH INTR	600.0	302.6	0.0	0.1	0.1	0.000				
109	PSEG2	PRCH INTR	800.0	59.8	0.0	0.0	0.0	0.000				
SYSTEM TOTALS				36175712.0	1463.8	888.8	2352.6	0.269				

UNIT TOTALS FOR 1997

UNIT INDEX	UNIT NAME	UNIT NAME	TOTAL CAPACITY	TOTAL EXPECTED ENERGY (MWHS)	FUEL COST ($M)	VARIABLE O&M COST ($MW)	TOTAL COST ($M)	TOTAL CAPACITY FACTOR	ENERGY TO STORAGE AND SALES (MWH)	CAPACITY FACTOR AFTER STORAGE AND SALES	EFFECTIVE CAPACITY MW %
1	INDPNT 2	NUC INTR	864.0	2724704.0	0.0	0.0	0.0	0.360			
3	INDPNT 3	NUC INTR	965.0	3043221.0	0.0	0.0	0.0	0.360			
4	INDPCT	DIST PEAK	72.0	0.0	0.0	0.0	0.0	0.000			
5	RVNSWD 1	RSID INTR	390.0	808328.2	184.8	2.4	187.2	0.237			
8	RVNSWD 2	RSID INTR	390.0	1417769.0	320.8	4.2	325.0	0.415			
13	RVNSWD 3	COL2 INTR	922.0	4152029.0	377.0	33.7	410.8	0.514			
14	RAVCT2	DIST PEAK	239.0	1.6	0.0	0.0	0.0	0.000			
15	RAVCT3	DIST PEAK	126.0	0.6	0.0	0.0	0.0	0.000			
16	RVCT4-11	DIST PEAK	142.0	0.5	0.0	0.0	0.0	0.000			
17	ASTORIA1	RSID INTR	149.0	19791.1	5.7	0.1	5.8	0.015			
18	ASTORIA2	RSID INTR	164.0	17802.2	5.1	0.1	5.2	0.012			
19	ASTORIA3	RSID INTR	387.0	546628.9	134.7	3.3	138.0	0.161			
22	ASTORIA4	RSID INTR	387.0	565764.1	139.9	3.4	143.3	0.167			
25	ASTORIA5	RSID INTR	395.0	391112.1	103.1	2.4	105.5	0.113			
28	ASTORIA6	RSID INTR	825.0	1631698.0	369.9	10.0	379.8	0.226			
29	ASTCT1	DIST PEAK	18.0	1.8	0.0	0.0	0.0	0.000			
30	ASTCT2	DIST PEAK	184.0	14.4	0.0	0.0	0.0	0.000			
31	ASTCT3	DIST PEAK	184.0	9.7	0.0	0.0	0.0	0.000			
32	ASTCT4	DIST PEAK	184.0	7.1	0.0	0.0	0.0	0.000			
33	ASCT5-13	DIST PEAK	172.0	3.7	0.0	0.0	0.0	0.000			
34	BOWLINE1	RSID INTR	401.0	1616393.0	332.4	2.2	334.6	0.460			
35	BOWLINE2	RSID INTR	400.0	1854351.0	381.1	2.5	383.6	0.529			
36	ROSETON1	RSD2 INTR	240.0	1317054.0	211.5	1.2	212.8	0.626			
37	ROSETON2	RSD2 INTR	237.0	1263161.0	203.3	1.2	204.5	0.608			
55	E RIV7	RSID INTR	170.0	26213.1	7.2	0.3	7.5	0.018			
56	NARROWS1	DIST PEAK	184.0	2.6	0.0	0.0	0.0	0.000			
57	NARROWS2	DIST PEAK	184.0	1.8	0.0	0.0	0.0	0.000			
58	GWNUSCT1	DIST PEAK	174.0	0.4	0.0	0.0	0.0	0.000			
59	GWNUSCT2	DIST PEAK	186.0	0.2	0.0	0.0	0.0	0.000			
60	GWNUSCT3	DIST PEAK	167.0	0.2	0.0	0.0	0.0	0.000			
61	GWNISCT4	DIST PEAK	142.0	0.1	0.0	0.0	0.0	0.000			
62	HUDCT1-5	DIST PEAK	83.0	0.0	0.0	0.0	0.0	0.000			
65	HUDSON6	RESD PEAK	17.0	0.0	0.0	0.0	0.0	0.000			
70	74TH-9	RSID INTR	58.0	285.3	0.1	0.0	0.1	0.001			
71	74TH-10	RSID INTR	58.0	189.4	0.1	0.0	0.1	0.000			
72	74TH-11	RSID INTR	31.0	132.9	0.0	0.0	0.1	0.000			
73	74TH CT	DIST PEAK	34.0	0.0	0.0	0.0	0.0	0.000			

UNIT TOTALS FOR 1997

UNIT INDEX	UNIT NAME	UNIT NAME	TOTAL CAPACITY	TOTAL EXPECTED ENERGY (MWHS)	FUEL COST ($M)	VARIABLE O&M COST ($MW)	TOTAL COST ($M)	TOTAL CAPACITY FACTOR	ENERGY TO STORAGE AND SALES (MWH)	CAPACITY FACTOR AFTER STORAGE AND SALES	EFFECTIVE CAPACITY MW %
75	59TH-14	RSID INTR	19.0	2.1	0.0	0.0	0.0	0.000			
76	59TH-15	RSID INTR	20.0	1.9	0.0	0.0	0.0	0.000			
77	59TH CT	DIST PEAK	40.0	0.0	0.0	0.0	0.0	0.000			
78	BUCHANAN	DIST PEAK	20.0	0.0	0.0	0.0	0.0	0.000			
79	KENT CT	DIST PEAK	12.0	0.0	0.0	0.0	0.0	0.000			
82	ARTKILL2	COL2 INTR	335.0	1722357.0	136.5	42.0	178.5	0.587			
85	ARTKILL3	COL2 INTR	461.0	2124611.0	163.2	51.8	215.0	0.526			
87	ARKLCT	DIST PEAK	18.0	0.0	0.0	0.0	0.0	0.000			
88	PEEKSKIL	SLWT INTR	50.0	322446.8	32.3	0.0	32.3	0.736			
98	HYDQ1S	PRCH BASE	780.0	3004559.0	0.0	244.7	244.7	0.440			
99	HYDQ2S	PRCH INTR	168.0	745454.6	0.0	105.9	105.9	0.507			
100	HYDQ2W	PRCH INTR	343.0	1230597.0	0.0	174.8	174.8	0.410			
101	ONHY1	PRCH BASE	161.0	1147590.0	0.0	163.0	163.0	0.814			
102	HYDQ3	PRCH BASE	194.0	1480159.0	0.0	210.2	210.2	0.871			
103	ONHY2	PRCH BASE	160.0	1073177.0	0.0	152.4	152.4	0.766			
104	NYPP1	PRCH INTR	300.0	1389408.0	0.0	287.9	287.9	0.529			
105	LILCO	PRCH INTR	500.0	664194.0	0.0	180.3	180.3	0.152			
106	NYPP2	PRCH INTR	800.0	33162.6	0.0	9.7	9.7	0.005			
107	NYPP3	PRCH INTR	1000.0	715897.7	0.0	194.4	194.4	0.082			
108	PSEG1	PRCH INTR	600.0	1510.7	0.0	0.6	0.6	0.000			
109	PSEG2	PRCH INTR	800.0	302.5	0.0	0.1	0.1	0.000			
SYSTEM TOTALS				37052048.0	3108.8	1884.7	4993.5	0.289			

UNIT TOTALS FOR 1983

UNIT INDEX	UNIT NAME	UNIT NAME	TOTAL CAPACITY	TOTAL EXPECTED ENERGY (MWHS)	FUEL COST ($M)	VARIABLE O&M COST ($MW)	TOTAL COST ($M)	TOTAL CAPACITY FACTOR	ENERGY TO STORAGE AND SALES (MWH)	CAPACITY FACTOR AFTER STORAGE AND SALES	EFFECTIVE CAPACITY MW %
4	INDPCT	DIST PEAK	72.0	16.3	0.0	0.0	0.0	0.000			
5	RVNSWD 1	RSID INTR	390.0	1410518.0	84.9	1.4	86.3	0.413			
8	RVNSWD 2	RSID INTR	390.0	1801623.0	107.3	1.8	109.1	0.527			
11	RVNSWD 3	RSID INTR	928.0	544320.7	33.2	0.5	33.8	0.067			
12	RVNSWD 3	COL1 INTR	928.0	4634463.0	143.4	14.4	157.9	0.570			
14	RAVCT2	DIST PEAK	239.0	328.7	0.0	0.0	0.0	0.000			
15	RAVCT3	DIST PEAK	126.0	130.5	0.0	0.0	0.0	0.000			
16	RVCT4-11	DIST PEAK	142.0	116.3	0.0	0.0	0.0	0.000			
17	ASTORIA1	RSID INTR	149.0	182226.6	13.6	0.4	14.0	0.140			
18	ASTORIA2	RSID INTR	164.0	212130.6	15.9	0.4	16.3	0.148			
19	ASTORIA3	RSID INTR	387.0	838854.4	54.4	1.7	56.1	0.247			
22	ASTORIA4	RSID INTR	387.0	775952.7	50.5	1.6	52.1	0.229			
25	ASTORIA5	RSID INTR	395.0	643620.0	44.6	1.3	46.0	0.186			
28	ASTORIA6	RSID INTR	825.0	2127338.0	126.9	4.4	131.3	0.294			
29	ASTCT1	DIST PEAK	18.0	175.3	0.0	0.0	0.0	0.001			
30	ASTCT2	DIST PEAK	184.0	1490.3	0.2	0.0	0.2	0.001			
31	ASTCT3	DIST PEAK	184.0	1118.8	0.1	0.0	0.1	0.001			
32	ASTCT4	DIST PEAK	184.0	884.0	0.1	0.0	0.1	0.001			
33	ASCT5-13	DIST PEAK	172.0	538.9	0.1	0.0	0.1	0.000			
34	BOWLINE1	RSID INTR	401.0	2345132.0	126.6	1.1	127.7	0.668			
35	BOWLINE2	RSID INTR	400.0	2486442.0	134.2	1.1	135.3	0.710			
36	ROSETON1	RSD2 INTR	240.0	1580833.0	66.8	0.5	67.3	0.752			
37	ROSETON2	RSD2 INTR	237.0	1578535.0	66.8	0.5	67.3	0.760			
41	FITZPATK	NUC INTR	123.0	726900.2	0.0	8.4	8.4	0.675			
47	WATRSID4	RSID INTR	20.0	3786.2	0.4	0.0	0.4	0.022			
49	WATRSID6	RSID INTR	14.0	2617.4	0.3	0.0	0.3	0.021			
50	WATR5,7	RSID INTR	74.0	10916.3	1.1	0.1	1.1	0.017			
51	WTR8,9	RSID INTR	72.0	11969.6	1.2	0.1	1.3	0.019			
52	WTR14,15	RSID INTR	116.0	21048.6	2.0	0.2	2.2	0.021			
53	E RIV5	RSID INTR	134.0	37537.7	3.5	0.2	3.6	0.032			
54	E RIV6	RSID INTR	134.0	34465.7	3.3	0.2	3.4	0.029			
55	E RIV7	RSID INTR	170.0	201323.2	14.5	0.9	15.4	0.135			
56	NARROWS1	DIST PEAK	184.0	426.7	0.1	0.0	0.1	0.000			
57	NARROWS2	DIST PEAK	184.0	323.7	0.0	0.0	0.0	0.000			
58	GWNUSCT1	DIST PEAK	174.0	95.0	0.0	0.0	0.0	0.000			
59	GWNUSCT2	DIST PEAK	186.0	74.6	0.0	0.0	0.0	0.000			
60	GWNUSCT3	DIST PEAK	167.0	52.2	0.0	0.0	0.0	0.000			

CONED-PASNY (CASE MR2)

UNIT TOTALS FOR 1983

UNIT INDEX	UNIT NAME	UNIT NAME	TOTAL CAPACITY	TOTAL EXPECTED ENERGY (MWHS)	FUEL COST ($M)	VARIABLE O&M COST ($MW)	TOTAL COST ($M)	TOTAL CAPACITY FACTOR	ENERGY TO STORAGE AND SALES (MWH)	CAPACITY FACTOR AFTER STORAGE AND SALES	EFFECTIVE CAPACITY MW %
61	GWNISCT4	DIST PEAK	142.0	34.8	0.0	0.0	0.0	0.000			
62	HUDCT1-5	DIST PEAK	83.0	16.6	0.0	0.0	0.0	0.000			
63	HUDSN2,3	RESD PEAK	34.0	4.1	0.0	0.0	0.0	0.000			
65	HUDSON6	RESD PEAK	17.0	2.0	0.0	0.0	0.0	0.000			
66	HUDSON7	RESD PEAK	101.0	0.2	0.0	0.0	0.0	0.000			
67	HUDSON7	RESD PEAK	126.0	12.6	0.0	0.0	0.0	0.000			
68	HUDSON8	RESD PEAK	151.0	13.2	0.0	0.0	0.0	0.000			
69	HUDSON10	RESD PEAK	40.0	3.4	0.0	0.0	0.0	0.000			
70	74TH-9	RSID INTR	58.0	729.4	0.1	0.0	0.1	0.001			
71	74TH-10	RSID INTR	58.0	590.5	0.1	0.0	0.1	0.001			
72	74TH-11	RSID INTR	31.0	348.2	0.0	0.0	0.0	0.001			
73	74TH CT	DIST PEAK	34.0	3.4	0.0	0.0	0.0	0.000			
74	59TH-13	RSID INTR	53.0	522.3	0.1	0.0	0.1	0.001			
75	59TH-14	RSID INTR	19.0	192.9	0.0	0.0	0.0	0.001			
76	59TH-15	RSID INTR	20.0	185.4	0.0	0.0	0.0	0.001			
77	59TH CT	DIST PEAK	40.0	7.4	0.0	0.0	0.0	0.000			
78	BUCHANAN	DIST PEAK	20.0	2.5	0.0	0.0	0.0	0.000			
79	KENT CT	DIST PEAK	12.0	1.3	0.0	0.0	0.0	0.000			
80	ARTKILL2	RSID INTR	350.0	1638229.0	96.0	2.3	98.4	0.534			
83	ARTKILL3	RSID INTR	501.0	2490674.0	141.4	3.6	144.9	0.568			
87	ARKLCT	DIST PEAK	18.0	14.0	0.0	0.0	0.0	0.000			
98	HYDQ1S	PRCH BASE	780.0	3004558.0	0.0	64.4	64.4	0.440			
99	HYDQ2S	PRCH INTR	208.0	1048942.0	0.0	41.8	41.8	0.576			
100	HYDQ2W	PRCH INTR	424.0	1521208.0	0.0	60.6	60.6	0.410			
101	ONHY1	PRCH BASE	199.0	1540818.0	0.0	61.4	61.4	0.884			
104	NYPP1	PRCH INTR	300.0	2016284.0	0.0	110.0	110.0	0.767			
105	LILCO	PRCH INTR	500.0	1024525.7	0.0	73.3	73.3	0.234			
106	NYPP2	PRCH INTR	800.0	796510.7	0.0	61.3	61.3	0.114			
108	PSEG1	PRCH INTR	600.0	95112.7	0.0	10.4	10.4	0.018			
109	PSEG2	PRCH INTR	800.0	32048.0	0.0	3.5	3.5	0.005			
SYSTEM TOTALS				37429808.0	1333.7	534.0	1867.7	0.313			

UNIT TOTALS FOR 1990

UNIT INDEX	UNIT NAME	UNIT NAME	TOTAL CAPACITY	TOTAL EXPECTED ENERGY (MWHS)	FUEL COST ($M)	VARIABLE O&M COST ($MW)	TOTAL COST ($M)	TOTAL CAPACITY FACTOR	ENERGY TO STORAGE AND SALES (MWH)	CAPACITY FACTOR AFTER STORAGE AND SALES	EFFECTIVE CAPACITY MW %
4	INDPCT	DIST PEAK	72.0	0.1	0.0	0.0	0.0	0.000			
7	RVNSWD 1	COL2 INTR	372.0	1272729.0	62.5	5.4	67.9	0.391			
8	RVNSWD 2	RSID INTR	390.0	1527786.0	177.3	2.6	180.0	0.447			
13	RVNSWD 3	COL2 INTR	922.0	4234113.0	210.1	18.1	228.2	0.524			
14	RAVCT2	DIST PEAK	239.0	5.4	0.0	0.0	0.0	0.000			
15	RAVCT3	DIST PEAK	126.0	1.9	0.0	0.0	0.0	0.000			
16	RVCT4-11	DIST PEAK	142.0	1.5	0.0	0.0	0.0	0.000			
17	ASTORIA1	RSID INTR	149.0	67397.0	9.9	0.2	10.1	0.052			
18	ASTORIA2	RSID INTR	164.0	66920.5	9.8	0.2	10.0	0.047			
19	ASTORIA3	RSID INTR	387.0	726628.6	91.9	2.6	94.4	0.214			
22	ASTORIA4	RSID INTR	387.0	795891.1	100.9	2.8	103.8	0.235			
25	ASTORIA5	RSID INTR	395.0	530539.1	71.8	1.9	73.6	0.153			
28	ASTORIA6	RSID INTR	825.0	1840569.0	214.1	6.6	220.6	0.255			
29	ASTCT1	DIST PEAK	18.0	5.4	0.0	0.0	0.0	0.000			
30	ASTCT2	DIST PEAK	184.0	42.6	0.0	0.0	0.0	0.000			
31	ASTCT3	DIST PEAK	184.0	29.2	0.0	0.0	0.0	0.000			
32	ASTCT4	DIST PEAK	184.0	22.9	0.0	0.0	0.0	0.000			
33	ASCT5-13	DIST PEAK	172.0	11.4	0.0	0.0	0.0	0.000			
34	BOWLINE1	RSID INTR	401.0	1758007.0	185.5	1.4	186.9	0.500			
35	BOWLINE2	RSID INTR	400.0	2006218.0	211.5	1.6	213.1	0.573			
36	ROSETON1	RSD2 INTR	240.0	1401928.0	115.5	0.8	116.3	0.667			
37	ROSETON2	RSD2 INTR	237.0	1349928.0	111.5	0.7	112.2	0.650			
51	WTR8,9	RSID INTR	72.0	1173.9	0.2	0.0	0.2	0.002			
52	WTR14,15	RSID INTR	116.0	1827.5	0.3	0.0	0.4	0.002			
53	E RIV5	RSID INTR	134.0	4063.7	0.7	0.0	0.8	0.003			
54	E RIV6	RSID INTR	134.0	3361.3	0.6	0.0	0.7	0.003			
55	E RIV7	RSID INTR	170.0	79173.4	11.1	0.6	11.7	0.053			
56	NARROWS1	DIST PEAK	184.0	8.3	0.0	0.0	0.0	0.000			
57	NARROWS2	DIST PEAK	184.0	5.7	0.0	0.0	0.0	0.000			
58	GWNUSCT1	DIST PEAK	174.0	1.1	0.0	0.0	0.0	0.000			
59	GWNUSCT2	DIST PEAK	186.0	0.7	0.0	0.0	0.0	0.000			
60	GWNUSCT3	DIST PEAK	167.0	0.5	0.0	0.0	0.0	0.000			
61	GWNISCT4	DIST PEAK	142.0	0.3	0.0	0.0	0.0	0.000			
62	HUDCT1-5	DIST PEAK	83.0	0.1	0.0	0.0	0.0	0.000			
65	HUDSON6	RESD PEAK	17.0	0.0	0.0	0.0	0.0	0.000			
67	HUDSON7	RESD PEAK	126.0	0.1	0.0	0.0	0.0	0.000			
69	HUDSON10	RESD PEAK	40.0	0.0	0.0	0.0	0.0	0.000			

UNIT TOTALS FOR 1990

UNIT INDEX	UNIT NAME	UNIT NAME	TOTAL CAPACITY	TOTAL EXPECTED ENERGY (MWHS)	FUEL COST ($M)	VARIABLE O&M COST ($MW)	TOTAL COST ($M)	TOTAL CAPACITY FACTOR	ENERGY TO STORAGE AND SALES (MWH)	CAPACITY FACTOR AFTER STORAGE AND SALES	EFFECTIVE CAPACITY MW	%
70	74TH-9	RSID INTR	58.0	25.5	0.0	0.0	0.0	0.000				
71	74TH-10	RSID INTR	58.0	16.6	0.0	0.0	0.0	0.000				
72	74TH-11	RSID INTR	31.0	12.0	0.0	0.0	0.0	0.000				
73	74TH CT	DIST PEAK	34.0	0.0	0.0	0.0	0.0	0.000				
74	59TH-13	RSID INTR	53.0	16.1	0.0	0.0	0.0	0.000				
75	59TH-14	RSID INTR	19.0	6.3	0.0	0.0	0.0	0.000				
76	59TH-15	RSID INTR	20.0	5.6	0.0	0.0	0.0	0.000				
77	59TH CT	DIST PEAK	40.0	0.0	0.0	0.0	0.0	0.000				
78	BUCHANAN	DIST PEAK	20.0	0.0	0.0	0.0	0.0	0.000				
79	KENT CT	DIST PEAK	12.0	0.0	0.0	0.0	0.0	0.000				
82	ARTKILL2	COL2 INTR	335.0	1823639.0	79.0	23.3	102.4	0.621				
85	ARTKILL3	COL2 INTR	461.0	2124611.0	89.3	27.2	116.5	0.526				
87	ARKLCT	DIST PEAK	18.0	0.2	0.0	0.0	0.0	0.000				
88	PEEKSKIL	SLWT INTR	50.0	334682.6	18.3	0.0	18.3	0.764				
9?	HYDQ1S	PRCH BASE	780.0	3004558.0	0.0	125.6	125.6	0.440				
99	HYDQ2S	PRCH INTR	208.0	1014827.1	0.0	76.3	76.3	0.557				
100	HYDQ2W	PRCH INTR	424.0	1521208.0	0.0	114.4	114.4	0.410				
101	ONHY1	PRCH BASE	199.0	1505893.0	0.0	113.3	113.3	0.864				
102	HYDQ3	PRCH BASE	240.0	1946839.0	0.0	146.5	146.5	0.926				
103	ONHY2	PRCH BASE	198.0	1406906.0	0.0	105.8	105.8	0.811				
104	NYPP1	PRCH INTR	300.0	1494829.0	0.0	158.9	158.9	0.569				
105	LILCO	PRCH INTR	500.0	925096.9	0.0	128.9	128.9	0.211				
106	NYPP2	PRCH INTR	800.0	166441.1	0.0	25.0	25.0	0.024				
107	NYPP3	PRCH INTR	1000.0	1230290.0	0.0	171.4	171.4	0.140				
108	PSEG1	PRCH INTR	600.0	6213.0	0.0	1.3	1.3	0.001				
109	PSEG2	PRCH INTR	800.0	1285.6	0.0	0.3	0.3	0.000				
SYSTEM TOTALS				36175712.0	1772.0	1263.9	3035.9	0.281				

UNIT TOTALS FOR 1997

UNIT INDEX	UNIT NAME	UNIT NAME	TOTAL CAPACITY	TOTAL EXPECTED ENERGY (MWHS)	FUEL COST ($M)	VARIABLE O&M COST ($MW)	TOTAL COST ($M)	TOTAL CAPACITY FACTOR	ENERGY TO STORAGE AND SALES (MWH)	CAPACITY FACTOR AFTER STORAGE AND SALES	EFFECTIVE CAPACITY MW %
4	INDPCT	DIST PEAK	72.0	0.4	0.0	0.0	0.0	0.000			
7	RVNSWD 1	COL2 INTR	372.0	1898660.0	170.5	15.4	185.9	0.583			
10	RVNSWD 2	COL2 INTR	370.0	1900571.0	168.7	15.4	184.1	0.586			
13	RVNSWD 3	COL2 INTR	922.0	4234187.0	384.1	34.4	418.5	0.524			
14	RAVCT2	DIST PEAK	239.0	15.8	0.0	0.0	0.0	0.000			
15	RAVCT3	DIST PEAK	126.0	5.7	0.0	0.0	0.0	0.000			
16	RVCT4-11	DIST PEAK	142.0	4.6	0.0	0.0	0.0	0.000			
17	ASTORIA1	RSID INTR	149.0	60520.0	17.3	0.4	17.6	0.046			
18	ASTORIA2	RSID INTR	164.0	60254.0	17.2	0.4	17.6	0.042			
19	ASTORIA3	RSID INTR	387.0	779403.8	192.0	4.7	196.7	0.230			
22	ASTORIA4	RSID INTR	387.0	805745.6	199.2	4.9	204.1	0.238			
25	ASTORIA5	RSID INTR	395.0	569335.7	150.1	3.4	153.5	0.165			
28	ASTORIA6	RSID INTR	825.0	1971437.0	446.7	12.0	458.8	0.273			
29	ASTCT1	DIST PEAK	18.0	13.7	0.0	0.0	0.0	0.000			
30	ASTCT2	DIST PEAK	184.0	110.7	0.1	0.0	0.1	0.000			
31	ASTCT3	DIST PEAK	184.0	77.3	0.0	0.0	0.0	0.000			
32	ASTCT4	DIST PEAK	184.0	61.1	0.0	0.0	0.0	0.000			
33	ASCT5-13	DIST PEAK	172.0	31.6	0.0	0.0	0.0	0.000			
34	BOWLINE1	RSID INTR	401.0	1689992.0	347.6	2.3	349.9	0.481			
35	BOWLINE2	RSID INTR	400.0	1938218.0	398.3	2.6	400.9	0.553			
36	ROSETON1	RSD2 INTR	240.0	1373668.0	220.6	1.3	221.9	0.653			
37	ROSETON2	RSD2 INTR	237.0	1312184.0	211.2	1.2	212.4	0.632			
55	E RIV7	RSID INTR	170.0	72456.1	19.8	1.0	20.8	0.049			
56	NARROWS1	DIST PEAK	184.0	23.5	0.0	0.0	0.0	0.000			
57	NARROWS2	DIST PEAK	184.0	16.4	0.0	0.0	0.0	0.000			
58	GWNUSCT1	DIST PEAK	174.0	3.5	0.0	0.0	0.0	0.000			
59	GWNUSCT2	DIST PEAK	186.0	2.4	0.0	0.0	0.0	0.000			
60	GWNUSCT3	DIST PEAK	167.0	1.6	0.0	0.0	0.0	0.000			
61	GWNISCT4	DIST PEAK	142.0	0.9	0.0	0.0	0.0	0.000			
62	HUDCT1-5	DIST PEAK	83.0	0.4	0.0	0.0	0.0	0.000			
65	HUDSON6	RESD PEAK	17.0	0.1	0.0	0.0	0.0	0.000			
70	74TH-9	RSID INTR	58.0	1758.8	0.7	0.1	0.7	0.003			
71	74TH-10	RSID INTR	58.0	1082.0	0.4	0.0	0.4	0.002			
72	74TH-11	RSID INTR	31.0	837.7	0.3	0.0	0.3	0.003			
73	74TH CT	DIST PEAK	34.0	0.1	0.0	0.0	0.0	0.000			
75	59TH-14	RSID INTR	19.0	16.3	0.0	0.0	0.0	0.000			
76	59TH-15	RSID INTR	20.0	14.4	0.0	0.0	0.0	0.000			

UNIT TOTALS FOR 1997

UNIT INDEX	UNIT NAME	UNIT NAME	TOTAL CAPACITY	TOTAL EXPECTED ENERGY (MWHS)	FUEL COST ($M)	VARIABLE O&M COST ($MW)	TOTAL COST ($M)	TOTAL CAPACITY FACTOR	ENERGY TO STORAGE AND SALES (MWH)	CAPACITY FACTOR AFTER STORAGE AND SALES	EFFECTIVE CAPACITY MW	%
77	59TH CT	DIST PEAK	40.0	0.2	0.0	0.0	0.0	0.000				
78	BUCHANAN	DIST PEAK	20.0	0.1	0.0	0.0	0.0	0.000				
79	KENT CT	DIST PEAK	12.0	0.0	0.0	0.0	0.0	0.000				
82	ARTKILL2	COL2 INTR	335.0	1821781.0	144.4	44.4	188.7	0.621				
85	ARTKILL3	COL2 INTR	461.0	2124385.0	163.2	51.8	215.0	0.526				
87	ARKLCT	DIST PEAK	18.0	0.1	0.0	0.0	0.0	0.000				
88	PEEKSKIL	SLWT INTR	50.0	334789.2	33.5	0.0	33.5	0.764				
98	HYDQ1S	PRCH BASE	780.0	3004558.0	0.0	244.7	244.7	0.440				
99	HYDQ2S	PRCH INTR	208.0	1008238.4	0.0	143.2	143.2	0.553				
100	HYDQ2W	PRCH INTR	424.0	1520918.0	0.0	216.0	216.0	0.409				
101	ONHY1	PRCH BASE	199.0	1494032.0	0.0	212.2	212.2	0.857				
102	HYDQ3	PRCH BASE	240.0	1923122.0	0.0	273.1	273.1	0.915				
103	ONHY2	PRCH BASE	198.0	1382249.0	0.0	196.3	196.3	0.797				
104	NYPP1	PRCH INTR	300.0	1426460.0	0.0	295.5	295.5	0.543				
105	LILCO	PRCH INTR	500.0	951112.1	0.0	258.2	258.2	0.217				
106	NYPP2	PRCH INTR	800.0	146672.1	0.0	42.9	42.9	0.021				
107	NYPP3	PRCH INTR	1000.0	1230142.0	0.0	334.0	334.0	0.140				
108	PSEG1	PRCH INTR	600.0	10306.4	0.0	4.3	4.3	0.002				
109	PSEG2	PRCH INTR	800.0	2302.0	0.0	1.0	1.0	0.000				
SYSTEM TOTALS				37051712.0	3285.9	2417.1	5702.9	0.296				

UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

ATOMIC SAFETY AND LICENSING BOARD

Before Administrative Judges:
James P. Gleason, Chairman
Frederic J. Shon
Dr. Oscar H. Paris

In the Matter of CONSOLIDATED EDISON COMPANY OF NEW YORK, INC. (Indian Point, Unit No. 2) POWER AUTHORITY OF THE STATE OF NEW YORK (Indian Point, Unit No. 3)	Docket Nos. 50-247 SP 50-286 SP April 12, 1983

CERTIFICATE OF SERVICE

I hereby certify that copies of "Testimony of Greater New York Council on Energy Witness Richard A. Rosen on Commission Question 6.3" have been served on all parties on the service list in the above-captioned proceeding by deposit in the U.S. mail, first class, this 12th day of April, 1983.

DRC

Dean R. Corren
Director, GNYCE

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