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Financing Strategies for Nuclear Power Plant Decommissioning

New England Conference of Public Utilities Commissioners, Inc.

Temple, Barker & Sloane, Inc.

Prepared for
U.S. Nuclear Regulatory
Commission

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ABSTRACT

The report analyzes several alternatives for financing the decommissioning of nuclear power plants from the point of view of assurance, cost, equity, and other criteria. Sensitivity analyses are performed on several important variables and possible impacts on representative companies' rates are discussed and illustrated.

EXECUTIVE SUMMARY

The choice of a strategy for financing the decommissioning of a nuclear power plant involves a balance between cost and risk. No financing alternative clearly emerges as the optimal choice.

Delaying the financing until decommissioning is the strategy with the lowest cost to consumers and investors. It also poses the highest risk that funding will not be available when required. This risk arises from the possibility of utility insolvency caused by a serious nuclear accident and from the difficulty of predicting the financial condition of the utility over a long time period.

These risks can be avoided by obtaining and securing the required funds at the beginning of the plant's life. Under most reasonable assumptions, funding at commissioning is considerably more expensive, however, than funding at decommissioning--perhaps three times more costly to consumers.

A sinking fund is a compromise alternative. It is approximately twice as expensive as the least expensive alternative but provides assurance that at least part of the funding will be available.

Although there is significant variation in cost among financing alternatives, the impact of decommissioning on consumer bills is small, typically less than 1 percent.

Ratemaking and tax treatment issues affect the cost of the alternatives but not significantly enough to change the above conclusions. Furthermore, consideration of equity implications, institutional barriers, and jurisdictional differences should not preclude any alternatives. Finally, interest and inflation rates can have significant impacts on both the absolute and relative costs of the alternative financing strategies.

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I. INTRODUCTION

This study by Temple, Barker & Sloane, Inc. (TBS) for the New England Conference of Public Utilities Commissioners (NEC/PUC) addresses the financial aspects of nuclear power plant decommissioning. The study's objective is to evaluate alternative financing and ratemaking strategies in light of the multiple, and sometimes conflicting, criteria of financial assurance, cost, equity, and legal and institutional feasibility.

Nuclear decommissioning is the process by which a nuclear power plant is taken out of service at the end of the plant's useful life and its radioactive material disposed of. Although all types of power plants are decommissioned, nuclear plants present a more technically difficult and expensive problem because of the residual radioactivity in the plant's structures and components. Proper decommissioning of nuclear plants is necessary to protect public health and prevent environmental damage.

The electric utility industry's experience with nuclear decommissioning is limited due to the small number of reactors which have been decommissioned. To date, barely a dozen facilities have been decommissioned, and these have been primarily small-scale experimental facilities. None of the large-scale, commercial reactors which are now common in the industry has yet been decommissioned.

One result of this lack of experience is considerable uncertainty regarding the technology of decommissioning. Several alternatives are being considered and studied, including dismantlement of the facility, placing the facility in safe storage followed at some later time by dismantlement, and entombment of the facility. Dismantlement would return the site to its original state. All materials would be transported to final disposal areas. Placing the facility in safe storage is usually viewed as a temporary measure until most radioactivity contained in the structures and components decays sufficiently to permit dismantlement. Placing the facility in safe storage involves removing fuel rods and radioactive liquids and keeping the facility intact and under guard. Entombment involves making the plant more physically secure, perhaps by encasing buildings in concrete.

Technical uncertainty is accompanied by cost uncertainty, although the costs are known to be large. Estimates range from \$38 to \$97 million for a commercial 1,000 mw reactor in 1978 dollars.[1] These costs are uncertain both because of unresolved technical issues and the timing of the decommissioning. Under one plausible scenario, a plant would be placed in safe storage for 100 years and then finally dismantled. It is extremely difficult to make either technical or economic projections over such a long period.

Numerous studies have been performed in both technical and economic areas to resolve some of the uncertainties. Several of the economic and financial studies were reviewed by TBS in another report, A Review of Methodologies for Analyzing Nuclear Decommissioning Financing, which was done under the same contract as this report.

This study goes beyond the scope of earlier ones by focusing on two important characteristics of nuclear decommissioning financing: cost and risk. Cost differences among financing strategies result primarily from differences between the utilities' cost of capital and the rate of return which they can earn on external investments. The timing of financing, the choice of amortization schedule, ratemaking treatment, and tax policies also affect cost. The risk of concern to regulators is whether funds will be available for decommissioning considering the difficulty of predicting the financial position of the utility over an extended period of time. In addition, there exists the attendant possibility of premature decommissioning caused by a serious nuclear accident or other unforeseen financial stresses.

These two characteristics, cost and risk, are in conflict. No single financing alternative emerges as dominant on both the risk and cost criteria. The policy maker must choose a financing strategy based on his tradeoffs between cost and risk.

The motivation for this study is to assist the current investigation by the Nuclear Regulatory Commission (NRC) of all aspects of decommissioning. Regulations will likely be promulgated to cover both the technology and the financing of decommissioning.

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[1] McLeod, N. Barrie and R. John Stouky; Factors Affecting Nuclear Power Generating Station Decommissioning Options and Decommissioning Cost Recovery; NUS Corporation, September 1979.

The study presents case studies of two New England utilities, although the conclusions are applicable to national policy. New England was selected because of the unique diversity of the institutional arrangements surrounding its nuclear plants. These institutional factors must be included in a complete financial and economic examination of alternative financing strategies.

The report is organized into five chapters, the first being introductory. The second discusses TBS's approach to decommissioning analysis and identifies the numerous alternatives for nuclear decommissioning financing and ratemaking. The following chapter describes the methodology used for the New England case studies. The fourth chapter presents the findings, and the final chapter summarizes the major conclusions of the study. Two appendices provide further background on the utility financial model used in the analysis and on the major assumptions embodied in the cases.

II. ALTERNATIVES FOR NUCLEAR DECOMMISSIONING FINANCING AND RATEMAKING

TBS's approach separates the analysis of nuclear decommissioning into technical, financial, and rate portions. This chapter describes the study approach and identifies the financing alternatives and the related rate issues which affect the financial analysis.

SEPARATION OF TECHNICAL, FINANCIAL, AND RATEMAKING ANALYSES

A plan for decommissioning a nuclear power plant involves several separate but related actions. These include:

- Selection of a technical plan for decommissioning the plant;
- Financing the decommissioning costs; and
- Incorporating these costs into electricity rates.

The timing of these actions is somewhat flexible. Timing is, in fact, one of the primary concerns of this report because it affects cost, risk, and equity.

The choice of a technical decommissioning plan can be made prior to plant construction, but the plan can be revised at any time prior to the end of the plant's life. The choice of options can actually be delayed indefinitely if the option of placing the facility in safe storage is chosen.

The financing of decommissioning can be done at any time prior to the physical decommissioning and after the costs have been estimated from the technical plan. The financing problem is to make sufficient funds available to cover costs by the time the costs are incurred. While the choice of a technical alternative will determine the amount of financing required, it does not affect the choice of financing strategy. The financing strategy should be decided upon before the start-up of the plant, regardless of the final choice.

In order to separate fully the technical and financial decisions, the financing is assumed to be complete by the end of the plant's useful life. At that time a liquid fund (e.g., a bank account or stock portfolio) is established which is sufficient to cover all decommissioning costs. If decommissioning is not completed immediately after the plant closes, the amount of the fund must take into account the future interest earned on the fund and the inflation in decommissioning costs. (If forecasts of interest and inflation are not perfect, some residual adjustments may be required after plant closing, but this amount should be small relative to the total required financing.) This separation of technical and financial decisions allows the choice of financing strategy to be independent of the technical assessment because the technical choice affects only the size of the final fund and has no effect on the relative merits of financing strategies.

Financing can also be separated from the incorporation of the costs into rates. For example, in one possible scenario, all of the funds for decommissioning are raised at the beginning of the plant's life, but the costs are included in rates over the entire operating period of the unit. This financing strategy is intended to minimize risk by keeping funds available for decommissioning throughout the plant's life, and the rate treatment is consistent with the regulatory principle of matching electricity rates with the period in which the plant is used and useful. Allowance for funds during construction is an example of financing during one period, the construction phase, and rate impacts in another, the plant's operating life.

Financing and ratemaking are separable in time, but they affect each other in quantity. On the one hand, the amount and timing of financing affect the amount of the rate increase. On the other hand, alternative rate treatments affect the level of rate increases and thus the desirability of alternative financing strategies.

FINANCING ALTERNATIVES

As discussed above, the financing of the decommissioning cost can occur at any time before decommissioning. Furthermore, this report assumes that the financing is complete by the end of the plant's life in order to divorce the financing from the timing of the physical decommissioning.

Three financing alternatives are examined in this report: funding at commissioning, sinking fund, and funding at decommissioning using amortization of a negative salvage value. They are characterized by differences in timing, and they yield different costs and risks.

In the first strategy, funding at commissioning, the utility raises funds by selling a combination of stocks and bonds at the beginning of the plant's life. These funds are segregated from other utility accounts into a trust fund and invested in low-risk liquid assets, e.g., government bonds, where they remain and accrue interest until needed for decommissioning.

A second approach, a sinking fund, involves the gradual accumulation of funds in a similar trust fund. Each year the utility collects additional revenues, issues additional securities, and contributes the proceeds to the trust fund. The trust therefore increases by the accrued interest as well as the annual utility contributions.

The third approach, funding at decommissioning, allows the utility to wait until the end of the plant's life to finance decommissioning. Although the utility collects decommissioning amortization each year based on the plant's negative salvage value, revenues received from customers for decommissioning during the plant's life are not isolated. The funds are treated as a source of internal funds and can be used by the utility for other, unrelated projects.

It is important to realize that each of these options is designed to raise the same amount of money by the last year of plant operation. This amount equals the total funding required to pay for all of the costs of placing the facility in safe storage, entombing, and/or dismantling the plant at some time after plant closure.

While the nominal future value of the three funding options will be the same, the net present value will not be the same because of the different cash flow streams. Funding at commissioning will have the highest net present value, largely due to the difference between the rate of return the utility can earn on an investment and the rate it must pay for borrowed funds. The return that the utility must pay is higher for two reasons. First, the decommissioning fund should be invested in low-risk, lower-return assets such as government or high quality corporate bonds. Second, part (typically half) of the utility's cost of capital is in common and preferred stock whose dividend payments are not tax deductible. The utility will therefore have to raise more money initially because the value of the fund will decrease in real terms over time. This alternative has the lowest risk, however, because the full amount of decommissioning is always available in a liquid fund.

Funding at decommissioning, on the other hand, has the lowest net present value. The utility will raise money from customers over the life of the plant (consistent with the matching principle mentioned earlier) and will use these funds to reduce its external financing requirements. With funding at decommissioning, consumers, in effect, lend the utility money and pay lower electricity rates than with funding at commissioning due to the utility's reduced financing costs. When the time for decommissioning arrives, the utility must raise the full amount through traditional means. The financial security of this option is based on the financing ability of the utility at some distant future time. Funding at decommissioning is riskier because of the uncertain financial status or even the uncertain existence of the utility 30 years in the future. In the case of a serious financial or technical problem leading to premature decommissioning, financing will probably be more difficult or at best, more expensive if a trust fund does not exist.

There are a number of critical parameters which affect the desirability of these financing alternatives. These include economic parameters such as interest and inflation rates. The discount rate used to evaluate the results is also important. Finally, the manner in which financing costs are incorporated into rates affects costs.

RATEMAKING ALTERNATIVES

Ratemaking policies will affect the costs to consumers of the financing alternatives. These policies are therefore important in the financing decision.

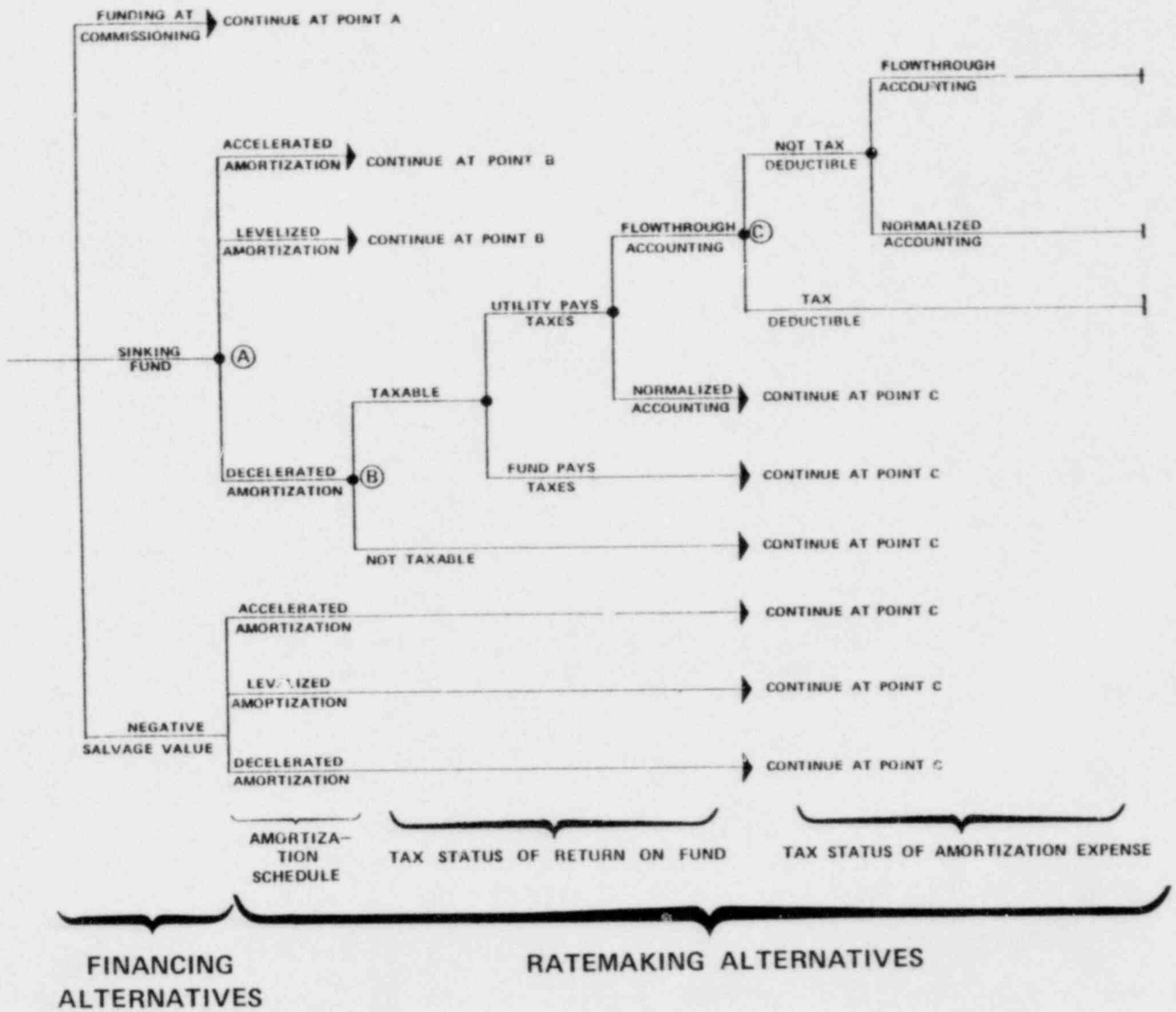
Rate treatment also is the major determinant of the fairness or equity of each alternative. There are two principles of equity involved. First, accepted regulatory accounting principles attempt to match rates with benefits. This implies that only those customers who receive the benefits of the nuclear plant should pay for the costs. Second, the beneficiaries should pay in proportion to the benefits received. This second tenet, much less widely accepted, implies that the incremental cost of a kilowatt-hour should be constant over time in constant dollars.

The relevant ratemaking issues fall into three categories:

- The decommissioning amortization schedule;
- The tax status of the return on the fund; and
- The tax status of the amortization expense.

Figure II–1

DECOMMISSIONING FINANCING ALTERNATIVES



Each of these issues alone can lead to several alternative policies. In combination with the three financing strategies, almost 100 combination financing/rate strategies become possible. (Figure II-1 illustrates these combinations.) The three rate issues are discussed below.

Decommissioning Amortization Schedules

Amortization is the amount of money collected from consumers each year for decommissioning. Similar to the depreciation of physical assets, amortization allows the utility to recover a large cost over time.

Just as there is more than one accepted method of computing depreciation, numerous amortization schedules are possible. The three general patterns are accelerated, straightline, and decelerated schedules. Accelerated schedules have larger payments in earlier years than in later years, and decelerated schedules are the reverse. A straightline schedule refers to a constant amortization amount each year.

Straightline amortization was selected for the case studies as the most likely alternative because it conforms with the convention of straightline depreciation of physical assets for rate purposes. As will be seen later, however, straightline amortization may not be the most desirable approach, so other options are also examined.

This report also assumes that the appropriate period over which to amortize decommissioning costs is the operating life of the plant or, for existing plants, the remaining life. Amortization over the entire plant life provides the greatest likelihood that all beneficiaries of the plant will share in the costs of decommissioning. In the cases where a plant has been operating for some time, the question of whether the uncollected amount accruing from the earlier period can be collected from present and future customers is one to be ultimately decided by regulatory commissions.

Tax Status of Return on the Fund

In two of the three selected financing strategies, funding at commissioning and sinking fund, a liquid reserve is accumulated and presumably is invested in a return-bearing asset. In this study, it is assumed that the investment is in financial assets which have low risk, such as government or high-quality corporate bonds, because a major purpose of the fund is to minimize risk. Sensitivity analysis is performed to determine the effects of investments in riskier assets.

An important issue regarding the form of the investment is the tax status of the return on the fund. If the fund is invested in certain types of government bonds, interest on the fund is tax-free. If invested in most securities, the return will be taxed under current tax law. In this case, taxes may be paid by the fund itself or by the utility, and, if by the utility, the taxes can be either flowed through or normalized.[2]

There are two alternatives for eliminating or significantly reducing taxes and thus decreasing the cost of decommissioning. The first is the establishment of a state controlled fund which would not be liable for federal taxation under current regulations. This type of fund would have to be established by state legislatures in accordance with IRS guidelines. The second alternative is investment of the fund in dividend bearing securities such as preferred stock. Current tax law provides that only 15 percent of the dividend income is taxable. While financially attractive, this strategy is riskier because of the stock price uncertainty.

The analysis in this report is based on the assumption that funds are invested in tax-free government bonds. This is roughly equivalent to the case where the return is not tax-free, but the taxes are paid by the fund, because yields from high-quality government bonds are almost equivalent to the after-tax yield from corporate bonds when the marginal tax rate is 46 percent. Investment in government bonds was selected over other strategies because of its simplicity and low financial risk. A tax-free, state controlled fund was not selected because it requires legislative action.

Tax Status of the Amortization Expense

The final issue to be considered is the tax status of the amortization expense. Under current tax law, the cost of decommissioning must be deducted as a current expense in the year or years incurred. It cannot be amortized for tax purposes over the life of the plant as it can for rate purposes.

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[2]Flowthrough and normalization refer to alternative timing strategies for incorporating costs into rates. With flowthrough, consumers pay for the utility's actual tax liability in each year. Actual taxes will increase steadily over time as the fund and its income grow, so normalization could be used to make the rate impact level.

The current tax law leads to an inequitable situation unless tax normalization is used. The inequity occurs because non-beneficiaries of the plant receive a large tax deduction when the plant is actually decommissioned--perhaps decades after the plant closes. Normalization would remedy this by charging the beneficiaries for taxes as if the amortization were deductible, and non-beneficiaries would not receive the benefit of the large deduction when decommissioning actually occurs.

Normalization may not entirely correct the inequity if the utility is unable to use the tax deduction in the actual year of decommissioning. As will be seen in a later case study, the single-plant Yankee companies in New England will have no electricity revenues against which to offset the deduction.

While the amortization of decommissioning costs is not tax deductible under current tax law, it may be possible under certain circumstances to claim as deductible payments to an external decommissioning fund. The Internal Revenue Service has indicated to NRC that case-specific revenue rulings would be required.[3] This study therefore examines the effects of tax deductible amortization for the two external fund cases: funding at commissioning and sinking fund.

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[3]Wood, Robert S., Assuring the Availability of Funds for Nuclear Facilities, unpublished paper, July 1979, p. 14.

III. METHODOLOGY

This analysis uses a case study approach. Complete financial projections were prepared for two New England utilities for a number of scenarios. The projections were made with TBS's utility financial model.

This chapter describes the methodology and two cases used in the study. Appendix A contains a more detailed description of the financial model, and Appendix B lists the major assumptions involved in the projections.

GENERAL APPROACH

The methodological approach can be characterized as incremental analysis of total-company projections. A computer model is used to prepare for each scenario a complete set of pro forma financial projections: balance sheets, income statements, and sources and uses of funds statements. Comparison of these alternative projections identifies the effects of alternative policies or events.

The preparation of total-company projections is important for two reasons. First, it allows a more accurate assessment of a particular policy in light of all other factors affecting the company. This is central to the concept of a case study. Second, it allows computation not only of the absolute impact of a given policy but also of the impact relative to a base case.

The relevant base case represents the state of the world in which nuclear decommissioning cost is not considered. This case, projected in this study for 40 years, must include forecasts of interest and inflation rates, electricity growth rates, and capital costs and construction plans. These data are, of course, difficult to forecast for 40 years, but any reasonable assumption can provide a suitable baseline against which to measure alternative decommissioning strategies. Appendix B discusses the major assumptions of the projections.

CASE DESCRIPTIONS

Two New England utilities were chosen as cases: Northeast Utilities and Maine Yankee. These two represent diverse forms of plant ownership: joint ownership by members of a holding company, sole ownership by one operating company, and joint ownership by several utilities through a stock company. They also represent both regulation in a single jurisdiction as well as multiple jurisdictions. Finally, they allow analysis of companies both with a single plant and with multiple units.

Northeast Utilities

Northeast Utilities (NU) is a holding company which services portions of Connecticut and Massachusetts through four operating subsidiaries:

- Connecticut Light and Power Company (CL&P);
- Hartford Electric Light Company (HELCO);
- Western Massachusetts Electric Company (WMECO); and
- Holyoke Water Power Company (HW[illegible].

Two of these subsidiaries, CL&P and HELCO, operate entirely in Connecticut, and the other two, WMECO and HWP, operate solely in Massachusetts. Approximately 80 percent of NU's operations are in Connecticut and 20 percent in Massachusetts.

With almost three million customers and 5,855 megawatts of generating capacity, NU is one of the largest utilities in the industry. By the end of 1978, NU's electric operating revenues were $834 million and its gross plant value was $3.1 billion. External financing requirements have averaged over $1[illegible]0 million in the last five years.[4]

Northeast Utilities currently owns and operates one of its own nuclear stations: the Millstone Station. Two units are in operation at Millstone, and a third is under construction. This station represents 28 percent of NU's generating capacity,

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[4] All data were obtained from the Uniform Statistical Report, an annual report by Northeast Utilities to the Edison Electric Institute.

and this figure will rise to 34 percent when Millstone 3 is completed. Table III-1 provides further background on the three units.

Table III-1

MILLSTONE STATION STATISTICS

Unit	Commis-sioning Date	Capacity (mw)	Percent Ownership			
			CL&P	HELCO	WMECO	HWP
1	1971	660	53	28	19	0
2	1976	812	53	28	19	0
3	1986*	1,150	35	18	12	0

*Estimated completion date.

Source: Uniform Statistical Report, 1978, and communication from Northeast Utilities.

NU also owns portions of several nuclear generating companies in New England through ownership in the Yankee operating companies. These companies are one-plant entities which are totally owned by other New England operating companies. NU's ownership in the Yankees, shown in Table III-2, represents 519 mw of capacity. In 1978, the Yankee companies supplied 17 percent of NU's total generation.

Table III-2

YANKEE STATISTICS

Unit	Commis-sioning Date	Capacity (mw)	Percent Ownership				
			CL&P	HELCO	WMECO	HWP	NU
Connecticut Yankee	1968	600	25.0	9.5	9.5	0	44.0
Maine Yankee	1972	829	8.0	4.0	3.0	0	15.0
Massachusetts Yankee	1960	185	15.0	9.5	7.0	0	31.5
Vermont Yankee	1972	563	6.0	3.5	2.5	0	12.0

Source: Exhibit 43, "Stockholder Companies and Percent Ownership of Nuclear Generating Companies in New England," FERC Docket No. ER78-360; The Statistics of Privately Owned Electric Utilities in the United States; and Maine Yankee's USR.

For the purposes of this case study, only decommissioning costs for the three Millstone units were examined; Yankee decommissioning costs are ignored. This approach recognizes that NU will probably provide for the Yankees' decommissioning costs by paying increased rates for electricity purchased from the Yankee companies.

The siting of all three Millstone units at one site may affect the technical decommissioning plan because the company will attempt to avoid large-scale construction or demolition activities at one unit while other units are still running. As discussed earlier, however, the financial analysis can be performed separately from the technical assessment. All units are assumed to have the same decommissioning costs in constant dollars, and the decommissioning fund for each unit is established by the end of its operating life.

Maine Yankee

The Maine Yankee Atomic Power Company owns and operates an 829 mw nuclear plant in Wiscasset, Maine. The company was incorporated in 1966 by 11 investor-owned utilities in New England. The sponsoring companies and their ownership are displayed in Table III-3.

Table III-3

OWNERSHIP IN MAINE YANKEE

Utility	Percent Ownership*
Central Maine Power Company	38
New England Power Company	20
Connecticut Light & Power Company	8
Bangor Hydro-Electric Company	7
Maine Public Service Company	5
Public Service Company of New Hampshire	5
Cambridge Electric Light Company	4
Montaup Electric Company	4
Hartford Electric Light Company	4
Western Massachusetts Electric Company	3
Central Vermont Public Service Corporation	2
	100

*Based on common stock ownership.

Source: 1978 Uniform Statistical Report.

In 1978, Maine Yankee's operating revenues were $70.4 million. The company's rates are solely under the jurisdiction of the Federal Energy Regulatory Commission because all of its power sales are at wholesale and in interstate commerce.

The financial arrangements of the company are largely determined by two agreements signed by the sponsoring utilities. The Power Contract requires each utility to purchase a portion of the plant's output and cover the plant's costs in proportion to its ownership share. Costs include fuel, operating costs, interest charges, and a return on common equity. The operating costs include a depreciation charge based on a 30-year plant life. The other agreement, the Capital Funds Agreement, requires the sponsors to provide the company's capital requirements not obtainable from other sources. This Agreement presumably covers capital expenditures associated with plant operations. Whether decommissioning falls within the purview of the Agreement is a legal question beyond the scope of this report.

Maine Yankee was selected as a case because of its unusual ownership arrangement. Any financing requirements determined by NRC should pertain to the Yankee companies as well as to ongoing investor-owned utilities.

IV. FINDINGS

This chapter presents the quantitative and qualitative findings of the study. Although cost and financial assurance (risk) are the primary evaluation criteria, equity and flexibility are also important. The chapter is organized around these four evaluation criteria.

The primary focus is on the three financing strategies discussed in Chapter II: funding at commissioning, sinking fund, and funding at decommissioning. For each financing strategy, at least one scenario is examined which includes straightline amortization, investment of the fund in tax-free bonds, and straight line normalization of the decommissioning tax deduction. This ratemaking treatment provides a reasonable and consistent basis for comparing the three financing strategies. Where most appropriate, other scenarios are also analyzed.

Results are presented for both case studies: Northeast Utilities and Maine Yankee. Most of the results are presented for the Connecticut-only portion of Northeast Utilities, designated NU/Connecticut in this report. This consolidation of CL&P and HELCO represents a company with operations totally within a single state. Unless otherwise stated, all NU results pertain to NU/Connecticut.

COST

In this study the cost of a decommissioning financing alternative is defined as the incremental revenue requirements imposed on utility customers. Incremental revenue requirements are determined by changes in ratebase, financing costs, and operating costs.

On the basis of the net present value of revenue requirements, a good measure of cost to consumers, funding at commissioning is the most expensive option, and funding at decommissioning is the least expensive. Results are presented in Table IV-1 for a discount rate of 9.4 percent--the decommissioning inflation rate plus 2 percent.[5] Funding at commissioning is approximately three times and sinking fund twice as expensive as funding at decommissioning under the assumption used.

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[5]A real discount rate of 2 percent was chosen as the approximate, historical real interest rate. See Wood, Robert S., op. cit., p. 24.

Table IV-1

NET PRESENT VALUE
OF REVENUE REQUIREMENTS

	Millions of Dollars	Percent Increase Over Baseline
Baseline	$39,528	-
Incremental Impacts of:		
Funding at Commissioning	283	0.72%
Sinking Fund	186	0.47
Funding at Decommissioning	91	0.23

Incremental revenue requirements can be interpreted as the average rate increase to electricity customers. While this measure disregards all issues related to rate design, the percentage increase in revenue requirements approximates the increase in a customer's total bill.

It can be seen in Table IV-1 that the increase in consumers' bills due to nuclear decommissioning is not large under any strategy, ranging between 0.2 and 0.7 percent for the utility studied. (This range is naturally sensitive to the assumed $50 million decommissioning cost and the utility's fuel mix.) As will be discussed later regarding equity, however, the magnitude of the rate impact varies over time.

While the ranking of the three alternatives is not affected by the choice of discount rate, the magnitude of the cost difference decreases at high discount rates. Figure IV-1 illustrates the change in cost for different discount rates. The lowest reasonable discount rate is 7.4 percent, the assumed rate of inflation for decommissioning costs. This rate is effectively a zero real discount rate.

Sensitivity to Interest and Inflation Rates

Given the 40-year horizon of this study, it is certainly proper to question the sensitivity of the results to changes in interest and inflation rates. There are three areas in this analysis where these rates are important: the return on the decommissioning fund, the inflation rate of decommissioning costs, and the utility's cost of capital.

Figure IV-1

SENSITIVITY ANALYSIS ON DISCOUNT RATES

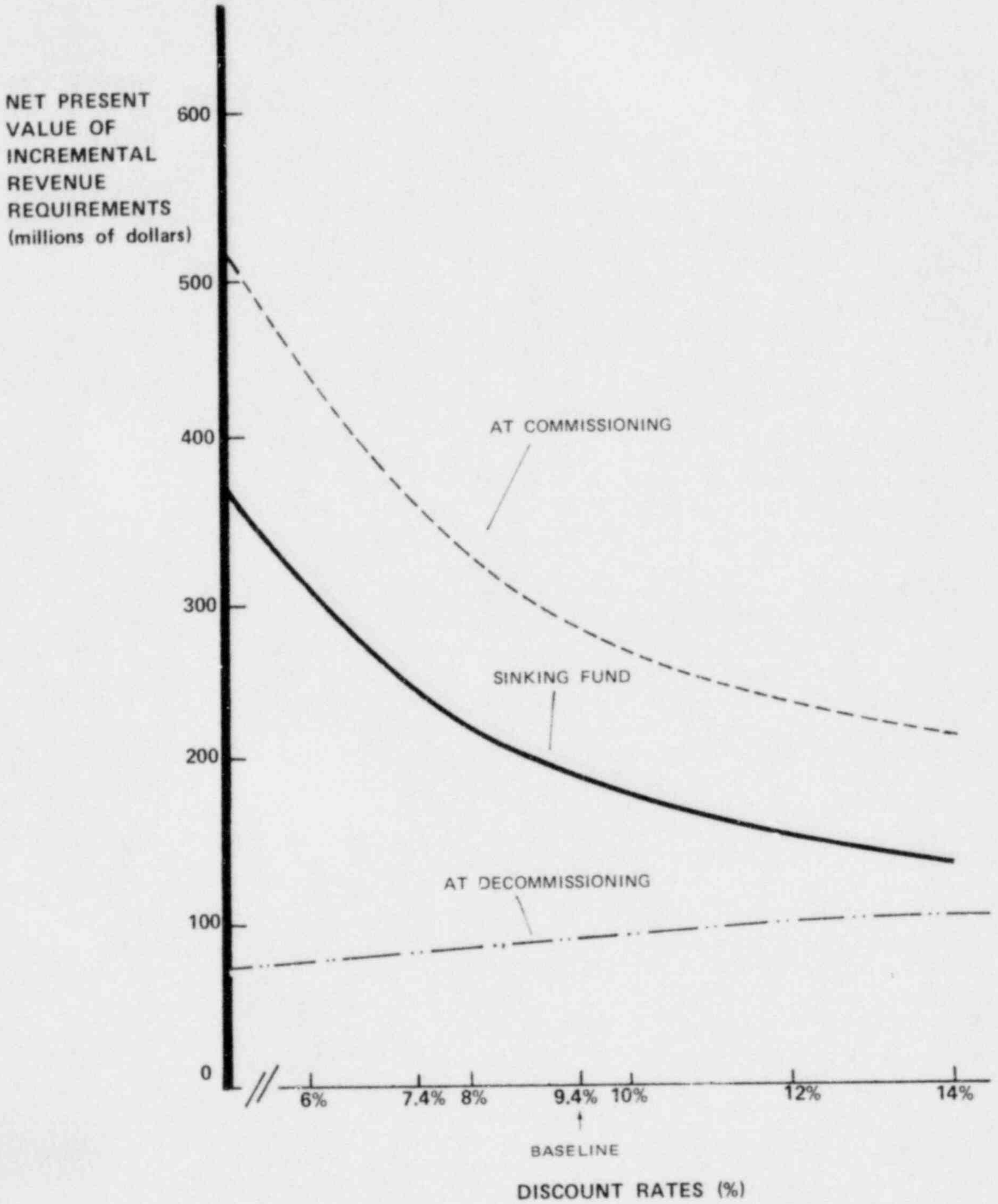

Figure IV-2 shows the effects of changing the rate of return (after taxes) on the decommissioning fund, all other parameters held constant.[6] At reasonable, risk-averse rates, there is no change in the ranking of the alternatives, although the relative impacts narrow at high rates of return. This is due to the fact that the funding at decommissioning option is unchanged because there is no liquid fund, but the two funded options decrease in cost if the fund is invested in higher return assets. At a sufficiently high rate, the three options actually reverse rank. This seems unlikely because such a high return asset would also normally reflect high risk. The after-tax return which reverses the ranking of the decommissioning alternatives is higher than the rate of inflation, and these returns are historically associated with risky investments. As discussed earlier, the most likely means of achieving such high returns would be investment in dividend-bearing stocks or the establishment of a tax-exempt state controlled fund.

Sensitivity analysis was also performed on the rate of inflation for decommissioning costs. The study assumed 7.4 percent for the entire 40-year study horizon, approximately 1.4 percent higher than the projected GNP deflator. Figure IV-3 illustrates the effects of changing the inflation rate for decommissioning costs. The cost of all strategies increases with the inflation rate because a larger sum must be raised in all years.

Finally, the costs of decommissioning are affected by the company's own costs for new capital, although the ranking remains unchanged. With funding at commissioning, increased costs of capital further aggravate the situation where the company borrows at a high rate and invests at a low rate. As can be seen in Table IV-2, increasing the cost of capital increases the cost of this option from $283 million to $388 million. If the discount factor is appropriately increased, however, the discounted revenue requirements increase only 4 percent to $294 million. Funding at decommissioning presents the opposite results because this option involves collection of funds from consumers before the decommissioning fund is established. Since the utility has the unrestricted use of the money collected for amortization, external financing requirements decline, and the value of the avoided financing increases with capital costs. With a 12 percent discount factor, the net present value of this option declines 16 percent to $76 million.

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[6] All of our sensitivity analysis is carried out in this manner.

Figure IV-2

SENSITIVITY ANALYSIS ON RATES OF RETURN ON THE DECOMMISSIONING FUND

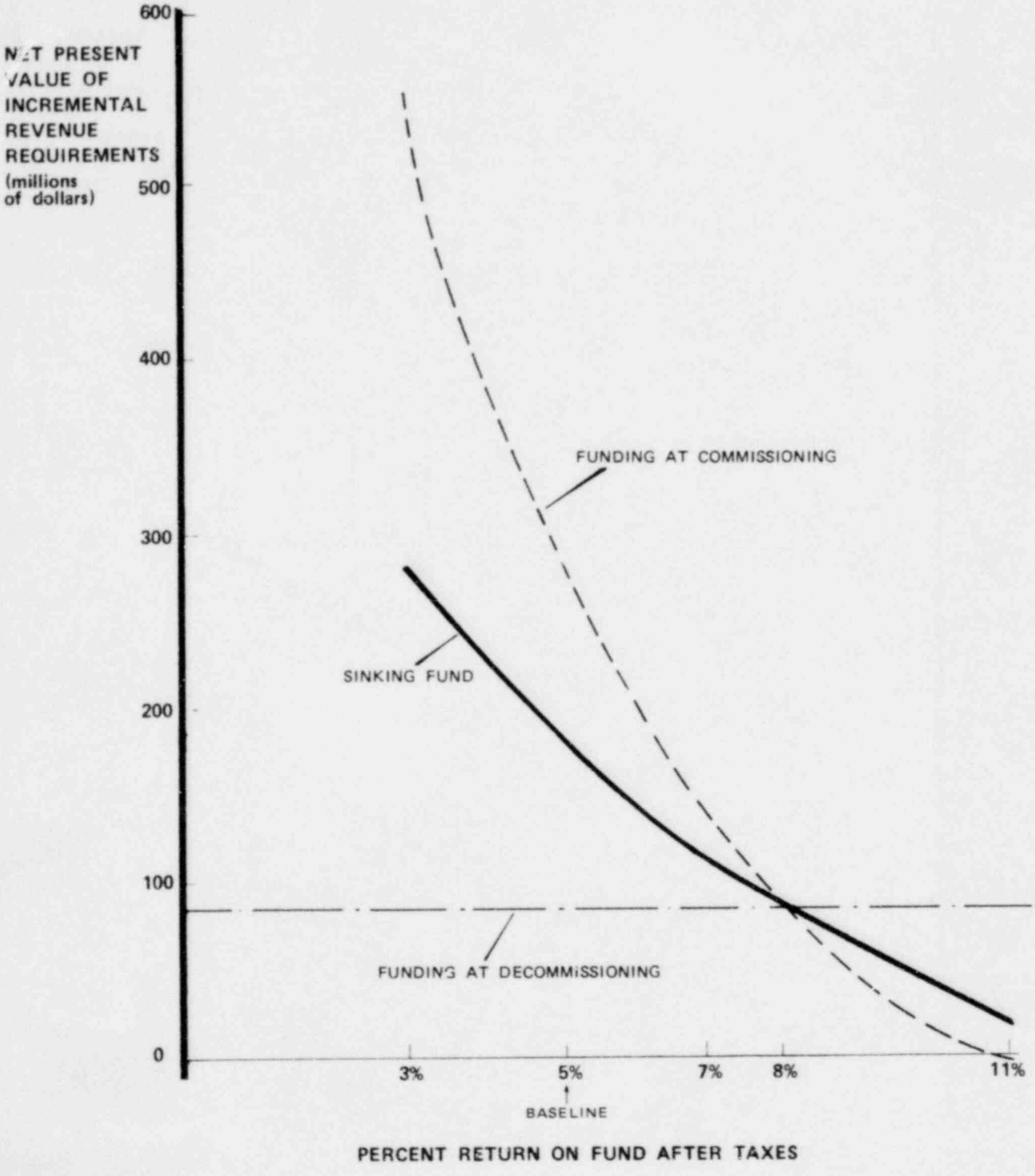

Figure IV-3

SENSITIVITY ANALYSIS ON INFLATION RATES

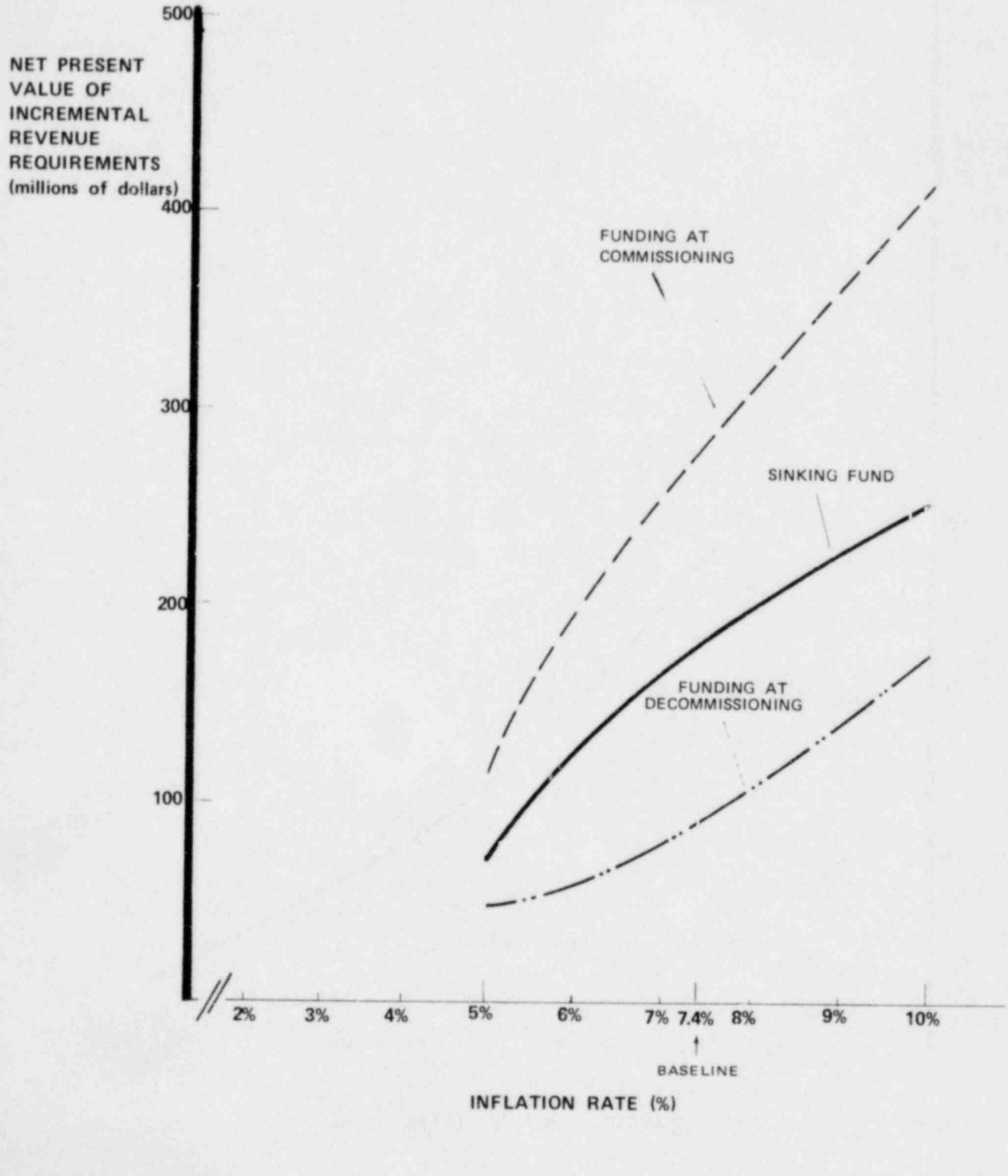

Table IV-2

SENSITIVITY ANALYSIS ON THE COST OF CAPITAL TO THE UTILITY

	Net Present Value of Incremental Revenue Streams (millions of dollars)		
	Baseline	High Interest* (discounted at 9.4%)	High Interest* (discounted at 12%)
Funding at Commissioning	283	388	294
Sinking Fund	186	240	165
Funding at Decommissioning	91	68	76

*This scenario assumes a 2 percent rise in the cost of all forms of capital.

To summarize the sensitivity analyses:

- As the rate of return that a utility can earn on external investments increases, the costs of two options, funding at commissioning and sinking fund, decrease. The ranking of the three financing strategies does not change for all reasonable rates of return.

- The costs for all alternatives increase if the inflation rate for decommissioning costs also increases. The ranking of the alternatives does not change, however.

- As the utility's cost of capital increases, the cost increases for funding at commissioning, and the cost decreases for funding at decommissioning. If the discount rate is adjusted, the differences are small.

The preceding sensitivity analyses investigated the effects of an incorrect assumption about a study parameter taken in isolation. In fact, most of these interest and inflation rates move in relative harmony. A much more likely scenario where all interest and inflation rates increase is presented below.

Table IV-3 illustrates the effect of combining all three changes: a high return on the decommissioning fund, increased decommissioning cost inflation, and higher utility cost of capital. The results demonstrate that these changes do indeed compensate for each other. The ranking remains unchanged, although funding at decommissioning loses some cost advantage.

Table IV-3

SENSITIVITY ANALYSIS ON
ALL INTEREST AND INFLATION RATES

	Net Present Value of Incremental Revenue Requirements (millions of dollars)	
	Baseline	High Interest and Inflation*
Funding at Commissioning	?83	295
Sinking Fund	186	202
Funding at Decommissioning	91	154

*This scenario assumes a 7 percent return on the decommissioning fund, 10 percent inflation, and a 2 percent increase in the cost of common, preferred, and debt financing. A discount rate of 12 percent was used.

Sensitivity to Decommissioning Tax Policy

Current tax laws view decommissioning expenses as a negative salvage value. The value of the plant at the end of its useful life is negative because a cost must be incurred to close the plant. This cost is recognized as a tax deduction in the year(s) incurred. Thus, the utility will actually pay greatly reduced taxes in the year(s) of decommissioning, which may not be completed until many years after the plant is shut down.

The tax normalization strategy assumed thus far is intended to reflect more equitably the decommissioning tax deduction in electricity rates over time. While actual taxes paid by the utility will still decrease significantly when the decommissioning occurs, taxes reported for rate purposes reflect the benefit of the large tax deduction spread evenly over the life of the plant. This is referred to as straightline (i.e., equal each year) normalization of the decommissioning tax deduction.

A reasonable alternative to the current tax policy would be to claim as tax deductible each year the contribution ade to the decommissioning reserve. In this case, actual taxes paid decrease each year during the life of the plant, and consumers get the advantage of the actual deduction rather than the normalized deduction.

NRC has investigated the possibility of annual decommissioning deductions with the Internal Revenue Service. While IRS will not make a generic ruling on the issue, utilities may be able to obtain a ruling from IRS on petition. In certain limited situations, the IRS has indicated that it will allow annual deductions for decommissioning expenses. Investor-owned utilities may be eligible for annual deductions if they meet four criteria. (Note that publicly owned utilities are generally exempt from federal income tax.)

> First, all funds collected from customers (or any other source) for decommissioning expense must be immediately segregated from the utility's assets. A utility may collect from its customers by its normal monthly billing procedures and deposit such funds in a blind trust immediately upon collection. In other words, the utility cannot have even short-term use of these funds. In fact, IRS suggested that perhaps a separate decommissioning account be established on a customer's bill. Second, the blind trust itself cannot be reinvested in a utility's assets. If it is desired that earnings from the trust fund themselves are tax-exempt, the fund should be invested in state or municipal tax-exempt securities. Third, the fund must be administered by parties not normally involved with the operations of the utility. A fourth restriction indicated by IRS pertains to when a utility overestimates decommissioning costs. If a state establishes a trust fund that meets the conditions described above, but provides that any excess funds after decommissioning expenses have been paid will be returned to the utility, the IRS has indicated that this provision would probably jeopardize the tax-exempt status of the fund.[7]

The funding at commissioning and sinking fund alternatives may be able to meet the criteria identified above. Table IV-4 presents the impacts of making tax deductible contributions to the decommissioning reserve each year for these two financing strategies. The ranking of the alternatives does not change.

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[7] Wood, Robert S., op. cit., p. 15.

Table IV-4

SENSITIVITY ANALYSIS ON TAX STATUS
OF DECOMMISSIONING FUND

	Net Present Value of Incremental Revenue Stream (millions of dollars)	
	Baseline	Alternate Tax Treatment*
Funding at Commissioning	283	296
Sinking Fund	186	135

*A discount rate of 9.4 percent was used.

These results are not very different because the non-deductible cases reflect the normalization of the decommissioning deduction. Thus the ratemaking policies in both tax scenarios in Table IV-4 reflect attempts to spread the tax deduction over the life of the plant. The relative costs of tax normalization and current year tax deduction are largely determined by other factors such as decommissioning amortization schedules and interest and inflation rates.

The ability to deduct currently the decommissioning reserve accumulations does have an important advantage, however. The decommissioning expense may actually be so large that the utility will be unable to take advantage of the full deduction. Shifting the deduction forward in time and spreading it over the life of the plant ensures that the company and its customers receive the full benefit of the deduction.

Table IV-5 compares the large deduction for decommissioning to the taxable income in the year of decommissioning. NU/Connecticut should have little problem using the tax deduction. Since the process of decommissioning a plant will most likely occur over several years, the deduction would also be spread over several years and thus the possibility of unused deductions decreases even further. If Millstone 1 and 2 are placed in safe storage until Millstone 3 is taken out of service, then the major decommissioning deductions for all three units may occur in the same time period. Nevertheless, TBS feels that there is a relatively low probability that decommissioning expenses would be unused for an ongoing utility with a mix of generating facilities.

Table IV-5

COMPARISON OF TAXABLE INCOME TO DECOMMISSIONING TAX DEDUCTION

(millions of dollars)*

	Millstone 1	Millstone 2	Millstone 3
Taxable Income	501	373	519
Tax Deduction	195	278	568

*Values for NU/Connecticut only.

Maine Yankee, however, presents a unique situation bec ıse it will not have any operating revenues against which to offset the decommissioning deduction. It is unclear whether the utilities which own Maine Yankee can take advantage of the deduction because a company's tax deductions cannot usually be claimed by its stockholders. If the deduction cannot be used, Yankee's own s will need to raise a significant amount of funds for decommıssioning at that time because the tax normalization scheme used in this report assumes that normalized tax savings will provide much of the cash flow necessary for decommissioning.

The major conclusion from the cost analysis of the three primary funding mechanisms is that funding at commissioning is more costly than a sinking fund which in turn is more costly than funding at decommissioning. Furthermore, this ranking is insensitive to most reasonable assumptions about interest and inflation rates and changes in tax policy. These results are most easily explained by the difference between the after-tax cost of capital to the utility (at the time of this writing approximately 13 percent) and the after-tax return that a utility can earn on its investments (currently approximately 8 percent). The more money the utility borrows at a high cost and invests at a lower return, the more expensive the financing option becomes to the company and its customers.

EQUITY

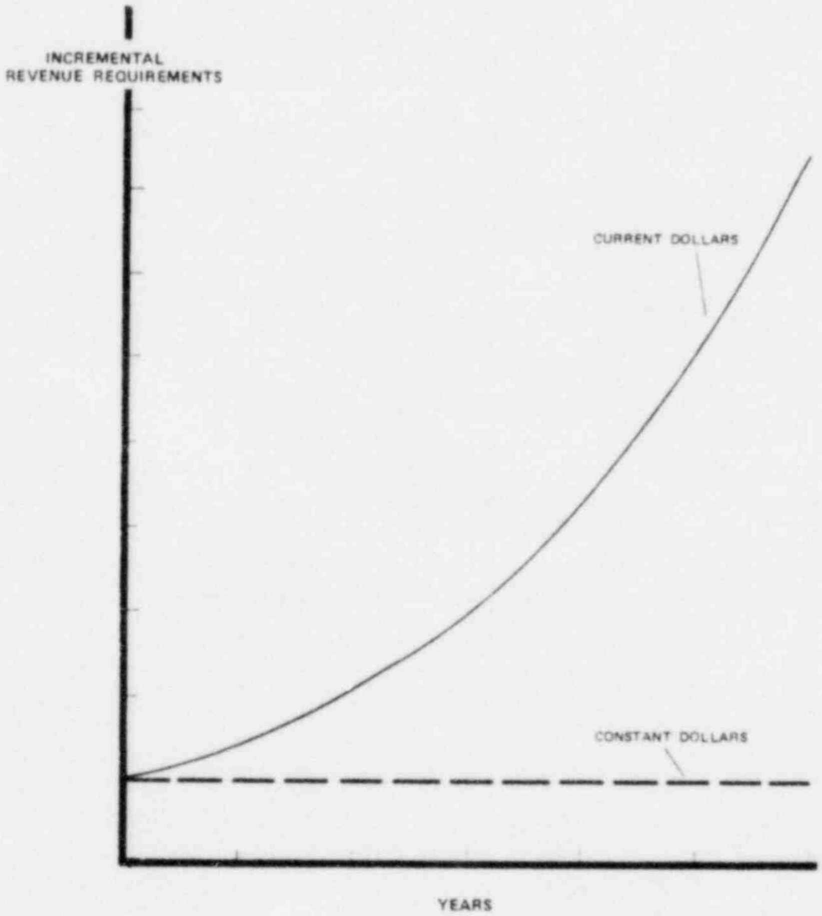
One of the goals of utility ratemaking is the fair apportioning of the cost of service among consumers. A reasonable standard of equity is to apportion costs to consumers in relation to the benefits received.

This goal of equity has been translated in this study into two operational objectives. First, the entire cost of decommissioning a nuclear power plant should be borne by the beneficiaries of the plant. Second, the incremental revenues required for decommissioning should increase each year at the rate of inflation, or, in other words, the rate impact in constant (deflated) dollars should be equal each year.

Figure IV-4 illustrates a hypothetically desirable pattern for decommissioning revenue requirements for a single nuclear plant. The decommissioning charge begins in the first year of the plant's operation and ends in the last. In current dollars, the charge increases at the rate of inflation. In constant dollars, the charge remains flat. Stated another way, the charge for decommissioning should increase proportionately to the cost of electricity.

Figure IV-4

DESIRABLE INCREMENTAL REVENUE STREAM OVER THE LIFE OF ONE PLANT



In practice, it will be difficult to achieve these objectives of equity because of uncertainties in forecasting costs and interest rates. For example, if a technical decommissioning strategy is adopted which requires a plant to be placed in safe storage for 100 years and then dismantled, the financial goal should be to establish a fund by the time the plant retires which with accumulated interest will be sufficient to pay all future decommissioning costs. A long-range cost forecast is thus required to compute the amount of the target fund. If costs are higher than anticipated, future ratepayers will shoulder the additional burden. If costs are lower, future ratepayers receive a windfall. In spite of this uncertainty, the goal of equity requires a current strategy based on an estimate of future costs.

Figure IV-5 presents the incremental revenue requirements for NU/Connecticut in both current and constant dollars. The effects of the units entering or leaving service can be seen by the sharp turns in the curve. (Unusual levels may occur in the first and last year of a plant's operation because commissioning and retirement are presumed to occur at mid-year.)

Figure IV-6 better illustrates the relative equity of the three strategies. In this graph, incremental revenue requirements have been divided by nuclear generation to adjust for the different timing of the three units.

Of the three strategies, funding at commissioning option is the most equitable. A sinking fund places a relatively larger burden on later ratepayers. Funding at decommissioning is the most inequitable; its negative revenue requirements in later years constitute a subsidy of later ratepayers by near-term customers.

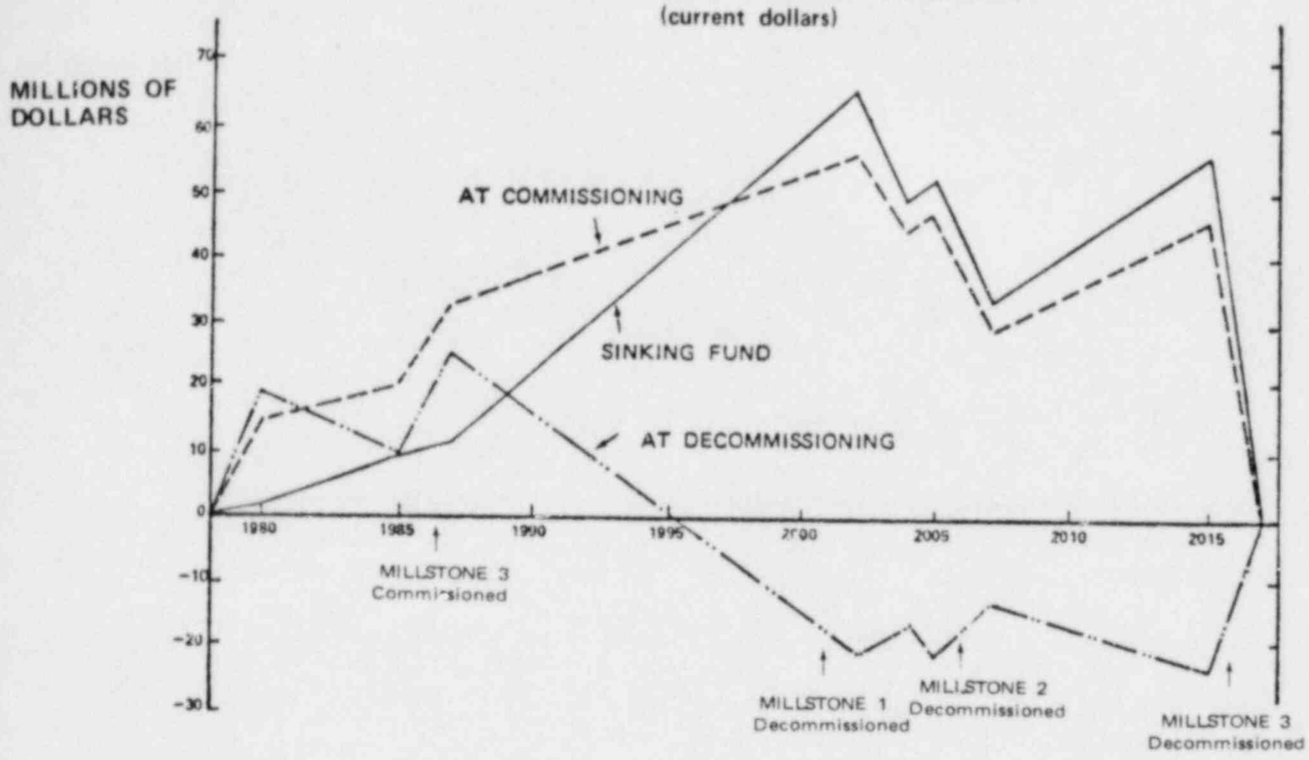
To determine why the three strategies have such different equity impacts, it is necessary to understand the components of the incremental revenue requirements. Figure IV-7 illustrates the current dollar incremental revenue requirements (for a one-unit decommissioning case) with the individual components identified. (All lines have been estimated with straight lines for illustration purposes.)

In each case, both decommissioning amortization and deferred income taxes are flat in current dollars. This was done to conform with the straight line depreciation of the plant's initial cost and the straight line normalization (in states which allow normalization) of income tax differences arising from book and tax depreciation. While this practice is viewed by TBS as the most likely to occur, it is certainly not optimal

Figure IV-5

INCREMENTAL REVENUE REQUIREMENTS

(current dollars)



INCREMENTAL REVENUE REQUIREMENTS

(constant dollars)

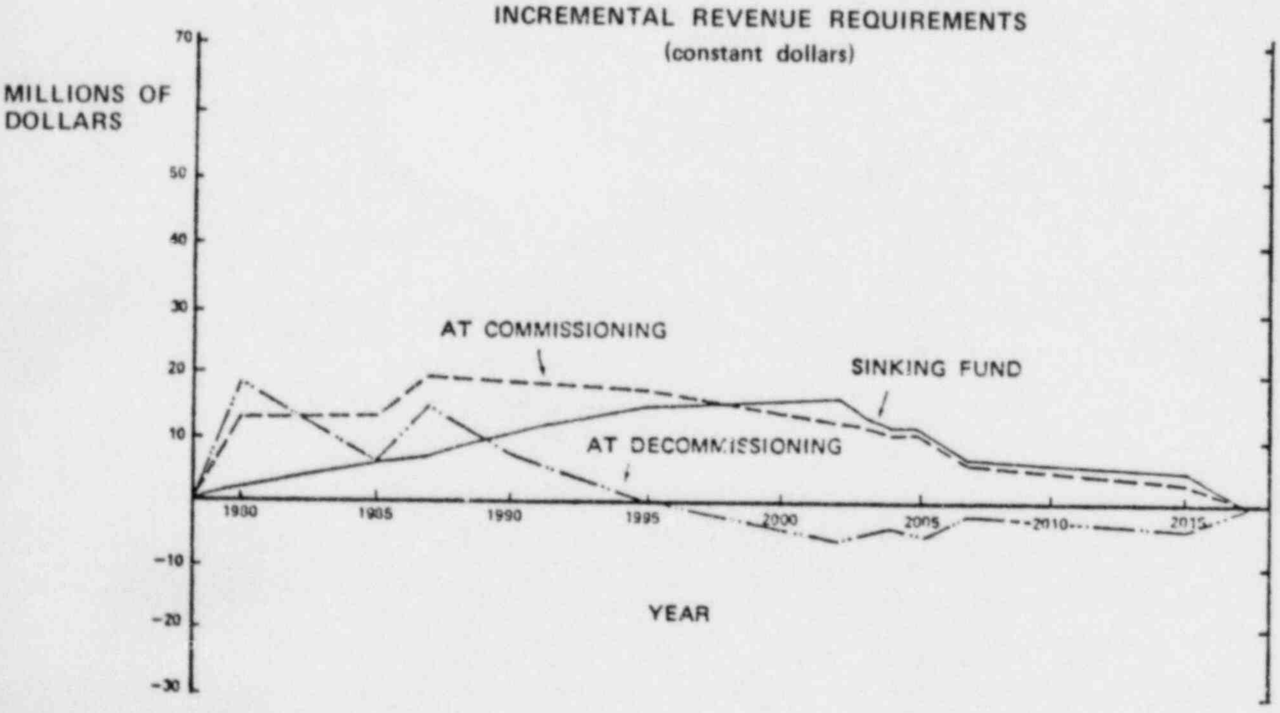
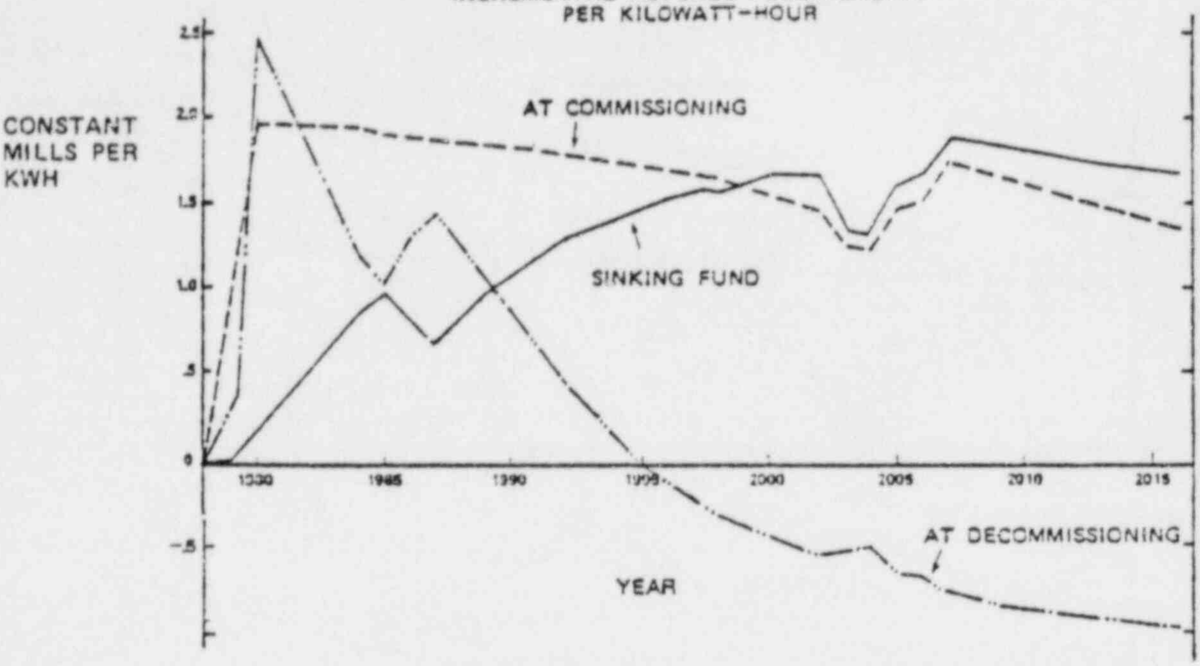


Figure IV-6

INCREMENTAL REVENUE REQUIREMENTS PER KILOWATT-HOUR



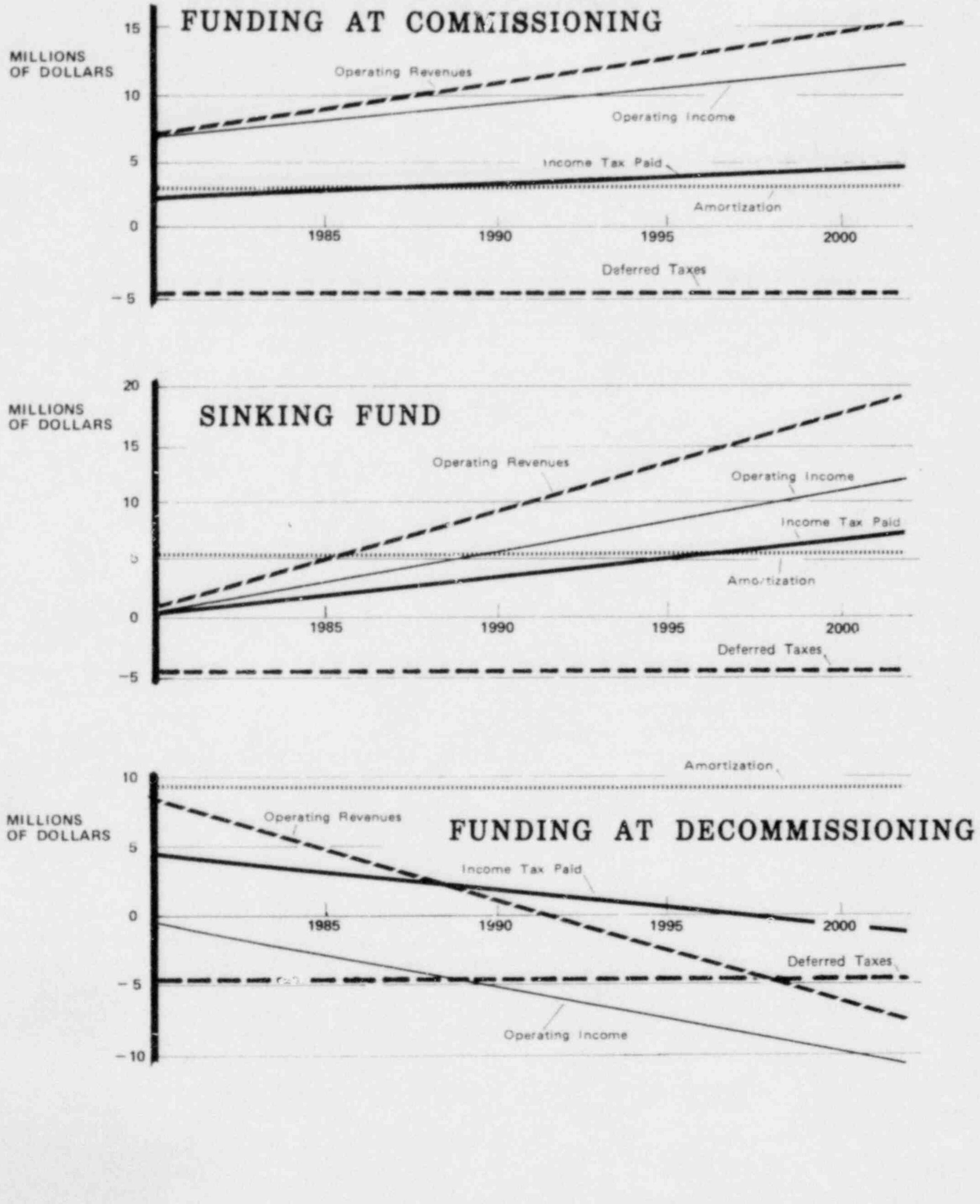
from the standpoint of equity. All straight line accounting practices in fact penalize near-term customers in times of inflation because the later depreciation charges can be repaid in cheaper dollars.

The major reasons for the differences among the three strategies are the effects of different levels of external financing. In the two funded cases, funding at commissioning and sinking fund, the unamortized portion of the fund should receive ratebase treatment because the associated capital costs are legitimate costs of providing service from the nuclear plant. Increased operating income requirements are therefore required to pay the increased interest expenses and common and preferred dividends. Increased income in turn leads to increased income taxes paid.

Funding at decommissioning has the opposite effect. The amortization less deferred (or in this case prepaid) income taxes provides a source of internal funds which allows the company's external financing requirements to be reduced. Compared to the baseline, this scenario has decreased operating income requirements. This results from the deduction of the decommissioning reserve from the ratebase because the reserve represents a costless source of funds advanced by consumers.

Figure IV-7

COMPONENTS OF INCREMENTAL REVENUE REQUIREMENTS FOR MILLSTONE I UNIT



The relative equity impacts of the three strategies differ, therefore, because of different operating income impacts. Precedent for this can also be found in traditional utility accounting. Just as straight line decommissioning amortization and normalization were compared to straight line plant depreciation, the non-straightline operating income can be compared to operating income on net plant value. Ratebase is generally tied to net plant value which declines over the plant's life. The associated operating income therefore declines over time in current dollars. The inequity of this practice is further aggravated by inflation.

<u>Sensitivity to Amortization Schedule</u>

The primary task in this study is the comparison of three decommissioning financing strategies. In order to make fair comparisons, the analysis thus far has paired these three funding strategies with a ratemaking treatment for decommissioning amortization, the tax status of the return on the fund, and the tax status of the decommissioning expense. As discussed above, this set of strategies produces differing levels of equity.

In this section the amortization schedule is allowed to vary in order to create three financing alternatives with comparable equity. In other words, instead of holding the amortization schedule constant and observing the resulting cost and equity, the analysis will now hold the equity constant and observe the resulting cost and amortization schedule. The resulting amortization schedules are not very likely to be implemented because they depart drastically from common practice, but as will be seen below, they permit definitive ranking of the three alternatives on the basis of cost and equity.

Figure IV-8 presents results for the three financing strategies where amortization schedules have been devised to produce roughly comparable equity. The incremental revenue requirements per nuclear-generated kilowatt-hour in constant dollars are approximately level over the lives of all three Millstone units. Funding at decommissioning is less expensive than the other alternatives in every year, and the sinking fund dominates funding at commissioning in every year.

Table IV-6 presents the relative costs in two ways. The first measure is the net present value of incremental revenue requirements. The second is the average increase in the cost of a nuclear-generated kilowatt-hour in 1979 dollars. Both measures give similar signals regarding the relative cost of the three strategies.

Figure IV-8

INCREMENTAL REVENUE REQUIREMENTS PER KILOWATT-HOUR FOR CONSTANT EQUITY SCENARIO

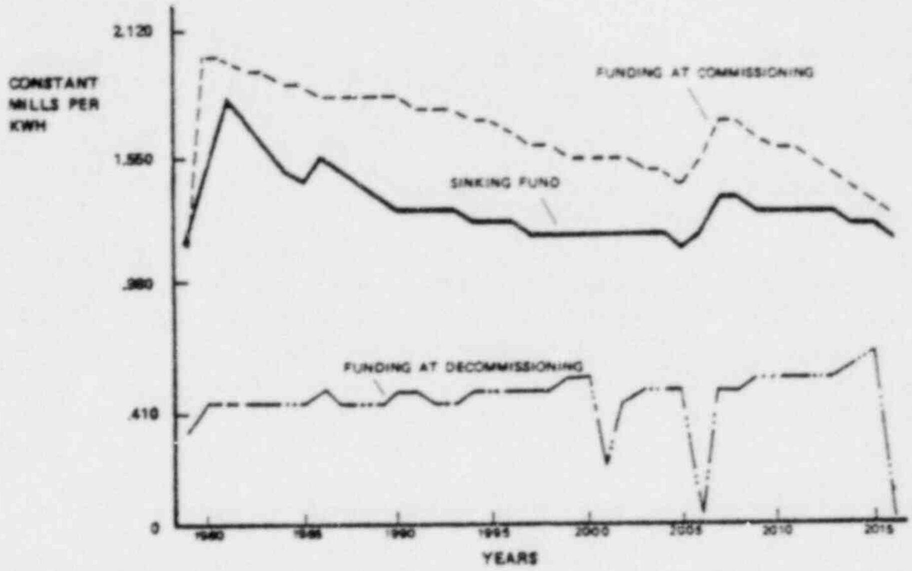


Table IV-6

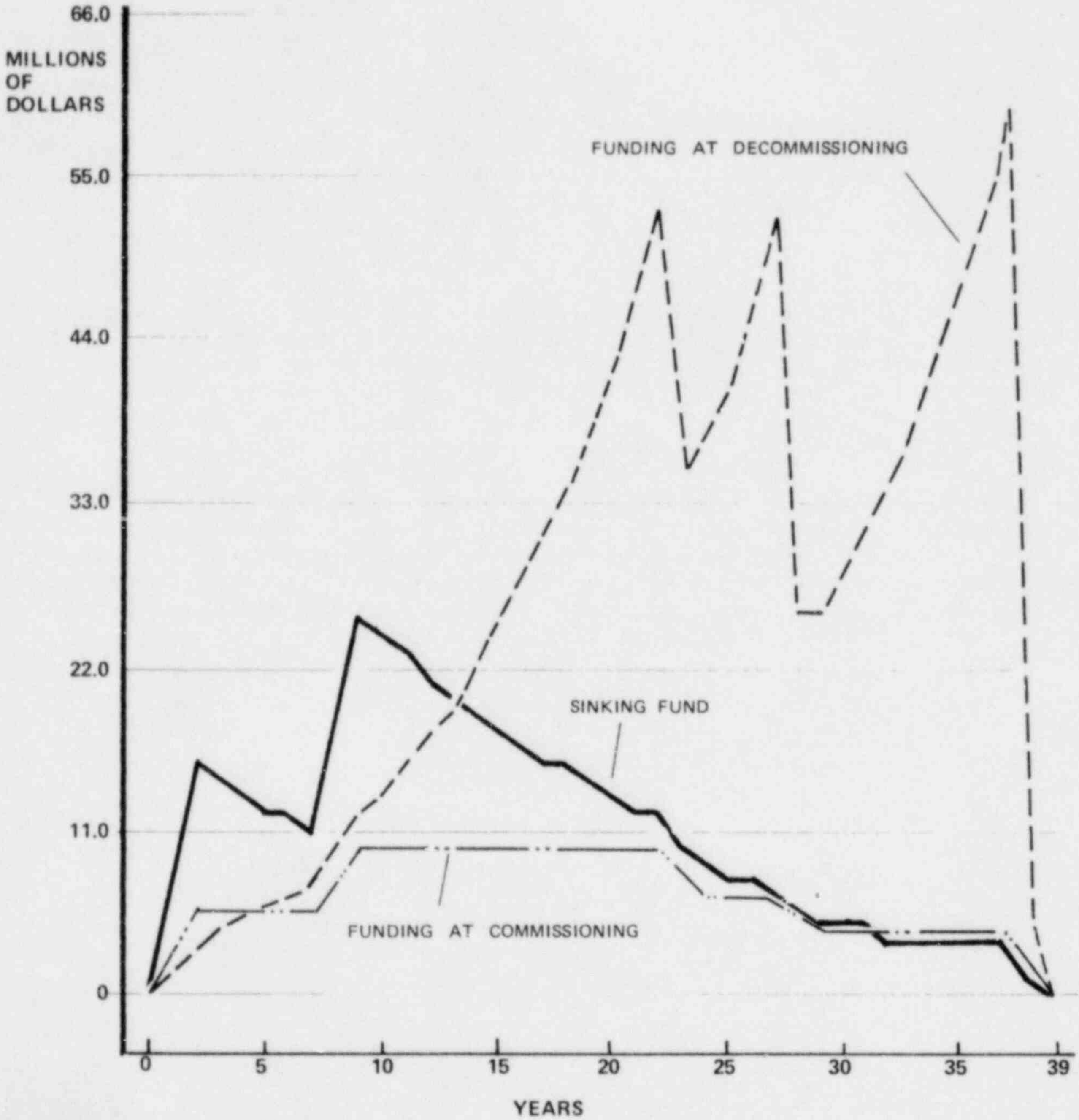
COSTS FOR CONSTANT EQUITY SCENARIO

	Net Present Value of Incremental Revenue Requirements (millions of dollars)	Average Increase in Incremental Revenue Requirements (constant mills per kwh)
Funding at Commissioning	283	1.62
Sinking Fund	224	1.32
Funding at Decommissioning	78	0.44

The amortization schedules which produce the above results are illustrated in Figure IV-9. The sinking fund requires an accelerated amortization schedule, and funding at decommissioning requires a decelerated schedule. The funding at commissioning option uses a straightline amortization schedule; it is unchanged from the earlier analysis.

Figure IV-9

AMORTIZATION SCHEDULES FOR CONSTANT EQUITY SCENARIO



This analysis of equity yields two important conclusions. First, all else being equal, the three primary funding mechanisms vary in their fairness to near- and long-term customers. Second, if equity is an important consideration, an amortization schedule can always be devised to produce equitable results for any financing strategy.

FINANCIAL ASSURANCE

The third criterion for evaluating alternative strategies for financing nuclear decommissioning is the level of financial assurance. Financial assurance as discussed in this report refers to the probability that a utility will be able to raise the necessary funds for decommissioning at the time they are required.

There are two reasons that a utility might not be able to raise the funds when required. First, if the financing requirements were inordinately large compared to the firm's normal requirements for funds, financing might be made difficult by bond indenture restrictions or extremely high costs of capital. Bankruptcy is the second case.

Table IV-7 demonstrates that decommissioning financing is not prohibitively large, assuming a $50 million cost. Funding at commissioning poses the largest burden by increasing external financing requirements 71 percent over the baseline in the year of financing. While large, this burden could be spread over a few years and would be manageable for most utilities.

Table IV-7

EXTERNAL FINANCING REQUIREMENT
FOR MILLSTONE 3

	Amount (millions of constant dollars)	Increase Over Baseline
Funding at Commissioning	81.8	70%
Funding at Decommissioning	18.6	15%

Funding at decommissioning creates much less of a burden because the utility does not have to raise the extra funds imposed by the differential between its own cost of capital and the rate it can earn on external investments. Sinking funds pose no problem at all. The increase in external financing over the baseline averages 1.3 percent over the period 1979-2016.

The second reason for concern with financial assurance is the possibility of utility insolvency. While the probability of bankruptcy of a major electric utility in this country is low, utilities today face a more difficult financial environment than they have in the past. Furthermore, predictions of utility financial status 30 or more years into the future are uncertain.

The specter of premature decommissioning provides further reason to be concerned. For example, at the time of this writing, a major utility is perceived by investors as having an uncertain financial position because of a serious accident at a nuclear power plant.[8] Thus, a premature decommissioning could create a large, unanticipated requirement for funds and, at the same time, financially destabilize the parent company.

One measure of the level of financial assurance provided by the three financing strategies is the ratio of the liquid decommissioning fund to the cost of decommissioning. Figure IV-10 illustrates that funding at commissioning is the only option which provides full security. A sinking fund's risk decreases over time as the fund grows. Funding at decommissioning, by definition, provides no fund prior to decommissioning.

It is important to note that the increased financial assurance of the two funded strategies is contingent not only on the timing of the financing but on the institutional arrangements. In the case of bankruptcy, funding at commissioning provides little more financial assurance than funding at decommissioning unless the fund is secured in a trust fund which is

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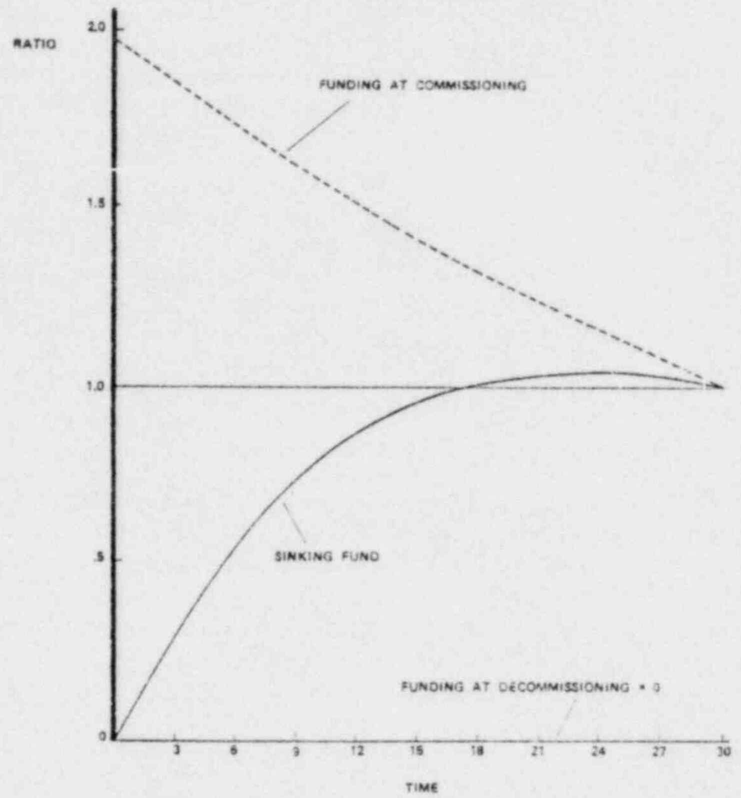
[8]This statement is based on the fact that, since the accident at Three Mile Island, investors have been demanding a significant risk premium on the stock and bonds of General Public Utilities and its subsidiaries. For example, in Salomon Brothers' recent ranking of 100 major electric utilities, GPU had the lowest common stock market to book ratio--27 percent--far below the next rated utility at 56 percent or the industry average of 80 percent. (Source: "Electric Utility Common Stock Market Data," Salomon Brothers, June 3, 1980.)

Figure IV-10

RATIO OF LIQUID FUND TO DECOMMISSIONING COST



legally reserved for decommissioning. If the funds remain in the general accounts of the company, the funds may revert to the company's creditors in the event of bankruptcy and thus may be unavailable for decommissioning.

In conclusion, funding at commissioning has greater financial assurance than a sinking fund, which in turn has greater financial assurance than funding at decommissioning. This ranking, as expected, is exactly reverse to the ranking on the basis of cost. Risk can always be reduced at a cost.

FLEXIBILITY

Decommissioning financing strategies should be responsive to a number of factors including uncertainty and the numerous situations in which the strategies will be used. Flexibility may not be as important a criterion as cost, equity, or risk, but institutional or practical barriers to the implementation of a particular strategy should be noted before NRC adopts a policy for the industry.

This section discusses responsiveness of the strategies to:

- Uncertainty about the future;
- Alternative reactor ownership agreements;
- Multiple jurisdictions; and
- Choice of technical decommissioning alternative.

Uncertainty About the Future

The analysis up to this point has incorporated assumptions about the future over a 40-year time horizon. While it should be clear that any strategy can incorporate any projection, it is less clear that strategies in practice can adjust to revisions in these projections.

Mid-course corrections may be required when new information becomes available regarding:

- Decommissioning costs;
- Reactor lives; and
- Interest and inflation rates.

The following discussion summarizes the impacts on cost, equity, and financial assurance of changes in each of the above.

If a mid-course correction is necessary because the estimates of decommissioning costs increase, then:

- The net present value of all incremental revenue requirements will increase;
- Later customers will be adversely affected because near-term customers will have underpaid; and
- Financial assurance will decrease because the ratio of the fund to the estimated decommissioning cost will have fallen.

If the estimated useful life of a reactor increases, then:

- The constant dollar cost of decommissioning will increase if decommissioning costs are increasing faster than the general rate of inflation;

- Near-term customers will have over-contributed their fair share; and

- Financial assurance will suffer slightly if the constant dollar cost increases.

If interest rates rise faster than expected, then:

- Cost will increase for the funded options if the spread increases between the utility's cost of capital and the rate of return on external investments; cost will decrease for the funding at decommissioning case;

- Equity will follow the change in cost; and

- Financial assurance will suffer if costs increase.

The practical ease with which different strategies can respond to such changes is also important. Most strategies can adapt equally to most changes. Funding at commissioning is likely to be less adaptable if an external trust fund is established, however, because withdrawals cannot typically be made from such trusts. Sinking funds have this restriction also, although it will not pose as much of a problem because the annual fund payments can be adjusted.

Alternative Reactor Ownership Arrangements

Nuclear power plants in the United States are owned through numerous arrangements, including:

- Sole ownership by one utility;

- Joint ownership by members of a holding company;

- Joint ownership by several utilities through a stock company; and

- Joint ownership by unrelated utilities.

Most of the analysis thus far has concentrated on a hypothetical sole ownership case--NU/Connecticut. This case is most useful for illustrating the simplest one-owner, one-state jurisdiction example. Northeast Utilities illustrates the holding company case, and Maine Yankee is an example of a stock company.

Joint ownership by members of a holding company or by unrelated companies should not pose barriers to the use of any financing mechanisms discussed thus far, because numerous accounting and financial arrangements could be made. For example, the subsidiaries of NU are responsible for their capital contributions toward joint construction projects. However, they turn to another NU subsidiary, Northeast Nuclear Energy Company, for the management of nuclear plant construction and operation and nuclear fuel purchasing. Similarly, unrelated joint owners could maintain their own decommissioning accounts or make contributions to a joint venture.

Maine Yankee, however, poses some unusual, primarily legal problems. The length of its NRC license and the agreements signed by the sponsor companies may be shorter than the actual reactor life, so that legal responsibilities become vague toward the end of the reactor life. These issues are broader than decommissioning, however.

Questions have been raised regarding the feasibility of the funding at decommissioning approach for one of the Yankee companies. In a recent case before the Federal Energy Regulatory Commission, the FERC staff argued that a sinking fund should be established for the Connecticut Yankee Company because funding at decommissioning amortizes a negative salvage value and leads to a negative ratebase.

TBS believes that funding at decommissioning using negative salvage value is a viable alternative financially, although it may not be desirable because of its risk. From the financial point of view, however, amortization of a negative salvage value is consistent with the existing problem of excess cash flow.

To understand this, first consider a single asset firm with no decommissioning requirement. Such a firm, which depreciates that asset but which does not have a construction or acquisition program, will generate a higher flow of funds than it has uses for funds. The company has two financial alternatives. One option is to gradually reacquire its own capital stock. The company needs to keep only nominal shares outstanding to retain its corporate identity. The second option is to accumulate and invest the excess funds which in turn can be liquidated and dispersed to investors at the plant's retirement. In either case, the company will raise sufficient financial assets during the plant's life to satisfy all liabilities including the refunding of the owner's equity.

Funding at decommissioning increases the excess cash flow because of the increaed amortization of the negative salvage value. The company can continue to pursue whichever financial policy it was planning without decommissioning. If the company reacquires its stock and bonds, it will merely do so at a faster rate. In fact, it will reacquire virtually all of its capital several years before the plant's retirement. If all goes as planned, the remaining amortization will provide for the cost of decommissioning. If the company accumulates and invests the excess funds, it will have sufficient funds at the end of the plant's life to satisfy all of the company's liabilities including decommissioning.

While the above discussion demonstrates that the negative salvage value approach presents no financial problems if all goes as planned, it should also be clear that there is a higher level of financial risk. Although the balance sheet appears strong enough to pay for decommissioning, there is no physical asset of value to support the liability. Thus if the plant were forced to close prematurely, there is no underlying financial strength against which to borrow.

Another potential problem with the Yankee organization is the possibility under current tax law that the tax deduction for decommissioning would not be able to be used. This problem is independent of financing strategy. TBS's projections show that, for Maine Yankee, taxable income in the last year of the plant's operation will be approximately $8 million and the deduction, if the plant is decommissioned that year, would be $258 million. It is highly unlikely that decommissioning could be completed in one year, however, and there will be no significant revenues after plant retirement.

In addition to the case studies of privately owned utilities discussed in this report, other plant ownership arrangements are possible including federal power authorities, municipalities, and rural electric cooperatives. In the case of federal ownership, the U.S. government is the guarantor of the organization's obligations. Funding at decommissioning is therefore more attractive in this case, because there is little risk that funds will be unavailable, although it is the U.S. taxpayer who absorbs the risk.

Municipal ownership is the unique case where the utility's cost of capital and the rate of return which can be earned on external investments are approximately equal because municipalities pay no income taxes. In that case, the cost differences among the three financing strategies should be less because a municipal entity does not have to pay for the difference between its borrowing and lending costs.

Rural electric cooperatives also present a unique financing situation. They are generally exempt from federal income taxes because they are cooperatives and distribute their margins. Thus their decommissioning fund would be able to accumulate at a ta'-free rate. As with municipal utilities, the cost difference among the three strategies should be less than for privately owned utilities because of the increased return on the fund.

Multiple Jurisdictions

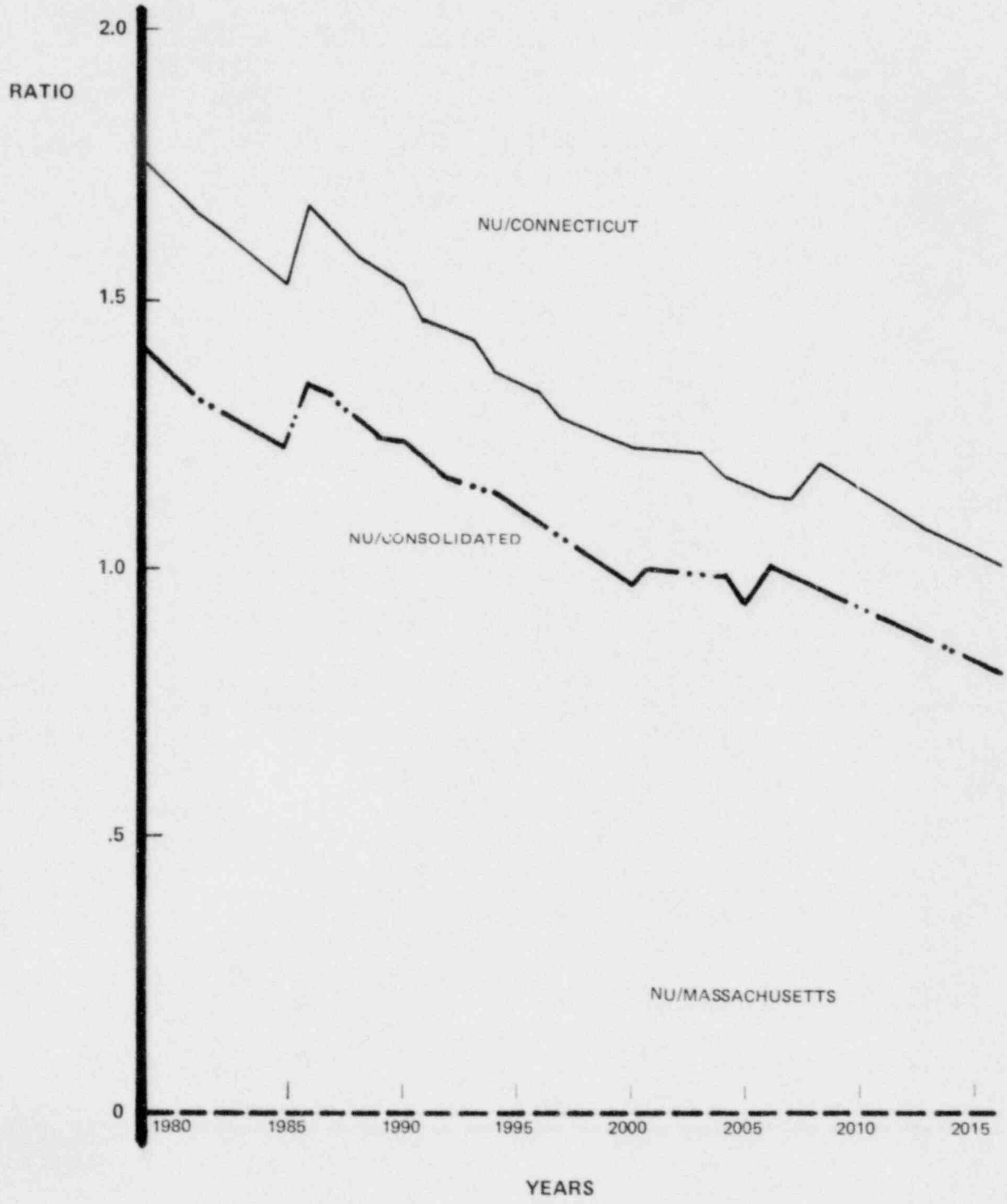
Most utilities are subject to more than one jurisdiction on rate and financial matters. Northeast Utilities is regulated by state commissions in Connecticut and Massachusetts as well as by FERC. Maine Yankee is primarily regulated by FERC, although its sponsors are regulated by five New England state commissions.

Multiple jurisdictions should not preclude the use of any strategy for decommissioning financing, although the use of different strategies in different jurisdictions will cause cross-jurisdictional subsidies. For example, Figure IV-11 illustrates the effect on Northeast Utilities of different strategies in its Massachusetts and Connecticut subsidiaries. In this hypothetical example, NU/Connecticut adopts funding at commissioning, and NU/Massachusetts uses funding at decommissioning. The figure presents a measure of financial assurance--the ratio of the liquid decommissioning fund to the current cost of decommissioning--for the two sets of subsidiaries and the parent company. If the holding company maintains the decommissioning accounts, or if a separate subsidiary is used, then Connecticut ratepayers will subsidize Massachusetts ratepayers. The subsidy occurs because Massachusetts ratepayers have chosen the low-cost, high-risk option, and yet the resulting financial assurance of the joint account is higher than anticipated because the Connecticut ratepayers have chosen to pay for the low-risk option.

In practice, cross-jurisdictional subsidies occur constantly and with much larger magnitude than those potentially created by conflicting decommissioning strategies. For example, the different timing of Massachusetts and Connecticut rate cases is sufficient to keep the actualized rate of return different in the two states. Thus it is frequently the case that one state

Figure IV–11

RATIO OF LIQUID FUND TO DECOMMISSIONING COST
FOR MULTI–JURISDICTIONAL CASE



earns a lower rate of return, and the state with the lower return is being temporarily subsidized by the other because the utility's common stock, which is sold only by the holding company, is evaluated by investors as the weighted average of all subsidiary returns. In general, utilities frequently are subject to different accounting rules in different jurisdictions.

Choice of Technical Alternative

The range of technical choices for plant decommissioning which are available today is not sufficiently diverse to affect the choice of financing strategy. The technical choice has therefore been ignored in this analysis because the technical choice and the financial choice are, for the most part, separable. A technical strategy is necessary to determine the magnitude and timing of expenses to be incurred, but once cost is determined, the goal of a financing strategy is to establish a fund for decommissioning in the year of the plant's retirement which will be sufficient to cover all decommissioning expenses. This fund must provide for future inflation, maintenance and surveillance expenses, and all costs associated with the final decommissioning whenever it occurs.

The choice of technical alternatives is therefore not a barrier to the use of any financing strategy. Long-term alternatives such as placing the facility in safe storage and deferred dismantlement run a higher risk of producing inequities because of the higher risk that the original estimate of the required fund was inaccurate. This will be the case regardless of financing strategy, however.

As discussed earlier, the Yankee companies may have to make alternative arrangements for any technical alternatives other than complete and immediate dismantlement because the Yankee corporate entity may cease to exist. The legal arrangements made for the Yankee plants do not, however, preclude the use of any financing strategies.

In summary, flexibility regarding uncertainty or alternative regulatory or ownership arrangements does not pose any serious barriers to the use of any of the three financing strategies. The worst inflexibility is the possible inability to withdraw funds from a blind trust. This may lead to a downward bias in the computation of the required fund which in turn may put an extra burden on later ratepayers.

V. CONCLUSIONS

The primary conclusion regarding nuclear decommissioning financing is that no alternative clearly dominates on the basis of all relevant criteria:

- Cost,
- Financial assurance,
- Equity, and
- Flexibility.

The three financing alternatives--funding at commissioning, sinking fund, and funding at decommissioning--are discussed below according to these four criteria.

COST

If cost is measured as the discounted, incremental revenue requirements, funding at decommissioning is the least costly strategy. Under one consistent strategy for ratemaking and tax treatment, a sinking fund is twice as expensive, and funding at commissioning is three times as expensive as funding at decommissioning.

Assuming a $50 million cost of decommissioning, none of these strategies significantly increases the cost of electricity to consumers, however. For the Northeast Utilities case study, decommissioning increases electricity rates by less than 1 percent for all strategies.

FINANCIAL ASSURANCE

Although funding at commissioning is the most costly alternative, it provides the highest level of assurance that funds will be available to pay for decommissioning. If the funds are secured in a trust fund which can legally be reserved for decommissioning even in the case of bankruptcy, then this alternative is the only one which guarantees that funds will be available when required.

Funding at decommissioning, which relies on the financial strength of the company to be able to provide funds when required, presents the highest financial risk. The experience of Three Mile Island demonstrates that a nuclear accident which would be serious enough to require premature decommissioning is an event which might seriously threaten the financing ability of the utility. In addition, there exists the uncertainty of predicting financial solvency for any utility 30 or more years into the future.

A sinking fund is a compromise between the two extreme strategies. It provides greater assurance than funding at decommissioning but at increased cost. Financial assurance is determined by the liquid reserve fund, which builds up over the plant's life. For a 30-year plant, 13 percent of the required cost is available in the fund after one year, and more than 70 percent is available after nine years.

EQUITY

The fairness of the rate impacts to consumers is largely determined by ratemaking and tax treatment. The amortization schedule is the most influential factor, and a schedule can theoretically be devised to insure equitable impacts. These schedules may depart from commonly accepted practice, however.

A major potential source of inequity stems from current tax law which requires that decommissioning costs be deducted in the year incurred. If this law is not changed, normalization of this large deduction is required to give the associated tax benefit to the same consumers who paid for decommissioning. Normalization may not be sufficient to insure equitable treatment for one-plant companies, however.

FLEXIBILITY

Uncertainty about interest and inflation rates makes financial planning for decommissioning difficult, but it does not preclude the use of any alternative. In all cases, long-term estimates of interest and inflation must be made in order to spread the burden of decommissioning equitably over time.

The funding at decommissioning and sinking fund options are the most sensitive to this uncertainty. Trust funds will be established for these options to secure the funds in the event of bankruptcy. Because withdrawals are typically difficult to make from such funds, there may be a tendency to underestimate the fund requirements.

Most alternative ownership arrangements do not pose problems for decommissioning financing. Maine Yankee, an example of a single-plant company, merits special attention because the company may cease to exist at the end of the plant's life. Even if it continues as a corporation, its revenue will probably be insufficient to utilize the tax deduction for decommissioning in the year(s) when the cost is incurred.

Ownership by organizations other than privately owned utilities affects the costs and risks of the financing alternatives. Although this study did not explicitly consider cases of federal, municipal, and cooperative ownership, the principles discussed in Chapters II and IV are applicable. If a non-corporate owner has greater financial stability, e.g., the federal government, then the requirement for a risk averse strategy is less. If the difference between the owner's after-tax costs of borrowing and investing is small, e.g., municipal ownership, then the differences in cost among strategies decreases significantly.

Multiple jurisdictions may lead to different rate treatment of decommissioning expenses in the different jurisdictions, but this does not preclude the use of any financing strategy. At worst, cross-jurisdictional subsidies will occur.

Finally, the choice of the technical decommissioning plan will affect the final cost of decommissioning, but it should not affect the financing strategy or ratemaking treatment.

APPENDIX A

RAm

BACKGROUND

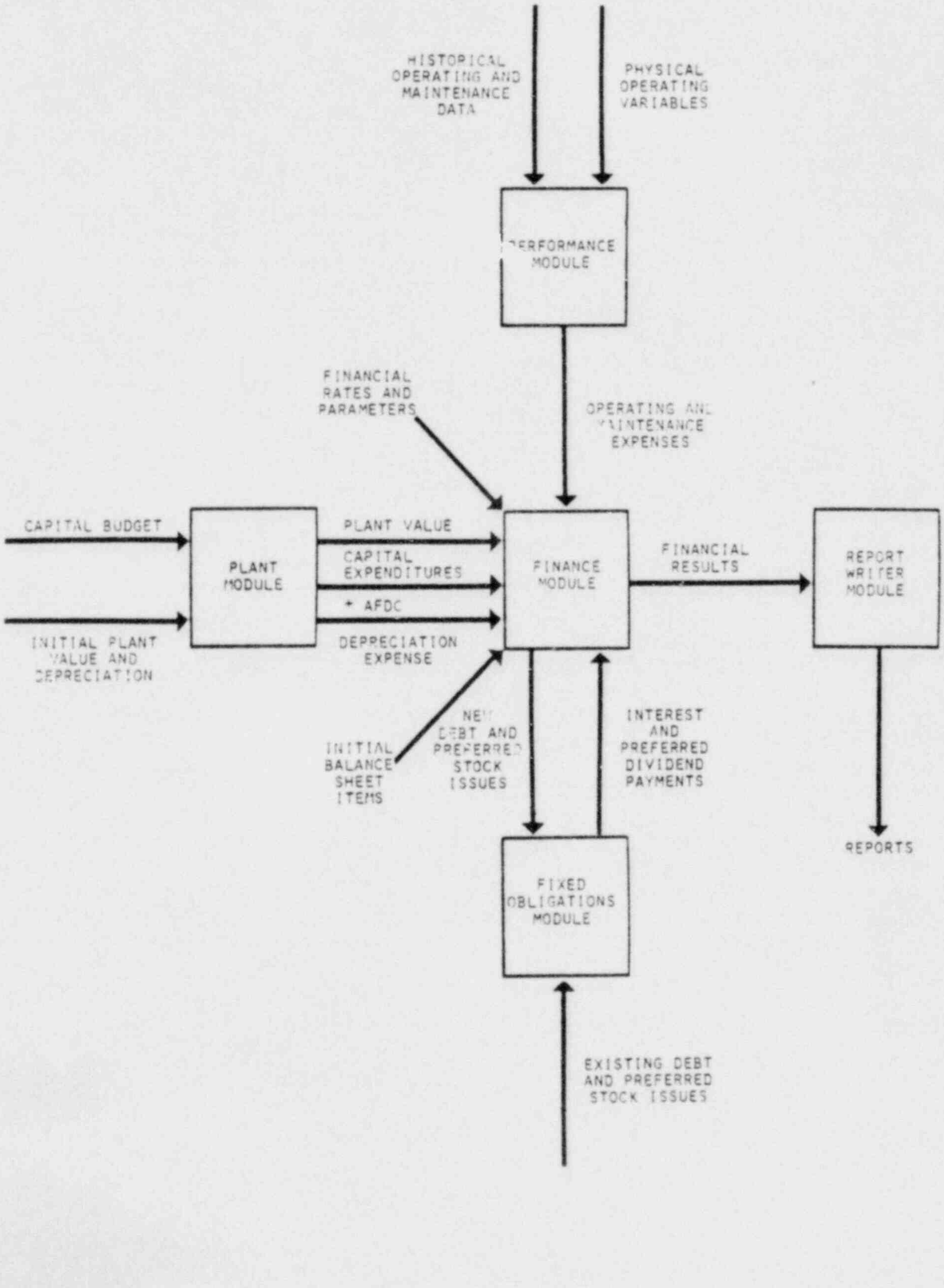
The Regulatory Analysis Model, RAm, is a computer-based model for making financial projections for an electric utility given a set of assumptions or projections concerning demand, capital expenditures, operating costs, and financial and regulatory policies.

RAm is an evolutionary step in a family of financial forecasting and policy-testing models developed by Temple, Barker & Sloane, Inc. (TBS). The advancement in the application of the principles developed by TBS was made possible by funding provided by the Experimental Technology Incentives Program of the National Bureau of Standards of the U.S. Department of Commerce. Technical oversight was provided by the Federal Power Commission. Several state regulatory commissions participated in the development and testing of RAm.

RAm utilizes a combination of historical data, input assumptions concerning financial and operating relationships, and regulatory and tax accounting logic in making financial projections. The logical structure has been developed to a level of detail that surpasses what is feasible in manual forecasting approaches and that enables RAm closely to mirror actual results.

RAm has been designed to accept input assumptions, e.g., future capital expenditures for various types of plant and equipment, from a variety of sources. The data items required by RAm may be developed by other, often complex, models. As an example, the capital budget required as an input to RAm may be an output from a capacity optimization program. RAm itself can be utilized to make some subsidiary forecasts. For example, estimates of future operations and maintenance costs may be derived from historical trends through the use of the performance evaluation module of RAm. Exhibit A-1 illustrates the flows of information utilized by RAm. RAm's design as a complement to other, often complex, tools of the planning process both simplifies its structure and adds to its flexibility of use.

Exhibit A-1
RAm



DESCRIPTION OF RAm

RAm is a complex model, but it is flexible and user-oriented. Its flexibility is evidenced not only by its ability to analyze numerous issues but also by the fact that the data required by the model can be of various levels of detail. The complexity of RAm is apparent only in the internal program structure of the model; conceptually and operationally, RAm is relatively straightforward. The conceptual structure of RAm will be described in detail in the remainder of this section. The reader should refer to the information flows described in Exhibit A-1.

There are five important functional parts, or modules, executed during RAm analysis. These are the Plant Module, the Performance Module, the Fixed Obligations Module, the Finance Module, and the Report Writer Module. Each of these modules will be described below. Further detail, including equations and source code documentation, is available from TBS upon request.

Plant Module: Plant Calculations

The Plant Module of RAm performs five functions:

- It determines the construction work in progress (CWIP) balance.
- It determines the allowance for funds used during construction (AFDC).
- It determines the amount of AFDC associated with each category of plant in service. (The model allows from one to ten categories of future plant, such as transmission, distribution, nuclear production, etc.)
- It determines the amount of depreciation, both tax and book, for each plant category.
- It determines net and gross plant value.

CWIP is calculated by taking the previous year's CWIP figure, adding to it all actual cash construction expenditures, and subtracting all increases in plant-in-service (before retirements). The AFDC component of CWIP is kept separate. All cash construction expenditures must be accounted for in either CWIP or plant-in-service. Therefore, the increase (or decrease) in CWIP is equal to cash construction expenditures less the amount transferred to plant-in-service.

The amount of AFDC shown as income in each year is calculated by multiplying the average year-end CWIP balance by the AFDC rate. AFDC is calculated on an annual basis and is not compounded. While the calculation of AFDC is simple, its accounting is more complex. The amount of AFDC in the CWIP account and the AFDC portion of each plant-in-service category must be kept separate because of the special nature of AFDC. When calculating the current year's AFDC amount, the AFDC portion of CWIP cannot be included. When depreciating the plant accounts for income tax purposes, only the non-AFDC portion of the plant cost can be depreciated. For book purposes, however, the AFDC portion of plant cost is depreciated.

To properly account for AFDC, a second calculation is made. The second calculation determines how much AFDC is associated with the plant going into service in a particular year. This amount is subtracted from the accumulated AFDC in the CWIP balance, and added to the accumulated AFDC in the plant in service balance. In effect, AFDC accounting parallels that of cash expenditures, with the CWIP account and each plant account having a corresponding AFDC account.

RAm computes three types of depreciation: book depreciation of plant, book depreciation of the AFDC component of plant, and tax (accelerated) depreciation of plant.

Book depreciation is calculated on a straightline basis by multiplying the gross value of each plant account and category by a depreciation rate. The AFDC component of plant is also depreciated on a straightline basis for book purposes, using the same depreciation rate as for book depreciation of plant.

Tax depreciation is calculated exclusive of AFDC. The net plant value (tax) of existing plant is estimated from annual tax depreciation and an average asset life determined from book depreciation. Tax depreciation is calculated on a double declining balance basis.

Performance Module: Calculation of Operations and Maintenance Expenses

Operations and maintenance expense (O&M) used by RAm may be developed independently or by the Performance Module of RAm.

The Performance Module of RAm can be used to develop statistical relationships between costs and services. It does this by performing a regression over time between each cost item and selected measures of service. The method of regression and selection of service measures are controlled by the analyst.

The relationships developed as part of performance evaluation may be used to project future O&M expenses. Projection is accomplished by supplying forecasts of the independent variables specified in the causal relationships--e.g., peak load and energy consumption--and calculating the value of each expense item for each future year.

An alternative procedure is available for projecting selected O&M items which do not lend themselves to the type of historical analysis described above. The user may independently determine the relations to be used and simply input the desired coefficients and the form of the relationship. These relationships may have the same form as those developed from historical data.

Fixed Obligations Module: Interest Calculations

The Fixed Obligations Module of RAm keeps track of and performs interest calculations on a utility's outstanding long-term debt and preferred stock issues (fixed obligations). In addition, it can measure the effect on interest and dividend payments and embedded interest rates of any new issue.

The debt file and preferred stock file created by the user contains a description of each issue, the year and date of issue, the year of retirement (if any), the interest or dividend rate, the original amount of issue, the current amount outstanding, and the annual sinking fund payment (if any). The Finance Module uses this file to make preliminary estimates of interest payments and calculates the amount of new debt and stock issues and adds them to the debt and stock files. The Fixed Obligations Module then uses the file to calculate the exact amount of long-term debt interest payments and preferred stock dividends. The information is then passed on to the Finance Module for use in the financial calculations. The amount of interest or dividends to be paid each year on each issue is assumed to be paid on the date of original issue and is prorated if the issue has not been outstanding for a full year.

Finance Module: Financial Calculations

The Finance Module is the heart of RAm. It performs the task of calculating required revenues and all the relevant financial parameters necessary to develop a pro forma income statement, balance sheet, and sources and uses of funds statement. In particular, the Finance Module calculates for each year of the forecast period:

- Ratebase
- Required revenues
- Net income and return on ratebase or equity
- Earnings available for common equity
- Common dividends paid
- Retained earnings
- Common stock issued
- Preferred stock issued
- Long-term debt issued
- Short-term debt issued
- Short-term debt interest payments
- Increase (or decrease) in net working capital
- Federal and state income taxes paid
- Gross revenues taxes paid
- Property taxes paid
- Investment tax credit (ITC) earned on investments
- Portion of the ITC which was deferred (under normalized accounting)
- Portion of the ITC which was used to reduce taxes on the books (normalized accounting)
- The tax deferral resulting from accelerated depreciation (normalized accounting).

The basis for the financial calculations in the Finance Module is the attainment of an income figure derived from the user-specified rate of return on rate base or on common equity. The Finance Module calculates the information necessary to develop an income statement from the bottom up. That is, net income is calculated first, then income taxes, interest, other income, operating income, operating expenses, and finally operating revenues.

The calculations are, for the most part, straightforward and simple. After subtracting preferred dividends (calculated by the Fixed Obligations Module) from net income, the remaining income is allocated between retained earnings and common dividends, using a user-specified ratio. Working up the income statement, income taxes are calculated using the prevailing federal and state income tax rate and the after-tax net income (less any non-taxable income, such as AFDC). This calculation is somewhat complicated because the effects of the various non-taxable items, tax deferral items, and ITCs must be accounted for. The amount of investment tax credit is calculated as a percent of the cash construction expenditures for the year, less a portion assumed to be ineligible for ITC (e.g., buildings, land, etc.). By adding net income and taxes paid and subtracting ITC, earnings before taxes (EBT) is determined. (Note that the entire ITC is taken for tax reporting in the year it is earned.) Adding in the long-term debt interest calculated by the Fixed Obligations Module and the interest on short-term debt calculated by the Finance Module (a given interest rate times the average short-term debt for the year) to EBT gives earnings before interest and taxes (EBIT). Subtracting other income (AFDC, calculated by the Plant Module, and any user-specified equity earnings in subsidiary companies) from EBIT yields operating income.

To determine operating revenues, the various expenses must be added to the operating income. The O&M expenses (fuel, operations, maintenance, purchased power, etc.) are provided by the Performance Module. Depreciation charges are calculated by the Plant Module. The remaining expense item, other taxes, is calculated by the Finance Module as a percent of average gross plant excluding AFDC (property tax) and of operating revenues (franchise, payroll, and miscellaneous taxes).

As the Finance Module calculates the items on the income statement, the calculations necessary to develop the other two basic financial statements, the balance sheet and sources and uses of funds, are performed. The capital expenditures and AFDC computed in the Plant Module require financing from internal sources (retained earnings, tax deferrals) and external sources (long- and short-term debt, preferred and common stock). Funds required in excess of internally generated funds are financed first through the issuance of short-term debt to a user-specified limit, then through the issuance of a user-specified mix of long-term debt, common stock, and preferred stock. If there exist internally generated funds in excess of expenditures, short-term debt will be reduced to a user-specified minimum, and any remaining funds will be put into the net working capital account.

For the purposes of this study, a number of new features were added to the model. The Finance Module computes an asset account, decommissioning fund, which represents the cumulative external trust fund available for decommissioning. A liabilities account, decommissioning reserve, contains the accrual for decommissioning. Decommissioning amortization and interest earned on the decommissioning fund is charged annually to the decommissioning reserve.

The model can simulate any of the three financing strategies: funding at commissioning, sinking fund, or funding at decommissioning. Given input assumptions about the cost of decommissioning and interest and inflation rates, the Finance Module will calculate the value of the fund, accumulated interest, decommissioning amortization, and changes in the decommissioning reserve. The model also computes required changes in actual and deferred income taxes, operating income, revenue requirements, interest and dividends, issues of long-term debt and common and preferred stock, and net working capital.

Report Writer Module: Generation of Financial Statements and Other Reports

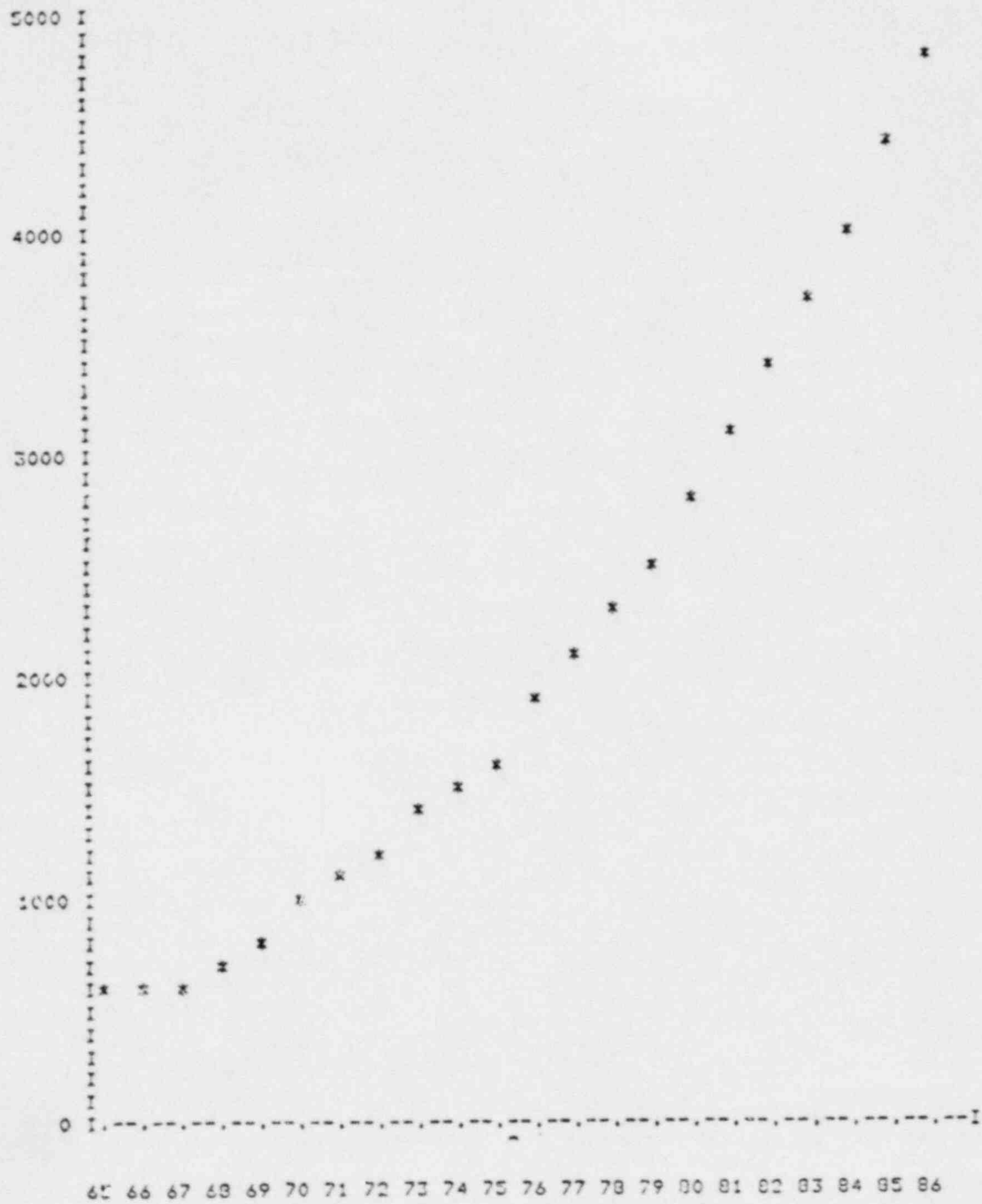
The last part of the Regulatory Analysis Model is the Report Writer Module. The Report Writer Module receives all the information calculated by the Finance, Fixed Obligations, and Performance Modules and displays these data in various user-specified reports. At present, the user has the option of printing income statements, balance sheets, sources and uses of funds statements, and O&M expense projections. The Report Writer Module allows the user to print these reports for any year or years over the forecast period in either constant or current dollars. The user also has the option of specifying which lines of each report are to be printed.

Exhibits A-2 through A-6 illustrate the main reports available from RAm. Exhibit A-7 is an auxiliary report, the Master Data File Report, which provides supplementary and more detailed data than are available in the other reports.

Exhibit A-2

ABC ELECTRIC COMPANY
O/M PROJECTION

THOUSANDS OF CURRENT DOLLARS



^ SIGNIFIES BEGINNING OF FORECASTED DATA

Exhibit A-3

LEGEND

```
* =     ACCOUNT-  502          FILE- LARC71
        COMPANY- ABC           DATE- 07/21/76

   STEAM - OPERATION - STEAM EXPENSE

        MULTIVARIATE LINEAR REGRESSION
        N =  700.238       +  .114359E-03*<1002>
        R-SQUARED = .9494   BASED ON 10 POINTS
```

DATA

ACCOUNT

	1965	1966	1967	1968	1969	1970	1971	1972	1973	1974	1975	1976	1977	1978
502	603.15	618.77	640.35	729.77	792.93	993.63	1106.30	1236.21	1387.96	1459.55	1604.15	1864.44	2050.40	2254.9

	1979	1980	1981	1982	1983	1984	1985	1986
502	2484.01	2768.27	3063.70	3356.81	3661.64	3996.99	4366.17	4790.01

COMPANY -ABC
FILE NO. - 55
DATE -03/21/77

Exhibit A-4

ABC ELECTRIC COMPANY
INCOME STATEMENT
DECEMBER 31

MILLIONS OF CURRENT DOLLARS

	1976	1977	1978	1979	1980	1981	1982	1983	1984
OPERATING REVENUES	308.13	614.64	485.36	497.53	538.09	692.77	732.72	751.36	886.83
-FUEL	151.30	166.43	183.08	220.58	263.69	290.28	338.17	392.79	447.48
-PURCHASED POWER	-53.11	216.65	67.49	17.48	-17.12	75.42	51.94	-6.33	40.97
-OPERATION	56.50	59.56	63.04	66.52	69.90	73.40	77.47	82.08	87.11
-MAINTENANCE	.60	2.70	2.70	2.70	2.70	5.40	5.40	6.30	6.30
-DEPRECIATION	29.16	30.25	31.54	34.93	39.95	43.61	46.02	49.41	53.69
TOTAL OPERATING EXPENSES	184.65	475.58	347.85	342.21	359.32	480.11	519.00	524.25	635.55
-OTHER TAX	20.38	37.57	30.51	31.54	34.31	43.30	45.78	47.17	55.16
-INCOME TAX PAID	28.15	22.52	24.94	36.53	45.61	58.49	60.76	65.00	75.39
-DEFERRED INCOME TAX	8.02	6.96	6.08	6.26	7.11	7.14	6.47	6.27	6.43
-DEF INVEST TAX CREDIT	3.86	6.53	5.92	3.04	3.20	.46	1.02	.89	-.05
TOTAL EXPENSES	245.05	549.16	415.29	419.59	449.55	597.49	633.03	644.57	772.48
OPERATING INCOME	63.08	65.48	70.07	77.94	88.54	95.28	99.69	106.79	114.35
+OTHER INCOME	0	0	0	0	0	0	0	0	0
+AFDC	4.78	9.66	15.55	15.92	9.96	7.46	9.01	9.14	5.41
INCOME BEFORE INTEREST	67.86	75.14	85.62	93.87	98.50	102.74	108.70	115.92	119.75
-INTEREST-LTD	25.19	27.62	31.74	35.17	37.34	38.64	40.70	43.94	45.33
-INTEREST STD	.24	.38	.38	.38	.38	.38	.38	.38	.58
NET INCOME	42.43	47.14	53.51	58.32	60.78	63.72	67.63	71.61	73.84
-PREFERRED DIVIDENDS	6.18	6.96	8.46	9.70	10.18	11.13	12.29	13.11	13.49
EARNINGS AVAIL COMM	36.24	40.19	45.04	48.62	50.60	52.59	55.34	58.49	60.36
-COMMON DIVIDENDS	32.62	36.17	40.54	43.76	45.54	47.33	49.60	52.65	54.32
RETAINED EARNINGS	3.62	4.02	4.50	4.86	5.06	5.26	5.53	5.85	6.04

Exhibit A–5

COMPANY -ABC
FILE NO. - 55
DATE -03/21/77

ABC ELECTRIC COMPANY
SOURCES AND USES OF FUNDS
DECEMBER 31

MILLIONS OF CURRENT DOLLARS

	1976	1977	1978	1979	1980	1981	1982	1983	1984
SOURCES									
INTERNAL									
NET INCOME	42.43	47.14	53.51	58.32	60.78	63.72	67.63	71.61	73.84
DEPRECIATION	29.16	30.25	31.54	34.93	39.95	43.61	46.02	49.41	53.69
DEFERRED INCOME TAXES	8.02	6.96	6.08	6.26	7.11	7.14	6.47	6.27	6.43
DEF INVEST TAX CREDIT	3.86	6.53	5.92	3.04	3.20	.46	1.02	.89	-.05
TOTAL INTERNAL	83.47	90.88	97.05	102.55	111.04	114.93	121.14	128.17	133.92
EXTERNAL									
COMMON STOCK	19.89	28.80	32.01	9.72	8.68	9.43	19.00	14.72	0
PREFERRED STOCK	5.99	12.19	23.28	5.83	5.50	16.82	10.51	8.82	0
LONG TERM DEBT	8.36	48.76	56.41	31.14	20.03	10.47	46.92	29.39	11.87
SHORT TERM DEBT	3.53	0	0	0	0	0	0	0	5.40
TOTAL EXTERNAL	37.78	89.74	111.69	46.70	34.21	36.72	76.44	52.92	17.27
TOTAL SOURCES	121.25	180.62	208.74	149.25	145.25	151.65	197.58	181.09	151.19
USES									
GR PLANT ADDITIONS +AFDC	42.94	37.99	56.84	176.37	163.91	87.28	81.56	151.13	141.36
CWIP INCREMENT	41.84	99.68	79.71	-85.69	-74.84	4.40	36.35	-37.27	-70.53
TOTAL CONST EXPENDITURES	84.78	137.66	136.55	90.67	89.08	91.69	117.91	113.86	70.82
PREFERRED DIVIDENDS	6.18	6.96	8.46	9.70	10.18	11.13	12.29	13.11	13.49
COMMON DIVIDENDS	32.62	36.17	40.54	43.76	45.54	47.33	49.80	52.65	54.32
DEBT RETIREMENT	0	0	11.87	9.90	0	0	11.87	0	11.87
PREF RETIREMENT	0	0	0	0	0	0	0	0	0
NET INCR WORKING CAPITAL	-2.33	-.17	11.31	-4.77	.45	1.50	5.71	1.47	.69
TOTAL USES	121.25	180.62	208.74	149.25	145.25	151.65	197.58	181.09	151.19

Exhibit A-6

COMPANY -ABC
FILE NO. - 55
DATE -03/21/77

ABC ELECTRIC COMPANY
BALANCE SHEET
DECEMBER 31

MILLIONS OF CURRENT DOLLARS

	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984
ASSETS										
GR ELEC PLANT	972.26	1009.95	1042.69	1094.28	1265.40	1424.06	1506.09	1582.40	1728.28	1864.39
-ACCUM DEPREC	255.19	279.10	304.10	330.39	360.07	394.77	433.13	473.90	518.06	566.50
NET ELEC PLANT	717.08	730.85	738.59	763.89	905.33	1029.29	1072.97	1108.50	1210.23	1297.89
+CWIP	50.44	92.28	191.95	271.67	185.97	111.14	115.54	151.89	114.62	44.08
NET ELEC UTIL PLANT	767.52	823.13	930.55	1035.56	1091.30	1140.43	1188.51	1260.39	1324.84	1341.97
NET WORKING CAPITAL	13.87	11.54	11.37	22.68	17.91	18.36	19.86	25.56	27.04	27.73
TOTAL ASSETS	781.38	834.67	941.92	1058.24	1109.21	1158.79	1208.36	1285.95	1351.88	1369.70
LIABILITIES										
COMMON STOCK	145.25	165.14	193.94	225.95	235.67	244.35	253.79	272.79	287.51	287.51
+RETAINED EARNINGS	101.88	105.51	109.53	114.03	118.89	123.95	129.21	134.75	140.60	146.63
TOTAL COMMON EQUITY	247.13	270.65	303.47	339.98	354.56	368.31	383.00	407.53	428.10	434.14
+PREFERRED STOCK	94.53	100.53	112.72	135.99	141.83	147.32	164.14	174.66	183.47	183.47
+LONG TERM DEBT	393.75	402.11	450.87	495.40	516.65	536.68	547.14	582.19	611.58	611.58
TOTAL CAPITAL	735.42	773.29	867.05	971.37	1013.04	1052.31	1094.29	1164.38	1223.16	1229.19
+SHORT TERM DEBT	1.47	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	10.40
+DEFERRED INCOME TAXES	19.13	27.15	34.11	40.20	46.46	53.57	60.71	67.18	73.44	79.88
+DEF INVEST TAX CREDIT	25.36	29.22	35.75	41.67	44.71	47.91	48.37	49.39	50.28	50.23
TOTAL LIABILITIES	781.38	834.67	941.92	1058.24	1109.21	1158.79	1208.36	1285.95	1351.88	1369.70

COMPANY -ABC
FILE NO. - 55
DATE -03/21/77

Exhibit A–7

ABC ELECTRIC COMPANY
MASTER DATA FILE
DECEMBER 31

MILLIONS OF CURRENT DOLLARS

	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984
FILE, DATE, COM, OPTIONS	55	03/21/77	ABC	R		N				
UNUSED FIELD	0	0	0	0	0	0	0	0	0	0
GNP DEFLATOR	1.00	1.05	1.11	1.17	1.24	1.30	1.36	1.44	1.52	1.61
ELECTRIC PLANT(GROSS,INS)	899.88	935.88	967.13	1017.38	1169.03	1309.94	1384.21	1453.74	1584.29	1706.60
CONST WORK IN PROGRESS	44.36	83.11	174.61	240.11	157.96	90.92	95.62	129.73	98.66	36.51
ACCUM DEPRECIATION	237.65	259.24	281.86	305.73	332.68	364.07	398.74	435.61	475.52	519.28
DEPREC THIS PER (ACCEL)	43.45	41.28	40.41	40.08	43.48	49.46	[illegible]	[illegible]	56.45	60.61
NET WORKING CAPITAL CUM	13.87	11.54	11.37	22.68	17.91	18.36	19.86	25.56	27.04	27.73
CUM COMMON STK ISSUED	145.25	165.14	193.94	225.95	235.67	244.35	253.79	272.79	287.51	287.51
COM STK ISSUED THIS PER	0	19.89	28.80	32.01	9.72	8.68	9.43	19.00	14.72	0
CUM RET EARNINGS GENER	101.88	105.51	109.53	114.03	118.89	123.95	129.21	134.75	140.60	146.63
RET EARNINGS GEN THIS PER	0	3.62	4.02	4.50	4.86	5.06	5.26	5.53	5.85	6.04
CUM PREF STK ISSUED	94.53	100.53	112.72	135.99	141.83	147.32	164.14	174.66	183.47	183.47
PREF STK ISSUED THIS PER	0	5.99	12.19	23.28	5.83	5.50	16.82	10.51	8.82	0
CUM LONG TERM DEBT	393.75	402.11	450.87	495.40	516.65	536.68	547.14	582.19	611.58	611.58
LNG TRM DBT ISS THIS PER	0	8.36	48.76	56.41	31.14	20.03	10.47	46.92	29.39	11.87
LNG TRM DBT REF THIS PER	0	0.	0	11.87	9.90	0	0	11.87	0	11.87
CUM SHORT TERM DEBT	1.47	5.00	5.00	5.00	5.00	5.00	5.00	5.00	5.00	10.40
SHT TRM DBT ISS THIS PER	0	3.53	0	0	0	0	0	0	0	5.40
CUM INC TAX DEFERRALS	19.13	27.15	34.11	40.20	46.46	53.57	60.71	67.18	73.44	79.88
INC TAX DEF THIS PER	0	8.02	6.96	6.08	6.26	7.11	7.14	6.47	6.27	6.43
CUM AFDC CAPITALIZED	72.39	74.08	75.57	76.91	96.37	114.12	121.88	128.66	143.99	157.78
AFDC CAPITALIZED THIS PER	0	1.69	1.49	1.34	19.47	17.75	7.76	6.78	15.33	13.79
OPERATING REVENUES	312.65	308.13	614.64	485.36	497.53	538.09	692.77	732.72	751.36	886.63
FUEL EXPENSE	0	151.30	166.43	183.08	220.58	263.89	290.28	338.17	392.79	447.48
PURCHASED POWER EXPENSE	-48.14	-53.11	216.65	67.49	17.48	-17.12	75.42	51.94	-6.33	40.97
OPERATION EXPENSE	58.60	56.50	59.56	63.04	66.52	69.90	73.40	77.47	82.08	87.11
MAINTENANCE EXPENSE	0	.80	2.70	2.70	2.70	2.70	5.40	5.40	6.30	6.30
DEPREC EXPENSE (STR LIN)	0	26.83	27.87	29.12	32.20	36.64	39.92	42.12	45.16	49.01
STATE INCOME TAXES	0	4.82	3.86	4.27	6.25	7.81	10.01	10.40	11.30	12.90

Exhibit A-7 (continued)

COMPANY -ABC
FILE NO. - 55
DATE -03/21/77

ABC ELECTRIC COMPANY
MASTER DATA FILE
DECEMBER 31

MILLIONS OF CURRENT DOLLARS

	1975	1976	1977	1978	1979	1980	1981	1982	1983	1984
FEDERAL INCOME TAXES	0	23.33	18.67	20.67	30.23	37.80	48.48	50.35	54.70	62.49
OTHER TAXES	0	20.38	37.57	30.51	31.54	34.31	43.30	45.78	47.17	55.16
OTHER INCOME	0	0	0	0	0	0	0	0	0	0
ALLOW FUNDS DURING CONST	6.07	4.78	9.66	15.55	15.92	9.96	7.46	9.01	9.14	5.41
INT EXP LONG TERM DEBT	0	25.19	27.62	31.74	35.17	37.34	38.64	40.70	43.94	45.33
INT RATE LTD AVERAGE	0	6.64	6.77	7.08	7.29	7.35	7.39	7.54	7.60	7.72
INT RATE LTD END OF PER	0	6.66	6.87	7.16	7.33	7.37	7.40	7.58	7.62	7.73
DIVIDEND EXP PREF STOCK	5.93	6.18	6.96	8.46	9.70	10.18	11.13	12.29	13.11	13.49
INT RATE PREF STK AVERAGE	0	6.39	6.57	6.85	7.02	7.08	7.18	7.29	7.36	7.38
INT RATE PREF STK END PER	0	6.46	6.68	6.99	7.05	7.11	7.25	7.33	7.38	7.38
INT EXP SHORT TERM DEBT	0	.24	.38	.38	.38	.38	.38	.38	.38	.58
UNUSED	0	0	0	0	0	0	0	0	0	0
COMMON DIVIDENDS	0	32.62	36.17	40.54	43.76	45.54	47.33	49.80	52.65	54.32
RETIREMENTS	4.00	5.25	5.25	5.25	5.25	5.25	5.25	5.25	5.25	5.25
% OF CWIP IN RATEBASE	0	0	0	0	0	0	0	0	0	0
% DEFERR NOT IN RATEBASE	0	0	0	0	0	0	0	0	0	0
NET INCOME	0	42.43	47.14	53.51	58.32	60.78	63.72	67.63	71.61	73.84
INVESTMENT TAX CREDIT	0	4.80	7.68	7.26	4.49	4.75	2.02	2.61	2.51	1.57
INVEST TAX CREDIT AMORT	0	.94	1.15	1.34	1.44	1.55	1.56	1.59	1.62	1.62
CAPITAL EXPENDITURE PLANT	0	41.25	36.50	55.50	156.90	146.16	79.53	74.78	135.80	127.56
SINKG FUND PAY THIS PER	0	0	0	0	0	0	0	0	0	0
CONSTRUCT EXPEND PLANT	0	80.00	128.00	121.00	74.75	79.12	84.23	108.89	104.73	65.42
NET WORK CAPITAL THIS PER	0	-2.33	-.17	11.31	-4.77	.45	1.50	5.71	1.47	.69
DEPRECIATION AFDC - CUM	17.53	19.86	22.24	24.66	27.40	30.70	34.30	38.29	42.53	47.22
INVEST TAX CREDIT CUMUL	25.36	29.22	35.75	41.67	44.71	47.91	48.37	49.39	50.28	50.23
TAX CREDIT	0	3.86	6.53	5.92	3.04	3.20	.46	1.02	.89	-.05
A F D C - CUM IN CWIP	6.07	9.16	17.34	31.55	28.01	20.21	19.92	22.15	15.96	7.57
DEPREC AFDC - THIS PER	0	2.33	2.38	2.42	2.74	3.30	3.69	3.91	4.24	4.68
RATEBASE	0	0	0	0	0	0	0	0	0	0
NET WORKG CAP (PUC INPUT)	0	0	0	0	0	0	0	0	0	0

Appendix B

MAJOR ASSUMPTIONS

A large amount of user input is required for the execution of RAm, and consequently many assumptions must be made about present and future operating conditions and parameters of the utility involved. This appendix lists the major assumptions involved in both the creation of the baseline and the alternate decommissioning scenarios.

Baseline

The following assumptions were incorporated into the baseline projections for both Northeast Utilities and Maine Yankee:

- [illegible].2 percent average inflation for the period [illegible]80-1990 (obtained from DRI forecasts); 5.6 percent average inflation for 1990-2017.
- 7.4 percent inflation for construction costs.
- Long-term debt and preferred stock interest rates of 9.5 percent; short-term debt rate descending from 9.5 percent to 8.5 percent over 40 years.
- No CWIP included in rate base.
- 9 percent rate of AFDC on CWIP.
- Normalization of income tax timing differences.

The following pertain only to Northeast Utilities:

- 3 percent average load growth over 40-year planning horizon.
- Fossil-fired capacity added to meet load growth with a 20 percent reserve margin.
- 11.8 percent inflation in fuel costs.

- Combined state and federal tax rate of 52.4 percent in Connecticut, 50.0 percent in Massachusetts.
- Target capital structure of 37.5 percent common equity, 12 percent preferred stock, and 50.5 percent long-term debt.
- 65 percent dividend payout ratio.
- 10 percent annual increase in short-term debt limits.
- 12 percent return on equity.
- 81 percent of expenses based in Connecticut; 19 percent in Massachusetts.

The following pertain to Maine Yankee only:

- Target capital structure of 31.7 percent common equity, 1.5 percent preferred stock, and 61.8 percent long-term debt.
- 100 percent dividend payout ratio.
- 10 percent return on equity.
- Combined federal and state income tax rate of 51.4 percent.
- Nuclear fuel expense growth at 8.2 percent.
- 7 percent inflation in nonfuel operations and maintenance expenses.

Decommissioning Scenarios

The following are the assumptions made to model the decommissioning of nuclear reactors:

- $50 million reactor decommissioning cost (in 1979 dollars), regardless of technological alternative.
- 7.4 percent inflation for decommissioning cost.

- 5 percent after-tax return on decommissioning fund.
- Reactor life of 30 years.
- Straightline normalization of decommissioning expense tax deduction.
- Millstone 3 completed on schedule in 1986.

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16. ABSTRACT (200 words or less)

The report analyzes several alternatives for financing the decommissioning of nuclear power plants from the point of view of assurance, cost, equity, and other criteria. Sensitivity analyses are performed on several important variables and possible impacts on representative companies' rates are discussed and illustrated.

17. KEY WORDS AND DOCUMENT ANALYSIS

17a. DESCRIPTORS

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17b. IDENTIFIERS/OPEN-ENDED TERMS

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