AN ECONOMIC EVALUATION OF THE REPLACEMENT OF OIL-FIRED GENERATION CAPACITY WITH COAL-FIRED CAPACITY

Prepared for

Energy Policy Division
Office of Planning and Evaluation
U.S. Environmental Protection Agency

Prepared by

Putnam, Hayes and Bartlett, Inc.
50 Church Street
Cambridge, Massachusetts 02138

March 1981

The assumptions, findings, conclusions, judgments, and views expressed herein are those of Putnam, Hayes and Bartlett, Incorporated and should not be interpreted as necessarily representing the official policies of the U.S. Government.

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SECTION I
INTRODUCTION AND SUMMARY

In March 1980 the Carter Administration proposed a legislative program to convert and replace oil and gas-fired electricity generating capacity with alternative sources of energy. The proposed program was designed to displace 750,000 barrels of oil per day and the natural gas equivalent of 250,000 barrels of oil per day by 1990. The electric utility industry, which consumes approximately 3 million barrels of oil and natural gas equivalent per day was the prime target of this proposed program to reduce our dependence on foreign oil.

The proposed program had two phases. The first phase would have required an amendment to the Powerplant and Industrial Fuel Use Act to prohibit oil burning at 107 utility boilers capable of converting to coal or other alternative fuels.[1] Grants totaling $3.6 billion would have been available to assist utilities with the mandatory conversions. The second phase provided for $6 billion in grants to encourage reduced oil and gas consumption by retiring additional oil and gas-fired generating units. The oil and gas displacement could be achieved through energy conservation, renewable resources, or the replacement of oil and gas-fired generation with alternative resources (coal, nuclear or synthetic fuels).

This report does not address the issue of conversion from oil to alternative fuels. Rather it focuses on the economics of the replacement of existing oil-fired units with new coal units (Phase II of the Carter Administration's proposal) and discusses the disincentives that currently exist for such replacement. The first section of the report summarizes the results of this analysis, describes the methodology used to analyze the economics of oil plant replacement, and presents the organization of the remainder of the report.

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[1]The Senate has since reduced this number to 80 oil-fired units.

SUMMARY OF RESULTS

Strictly from an economic standpoint, absent the effects of rate regulation, the capital costs of constructing a new coal plant are more than offset by the savings in fuel costs over the life of the plant.[1] The present value of the cost of providing power from the coal plant--both fuel and capital costs--is approximately 85 percent of the cost of fuel for providing an equivalent amount of power from an existing oil plant over the life of the coal plant.

While the replacement of oil-fired units with coal units is favored from an economic standpoint, four conditions exist which provide a disincentive to utilities to undertake such investments. These disincentives include:

- The significant uncertainty regarding the cost of a new coal plant compared to the costs of an existing oil plant,
- Rate-setting procedures which make such replacement unattractive for the utility's customers and/or stockholders,
- The inability of the utilities to finance replacement capacity in addition to the capacity needed to serve load growth, and
- The difficulty in siting and obtaining licenses for new plants.

The first three of these disincentives are analyzed in Section II of this report. The following conclusions concerning the first three disincentives can be drawn from this analysis:

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[1] The economics of such replacement are, of course, dependent upon the assumptions used in the analysis. All of these assumptions are detailed in Appendix A of this report. Section II of this report illustrates the sensitivity of the results to some of the key assumptions.

- **Uncertainty in costs may cause a utility to prefer the continued use of an existing oil plant.**

  --Construction costs of $1852 per kilowatt in 1979 dollars would make the replacement of oil-fired capacity uneconomical.[1]

  --If coal costs per kilowatt-hour were to rise to 72 percent of the cost of oil, oil plant replacement would be uneconomical.

  --Coal costs 20 percent higher than anticipated combined with a capital cost of $1430 per kilowatt would make the replacement uneconomical.

- Rate-setting practices provide a significant disincentive for new plant construction.

  --Rate-setting practices such as flow-through accounting, the exclusion of construction work in progress from the rate base, inadequate allowed rates of return, regulatory lag, and, in some cases, fuel adjustment clauses provide a disincentive to the utility to replace oil-fired generating capacity.

  --Under standard rate-setting practices, the construction of a coal plant will result in higher rates for consumers in the near term and lower rates in the future.[2] Regulators may be hesitant to approve construction plans which result in increases in rates in the short run. However, if the consumers' discount rate is below 17 percent, the consumers would prefer to have the utility replace the oil plant.[3]

- The financial condition of some utilities is currently so poor as to preclude the investment in a new coal plant.

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[1]The cost per Kilowatt of a new coal plant has been estimated to be $973 but the cost can be significantly higher depending upon siting problems and pollution control requirements.

[2]The customer must pay capital costs on the new coal plant as well as fuel costs if the coal plant is constructed. In the near term the differential between oil and coal costs is lower than the capital costs of the coal plant borne by the customer; however, in the future the capital costs borne by the customer are lower than the differential between oil and coal costs.

[3]The consumers' discount rate is the time value placed on money by the utility's customers.

--The financial condition of some of the utilities in the Northeast is sufficiently poor such that these utilities will not be able to finance the replacement of oil-fired capacity in addition to its current capital requirements.

The first conclusion implies that rate-setting procedures, regulatory practices, and/or economic conditions which serve to reduce the uncertainty associated with the construction of new coal plants would eliminate some of the existing disincentive to construct new plants. Examples of measures which would reduce uncertainty would be adequate and predictable rate increases, inclusion of construction work in progress in the rate base, streamlined procedures for obtaining licenses for new plants and a reduction in the general rate of inflation throughout the economy.

The second conclusion means that the Public Utility Commission (PUC) must ensure that the return on the coal plant investment is adequate so that the utility has an incentive to invest in the new coal plant. In addition, the PUC should consider optimizing the time pattern of the utility's recovery of costs such that the consumer gains in the short term from the construction of a coal plant.

The final conclusion implies that, in some cases, regardless of the economics of oil replacement, such replacement will not occur without a substantial improvement in the utilities' overall financial positions. In these cases, the reduction in the uncertainty associated with construction and fuel costs and/or more favorable rate-setting practices may not be adequate incentive to encourage the replacement of oil-fired capacity. The provision of $6 billion in grants may provide much needed financial assistance to utilities. Whether or not this amount is sufficient to enable utilities to finance the replacement of oil-fired generating capacity is not analyzed in this report.

However, this report did consider whether the grant or other proposed incentives would be effective in reducing the disincentives that currently exist. This analysis is discussed briefly at the end of Section II.

METHODOLOGY

In order to understand the economics of replacement under various regulatory and economic conditions, the cost of providing power from a coal plant and an oil plant was simulated using a utility financial simulation model. This model was used to simulate the incremental effects on the utility's revenue requirement, cash flow, and rate base of an investment in a 410 MW coal plant. The coal plant was assumed to run at 50 percent of its effective capacity of 375 MW.[1]

This model can be used to analyze the financial condition of an entire utility or group of utilities or, as in this case, the economics of a single investment decision. Estimates of fuel costs, construction costs, operating and maintenance costs, and capital costs are input into the model.[2] The model then produces a set of financial statements--income statement, balance sheet, and funds flow--resulting from these costs and the regulatory conditions imposed on the model. The regulatory conditions include flow-through or normalized accounting, the

[1]This is a worst case assumption. Larger coal plants run at a higher capacity factor will be more economical.

[2]The model compares the fuel costs, operating and maintenance costs, and capital costs of a new coal plant with the fuel and operating and maintenance costs of an existing oil plant. In each case--whether or not the coal plant is constructed--it was assumed that the capital recovery charges for the oil plant (remaining depreciation and the return on the undepreciated portion of the plant) would be the same. Therefore, capital recovery charges for the oil plant were not considered in this comparative analysis.

inclusion or exclusion of contruction work in progress (CWIP) from the rate base, the period of regulatory lag for fuel costs and for capital costs, and the allowed rate of return.

In addition to the analysis performed using the utility financial simulation model, a financial analysis of six Northeast utilities was performed. This analysis reviewed the ability of these utilities to finance the replacement of oil-fired capacity. While these utilities are not typical of all utilities, they are typical of utilities with old oil-fired generating units. Included in this analysis is a review of each utility's internal and external financial capability, as well as a review of the capital requirements of the utility's current construction plans.

PLAN OF THIS REPORT

The remainder of this report is organized as follows:

- Section II presents the results of the analysis of the economics of oil plant replacement and the disincentives which exist for such replacement.
- Appendix A presents the assumptions and data used in the analysis.
- Appendix B summarizes the analysis of the financial condition of six Northeast utilities.

All exhibits are located at the end of each Section or Appendix.

SECTION II
REPLACEMENT OF OIL PLANTS

Phase I of the Carter Administration's proposed oil backout program would have required the conversion of 107 oil-fired generating units to coal.[1] Grants totaling $3.6 billion would have been provided to assist the utilities required to convert. Phase II of this program provided for $6 billion in grants to encourage voluntary replacement of additional oil-fired generating units with alternative power sources including conservation, renewable resources, and alternative fuels such as coal, nuclear and synthetic fuels. This section reviews the economics underlying the replacement of oil-fired units with coal units. A discussion of some of the disincentives for this replacement is then provided. Finally, the ability of Phase II of the proposed oil backout program to eliminate some of these disincentives is reviewed.

ECONOMIC EVALUATION OF OIL PLANT REPLACEMENT

To evaluate the desirability of replacing older oil plants with new coal plants from an economic standpoint absent rate-setting effects, the savings from the lower fuel costs should be compared to the cost of the new plant, less all related tax consequences. All costs are discounted to their present value equivalent recognizing that a dollar a year from now does not have the same value as a dollar today. This "capital budgeting" type of analysis would determine whether, absent rate-setting effects, it is desirable from the utility stockholders' point of view to replace older oil plants with new coal plants.

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[1]In the Senate version of this legislation, the number of plants which would be required to convert was reduced to 80.

Exhibit II-1 presents the cash flows resulting from the investment in a new coal plant.[1] These cash flows include:

- The cost of plant construction;
- The investment tax credit which reduces the tax liability of the firm by 10 percent of all qualifying investments;
- The tax shield resulting from the depreciation of the plant;
- The cost of fuel and of operating and maintaining the coal plant; and
- The investment in working capital, predominantly for fuel inventories.

These cash flows are summed and discounted at the utility's after-tax weighted average cost of capital.[2] As shown in Exhibit II-1, the present value of the coal plant investment is $1133 million, including fuel costs over the life of the plant.

The present value of the costs of operating the oil-fired plant is shown in Exhibit II-2. The cash flows considered include the cost of fuel, the cost of operating and maintaining the oil plant, and the investment in working capital (fuel inventories).[3] The present value of these costs is $1337 million. Thus, strictly from an economic standpoint, the replacement of oil capacity with coal capacity will represent a savings of $204 million ($1337 million less $1133 million).

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[1]The data and assumptions on which this analysis is based are presented in Appendix A. The results of this analysis are highly dependent upon these assumptions.

[2]Since we are concerned with the economics of replacement from the utility stockholder's point of view, absent rate-setting effects, these flows are discounted at the utility's actual cost of capital assumed in the analysis (which assumes a 15 percent rate of return on equity) and not the rate of return on capital allowed by the Public Utility Commission (which includes a 13.5 percent return on equity capital).

[3]As explained in Section I and Appendix A, these costs do not include the capital recovery charges associated with the oil plant since these capital recovery charges will be incurred whether or not the coal plant is constructed.

REASONS REPLACEMENT IS NOT OCCURRING

There may be several reasons why oil plant replacement is not taking place currently. The disincentives which exist include:

- The uncertainty regarding the cost of a new coal plant versus the cost of an existing oil plant,
- Rate-setting practices which can make replacement uneconomical for the utility's consumers and/or stockholders.
- The inability of the utilities to finance replacement capacity in addition to capacity needed to serve load growth, and
- The difficulty in siting and obtaining licenses for new plants.

The first three reasons cited are analyzed below.

UNCERTAINTY

The economics of the replacement of oil-fired generating capacity depend upon the estimated future cost of oil versus coal and the anticipated cost of constructing a new coal plant. Both future fuel and construction costs are highly uncertain. Given this uncertainty, the utility may be hesitant to construct a new coal plant.

To understand how uncertainty affects the decision to construct a new coal plant, a "breakeven" analysis is presented below. This analysis calculates the amount of increase in construction costs and fuel costs which can occur before the construction of the coal plant becomes unattractive from an economic standpoint.

Construction Costs

As discussed in Appendix A, it was assumed that a bituminous coal plant constructed in the Northeast would cost \$723 per kilowatt for generating capacity, \$100 per kilowatt for transmissions and distribution facilities, and \$150 per kilowatt for related pollution control equipment--a total of \$973 per kilowatt in 1979 dollars. Recent experience with the construction of coal plants indicates that delays in construction and higher than anticipated inflation have often resulted in increased construction costs. The economics of oil plant replacement depend upon the anticipated construction cost of the new coal plant. If the investment cost of coal plant amounted to \$1852 per kilowatt (1979 dollars) rather than \$973 per kilowatt, the replacement of the oil plant would no longer be desirable from an economic standpoint.

Even if the construction of the coal plant were still economically justifiable, increases in construction cost may be difficult for the utility to finance. Financing difficulties are discussed in more detail below.

Coal and Oil Costs

An additional uncertainty lies in the projections of the differential between oil and coal costs. Currently the cost of bituminous coal in the Northeast equals 50 percent of the cost of fuel oil #6 per kilowatt-hour. However, according to one forecast, coal costs are projected to rise at a 5 percent real rate (net of inflation) in the near term; while oil costs are projected to rise only 3 percent in real terms.[1] This trend

[1] This forecast reflects the projections published by Data Resources, Inc. in their Energy Review, Winter 1980.

then reverses itself after 1986 when oil costs are projected to increase at a steeper rate than coal costs.

If instead coal prices continued to rise at the 5 percent real rate until 1992 and then rose at the same rate as oil prices in the remaining years of the analysis, the cost of coal per kilowatt-hour would rise to approximately 72 percent of the cost of oil by 1992. This increase in coal costs would result in the coal plant having a higher present value cost than the oil plant.

Such an increase implies coal prices approximately 38 percent higher than projected each year. While this may appear extreme, uncertain fuel costs together with uncertain coal plant construction costs may lead to hesitance on the part of utilities to replace oil plants. For example, if coal costs were 20 percent higher than projected and construction costs were $1430 per kilowatt (1979 dollars), the economics again would favor not replacing the oil plant.

EFFECT OF RATE-SETTING PRACTICES

Although the decision to replace oil plants may be sound from a purely economic standpoint, the rate-setting environment may cause the utility to favor maintaining the oil plant. The rate-setting practices may make replacement unattractive for the utility's stockholders and/or customers. The effect of the different regulatory practices on the stockholder and the customer is discussed below.

Stockholder Impact

The Public Utility Commission (PUC) determines the rates the utility will be allowed to charge customers for the electricity provided. These rates are calculated by determining the "revenue requirement" of the utility. The "revenue requirement" is, in theory, sufficient to compensate the utility for its operating costs, including taxes, plus provide a return on the capital invested in the plant. In theory, the impact of the construction of the coal plant should result in an after-tax revenue requirement[1] over the life of the plant equal to $1133 million. This would exactly equal the present value of the cost of the coal plant investment.

If the revenue requirement resulting from the construction of the coal plant does not cover the costs of constructing coal plant, profits will decline and hence, the rate of return on common equity will decline. Thus, the utility's common stockholders will find the construction of the coal plant unattractive.

There are many reasons why the revenue requirement in practice does not precisely reflect the costs calculated above. These reasons include rate-setting practices which affect either the timing or the amount of the utility's revenue. These rate-setting practices include:

- Flow-through accounting which requires the utility to immediately pass on the benefits of the investment tax credit and the benefits of accelerated depreciation to the consumer, instead of allowing the utility to "normalize" these credits and pass them onto the consumer over the life of the plant;
- Allowance for Funds Used During Construction (AFDC) which requires the utility to capitalize the capital costs of the investment during the construction period and then allows the utility to recover these costs

[1]The revenue requirement after taxes will equal the utility's revenue requirement multiplied by one minus the utility's marginal income tax rate. The revenue requirement is not normally stated on an after-tax basis. However, in this case, it is necessary to do so in order to be able to directly compare the present value of the revenue requirement to the present value of the after-tax costs of the coal plant computed above.

over the life of the plant, rather than allowing the utility to include construction work in progress (CWIP) in the rate base and thus to earn a cash return on the plant during the construction period;[1]

- <u>An inadequate allowed rate of return</u> which does not provide a sufficient return on the utility's equity shareholders; and[2]

- <u>Regulatory lag</u> which allows the utility to recover the capital cost incurred only after some lag.[3]

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[1]Many PUC's exclude construction work in progress (CWIP) from the rate base. However, to offset the cost of funds tied up in construction, PUC's provide for an "allowance for funds used during construction (AFDC)." A return on CWIP is calculated annually. This return (AFDC) is added to the utility's net income and a corresponding amount is added to the CWIP account on the balance sheet, thereby increasing the asset value of the plant. When the plant is completed, the total amount of the construction costs plus accumulated AFDC is added to the rate base. The utility is then allowed to earn a return on this increased rate base and is allowed to depreciate the total amount--both the construction costs and accumulated AFDC--for rate-making purposes. The effect of this calculation is to postpone the receipt of cash earnings on the investment until the plant is actually placed into service.

The credit to net income and corresponding debit to CWIP on the balance sheet is an accounting transaction only and does not represent an increase in the cash earnings of the utility. Therefore, AFDC represents non-cash income and as such should not be regarded as a source of funds for the utility. This lowers the "quality of earnings" of the utility.

If the AFDC rate is set too low and/or the utility is not allowed to earn a return on past AFDC (that is, a compound rate of return on CWIP), the AFDC will be inadequate to compensate the utility for the cost of capital for construction of the plant.

[2]An inadequate rate of return will cause the market price of the stock to fall below the book value of the stock. This makes it difficult for the utility to issue common stock to raise funds for its construction program since any new common stock will dilute the book value of the current shareholders' stock.

[3]In this analysis, it is assumed that fuel and other operating costs are recovered without lag through a fuel adjustment clause. In reality, a lag of one or more months may be built into the fuel adjustment clause.

To measure the effect of altering the rate-setting practices, the allowed after-tax revenue requirements resulting from the coal plant construction under different rate-setting practices was compared to the cost of constructing the coal plant. The base case rate-setting practices assume flow-through of all tax credits/benefits to the consumer, the exclusion of CWIP from the rate base, an allowed rate of return of 9.66 percent compared to an actual cost of capital of 10.2 percent,[1] and a one year lag in the recovery of capital costs and no lag in the recovery of fuel costs.

The effect of the first two of the above regulatory practices is shown in Exhibit II-3. As shown in this exhibit, the after-tax revenues allowed to be recovered by the utility as a result of the coal plant investment of $1078 million over the life of the coal plant investment if the utility is not allowed to include CWIP in the rate base and is required to flow-through all tax credits and benefits (base case). If the utility is allowed to normalize all tax benefits and to include CWIP in its rate base, the allowed after-tax revenues are $1094 million. However, the allowed after-tax revenues are still below the cost of constructing the coal plant of $1133 million. Thus, the utility's profits will decline as a result of constructing the new coal plant and the return to the common stockholders will also decline.

The incremental effects of allowing the utility to earn an adequate rate of return and of eliminating the regulatory lag are shown in Exhibit II-4. As this exhibit shows, an increase in the rate of return from 9.66 percent to 10.20 percent increases the allowed after-tax revenues to $1108 million.[2] Eliminating

[1]The rate of return of 9.66 percent is a weighted average cost of capital which includes an assumed allowed rate of return on equity of 13.5 percent rather than the actual cost of equity capital assumed to be 15 percent.

[2]This scenario assumes that the utility is allowed to normalize all tax credits and is allowed to include CWIP in the rate base.

regulatory lag increases the allowed after-tax revenues to $1118 million. Combining the increase in allowed return with the elimination of regulatory lag causes the allowed after-tax revenues to increase to $1133 million which exactly equals the cost of constructing the coal plant. Thus, the utility's stockholders would be indifferent to the replacement of the existing oil plant with a new coal-fired plant.

In order to have the after-tax revenue requirement match the costs incurred by the utility, rate-setting practices in some states would have to be altered. The utility's stockholders would be adversely affected by investment in a coal plant if tax credits are flowed through to consumers, CWIP is not allowed in the rate base, an inadequate return is allowed, and/or regulatory lag is present. When the allowed after-tax revenue requirements is less than the cost of the investment, the utility has a disincentive to replace oil plants with coal plants.

Customer Impact

The PUC must consider the impact of the coal plant investment on the price of power to consumers. These prices will vary depending upon the rate-setting practices imposed by the PUC.

As discussed above, the PUC determines the revenue requirement of the utility. This revenue requirement divided by the kilowatt-hours provided gives the average cost of electricity per kilowatt-hour for the customer. Exhibit II-5 illustrates graphically the cost of kilowatt-hour of power from the oil plant versus the coal plant under different rate-setting conditions. In all cases, the cost of a kilowatt-hour from the coal plant is higher in the years immediately after the coal plant is completed. This is due to the large increase in the rate base in this year and consequently, higher capital costs are included in the revenue requirement. The utility earns a rate of return on the value of its plant less accumulated depreciation (net plant). Since the value of its net plant for any single investment declines over time, the capital recovery decreases over time. This "front loading" of the capital charges results in higher consumer prices in the near term and lower costs in the future for the coal plant as compared to the oil plant.[1]

It is possible to spread these capital charges more evenly over the life of the investment. Depending upon the consumers' discount rate, the consumer may prefer to realize some of the benefits of the lower fuel costs earlier and pay slightly higher costs in the future. To accomplish this the PUC could levelize the recovery of the capital costs in nominal or in real terms. This is illustrated in Exhibit II-6. This exhibit shows the amount of capital recovery for the new plant included in the rates under the current method, under levelized capital recovery in nominal terms, and under levelized capital recovery in real terms. In each case the total present value of the capital recovery charges is equal using a discount rate equal to the rate of return allowed by PUC. A discount rate equal to the rate of return allowed the utility by the PUC is used to levelize the capital charges in order to ensure that the revenue requirement in each case would adequately cover the capital costs incurred by the utility <u>if</u> the allowed rate of return reflected the actual cost of capital to the utility.

The utility, however, will not be indifferent to the capital recovery method chosen if the discount rate used to levelize the capital recovery charges is lower than the actual

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[1]As explained previously, the capital costs of the coal plant exceed the fuel savings (the cost of oil less the cost of coal) in the near term. However, in the future the capital costs of the coal plant are lower than the fuel savings.

cost of capital. The present value to the utility, discounting at their actual cost of capital, is highest under the current method of capital recovery.[1] Therefore, an additional alternative is considered which includes an increase in the allowed rate of return along with levelized capital recovery in real terms.

The pattern of rates under each capital recovery method is compared to the rates for the oil plant in Exhibit II-7. As shown in this exhibit, the rates under the levelized capital recovery method in real terms are equal or less than the rates for the oil plant over the entire period (even with an increase in the future (after 1996) under both methods of levelizing the capital recovery compared to the rates using the current method of capital recovery).

As stated above the preferred pattern of rates from the consumers' standpoint will depend upon the consumers' discount rate.[2] Exhibit II-8 gives the present value of the cost of a single kilowatt-hour each year using various discount rates under the different capital recovery methods and different regulatory conditions.

The following observations can be made from this exhibit:

- The consumer prefers the coal plant investment for each of the discount rates given.[3]

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[1] The higher the discount rate the more valuable are cash flows which occur in the near term compared with cash flows in the distance.

[2] The consumers' discount rate refers to the time value placed on money by the utility's customers. This analysis is accurate for the group of consumers in the service territory assuming that their discount rate does not change over time as a result of changes in the composition of the group over time.

[3] This is true for discount rates as high as 17 percent. At 17 percent, the consumer would prefer to pay the cost of the oil plant rather than the cost of the coal plant under the regulatory conditions assumed in Scenario 4.

- At consumer discount rates below 10.2 percent the consumer would prefer the utility normalize rather than flow-through its tax credits. (Scenario 2 versus Scenario 1.)

- The consumer would prefer to exclude CWIP from the rate base at discount rates above 8 percent. (Scenario 1 versus Scenario 3.)

- For discount rates above 10.2 percent the consumer would prefer either method of levelizing the capital recovery charges. (Scenarios 5 and 6 versus Scenario 1.)

- At discount rates above 11 percent, the consumer would prefer the utility be allowed to earn 15 percent return on equity using a levelized capital recovery in real terms rather than the current method of capital recovery with a 13.5 percent return on equity. (Scenario 7 versus Scenario 1 and Scenario 8 versus Scenario 2.)

- At a 15 percent discount rate the consumer would prefer the utility be allowed to normalize tax credits and earn a 15 percent return on equity using levelized capital recovery in real terms rather than flow-through these credits and earn a 13.5 percent return on equity using the current method of capital recovery. (Scenario 8 versus Scenario 1.)

The PUC's should give some thought to optimizing the time pattern of the utility's recovery of costs such that the consumer gains from the construction of a coal plant. This, hopefully, would reduce consumer and regulator resistance to the construction of economical coal plants.

FINANCING DIFFICULTIES

Some of the Northeastern utilities are contesting Department of Energy orders to convert oil-fired generating units to coal. The reason cited for the appeals is the lack of available funding for the conversions. Thus, even if the PUC were to adopt more liberal rate-setting practices, the utility might still find it difficult to replace oil plants.

The funds required for constructing the coal plant are shown in Exhibit II-9. This exhibit shows the total funds required for the investment less the funds available from any investment tax credits which are not flowed through to consumers and funds available from the return earned on any CWIP allowed in the rate base. The total funds required range from $719.6 million for a utility which flows through its tax credits and is not allowed to include CWIP in its rate base to $577.0 million for a utility allowed to normalize its tax credits and include all CWIP in the rate base. Therefore, changes in rate-setting practices can amount to as much as a 20 percent difference in the funds required. However, the funds required in all cases are still substantial.

To understand the magnitude of the financing difficulties for some utilities, a brief financial review of six Northeastern utilities was performed.[1] A summary of this review is provided in Exhibit II-10.[2] This exhibit indicates that:

- All of the utilities will be required to finance over 60 percent of their construction programs over the next five years with externally-generated funds.[3]
- In 1979 the proportion of earnings comprised of non-cash AFDC ranged from 36 percent for Connecticut Light & Power to a staggering 92 percent for the Public Service Company of New Hampshire.[4]
- Two of the six utilities have applied for exemptions from Department of Energy orders to convert oil-fired units to coal. (United Illuminating and Connecticut Light and Power.)

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[1] These utilities are not representative of all utilities but are indicative of utilities with old oil-fired units.

[2] A discussion of each utility is included in Appendix B.

[3] Nationally, 64 percent of funds were generated externally in 1979.

[4] As explained above, AFDC is a non-cash credit to earnings. The internal cash flow available to the utility for the payment of dividends and for funding capital expenditures is net income less AFDC plus depreciation and any other non-cash expenses.

- Four of the six utilities are prohibited by bond indenture provisions from issuing new unsubordinated debt. (The exceptions are Boston Edison and New England Power.)
- Five of the six utilities have construction plans dominated by nuclear plants. The only exception is New England Power which is aiming to reduce peak demand growth from 3.1% to 1.9% by relying on conservation and load management programs.[1]

As these points indicate, four of these Northeastern utilities are severely strained financially and an additional capital requirement of $0.6 billion for the construction of a coal plant cannot be absorbed in the short term even under rate-setting practices favorable to the utility.

Financial pressures would be eased if the pending legislation passes. This would provide $6 billion in grants to utilities who voluntarily replace oil-fired capacity. This analysis did not consider whether or not the amount of grants available to specific utilities would be sufficient to enable them to finance the replacement of oil capacity. However, the analysis did consider whether the grant or other proposed incentives would help to eliminate the disincentives which currently exist. This analysis is reviewed below.

EFFECTIVENESS OF PROPOSED
INCENTIVES

Several proposals, in addition to the oil backout program, have been suggested as incentives to encourage the utilities to replace oil-fired generation with coal-fired plants. These programs include:

[1]The addition of these nuclear plants may permit some of these utilities to retire their older oil-fired plants.

- A dollar per barrel bounty for each barrel of oil per day eliminated,
- Grants or loans which are repaid on the basis of fuel savings,
- Sale/leaseback arrangements for coal plants,
- Splitting the total cost savings between the utility's stockholders and its customers,
- Modifying the recovery of the capital costs of the plant and providing for a higher rate of return on equity for the utility's stockholders, and
- Elimination of the fuel adjustment clause.

Each of these proposals is discussed below in terms of how likely they are to reduce the disincentives for oil plant replacement discussed throughout this report--uncertainty regarding the economics of oil plant replacement, rate-setting practices, and the poor financial condition of the utilities.

Dollar Per Barrel Bounty

Phase II of the proposed oil backout program provided for a bounty to be paid to the utility for each barrel of oil per day eliminated. This bounty would have amounted to $10,000 per barrel. If the utility retired a 410 MW plant which ran at 50 percent of its 375 MW capacity, it would eliminate 6700 barrels per day of oil.[1] A grant for the amount $67 million would have been given to the utility during the construction period. Using the costs cited above, this would amounted to 17 percent of the initial investment in 1979 dollars.

[1] Assuming a barrel of residual oil contains 6.287 million Btu's and the plant has a heat rate of 9,340 Btu/Kwh.

This proposed program would help ease the financing burden faced by the utility by providing cash when it is most sorely needed--during the construction period. It would also reduce the cost of the coal plant and hence reduce the uncertainty concerning the economics of the new coal plant. The disincentives for coal plant construction which stem from rate-setting procedures are not likely to be reduced as a result of this program.

Grants Repaid out of Fuel Savings

One proposal suggests that the utility be given a grant during the construction period. The utility would then repay this grant out of the fuel savings it achieves through the replacement of oil with coal or nuclear fuel. An arrangement very similar to this has been in effect for several years in Ontario, Canada. Government loans were provided to Ontario Hydro for the construction of a nuclear plant. These loans are being repaid from the fuel savings realized by Ontario Hydro over the life of the plant.

This arrangement will help ease the financing burden of the utility. It will also significantly reduce the economic uncertainty regarding oil plant replacement since the utility need not repay the grant if no fuel savings are realized. The existing rate-setting disincentives are unlikely to be reduced by this proposal.

Sale/Leaseback Arrangement

This proposal would allow investors other than the utility to construct coal plants and then lease them to the utility for the life of the plant. This would eliminate the financial problems facing the utilities since they would not need to provide the funds for the initial construction of the plant. The uncertainty concerning the economics of a coal plant is not reduced; it is merely transferred from the utility to the other investors. The rate-setting procedures which currently provide a disincentive for investment may or may not be reduced depending upon the structure of the lease payments and the recovery of these lease payments through rates. If the lease payments are constant, the effect will be to levelize the recovery of the capital costs in the revenue requirement. As shown above, the consumer may prefer this under certain discount rates. The disincentives stemming from rate-setting procedures that exist from the point of view of the utility's stockholders will be eliminated as long as the full amount of the lease payments is recovered in the rates in a timely fashion.

Splitting of Total Cost Savings

Under this proposal the utility's shareholders and customers would share the cost savings realized by replacement of an oil-fired plant with a coal-fired plant. Under current rate-setting practices, all savings are passed onto the customers of the utility.

This proposal would not ease the financing faced by the utilities nor would it reduce the uncertainty regarding the economics of oil plant replacement. The likely effect of this proposal would be an increase in the rate of return to the equity shareholders. This would eliminate some of the current disincentive that exist due to rate-setting practices from the point of view of the stockholder. Consumers would be worse off under this proposal and thus, any existing rate-setting disincentives which exist from the point of view of the consumer would increase.

Modifying the Recovery of Capital Costs and Higher Returns on Equity

This proposal has been discussed in some detail above. The capital charges in the revenue requirement each year would be levelized in real or nominal terms rather than being based on depreciated book value. In addition, the rate of return on equity allowed by the PUC would be increased.

As demonstrated above, this proposal could eliminate some of the existing rate-setting disincentives for both the stockholder (by providing a higher rate of return) and the consumer (by allowing the cost savings to be realized earlier and slightly higher rates to be paid later). This proposal has no impact on the cash available for new construction nor does it reduce the uncertainty regarding the economics of oil plant replacement.

Elimination of the Fuel Adjustment Clause

The elimination of the fuel adjustment clause would require the utility to file for a rate increase each time its fuel costs rise, just as the utility must currently file a rate case in order to recover increases in capital costs. This would equalize the lag between the recovery of fuel and capital charges. Thus the utility would have no incentive to minimize capital costs in trade for higher fuel costs.

This proposal would worsen the financial position of the utilities by increasing the lag in the recovery of increased fuel costs. Thus the utilities' ability to finance new plants would be reduced even further. The uncertainty regarding coal plant construction costs and fuel costs would not be reduced under this proposal. Whether or not the disincentives for coal plant construction due to rate-setting procedures is increased or decreased would depend upon the current lag in the recovery of fuel costs. A substantial increase in the lag in the recovery of increases in fuel costs could provide an incentive to both stockholders and consumers to have the utility replace a high fuel-low capital cost oil-fired unit with a low fuel-high capital cost coal-fired unit.

EXHIBIT II-1

COST OF NEW COAL PLANT[1]
(MILLIONS OF DOLLARS)

Year	Investment	Investment Tax Credit	Tax Shield From Depreciation: Pollution Control	Tax Shield From Depreciation: Other	After-Tax Expenses: O&M	After-Tax Expenses: Fuel	Additions to Working Capital	Total Cash Flow	Present Value of Cash Flow at 10.2%
1980	9.07	(0.80)			3.19	27.75	0.74	39.95	39.95
1981	13.60	(1.20)			3.44	30.84	0.81	47.49	43.09
1982	22.66	(1.99)			3.72	34.29	0.91	59.59	49.07
1983	45.22	(4.03)			4.01	38.17	1.02	84.39	63.06
1984	123.37	(11.36)			4.33	42.47	1.13	159.94	108.45
1985	190.83	(17.56)			4.68	47.27	1.26	226.48	139.35
1986	202.51	(18.35)			5.06	52.58	1.39	243.22	135.80
1987			(8.62)	(21.05)	9.36	36.47	(2.88)	13.28	6.73
1988			(8.62)	(20.14)	10.11	40.37	1.13	22.85	10.51
1989			(8.62)	(19.22)	10.92	44.68	1.25	29.01	12.10
1990			(8.62)	(18.31)	11.79	49.15	1.30	35.31	13.37
1991			(8.62)	(17.39)	12.73	54.07	1.43	42.22	14.51
1992				(16.48)	13.75	59.51	1.57	58.35	18.19
1993				(15.56)	14.85	64.89	1.58	65.76	18.60
1994				(14.65)	16.04	72.03	2.03	75.45	19.37
1995				(13.73)	17.32	78.95	2.00	84.54	19.69
1996				(12.81)	18.71	86.54	2.19	94.63	20.00
1997				(11.90)	20.20	94.85	2.39	105.54	20.25
1998				(10.98)	21.82	104.04	2.63	117.51	20.46
1999				(10.07)	23.57	113.99	2.85	130.34	20.59

[1] Includes all related pollution control investments.

EXHIBIT II-1 (continued)

COST OF NEW COAL PLANT[1]
(MILLIONS OF DOLLARS)

Year	Investment	Investment Tax Credit	Tax Shield From Depreciation Pollution Control	Tax Shield From Depreciation Other	After-Tax Expenses O&M	After-Tax Expenses Fuel	Additions to Working Capital	Total Cash Flow	Present Value of Cash Flow at 10.2%
2000				(9.15)	25.45	125.02	3.15	144.47	20.71
2001				(8.24)	27.49	137.02	3.42	159.69	20.77
2002				(7.32)	29.69	148.56	3.35	174.28	20.57
2003				(6.41)	32.06	162.83	4.05	192.53	20.62
2004				(5.49)	34.63	178.52	4.45	212.11	20.62
2005				(4.58)	17.40	195.66	4.85	233.33	20.58
2006				(3.66)	40.39	214.49	5.32	256.54	20.53
2007				(2.75)	43.62	235.16	5.83	281.86	20.47
2008				(1.83)	47.11	257.78	6.36	309.42	20.39
2009				(0.92)	50.88	282.61	6.97	339.54	20.31
2010					54.95	309.75	7.60	372.30	20.20
2011					59.34	339.61	8.35	407.30	20.06
2012					64.09	372.28	9.12	445.49	19.91
2013					69.22	408.04	9.96	487.22	19.76
2014					74.76	447.28	10.91	532.95	19.61
2015					80.74	490.38	11.96	583.08	19.47
2016					87.20	532.29	11.79	631.28	19.13
2017							(144.17)[2]		(3.96)
	Cumulative Present Value								$1,132.89

[1] Includes all related pollution control investments.

[2] Refund of working capital at the end of the life of the plant.

EXHIBIT II-2

COST OF EXISTING OIL PLANT
(MILLIONS OF DOLLARS)

Year	After-Tax Expenses O&M	After-Tax Expenses Fuel	Additions to Working Capital	Total Cash Flow	Present Value Cash Flow at 10.2%
1980	3.19	27.75	0.74	31.68	31.68
1981	3.44	30.84	0.81	35.09	31.84
1982	3.72	34.29	0.91	38.92	32.05
1983	4.01	38.17	1.02	43.20	32.28
1984	4.33	42.47	1.13	47.93	32.50
1985	4.68	47.27	1.26	53.21	32.74
1986	5.06	52.58	1.39	59.03	32.96
1987	5.46	58.48	1.54	65.48	33.18
1988	5.90	65.05	1.71	72.66	33.41
1989	6.37	72.38	1.90	80.65	33.65
1990	6.88	80.47	2.10	89.45	33.87
1991	7.43	89.57	2.35	99.35	34.13
1992	8.02	99.59	2.59	110.20	34.36
1993	8.66	110.80	2.89	122.35	34.61
1994	9.36	123.27	3.21	135.84	34.87
1995	10.11	137.09	3.55	150.75	35.12
1996	10.91	152.51	3.95	167.37	35.38
1997	11.79	169.95	4.46	186.20	35.72
1998	12.73	188.74	4.81	206.28	35.91
1999	13.75	209.98	5.42	229.15	36.20
2000	14.85	233.57	6.02	254.44	36.47
2001	16.04	259.77	6.67	282.48	36.74
2002	17.32	289.01	7.44	313.77	37.04
2003	18.70	321.45	8.24	348.39	37.31
2004	20.20	357.60	9.17	386.97	37.61
2005	21.82	397.79	10.19	429.80	37.91

EXHIBIT II-2 (continued)

COST OF EXISTING OIL PLANT
(MILLIONS OF DOLLARS)

Year	After-Tax Expenses O&M	After-Tax Expenses Fuel	Additions to Working Capital	Total Cash Flow	Present Value Cash Flow at 10.2%
2006	23.56	442.53	11.33	477.42	38.21
2007	25.45	492.25	12.57	530.27	38.51
2008	27.48	547.56	12.96	587.90	38.74
2009	29.68	609.20	16.57	655.45	39.20
2010	32.06	677.62	17.25	726.93	39.45
2011	34.62	753.79	19.19	807.60	39.77
2012	37.39	838.56	21.33	897.28	40.10
2013	40.38	932.76	23.68	996.82	40.42
2014	43.61	1,037.67	26.35	1,107.63	40.76
2015	47.10	1,154.28	29.27	1,230.65	41.09
2016	50.87	1,284.02	32.53	1,367.4[illegible]	41.43
			Cumulative Present Value		$1,337.22

EXHIBIT II-3

REVENUE REQUIREMENT RESULTING FROM COAL PLANT INVESTMENT[1] (1980 PRESENT VALUE, MILLIONS OF DOLLARS AFTER TAX)

	CWIP Allowed in Rate Base	
	No	Yes
Tax Credits		
Flow-Through	Base Case $1078	$1088
Normalized	$1084	$1094

[1] Assuming an allowed rate of return after-tax of 9.66% and a one year delay in recovering capital cost.

EXHIBIT II-4

REVENUE REQUIREMENT RESULTING FROM COAL PLANT INVESTMENT[1] (1980 PRESENT VALUE, MILLIONS OF DOLLARS AFTER TAX)

	Regulatory Lag	
Rate of Return	One Year	None
	Base Case	
9.66%	$1094	$1118
10.20%	$1108	$1133

[1]Assuming tax credits are normalized and CWIP is allowed the rate base.

EXHIBIT II-5

COMPARISON OF RATES
UNDER ALTERNATIVE
REGULATORY CONDITIONS
(1980 ¢/kwh)

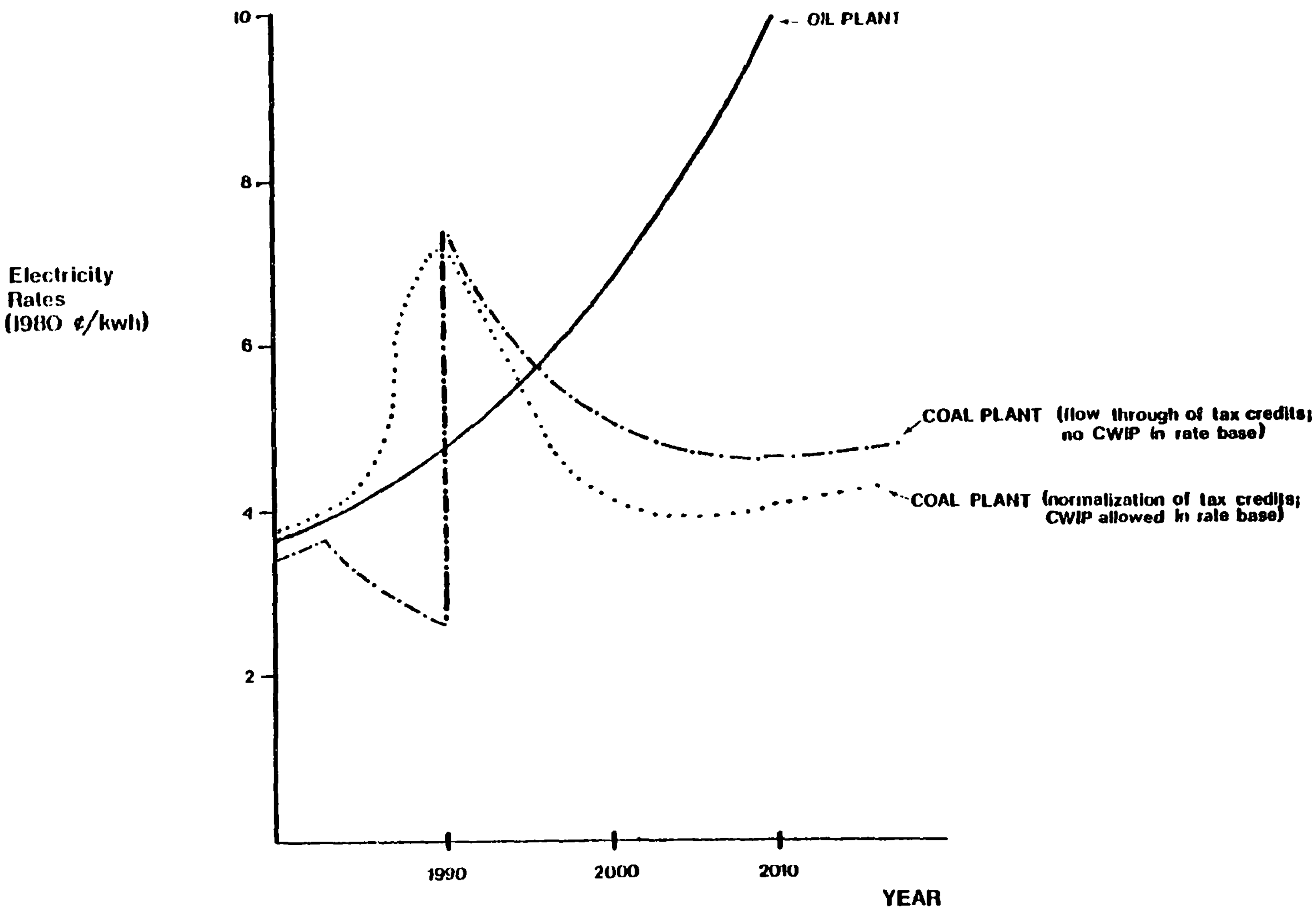

EXHIBIT II-6

COMPARISON OF ALTERNATIVE
CAPITAL RECOVERY METHODS
(¢/kwh, nominal)

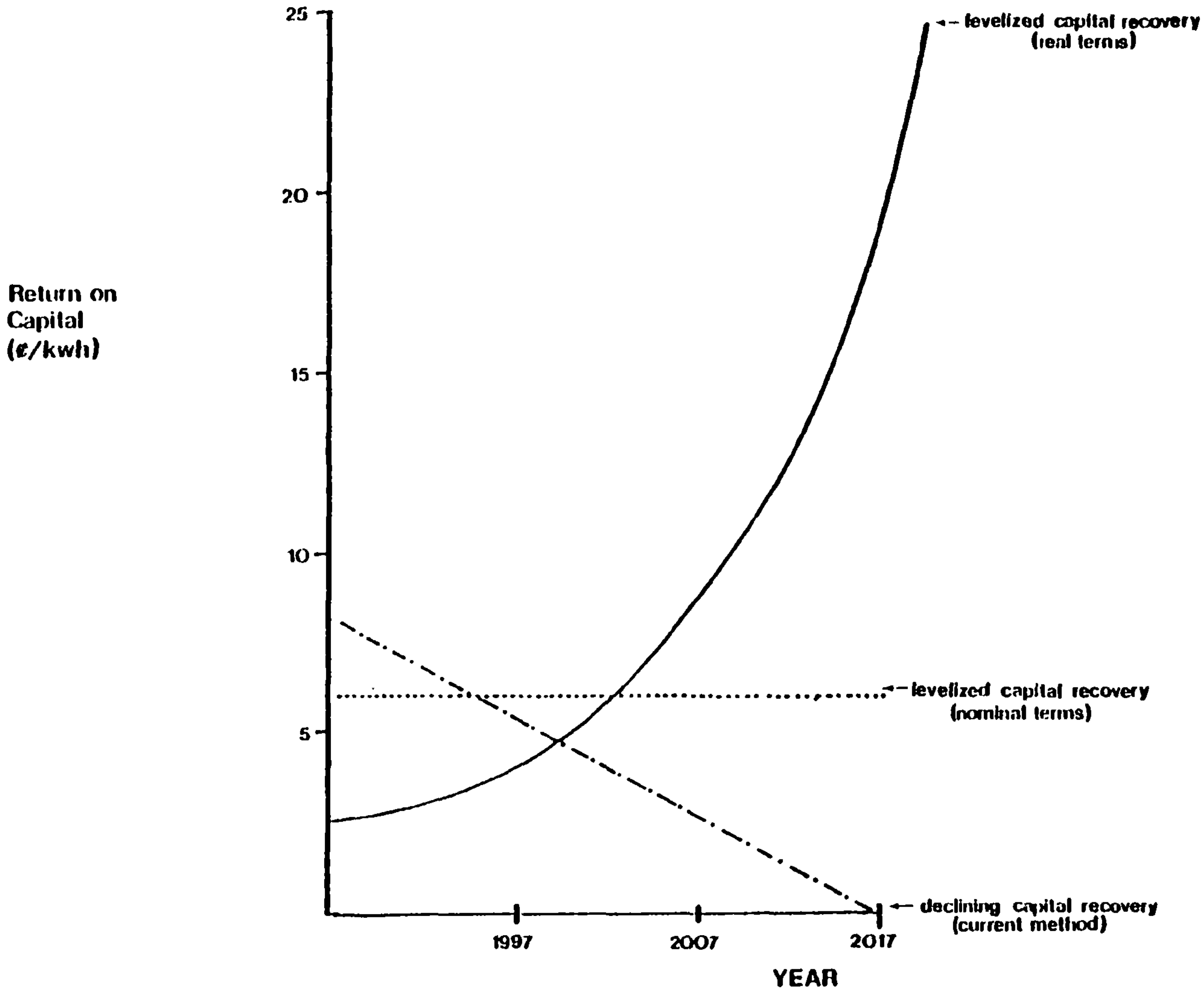

EXHIBIT II-7

COMPARISON OF RATES UNDER ALTERNATIVE
CAPITAL RECOVERY METHODS
(1980 ¢/kwh)

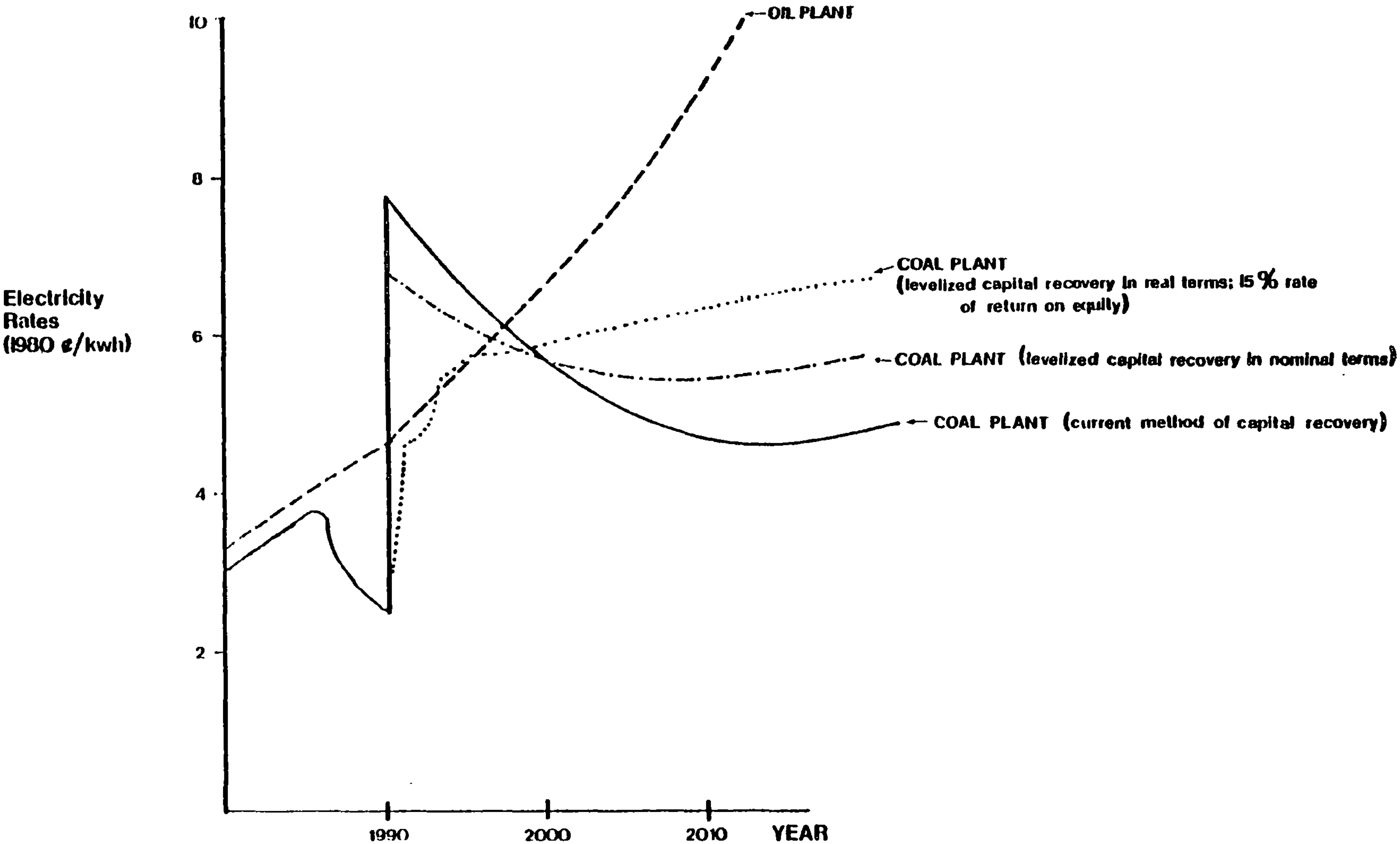

EXHIBIT II-8

1980 PRESENT VALUE OF THE PRICE
OF ONE KILOWATT-HOUR EACH YEAR
(CENTS)

Consumers' Discount Rate[1]	Oil Plant	Coal Plant Scenario[2]							
		#1	#2	#3	#4	#5	#6	#7	#8
8%	236.42	185.71	184.45	185.89	184.63	186.96	189.07	197.94	191.68
10.2%	157.99	130.74	131.47	131.98	132.71	130.27	129.11	131.63	132.36
15%	78.38	70.76	73.17	72.96	75.37	69.28	66.41	67.52	69.94

[1] The discount rates chosen are for illustrative purposes only--8 percent is the assumed rate of inflation, 10.2 percent is the utility's cost of capital and 15 percent is the rate of return required by the utility's equity shareholders. There is currently no agreement on the appropriate consumer discount rate.

[2] Scenarios are described on the following page.

[2] Description of Scenarios

Scenario	Description
#1	Flow-through of all tax credits; no CWIP in rate base.
#2	Normalization of all tax credits; no CWIP in rate base.
#3	Flow-through of all tax credits; all CWIP in rate base.
#4	Normalization of all tax credits; all CWIP in rate base.
#5	Flow-through of all tax credits; no CWIP in rate base; levelized capital recovery in nominal terms.
#6	Flow-through of all tax credits; no CWIP in rate base; levelized capital recovery in real terms.
#7	Flow-through of all tax credits; no CWIP in rate base; levelized capital recovery in real terms; increase in allowed rate of return on equity to 15 percent.
#8	Normalization of all tax credits; no CWIP in rate base; levelized capital recovery in real terms; increase in allowed rate of return on equity to 15 percent.

EXHIBIT II-9

FUNDS REQUIRED FOR CONSTRUCTION
(MILLIONS OF NOMINAL DOLLARS)

	Coal Plant Scenario[1]					
	#1	#2	#3	#4	#9	#10
1980	11.0	10.2	10.7	9.9	11.0	10.2
1981	15.9	14.7	14.9	13.6	15.9	14.7
1982	26.7	24.7	24.2	22.2	26.7	24.7
1983	52.8	49.7	47.5	43.5	52.7	48.6
1984	140.1	128.7	128.6	117.2	139.2	127.8
1985	222.3	204.7	198.1	180.6	218.9	201.4
1986	250.8	232.6	208.2	190.0	244.3	226.1
Total	719.6	664.3	632.2	577.0	708.7	653.5

Percentage difference compared with Scenario #1

Ø	(7.7%)	(12.1%)	(19.8%)	(1.5%)	(9.2%)

[1] Scenarios as defined on Exhibit II-8. In addition, Scenario #9 and Scenario #10 are comparable to Scenarios #1 and #2 except that the utility is allowed to include pollution control CWIP in the rate base. Scenarios #5, #6, and #7 in Exhibit II-8 will have the same funds required for construction as Scenario #1. Scenario #8 will have the same funds required for construction as Scenario #2.

EXHIBIT II-10

SUMMARY OF FINANCIAL POSITIONS
OF SIX NORTHEASTERN UTILITIES

	Future Financing Requirements (1980-1984)	Estimated Portion to be Financed Externally	Interest Coverage Ratio, 1978[1]	AFDC as a Percentage of Earnings, 1979
Boston Edison	$948+ million	67%	2.59	44%
Connecticut Light & Power	$890 million[2]	N/A	1.85	36%
Long Island Lighting	$2.6 billion	62%	1.86	66%
New England Power	$641 million[3]	68%	2.91	43%
Public Service Company of New Hampshire	$850 million[4]	89%	3.17[5]	92%
United Illuminating	$401 million	90%	1.91	65%

N/A = not available

[1] Calculated using the SEC formula, taken from "Statistics of Privately-Owned Electric Utilities in the United States - 1978."

[2] Excluding the cost of anticipated federal requirements mandating conversion of five of the Company's oil-fired generating units to coal and excluding the cost of constructing the Seabrook Nuclear Plant. Connecticut Light & Power is attempting to sell its remaining 4.5% interest in the Seabrook Plant. The cost of converting five of the Company's oil-fired units is estimated to be between $137 and $306 million.

[3] These expenditures are for the 1980-1982 period only.

[4] Expenditures for 1980-1985 period.

[5] The Company's interest coverage ratio has fallen significantly since 1978 and is currently below the minimum required by their bond indenture provisions.

APPENDIX A
DATA AND ASSUMPTIONS

This appendix discusses the data and assumptions used in the analysis presented in this report. These data and assumptions include:

- a projection of future oil and coal prices,
- a projection of construction costs for a new coal plant,
- a projection of future operating and maintenance costs,
- estimates of the marginal capital costs of the utility, and
- assumptions regarding effective tax rates.

Each of these projections and estimates is discussed below. Assumptions regarding the treatment of the capital charges associated with the oil plant in this analysis are then reviewed.

FUEL PRICES

The projections of fuel costs are based on the delivered cost of coal and fuel oil for New England utilities in 1979[1] and inflation factors from the Data Resources, Inc. Energy Review, Winter 1980. The 1979 delivered cost of fuel in New England is:

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[1] Published in Cost and Quality of Fuels for Electric Utility Plants - 1979, U.S. Department of Energy, June 1980.

	Average Cost of Fuel, Delivered (1979 ¢/mm BTU)
Coal (2.01% - 3.00% sulfur)	152.7
Fuel Oil (0.51% - 1.00% sulfur)	316.8

These costs are projected to increase in real terms (net of general inflation) at the following rates:

	Percentage Increase (in Real Terms)	
	Coal	Fuel Oil
1980 - 1985	5.0%	3.0%
1986 - 1991	2.5%	3.0%
1991 - 1995	1.9%	3.1%
1996 - 2020	1.5%	3.0%

These fuel costs were translated into a cost per kilowatt-hour of electricity generated based on the following assumed heat rates:

	Heat Rates (btu/kWh)
Coal Plant	9,832
Oil Plant	9,340

Total fuel costs were calculated by multiplying the total kilowatt-hours generated by the cost of fuel per kilowatt-hour. The total kilowatt-hours generated were based on an assumed capacity factor of 50 percent for both the coal and oil plant.[1] The analysis assumed a 410 MW plant (gross capacity) with an effective capacity of 375 MW.[2]

[1] This is not assumed to be a base unit but rather a mid-range or cycling unit.

[2] This includes the derating of the plant capacity due to the flue gas desulfurization equipment.

COAL PLANT CONSTRUCTION COSTS

The following construction costs were assumed:

	Construction Cost[1] (1979 $/kw)
Coal Plant	$723
Transmission	100
Pollution Controls	150

These costs are based on examination of recently constructed coal plants and on information provided by EPA. Inflation in these capital costs was assumed to be 8 percent each year.

A seven year construction period was assumed between 1980 and 1986. The percentage of the total construction costs assumed to be expended in each year is shown in Exhibit A-1. The factors shown in this exhibit were based on information provided in Utility FGD Costs: Reported and Adjusted Costs For Operating FGD Systems, PEDCo Environmental Inc., September 1978 (PEDCo report).

OPERATING AND MAINTENANCE COSTS

The operating and maintenance costs assumed were as follows:

	Operating & Maintenance Cost (1979 ¢/kWh)
Oil Plant	0.35
Coal Plant	
Scrubber	0.45
Other	0.15

[1] Excluding AFDC which is accounted for explicitly in the utility financial simulation model.

These estimates are based on an examination of recent operating experience at new coal plants and older oil plants and on information provided in the PEDCo report.[1] These costs were assumed to increase at an annual rate of 8 percent over the time period of analysis.

CAPITAL COSTS

The following capital costs were assumed for this analysis:

	Capital Costs
Debt	12%
Preferred Stock	13%
Equity	
Actual	15%
Allowed by PUC	13.5%

The cost of debt was estimated using the average yield on Baa-rated public utility bonds over the past 18 months (January 1979 through June 1980).[2] Preferred stock was assumed to yield one percentage point above the cost of debt. It was also assumed that the cost of equity capital which the Public Utility Commission (PUC) allowed the utility to recover in its rates would be 13.5%; while the actual cost of equity capital would be approximately 15 percent.

In order to calculate a weighted average cost of capital the following capital structure was assumed:

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[1]These data are provided by each utility for each generating unit on FERC Form 10.

[2]As reported in Moody's Bond Record.

	Capital Structure
Debt	51.5%
Preferred Stock	12.5%
Equity	36.0%

This capital structure is representative of a typical Northeastern electric utility. The calculation of the after-tax weighted average cost of capital is shown in Exhibit A-2. As shown in this exhibit, the actual after-tax weighted average cost of capital is 10.2 percent. The after-tax weighted average cost of capital allowed by the PUC is 9.66 percent. The AFDC rate used in this analysis is the after-tax weighted average cost of capital allowed by the PUC of 9.66 percent.

TAX ASSUMPTIONS

The following tax rates were used in this analysis.

	Tax Rate
Federal Income Tax	46%
State Income Tax	5%
Investment Tax Credits	10%

Since state income taxes paid are deductible from federal taxes, the effective marginal income tax rate is:

$$T_F + T_S * (1 - T_F) =$$

$$0.46 + 0.05 * (1 - 0.46) = 0.487$$

where: T_F = the federal income tax rate

and T_S = the state income tax rate

Thus, the effective marginal income tax rate is 48.7 percent.

The investment tax credit decreases a firm's tax liability by an amount equal to 10 percent multiplied by the amount of qualifying investments. Based on a detailed examination of the construction costs of a coal plant provided in Capital Cost Addendum: Multi-Unit Coal and Nuclear Stations, United Engineers and Constructors, Inc., February 1978. It was assumed that 88 percent of the coal plant investment and 100 percent of the transmission and pollution control investments would qualify for the investment tax credit. It was also assumed that the utility would have sufficient income tax liability to enable it to realize all of its available tax credits.

The last tax assumption pertains to the depreciation of plant and equipment. In accordance with Internal Revenue Service (IRS) regulations, the coal plant and transmission investment was depreciated over 23 years period using the sum-of-the-years' digits method of accelerated depreciation. The pollution control investment was depreciated using the straight-line method over 5 years.

UNDEPRECIATED PORTION OF OIL PLANT

No assumption was made concerning the remaining book and tax value of the oil plant. It was assumed that the utility would be allowed to keep the oil plant in its rate base until it was fully depreciated even if the coal plant was constructed. Thus, any depreciation expense and capital charges associated with the oil plant would remain the same whether or not the coal plant is constructed. Therefore, these costs were disregarded in this comparative analysis.

EXHIBIT A-1

PERCENTAGE OF TOTAL COSTS EXPENDED IN EACH YEAR OF CONSTRUCTION PERIOD

	Coal Plant	Transmission	Pollution Controls
1980	2%		
1981	3		
1982	5		
1983	9		5%
1984	18	30%	25
1985	28	30	50
1986	35	40	20
1980 to 1986	100%	100%	100%

EXHIBIT A-2

CALCULATION OF AFTER-TAX WEIGHTED AVERAGE COST OF CAPITAL

	Before-Tax Cost	After-Tax Cost[1]	Portion of Capital Structure	After-Tax Cost * Portion of Capital Structure
Debt	12.0%	6.2%	.515	3.27
Preferred Stock	13.0	13.0	.125	1.63
Equity				
Actual	15.0	15.0	.360	5.40
Allowed by PUC	13.5	13.5		4.86
Weighted Average Cost of Capital				
Actual				10.20%
Allowed by PUC				9.66%

[1] Interest payments on debt are tax deductible. Therefore, the after-tax cost of debt is 12 percent multiplied by one minus the corporate marginal tax rate of 48.7 percent. The derivation of this tax rate is explained in this Appendix.

APPENDIX B

FINANCIAL ANALYSIS OF SIX NORTHEASTERN UTILITIES

This appendix presents a brief financial review of six Northeastern utilities. The utilities reviewed are the Public Service Company of New Hampshire, United Illuminating, Long Island Lighting, Connecticut Light and Power, New England Power and Boston Edison. Each utility is discussed below.

PUBLIC SERVICE COMPANY OF NEW HAMPSHIRE

The Public Service Company of New Hampshire (PSNH) is in extremely poor financial position due to the severe financing problems associated with its share of the Seabrook Nuclear Facility.[1] The New Hampshire State Legislation ruled that PSNH could not include construction work in progress (CWIP) in its rate base. As a result of this law, financing has become difficult and PSNH has attempted to reduce its ownership of this plant from its present 50% to 28%. Even if this is accomplished, the utility still faces financing requirements of over $850 million between 1980-1985.

The utility's earnings per share have fluctuated in recent years and AFDC as a percent of earnings reached a staggering 92% in 1979. Thus, 92 percent of the Company's income provides no funds for capital expenditures (AFDC is non-cash income.)

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1 The Company's entire capacity expansion is dependent on this plant.

The interest coverage ratio for the company has fallen below the minimum allowed in its bond indentures[1] and its preferred stock coverage ratio has fallen to 1.79 with the sale of 1.5 million shares in February of 1980.[2] Thus, the ability of PSNH to issue additional debt or preferred stock at this time is extremely limited. It is estimated that of the $850 million required between 1980-1985, only 11% will be financed internally. Even if PSNH is able to sell off part of its interest in Seabrook, the company would have no funds available for any added construction.

UNITED ILLUMINATING

United Illuminating (UI), located in Connecticut, has experienced increasing sales (kwh) and a steady cash flow per share in recent years, but the utility is experiencing serious financial difficulties. UI's cash flow has been adversely affected by the two month lag in billing of increased fuel costs and by the State's 5 percent tax on gross revenues.[3]

UI faces two immediate problems. First, dividends in 1979 were backed by reported earnings which are over 65% non-cash AFDC. Secondly, UI is presently prohibited by its indenture provisions from increasing the amount of its unsubordinated indebtedness.[4] The company does believe that it can

[1] Income before taxes must be two times interest charges in order to issue unsubordinated debt.

[2] A second sale of 1.5 million is planned later in 1980. This will decrease the coverage ratio to its limit of 1.5.

[3] As revenues increase due to fuel costs, revenue taxes rise. These increased taxes are not recovered through the fuel adjustment clause.

[4] Income before Federal taxes must be at least twice annualized interest charges in order to issue unsubordinated debt.

issue at least $25 million of additional preferred stock, provided that net proceeds from the sale of stock are used to repay short-term debt.[1]

Capital outlays are expected to peak during the 1981-1984 period at which point only 10% of the $305 million of expenditures will be generated from internal sources. Because of United Illuminating's inability to generate funds internally, and its poor coverage position, the company is attempting to cut back its construction program. UI is trying to sell half of its 20% interest in the Seabrook Nuclear Project and the company is seeking exemption from a DOE order to convert UI's largest oil-burning generating unit to coal.[2]

LONG ISLAND LIGHTING

Long Island Lighting (LILCo) has one of the highest proportions (45%) of sales to residential customers of any U.S. utility. This, according to the utility, results in a stable operating environment. From a cash flow standpoint, the earnings per share have been steady. But in terms of capital financing, LILCo has encountered recent problems. The company's capital requirements are estimated to be $448 million in 1980 of which over 80% will be financed externally

Although dividends paid have been increasing annually, an increasing percentage of the earnings on which this is based is derived from non-cash AFDC. AFDC was 66 percent of earnings in 1979.

[1]Preferred stock coverage ratio must equal 1.5 in order to increase long-term indebtedness.

[2]This conversion could add $37 to $128 million to capital requirements.

LILCo has fallen below its interest coverage limit of 2.0 and its preferred stock coverage ratio of 1.58 is nearing the limit of 1.50. For future capital financing the utility will have to rely on sales of common stock and mortgage bonds. For the years 1980-1984 the capital requirements are estimated at $2.6 billion and it is estimated that external financing of $1.6 billion will be needed.

The majority of the capital expenditures by LILCo will be for nuclear facilities, including the Shoreham Nuclear Plant which is projected to start operating in 1982 and the Nine Mile Point #2 Plant which is scheduled to be completed in 1986. Because of these major construction expenditures, and the company's poor internal financing position, it is doubtful that LILCo could absorb any substantial increases in capital costs.

CONNECTICUT LIGHT AND POWER COMPANY

The Connecticut Light & Power Company (CLP) is a wholly-owned subsidiary of Northeast Utilities. The financial position of CLP has and will continue to be strained because of its investment in new nuclear facilities. To ease the strain, the company has sold part of its interest in the Seabrook Plant for $46.9 million.[1] Excluding the Seabrook Plant, CLP still requires $481 million from 1980-1984 to finance the Millstone #3 Nuclear Facility. Total planned construction expenditures amount to $370 million over the 1980-1984 period.

[1]Decreased from its initial share of 12% of 4.5% with an ultimate goal of selling all its interest.

In addition to the construction expenditures, the company's financing requirements during the period of 1980-1984 also include $160 million to meet long-term debt and preferred stock sinking fund and debt maturity requirements. Of this amount, $123.5 million will be due in 1982.

Northeast Utilities has been a major supplier of capital to CLP and it is anticipated that NU will contribute $40 million to CLP during 1980. The continued supply of these funds is unsure though, because of the poor financial position of the parent company. NU had only a 9.1% return on common equity in 1979 and there is no assurance that NU can continue to sell its common shares in amounts necessary to be able to provide capital to CLP, and thus will force CLP to use more external financing.

CLP, without capital from NU, will find it difficult to finance its current construction program. The interest coverage ratio has been near the limit for the last three years while the preferred stock coverage dropped below its limit (1.50) to 1.45 in 1979. The company has already stated that it would be incapable of financing any DOE requirements for converting oil-fired units to coal.[1] The cost of these conversions would add between $137 to $306 million to the construction expenditures depending upon whether flue gas desulfurization equipment is required for each of the units.

NEW ENGLAND POWER

The New England Power Company (NEP) is a wholly-owned subsidiary of the New England Electric System (NEES) and

[1] The company is presently contesting existing efforts by DOE to require such conversions.

accounts for nearly 70% of the parent company's revenues. NEP received nearly $70 million from its parent company during the 1978-79 period and is taking part in NEES's 15-year program (NEESPLAN) which is aimed at reducing peak demand growth from 3.1% to 1.9% and reducing the amount of new capacity needed.[1] The company has also planned to convert six oil burners to coal so that by 1982 coal will dominate the fuel mix at 42% with oil dropping to 37%. These conversions are part of a construction budget which calls for $205 million to be spent in 1980, $248 million in 1981 and $188 million in 1982.

All of the construction expenditures were met with internal funds and with capital contributions from the parent company in 1979 and 1980. Most of 1981 and 1982 requirements will be met by the sale of common shares through the dividend reinvestment and employee stock ownership plans and $90 million of pollution control bonds.

NEES has filed for rate increases and the company is attempting to persuade regulators that companies that stress conservation should be allowed to reward investors with a higher return.

Although AFDC represented 43 percent of earnings in 1979, New England Power has been in strong financial condition during the past two years. The interest coverage ratio of 2.905 (in 1978) was one of the highest for New England utilities. Overall, the company's estimated capital expenditures appear to be within its ability to finance them.

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[1] Only 700 MW is planned--500 MW of nuclear power and 200 MW of renewable sources (wood, trash, etc.).

BOSTON EDISON

Boston Edison is in a good financial position relative to the majority of other utilities operating in New England. The percent of capital funds that Boston Edison has generated internally has risen from 36% in 1974 to over 80% in 1979. This trend is in sharp contrast to most utilities.[1]

AFDC represented 44 percent of earnings in 1979. The interest coverage ratio of Boston Edison has remained over 2.5 in both 1978 and 1979, despite the increases in interest rates.

Because of the company's internal financing ability and since the market value of the company's stock is more than 25% below book value, the company's 1980 capital expenditures of approximately $145 million will be financed with only $50 million of external financing. Capital outlays in the next four years (1981-1984) will average more than $200 million a year. These expenditures are based on a construction permit being granted for the Pilgram #2 Nuclear Plant in 1981. This stepped-up construction program will require $140 to $150 million of external financing each year.

[1] National average of funds generated internally was 36% in 1979.