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Nuclear Plant Cancellations: Causes, Costs, and Consequences

Energy Information Administration
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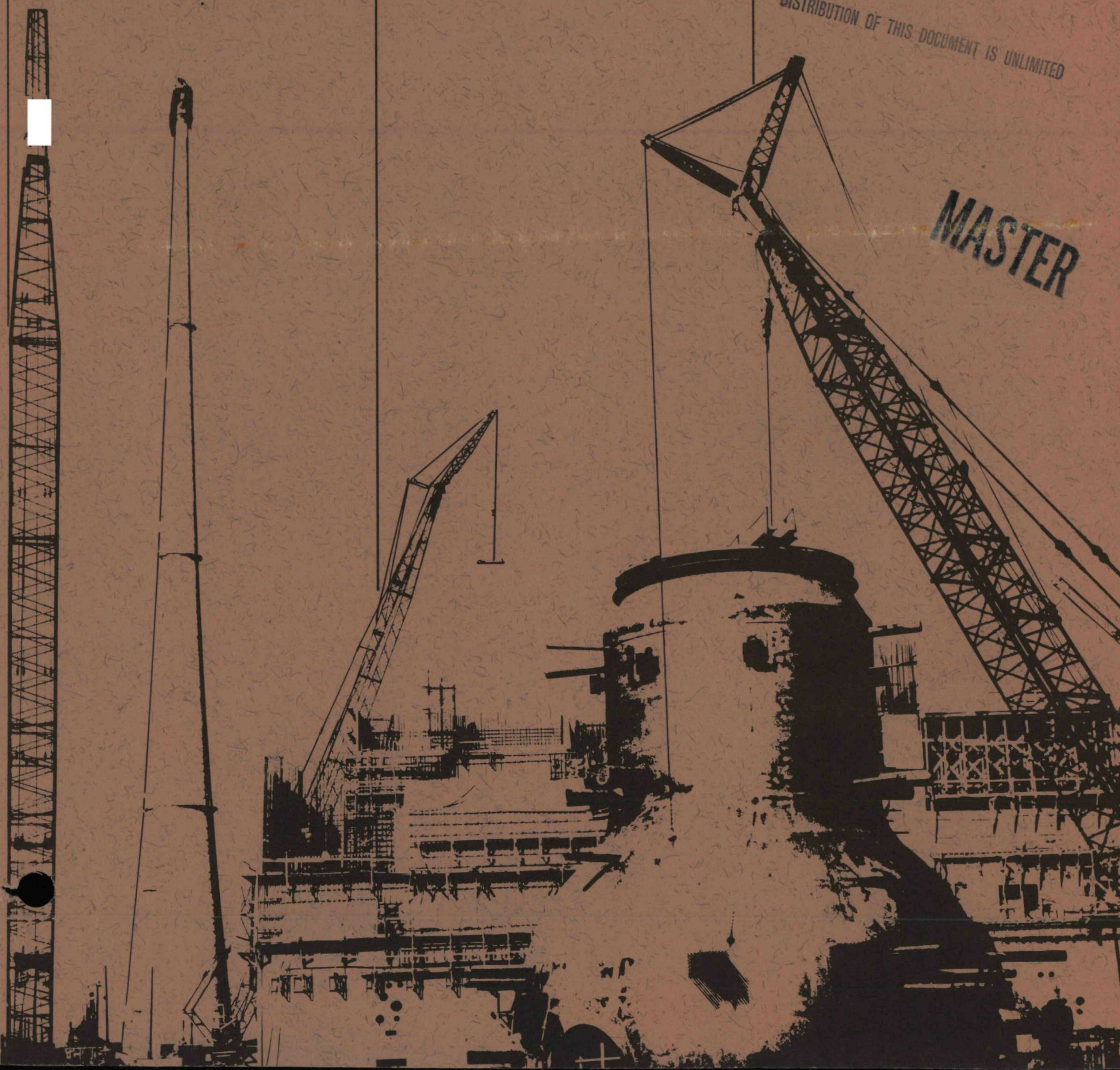

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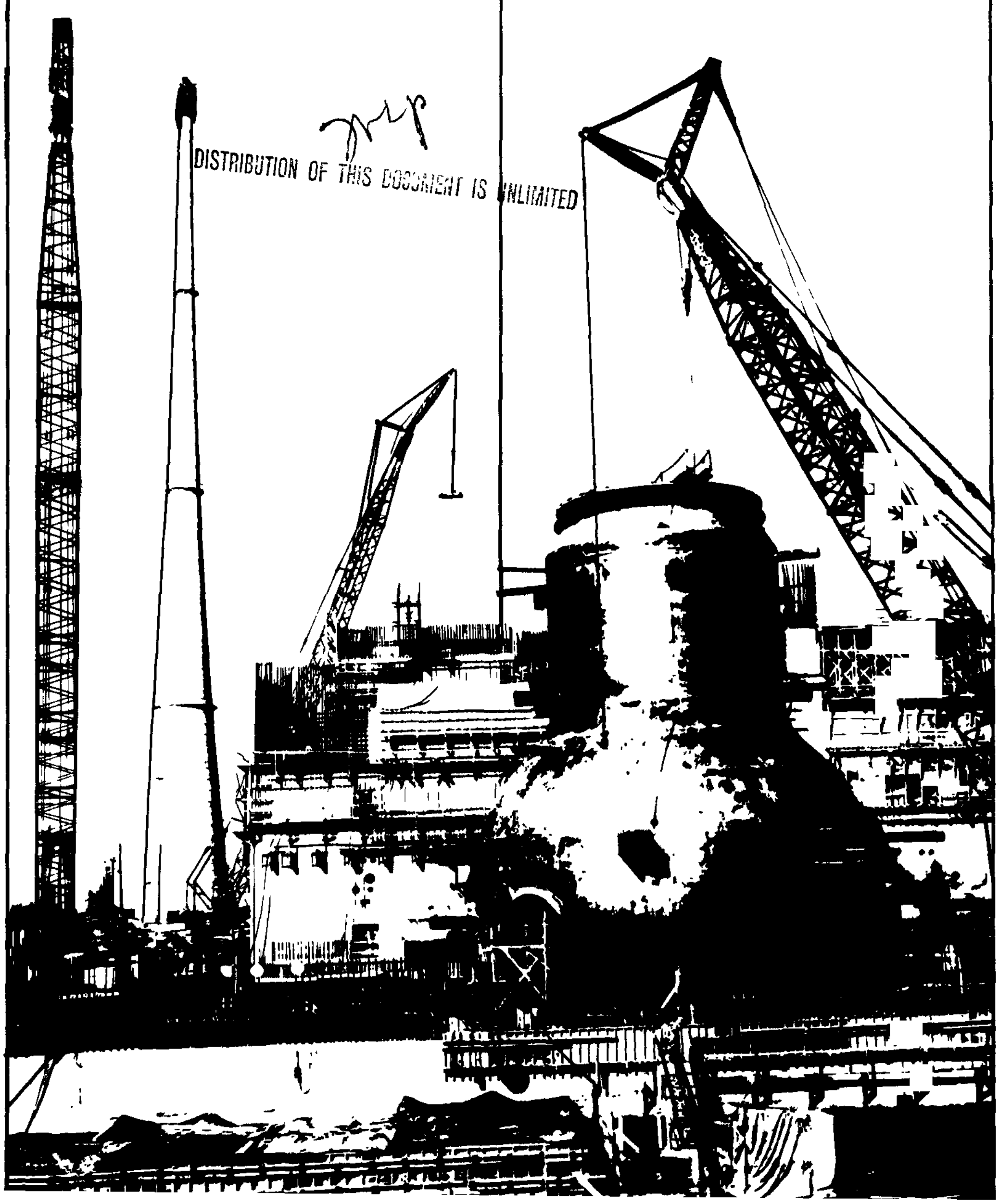

DATA CONTACTS

This report was prepared for the Office of Coal, Nuclear, Electric, and Alternate Fuels by a contractor, J. A. Reyes Associates, of Washington, D.C. (contract number DE-AC01-EI81-11816). Questions regarding the content of the report may be directed to the National Energy Information Center (202/252-8800) or to the principal researcher and author, Robert L. Borlick (301/657-8257). Other questions on the report, particularly as they relate to nuclear power forecasting and analysis, should be directed to R. Gene Clark, Director of the Nuclear and Alternate Fuels Division (202/252-6363), and to Andrew Reynolds or Mark Gielecki, Nuclear and Alternate Fuels Division (202/252-6241).

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EXECUTIVE SUMMARY

This study was conducted for the Energy Information Administration (EIA) within the U.S. Department of Energy. It has three objectives:

- To present a history of nuclear power plant cancellations, including estimates of the sunk costs involved.
- To develop estimates of the costs associated with the potential cancellation of nuclear power plants currently planned or under construction.
- To determine how the costs of these potential cancellations are likely to be regionally distributed and allocated among three major groups: utility ratepayers, utility shareholders, and income taxpayers.

The study first examined the history of nuclear power plant cancellations, then selectively examined the regulatory treatment of costs for those cancellations which involved more than $50 million in losses. This revealed the precedents established for allocating the costs of project abandonment among the three major payer groups and provided a basis for projecting the regulatory treatment likely to be adopted in future cancellations. The study then identified specific nuclear units currently planned, or under construction, which are most vulnerable to cancellation in the future. Finally, data on expenditures for these plants and the additional costs associated with their cancellation were used to estimate the total potential costs of abandonment and their regional distributions.

The major conclusions of this study are as follows:

- The Nation's electric utility industry has substantially reduced its earlier commitment to nuclear power, by cancelling almost half the nuclear capacity it had ordered since the inception of commercial nuclear power.
- Five major causes of nuclear power plant cancellations have been identified, the most significant being: lower forecasted load growth, construction financing constraints, and reversals in the cost advantage of some nuclear units.
- In the past, the regulatory treatment of nuclear power plant cancellations most frequently adopted by regulatory commissions allocated most of the abandonment costs to utility ratepayers and income taxpayers, rather than to utility investors.
- A number of nuclear power plants in various stages of completion have been identified as being vulnerable to cancellation and potentially involve total abandonment costs ranging from $4.5 to $8.1 billion.
- If completed, many of the nuclear power plants already cancelled, or subject to cancellation in the near future, could provide net economic benefits to ratepayers and the Nation as a whole -- primarily by replacing electricity generated by oil- and natural gas-fired power plants.

History of Nuclear Power Plant Cancellations

By year-end 1982, the electric utility industry had cancelled 100 nuclear units, totalling 109,754 megawatts-electric (MWe) of capacity.[1] These cancellations represented 45 percent of the total commercial Nuclear Steam Supply System (NSSS) capacity previously ordered. For comparison, only 39 fossil fuel-fired generating units, totalling about 23,000 MWe, have been cancelled since 1972, the year of the first nuclear cancellations.

The costs associated with these nuclear plant cancellations have been substantial. It is estimated that about $10 billion was expended on the 100 nuclear units cancelled since 1972, which represents nearly 7 percent of all utility expenditures for power plant construction during that period. Most of these cancellation costs have been incurred since 1977, during which time 72 reactors have been cancelled, 42 of which involved abandonment costs of at least $50 million per plant cancellation. Publicly owned utilities have been disproportionately represented in these cancellations -- $4.2 billion of the total cost of nuclear power plant cancellations was accounted for by six reactors that were being constructed by publicly owned utilities.

Five major reasons were identified as underlying these cancellations:

- Lower forecasted load growth
- Financial constraints
- Regulatory changes and uncertainty
- Reversal of economic advantage
- Denial of certification by the State.

The fact that these reasons were cited does not necessarily confirm that they were indeed the causes underlying the individual cancellation decisions. To further test their validity, each of the five reasons was examined to determine whether it is consistent with empirical data reflecting industry-wide conditions, and whether it represents a sufficient rationale for cancelling a power plant.

Lower Forecasted Load Growth

Downward revision in load forecasts was cited as causing, or contributing to, about half the plant cancellations. This is consistent with the peak load forecasts submitted by the utilities to the North American Electric Reliability Council (NERC) over the past 15 years. A reduction in a utility's forecasted growth in peak load may, or may not, be a sufficient reason to cancel planned nuclear capacity, depending on how far into the future the plant would have to be deferred until the growth in electricity demand justifies resumption of construction. Another consideration is that for many utility systems the scheduled addition of planned nuclear capacity could be justified solely on the basis of the displacement of higher cost generation from existing oil-fired and/or natural gas-fired capacity.

However, if a utility is experiencing difficulty in financing new capacity, a reduction in its forecasted peak load growth will make nuclear plant cancellations all the more attractive by improving the utility's near-term financial position without jeopardizing its legal obligation to serve its customers.

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[1] In this study, a nuclear power plant cancellation is defined as having occurred when a utility orders the Nuclear Steam Supply System (NSSS) for the plant and later decides against completing it.

Financial Constraints

Because of their greater flexibility in setting electric rates, publicly owned utilities can more easily cover increases in their operating costs than can their privately owned counterparts. Consequently, limitations on capital available for new construction is predominantly a problem faced by investor-owned utilities -- the segment of the industry which provides about three-fourths of the Nation's electricity. Investor-owned utilities claim that constraints on raising capital were solely responsible for the cancellation of five nuclear units and contributed to the cancellation of 39 other units.

Over the past 17 years, the amounts of capital investment required annually to sustain the construction programs of investor-owned utilities dramatically increased. As a result, these utilities must now rely on the capital markets for over half of their new capital requirements, whereas in the 1960-1965 period only 30 percent of their capital requirements were met from external sources. Unfortunately, this increased reliance on the capital markets has occurred during an era when utility bond and preferred stock coverage ratios have fallen perilously close to their minimum indenture limits, and most utility common stock prices have fallen well below their respective book values.

Although the unfavorable capital market conditions have not precluded electric utilities from raising funds through the sale of common stock, such sales have harmed utility investors by diluting earnings per share and depressing common stock prices even further. To limit such devaluation, utility managements have a strong incentive to curtail investment, a strategy which appears to have been widely adopted within the industry.

Limited capital availability is a valid reason to cancel planned generating capacity of all types, but nuclear plants are particularly vulnerable because of their longer lead times, higher capital costs, and greater uncertainty over what those costs will ultimately be.

Regulatory Changes and Uncertainty

Utility spokespersons stated that continuously changing regulations, licensing delays, and uncertainty regarding future standards for nuclear plants, although not solely responsible, substantially contributed to the cancellation of 37 units.

The experience of operating nuclear power plants over the past 15 years has revealed many unforeseen safety- and health-related problems requiring correction and continuing oversight. Furthermore, it appears that the safety regulatory process was not prepared to deal with problems in an efficient manner. Perhaps the most familiar example of this was the 10-month moratorium on the issuance of operating licenses and the promulgation of new rules requiring the completion and approval of emergency evacuation plans prior to licensing, both of which occurred in response to the Three Mile Island accident.

Although many utilities cited the regulatory climate as a primary reason for some plant cancellations, this reason alone is insufficient justification. It can, however, create sufficient conditions for cancellation by increasing planning lead-times and construction costs. The former impact may force reliance on a shorter lead-time alternative to ensure meeting the utility's projected load growth. The latter impact may reverse the generation economics of the nuclear power plant relative to other alternatives -- particularly coal-fired power plants. In addition, increased construction cost due to regulatory factors exacerbates the impact of financial constraints.

Reversal of Economic Advantage

The utilities reported that 18 nuclear units were cancelled partly, or solely, because the economics of alternative generation sources became more favorable. During the period, 1967 to 1977, when the utilities initially made commitments to construct these units, nuclear power appeared to offer the cheapest new source of baseload generation. However, during the interim period covering the normal planning and construction lead-times of these plants, as well as unanticipated delays, the economic advantage of these units was continuously eroded. An EIA study released in mid-1982 concluded that new nuclear plants entering service in 1995 would offer a significant cost advantage over coal-fired plants only in New England and the South Atlantic Regions.[2]

Denial of Certification by the State

State siting authorities forced the cancellation of six nuclear units by denying them certificates of convenience and necessity. In general, five major reasons were cited for denials of certification:

- Forecasted demand for electricity was too low to justify the additional capacity.
- The plant was not the least-cost alternative.
- The utility could not finance the plant's construction.
- State law prohibited the siting of the proposed nuclear plant.
- Political opposition.

The first two reasons have been discussed above. The third reason is not a sufficient rationale because an investor-owned utility's ability to finance construction is essentially determined by its ability to raise electric rates, which is under the control of the utility's regulatory commission. Thus, if a new power plant is considered to be desirable, the required financial resources can be assured by the commission granting prompt and adequate rate relief.

A number of States have enacted laws that place prohibitions on the siting of proposed nuclear power plants. For example, in 1976, California passed a law prohibiting the certification of sites for nuclear power plants that were not already under construction until the issues of fuel rod reprocessing and nuclear waste disposal are resolved and underground/berm containment is studied.

In addition to ratepayer advocates, possible sources of political opposition to nuclear plant construction include conservationists, environmentalists, and businesses with vested interests in other fuels -- particularly coal.

Regulatory Treatment of Nuclear Plant Abandonment Costs

The regulatory treatment of the costs associated with each of 33 cancelled nuclear units at 21 plant sites was analyzed to determine who will bear these costs and to provide a basis for predicting who will bear the costs of future cancellations. These nuclear

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[2] Energy Information Administration, U.S. Department of Energy, Projected Costs of Electricity from Nuclear and Coal-fired Power Plants, DOE/EIA-0356/1/2 (Washington, D.C., August 1982).

units were selected because they involved more than $50 million per site and because the treatment of their respective costs had already been adjudicated by at least one regulatory commission. All of these units were cancelled prior to January 1, 1983.

Definition of Abandonment Cost

The abandonment cost of a cancelled nuclear power plant is defined as that cost which would have been avoided if the project had never been undertaken. Abandonment cost consists of the following components:

- Cash expenditures
- Allowance for Funds Used During Construction (AFUDC)[3]
- Contract cancellation penalties
- Salvage value (a "negative" cost)
- Site shutdown costs.

The first two components account for most of the cost and are accurately known at the time of cancellation. The latter three components are generally not accurately known for months, or even years, following cancellation.

Allocation of Abandonment Costs

The regulatory process allocates most of a cancelled plant's abandonment costs among utility ratepayers, utility investors, and income taxpayers. A specific method of allocation is chosen by each regulatory commission having jurisdiction over the utility owners of the cancelled plant. First the commission determines what portion of the abandonment costs was prudently incurred by the utility managements; only those costs prudently incurred are eligible for recovery from ratepayers. The methods used to allocate the eligible costs are classified in this study according to the degree to which the utility is allowed to recover these costs from ratepayers. The three categories are:

- Full recovery
- No recovery
- Partial recovery.

Full recovery. Abandonment costs may be fully recovered, in which case utility investors gradually recoup their original investment from their ratepayers over a period of years while also earning a fair return on the unamortized balance. Income taxpayers benefit from this treatment because the ratepayers must also pay income taxes on the return earned on the unamortized balance, as well as on the project's accrued AFUDC as it is amortized along with the original investment.

No Recovery. The converse of full recovery is no recovery, whereby ratepayers are virtually unaffected by the plant cancellation. Under this regulatory treatment, the entire abandonment cost is borne by utility investors and income taxpayers. The latter group shares approximately half the cost because the utility is allowed to write off the capitalized plant investment against its taxable income in the year of cancellation.

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[3]Allowance for Funds Used During Construction (AFUDC) is the capital carrying charge that accrues on the funds invested in utility projects during the planning and construction stages.

Partial Recovery. The most complex methods for allocating abandonment costs involve sharing them among the three major payer groups. Typically the utility is allowed to recover its original investment in the plant, as well as the accrued AFUDC, through amortization of the abandonment cost, thereby increasing its rates correspondingly over some period of years. However, during this period, the utility is not allowed to earn a return on the unamortized balance, thus forfeiting the capital carrying costs on part of its investment. The longer the amortization period, the greater is the fraction of abandonment cost borne by investors. The impact on investors is partially alleviated by the write-off of the loss for income tax purposes in the year of cancellation, thereby shifting part of the cost burden to income taxpayers.

A number of other partial recovery options are possible, depending on how much (if any) of the project AFUDC is allowed to be recovered and how much (if any) of the amortized balance is allowed to earn a return. Although such variants have been employed in a few past cancellations, the partial recovery method described above was generally adopted in the past and is likely to be the standard of the future.

Methods Adopted by Regulatory Jurisdiction

The only regulatory body to consistently and unequivocally allow full recovery of costs is the New York Public Service Commission. Nuclear plant cancellations so treated include Sterling, Jamesport 1 & 2, and New Haven 1 & 2. In four other plant cancellations outside of New York State -- Greenwood 2 & 3, Douglas Point 1 & 2, Black Fox 1 & 2, and Sundesert 1 & 2 -- site-related costs were allowed to be fully recovered through reclassification as plant held for future use and inclusion in the utility rate bases.

Five nuclear plant cancellations were accorded no recovery of costs: Davis-Besse 2 & 3, Erie 1 & 2, Tyrone 1, Pebble Springs 1 & 2 and WPN 5. Initially the Ohio Public Utility Commission allowed partial recovery of the costs for the Davis-Besse and Erie plant cancellations, but that decision was reversed by the Ohio Supreme Court, which ruled that the State's statutes did not recognize project abandonment cost as a legitimate cost of service. The case is now before the U.S. Supreme Court.

In the Tyrone 1 case, most of the plant's abandonment costs were imposed on Northern States Power Company of Minnesota through an interstate wholesale rate approved by the Federal Energy Regulatory Commission (FERC). Despite this, the Minnesota and North Dakota Commissions refused to recognize these costs as legitimate cost of service items and initially prohibited any recovery from ratepayers. The South Dakota Public Utility Commission deferred its decision until the FERC decision was no longer subject to judicial review. After considerable litigation, North and South Dakota have agreed to allow the recovery of Tyrone 1 costs in accordance with the FERC decision. In Minnesota, these costs are being collected, subject to refund, until the case is decided by the State Supreme Court.

The Pebble Springs 1 & 2 and WPN 5 cancellations were denied all cost recovery in Oregon and Wyoming. The Oregon Public Utility Commissioner directed Portland General Electric (PGE) and Pacific Power and Light (PP&L) to write off their investments in these plants entirely against common shareholders' equity. His decision was based on the recent passage of Ballot Measure 9, which prohibits a utility from charging rates derived from a rate base that includes property not currently providing utility service to its customers. However, the Commissioner ameliorated the adverse impacts on the utilities by allowing them to repurchase some of their low-interest bonds that were selling at a discount and to use the resulting capital gains to offset the plant write-offs.

PP&L was denied any cost recovery by the Wyoming Public Service Commission on the grounds that the cancelled plants are not used and useful. PP&L has appealed the case to the Wyoming Supreme Court.

Partial recovery was by far the most common regulatory treatment employed in past cancellations. Of the 21 cancellations involving regulatory commission decisions, 16 were accorded partial recovery by one or more commissions. The amortization periods ranged from 2 to 20 years, with 10 years being the most frequently chosen length. In all but 6 of these regulatory proceedings, involving 5 plants, the utilities were allowed to recover all project costs, including AFUDC accrued up to the dates of cancellation (or up to the dates when a prudent management would have cancelled), but were allowed no return on the unamortized balance. The exceptions to this were <u>Harris 3 & 4</u>, <u>Black Fox 1 & 2</u>, <u>Pilgrim 2</u>, <u>Surry 3 & 4</u>, and <u>Sundesert 1 & 2</u>.

Regarding Harris 3 & 4, the North Carolina Utilities Commission allowed Carolina Power and Light (CP&L) to earn a return on that portion of the unamortized balance contributed by debt investors.

In the case of Black Fox 1 & 2, the Oklahoma Corporate Commission allowed Public Service of Oklahoma (PSO) to earn a return on that portion of the unamortized balance contributed by debt and preferred equity investors.

In the Pilgrim 2 cancellation, the portion of AFUDC attributed to the common equity investor was disallowed by the Massachusetts Department of Public Utilities for both Boston Edison Company (BECO) and Commonwealth Electric Company (CECO). However, BECO was allowed to earn a return on the non-AFUDC portion of the plant's cost and CECO was not.

With respect to the Surry 3 & 4 cancellations, the Virginia State Corporation Commission would not allow the Virginia Electric Power Company (VEPCO) to recover any of its accrued AFUDC.

In adjudicating the Sundesert cancellation, the California Public Utilities Commission disallowed all accrued AFUDC on the non-site-related costs, arguing that this appropriately forced investors to bear more of the risk of project noncompletion.

In the CP&L, PSO, and BECO cases the respective regulatory commissions stated that they allowed returns on the unamortized balances because of their concern that these companies would otherwise lack the financial resources to fulfill their service obligations in the future.

<u>Quantification of Abandonment Costs</u>

The relative allocation of abandonment costs among the three major payer groups was quantitatively estimated for a hypothetical nuclear plant cancellation, assuming that the accumulated outlays for power plants under construction, i.e., construction work in progress (CWIP), is not included in the ratebase and the most common partial cost recovery option is adopted. The plant is assumed to be cancelled in mid-1983 and the costs amortized over a period which was varied parametrically from 2 to 30 years. The present values of the incremental cash flows imposed on each payer group were then calculated, yielding the results shown in Table ES1.

Table ES1. Distribution of Costs Associated with Cancelled Nuclear Power Plants Among Three Major Payer Groups for Various Lengths of Amortization

Length of Amortization (Years)	Ratepayer's Discount Rate (Percent)	Present Share of Costs Borne by Each Group (Percent of Total)		
		Utility Investors[a]	Ratepayers[b]	Income Taxpayers[c]
2	5.5	12	69	19
2	Intermediate	13	65	22
2	20	14	64	22
5	5.5	18	56	26
5	Intermediate	19	49	32
5	20	22	45	33
10	5.5	25	39	36
10	Intermediate	28	30	43
10	20	32	23	46
15	5.5	30	27	43
15	Intermediate	34	16	50
15	20	37	9	54
20	5.5	35	16	49
20	Intermediate	38	6	56
20	20	41	1	58
30	5.5	42	-2	60
30	Intermediate	43	-6	63
30	20	44	-8	64

[a]Annual cash flows to utility investors were discounted using rates that were 2 percentage points higher than yields offered by U.S. Treasury bonds that mature in the same respective years in which these cash flows are received.

[b]Annual cash flows to ratepayers were discounted using the rates shown in the second column of the table for the lower- and upper-bound cases. For the intermediate case, these cash flows were discounted at the same rates that were applied to the utility cash flows.

[c]For the cases employing the ratepayer's lower- and upper-bound discount rates, annual cash flows to the government were discounted using rates equal to the yields offered by U.S. Treasury bonds that mature in the same respective years in which these cash flows are received. For the intermediate case, these cash flows were discounted at the same rates that were applied to the utility cash flows.

As expected, the percentage of total cost borne by utility investors increases with the length of amortization. Not expected is the fact that in all cases investors pay less than half the cost; for the most frequently adopted 10-year period, investors bear only about one-third of the total cost.

The cost burden on ratepayers decreases with the length of amortization, becoming virtually nonexistent -- or even negative -- for periods in excess of 20 years. During the construction period, ratepayers enjoy lower rates because the deferred taxes associated with interest payments made on the debt-financed portion of the plant prior to cancellation are typically subtracted from the ratebase. If the amortization period is sufficiently long the present value of this early benefit to ratepayers is never completely offset by the present value of the amortized abandonment cost.

Finally, this analysis reveals that a substantial portion of the abandonment costs are borne by income taxpayers, primarily because of the provision for reducing taxable income by writing off the capitalized investment in the plant in the year of cancellation. Regardless of the length of amortization, income taxpayers consistently bear more of the costs than do the utility investors, thereby introducing incentives to cancel plants in more advanced stages of construction than would otherwise be present if such tax write-offs did not exist.

Potential Nuclear Power Plant Cancellations

As noted above, 100 nuclear units were cancelled as of December 31, 1982. Industry observers anticipate additional cancellations through 1995. Two groups of "at risk" units currently under construction and vulnerable to cancellation were identified, hereafter referred to as:

- The Base Case
- The Worst Case.

Base Case

This case is based on the "Utility Financial Constraints" case in the Energy Information Administration's 1981 Annual Report to Congress. Based upon precedent cancellations, the Base Case assumes that only those nuclear units that were more than 20 percent complete by the end of 1981 will be completed, which implies that 13 units are vulnerable to cancellation. All of these units have the NSSS ordered, 9 have received construction permits (CP), and 2 others have had their CP applications docketed. According to the individual utility's load growth expectations, financial capabilities, and regulatory environment, some of these units are less likely to be cancelled than are others. The total investment in these 13 units through June 1982, including accrued AFUDC, was about $4 billion. The units in the Base Case are identified and described in Table ES2.

Worst Case

The Worst Case consists of the units in the Base Case plus five other units, three of which are more than 30 percent complete. These units were identified as being "at risk" by the NRC, Salomon Brothers, Merrill Lynch, and the EIA, principally as a result of large changes in load growth expectations and financial limitations. Total investment in the Worst Case units through June 1982, including accrued AFUDC, was about $8 billion. The additional units in the Worst Case are identified and described in Table ES3.

Table ES2. Nuclear Unit Cancellations in the Base Case: Status as of June 30, 1982[a]

Unit Name	Size (MWe)	Federal Region	Constructing Utility	Estimated Operation Date[b]	Percent Completed	Cumulative Expenditures Reported (Millions of Dollars)[c]
Seabrook 2	1,120	I	PSCo. of N.H.	1986	15	600-700
Cherokee 1	1,280	IV	Duke Power	N/S	18	500-600
Harris 2	900	IV	Carolina P&L	1989	4	200-300
Vogtle 2	1,100	IV	Georgia Power	1988	11	300-400
Yellow Creek 2	1,285	IV	TVA	N/S	3	200-300
Clinton 2	933	V	Illinois Power	N/S	1	<50
Marble Hill 2	1,130	V	PSCo. of Indiana	1988	21	400-500
Carroll County 1 ..	1,120	V	Commonwlth. Edison	N/S	0	<50
Carroll County 2 ..	1,120	V	Commonwlth. Edison	N/S	0	<50
River Bend 2	934	VI	Gulf States Util.	N/S	1	50-100
South Texas 2	1,250	VI	Houston L&P	1989	18	800-900
Skagit 1	1,277	X	Puget Sound P&L	1991	0	400-500[d]
Skagit 2	1,277	X	Puget Sound P&L	1993	0	
Total (13 Units)	14,726	--	--	--	--	3,450-4,450

[a]The Base Case reflects the financial constraints developed by the Energy Information Administration, published in: Energy Information Administration, U.S. Commercial Nuclear Power, DOE/EIA-0315 (Washington, D.C., 1982).

[b]Estimated date of commercial operation.

[c]Total of direct expenditures and AFUDC reported by the utilities in a telephone survey conducted in June 1982. Ranges of costs are shown here to preserve the confidentiality of some of the data.

[d]This figure includes costs accrued for both units.

N/S = not scheduled.

Source: U.S. Nuclear Regulatory Commission, Nuclear Power Plants, Construction Status Report, Data as of 06/30/82, NUREG-0030, Vol. 6, No. 2, October 1982. Utility cost data compiled by J.A. Reyes Associates.

Table ES3. Additional Nuclear Unit Cancellations in the Worst Case: Status as of June 30, 1982

Unit Name	Size (MWe)	Federal Region	Constructing Utility	Estimated Operation Date[a]	Percent Com-pleted	Cumulative Expenditures Reported (Millions of Dollars)[b]
Limerick 2	1,055	III	Phila. Electric	1987	30	400-500
Grand Gulf 2	1,250	IV	Mississippi P&L	N/S	23	500-600
Hartsville A-1	1,233	IV	TVA	1991	44	900-1,000
Hartsville A-2	1,233	IV	TVA	1992	34	500-600
Yellow Creek 1	1,285	IV	TVA	N/S	35	800-900
Subtotal (5 Units)	6,056	--	--	--	--	3,100-3,600
Worst Case Total (18 units)[c]	20,782	--	--	--	--	6,550-8,050

[a]Estimated date of commercial operation.

[b]Total of direct expenditures and AFUDC reported by the utilities in a telephone survey conducted in June 1982. Ranges of costs are shown here to preserve the confidentiality of some of the data.

[c]Total from Tables ES2 and ES3.

N/S = not scheduled.

Sources: NRC Memo from W. Dircks to Commissioner Ahearn, March 18, 1982; Salamon Brothers, Electric Utility Quality Measurements, April 4, 1982; Merrill Lynch, Electric Utility Industry: Nuclear Power Plants -- Another Look, May 1982; U.S. Nuclear Regulatory Commission, Nuclear Power Plants, Construction Status Report, Data as of 06/30/82, NUREG-0030, Vol. 6, No. 2, October 1982. Utility cost data compiled by J.A. Reyes Associates.

Potential Abandonment Cost Estimates

Abandonment costs were estimated for each of the "at risk" units. Due to the uncertainty surrounding contract cancellation penalties, salvage value, and site-shutdown costs, these cost components could be only roughly estimated on the basis of data covering past cancellations and TVA estimates covering their eight "at risk" units. The abandonment costs estimated for the Base Case and the Worst Case, aggregated to the Federal, regional and national levels, are shown in Table ES4.

In both the Base Case and the Worst Case, the Southeast (Region IV) is likely to be the most heavily impacted, potentially bearing one-third to over one-half of the total abandonment costs, respectively. This disproportionate effect is primarily due to TVA's ambitious construction program.

The TVA cancellations are especially ironic because, unlike its investor-owned counterparts, this utility is not capital-constrained. However, it cannot economically justify the completion of at least four units because downward revisions in its load forecasts have pushed the need for these units so far into the future that the annual costs of "mothballing" them, combined with the increased uncertainty due to technological advances, adversely affects their ultimate economic attractiveness. At the same time, several utilities that have power exchange agreements with TVA are heavily dependent on expensive oil- and natural gas-fired generation. These utilities could probably reduce their future rates to customers through purchases of surplus power from TVA. However, as of January 1, 1983, TVA could not consummate any such sales agreements.

Allocation of Potential Abandonment Costs

The ratemaking treatment accorded the abandonment costs of past nuclear plant and major non-nuclear project cancellations provides valuable precedents for projecting the treatment of these costs for the "at risk" units in the Base Case and Worst Case. An examination of each regulatory commission having jurisdiction over one or more of these "at risk" plants reveals that the most frequently used regulatory treatment is amortization of abandonment costs with no return earned on the unamortized balance. The jurisdictional exceptions to this are:

- New York (full recovery)
- Wyoming (no recovery)
- Oregon (no recovery)
- California (partial recovery with AFUDC disallowed)
- Maine (partial recovery with AFUDC disallowed)
- Massachusetts (partial recovery with common equity AFUDC disallowed and a return only on the non-AFUDC portion of unamortized balance).

Because the publicly owned utilities, such as TVA, do not have equity investors who contributed risk capital, the abandonment costs of their cancelled projects must be fully recovered from ratepayers. The only other alternative -- that of defaulting on their bonds -- could have a potentially disastrous effect on their future ability to raise capital.

Table ES4. Potential Nuclear Plant Abandonment Costs by Federal Region (Millions of Constant Mid-1982 Dollars)

Federal Regions	Costs Under Base Case	Costs Under Worst Case
I	749	749
II	0	0
III	0	555
IV	1,528	4,621
V	684	684
VI	993	993
VII, VIII, and IX	0	0
X	530	530
Total	4,484	8,132

Summary

Approximately half of the total commercial nuclear plant capacity ordered since the inception of the program has been cancelled, inflicting a substantial cost burden on the Nation.

Critics have argued that the commitments made to nuclear power by utility managements were premature and imprudent because the technology was commercially unproven and the total economic costs of larger reactors were highly uncertain. Others have argued that at the time these commitments were made, utilities had based their decisions on the best forecasts and economic information available to them, and that the net benefits derived from those nuclear units completed and successfully operated will far outweigh the costs of the units cancelled or shut down.

This study does not resolve these conflicting views; however, one important finding is that the great majority of cancellation costs have been levied upon utility ratepayers and taxpayers, who had little or no control over the planning and construction of power plants. This observation implies that the responsibility for these activities has been virtually divorced from the parties who will ultimately reap the benefits and/or pay the costs. It is possible that this situation is an unavoidable consequence of the regulatory environment within which utility decisionmaking has been carried out.

1. INTRODUCTION

This report focuses on the causes of, and costs associated with, the cancellation of nuclear power plants. It is based on a study conducted by J.A. Reyes Associates, Inc., (JAR) for the Nuclear and Alternate Fuels Division, Office of Coal, Nuclear, Electric and Alternate Fuels, Energy Information Administration. The study was funded under Task Assignment 4 of DOE Contract No. DE-AC01-EI81-11816.

Study Objectives

The objectives of this study were three-fold:

- To present a history of nuclear power plant cancellations, including estimates of the sunk costs involved.
- To develop estimates of the costs associated with the potential cancellation of nuclear power plants currently planned or under construction.
- To determine how the costs of these potential cancellations are likely to be regionally distributed and allocated among three major groups: utility ratepayers, utility shareholders, and income taxpayers.

The last point deserves expansion. When an investor-owned utility cancels a partially completed project it incurs a loss which it can write off against its taxable income. As a result, both Federal and State governments suffer a reduction in the income tax revenues received from that utility company. This effect is further compounded by reductions in capital gains tax revenues received from the utility's investors who sell some of their common stock at a lower price than that which would have prevailed if the cancellation loss had not occurred. Ultimately, all of these losses in tax revenues are redistributed among income taxpayers, either through compensatory tax increases or through foregone tax reductions.

Approach

The analysis first examined the history of nuclear plant cancellations. This information was used to define the scope of the cancellation problem, to determine the costs incurred to date, and to review the regulatory treatment of those costs.

The second step was to determine the probable allocations of costs among utility investors, ratepayers, and income taxpayers. With this end in mind, a review of the regulatory treatment of past nuclear plant cancellations involving significant cost was conducted. In this study "significant" is defined as more than $50 million. Precedential cases were identified and studied in detail in order to understand the factors underlying the decisions made by the respective public utility commissions. These findings were then used to project how regulatory commissions would most likely treat the abandonment costs arising from future plant cancellations.

The final step was to identify the specific nuclear plants currently planned, or under construction, which are most susceptible to cancellation. This list was based on a review of available data on the construction status of planned reactors. Information published by the Nuclear Regulatory Commission (NRC), the Wall Street Journal, brokers and investment houses, and the Department of Energy (DOE) concerning the likelihood that each will be cancelled was also used in developing the list. Once the "at risk" population was identified, data on expenditures for these plants, and additional costs associated with their cancellation, were used to estimate the total potential costs, and their regional distributions, if these plants are cancelled in the near future.

Organization of the Report

Section 2 of the report provides a history of nuclear plant cancellations over the past decade. It shows the licensing status, expenditures, and construction status for each cancelled plant at the time of abandonment. The reasons cited by utilities for their cancellation decisions are enumerated and reconciled with historical data describing changes in electricity demand forecasts, utility industry financial indicators, plant construction costs, and regulatory requirements.

Section 3 presents a general discussion of the regulatory treatment of abandonment costs, then examines the specific treatment accorded these costs in cases where they were substantial. Finally, the relative distribution of the cost burden among utility investors, ratepayers, and income taxpayers is quantified for a hypothetical nuclear plant cancellation.

Section 4 presents two scenarios of nuclear power plant cancellations in the near future. The Base Case scenario includes plants very susceptible to cancellation. The Worst Case scenario includes additional plants which are also susceptible but less likely to be cancelled. Information on expenditures to date and potential cancellation costs for these plants is used to estimate the abandonment costs associated with their cancellations. This Section also estimates the regional distribution of these costs.

Section 5 presents the conclusions of the study.

2. HISTORY OF NUCLEAR PLANT CANCELLATIONS

Definition of Plant Cancellation

Before a comprehensive list of nuclear plant cancellations could be developed, it was necessary to define what represented a bonafide cancellation. Two conditions were set for a plant to be considered cancelled:

- The utility owner(s) made a significant commitment of resources to building the plant.
- The decision to construct the plant was subsequently reversed.

A utility normally takes one or more of the following actions early in the planning process that express a commitment to construct a nuclear plant:

- It publicly announces plans to build the plant.
- It applies to the Nuclear Regulatory Commission (NRC) for a construction permit (CP).
- It orders a nuclear steam supply system (NSSS).

However, only the last of these actions expresses an actual commitment of resources. When a utility announces plans to construct a nuclear power plant -- normally in a press release or in its annual report -- it makes only a verbal commitment. Through its announcement the utility does not incur significant costs or enter into legal obligations, and can easily abort its construction plans at minimal cost. Similarly, when a utility applies to the NRC for a CP, it pays only a $125,000 application fee and is not bound to its decision to construct the plant.[1] The application can be withdrawn at any time and the utility pays only the costs incurred by the NRC to review the application up to the time of withdrawal.[2] For these reasons, neither announcement of construction plans nor application to the NRC for a CP can be considered a significant financial commitment to plant construction.

In contrast, the ordering of an NSSS from a vendor -- either through a letter of intent or by signing an actual contract -- legally obligates a utility to pay, at a minimum, cancellation fees stipulated in the contract and probably some additional costs incurred by the vendor prior to cancellation. Thus, a utility is likely to consider carefully its decision to order an NSSS, given the potential losses associated with cancellation.

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[1]Title 10 CFR, Part 170, Fees.

[2]This is the position taken by the NRC. However, 17 utilities that have cancelled units after paying the application fee are currently suing the commission for recovery of the fee.

For the above reasons, this study employs the criterion that a nuclear plant cancellation has occurred when the utility owner(s) ordered an NSSS and subsequently cancelled it. The Department of Energy and the Atomic Industrial Forum also use this definition of cancellation.

Past Cancellations

The first commercial order for a nuclear steam supply system (NSSS) was placed in 1953. By the end of 1974, the Nation's electric utility industry had 29,921 megawatts (MWe) of nuclear plant capacity licensed for commercial operation.[3] That year also represented the high-water mark in terms of the industry's commitment to future additions to nuclear plant capacity, with orders placed for about 217,000 MWe of new capacity, exclusive of about 13,000 MWe which were previously cancelled. Table 1 presents a comprehensive annual breakdown of all nuclear plant cancellations through the end of 1982.

The first cancellations of nuclear units occurred in 1972. This marked the beginning of a trend which has continued to the present. By the end of 1982, the industry had announced the cancellation of 100 nuclear units at 56 sites, totalling almost 110,000 MWe of electric capacity. For comparison, only 39 fossil fuel-fired generating units, totalling about 23,000 MWe, were cancelled during the same time period.

Initially, the utilities terminated only units that were in the early stages of planning, i.e., "paper" plants. Although orders for the NSSS had been placed for all units, many never reached the site selection stage, or received limited work authorizations or construction permits. In recent years, nuclear units in more advanced stages of development have been cancelled. This is revealed in Table 2, which shows the stages, or milestones, in the construction process through which each unit had passed at the time of cancellation.

By 1980, none of the nuclear units underway were still at the "paper" stage. Utilities were cancelling nuclear units where construction permits had been been applied for, and in many cases granted by the NRC. In the most recent round of terminations, plants well into the construction process have been abandoned.

Reasons Underlying Cancellations

To establish the reasons underlying the 100 nuclear unit cancellations, and to determine whether there is any consistent relationship between the year of cancellation and these reasons, each cancellation was investigated using two sources of information. For cancellations which involved costs exceeding $50 million and which were already adjudicated by at least one regulatory commission, the reasons were obtained from the written commission decisions. For all other cancellations the constructing utilities were directly contacted. Five major reasons for cancelling planned nuclear units were identified and are listed below in the order of frequency with which they were cited:

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[3]Energy Information Administration, U.S. Department of Energy, Monthly Energy Review, DOE/EIA-0035(82/08) (Washington, D.C., 1982).

Table 1. Nuclear Units Ordered and Cancelled in Each Year, 1972-1982

	Orders Placed		Cancellations		Cumulative Orders	
Year	Number	MWe	Number	MWe	Number	MWe
Pre-1972	131	109,392	0	--	131	109,392
1972	38	41,315	7	6,117	162	144,590
1973	41	46,791	0	0	203	191,381
1974	28	33,263	7	7,216	224	217,428
1975	4	4,148	13	14,699	215	206,877
1976	3	3,804	1	1,150	217	209,531
1977	4	5,040	10	10,814	211	203,757
1978	2	2,240	14	14,487	199	191,510
1979	0	0	8	9,552	191	181,958
1980	0	0	16	18,001	175	163,957
1981	0	0	6	5,781	169	158,176
1982	0	0	18	21,937	151	136,239
Total	251	245,993	100	109,754	151	136,239

Sources: Energy Information Administration, U.S. Department of Energy, U.S. Commercial Nuclear Power, DOE/EIA-0315 (Washington, D.C., March 1982); Atomic Industrial Forum, "Historical Profile of U.S. Nuclear Power Development," AIF Background Info, December 31, 1981, and "Nuclear Power Plants in the United States," AIF Info, January 1, 1983.

Table 2. Milestones Completed at Time of Cancellation

Year of Cancellation[a]	Milestone Completed[b]								
	Ordered NSSS		Applied for CP		LWA or CP Issued		Construction Started		Percent Construction Completed
	No.	MWe	No.	MWe	No.	MWe	No.	MWe	
1972	7	6,117	3	2,415	0	--	0	--	0
1973	0	--	0	--	0	--	0	--	0
1974	7	7,216	2	2,226	2	2,226	0	--	0
1975	13	14,699	6	6,178	2	1,540	0	--	0
1976	1	1,150	1	1,150	0	--	0	--	0
1977	10	10,814	6	6,328	2	1,718	0	--	0
1978	14	14,487	8	7,567	0	--	0	--	0
1979	8	9,552	6	7,152	1	1,100	0	--	0
1980	16	18,001	16	18,001	7	7,239	4	3,789	0.5-5.6
1981	6	5,781	6	5,781	5	4,631	5	4,631	0.5-19
1982	18	21,937	17	20,667	11	13,157	9	10,597	2.0-27
Total ...	100	109,754	71	77,465	30	31,611	18	19,017	--

[a]According to the Energy Information Administration and the Atomic Industrial Forum, there were no nuclear reactors ordered and subsequently cancelled prior to 1972.

[b]NSSS, Nuclear Steam Supply System; CP, Construction Permit; LWA, Limited Work Authorization.

Sources: U.S. Department of Energy, U.S. Central Station Nuclear Electric Generating Units: Significant Milestones, various issues, 1978-1982; Atomic Industrial Forum, "Historical Profile of U.S. Nuclear Power Development," AIF Background Info, January 1, 1983.

- Lower forecasted load growth
- Financial constraints
- Regulatory changes and uncertainty
- Reversal of economic advantage
- Denial of certification by the State.

Table 3 identifies the 100 units that were cancelled, and Table 4 presents the major reasons cited as underlying their respective cancellations. The distribution of the data across the 11-year period is relatively uniform with respect to all reasons except "reversal of economic advantage," which is more frequently cited in later years.

The number of times a reason is cited is an imprecise indicator of its relative importance in causing, or contributing to, nuclear unit cancellations. This is because most of the 100 units cancelled involved two or more reasons and it is impossible to separate the respective importance of each without conducting a detailed analysis of the individual unit cancellation decisions. Because this was outside the scope of the study, analysis was limited to an examination of each of the five major reasons from the perspective of whether it is generally supported by empirical data reflecting industry-wide conditions and whether it constitutes a sufficient rationale for cancelling a planned or partially constructed nuclear unit. Within this context, each reason is discussed below.

Lower Forecasted Load Growth

Significant downward revision in the forecasted growth in peak load was the reason most frequently cited, being involved in about half of the units cancelled. As early as 1973, one utility determined that its revised forecast of future electricity demand could no longer support the construction of two planned nuclear units. By the end of 1982, almost half of the utilities cancelling nuclear units cited this as a reason for their cancellations.

The actions of the utilities are consistent with the data in Table 5, which presents the projections of long-term growth rates in summer peak loads prepared by each of the nine Regional Electric Reliability Councils in the years 1966 through 1981. From 1966 through 1972, growth in regional summer peaks was forecasted at average annual rates of about 7 percent or greater. This caused utilities to plan ambitious construction programs which would have approximately doubled installed generating capacity in 10 years. In 1973, however, the Arab oil embargo caused sharp increases in utility fossil fuel costs, which in turn raised the price of electricity and created a nationwide economic slowdown. This resulted in marked reductions in the near-term growth of electricity demand, and ultimately in the forecasts of long-term load growth as well. As Table 5 shows, there has been a continual downward trend in long-term projections since 1973. The utility industry currently forecasts average annual growth rates for regional summer peak loads of only 1.8 to 4.2 percent annually for the period 1982 to 1991.

A downward revision in a utility's forecasted peak load growth can provide sufficient rationale for cancelling one or more nuclear units if the resulting adjustment to the utility's capacity expansion plan moves the in-service dates of the units far enough into the future. One consequence of a lengthy deferral is that the ultimate cost of the completed unit becomes increasingly uncertain; thus, it is no longer clear that it offers an economic advantage over alternative projects such as coal-fired power plants, conservation programs or even new, developing technologies which are not feasible or economically competitive today. This may be true even for nuclear units well into construction, depending on how long they must be deferred and how much it will cost to complete them.

Table 3. Nuclear Reactor Cancellations by U.S. Utilities Since 1972

Year of Cancellation	Nucleai Unit	Net Design MWe	Utility[a]
1972	Bell Station	838	New York State Electric and Gas
	Crystal River 4	897	Florida Power Corporation
	Malibu	462	Los Angeles Department of Water and Power
	Verplank 1	1,115	Consolidated Edison
	Verplank 2	1,115	Consolidated Edison
	Perryman 1	845	Baltimore Gas and Electric
	Perryman 2	845	Baltimore Gas and Electric
1973	None	--	--
1974	Tyrone 2	1,150	Northern States Power
	Vidal 1	770	Southern California Edison
	Vidal 2	770	Southern California Edison
	Vogtle 3	1,113	Georgia Power
	Vogtle 4	1,113	Georgia Power
	Quanicassee 1	1,150	Consumers Power
	Quanicassee 2	1,150	Consumers Power
1975	Fulton 1	1,160	Philadelphia Electric
	Fulton 2	1,160	Philadelphia Electric
	Fermi 3	1,171	Detroit Edison
	St. Rosalie 1	1,160	Louisiana Power and Light
	St. Rosalie 2	1,160	Louisiana Power and Light
	Barton 3	1,159	Alabama Power
	Barton 4	1,159	Alabama Power
	Summit 1	770	Delmarva Power and Light
	Summit 2	770	Delmarva Power and Light
	Orange 1	1,300	Florida Power Corporation
	Orange 2	1,300	Florida Power Corporation
	Somerset 1	1,200	New York State Electric and Gas
	Somerset 2	1,200	New York State Electric and Gas
1976	Allens Creek 2	1,150	Houston Lighting and Power
1977	Douglas Point 1	1,146	Potomac Electric Power
	Douglas Point 2	1,146	Potomac Electric Power
	Sears Isle	1,150	Central Maine Power
	South Dade 1	1,100	Florida Power and Light
	South Dade 2	1,100	Florida Power and Light
	Surry 3	859	Virginia Electric Power
	Surry 4	859	Virginia Electric Power
	Ft. Calhoun 2	1,136	Omaha Public Power District
	Barton 1	1,159	Alabama Power
	Barton 2	1,159	Alabama Power

See footnote at end of table.

Table 3. Nuclear Reactor Cancellations by U.S. Utilities Since 1972 (continued)

Year of Cancellation	Nuclear Unit	Net Design MWe	Utility[a]
1978	North Coast 1	583	Puerto Rico Water Resources Authority
	Sundesert 1	974	San Diego Gas and Electric
	Sundesert 2	974	San Diego Gas and Electric
	Blue Hills 1	918	Gulf States Utilities
	Blue Hills 2	918	Gulf States Utilities
	Zimmer 2	1,170	Cincinnati Gas and Electric
	Atlantic 1	1,150	Public Service Electric and Gas
	Atlantic 2	1,150	Public Service Electric and Gas
	Atlantic 3	1,150	Public Service Electric and Gas
	Atlantic 4	1,150	Public Service Electric and Gas
	Haven 2	900	Wisconsin Electric Power
	South River 1	1,150	Carolina Power and Light
	South River 2	1,150	Carolina Power and Light
	South River 3	1,150	Carolina Power and Light
1979	Greene County	1,212	Power Authority State of New York
	Tyrone 1	1,100	Northern States Power
	Palo Verde 4	1,270	Arizona Public Service
	Palo Verde 5	1,270	Arizona Public Service
	NEP 1	1,150	New England Power and Light
	NEP 2	1,150	New England Power and Light
	Stanislaus 1	1,200	Pacific Gas and Electric
	Stanislaus 2	1,200	Pacific Gas and Electric
1980	Davis-Besse 2	906	Toledo Edison
	Davis-Besse 3	906	Toledo Edison
	Erie 1	1,267	Toledo Edison
	Erie 2	1,267	Toledo Edison
	Jamesport 1	1,150	Long Island Lighting
	Jamesport 2	1,150	Long Island Lighting
	New Haven 1	1,250	New York State Electric and Gas
	New Haven 2	1,250	New York State Electric and Gas
	Sterling	1,150	Rochester Gas and Electric
	Haven 1	900	Wisconsin Electric Power
	Greenwood 2	1,264	Detroit Edison
	Greenwood 3	1,264	Detroit Edison
	Forked River 1	1,070	Jersey Central Power and Light
	North Anna 4	907	Virginia Electric Power
	Montague 1	1,150	Northeast Utilities
	Montague 2	1,150	Northeast Utilities

See footnote at end of table.

Table 3. Nuclear Reactor Cancellations by U.S. Utilities Since 1972 (continued)

Year of Cancellation	Nuclear Unit	Net Design MWe	Utility[a]
1981	Bailly	644	Northern Indiana Public Service
	Pilgrim 2	1,150	Boston Edison
	Callaway 2	1,120	Union Electric
	Harris 3	900	Carolina Power and Light
	Harris 4	900	Carolina Power and Light
	Hope Creek 2	1,067	Public Service Electric and Gas
1982	WPN 4	1,218	Washington Public Power Supply System
	WPN 5	1,240	Washington Public Power Supply System
	Black Fox 1	1,150	Public Service of Oklahoma
	Black Fox 2	1,150	Public Service of Oklahoma
	Perkins 1	1,280	Duke Power
	Perkins 2	1,280	Duke Power
	Perkins 3	1,280	Duke Power
	Vandalia	1,270	Iowa Power and Light
	Pebble Springs 1	1,260	Portland General
	Pebble Springs 2	1,260	Portland General
	Hartsville B1	1,233	Tennessee Valley Authority
	Hartsville B2	1,233	Tennessee Valley Authority
	Phipps Bend 1	1,233	Tennessee Valley Authority
	Phipps Bend 2	1,233	Tennessee Valley Authority
	Allens Creek 1	1,150	Houston Lighting and Power
	Cherokee 2	1,280	Duke Power
	Cherokee 3	1,280	Duke Power
	North Anna 3	907	Virginia Electric Power

[a]In cases where there is more than one owner, the constructing utility is listed.

Table 4. Reasons Cited by Utilities for Their Nuclear Reactor Cancellations

Nuclear Unit	Lower Forecasted Load Growth	Financial Constraints	Regulatory Changes and Uncertainty	Reversal of Economic Advantage	Denied Certification by State	Other (see notes)
	Reasons Cited for Cancellation					
1972						
Bell Station	--	--	--	--	--	([a])
Crystal River 4 ..	--	--	X	--	--	--
Malibu	--	--	--	--	--	([b])
Verplank 1	X	X	--	--	--	([c])
Verplank 2	X	X	--	--	--	([c])
Perryman 1	--	--	--	--	--	([d])
Perryman 2	--	--	--	--	--	([d])
1974						
Tyrone 2	X	--	--	--	--	--
Vidal 1	--	X	X	--	--	--
Vidal 2	--	X	X	--	--	--
Vogtle 3	X	X	--	--	--	--
Vogtle 4	X	X	--	--	--	--
Quanicassee 1	X	X	X	--	--	--
Quanicassee 2	X	X	X	--	--	--
1975						
Fulton 1	--	--	--	--	--	([e])
Fulton 2	--	--	--	--	--	([e])
Fermi 3	--	X	--	--	--	--
St. Rosalie 1	X	X	--	--	--	--
St. Rosalie 2	X	X	--	--	--	--
Barton 3	--	--	X	X	--	--
Barton 4	--	--	X	X	--	--
Summit 1	--	--	--	--	--	([e])
Summit 2	--	--	--	--	--	([e])
Orange 1	--	X	X	--	--	--
Orange 2	--	X	X	--	--	--
Somerset 1	--	--	--	--	--	([f])
Somerset 2	--	--	--	--	--	([f])
1976						
Allens Creek 2 ...	X	X	--	--	--	--

See footnotes at end of table.

Table 4. Reasons Cited by Utilities for Their Nuclear Reactor Cancellations (continued)

Nuclear Unit	Reasons Cited for Cancellation: Lower Forecasted Load Growth	Financial Constraints	Regulatory Changes and Uncertainty	Reversal of Economic Advantage	Denied Certification by State	Other (see notes)
1977						
Douglas Point 1 ..	X	--	--	--	--	--
Douglas Point 2 ..	X	--	--	--	--	--
Sears Isle	--	X	--	--	--	--
South Dade 1	--	X	X	--	--	--
South Dade 2	--	X	X	--	--	--
Surry 3	--	X	X	--	--	--
Surry 4	--	X	X	--	--	--
Ft. Calhoun 2	X	--	X	X	--	--
Barton 1	--	--	X	X	--	--
Barton 2	--	--	X	X	--	--
1978						
North Coast 1	X	--	X	--	--	--
Sundesert 1	--	X	X	--	--	(g)
Sundesert 2	--	X	X	--	--	(g)
Blue Hills 1	X	X	--	--	--	--
Blue Hills 2	X	X	--	--	--	--
Zimmer 2	--	--	X	X	--	--
Atlantic 1	X	--	--	--	--	--
Atlantic 2	X	--	--	--	--	--
Atlantic 3	X	--	--	--	--	--
Atlantic 4	X	--	--	--	--	--
Haven 2	X	--	X	X	--	--
South River 1	X	X	--	--	--	--
South River 2	X	X	--	--	--	--
South River 3	X	X	--	--	--	--
1979						
Greene County	--	--	X	X	--	--
Tyrone 1	--	--	--	--	[h]X	--
Palo Verde 4	X	--	--	--	--	--
Palo Verde 5	X	--	--	--	--	--
NEP 1	--	--	--	[i]X	--	--
NEP 2	--	--	--	[i]X	--	--
Stanislaus 1	--	--	--	--	--	(j)
Stanislaus 2	--	--	--	--	--	(j)

See footnotes at end of table.

Table 4. Reasons Cited by Utilities for Their Nuclear Reactor Cancellations (continued)

Nuclear Unit	Reasons Cited for Cancellation: Lower Forecasted Load Growth	Financial Constraints	Regulatory Changes and Uncertainty	Reversal of Economic Advantage	Denied Certification by State	Other (see notes)
1980						
Davis-Besse 2	X	X	X	--	--	--
Davis-Besse 3	X	X	X	--	--	--
Erie 1	X	X	X	--	--	--
Erie 2	X	X	X	--	--	--
Jamesport 1	--	--	--	--	[k]X	--
Jamesport 2	--	--	--	--	[k]X	--
New Haven 1	--	--	--	--	[l]X	--
New Haven 2	--	--	--	--	[l]X	--
Sterling	X	--	--	--	[m]X	--
Haven 1	X	--	X	X	--	--
Greenwood 2	--	X	X	--	--	--
Greenwood 3	--	X	X	--	--	--
Forked River 1 ...	--	X	--	--	--	--
North Anna 4	X	X	X	--	--	--
Montague 1	X	X	--	--	--	--
Montague 2	X	X	--	--	--	--
1981						
Bailly	--	--	X	X	--	([n])
Pilgrim 2	--	X	--	--	--	--
Callaway 2	--	X	--	--	--	--
Harris 3	X	--	--	--	--	--
Harris 4	X	--	--	--	--	--
Hope Creek 2	X	X	--	--	--	--
1982						
WPN 4	X	X	--	--	--	--
WPN 5	X	X	--	--	--	--
Black Fox 1	--	--	--	X	--	--
Black Fox 2	--	--	--	X	--	--
Perkins 1	X	X	X	--	--	--
Perkins 2	X	X	X	--	--	--
Perkins 3	X	X	X	--	--	--
Vandalia	X	--	X	--	--	--
Pebble Springs 1 .	X	--	X	X	--	--
Pebble Springs 2 .	X	--	X	X	--	--

See footnotes at end of table.

Table 4. Reasons Cited by Utilities for Their Nuclear Reactor Cancellations (continued)

Nuclear Unit	Reasons Cited for Cancellation: Lower Forecasted Load Growth	Financial Constraints	Regulatory Changes and Uncertainty	Reversal of Economic Advantage	Denied Certification by State	Other (see notes)
1982 (continued)						
Hartsville B1	X	--	--	--	--	--
Hartsville B2	X	--	--	--	--	--
Phipps Bend 1	X	--	--	--	--	--
Phipps Bend 2	X	--	--	--	--	--
Allens Creek 1 ...	--	--	--	X	--	--
Cherokee 2	X	--	--	--	--	--
Cherokee 3	X	--	--	--	--	--
North Anna 3	--	--	X	X	--	--
Total Citations	52	44	38	18	6	17

[a]Local citizens strongly opposed the plant, claiming its location would create thermal pollution in Cayuga Lake.

[b]The AEC revoked the construction permit because the plant site was not determined to be geologically sound.

[c]Environmentalists disputed use of the Hudson River as a cooling system.

[d]NRC found the site unsuitable due to high population density and the proximity of hazardous materials.

[e]Gulf General Atomic reneged on its contractual agreement to provide high temperature gas-cooled reactors.

[f]Potential seismic problems were discovered, requiring more intensive investigation which would have delayed the plant beyond the date when its capacity would have been needed.

[g]In 1976, the California legislature passed a law prohibiting the site certification of new nuclear power plants until the issues of spent fuel reprocessing and nuclear waste disposal are resolved by the Federal government and until the State's Energy Commission completes a study on the feasibility of undergrounding and berm containment. Timely completion of the Sundesert plant would have required legislative exemption from this law, the passage of which was uncertain.

[h]Certification was denied because the Wisconsin Public Service Commission was unconvinced that the plant was needed to serve Wisconsin customers and it rejected regionwide planning.

[i]It was determined that the implementation of conservation and load management programs, and the conversion to coal of existing units, could satisfy current and projected demand.

[j]The NSSS for these units were originally ordered for a Mendocino location that was found unsuitable and abandoned in 1973. Then, Stanislaus 1 and 2 were cancelled in response to the nuclear moratorium law enacted in 1976 (see footnote g above).

[k]N.Y. State siting Board decided a coal-fired plant would achieve a desirable diversification of LILCO's fuel mix.

Footnotes to Table 4 (continued)

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[l]Certification was denied because participation of the co-owner, LILCO, was not firmly established.

[m]Construction permit ran out during a delay that started in order to examine the plant design and continued due to intervention by consumer groups.

[n]Certification was revoked when reexamination of updated load forecasts put in doubt the need for the new capacity.

Sources: Energy Information Administration, Department of Energy, U.S. Commercial Nuclear Power, DOE/EIA-0315 (Washington, D.C., March 1982); Atomic Industrial Forum, "Historical Profile of U.S. Nuclear Power Development," AIF Background Info, January 1, 1983; principal investigator's personal communications with executives of selected utilities.

Table 5. Average Annual Rates of Growth in Summer Peak Load Forecasted by the Electric Reliability Councils, 1967-1981

	Average Annual Forecasted Rate of Growth in Peak Loads for Period Shown (Percent)[a]															
Region[b]	1967-1970	1968-1973	1969-1974	1970-1975	1971-1976	1972-1977	1973-1978	1974-1979	1975-1980	1976-1985	1977-1986	1978-1987	1979-1988	1980-1989	1981-1990	1982-1991
ECAR	7.5	8.4	7.1	8.1	8.4	8.3	8.1	6.9	7.6	6.6	5.8	5.3	4.4	4.0	3.3	3.0
ERCOT ...	9.6	9.3	10.1	9.0	9.1	9.6	9.5	10.0	8.3	6.8	6.0	5.6	5.2	5.6	4.4	4.2
MAAC	6.8	7.4	7.3	8.0	8.8	8.3	7.7	6.3	5.9	5.6	5.0	3.5	3.3	2.9	1.9	2.0
MAIN	7.5	8.5	6.6	8.2	8.4	8.3	7.9	7.6	7.5	7.0	6.2	5.5	4.8	4.2	2.9	2.6
MARCA ...	7.1	7.6	8.2	7.8	8.1	8.2	8.8	7.9	7.0	6.7	6.9	5.5	5.6	5.5	3.7	3.9
NPCC	6.8	7.4	7.3	8.1	8.8	8.3	7.7	6.3	5.5	4.6	4.9	3.2	3.4	1.9	1.5	1.8
SERC	8.0	9.0	9.0	9.5	10.3	10.8	9.9	9.6	8.7	6.9	6.7	6.0	5.6	4.4	3.2	2.8
SPP	9.6	9.3	10.1	9.0	9.1	9.6	9.5	10.0	8.1	8.3	7.3	6.3	6.0	5.4	3.3	3.3
WSCC	8.1	7.9	8.2	7.7	7.6	7.3	8.7	7.5	6.6	6.2	5.4	5.3	4.9	4.5	3.7	2.8

[a]Each forecast was prepared in the year prior to the start of the forecasted period. For example, the forecast for 1967-70 was prepared in 1966.

[b]Prior to 1975, data were reported for the eight Federal Power Regions. These data were correlated with the Regional Reliability Councils and are reported in the table in this form. The nine councils are as follows: ECAR, East Central Area Reliability Council; ERCOT, Electric Reliability Council of Texas; MAAC, Mid-Atlantic Area council; MAIN, Mid-America Interpool Network; MAPP, Mid-Continent Area Power Pool; NPCC, Northeast Power Coordinating Council; SERC, Southeastern Electric Reliability Council; SPP, Southwest Power Pool; WSCC, Western Systems Coordinating Council.

Note: Average annual growth rate for 1967 was based on a four-year forecast. The figures for 1968-1976 were derived from 6-year forecasts; after 1976, they were based on 10-year forecasts.

Sources: National Electric Reliability Council, Electric Power Supply and Demand 1982-1991, August 1982. Data from previous NERC reports summarized in Edison Electric Institute, Electric Power Survey, issues from April 1967 to April 1981.

An alternative to cancellation is to "mothball" the unit until electricity demand grows enough to justify resuming construction. Mothballing imposes additional costs due to the need for interim maintenance activities required to preserve the partially completed structure and plant equipment already delivered to the utility. These annual maintenance costs must be included when considering whether to mothball or cancel a nuclear unit. Nonetheless, despite the increased costs and uncertainty associated with delayed completion, the expectation of lower rates of growth in peak load will not be sufficient to justify cancelling some nuclear units, but rather to defer them. Exactly which situation pertains in a specific case depends largely on how far into the future plant completion must be deferred; the shorter the deferral period, the greater the likelihood that plant deferral will be the preferred route.

For many utility systems the addition of planned nuclear capacity would result in the displacement of higher cost generation from existing oil-fired and natural gas-fired plants utilized in base load. In these cases, the fuel savings provide an economic justification for completing the nuclear plant on schedule, a conclusion relatively insensitive to the lower growth in peak load. This situation is likely to occur in regions where more than 5 to 10 percent of the electricity is generated with oil or natural gas.[4] According to the latest North American Electric Reliability Council's projections, shown in Figure 1, this will still be the case in MACC, ERCOT, NPCC, SPP, WSCC, and SERC by 1991 (see Appendix A for a description of these regions). In the SERC region, virtually all of the oil-fired generation occurs in Florida, making the utilities in that state particularly suitable candidates for new capacity to displace oil. This conclusion is strengthened further by the fact that SERC is not operated as one unified power pool and thus currently does not fully exploit opportunities for economic energy exchanges.

Finally, if a utility is having difficulties financing new construction (discussed below in the subsection on Financial Constraints), cancellation of planned additions to capacity offers the utility a means of improving its near-term cash flow and possibly minimizing its losses. In addition, if its forecasted load growth has unexpectedly dropped, such cancellations may not jeopardize the utility's legal obligation to provide reliable service, although net savings from oil and natural gas displacement may not be achieved, thereby costing its customers more. By canceling, rather than deferring new plant capacity, a utility can quickly begin to recover all, or most, of its sunk investment through higher rates. Section 3 describes the regulatory methods through which such cost recoupment is accomplished.

Financial Constraints

While both the investor-owned and publicly owned utilities have required increasing amounts of capital to finance construction, the problem of financial constraints primarily applies to the investor-owned utilities -- the segment of the industry which accounted for approximately three-fourths of all installed capacity and electricity generation in the United States during the past 15 years. Similarly, of the 100 reactors cancelled over the survey period, 88 were being constructed by investor-owned utilities. These utilities claim that 5 nuclear units were cancelled solely because capital was not

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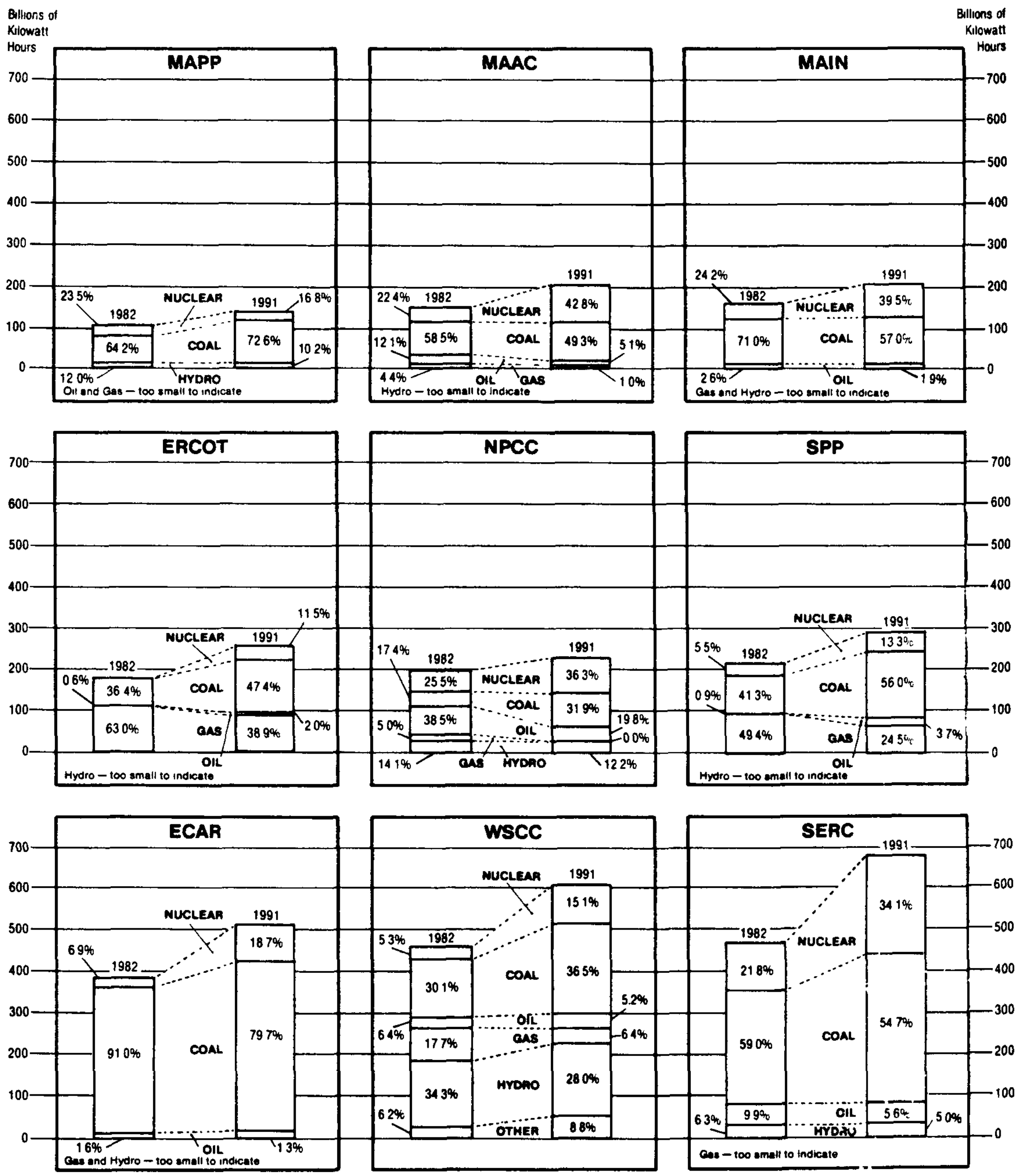
[4]This criterion is generalized from an analysis for Middle South Utilities: R. Borlick and D. Crawford, Middle South Utilities System, Optimal Generation Expansion Study, Final Report, Energy Management Associates, November 1980.

Figure 1. Projected Electric Generation by Principal Energy Sources



Note: The difference between the sum of the parts and 100 percent represents the share of electric generation by sources not shown, including net pumped storage requirements.

Source: North American Electric Reliability Council, Electric Power Supply and Demand, 1982-1991; Annual Data Summary Report for the Regional Reliability Councils of NERC, August 1982.

available on reasonable terms. For another 39 units, financial constraints were cited along with one, or more, other reasons for cancellation.

The publicly owned utilities have been readily able to accommodate cancellation costs because they have greater flexibility in raising electric rates to recover all costs of providing service, including principal and interest payments on outstanding debt. In addition, municipalities and cooperatives enjoy unique tax advantages relative to the investor-owned utilities. Nonetheless, nuclear plant cancellations have raised the cost of new debt and the associated cost of electricity production for all utilities participating in the ownership of nuclear plants under construction. While the publicly owned utilities can float new bond issues without seriously jeopardizing their financial stability, a saturated marketplace will demand higher interest rates on new bond issues for either type of utility, particularly for enterprises with higher perceived risks due to their involvement in nuclear projects.[5]

Over the past 17 years, the amounts of capital required to sustain construction programs has risen dramatically. Capital requirements increased due to higher interest rates, rapidly escalating construction costs, construction schedule delays, new pollution control requirements for fossil-fired plants, and changing and uncertain design requirements for nuclear plants.

In the period 1960 to 1965, investor-owned electric utilities generated more than half the capital needed for new plant construction from internal sources -- retained earnings, depreciation, and deferred taxes. In 1965, only 30 percent of the industry's capital requirement was generated through external markets.[6] By 1980, however, externally generated dollars accounted for 53 percent of total capital requirement.[7] This growing disparity between internally generated funds and capital requirements for investor-owned utilities is shown in Table 6.

The need for externally generated funds had increased significantly between 1965 and 1970. In 1970, utility earnings began to decline as a result of regulatory lag in granting rate increases, general inflation and a bottoming out in the downward trend in electric operating costs. Then in 1973, operating costs rose sharply due to higher fossil fuel costs brought about by the Arab oil embargo and its impact on domestic fuel prices. Utility fuel costs as a percentage of operating revenue rose from 15 percent

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[5]New bond issues are restricted by the requirement that the governing bodies which oversee the operations of publicly owned utilities normally must approve major expenses and financing activities. Recently, the Ninth Circuit Court found unconstitutionala referendum requiring that the Washington Public Power Supply System gain ratepayer approval before issuing revenue bonds. But that ruling was based on the referendum's interference with existing contracts, and did not challenge the right of taxpayers to control bond issues.

[6]Federal Power Commission, Statistics of Privately Owned Electric Utilities in the United States, 1971, October 1972.

[7]Energy Information Administration, Department of Energy, Statistics of Privately Owned Electric Utilities in the United States, 1980 Annual, Classes A & B Companies (Washington, D.C., October 1981).

Table 6. The Growing Difference Between Internally Generated Funds and Capital Requirements Among Class A and B Investor-Owned Electric Utilities, 1965-1980 (Billions of Dollars)

Fund Patterns	1965	1970	1975	1980
Sources of Funds (Internal and Other)				
Net Income	2.5	3.4	6.2	10.7
Less AFUDC[a]	-0.1	-0.6	-1.6	-4.4
Non-Cash Charges[b]	1.8[c]	2.1	4.3	10.1
Other Sources[d]	--	1.1	2.0	3.1
Total	4.2	6.0	10.9	19.5
Uses of Funds				
Additions to Plant	4.0	10.5	15.2	24.6
Dividends Paid[e]	1.8	2.5	4.6	8.5
Securities and Debt Retirement[f]	0.2	0.9	1.2	4.8
Other Uses[g]	--	0.6	1.4	3.5
Total	6.0	14.5	22.4	41.4
External Capital Requirement	1.8	8.5	11.5	21.9

[a]Prior to 1977, Allowance for Funds Used in Construction was reported on FPC (later FERC) Form 1 in one account on the Income Statement, which included the returns on debt, preferred equity and common equity capital used to support construction. In 1977, and thereafter, AFUDC was divided between two accounts: (1) Allowance for Other Funds Used During Construction (AOFDC), which reflects the returns on preferred and common equity capital, and (2) Allowance for Borrowed Funds Used During Construction (ABFDC), which reflects the interest on debt capital.

[b]Consists of depreciation, depletion, amortization, net increases in provision for deferred income taxes, investment tax credit adjustments, and any other non-cash charges to income.

[c]Excludes depletion.

[d]Consists of sales of noncurrent assets, contributions from associated and subsidiary companies and a net of any other sources of funds not from operation or new issues of securities. Not available for 1965.

[e]Consists of dividends paid on preferred and common stock.

[f]Consists of redemptions of long-term debt, preferred stock, and capital stock; net decreases in short-term debt; and any other funds for retirement.

[g]Consists of purchase of other noncurrent assets, investments in and advances to associated and subsidiary companies, and other applications of funds. Not available for 1965.

Sources: Energy Information Administration, U.S. Department of Energy, Statistics of Privately Owned Electric Utilities in the United States, 1980 Annual, Class A and B Companies, DOE/EIA-0044(80), (Washington, D.C., October 1981). Federal Power Commission, Statistics of Privately Owned Electric Utilities in the United States, 1975, October 1976; and Statistics of Privately Owned Electric Utilities in the United States, 1970, October 1971. Edison Electric Institute, Statistical Yearbook of the Electric Utility Industry (various years).

in 1967 to 33 percent in 1979.[8] This represents a ten-fold increase in actual dollar outlays. At the same time, consumer activism was also placing increased political pressure on state regulatory commissions to hold down electricity rates, further exacerbating the adverse effects of regulatory lag.

As mentioned earlier, the oil embargo also marked the beginning of an era of generally declining rate of growth in electricity demand which subjected utility operating revenues, and operating income, to further uncertainty.

During the period under discussion, cash earnings diminished as a percent of net income while earnings in the form of "IOU's" for future cash payment increased. The changing composition of earnings from 1965 to 1980 is shown in Figure 2. This change resulted because, as construction programs grew, utilities had increasing amounts of capital tied up in construction work in progress (CWIP) that generated noncash allowance for funds used during construction (AFUDC) earnings, to be recovered only when plants become "used and useful," i.e., generate electricity. As lead times and construction costs for new plants increased -- especially for nuclear units which are extremely capital-intensive and take up to a decade or more to license and build -- the portion of earnings represented by AFUDC inexorably rose.

The investor-owned utilities' increased dependence on the capital markets for long-term financing has been a costly venture for their investors because of the changes in the industry's financial status and generally bearish market conditions throughout the 1970's. Table 7 presents measures which are indicators of their ability to raise funds in the capital markets. As the table shows, there has been a substantial reduction in the number of utilities with bond ratings of investment quality. While 89 percent of the companies sampled by Merrill Lynch in 1965 had Moody's ratings above Baa, only 37 percent had maintained this rating in 1980. Ratings of Baa or lower effectively prohibit many institutional investors from purchasing a company's bonds.

Selling new issues of both long-term debt and preferred stock is currently limited for most utilities as a result of their low interest and preferred dividend coverage ratios. Generally, the legal covenants of outstanding bonds and preferred stock require the maintenance of interest and preferred dividend coverage ratios of approximately 2.0 and 1.5, respectively.[9] As the actual ratios have approached these minimum values, the investment ratings of their bonds and preferred stocks have been downgraded, making new issues more difficult to sell.

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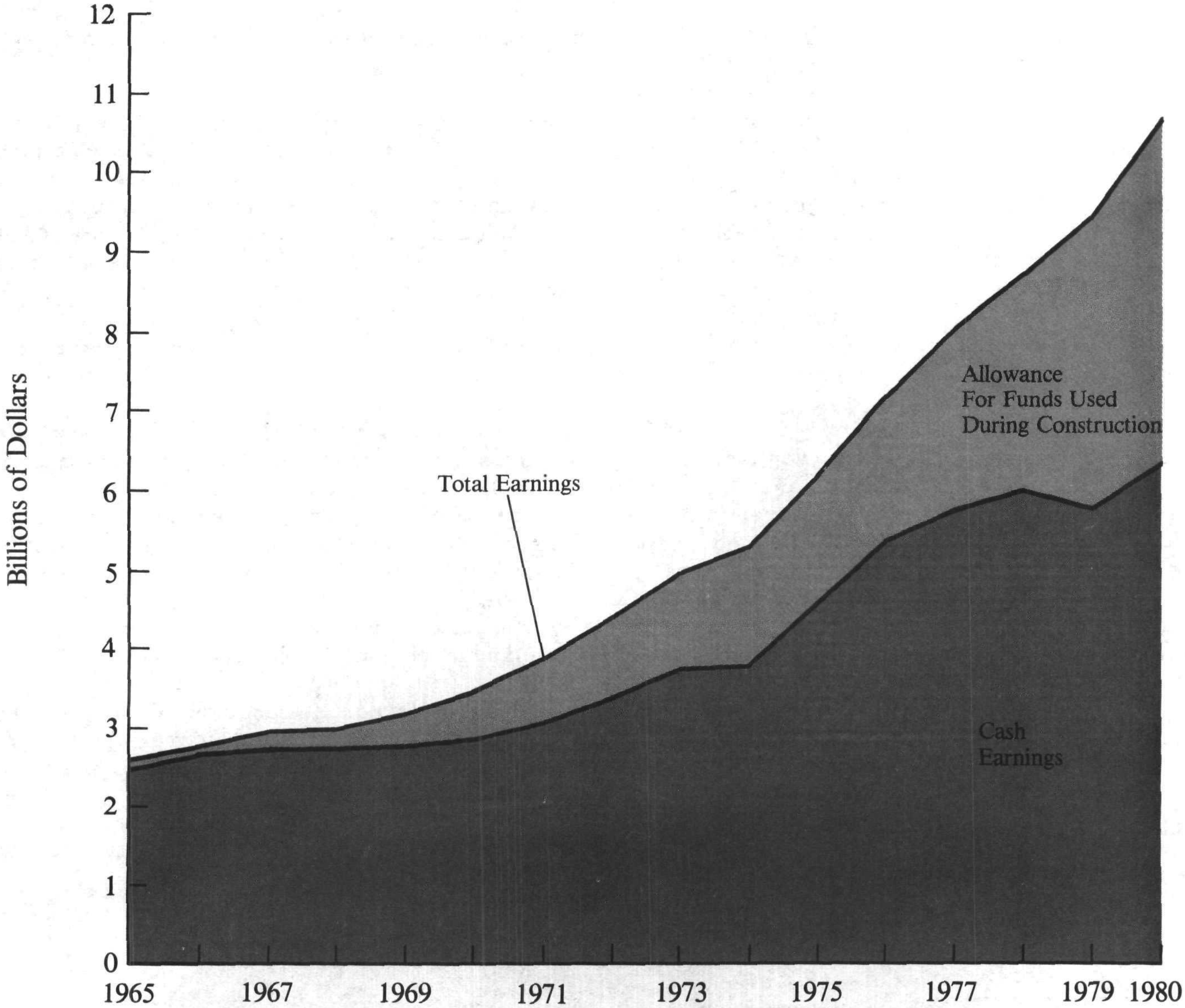
[8]Energy Information Administration, U.S. Department of Energy, Statistics of Privately Owned Electric Utilities in the United States, 1980 Annual, Class A & B Companies, DOE/EIA-0044(80), (Washington, D.C., October 1981); Federal Power Commission, Statistics of Privately Owned Electric Utilities in the United States, 1974, October 1975.

[9]The minimum interest coverage ratio for first mortgage bonds and the dividend coverage ratio for preferred stock are prescribed by Securities and Exchange Commission Releases 13105 and 13106, respectively, both dated February 16, 1956. Although the SEC requirements apply only to the securities of companies subject to the Public Utility Holding Company Act of 1935, they are generally followed throughout the electric utility industry.

Figure 2. Composition of Investor-Owned Class A and B Electric Utility Earnings, 1965-1980



Note: Prior to 1977, AFUDC was reported on FPC (later FERC) Form 1 in one account on the Income Statement, which included the returns on debt, preferred and common equity capital used to support construction. In 1977, and thereafter, AFUDC was divided between two accounts: (1) Allowance for Other Funds Used During Construction (AOFDC), which reflects the returns on preferred and common equity capital, and (2) Allowance for Borrowed Funds Used During Construction (ABFDC), which reflects the interest on debt capital.

Source: Federal Power Commission, Statistics of Privately Owned Electric Utilities in the United States, 1974, October 1975; Energy Information Administration, U.S. Department of Energy, Statistics of Privately Owned Electric Utilities in the United States, 1980 Annual, Class A&B Companies, October 1981.

Table 7. Financial Measures of the Investor-Owned Electric Utility Industry's Ability to Raise Capital Externally

Financial Measures	1965	1970	1975	1980	Percent Change, 1965-1980
Debt and Preferred Equity					
Mortgage Bond Coverage Ratio[a,b]	5.5	3.5	2.8	2.6	-53
Preferred Stock Coverage Ratio[a,c]	3.0	2.2	1.8	1.7	-43
Percentage of Companies with Bond Ratings above Baa[d]	89	78	50	37	-58
Average Return on Newly Issued A-rated Utility Bonds (percent)	4.7	9.2	10.3	13.4	185
Average Return on Newly Issued Preferred Medium-Grade Utility Stocks (percent) ...	4.7	7.8	10.6	12.7	170
Common Equity					
Return on Common Equity (percent)[a]	12.6	11.8	11.5	11.5	-9
Market-to-Book Ratio[e,f]	2.3	1.3	0.8	0.7	-70
Common Dividend Yield[e,g]	3.3	5.9	9.7	12.0	264

[a]Composite ratios for all class A and B investor-owned electric utilities.

[b]The first mortgage bond coverage ratio is based on the definition in Securities and Exchange Commission release 13105. The numerator is net utility operating income, before interest expense or income taxes, plus the lower of net non-operating income or loss (including allowance for funds used during construction) or 10% of net operating income as described above. The denominator is total interest on secured debt.

[c]The preferred stock coverage ratio is based on the definition in Securities and Exchange Commission release 13106. The numerator is gross utility income, after income taxes but before interest expense, including all non-operating income, such as allowance for funds used during construction. The denominator is total interest on all debt plus preferred dividends.

[d]Based on a sample of 73 companies. Bond ratings provide a measure of investment quality and safety (i.e., probability of payment of interest and principal). The ratings referred to here are based on the nine point rating scale used by Moody's, one of the two major rating agencies. The highest quality rating is Aaa, whereas Baa is an indication that the company is developing speculative characteristics.

[e]Composite ratios for class A investor-owned electric utilities included in the COMPUSTAT II data base.

[f]The market-to-book ratio is the market price of a common stock divided by the net value of the assets behind each share of stock as shown on the books of the corporation. A market-to-book ratio below 1.0 reflects the perception of investors that a company will earn an accounting (or "book") return on its assets which is less than its cost of capital.

[g]The dividend yield measures the common shareholder's return on the market value of his investment from the dividend alone. A high dividend yield indicates that the investors see a greater risk and/or less potential for growth in dividends and earnings.

Footnotes to Table 7 (continued)

Sources: Energy Information Administration, U.S. Department of Energy, Statistics of Privately Owned Electric Utilities in the United States, 1980 Annual, Classes A and B Companies (Washington, D.C., October 1981); Federal Power Commission, Statistics of Privately Owned Electric Utilities in the United States, 1974, October 1975; Moody's Public Utility Manual, Vol. 1, 1981; Salomon Brothers, Market Research Group, August 1982; Utility COMPUSTAT II, Standard & Poor's Compustat Services, Inc.; Securities and Exchange Commission, Release 13105, Statement of Policy Regarding First Mortgage Bonds Subject to the Public Utility Holding Company Act of 1935, February 16, 1956, and Release 13106, Statement of Policy Regarding Preferred Stocks Subject to the Public Utility Holding Company Act of 1935, February 16, 1956.

Although electric utilities could still raise capital through the sale of common stock, most of them have a strong incentive to limit these issuances. As Table 7 shows, the average rate of return earned on common equity actually declined between 1965 and 1980 despite high inflation rates throughout the economy during that period. In contrast, the rates of return offered to investors on utility bonds and preferred stocks, which are generally recognized as less risky investments than utility common stocks, almost tripled, and by 1980 they exceeded the average rate of return earned on common equity. This is clear evidence that most of the investor-owned utilities were earning rates of return which fell short of their respective costs of capital.

The inadequate rates of return on common equity have helped depress the market prices of utility stocks below their book values, as Table 7 also reveals. One result is that each new common stock offering dilutes a company's earnings per share, placing further downward pressure on its common stock price. To limit this devaluation, utility managements have a strong incentive to follow a "capital minimization" strategy, i.e., curtail investment instead of selling new common stocks.[10] A policy of making only the investments which are absolutely necessary to ensure the continuity of service does, in fact, appear to have been widely adopted by the investor-owned utilities. In part, this is evidenced by the number of nuclear plants cited as being cancelled for financial reasons.

In summary, the existence of financial constraints appears to be a valid and continuing reason to rationally cancel all types of additions to generating capacity. Nuclear plants have been more frequent targets for cancellation than coal-fired plants because they have longer lead times and higher absolute capital costs (30 to 100 percent higher) that are less predictable. A number of nuclear plants have been cancelled in spite of the potential benefits they offer, such as reducing operating costs and dependence on imported oil, in an attempt to improve the financial health of the utilities constructing them. Indeed, the lifetime economic benefits that might accrue in such cases could be in the billions of dollars. Unfortunately, more specific quantitation of potential benefits foregone is outside the scope of this analysis.

Regulatory Changes and Uncertainty

According to utility spokespersons, continuously changing regulations, licensing delays and uncertainty surrounding future standards for nuclear plants -- primarily originating at the AEC and its successor, the NRC -- have substantially contributed to the cancellation of 38 units. While utilities acknowledge their responsibility for the safe utilization of nuclear power, they also feel that the regulatory environment is unnecessarily cumbersome. They assert that it has jeopardized nuclear construction by:

- Causing delays in the issuance of construction permits and operating licenses, thereby lengthening planning and lead times

- Frequently changing design requirements which impose additional construction and sometimes require backfitting of equipment

- Creating uncertainty as to when planned reactors will be licensed for commercial operation.

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[10] Peter Navarro, "Our Stake in the Electric Utility's Dilemma," Harvard Business Review, May-June 1982.

Regulatory requirements governing nuclear construction and licensing expanded significantly after 1971. In addition, in response to the Calvert Cliffs case, the Supreme Court declared that the National Environmental Policy Act of 1969 required the Atomic Energy Commission (later the NRC) to prepare, as part of their licensing process, environmental impact statements which examine alternatives to the nuclear plant under consideration and the effect of each on the environment.[11]

Many unforeseen safety- and health-related problems associated with nuclear power requiring correction and continuing oversight (including retrofitting portions of plant under construction or already completed) have surfaced over the past 10 years through operational experience gained as successively larger reactors have entered service. Coping with these problems has slowed down regulatory functions, increased the number of standards, and resulted in an inefficient and cumbersome regulatory process. Figure 3 shows the evolutionary trends in the number of standards, construction and licensing lead times, and reactor sizes and costs.

More recent events have only complicated the regulatory process for commercial nuclear power. After the Three Mile Island nuclear accident, there was a 10-month moratorium on the issuance of operating licenses, and a new NRC ruling which required the completion and approval of State and local emergency evacuation plans prior to licensing. Additional standards emerged as a result of follow-up studies, which caused more delays in construction programs.

Although many utilities cited regulatory changes and uncertainties as a collateral reason for their cancellation decisions, it was never cited as being the sole justification for plant cancellation. Regulatory changes and uncertainty can, however, indirectly create sufficient conditions for cancellation through impacts on planning lead-times and construction costs.

Increasing the lead-time of a nuclear plant can prevent that plant from entering service in time to meet a utility's projected load, thereby forcing reliance on an alternative with a shorter lead-time, such as a coal-fired plant. Longer lead-times also increase the uncertainty regarding the total construction cost.

Increases in construction costs can be caused by the imposition of additional plant design requirements to meet safety standards not in effect when the utility first decided to build the plant. In addition, regulatory delays can increase the capital carrying charges which accrue during construction. This potential for unknown increases in construction costs creates uncertainties concerning the generation economics of the nuclear plant and the utility's ability to raise the capital required to complete it.

Reversal of Economic Advantage

Although only five nuclear units appear to have been cancelled solely because of a reversal in generation economics, this reason was cited in conjunction with lower forecasted load growth and/or regulatory changes and uncertainty, as underlying the cancellation of 13 other units. As discussed earlier, these latter two conditions, by themselves, may be insufficient to justify a decision to cancel a plant, but each substantially contributes to that decision when the project's generation economics have become marginal.

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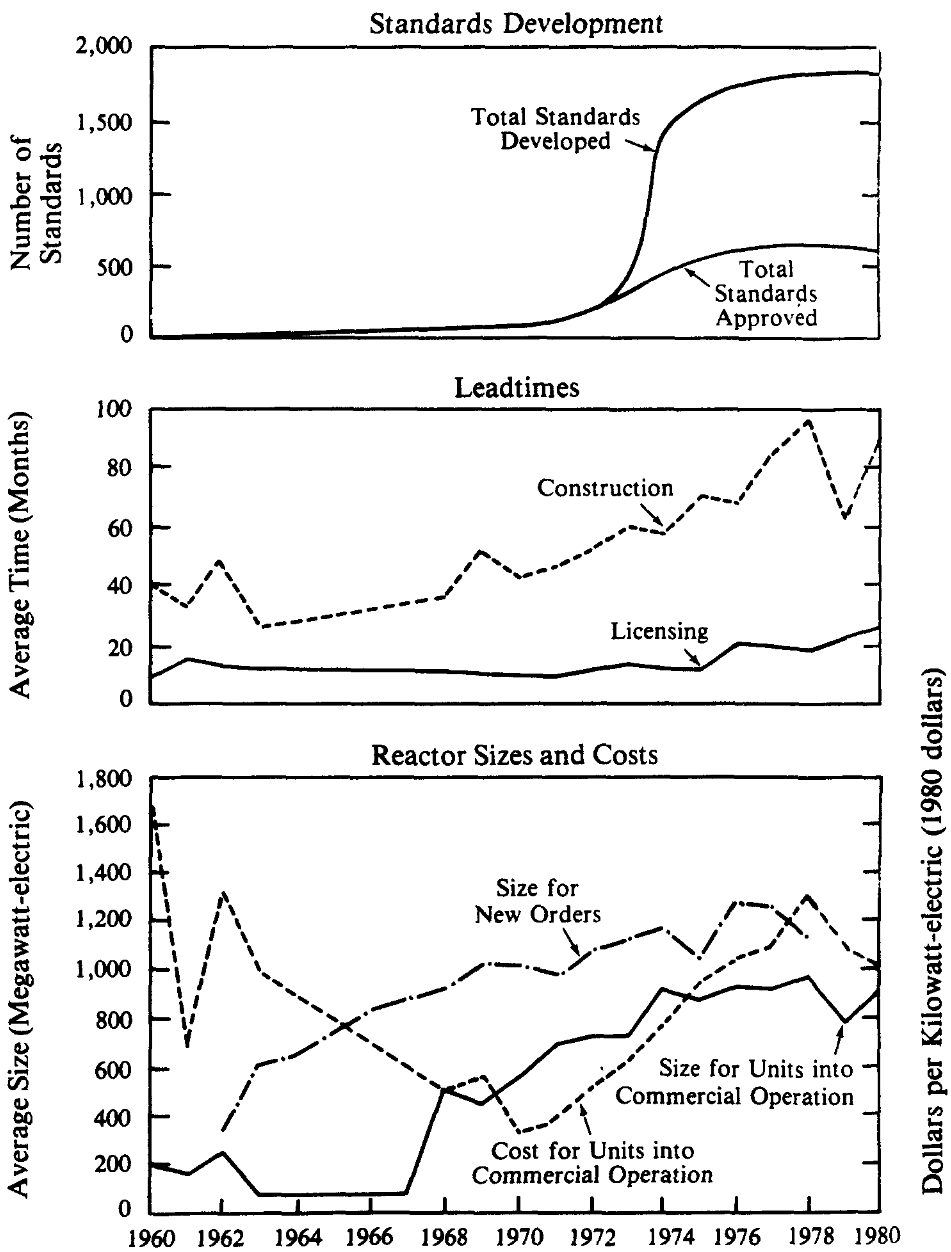
[11] Calvert Cliffs vs. AEC, 449 F. 2d 1109 (D.C. Circular 1971).

Figure 3. Evolution of Commercial Nuclear Power, Trends in Standards Development, Leadtimes, Reactor Sizes, and Costs, 1960-1980



Source: Energy Information Administration, U.S. Department of Energy, Projected Costs of Electricity from Nuclear and Coal-fired Power Plants, Vol. 2, DOE/EIA-0356/2 (Washington, D.C., November 1982).

During the period from 1967 to 1977, when utilities made their initial commitments to construct the nuclear units they eventually cancelled, nuclear power was believed to be the most economic alternative for electricity generation. A number of studies completed during that period concluded that, in most regions of the country, nuclear power plants would provide substantially cheaper baseload electricity than coal-fired plants. However, the planned nuclear plants have had long licensing and construction lead-times, and experienced delays of up to 5 years. During this period, their economic advantage has slowly and continuously eroded.

Since the mid-1960's, the construction costs of both nuclear and coal-fired plants -- nuclear power's closest competitor -- have escalated dramatically. This was a result of inflation in construction wage rates, equipment and materials. Other contributing factors were high interest rates and changes in plant designs dictated by more stringent environmental and safety requirements. While these factors have affected both plant types, as Figure 4 shows, nuclear plant capital costs have escalated more rapidly than coal-fired plant costs. The result has been a substantial retreat from the commanding economic advantage nuclear power once had over coal.

In 1982, the Energy Information Administration (EIA) released a study in which it was concluded that new nuclear power plants would offer a relative economic advantage over new coal-fired plants only in the New England and South Atlantic regions of the country.[12] This is illustrated in Figure 5. The figure also shows that in the Southwest and North Central regions of the country, which are situated at or near large surface deposits of coal, new coal-fired plants have a distinct economic advantage. For the remaining regions of the country, the EIA report indicates that neither option offers a significant advantage over the other. Furthermore, as plant construction leadtimes become more protracted, the nuclear option is projected to be noncompetitive.

This relative decline in economic advantage, combined with the current perception that nuclear power plants are riskier investments than coal-fired plants, has caused utilities to question the value of completing nuclear units that are still in the early stages of construction. Although a case-specific analysis of each nuclear plant would be required to determine whether it continues to be the most economical generation alternative, in several recently documented cases, the utility (or its regulatory commission) concluded that the nuclear plant in question was no longer the economically preferred choice.[13]

The economic advantage of nuclear power must also be compared to demand-side alternatives, such as conservation and load management measures. Since the net effect of these alternatives is to reduce electricity demand, they may provide reasons to defer rather than cancel, new plants. (See previous subsection on Lower Forecasted Load Growth.)

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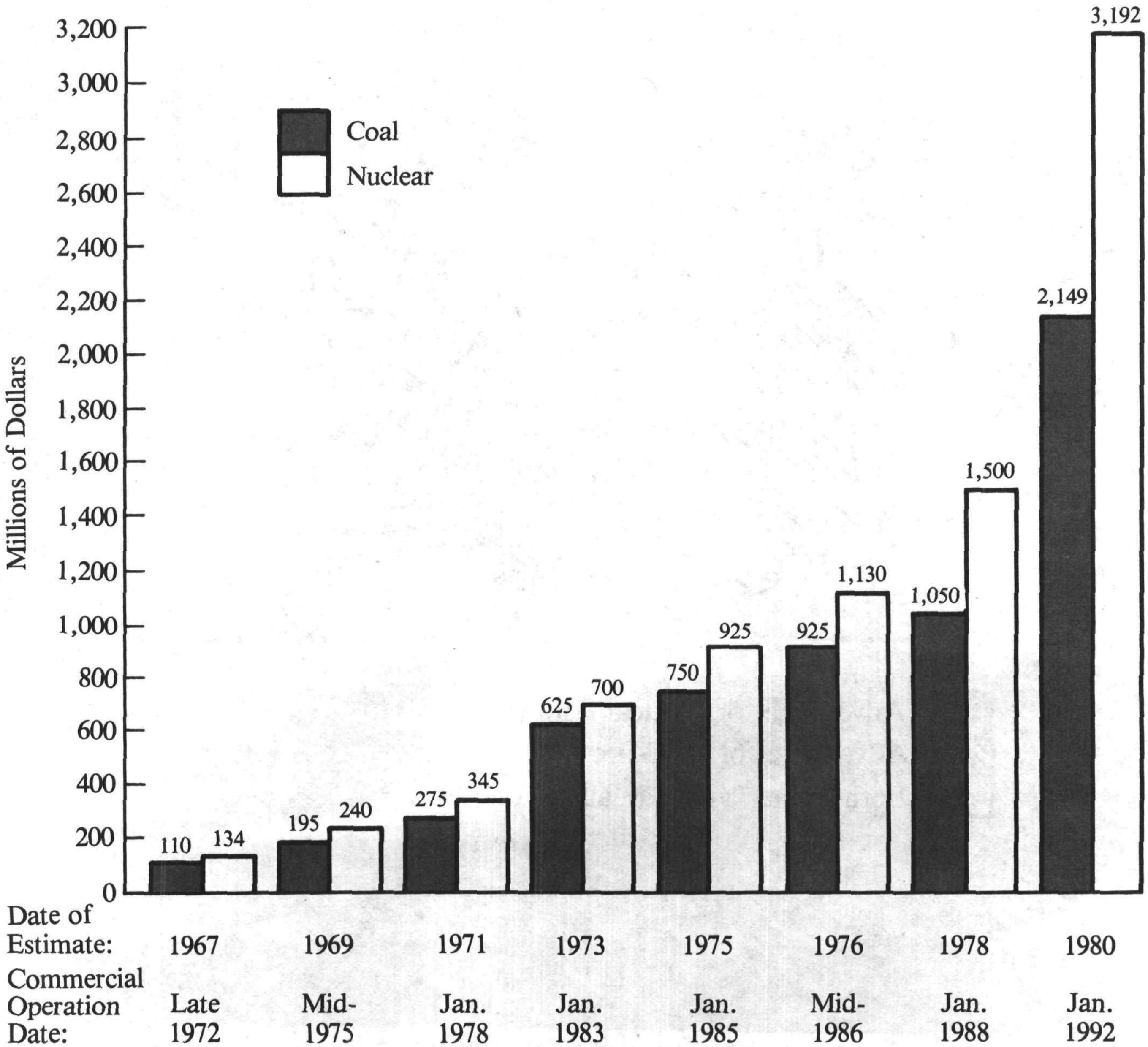
[12]Energy Information Administration, U.S. Department of Energy, Projected Costs of Electricity from Nuclear and Coal-Fired Power Plants, DOE/EIA-0356/1/2 (Washington, D.C., August 1982).

[13]The recent cancellations of Black Fox 1 & 2 (Public Service of Oklahoma), Bailly (Northern Indiana Public Service Company), and Allens Creek 1 (Houston Lighting and Power Company), are documented cases of this reversal in generation economics.

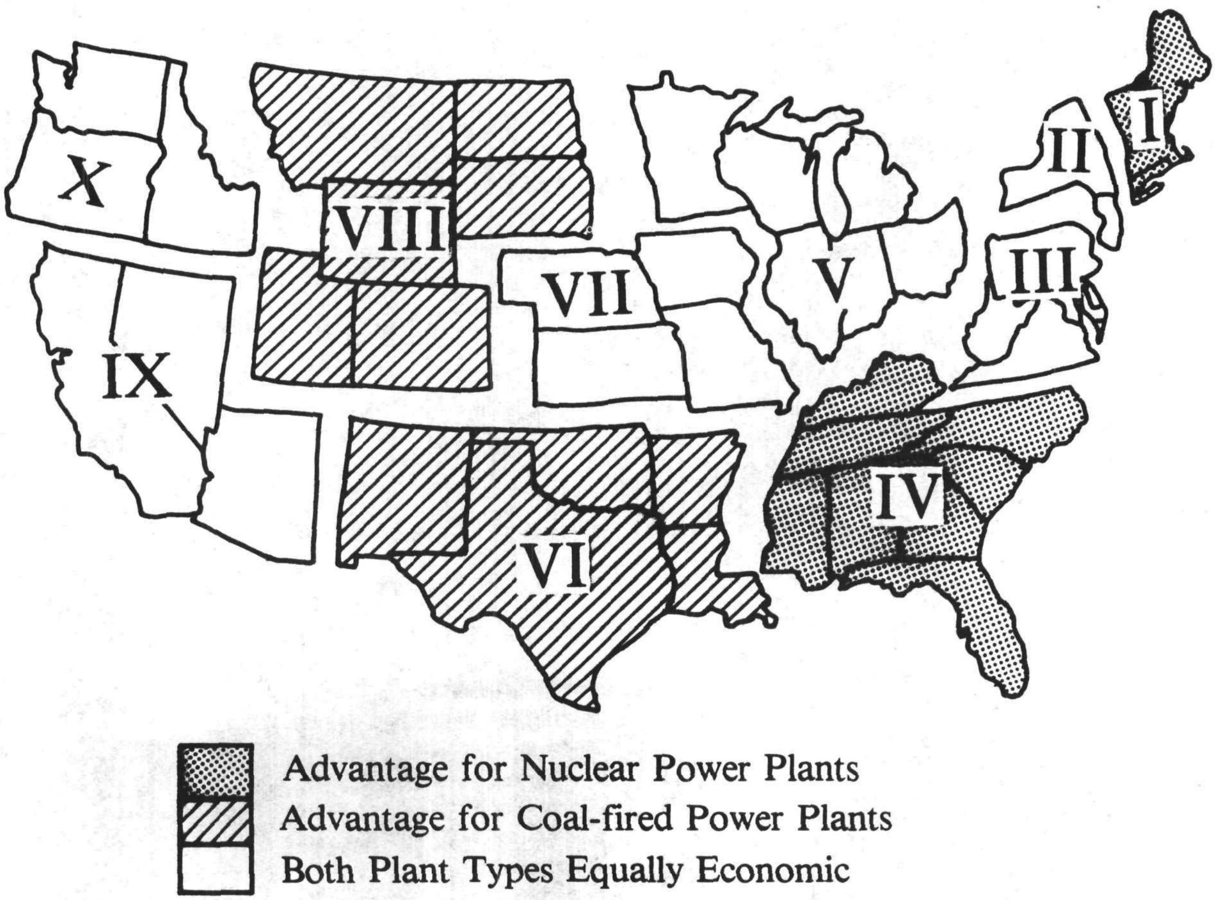
Figure 4. Fossil and Nuclear Plant Capital Cost Estimates, 1967-1980 (Millions of Current Dollars for 1,000-MWe Plants)[a]



[a]Dollars are those current during the year of commercial operation.

Source: U.S. Atomic Energy Commission Reports WASH 1082, WASH 1150, WASH 1230, WASH 1345, WASH 1345 Revised, NUREG, EEDB-1, and Current EEDB-111.

Figure 5. Comparative Bus-Bar Costs for Nuclear and Coal-Fired Power Plants: Regional Advantages for Plants Operational in 1995



Note: Advantage implies that one plant type has a levelized cost differential greater than 5 percent over the other plant type. If cost differentials are less than 5 percent, both plant types are considered economic choices.

Source: Energy Information Administration, U.S. Department of Energy, Projected Costs of Electricity from Nuclear and Coal-Fired Power Plants, Vol. 1, DOE/EIA-0356/1 (Washington, D.C.: August 1982).

Denial of Certification by State

Six nuclear units were cancelled after the State siting authority denied the application for certification. The reasons given by the States for the denials, which were different in each case, are footnoted in Table 4. Denial of a certificate of convenience and necessity, or a comparable certificate, by a State siting authority is clearly a sufficient reason for a utility to cancel a plant. Without that certificate, the utility has no assurance that the completed plant will be allowed in the rate base, or that any of the plant's costs can be recovered if it is cancelled.

In some cases the validity of the reasons given by the States for denial of certification are questionable. Generally they fall into one of the following categories:

- Forecasted demand for electricity was too low to justify the additional capacity.
- The plant was not the least-cost alternative.
- The utility could not finance the plant's construction.
- State law prohibited the siting of the proposed nuclear plant.
- Political reasons.

The validity of the first two reasons has already been discussed; the remaining three warrant some further comment.

A State regulatory commission cannot rationally justify the cancellation of a nuclear unit solely on the grounds that the utility lacks the resources to finance it. This is so because the commission has the power to increase the utility's rate of return by authorizing higher electricity rates, thereby ensuring its financial health and thus its ability to raise the needed capital. This is true despite the fact that such actions are likely to be strongly opposed by electricity consumer groups who can apply political pressure to the commissioners.

A number of States have enacted laws that place prohibitions on the siting of proposed nuclear power plants. In this regard, California has been the leader of the trend. In 1976, the California legislature passed a law prohibiting the certification of sites for nuclear power plants not already under construction on January 1, 1977, until (1) the issues of fuel rod reprocessing and nuclear waste disposal are resolved and (2) underground and berm containment are studied by the California Energy Resources Conservation and Development Commission.

It is claimed that this law caused the cancellation of the Pacific Gas and Electric Company's Stanislaus plant and contributed to the decision by the San Diego Gas and Electric Company to cancel its Sundesert plant. Several California utilities have sued the State, arguing that the law conflicts with the preemptive nature of the U.S. Atomic Energy Act of 1954. In 1981, the Ninth Circuit Court upheld the California law, concluding that it addressed economic and planning issues of nuclear power rather than the issue of radiation hazard, which is preemptively addressed by Federal law. The case is now before the U.S. Supreme Court.

Ratepayer advocates are not the only groups with political power. Others with possible interest in blocking the construction of nuclear power plants -- for a variety of reasons -- include conservationists, environmentalists, and businesses with interests in other fuels, particularly coal. Any of these parties can influence a state siting authority to deny certification of a nuclear power plant, even if it is needed and appears to be the lowest cost generation alternative.[14]

Summary

The predominant conclusion that emerges from the brief history of nuclear power is that the electric utility industry has fallen far short of fulfilling its earlier commitment to the technology. At the end of 1974, with about 30,000 MWe of nuclear generating capacity in commercial service, the industry had commitments for an additional 217,000 MWe to be completed by the early 1990's. Since then, these commitments have been steadily reduced through plant cancellations. By the end of 1982, only about half of the originally planned capacity has survived.

Five major reasons have been identified as being partially, or totally, responsible for the plant cancellations, the three most significant reasons being the dramatic reductions in the forecasted growth in electricity demand, the financial constraints faced by most investor-owned utilities, and the reversals in the economic advantage of nuclear power plants over coal-fired alternatives.

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[14]It has been alleged that the Tyrone 1 nuclear unit was denied certification by the Wisconsin Public Utility Commission because of antinuclear bias. Although two of the three commissioners rationalized their decisions on the basis of insufficient demand growth, in the same opinion they ordered a study of a substitute coal-fired plant, to be built on the Tyrone site, whose size would be approximately equal to Northern States Power's share of the proposed nuclear unit. The third commissioner supported completion of Tyrone.

3. REGULATORY TREATMENT OF NUCLEAR PLANT ABANDONMENT COSTS

Introduction

To determine who has borne the costs of previously cancelled nuclear power plants, and to predict who will bear the costs of future cancellations, selected regulatory cases already decided by the FERC and the State regulatory commissions were studied. The size of the abandonment cost (defined below) in each cancellation was used to determine which cases would be investigated in depth.[1] Because most plants likely to be cancelled in the future involve investments of at least $50 million, the analysis was limited to cancelled plants with abandonment costs exceeding this amount, listed in Table 8. Profiles of the 42 cancelled units which meet this requirement are presented in Table 9.

The units investigated were cancelled in the years 1977 through 1982. Twenty-six had Limited Work Authorizations or Construction Permits issued, and 18 were already under construction. The greatest losses were generally associated with those in the most advanced stages of construction. Most units that never reached the construction stage involved abandonment costs of less than $100 million. In contrast, WPPSS 4 and 5, which were 25 and 17 percent complete, respectively, involved a combined abandonment cost of $2.25 billion.

Definition of Abandonment Cost

The abandonment cost of a cancelled nuclear power plant is the total cost recognized by traditional utility accounting practices which would have been avoided if the project had never been undertaken. This concept contrasts with that of the economic opportunity cost to the Nation of not completing the plant, which includes the foregone fuel savings attributable if the nuclear plant had displaced more expensive generation, the projected indirect effects of lower cost electricity on economic growth if the nuclear plant could have indeed provided it, and associated externalities such as environmental impacts. Although the investigation of the economic opportunity costs of nuclear plant cancellations is a significant issue, it is beyond the scope of this study.

Abandonment cost consists of the following components:

- Cash expenditures
- Allowance for funds used during construction

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[1]The abandonment costs were obtained from a variety of sources -- FERC Form 1 submissions, annual reports, regulatory commission opinions, and utility executives. Some of these sources did not break down the costs in enough detail to allow restatement in a form which exactly follows the definition of abandonment cost used in this report; thus, the quantitative estimates presented here must be considered as crude approximations of the actual abandonment costs. Nonetheless, they are accurate enough for the purposes of this study.

Table 8. Utility Ownership of Cancelled Nuclear Units with Abandonment Costs Exceeding $50 million

Plant Name	Size (MWe)	Federal Region	Utility Ownership
Pilgrim 2	1,150	I	Boston Edison (59%) New England Power (11%) Others (30%)[a]
Sterling	1,150	II	Orange and Rockland (33%) Rochester Gas and Electric (28%) Central Hudson Gas and Electric (17%) Niagara Mohawk Power (22%)
Jamesport 1&2	2,300	II	New York State Electric and Gas (50%) Long Island Lighting (50%)
New Haven 1&2	2,500	II	Long Island Lighting (50%) New York State Electric and Gas (50%)
Atlantic 1&2	2,300	II	Public Service Electric and Gas (80%) Jersey Central Power and Light (10%) Atlantic City Electric (10%)
Hope Creek 2	1,067	II	Public Service Electric and Gas (95%) Atlantic City Electric (5%)
Forked River 1	1,070	II	Jersey Central Power and Light (100%)
Douglas Point 1&2 ...	2,292	III	Potomac Electric Power (100%)
Surry 3&4	1,718	III	Virginia Electric Power (100%)
North Anna 3	907	III	Virginia Electric Power (100%)
North Anna 4	907	III	Virginia Electric Power (100%)
Hartsville B1&B2	2,466	IV	Tennessee Valley Authority (100%)
Phipps Bend 1&2	2,466	IV	Tennessee Valley Authority (100%)
Harris 3&4	1,800	IV	Carolina Power and Light (100%)
Cherokee 2&3	2,560	IV	Duke Power

See footnote at end of table.

Table 8. Utility Ownership of Cancelled Nuclear Units with Abandonment Costs Exceeding $50 million (continued)

Plant Name	Size (MWe)	Federal Region	Utility Ownership
Davis-Besse 2&3	1,812	V	Ohio Edison (39.3%) Cleveland Electric Illuminating (29.6%) Toledo Edison (17.3%) Duquesne Power and Light (8%) Pennsylvania Power Company (6.8%)
Erie 1&2	2,534	V	Ohio Edison (39.3%) Cleveland Electric Illuminating (29.6%) Toledo Edison (17.3%) Duquesne Power and Light (8%) Pennsylvania Power Company (6.8%)
Greenwood 2&3	2,528	V	Detroit Edison (100%)
Bailly Nuclear	644	V	Northern Indiana Public Service (100%)
Callaway 2	1,120	V	Union Electric (100%)
Tyrone 1	1,100	V	Northern States Power (67.6%) Lake Superior District Power (2%) Cooperative Power Association (17.4%) Daryland Power Cooperative (13%)
Allens Creek 1	1,150	VI	Houston Lighting and Power (100%)
Black Fox 1&2	2,300	VI	Public Service of Oklahoma (60.9%) Ass. Elec. Coop. of Springfield (21.7%) Western Farmers Elec. Coop. (17.4%)
Sundesert 1&2	1,948	IX	San Diego Gas and Electric (100%)
Pebble Springs 1&2 ...	2,520	X	Portland General (47.1%) Pacific Power and Light (29.4%) Puget Sound Power and Light (23.5%)
WPN 4	1,218	X	Washington Public Power Supply (100%)
WPN 5	1,240	X	Washington Public Power Supply (90%) Pacific Power and Light (10%)

[a]Other owners included Commonwealth Electric Company, New Bedford Gas and Electric Light Company, Vermont Electric Cooperative, Inc., Central Vermont Public Service Company, Montaup Electric Company, Massachusetts Municipal Wholesale Electric Company, Public Service Company of New Hampshire, Central Maine Power Company, and Fitchburg Gas and Electric Light Company. Because no one of these utilities owned a substantial share of the plant, cost recovery was not studied.

Table 9. Status of Cancelled Nuclear Units with Abandonment Costs Exceeding $50 Million

Plant Name	Permit Status[b]	Date of Cancellation	Percent of Construction Complete	Abandonment Costs[a] (Millions of Dollars) Nominal	Constant[c]
Pilgrim 2	CP docketed	9/81	0	394	410
Sterling	CP issued	2/80	0	129	151
Jamesport 1&2	CP issued	9/80	0	120	134
New Haven 1&2	CP docketed	3/80	0	79	96
Atlantic 1&2	CP docketed	1/78	0	328	461
Hope Creek 2	CP issued	12/81	19	419	432
Forked River 1	CP issued	11/80	5.6	414	489
Douglas Point 1&2 ...	CP docketed	7/77	0	65	95
Surry 3&4	CP issued	3/77	0	98	146
North Anna 3	CP issued	11/82	8	512	504
North Anna 4	CP issued	11/80	4	155	170
Hartsville B1&B2	CP issued	8/82	17 (Unit 1) 7 (Unit 2)	718	713
Phipps Bend 1&2	CP issued	8/82	29 (Unit 1) 5 (Unit 2)	1,201	1,193
Harris 3&4	CP issued	12/81	<1	187	203
Cherokee 2&3	CP issued	11/82	0	68	67
Davis-Besse 2&3	Limited work authorization	1/80	<1	120	142
Erie 1&2	CP docketed	1/80	0	107	127
Greenwood 2&3	CP docketed	3/80	0	71	83
Bailly Nuclear	CP issued	8/81	0.5	191	200
Callaway 2	CP issued	10/81	0.7	70	72
Tyrone 1	CP issued	8/79	0	103	126
Allens Creek 1	CP docketed	8/82	0	362	360
Black Fox 1&2	Limited work authorization	2/82	5 (Unit 1) 2 (Unit 2)	390	397
Sundesert 1&2	CP docketed	5/78	0	92	126
Pebble Springs 1&2 ...	CP docketed	10/82	0	293	289
WPN 4&5	CP issued	1/82	24.9 (Unit 4) 17 (Unit 5)	2,225	2,271
Total Costs	--	--	--	8,911	9,457

[a]These costs were obtained from a variety of sources: FERC Form 1 submissions, annual reports, regulatory commission opinions, and utility executives. Some of these sources did not break the total loss down in sufficient detail to determine whether they followed the strict definition of abandonment loss as defined in this report; therefore, these costs must be considered as approximations of the abandonment costs.

[b]Status at time of cancellation.

[c]Abandonment costs are expressed in nominal dollars as of the date of cancellation as well as in mid-1982 constant dollars. The constant dollar estimates were obtained by applying the appropriate GNP implicit price deflators to the nominal dollar costs.

CP = construction permit.

- Contract cancellation penalties
- Salvage value
- Site shutdown costs.

Cash Expenditures

The cash expenditures, cumulative to the date of cancellation, cover land acquisition, site improvement, construction labor, materials and equipment, engineering and environmental studies, and all licenses and permits. These expenditures are likely to be the largest component of the abandonment cost, and are accurately known by the utility owner(s) at the time of cancellation.

Allowance for Funds Used During Construction

A utility invests large amounts of capital during the planning and construction of a nuclear plant, which typically extends up to 8 or more years. Most of this capital is borrowed in the form of debt and preferred stock which require annual interest and dividend payments. The remainder is provided by common equity shareholders who also require a return on their investment, though not entirely in the form of current annual cash dividends. The costs of using funds from all of these sources are accumulated and treated as part of the plant's total cost along with its cash expenditures. These capital carrying charges are typically referred to as interest during construction (IDC) or as allowance for funds (used) during construction (AFDC or AFUDC). In this report the term AFUDC, allowance for funds used during construction, will be used. Because AFUDC is a calculated charge derived from direct expenditures, it is also known fairly accurately by the utility owner(s) at the time of cancellation.

Accumulation of AFUDC after the project cancellation date may be allowed in some regulatory jurisdictions but not in others. Thus, depending on the regulatory treatment allowed, the abandonment costs may be measured at different points in time. Accruing AFUDC beyond the cancellation date is essentially a restatement of those costs in dollars of lower purchasing power, reflecting the effects of general inflation and also a "real interest rate" effect to account for the time value of money. To the extent allowed by the data, this report expresses all abandonment costs as of the date of plant cancellation.

Contract Cancellation Penalties

When a nuclear plant is cancelled, there are likely to be numerous contracts in existence covering work not yet completed and/or paid for. Because disbursements are likely to be spread over the entire period, the full cost of these contracts is not reflected in the cumulative direct expenditures. Although the utility could be held liable for the full value of these contracts, a settlement for some lesser amount is normally negotiated between the utility and the various vendors. Still, this component of abandonment cost can be quite substantial and may not be accurately known until several years after the cancellation date if lengthy negotiations ensue.

Salvage Value

The salvage value of a cancelled project is not really a cost but rather a revenue to be credited against other cost components in calculating the project's net abandonment cost. It can also be viewed as a "negative" cost. The salvage value is the amount gained from the sale of plant equipment and other resources and materials at the site.

The land on which a cancelled plant was sited may be either sold or carried as "plant held for future use." Among recent cancellations, utilities have generally retained the land with the intent of building a powerplant on it someday. The proceeds from selling various major plant components, such as the NSSS and turbine-generators, are typically subsumed in negotiating contract cancellation costs if the components have not been delivered to the site. Once delivered, these components may be resold, although perhaps at a large discount, thus contributing to the salvage value.

Another item that could contribute substantially to salvage value is the resale of nuclear fuel and enrichment rights. The remainder of the salvage opportunities are limited to such miscellaneous items as specialized construction equipment, unused construction materials and transportation equipment. These miscellaneous items represent a relatively small percentage of the plant's abandonment costs. The salvage value of a cancelled plant is not likely to be known accurately until buyers are found for the major items, which could take several years.

<u>Site Shutdown Costs</u>

Given the scarcity of suitable plant sites, it is likely that a power plant of some type will be constructed on the cancelled plant's site at some future time. Whether the utility sells the land on which the plant was sited, or saves it for future use, it will incur some cost in shutting down the site. In some cases the utility is required to restore the site as well. These costs are generally unknown at the time of cancellation, but account for only a small percentage of the abandonment cost.

Regulatory Methods for Allocating Abandonment Costs

At least as important as the determination of a cancelled plant's abandonment cost is the issue of who pays. In the case of abandonment costs incurred by a publicly owned utility -- such as TVA, the Washington Public Power Supply, or a municipal utility -- the respective ratepayers are the only group available to bear the cost. In contrast, the abandonment cost incurred by a privately owned utility can be, and typically is, allocated among three major groups:

- Utility ratepayers
- Utility investors
- Income taxpayers.

As described in Section 1, income taxpayers become involved because the Federal and State governments lose or gain income tax revenues on the basis of the specific regulatory method used to allocate abandonment costs.

Regardless of the type of utility, ratepayers are the group likely to bear a major share of the costs of plant cancellations. This is usually justified on the grounds that the utility undertook the project solely to satisfy its legal obligation to serve ratepayers. Those costs not borne by ratepayers are shared between the utility investors (predominantly the common shareholders) and income taxpayers. Taxpayers become involved because any cost borne by the utility reduces its taxable income, and consequently its tax liability as well as that of its investors.

The specific method of allocating the abandonment costs incurred by a privately owned utility among ratepayers, investors, and taxpayers is determined by the regulatory commission(s) having jurisdiction over that utility. But before adopting any such method, the commission first determines to what degree the abandonment costs were prudently incurred by the utility's management, in order to qualify them as being eligible for recovery from the ratepayers.

The Management Prudence Criterion

To assess management prudence, the following questions are addressed by the regulatory commission:

- Was the initial decision to proceed with the plant sound?
- Were the costs incurred during the period of project viability necessary and economical?
- Was the decision to cancel the plant sound?
- Did management cancel the plant as soon as information confirming the appropriateness of cancellation became available?

If these four conditions are met, the costs of an abandoned project are considered to have been prudently incurred and eligible for recovery from ratepayers. Generally, there is little debate over the prudence of the decision to build the plants because when most of these plants were planned, nuclear power appeared to offer the cheapest source of baseload electricity. Of all the costs incurred during the project period, only a small amount is normally disallowed for being unnecessary or uneconomic. Examples of these costs are advertising, public relations expenses, and political lobbying expenses.[2] Finally, by the time a plant is cancelled, it is usually clear that the cancellation decision was sound, but there is often debate over whether the plant should have been cancelled sooner. If the commission determines that a unit should have been cancelled sooner, given the information available to the utility's management, the costs incurred after the prudent cancellation date are disallowed. Such costs are borne by the utility investors (predominantly the common shareholders) and by income taxpayers.

The methods used to allocate the prudent abandonment costs of cancelled nuclear plants are classified here according to the degree to which the utility is allowed to recover these costs from ratepayers through rates. They are:

- Full recovery
- No recovery
- Partial recovery.

Full Recovery

A utility may be allowed to recover all of the eligible abandonment costs through future rate increases. Using this method, the utility investors receive all of their original capital as well as a fair return on the money, including the accrued AFUDC, for the time it was committed. In addition, because income taxes must be paid on the earned return, taxpayers also benefit from this form of regulatory treatment. These taxes are not paid

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[2] Examples of such disallowances appear in the Pilgrim 2 and Sundesert nuclear cancellation proceedings.

by the utility investors, but rather are directly passed through to the ratepayers along with the plant's abandonment costs. From an economist's perspective, income taxes are not real costs to the Nation because they do not represent economic resources consumed; they are transfer payments from one group of citizens to another.

When a cancelled nuclear plant is replaced by a substitute plant to be constructed on the same site, an alternative method of full cost recovery is generally used. The sunk costs, including accrued AFUDC, are reclassified as construction work in progress (CWIP) for the replacement plant. Full recovery is allowed, but deferred until the substitute plant is completed. Use of this method is usually limited to the planning expenses of projects cancelled in the preconstruction stage, and to costs related to site development and improvement.

<u>No Recovery</u>

A second approach to allocating project abandonment costs is to completely disallow them for ratemaking purposes, thereby forcing the utility investors and income taxpayers to bear the entire cost. More specifically, the sharing of these costs between investors and taxpayers arises because the utility writes off the cost as an extraordinary loss in the year of cancellation, thereby reducing its tax liability for that year. The actual cost to utility investors is reduced by the amount of the tax saving -- up to 50 percent of the project's abandonment cost -- which depends on the utility's unused investment tax credits and tax losses carried forward from previous years. Because of the foregone tax revenues, a transfer occurs from utility investors to taxpayers.

<u>Partial Recovery</u>

The most complex methods of cost allocation involve the sharing of the abandonment costs among ratepayers, utility investors and income taxpayers. Because the ratemaking process functions in a legal environment, requiring the observance of regulatory laws, precedents and generally accepted accounting principles, a regulatory commission cannot allocate these costs among the three groups in an arbitrary manner. Instead, regulators must choose from a menu of legally defensible ratemaking options, each of which imposes its own pattern of cost allocation. Nonetheless, the available options offer considerable flexibility.

The partial recovery options employed in past plant cancellations involving over $50 million are described briefly below.

<u>Option 1</u>: Amortization of the sunk costs over a period of 1 to 20 years with no return earned on the unamortized balance.

<u>Option 2</u>: Same as Option 1 except that only the portion of the unamortized balance contributed by common and preferred equity shareholders is precluded from earning a return.

<u>Option 3</u>: Same as Option 1, except that only the portion of the unamortized balance contributed by common equity shareholders is precluded from earning a return.

<u>Option 4</u>: Same as Option 1 except that AFUDC attributed to common equity financing is not recoverable.

Option 5: Same as Option 4 except that a return is earned on the unamortized balance of direct project outlays but not on the AFUDC.

Option 6: Same as Option 1 except that no AFUDC is recoverable.

Figure 6 categorizes the six partial recovery options with respect to two dimensions of regulatory treatment, the treatment of AFUDC and of the unamortized balance of recoverable costs. As the empty cells in the figure suggest, other regulatory schemes are possible but were not employed in the cases examined in this study. The six options which were employed are further discussed below.

Option 1. This is the option most commonly used to allocate the abandonment costs of a cancelled nuclear plant. Typically, the unamortized balance of the costs are precluded from earning a return on the grounds that the project was not, and never will be, "used and useful." This results in a sharing of the abandonment cost between a utility's ratepayers and its investors; the former group reimburses the latter for the project's abandonment costs (net of income tax savings) over an extended amortization period, while the latter group foregoes the carrying charges on the unamortized balance of these costs during that period. Obviously, the longer the amortization period, the greater will be the portion of the abandonment costs borne by the investors. Thus, setting the length of the amortization period provides the regulators with considerable control over the cost allocation between the two groups.

The "income tax savings" referred to above are actually more like deferrals of tax payments. In the year of cancellation, the total cash expenditures on the plant throughout its construction are written off as a loss against the utility's taxable income for that single year. In future years, as this component of abandonment cost is amortized, the resulting incremental revenues received by the utility directly translate into incremental taxable income and the "tax saving" of the initial year is gradually repaid over time.[3] These incremental taxes become part of the utility's cost of service expenses in the years they are paid and thus are included in the rates charged to customers. During the interim period the utility enjoys interest free use of these deferred taxes, which reduces the amount of the unamortized balance earning no return. This deferral of taxes represents a transfer payment from taxpayers to investors.

Finally, because Option 1 requires the ratepayer to reimburse the utility for the accrued AFUDC, taxpayers may receive a net benefit despite the aforementioned tax deferrals. In each year that AFUDC is amortized through higher rates, the resulting incremental revenues are taxable income. Those portions of AFUDC attributed to common and preferred equity financing create tax liabilities which are paid by ratepayers. The portion of AFUDC attributed to debt financing also gives rise to incremental tax liabilities as it is amortized; however, these taxes are effectively paid by the utility. This is because the interest payments made during the construction period on the debt financing creates tax savings in those years which are normalized, i.e., placed in a deferred tax account in the year received, to be later amortized over the service life of the plant, thereby

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[3]The incremental income taxes paid in future years may not exactly sum to the saving realized in the year of cancellation because the utility's marginal income tax rate may change for a variety of reasons, e.g., lack of taxable income or statutory changes to the Federal or State tax rates. Thus the "deferral" of income taxes and their subsequent payment is only approximately true.

Figure 6. Classification of Partial Cost Recovery Methods Used in Past Nuclear Plant Cancellations

Portion of Project AFUDC[a] for Which Amortization is Allowed	Portion of Unamortized Balance on Which a Return is Earned			
	None	Debt Only	Preferred Equity and Debt Only	All Except AFUDC[a]
All	Option 1 (Most Commonly Used)	Option 2	Option 3	
Preferred Equity and Debt Only	Option 4			Option 5
Debt Only				
None	Option 6			

[a]AFUDC, Allowance for Funds Used During Construction.

reducing the rates customers pay and thus the utility's taxable income. This tax normalization convention is adopted to better match the benefits of the tax savings arising from AFUDC interest payments with the ratepayers who ultimately pay for that AFUDC (as well as the rest of the plant's cost). In the case of a plant cancellation, the funds in this deferred tax account are typically amortized as a credit against rates over the same period used to amortize the abandonment costs. Since this also corresponds to the timing of the tax liability created by amortization of the debt portion of accrued AFUDC, the resulting rate reduction reduces the utility's income tax liabilities by approximately the amount which would otherwise have to be paid on the incremental revenues associated with amortization of the debt component of AFUDC.

Option 2. This option differs from Option 1 in that the utility's common equity and preferred equity shareholders only forego the carrying costs on that portion of the unamortized balance attributed to them, but earn annual returns on the remaining portion attributed to debt financing. This also gives rise to increased income tax liabilities created by these annual returns which are in addition to the taxes associated with Option 1.

Option 3. This option differs from Option 2 only in that it additionally allows a return to be earned on the preferred equity portion of the unamortized balance. This also increases the income tax liability.

Option 4. This is a minor variation of Option 1, in that the recovery of AFUDC accrued on the common equity portion of the investment is disallowed. Relative to Option 1, this option shifts more of the project costs (equal to the amount of disallowed AFUDC) from the ratepayers to the common shareholders and eliminates the tax liability which would have been otherwise created by amortization of the common equity portion of AFUDC.

Option 5. This option is similar to Option 4, but additionally allows a return to be earned on the cancelled project's unamortized cash expenditures. This Option provides greater cost recovery for common shareholders than Options 1 or 4 and may be roughly comparable to Option 2 or 3. It also creates additional income tax liabilities relative to Option 1.

Option 6. This option allows neither the recovery of any AFUDC nor any return to be earned on the unamortized balance. Of the five options described here, this one places the greatest burden of the project's abandonment costs on the utility investors. It also creates an unequivocal transfer payment from income taxpayers to the ratepayers because there are no liabilities arising from amortization of AFUDC or from a return earned on the unamortized balance of the project's cash expenditures. Furthermore, because of the tax deferral associated with the write-off of the loss in the year of cancellations, income taxpayers bear a substantial fraction of the abandonment cost when this regulatory option is employed.

Regulatory Methods Adopted in Various Jurisdictions

The regulatory methods adopted by various commissions in past nuclear plant cancellations involving abandonment costs exceeding $50 million are summarized in Table 10. The reasons cited by the various regulatory commissions for adopting these methods are summarized in Table 11. The specific cases, classified by the degree of recovery method accepted, are discussed below.

Table 10. Commission Decisions on Allocation of Nuclear Plant Abandonment Costs Exceeding $50 Million[a]

Nuclear Unit	Commission	Utility	Cost Recovery Allowed	Amortization Period (Years)	CWIP[b] for Alternate Plant	Treatment of Unamortized Balance	Treatment of AFUDC[b]
Pilgrim 2	Massachusetts DPU	Boston Edison	Partial	13	--	Levelized carrying charge allowed on non-AFUDC portion of costs	Only debt and preferred equity portions amortized
		Commonwealth Elec.	Partial	2	--	No return allowed	Only debt and preferred equity portions amortized
	Vermont PUB	Central Vermont Public Service	Partial	10	--	No return allowed	Amortized
Sterling 1	New York PSC	Rochester G&E	Full	5	--	Return allowed	Amortized
		Central Hudson G&E	Full	5	--	Return allowed	Amortized
		Niagara Mohawk	Full	3	--	Return allowed	Amortized
		Orange & Rockland	Full	10	--	Return allowed	Amortized
Jamesport 1&2	New York PSC	LILCO	Full	--	All costs	--	--
		N.Y. State E&G	Full	--	All costs	--	--
New Haven 1&2	New York PSC	LILCO	Full	([c])	--	Return allowed	Amortized
		N.Y. State E&G	Full	([c])	--	Return allowed	Amortized
Atlantic 1&2	New Jersey BPU	Public Serv. E&G	Partial	20	--	No return allowed	Amortized
		Jersey Central P&L	Partial	20	--	No return allowed	Amortized
		Atlantic City Elec.	Partial	20	--	No return allowed	Amortized
Hope Creek 2	New Jersey BPU	Public Serv. E&G	Partial	[d]15	--	No return allowed	Amortized
		Atlantic City Elec.	Partial	[d]15	--	No return allowed	Amortized
Forked River 1	New Jersey BPU	Jersey Central P&L	Partial	[d]15	--	No return allowed	Amortized
Douglas Point 1&2 ..	D.C. PSC	PEPCO	Full	10	Land cost only	Return allowed	Amortized
	Maryland PSC	PEPCO	Partial	10	Site-related costs only	No return allowed	Amortized
	Virginia SCC	PEPCO	Partial (land costs disallowed)	10	--	No return allowed	Amortized
Surry 3&4	FERC	VEPCO	Partial	10	--	No return allowed	Amortized
	Virginia SCC	VEPCO	Partial	10	--	No return allowed	Disallowed
	W. Virginia SCC	VEPCO	Partial	10	--	No return allowed	Amortized
	N. Carolina UC	VEPCO	Partial	10	--	No return allowed	Amortized
North Anna 4	Virginia SCC	VEPCO	Partial	10	--	No return allowed	Amortized
	W. Virginia PSC	VEPCO	Partial	20	--	No return allowed	Amortized
	N. Carolina UC	VEPCO	Full	10	--	Return allowed	Amortized
Harris 3&4	N. Carolina UC	Carolina P&L	Partial	10	--	Return allowed on debt portion of unamortized costs	Amortized
Davis-Besse 2&3 .... and Erie 1&2	FERC	Cleveland Elec.	Partial	10	--	No return allowed	Amortized
	Ohio PUC	Cleveland Elec.	Partial	[e]10	--	No return allowed	Amortized[e]
		Ohio Edison	Partial	[e]10	--	No return allowed	Amortized[e]
		Toledo Edison	Partial	[e]10	--	No return allowed	Amortized[e]
Greenwood 2&3	Michigan PSC	Detroit Edison	Partial	10	Land cost	No return allowed	Amortiz

See footnotes at end of table.

Table 10. Commission Decisions on Allocation of Nuclear Plant Abandonment Costs Exceeding $50 Million (continued)

Nuclear Unit	Commission	Utility	Cost Recovery Allowed	Amortization Period (Years)	CWIP[b] for Alternate Plant	Treatment of Unamortized Balance	Treatment of AFUDC[b]
Bailly	Indiana PSC	N. Indiana Pub. Svc.	Partial	15	--	No return allowed	Amortized
Tyrone 1	FERC	Northern States	Partial	10	--	No return allowed	Amortized
	Wisconsin PSC	Northern States	Partial	5	--	No return allowed[g]	Amortized[g]
		Lake Superior DPC	Full	5	--	Return allowed	Amortized
	Minnesota PUC	Northern States	None[h]	--	--	--	--
	N. Dakota PSC	Northern States	None[i]	--	--	--	--
	S. Dakota PUC	Northern States	None[j]	--	--	--	--
Allens Creek 1	Texas PUC	Houston L&P	Partial	10	--	No return allowed	Amortized[k]
Black Fox 1&2	Oklahoma Corp. Commission	Public Service of Oklahoma	Partial	10	Site-related costs only	Return allowed on debt and preferred equity portions of unamortized costs	Amortized
Sundesert 1&2	California PUC	San Diego G&E	Partial	5	Site-related costs, except AFUDC	No return allowed on non-site-related costs	Disallowed
Pebble Springs 1&2	Oregon Commissioner	Portland General	None[l]	--	--	--	--
		Pacific P&L	None[l]	--	--	--	--
	Wyoming PSC	Pacific P&L	None[m]	--	--	--	--
WPN 5	Oregon Commissioner	Pacific P&L	None[l]	--	--	--	--
	Wyoming PSC	Pacific P&L	None[m]	--	--	--	--

[a]This table includes only those units and regulatory jurisdictions for which a decision has been reached regarding cost recovery.

[b]CWIP, construction work in progress; AFUDC, allowance for funds used during construction.

[c]The Administrative Law Judge recommended full cost recovery through levelized charges, which provide a return on the unamortized balance over time periods to be determined in future rate cases. The New York PSC has not yet considered these cases.

[d]The commission authorized a schedule of annual payments which decrease each year. As a result, the utility recovers most of the abandonment loss in the first 5 years.

[e]The Ohio Supreme Court reversed the Ohio PUC decision, re Cleveland Electric Illuminating Company (CEI), on grounds that Ohio statutes do not allow project abandonment costs to be included as cost-of-service. CEI has appealed the case to the U.S. Supreme Court. In the interim, project abandonment costs will be disallowed in future rate cases of all Ohio utilities.

[f]The cost of land has been reclassified as Plant Held for Future Use, for accounting purposes. Its treatment for ratemaking purposes has not yet been decided. The cost amortization shown here is the Administrative Law Judge's recommendation. The final decision of the PUC will be made in an ongoing rate case.

[g]The Wisconsin PSC is allowing Northern States Power/Wisconsin to recover from ratepayers only 13 percent of the utility's share of the abandonment cost, in accord with the coordinating agreement (covering cost sharing) that the company has with its parent, Northern States Power/Minnesota (NSPM). The PSC also requires that the remainder be recovered from the parent through FERC-approved wholesale rates.

[h]Minnesota PUC disallowed all costs. The State Circuit Court found in favor of the company and ordered the PUC to allow NSPM to recover the costs of Tyrone. The case is now before the State Supreme Court. In the interim, NSPM is recovering its costs from Minnesota ratepayers, subject to refund.

[i]The North Dakota PSC initially disallowed all costs. They were reversed by the North Dakota Supreme Court which supported the FERC decision. North Dakota's share of the Tyrone costs are now being recovered through higher rates which reflect the FERC partial cost recovery treatment.

[j]South Dakota PUC postponed any decision on cost recovery until the FERC decision is affirmed or reversed by the courts.

[k]Some of the CWIP for Allens Creek was allowed in rate base and therefore did not give rise to AFUDC. The AFUDC which accrued on that portion of plant cost determined to be prudently incurred was fully amortized.

[l]The Oregon Commissioner interpreted a recently enacted state law (Ballot Measure 9) as prohibiting the recovery from ratepayers of any costs associated with a plant not presently used for providing utility service to the customer. However, he allowed PGE and PP&L to offset their losses with the extraordinary gains they realized from the reacquisition of some of their outstanding bonds, which were selling at discount prices.

[m]The Oregon PSC disallowed all costs, on the basis that the cancelled plant would not have been useful. PP&L has appealed to the Wyoming Supreme Court.

Table 11. Reasons Cited by Commissions as the Bases for Their Regulatory Treatment of Cancelled Nuclear Plants[a]

Reasons Cited in Commission Decisions	Full Recovery: Amortization (years) 1-5	Full Recovery: Amortization (years) 6-10	Full Recovery: CWIP for Alternate Plant	Partial Recovery: Amortization (years) 1-5	Partial Recovery: Amortization (years) 6-10	Partial Recovery: Amortization (years) 11-20	No Recovery
Plant would have solely benefitted ratepayers	C,D,E	F	--	--	--	--	--
Plant was undertaken to fulfill utility's service obligations	C,D,E I[c],J[c]	F,I[c],J[c]	--	--	BB,DD, EE	A,N,FF	--
Abandonment costs are legal cost-of-service items created by decision to cancel	--	--	--	--	BB[b]	FF	--
Need to support utility's ability to raise capital	C,D,E, I[c],J[c]	I[c],J[c]	--	--	--	A,N	--
Rate of return allowed cannot or did not compensate investors for risk of extraordinary losses	--	--	--	--	T[d],MM	A	--
Utility will suffer serious financial hardship if it must absorb any loss	II	--	--	--	--	--	--
Absorbing entire loss could bankrupt utility, thereby impairing service quality	--	--	--	--	MM	--	--
Fair and reasonable for utility to recover legitimate costs associated with long-term debt financing of plant	--	--	--	--	Z	--	--
Small loss; short amortization will not burden ratepayers	E	--	--	--	--	--	--
Short amortization period reduces adverse impact of no return	--	--	--	OO,B	--	--	--
Longer amortization period would increase investors' perception of risk	C,D,E,	F	--	--	--	--	--
Longer amortization would burden the utility beyond the loss it is already taking	--	--	--	HH	--	--	--
Longer amortization eases ratepayers' burden	C[e],D[e], E[e]	F[e]	--	--	--	A,FF	--
Longer amortization needed to firmly determine all costs before recovery from ratepayers	--	P	--	--	GG	--	--
Substitute plant may be built on the same site	--	--	G,H,P,Q, MM,OO	--	--	--	--
Plant site will not be used within 4 years	--	--	--	--	--	--	R
Wish to avoid penalizing stockholders when management made prudent decisions	--	Y	--	--	--	--	--
Desire equitable sharing of costs between ratepayers and common stockholders	--	--	--	OO	Q,S,U, V,Z,AA, CC,GG	A,O,FF	--
Desire equitable sharing of costs between present and future ratepayers	--	--	--	--	Z	--	--
No return should be earned because the plant was not, and will never be, "used and useful"	--	--	--	--	S,T,W, CC,DD, EE,NN	A[f],FF	--
No return should be earned on funds not provided by utility's investors	--	P[g]	--	--	--	--	--
Common stockholders should bear some of the risk of project failure	--	--	--	OO	S,T,W, GG,MM	A	--

See footnotes at end of table.

Table 11. Reasons Cited by Commissions as the Bases for Their Regulatory Treatment of Cancelled Nuclear Plants[a] (continued)

Reasons Cited in Commission Decisions	Full Recovery: Amortization (years) 1-5	Full Recovery: Amortization (years) 6-10	Full Recovery: CWIP for Alternate Plant	Partial Recovery: Amortization (years) 1-5	Partial Recovery: Amortization (years) 6-10	Partial Recovery: Amortization (years) 11-20	No Recovery
Stockholders should bear all losses because the plant will never provide benefits to ratepayers	--	--	--	--	--	--	JJ,KK, PP,QQ RR,SS, TT
Ratepayers should not pay for management errors	C[e],D[e],E[e]	F[e]	--	--	--	--	KK
Utility attempted to obstruct regulatory oversight over its investment decisions	--	--	--	--	--	A[f]	--
Decision to cancel was not timely, causing excessive cost incurrence	C[e],D[e],E[e]	F[e]	--	OO	NN	A	--
Utility is financially able to bear the cost	--	--	--	--	NN	A[f],O,FF	--
If the utility is allowed no cost recovery half the loss is borne by the taxpayers	--	--	--	--	--	A[f]	--
Commission would have allowed utility to recover more costs if utility had requested it	--	--	--	--	--	HH	--
Decision deferred until FERC ruling no longer subject to judicial review	--	--	--	--	--	--	LL[h]
Utility coordinating agreement requires cancel- lation costs be shared as would costs of success	--	--	--	--	GG	--	--
Utility improperly approached Commission before cancellation to learn what monetary treatment it could expect	--	--	--	--	NN	--	--
Decision follows precedent(s) of Commission	I[c],J[c]	I[c],J[c],P[g]	G,H	B	R,S,T,U, W,Z,AA, CC,DD, EE,GG,NN	A,C,D, E,F,FF	--
No reasons given	--	--	--	X[i]	--	--	--

[a]The following letter codes are used to designate cancelled nuclear units, the Commissions issuing decisions, and the utility affected:

A	Pilgrim 2	Mass. DPU	Boston Edison
B	Pilgrim 2	Mass. DPU	Commonwealth Elec.
C	Sterling 1	New York PSC	Rochester G&E
D	Sterling 1	New York PSC	Central Hudson G&E
E	Sterling 1	New York PSC	Niagara Mohawk
F	Sterling 1	New York PSC	Orange & Rockland
G	Jamesport 1&2	New York PSC	Long Isl. Lighting
H	Jamesport 1&2	New York PSC	New York State E&G
I	New Haven 1&2	New York PSC	Long Isl. Lighting
J	New Haven 1&2	New York PSC	New York State E&G
K	Atlantic 1&2	New Jersey BPU	Public Service E&G
L	Atlantic 1&2	New Jersey BPU	Jersey Central P&L
M	Atlantic 1&2	New Jersey BPU	Atlantic Electric
N	Hope Creek 2	New Jersey BPU	Public Service E&G
O	Forked River 1	New Jersey BPU	Jersey Central P&L
P	Douglas Pt. 1&2	D.C. PSC	Potomac Elec. Pwr.
Q	Douglas Pt. 1&2	Maryland	Potomac Elec. Pwr.
R	Douglas Pt. 1&2	Virginia PSC	Potomac Elec. Pwr.
S	Surry 3&4	FERC	Virginia Elec. Pwr.
T	Surry 3&4	Virginia SCC	Virginia Elec. Pwr.
U	Surry 3&4	W. Virginia PSC	Virginia Elec. Pwr.
V	Surry 3&4	N. Carolina PUC	Virginia Elec. Pwr.
W	North Anna 4	Virginia SCC	Virginia Elec. Pwr.
X	North Anna 4	W. Virginia PSC	Virginia Elec. Pwr.
Y	North Anna 4	N. Carolina PUC	Virginia Elec. Pwr.
Z	Harris 3&4	N. Carolina PUC	Carolina P&L
AA	Davis-Besse 2&3 and Erie 1&2	FERC	Cleveland Elec. Illum.
BB	Davis-Besse 2&3 and Erie 1&2	Ohio PUC	Cleveland Elec. Illum.
CC	Davis-Besse 2&3 and Erie 1&2	Ohio PUC	Ohio Edison
DD	Davis-Besse 2&3 and Erie 1&2	Ohio PUC	Toledo Edison
EE	Greenwood 2&3	Michigan PSC	Detroit Edison
FF	Bailly	Indiana PSC	N. Indiana Pub. Svc.
GG	Tyrone 1	FERC	Northern States Pwr.
HH	Tyrone 1	Wisconsin PUC	Northern States Pwr.
II	Tyrone 1	Wisconsin PUC	Lake Superior Dist. Power
JJ	Tyrone 1	Minnesota PUC	Northern States Pwr.
KK	Tyrone 1	N. Dakota PSC	Northern States Pwr.
LL	Tyrone 1	S. Dakota PUC	Northern States Pwr.
MM	Black Fox 1&2	Oklahoma CC	Pub. Serv. of Okla.
NN	Allens Creek 1	Texas PUC	Houston L&P
OO	Sundesert 1&2	California PUC	San Diego G&E
PP	Pebble Spr. 1&2	Oregon PUC	Portland Gen. Elec.
QQ	Pebble Spr. 1&2	Oregon PUC	Pacific P&L
RR	WPN 5	Oregon PUC	Pacific P&L
SS	Pebble Spr. 1&2	Wyoming PSC	Pacific P&L
TT	WPN 5	Wyoming PSC	Pacific P&L

Footnotes to Table 11 (continued)

[b]This rationale was rejected by the Ohio Supreme Court, which concluded that the Ohio statutes did not allow recovery of any abandonment costs from ratepayers.

[c]The Administrative Law Judge recommended full cost recovery through levelized charges, which provide a return on the unamortized balance over time periods to be determined in future rate cases. The New York PSC has not yet considered these cases.

[d]Commissioner Shannon, in dissenting, stated that Surry 3 & 4 deserved rate base treatment because VEPCO's allowed rate of return was set too low and its depreciation rates do not account for potential abandonments.

[e]Commissioner Mead, in dissenting, stated several reasons why the utilities should bear at least some of the costs and that longer amortization periods should be adopted. She also questioned the validity of past commission precedents because the Sterling loss was so much larger than in any previous case.

[f]Commissioner Sprague, in dissenting, stated his opinion that all costs should be borne by shareholders.

[g]The Douglas Point cancellation resulted in a net gain because the uranium for the plant was sold at a profit which was larger than the abandonment loss. The profit and loss are being concurrently amortized. The intent of the D.C. PSC was to pass all benefits of the combined transaction onto the ratepayers. Allowing PEPCO full cost recovery of the abandonment loss was an inadvertent result and the PSC has stated that it does not consider its decision as precedential. The 10-year amortization period was chosen on the basis of precedent.

[h]South Dakota PUC has allowed Northern States Power to accumulate a carrying charge until final disposition of the case.

[i]North Anna 4 abandonment was decided through a settlement agreement between the West Virginia PSC staff and VEPCO.

Cancellations Granted Full Recovery

The New York Public Service Commission has consistently followed its earlier precedent of allowing utilities to fully recover all prudently incurred costs.[4] Major plant cancellations in this jurisdiction include Sterling, Jamesport 1 & 2, and New Haven 1 & 2. Final disposition of the Jamesport abandonment costs awaits the decisions of the utility owners regarding the possible construction of a coal-fired plant on the same site.

For four plant cancellations -- Greenwood 2 & 3, Douglas Point 1 & 2, Black Fox 1 & 2, and Sundesert 1 & 2 -- the costs related to the acquisition and improvement of the plant site were separated from the other abandonment costs, reclassified as plant held for future use, and placed in the utility rate bases.

The treatment accorded the Douglas Point cancellation by the Public Service Commission of the District of Columbia is less generous than Table 10 implies. In this case, Potomac Electric Power (PEPCO) sold the uranium intended for the Douglas point plant at a profit which substantially exceeded the total abandonment cost of the plant. The utility proposed a concurrent 10-year amortization of the gain on the uranium sale and of the abandonment costs which would result in a net credit being flowed through to the ratepayers. PEPCO also requested that no return be earned on the unamortized balance, but since the balance was a net gain rather than a loss, such treatment would have allowed PEPCO to earn a de facto return on the cost-free net unamortized balance over the 10 years. In an unprecedented decision, the commission ordered the deduction of the unamortized net balance from the rate base, thereby depriving PEPCO of any benefit beyond that of offsetting the abandonment cost of the plant. The adjustment ordered by the commission is equivalent to placing in rate base the unamortized balance of the abandonment cot while simultaneously subtracting out the unamortized balance of the gain on the sale. The commission's own staff objected to this adjustment, arguing that it would establish a precedent for adding unamortized losses to the rate base in future project cancellations. However, the commission rejected the staff's argument, asserting that it is not inconsistent to reduce the rate base when projects yield net gains, but to not increase the rate base when projects yield net losses. In this regulatory climate PEPCO can expect to receive only partial recovery (most likely Option 1) if it cancels projects in the future that involve losses.

The North Carolina Utilities Commission allowed VEPCO to fully recover the abandonment costs of North Anna 4; this decision was a significant departure from the partial recovery treatment it gave the Surry 3 & 4 cancellations. In its final opinion, the PUC stated that it wanted to ". . . avoid penalizing stockholders as a result of prudent management decisions."[5]

In the case of Tyrone 1, the Wisconsin Public Utility Commission allowed Lake Superior District Power Company to fully recover its costs on the grounds that this very small

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[4]The most recent NYPSC case affirming this precedent was the Indian Point 1 nuclear retirement in 1981.

[5]North Carolina Utilities Commission, case No. E22, Sub 257, evidence and conclusions for finding of Fact No. 6, p. 7.

utility ". . . is not in a position to carry any portion of the loss without suffering serious financial hardship."[6] The commission further stated that: "Since Northern States Power did not request a return on the unamortized balance, the commission will not allow it to earn a return."[7] On first reading, this statement appears to imply that if the utility had requested a return on the unamortized balance it would have been granted such treatment. However, it is not clear what the commission would have done if Northern States Power had requested full cost recovery.

Cancellations Granted No Recovery

The following five nuclear plant cancellations were denied cost recovery: Davis-Besse 2 & 3, Erie 1 & 2, Tyrone 1, Pebble Springs 1 & 2, and WPN 5.

Initially, the Ohio utilities owning Davis-Besse 2 & 3 and Erie 1 & 2 were allowed partial recovery (Option 1) by the Ohio Public Utility Commission. Upon appeal by the Ohio Office of Consumers' Counsel, the Ohio Supreme Court interpreted the State's statutes as not recognizing plant abandonment costs as a legitimate cost of service. The case is now before the United States Supreme Court.

The Tyrone 1 case is another in which no cost recovery was allowed. The share of the Tyrone 1 abandonment costs borne by Northern States Power Company of Minnesota (NSPM) are being imposed on that utility through an interstate wholesale rate approved by the FERC. Under the "Narragansett Doctrine," State commissions are required to recognize such wholesale rates as a legitimate cost of service.[8] Despite the FERC ruling, the Minnesota Public Utility Commission and the North Dakota Public Service Commission prohibited NSPM from recovering any of the abandonment cost through higher rates in their jurisdictions on the grounds that the Tyrone investment will never provide any benefits to their ratepayers. The South Dakota Public Utility Commission refused to make any decision until the FERC decision was affirmed and no longer subject to judicial review. Instead it deferred any cost recovery until the case was clearly resolved.

The decisions of the Minnesota, North Dakota, and South Dakota Commissions regarding Tyrone 1 cost recovery have resulted in considerable litigation. In Minnesota, the company took their case to the State court which reversed the Commission decision and ordered the Commission to allow NSPM to recover the FERC-approved charges through rates. The Commission appealed the case to the Minnesota State Supreme Court, which will decide the issue of whether the Commission has jurisdiction to review FERC-approved rates. Whatever the outcome, the case could then be appealed to the U.S. Supreme Court. In the interim, NSPM is collecting the Tyrone 1 costs from Minnesota ratepayers, subject to refund.

In North Dakota, the Tyrone case was appealed to the State Supreme Court, which found in favor of the company based on the Narragansett doctrine. The Court ordered the Commission to allow the company to flow through the Tyrone-related wholesale rates, subject to refund if the FERC decision was revised. In January 1982, NSPM began collecting Tyrone 1 cancellation costs through higher rates to its North Dakota customers.

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[6] Public Service Commission of Wisconsin, Case CA-5447, Findings of Fact, Conclusions of Law and Order, February 6, 1981, p. 14.

[7] Ibid.

[8] Narragansett Electric Company v. Burke, 381, A. 2d 1358 (R.I. 1977).

In South Dakota, the State Circuit Court ruled against the Commission, but this decision was reversed by the State Supreme Court. Thus, NSPM is still not recovering any of the Tyrone 1 costs in this jurisdiction, although it is being allowed to accrue a carrying charge on those costs in the event the FERC rates are ultimately upheld.

In a parallel attack launched at the Federal level, Minnesota and South Dakota appealed the FERC decision before the Eighth Circuit Court which ruled that the cost apportionment formula adopted by the FERC resulted in just and reasonable rates. That ruling is now final, since the time period for appeal to the U.S. Supreme Court has expired. Thus, the FERC decision is no longer subject to judicial review.

The Pebble Springs 1 & 2 and WPN 5 plant cancellations were denied all cost recovery in two separate jurisdictions: Oregon and Wyoming. In Oregon, the Public Utility Commissioner directed Portland General Electric (PGE) and Pacific Power and Light (PP&L) to write off their investments in Pebble Springs 1 & 2 and WPN 5 entirely against common shareholders' equity.[9]

The Commissioner's decision regarding cost recovery was a direct result of the recent passage of Ballot Measure 9 by Oregon voters which specifically prohibits a public utility from charging rates derived from a rate base which includes any property not presently providing utility service to the customers. The Oregon Commissioner broadly interpreted this law as requiring shareholders to bear all of the costs of unsuccessful projects.[10] However, in the same decisions he allowed the two utilities to retain the extraordinary gains resulting from the sales of tax benefits under ERTA and from the repurchase of some of their low-interest bonds which were selling at a substantial discount from book value. In contrast, the generally accepted regulatory treatment in widespread practice today is to flow through any gains (or losses) from such repurchases to the ratepayers. To the extent that these extraordinary gains are allowed to be retained by common shareholders as a quid pro quo for their absorbing the costs of plant cancellation, those costs will in fact be borne by future ratepayers who will be burdened with the utilities' higher cost of capital resulting from the retirement of those low-interest bonds.

Pacific Power & Light also operates in Wyoming and requested recovery of the Pebble Springs 1 & 2 and WPN 5 abandonment costs allocated to its Wyoming service area. The Wyoming Public Service Commission denied any such cost recovery on the grounds that these plants are not used and useful. In stark contrast to the arguments adopted by other jurisdictions (particularly New York State), the Commission concluded that ". . . the risk of loss to public utility investors is not lessened by the fact that a public utility incurs a service obligation."[11] PP&L appealed the Commission's decision, but the District Court upheld the Commission. The case is now before the Wyoming Supreme Court.

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[9]Oregon is unique in that its public utility commission consists of only one commissioner.

[10]Oregon Public Utility Commissioner, UF3796, Order No. 82-251, April 8, 1982; UF3779, Order No. 82-606, August 18, 1982; and UF3796, Order No. 82-677, September 23, 1982.

[11]Wyoming Public Service Commission, Docket Nos. 9617 sub 11, 9628 sub 6, and 9454 sub 17, Memorandum Opinion and Final Order, December 2, 1982.

Cancellations Granted Partial Recovery

As revealed in Table 10, partial recovery employing Option 1 was the most common regulatory treatment accorded past cancellations of nuclear plants involving substantial losses. Typically, a 10-year amortization period was adopted. Some cases involved longer periods, ranging from 13 to 20 years, and three involved shorter periods. In their final opinions, the commissions most frequently gave the following reasons for deciding on partial recovery:

- It affords an equitable sharing of costs between ratepayers and common shareholders.
- Common shareholders should bear some of the risk of project failures.
- The plant was not, and will never be, "used and useful."
- It follows Commission precedents.

The five cases of partial recovery which deviated from Option 1 treatment involved four plants: Harris 3 & 4, Black Fox 1 & 2, Pilgrim 2, and Sundesert 1 & 2. Although the Allen's Creek 1 cancellation also received Option 1 treatment, it is noteworthy because of the way the utility was penalized for imprudence. Each of these is discussed below.

In adjudicating the cancellation of Harris 3 & 4, the North Carolina Utilities Commission allowed the company to earn a return on the debt portion of the unamortized balance (i.e., Option 2 treatment). The Commission concluded:

> . . . that CP&L's preferred and common shareholders, who control the Company's management through its elected Board of Directors, should not be permitted to receive a return on monies invested by management in plant that was subsequently cancelled even though the initial decision to build said plant and the ultimate decision to cancel same were clearly reasonable and prudent . . . .[12]

However, the Commission also concluded that:

> . . . it is fair and reasonable to allow CP&L to collect through rates the legitimate costs associated with servicing the long-term debt related to the unamortized portion of the cancellation costs in question . . . ;

and

> . . . the long-term debt holder has very little direct impact on CP&L's management . . . .[13]

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[12]North Carolina Utilities Commission, Docket No. E-2, Sub 444, Evidence and Conclusions, Finding of Fact No. 11, September 24, 1982, p. 54.

[13]Ibid.

The logic of the Commission's argument could be flawed because it assumes that allowing a return on the debt component somehow guarantees that bond holders will receive their interest and principle payments, and conversely, that disallowing such a partial return would necessarily place these security holders in jeopardy. This is not so. Except where a company is at the brink of bankruptcy, the primary impact of not allowing a partial return to be earned on the unamortized balance would be to shift more of the plant's abandonment costs to common equity shareholders and income taxpayers. Holders of debt, and most likely preferred stock as well, would not be affected. Perhaps the Commission fully realizes this but had to justify its decision to apportion the costs in a manner which did not appear arbitrary and capricious. Further straining credibility was the Commission's argument that some of the unamortized balance could be legally included in the rate base because it qualified as working capital.[14]

In the Black Fox case, the Oklahoma Corporation Commission adopted Option 3 cost recovery. It also reduced the portion of the abandonment cost to be recovered through rates by the following amounts:

- Site-related investment which can be utilized for a coal-fired power plant (to be carried as CWIP)
- All advertising and public relations expenses related to the Black Fox project
- Proceeds from the sales of equipment, materials and supplies charged to the Black Fox project
- Value of equipment utilized elsewhere on utility's system
- All extraordinary gains realized by the utility from 1974 to January 15, 1982.

The Commission also ordered that all extraordinary gains realized by Public Service of Oklahoma (PSO) during the amortization period and any profits from off-system sales of electricity should be credited against the equity portion of the unamortized balance. Finally, PSO's quantifiable share of profits resulting from the gas processing operations of its subsidiary, Transok Pipeline Company, are to be applied to reduce the debt and preferred portion of the unamortized balance of project costs.

Under Option 3 cost recovery, a return is only earned on the debt and preferred equity portions of the unamortized balance of the recoverable cost. Black Fox is the only cancellation for which this Option was adopted. The Oklahoma Corporation Commission justified its use by arguing that the cost to the utility of preferred equity and debt capital would be substantially increased if the preferred dividend and interest payments associated with capital invested in the plant were not guaranteed. This argument is flawed for essentially the same reasons discussed above with respect to the Harris 3 & 4 cancellation.

In choosing to allow PSO to earn this partial return, the Commission acknowledged concern over the utility's financial ability to fulfill its service obligation. It also avoided indemnifying the common equity investors against all loss. Furthermore, it stated that in future rate cases it would consider granting a partial return on the common equity

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[14]North Carolina Utilities Commission, Docket No. E-2, Sub 444, Evidence and Conclusions, Finding of Fact No. 11, September 24, 1982, p. 55.

portion if that became necessary to maintain PSO's financial integrity and ability to attract capital at reasonable cost.

For the Pilgrim 2 cancellation, two different cost recovery options were adopted by the Massachusetts Department of Public Utilities. Commonwealth Electric was allowed Option 4 and Boston Edison allowed Option 5. As explained earlier, the difference between these options is that the latter allows a return to be earned on a portion of the unamortized balance whereas the former does not. In its filing, Commonwealth Electric Company did not request carrying charges on the unamortized balance. This regulatory treatment was consistent with the precedent set by the Department in the Montague nuclear plant cancellation for the Western Massachusetts Electric Company.[15]

In the Boston Edison case, the lengthy, 13-year amortization period set by the Department, combined with the utility's poor financial condition (which precipitated the Pilgrim 2 cancellation), warranted that a return be allowed to give the company sufficient financial resources to fulfill its service obligation in the future. The Department's reason for disallowing the equity portion of AFUDC in both these cases was also based on the precedent set in the Montague cancellation.

For the Sundesert cancellation, the California Public Utility Commission chose Option 6 cost recovery for the nonsite-related costs. This option precludes recovery of any project AFUDC. Two reasons were given by the commission for excluding AFUDC -- to make the investors bear more of the risk of project noncompletion and to share the abandonment costs equitably between investors and ratepayers.

In its examination of the facts leading to the cancellation of Allen's Creek 1, the Texas Public Utilities Commission found that Houston Lighting & Power (HL&P) was imprudent by not having cancelled the plant at least 2-1/2 years earlier. Accordingly, it disallowed approximately $166 million of the $362 million the utility was seeking to recover. The unusual aspect of this action is that the Commission decision stipulated that HL&P shareholders absorb the entire $166 million on an after-tax basis, and that the income tax savings associated with the tax write-off would be flowed through to the ratepayers uniformly over a 10-year period. The net effect of this was to impose on HL&P an equivalent pre-tax loss of $277 million. In light of the unorthodox nature of the Commission's treatment of taxes, the company is seeking relief in the courts.

Quantification of Abandonment Cost Allocation

Quantitative estimates of the allocation of abandonment costs among the three major groups of payers were calculated for a hypothetical nuclear plant where Option 1 cost recovery was adopted. The plant was assumed to be cancelled in mid-1983 and the amortization period was then varied from 2 to 30 years, with one case employing 10 years -- the period most frequently adopted in past nuclear plant cancellations.

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[15]Massachusetts Department of Public Utilities, Western Massachusetts Electric Company, D.P.U. 558, 1981. This cancellation is not included in Tables 10 and 11 because its abandonment cost was less than $50 million.

The estimation methodology involved three steps:

- Formulation of the incremental annual cash flows of each payer group during the period extending from the start of construction through amortization
- Determination of the appropriate discount rates applicable to each payer group
- Calculation of the the net present value of each group's cash flow stream.

It is assumed that the project's discount rate is independent of the method used to allocate the abandonment costs. Also, it is assumed that regulators will use the appropriate price elasticity of demand when setting prices, so that the desired increase in revenue will be realized.

Appendix C contains a detailed description of the methodology employed, including full treatment of the 10-year amortization case and a listing of the computer program employed to calculate the present values. It also contains tables showing the year-by-year cash flow components for each group of payers for the 10-year amortization period.

Table 12 presents the present values of the costs borne by each group, and their relative distributions, over the range of amortization periods and for three different ratepayer discount rates. In addition to using discount rates reflecting the cancelled project's risk level, reasonable upper and lower bounds were also adopted in order to bracket the present values of the actual costs. This was done because of the difficulty in determining the appropriate discount rate to apply to this heterogeneous group.

The results shown in Table 12 are most interesting. As one would expect, the percentage of the total cost burden borne by utility investors increases with the length of amortization. What is not so obvious is that this group pays less than half the total costs -- even in the extreme case of 30-year amortization. In the most frequently adopted case of 10-year amortization, this group pays less than one-third of the total costs.

With respect to ratepayers, Table 12 reveals that this group's cost burden decreases as the length of amortization increases, becoming almost negligible for amortization periods of 20 or more years. In fact, for some length of amortization approaching 30 years, ratepayers as a group actually derive a net monetary benefit from the plant's existence even though it was cancelled. This paradox exists because the rate reductions that ratepayers enjoyed as a result of the income tax savings on the debt financing of the plant, primarily before cost amortization began, provided monetary benefits which outweighed the subsequent increases in rates.

Finally, the analysis reveals that a substantial portion of the total cost is borne by income taxpayers, primarily because of the deferral of income tax revenues resulting from the write-off of the plant's sunk costs in the year of cancellation. As Table 12 shows, in every case the present value of the income tax revenues lost substantially exceeds the present value of the costs borne by utility investors. Thus, the government sector greatly cushions the cost impact of nuclear plant cancellations on utility owners -- thereby introducing incentives to cancel plants which are in more advanced stages of construction than would be the case if the tax writeoffs did not exist.

Table 12. Distribution of Costs Associated with Cancelled Nuclear Power Plants Among Three Major Payer Groups for Various Lengths of Amortization

Length of Amortization (Years)	Ratepayers Discount Rate (Percent)	Present Value of Costs Borne by Each Group: Utility Investors[a] Amount (Millions of Dollars)	Utility Investors[a] Share (Percent of Total)	Ratepayers[b] Amount (Millions of Dollars)	Ratepayers[b] Share (Percent of Total)	Income Taxpayers[c] Amount (Millions of Dollars)	Income Taxpayers[c] Share (Percent of Total)
2	5.5	108	12	610	69	173	19
2	Intermediate	108	13	557	65	194	22
2	20	108	14	490	64	173	22
5	5.5	165	18	514	56	245	26
5	Intermediate	165	19	424	49	270	32
5	20	165	22	336	45	245	33
10	5.5	237	25	373	39	340	36
10	Intermediate	237	28	256	30	366	43
10	20	237	32	169	23	340	46
15	5.5	288	30	252	27	411	43
15	Intermediate	288	34	138	16	434	50
15	20	288	37	69	9	411	54
20	5.5	325	35	149	16	464	49
20	Intermediate	325	38	52	6	482	56
20	20	325	41	5	1	464	58
30	5.5	373	42	-15	-2	536	60
30	Intermediate	373	43	-59	-6	545	63
30	20	373	44	-68	-8	536	64

[a]Annual cash flows to utility investors were discounted using rates that were 2 percentage points higher than yields offered by U.S. Treasury bonds that mature in the same respective years in which these cash flows are received.

[b]Annual cash flows to ratepayers were discounted using the rates shown in the second column of the table for the lower- and upper-bound cases. For the intermediate case, these cash flows were discounted at the same rates that were applied to the utility cash flows.

[c]For the cases employing the ratepayer's lower- and upper-bound discount rates, annual cash flows to the government were discounted using rates equal to the yields offered by U.S. Treasury bonds that mature in the same respective years in which these cash flows are received. For the intermediate case, these cash flows were discounted at the same rates that were applied to the utility cash flows.

Summary

This section has examined the regulatory treatment accorded nuclear power plants cancelled over the past 10 years which involved substantial abandonment costs. It was found that a number of options have been adopted for allowing the utility owners to recover varying amounts of their investment; however, the option most commonly chosen by regulators has been to amortize the plant's abandonment loss over a fixed period (usually about 10 years) but not to allow the utility to earn a return on the unamortized balance. This approach is usually justified on the grounds that it yields an equitable sharing of the costs between utility ratepayers and shareholders.

The only consistent exception to the generally adopted practice has been that of the New York Public Service Commission, which has allowed a fully compensatory return to be earned, thereby virtually indemnifying the utility investor against absorbing any of the cost.

Even in those cases of partial cost recovery, however, where the utility is not allowed to earn a return on the unamortized balance, most of the abandonment costs are borne by ratepayers and a third, less visible group -- income taxpayers. One important consequence of this is to encourage the cancellation of nuclear plants which the utility owners cannot finance on terms favorable to their investors, even when the completion of those plants may be in the best interests of their ratepayers.

4. POTENTIAL NUCLEAR PLANT CANCELLATIONS

This section identifies nuclear power plants most likely to be cancelled over the next 13 years and estimates the associated abandonment costs and their regional distribution.

"At Risk" Nuclear Power Plants

As discussed in Section 2, 100 nuclear units were cancelled by December 31, 1982. It is likely that additional cancellations will occur during the 1983-1995 period. After consolidating and reviewing all available information, two groups of "at risk" nuclear units currently under construction but vulnerable to cancellation, were identified. These two groups will hereafter be referred to as:

- The Base Case
- The Worst Case.

Each case is described below.

The Base Case

The Base Case is similar to the "Utility Financial Constraints" case in the Energy Information Administration's (EIA) 1981 Annual Report to Congress, in which it was assumed that reactors which were less than 20 percent complete by the end of 1981 were prime candidates for cancellation.[1] Currently, 13 of the 74 units now planned or under construction fall into this group. Table 13 shows the licensing status, constructing utility, and scheduled completion date for each of these units. It also shows the cumulative investment in each unit through June 1982.

The NSSS has been ordered for all units listed. Nine units have received construction permits (CP), and two others have had their CP applications docketed. Almost half the units have no scheduled completion date, which is indicative of their tentative nature.

The Worst Case

The Worst Case was developed by adding to the Base Case five selected nuclear units that were more than 20 percent complete by the end of 1981 but which have been identified by

[1] Energy Information Administration, U.S. Department of Energy, U.S. Commercial Nuclear Power, DOE/EIA-0315 (Washington, D.C., March 1982). The 20 percent milestone was adopted as a point at which the financial commitment in a project was too great to warrant cancellation, i.e., an economic "point of no return." Hope Creek 2, cancelled in December 1981 with 19 percent completion reported, served as the precedent in establishing this assumption.

Table 13. Nuclear Unit Cancellations in the Base Case: Status as of June 30, 1982[a]

Unit Name	Size (MWe)	Federal Region	Constructing Utility	Estimated Operation Date[b]	Percent Completed	Cumulative Expenditures Reported (Millions of Dollars)[c]
Seabrook 2	1,120	I	PSCo. of N.H.	1986	15	600-700
Cherokee 1	1,280	IV	Duke Power	N/S	18	500-600
Harris 2	900	IV	Carolina P&L	1989	4	200-300
Vogtle 2	1,100	IV	Georgia Power	1988	11	300-400
Yellow Creek 2	1,285	IV	TVA	N/S	3	200-300
Clinton 2	933	V	Illinois Power	N/S	1	<50
Marble Hill 2	1,130	V	PSCo. of Indiana	1988	21	400-500
Carroll County 1 ..	1,120	V	Commonwlth. Edison	N/S	0	<50
Carroll County 2 ..	1,120	V	Commonwlth. Edison	N/S	0	<50
River Bend 2	934	VI	Gulf States Util.	N/S	1	50-100
South Texas 2	1,250	VI	Houston L&P	1989	18	800-900
Skagit 1	1,277	X	Puget Sound P&L	1991	0	400-500[d]
Skagit 2	1,277	X	Puget Sound P&L	1993	0	
Total (13 Units)	14,726	--	--	--	--	3,450-4,450

[a]The Base Case reflects the financial constraints developed by the Energy Information Administration, published in U.S. Commercial Nuclear Power.

[b]Estimated date of commercial operation.

[c]Total of direct expenditures and AFUDC reported by the utilities in a telephone survey conducted in June 1982. Ranges of costs are shown here to preserve the confidentiality of some of the data.

[d]This figure includes costs accrued for both units.

N/S = not scheduled.

Source: U.S. Nuclear Regulatory Commission, Nuclear Power Plants, Construction Status Report, Data as of 06/30/82, NUREG-0030, Vol. 6, No. 2, October 1982. Utility cost data compiled by J.A. Reyes Associates.

the NRC, Salomon Brothers, Merrill Lynch, and the EIA as likely candidates for cancellation.[2] Factors considered by these groups in their selection of the additional "at risk" plants were the current rate of construction, deferral decisions already made, and information from the utilities regarding their plans. Table 14 lists the five additional units included in the Worst Case. Four of these units have at least 30 percent of their construction complete and all but Grand Gulf 2 have the reactor pressure vessel installed.

In the Worst Case, the TVA Hartsville "A" units are probably the least likely to be cancelled because they are so advanced in construction and because the TVA board recently voted to continue their construction. The justification for including these units in the Worst Case is based on TVA's own internal analysis which concluded that if actual growth in electricity demand equals TVA's high forecast (the likelihood of which is only one in ten), completion of these units will be a "break even" proposition.[3] However, if actual load growth falls substantially below TVA's mid-range forecast (the likelihood of which is one in two) the additional costs imposed on TVA's ratepayers over the next 20 years could exceed $700 million (in 1981 dollars).[4] Due to the tenuous nature of the economic payoff on the Hartsville "A" units, their potential cancellation appears credible.

Methodology for Estimating Potential Abandonment Costs

The abandonment costs, as defined in Section 3 of this report, were estimated for each of the "at risk" units. The methodology used to develop estimates for the various components of abandonment cost is described below.

Cash Expenditures and AFUDC

Estimates of the expenditures and AFUDC accumulated to June 1982 were obtained through a telephone survey of the constructing utilities. The cost data for individual units are presented as ranges in Tables 13 and 14 because several utilities do not wish to publicly reveal the specific figures at this time. However, the actual data were used to develop the aggregate regional costs.

Contract Cancellation and Salvage Value

These cost components were difficult to estimate, because they are highly dependent on the specific contract terms negotiated by the utilities, on the states of completion of the various contracts and on the resale potential for the major plant components. In most cases even the constructing utilities could not estimate, with confidence, what

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[2]Memo from William Dircks to Commissioner Ahearn, March 18, 1982; Salomon Brothers, Electric Utility Measurements, April 4, 1982; Merrill Lynch, Electric Utility Industry: Nuclear Power Plants -- Another Look, May 1982; Energy Information Administration, Estimates of Future U.S. Nuclear Power Growth, SR-NAFD-83-01 (Washington, D.C., January 1983).

[3]Tennessee Valley Authority, Office of Power, Review of the TVA Load Growth/Plant Construction Situation, January 1982.

[4]Ibid.

Table 14. Additional Nuclear Unit Cancellations in the Worst Case: Status as of June 30, 1982

Unit Name	Size (MWe)	Federal Region	Constructing Utility	Estimated Operation Date[a]	Percent Completed	Cumulative Expenditures Reported (Millions of Dollars)[b]
Limerick 2	1,055	III	Phila. Electric	1987	30	400-500
Grand Gulf 2	1,250	IV	Mississippi P&L	N/S	23	500-600
Hartsville A-1	1,233	IV	TVA	1991	44	900-1,000
Hartsville A-2	1,233	IV	TVA	1992	34	500-600
Yellow Creek 1	1,285	IV	TVA	N/S	35	800-900
Subtotal (5 Units)	6,056	--	--	--	--	3,100-3,600
Worst Case Total (18 units)[c]	20,782	--	--	--	--	6,550-8,050

[a]Estimated date of commercial operation.

[b]Total of direct expenditures and AFUDC reported by the utilities in a telephone survey conducted in June 1982. Ranges of costs are shown here to preserve the confidentiality of some of the data.

[c]Total from Tables 13 and 14.

N/S = not scheduled.

Sources: NRC Memo from W. Dircks to Commissioner Ahearn, March 18, 1982; Salamon Brothers, Electric Utility Quality Measurements, April 4, 1982; Merrill Lynch, Electric Utility Industry: Nuclear Power Plants -- Another Look, May 1982; U.S. Nuclear Regulatory Commission, Nuclear Power Plants, Construction Status Report, Data as of 06/30/82, NUREG-0030, Vol. 6, No. 2, October 1982. Utility cost data compiled by J.A. Reyes Associates.

ese costs would be. The utilities that have estimated these costs were unwilling to discuss their results because this information could adversely affect negotiations with vendors if their plants are actually cancelled.

On the basis of the contract cancellation costs and salvage values associated with past cancellations, and the TVA estimates for its eight "at risk" units (see Appendix B), very rough estimates of these costs were developed. For most units in the Base Case, and all units in the Worst Case, contract cancellation costs, net of salvage values, are likely to be less than 25 percent of the total abandonment costs. In light of this, the net value of these two cost components was roughly estimated to average $50 million per unit, although the costs associated with individual units could substantially deviate from this figure.

Site-Related Costs

As shown in Section 3, the general consensus appears to be that the construction sites of cancelled nuclear plants are valuable properties which are best utilized for some type of power plant in the future. Thus, much of the cost incurred in acquiring and improving the site is recoverable. Based on past nuclear cancellations, these site-related costs are estimated to average $30 million per site.

Potential Abandonment Cost Estimates

The abandonment costs estimated for the Base Case and Worst Case, aggregated to the Federal regional and national levels, are shown in Table 15. Comparing the national totals for abandonment costs shown in this table with the total costs shown in Table 9 reveals that the Worst Case involves costs which approach those of the 42 previously cancelled units involving more than $50 million.[5] With respect to the regional distribution of cost, Table 15 shows that the Southeast (Region IV) is likely to be the most heavily impacted, potentially bearing from one-third to over one-half of the Nation's total abandonment costs in the Base Case and the Worst Case, respectively. TVA's nuclear construction program, which was the most ambitious in the country and is now in jeopardy due to reduced load growth, is the primary reason for this disproportionate effect. All of these plants are in advanced stages of construction; thus, their cancellation would involve huge abandonment costs.

The TVA cancellations are especially ironic. Unlike the investor-owned utilities, TVA can raise the capital needed to complete all of its plants, but cannot economically justify the completion of at least four units because of the dramatic downward revision of its load growth forecast. Meanwhile, some of the utilities having power exchange arrangements with TVA are heavily dependent on expensive oil- and natural gas-fired generation and could substantially reduce their customer's future electric bills through purchases of surplus baseload nuclear and/or coal-fired energy from TVA. Such offsystem sales might allow TVA to carry its nuclear plants until such time as its own growth in native load could absorb their full output. If completed, the eight TVA units would save the equivalent of approximately 230,000 barrels per day of residual oil consumption. The TVA has not been successful thus far in its efforts to find buyers for this excess power.

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[5]This statement is valid even when the abandonment costs of the previously cancelled units are expressed in constant, mid-1982 dollars.

Table 15. Potential Nuclear Plant Abandonment Costs by Federal Region (Millions of Constant Mid-1982 Dollars)

Federal Regions	Costs Under Base Case	Costs Under Worst Case
Region I	749	1,304
New England		
Region II	0	0
New York/New Jersey		
Region III	0	555
Middle Atlantic		
Region IV	1,528	4,621
South Atlantic		
Region V	684	684
Midwest		
Region VI	993	993
Southwest		
Regions VII, VIII, and IX	0	0
Central		
North Central		
West		
Region X	530	530
Northwest		
Total	4,484	8,132

Regulatory Precedents for the Allocation of Potential Abandonment Costs

The ratemaking treatment accorded the abandonment costs of past nuclear plant cancellations provides valuable precedents for projecting the treatment of costs in future cancellations. Even in those jurisdictions which have not yet adjudicated nuclear plant cancellations, major non-nuclear project cancellations may provide useful precedents. It is reasonable to assume that regulatory commissions will apply the same treatment for future cancellations as they did for past cancellations where the circumstances are similar.

Table 16 summarizes the precedential decisions applicable to each "at risk" nuclear unit in the Base Case and Worst Case. As shown there, most of the regulatory commissions with jurisdiction over these units have already adjudicated at least one nuclear plant cancellation.

Summary

The near future of commercial nuclear power could very likely include further plant cancellations. Many of these plants are advanced in construction and could involve abandonment costs approaching, or exceeding, $1 billion per unit. The total costs of these cancellations could approximately equal the combined costs of all major cancellations in the past. Because the completion of many of these plants could result in the displacement of electricity generated by oil and natural gas, thereby reducing the Nation's oil imports, this situation may not serve the best interest of electricity consumers or the Nation at large.

Table 16. Likely Regulatory Treatment of Potential Nuclear Plant Cancellations

Nuclear Unit(s)	Utility Owner(s)	Regulatory Jurisdiction(s)	Regulatory Precedent(s)	Likely Recovery Option
Carroll County 1&2 ..	Commonwealth Edison	Illinois	None	Unknown
Cherokee 1	Duke Power	No. Carolina	Surry, North Anna, Harris	Option 1 or 2
		So. Carolina	None	Unknown
Clinton 2	Illinois Power (80%)	Illinois	None	Unknown
	Two Illinois Coops (20%)	Not Regulated	--	Full Recovery
Grand Gulf 2	Middle South Energy (90%)	FERC	Tyrone	Option 1
	South Mississippi Electric Power Assn. (10%)	Not Regulated	--	Full Recovery
Harris 2	Carolina P&L (83.83%)	No. Carolina	Surry, North Anna, Harris	Option 1 or 2
		So. Carolina	None	Unknown
		FERC	Tyrone	Option 1
	No. Carolina Eastern Mncpl. Power Assn. (16.17%)	Not Regulated	--	Full Recovery
Hartsville A1&A2	TVA	Not Regulated	--	Full Recovery
Limerick 2	Philadelphia Elec.	Pennsylvania	None	Unknown
Marble Hill 2	Pub. Svc. of Indiana (83%)	Indiana	Bailly	Option 1
	Wabash Valley Power Assn.(17%)	Not Regulated	--	Full Recovery
River Bend 2	Gulf States Utilities	Louisiana	Blue Hills	Full Recovery
		Texas	Allens Creek	Option 1
Seabrook 2	Public Service of N.H. (35.6%)	New Hampshire	None	Unknown
		FERC	Tyrone	Option 1
	United Illuminating (17.5%)	Connecticut	Montague	Option 1
	Massachusetts Mncpl. Wholesale Elec. (11.6%)	Not Regulated	--	Full Recovery
	New England Power (10 %)	FERC	Tyrone	Option 1
	Central Maine Power (6%)	Maine	Montague, Sears Isle	Option 6
	Connecticut L&P (4.1%)	Connecticut	Montague	Option 1
	Commonwealth Elec. (3.5%)	Massachusetts	Pilgrim 2, Montague	Option 4 or 5
	Montaup Elec. (2.9%)	Massachusetts	Pilgrim 2, Montague	Option 4 or 5
	Bangor Hydro-Elec. (2.2%)	Maine	Montague, Sears Isle	Option 6
	Central Vt. Pub. Svc. (1.6%)	Vermont	Pilgrim 2	Option 1
		New Hampshire	None	Unknown
	Maine Pub. Svc. (1.5%)	Maine	Montague, Sears Isle	Option 6
	Fitchburg G&E (0.9%)	Massachusetts	Pilgrim 2, Montague	Option 4 or 5
	Other Mncpls. & Coops (2.8%)	Not Regulated	--	Full Recovery

See footnote at end of table.

Table 16. Likely Regulatory Treatment of Potential Nuclear Plant Cancellations (continued)

Nuclear Unit(s)	Utility Owner(s)	Regulatory Jurisdiction(s)	Regulatory Precedent(s)	Likely Recovery Option
Skagit 1&2	Puget Sound P&L (40%)	Washington	None	Unknown
		FERC	Tyrone	Option 1
	Pacific P&L (20%)	California	Sundesert	Option 6
		Idaho	None	Unknown
		Montana	None	Unknown
		Oregon	Pebble Springs	No Recovery
		Washington	None	Unknown
		Wyoming	Pebble Springs	No Recovery
		FERC	Tyrone	Option 1
	Washington Water Power (10%)	Idaho	None	Unknown
		Washington	None	Unknown
	Portland General Elec. (30%)	Oregon	Pebble Springs	No Recovery
		FERC	Tyrone	Option 1
South Texas 2	Houston L&P (30.8%)	Texas	Allens Creek	Option 1
	Central P&L (25.2%)	Texas	Allens Creek	Option 1
	City of Austin (16%)	Not Regulated	--	Full Recovery
	City of San Antonio (28%)	Not Regulated	--	Full Recovery
Vogtle 2	Georgia Power (50.7%)	Georgia	None[a]	Unknown
		FERC	Tyrone	Option 1
	Oglethorpe Power (30%)	Not Regulated	--	Full Recovery
	Municipal Elec. Authority of Georgia (17.7%)	Not Regulated	--	Full Recovery
	City of Dalton (1.6%)	Not Regulated	--	Full Recovery
Yellow Creek 1&2	TVA	Not Regulated	--	Full Recovery

[a]In Georgia's two previous nuclear cancellations, Vogtle 3 & 4, the adjudication of small abandonment losses ($707,704) as a non-recurring expense did not establish a reliable precedent.

5. CONCLUSIONS

This section presents the major conclusions of the study, along with the supporting evidence, causes, and implications. The major conclusions are as follows:

- The Nation's electric utility industry has substantially reduced its earlier commitment to nuclear power by cancelling almost half the nuclear capacity it had ordered since the inception of commercial nuclear power.

- Five major causes of nuclear power plant cancellations have been identified, the most significant being: lower forecasted load growth, construction financing constraints and reversals in the cost advantage of some nuclear units.

- In the past, the regulatory treatment of nuclear power plant cancellations most frequently adopted by regulatory commissions allocated most of the abandonment costs to utility ratepayers and income taxpayers, rather than to utility investors.

- A number of nuclear power plants in various stages of completion have been identified as being vulnerable to cancellation and potentially involve total abandonment costs ranging from about $4.5 to $8.1 billion.

- If completed, many of the nuclear power plants already cancelled, or subject to potential cancellation in the near future, could provide net economic benefits to ratepayers and the Nation as a whole -- primarily by replacing electricity generated by oil- and natural gas-fired power plants.

Each of these conclusions is briefly discussed below.

Reduced Commitment to Nuclear Power by the Electric Utility Industry

In 1974, the electric utility industry had about 30,000 megawatts of nuclear capacity in commercial service and had commitments for an additional 217,000 megawatts of nuclear capacity to be completed by the early 1990's. By the end of 1982, almost 110,000 MWe of planned capacity had been cancelled. Furthermore, an additional 21,000 MWe currently planned or under construction remain vulnerable to cancellation, principally because this capacity is still subject to the same factors that influenced plant cancellations in the past.

One consequence of the electric utility industry's reduced nuclear expansion program is that ratepayers of the utilities cancelling nuclear units will pay higher electric rates during the period over which the sunk costs of these units are amortized. In addition, many will pay higher rates beyond that period because some of the cancelled units, if completed, could displace electricity generated with more expensive fuels -- particularly oil and natural gas. Thus, opportunities could have been lost to reduce the Nation's dependence on imported oil. Finally, Federal, State and some local governments will lose income tax revenues to the extent that the costs of cancelled nuclear units are written off against the utilities' taxable incomes.

Major Causes of Nuclear Power Plant Cancellations

The dramatic reversal in the ambitious plan to expand nuclear generating capacity is attributed to five major underlying causes: lower forecasted load growth, constraints on the ability to finance construction, reversals in the cost advantage of nuclear power over coal-fired generation, a changing and uncertain regulatory climate, and denials of plant certification by some state powerplant siting authorities. Of these, the first three factors appear to be responsible for most of the cancellations.

Revised forecasts of future growth in peak electricity demand were cited as the sole reason behind 17 unit cancellations and as having contributed to the cancellation of 34 other units, along with other causes. Financial constraints were cited as being the sole cause of the decision to terminate only 5 units but also contributed to the cancellation of 39 other units. A reversal in the generation economics of nuclear power relative to other alternatives -- particularly coal-fired generation -- was cited as being the sole reason for cancelling 5 nuclear units and was a consideration in the cancellation of 13 other units.

The initial impact of reduced load growth is to defer the in-service date of planned generating capacity. However, if that in-service date is moved far enough into the future, a point is reached where the annual costs of maintaining a construction restart capability, combined with the increased uncertainty surrounding the ultimate cost of the new capacity relative to its alternatives, prescribes that project cancellation is the most economic choice. Finally, if one or both of the other significant causes of cancellations are present, reduced load growth further reinforces their effect because utility managements are provided with the time to consider other opportunities without jeopardizing their obligations to serve customers.

The inability of most investor-owned utilities plants to earn rates of return on investment at least equal to their respective costs of capital during much of the past decade substantially limited their access to debt capital and also made additional investment of equity capital punitively unattractive. As a result, many investor-owned utilities appear to have adopted a strategy of restricting new investment to just those projects which are absolutely necessary to fulfill the utilities' service obligations. In light of this, nuclear plants and other major projects, such as coal-fired or hydroplants, in early stages of planning or construction, were vulnerable targets for cancellation, particularly since the sunk costs of the cancelled plants would be borne predominantly by parties other than utility investors. However, nuclear plants have been among the most vulnerable because of their long lead times, high capital intensity, and the uncertainties shrouding their ultimate costs and completion dates.

Six to fifteen years ago, when utilities made initial commitments to construct the nuclear units that they subsequently cancelled, both industry and Federal government studies gave nuclear power a significant cost advantage over coal-fired generation in most regions of the country. In the intervening years, this cost advantage has narrowed to the point where today, in most regions, nuclear power no longer offers a clear cost advantage over coal and additionally involves a greater degree of uncertainty. One consequence of this is that many utilities, and their regulators, are re-examining ongoing nuclear projects from the perspective of whether they should be cancelled, and that less uncertain options, such as coal-fired power plants, be constructed inste[illegible]

Allocation of Abandonment Costs by Regulatory Commissions

Most State regulatory commissions and the FERC have allowed utilities that cancelled nuclear plants to recover all, or most, of the abandonment costs incurred up to the date of cancellation by amortizing them through rates over a period of years. But typically, no return was allowed to be earned on the unamortized balance, thereby forcing the utility investors to bear some of the economic loss. The longer the period of amortization, the greater is the burden shifted to the investors.

An analysis of the 42 nuclear units cancelled through December 31, 1982, which involved abandonment costs exceeding $50 million, revealed that in 22 of the 48 related cases adjudicated (consisting of unique cancelled plant-regulatory commission-utility owner combinations) the utility owner was allowed to amortize the full abandonment costs (including AFUDC) over periods ranging from 5 to 20 years (10 years being the most frequently chosen period) but was not allowed to earn a return on the unamortized balance. In 11 cases the utility owner was allowed to fully recover all costs, including a return on the unamortized balance. Only in 8 cases (all addressing the Tyrone 1, Pebble Springs 1 & 2, and WPN 5 plant cancellations) was all cost recovery disallowed. The decisions in the remaining 7 cases allowed varying degrees of cost recovery.

The reasons underlying the relative consistency in the regulatory treatment of nuclear plant abandonment costs are fourfold, based on the documented opinions of the regulatory commissions. First, and perhaps foremost, is a political desire to share the costs equitably between the utility's ratepayers and its investors. Second, in most jurisdictions a utility is legally prohibited from earning a return on a plant which is not "used and useful." Next is the view that investors should be penalized when a major project controlled by the management representing them fails to reach fruition. Finally, there is the precedential value of a commission's previous decisions, which contributed a uniformity to the regulatory treatment of similar cases following the landmark decisions.

A present-value analysis of the costs allocated to the three major payer groups for a hypothetical plant cancellation involving amortization over 10 years, with no return earned on the unamortized balance, yielded the following approximate distribution of costs: utility investors, 30 percent; utility ratepayers, 30 percent; and income taxpayers, 40 percent. One important impact of the relatively modest proportion of abandonment costs allocated to investors is to encourage utilities to cancel partially completed plants which they cannot finance on terms favorable to their respective common shareholders. Furthermore, the greater the degree of cost recovery allowed, the greater is the incentive to cancel the plant. This would suggest that the responsibility for planning and constructing capital-intensive power plants has been virtually divorced from the parties who will ultimately reap the benefits and/or pay the costs. It is possible that this situation is an unavoidable consequence of the regulatory environment within which utility decisionmaking has been carried out.

Nuclear Power Plants Vulnerable to Cancellation

Many nuclear power plants are still subject to cancellation in the future if the major causes for precedent terminations persist. A Base Case scenario of plants under construction which are highly vulnerable to being cancelled consists of 13 units, totalling about 15,000 MWe. On June 30, 1982, these units ranged from 0 to 21 percent complete. A Worst Case scenario consists of the 13 Base Case units plus 5 additional units, which are further advanced in construction.

If all of the units in the Base Case scenario are cancelled in the near future, their combined abandonment costs will be about $4.5 billion, expressed in mid-1982 dollars. Cancellation of all units in the Worst Case scenario would add about another $3.6 billion, expressed in mid-1982 dollars. For comparison, the combined abandonment costs of the 42 nuclear units involving more than $50 million, already cancelled through December 1982, amounted to about $9.5 billion, expressed in mid-1982 dollars.

As with past cancellations, most of the cost burden of future unit cancellations will be borne by the ratepayers and taxpayers, primarily because most of the "at risk" plants are regulated by jurisdictions which have established precedents for allowing the amortization of abandonment costs through increased rates. This is further reinforced by the fact that over one-fourth of the potential cancellation costs in the Worst Case scenario is attributed to units owned by TVA. For these cancellations, ratepayers will bear virtually the entire cost burden because there are no investors involved and TVA does not pay income taxes against which the losses can be deducted.

Compared to cancellation costs in the past, the reason for the relatively high cost associated with the potential cancellation of so few units is that many of the units currently "at risk" are in advanced stages of construction. In most cases, these projects have already taken delivery of the nuclear reactor and other major components. In addition, due to the depressed nature of the U.S. and world markets for nuclear power plants, the owners of cancelled units are forced to compete against each other for the few potential buyers. Thus, units cancelled in the foreseeable future are likely to yield very limited salvage values to offset their sunk costs.

Potential Benefits of Completing Nuclear Power Plants Already Cancelled or Subject to Potential Cancellation in the Near Future

Except for units cancelled specifically because of a reversal in the comparative generation economics, the completion of nuclear units under construction could offer the cheapest alternatives to meeting future increases in baseload demand. Furthermore, in those regions projected to be still depending on oil- or natural gas-fired generation for baseload power in the 1990's, not just for supplying peak-load service a few hours each day, the on-schedule completion of some nuclear units could probably be cost-justified on the basis of displacing generation from those expensive fuels. Also, the adverse secondary effects of higher electricity prices on regional economic development and the balance-of-payments effects of higher oil imports must be considered.

A number of studies conducted in the past 5 years for utilities or Government agencies, including DOE, support a consensus that utility systems with heavy reliance on oil or natural gas as boiler fuels could lower the cost of electricity to their customers by placing in service nuclear or coal-fired capacity in excess of that needed for service reliability alone. Based on the latest NERC projections of fuel mix in 1990, this situation is almost certain to hold in New England, New York, Florida, the Southwest (especially Texas), and in California. Three units in the Base Case scenario and one unit in the Worst Case scenario are located in the regions mentioned above.

Opportunities for displacing electricity generated with oil or natural gas may not be limited to these four units, since electricity can be generated in some regions deep in nuclear and coal-fired capacity and exported to regions dependent on oil and gas fuels. Within this context, a unique situation currently exists with respect to the potential cancellation of three of four additional units undertaken by the Tennessee Valley Authority (TVA). Hartsville A1 and A2 and Yellow Creek 1 are quite advanced in construction, so it is unlikely that cheaper alternatives for baseload power exist if the units were to be completed on schedule.

The four units identified above as being sited in regions dependent on oil and natural gas (Seabrook 2, River Bend 2, South Texas 2, and Grand Gulf 2) are primarily investor-owned utilities with a smaller participation by public entities. In light of the poor financial condition of most investor-owned utilities, there must be considerable pressure to cancel these plants rather than further invest in them. This is particularly true for River Bend 2, which involves relatively little sunk investment.

In contrast to the situation faced by most investor-owned utilities, TVA is not encumbered by construction financing constraints to the same degree and could have less difficulty completing any or all of the units currently under construction. Four TVA units were recently cancelled because the additional capacity would not be needed before the late 1990's at the earliest. The annual costs of maintaining a construction restart capability for these plants, combined with the uncertainties shrouding the future economics of generating the needed power with the other technologies, made unattractive the option of mothballing these plants for so long a period.

TVA also considered completing the plants on schedule and selling the available power to other utilities until their own indigenous load grew sufficiently to absorb it, but for a variety of reasons -- economic, institutional, political, and legal -- no suitable buyers were found. This impasse was unfortunate because several contiguous regions, such as the Southwest Power Pool and the western sectors of the Southeastern Electric Reliability Council, could be short of capacity by the early 1990's, as well as prime candidates for displacement of oil- and gas-fired capacity from baseload service.

Appendix A

MAPS OF FEDERAL REGIONS
AND NORTH AMERICAN ELECTRIC RELIABILITY COUNCIL REGIONS

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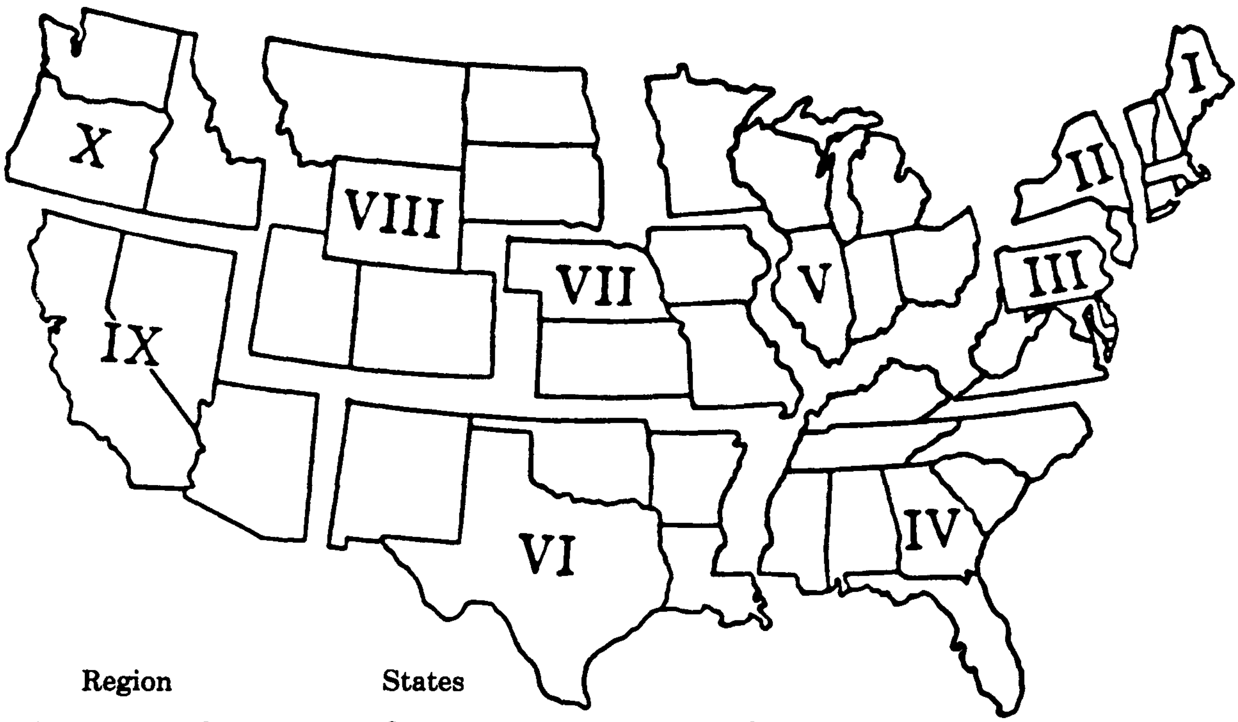
Appendix A

MAPS OF FEDERAL REGIONS AND NORTH AMERICAN ELECTRIC RELIABILITY COUNCIL REGIONS

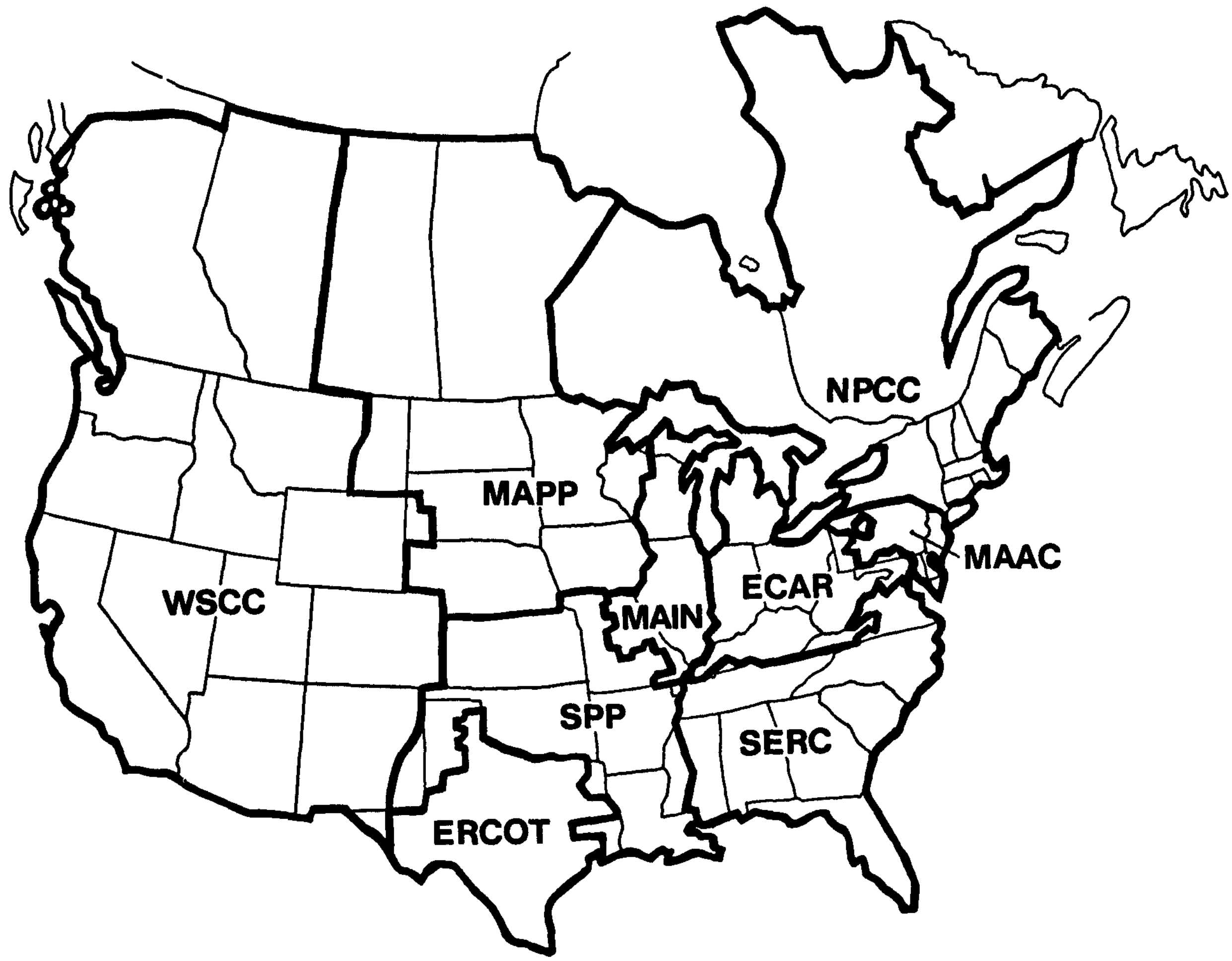
The maps in this appendix show the division of the United States into different regions, as designated by the Federal government (Figure A1) and by the North American Electric Reliability Council (NERC) (Figure A2). NERC was formed by the electric utility industry in 1968, with the objective of promoting reliability and adequacy of bulk power supply in the electric utility systems of North America. NERC consists of nine Regional Reliability Councils, encompassing virtually all of the power systems in the United States and Canada.

Figure A1. Federal Regions



	Region	States
I	New England	Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, Vermont
II	New York New Jersey	New Jersey, New York
III	Middle Atlantic	Delaware, District of Columbia, Maryland, Pennsylvania, Virginia, West Virginia
IV	South Atlantic	Alabama, Florida, Georgia, Kentucky, Mississippi, North Carolina, South Carolina, Tennessee
V	Midwest	Illinois, Indiana, Michigan, Minnesota, Ohio, Wisconsin
VI	Southwest	Arkansas, Louisiana, New Mexico, Oklahoma, Texas
VII	Central	Iowa, Kansas, Missouri, Nebraska
VIII	North Central	Colorado, Montana, North Dakota, South Dakota, Utah, Wyoming
IX	West	Arizona, California, Hawaii, Nevada
X	Northwest	Alaska, Idaho, Oregon, Washington

Figure A2. North American Electric Reliability Council Regions



ECAR
East Central Area Reliability Coordination Agreement

ERCOT
Electric Reliability Council of Texas

MAAC
Mid-Atlantic Area Council

MAIN
Mid-America Interpool Network

MAPP
Mid-Continent Area Power Pool

NPCC
Northeast Power Coordinating Council

SERC
Southeastern Electric Reliability Council

SPP
Southwest Power Pool

WSCC
Western Systems Coordinating Council

Note: The North American Electric Reliability Council (NERC) was formed by the electric utility industry in 1968 to promote the reliability and adequacy of bulk power supply in the electric utility systems of North America. NERC consists of nine Regional Reliability Councils encompassing virtually all of the power systems in the United States and Canada.

Source: North American Electric Reliability Council, Electric Power Supply and Demand, 1982-1991; Annual Data Summary Report for the Regional Reliability Councils of NERC, August 1982.

Appendix B

TVA COST AND SCHEDULE INFORMATION FOR
HARTSVILLE, PHIPPS BEND, AND YELLOW CREEK
NUCLEAR PLANTS

Appendix B

TVA COST AND SCHEDULE INFORMATION FOR HARTSVILLE, PHIPPS BEND, AND YELLOW CREEK NUCLEAR PLANTS

The following table (Table B1) shows information, provided by the Tennessee Valley Authority (TVA) in response to a request by J. A. Reyes Associates, on the current status of TVA's Hartsville, Phipps Bend, and Yellow Creek nuclear plants. Construction work on each of these plants has been deferred, as indicated in the table. The information shown was updated on July 26, 1982.

Table B1. Tennessee Valley Authority Cost and Schedule Information for Hartsville (HTN), Phipps Bend (PBN), and Yellow Creek (YCN) Nuclear Plants

Cost and Schedule Information	Nuclear Plant							
	HTN-A1	HTN-A2	HTN-B1	HTN-B2	PBN-1	PBN-2	YCN-1	YCN-2
Percent Complete	44	34	17	7	27	5	35	3
Expenditures as of June 1982 (Millions of Dollars)								
Expenditures Including Interest	890	501	356	292	711	260	776	248
Capitalized Interest (AFUDC)	70	38	23	19	41	8	41	8
Total	960	539	379	301	752	268	817	256
Additional Estimated Funds to Terminate Construction if Cancelled in June 1982 (Millions of Dollars)[a]								
Contract Payoffs	21	46	13	9	56	50	85	23
Site Restoration Cost[b] ..	12	3	3	3	12	3	12	3
Total	33	49	16	12	68	53	97	26
Original Cost Estimate (Millions of Dollars)[c]	350	290	430	355	880	720	1,045	855
Date of Estimate	1/72	1/72	1/72	1/72	1/75	1/75	1/75	1/75
Original Estimated Commercial Operation Date[d]	4/79	4/80	10/79	10/80	4/82	4/83	4/83	4/84
Cost Estimate Immediately Before Deferral Decision (Millions of Dollars)[c]	3,762	3,078	4,362	3,568	2,960	3,135	4,130	2,915
Date of Estimate	12/81	12/81	8/80	8/80	8/80	8/80	12/81	8/80
Estimated Commercial Operation Date Immediately Before Deferral Decision	4/91	4/92	4/95	4/96	2/89	4/94	10/90	4/93
Current Project Status[e] ...	D/R	D/R	D/I	D/I	D/I	D/I	D/R	D/I

[a]The TVA Board has made no decision to cancel any of the deferred nuclear units.

[b]Estimate reflects a minimum restoration effort, i.e., fencing, barricading entrance, grading for drainage, and removing salvageable equipment to storage. Duration of the restoration effort is assumed to be 12 months.

[c]Estimate includes capitalized interest (AFUDC) and is expressed in escalated dollars.

[d]No current estimates are available for deferred units, since no schedule is established.

[e]D/R = deferred with restart capability maintained. D/I = deferred indefinitely.

Source: Tennessee Valley Authority.

Appendix C

METHODOLOGY FOR QUANTIFYING THE ALLOCATION OF PROJECT ABANDONMENT COSTS

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Appendix C

METHODOLOGY FOR QUANTIFYING THE ALLOCATION OF PROJECT ABANDONMENT COSTS

Each specific regulatory treatment of abandonment costs imposes its own unique pattern of cost allocation among the three major groups involved. Through the use of present value analysis the distribution of these costs can be estimated from the annual incremental cash flows associated with each regulatory option. Although they can only be viewed as very rough approximations, such estimates provide useful insights into the relative sharing of the costs of aborted nuclear plants.

Approach

The methodological approach used in this study to derive the distribution of abandonment consists of the following steps:

- Determination of the respective discount rate applicable to each payer group
- Formulation of the incremental cash flows imposed on each major payer group by the regulatory treatment adopted
- Numerical evaluation of the cash flows and their present values.

The method employed here to quantify the present value of the utility's cash flows differs from that which is generally used (i.e., the textbook method) in that the company's weighted average after-tax cost of capital is not adopted as the discount rate. Instead, the Adjusted Present Value (APV) method, first proposed by Stewart Myers in 1974, is used.[1] The present value of the project is first evaluated as if it were financed entirely with equity capital. Then an adjustment is explicitly made to account for the effects of any other types of capital employed -- primarily debt financing, which creates income tax deductions that further increase a project's present value over that obtained using only equity financing.

The APV method offers the following important advantages over the classical textbook method:

- It need not be assumed that a project involves the same level of risk as the firm's total portfolio of projects determining its cost of capital.
- It need not be assumed that the project is financed in a manner which holds constant the ratio of the market value of the company's outstanding debt capitalization to the market value of its outstanding equity capitalization.

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[1]S. C. Myers, "Interactions of Corporate Financing and Investment Decisions -- Implications for Capital Budgeting," Journal of Finance, 29: 1-25, March 1974.

Relaxation of the latter constraint is particularly important because investor-owned electric utilities appear to hold constant their capitalization ratios on the basis of book (accounting) values -- not market values.

The independence of the capitalization ratio in the APV method is based on the well-known Modigliani-Miller (MM) hypothesis, which states that the present value of a project is independent of the amount of debt financing employed, exclusive of income tax effects.[2] This is alleged to be so because as the percentage of lower cost debt financing increases, the cost of the equity capital (and, to a lesser extent, the cost of the debt capital as well) increases correspondingly, such that the weighted average of the two costs remains constant. Although the MM hypothesis has been criticized for being based on the assumption of perfect capital markets, it is not clear to what extent real-world deviations from the perfect market assumption degrade the predictions based on it. A number of respected professors of finance accept the hypothesis as being reasonably valid over the ranges of debt financing generally employed by most companies.

Because the APV method requires calculation of the present value of the income tax savings created by interest payments, the utility's incremental cash flows associated with the cancelled nuclear plant must explicitly include such savings. These income tax savings are also included in the government's cash flows and in those of the utility's ratepayers during the years when the savings are no longer retained by the utility. This is further discussed below.

Discount Rates

Because they are most straightforward, the discount rates applicable to the government, i.e., to income tax revenues, are treated first. The treatment of discount rates applicable to the utilities' cash flows then follows as it builds on the results developed for income tax revenues. Finally, the most controversial discount rates are addressed -- those applicable to ratepayers.

Government Income Tax Revenues

The discount rates applicable to federal income tax revenues are relatively straightforward. The U.S. Treasury uses the proceeds of government security sales to manage the timing differences between the receipt of tax revenues and the outlays required to finance the government. Thus, alterations in the timing of tax revenues caused by the regulatory treatment of abandonment costs are accomodated by incrementally increasing or decreasing the sale of new government securities. Consequently, the yields on government securities, particularly 12-month Treasury bills, are the appropriate discount rate to use in calculating the present values of abandonment costs borne by Federal income taxpayers.

With respect to State and local income tax revenues, the appropriate discount rates are not so straightforward. While these political entitites are also likely to accomodate tax revenue timing differences through borrowing, most of this occurs through the use of local securities exempt from Federal income tax whose yields are significantly lower

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[2] F. Modigliani and M. H. Miller, "Corporate Income Taxes and the Cost of Capital: A Correction," American Economic Review, Vol. 53, June 1963.

than those offered on comparable U.S. government securities of comparable maturities. Furthermore, the tax-exempt yields do not fully reflect the opportunity costs to income taxpayers because implicit Federal subsidies are involved. Fortunately, the effect of nuclear plant cancellations on incremental state and local income tax revenues is small relative to their impact on Federal tax revenues. For this reason, the error introduced by applying the discount rates for Federal tax revenues to the tax revenues of state and local governments is acceptably small.

At this point it is useful to introduce the concept of the forward interest rate:

> The forward interest rate for year t is that interest rate which an investor will commit to today to loan money at the start of year t in return for receiving with certainty his principle plus interest calculated at that rate, at the end of year t.

The forward interest rate for year t is closely approximated by the yields the capital market anticipates will be offered on 12-month Treasury bills to be issued at the start of year t. For this reason the forward interest rates are the appropriate discount rates to use in calculating the present value of future income tax revenues.

If Treasury bills were traded more extensively in the future markets, the forward interest rates required here could be directly observed. At present the best estimates of these rates must be derived from the yield curve for Treasury bonds maturing at various dates in the future. These rates include risk premiums to account for uncertainty over future inflation rates. A method for deriving the forward interest rates is presented in Ibbotson and Sinquefield.[3] A somewhat refined version of this method is as follows.

The yield on a long-term bond maturing in n years is related to the forward interests occurring over that same time period by:

$$(1 + Y_n)^n = \prod_{i=1}^{n} (1 + F_i) \quad , \tag{C1}$$

where: Y_n = the yield on a bond maturing in n years, and
F_i = the forward interest rate in the future year i.

Given two bonds with maturities differing by exactly one year:

$$1 + F_n = \frac{\prod_{i=1}^{n} (1 + F_i)}{\prod_{i=1}^{n-1} (1 + F_i)} = \frac{(1 + Y_n)^n}{(1 + Y_{n-1})^{n-1}} \quad . \tag{C2}$$

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[3] R. G. Ibbotson and R. A. Sinquefield, Stocks, Bonds, Bills and Inflation: The Past and the Future, Financial Analysts Research Foundation, Charlottesville, Virginia, 1982.

Therefore, the annual forward interest rate n years into the future is:

$$F_n = \frac{(1 + Y_n)^n}{(1 + Y_{n-1})^{n-1}} - 1 \quad . \tag{C3}$$

Starting with the first and working forward, each of the forward interest rates can be obtained sequentially.

Before equation (C3) can be applied, some adjustments must be made for securities selling at a discount or a premium from the redemption (par) values. This is because the yield of a bond selling at a discount is biased downward, since part of its return is potentially taxable at the preferred long-term capital gains rate. Conversely, the yield of a bond selling at a premium is biased upward because the high interest payments are taxed as ordinary income. To neutralize the distorting tax effects on the yields of bonds selling below or above par value, "par-value-equivalent" portfolios were constructed, consisting of pairs of bonds for each future year such that the capital gain realized by the sale of one bond group would exactly offset the capital loss realized by the sale of the other bond group.

The method described above was applied to U.S. Treasury securities to estimate the forward interest rates from mid-1982 through mid-1992. The reference to mid-year was made for consistency with the cash flow assumptions employed in the model described earlier. Table C1 illustrates the process and presents the results.

While the adjustment made for security price discounts and premiums removed most of the instability from the estimates of forward interest rates, the results remain somewhat erratic, as Table C1 shows. This is probably because small, random deviations in the yields are magnified in the process of extracting the year-to-year differentials. For this reason, the geometric mean of the forward rates estimated for the years mid-1985 through mid-1992 was adopted as the discount factor for all years beyond mid-1985.

Utility

From the perspective of the utility, a nuclear plant cancellation can be viewed as just one more project undertaken by the corporation. In this case, the project's cash flows are the incremental revenues received through the amortization of the project's sunk costs. To calculate the present value of these revenues to the utility, the appropriate discount rate to apply to the expected future cash flows is that which is commensurate with the degree of risk that the actual cash flows will deviate from these expected values. A low risk project requires the use of a discount rate lower than that applicable to the utility's weighted average cost of capital; conversely, a high risk project requires the opposite.

There are four sources of risk associated with the recovery of a cancelled project's cost through amortization:

- Future kWh sales may not occur as forecasted.
- Future regulatory commission action may reduce or eliminate the amortization rate or amount.

Table C1. Estimation of Forward Interest Rates for Mid-1982 Through Mid-1992

12-Month Period	Maturity Date of Security	Price[a] (Dollars)	Security Yield (Percent)	Weight (Percent)	Portfolio Yield (Percent)	Forward Interest Rate[b] (Percent)
7/82-6/83 ...	6/83	[c]N/A	8.71	100	8.71	8.71
7/83-6/84 ...	6/84	989.7	9.48	87	9.53	10.36
	6/84	1066.3	9.85	13		
7/84-6/85 ...	6/85	1086.3	10.16	29	9.79	10.31
	8/85	965.6	9.64	71		
7/85-6/86 ...	5/86	943.8	9.76	30	10.29	11.18
	6/86	112.81	10.52	70		
7/86-6/87 ...	5/87	1119.1	10.55	58	10.24	10.04
	11/87	912.8	9.80	42		
7/87-6/88 ...	5/88	923.4	10.06	63	10.34	10.84
	7/88	113.06	10.83	37		
7/88-6/89 ...	5/89	969.4	9.87	85	10.01	8.05
	7/89	116.94	10.82	15		
7/89-6/90 ...	5/90	925.3	9.57	23	10.13	10.97
	8/90	1022.5	10.30	77		
7/90-6/91 ...	No below-par bond prices maturing this year					10.83
7/91-6/92 ...	5/92	1172.5	10.80	48	10.27	10.83
	8/92	839.4	9.79	52		

[a]Based on price quotations of November 3, 1982.

[b]Geometric mean of forward interest rates for the period 7/85 through 6/92 is 10.48 percent.

[c]Not Applicable; a Treasury bill was the basis for this yield, so no price adjustment was required.

- The utility's marginal income tax rate may change.

- Future inflation rates may deviate from the forecasted rates.

kWh Sales. Generally, the regulatory method used to recover abandonment costs is to add a surcharge to each kWh sold. The size of the surcharge is determined in a rate case and consists of dividing the annual cost to be amortized by kWh sales projected for that year. If actual sales fall short of this projection, so will the costs recovered; if actual sales are greater, costs will be over-recovered. Once these revenues are received, the regulatory commission cannot redress the deviations because doing so would constitute "retroactive ratemaking." Although this over/under-recovery risk is inherent in all revenue-producing projects the utility undertakes, most other projects involve some fixed operating costs; thus, a small percentage of change in revenue causes a larger percentage change in the project's net cash flow.

In contrast, the only operating costs involved in the amortization of nuclear plant abandonment costs are incremental income taxes, all of which are of a variable nature. Since annual kWh sales are not likely to deviate from the projected annual levels by more than a few percent during the period between rate cases, their impact on project cash flows introduces a very modest risk.

Future Regulatory Action. Future actions by the commission(s) having jurisdiction over the utility are a second source of risk. While it is certainly possible that a regulatory commission could modify or reverse the cost recovery decision made by a previous commission, such action is not very likely. Even when it does occur, the prohibition on retroactive ratemaking limits its impact on the utility. Thus, regulatory uncertainty adds only a small risk to previously settled cost recovery projects.

Change in Tax Rate. In the year of project cancellation the utility immediately reduces its net loss from the project by the income taxes saved by the write-off. However, in subsequent years the incremental revenues, received as a result of project amortization through higher rates, are fully taxable as income at the utility's marginal tax rate; thus, any unforeseen change in the marginal tax rate also changes the project cash flows. This could occur because of changes in tax laws (e.g., the reduction in the Federal corporate tax rate in 1981) or because of extraordinary losses which eliminate the utility's tax liability for some years, thereby reducing its marginal tax rate to zero. The latter of these two has the greater likelihood of occuring, but it is still small.

Future inflation rates. The last risk factor -- future inflation -- is clearly important, as demonstrated by the economic history of the last decade. Specifically, it is important because it erodes the real value of the cash flows the utility receives, since these revenues are fixed, nominal dollar flows reflecting the cancelled project's historical accounting costs. Inflation risk affects fixed income securities in the same way. Thus, the yields offered by long-term bonds include a risk premium to compensate for the uncertainty surrounding the inflation rates expected to occur over the term of the security, i.e., to compensate for the risk that the actual (ex post) future inflation rates may differ from the expected (ex ante) rates.

The above discussion suggests that the discount rate applicable to a utility project consisting of the after-tax cash flows received from the amortizing of abandonment losses is more risky than investments in long-term bonds of varying maturities extending ove the period of amortization, but less risky than the average project undertaken by the utility.

The appropriate discount rates will generally vary from year to year, reflecting both inflation expectations and the increased risk associated with estimating the inflation rates further into the future. This variation is captured in this analysis by basing the utility discount rates on the forward interest rates (estimated in the last section). A modest risk premium of 2 percentage points is added to these rates to compensate investors for the noninflation related risk factors discussed above. For comparison, studies done in recent years estimate the cost of capital for electric utilities to be about 3 to 4 percentage points above the yields on long-term government bonds.[4]

Ratepayers

Determining the appropriate discount rates to apply for ratepayers presents a nettlesome problem -- primarily because of the heterogeneous nature of the customer population with respect to their preferences regarding consumption vs. savings, risk avoidance, discretionary income, access to capital markets, interest rate spreads between borrowing and lending, and other factors. To avoid the quagmire of what the "correct" discount rate is, this analysis uses reasonable lower and upper bounds which bracket the weighted average equivalent rate appropriate for the entire ratepayer population. An intermediate case is also examined, in which the ratepayers' discount rates are assumed to be homogeneous and equal to the utility's discount rate.

The value adopted for the lower bound is the interest rate on passbook savings accounts. Since this rate is regulated by Federal law, it was easily obtained for the 1972-82 period and was conservatively projected to remain at 5.5 percent throughout the amortization period. Note that the forward interest rate estimates imply that the capital markets expect the general inflation rate to average about 7 to 9 percent per annum over the next 10 years, so there is little reason to expect these interest rates to drop in the foreseeable future.

The value adopted for the upper bound is 20 percent, because it roughly corresponds to the interest rates currently charged for consumer credit loans, particularly credit card balances. Because of the "stickiness" of these interest rates and the inflation forecast implied in current treasury bond yields, there is little reason to expect these rates to change.

That the two rates chosen for ratepayers bracket the weighted average, or equivalent, discount factor applicable to that group is further supported by the fact that virtually every electric utility likely to participate in a nuclear power plant derives over half of its Kwh sales from industrial, commercial, or governmental customers. The appropriate discount factor to apply to these classes of ratepayers is closely tied to (i.e., within a few percentage points of) the forward interest rates. As revealed in Table C2, the forward interest rates covering the next 10 years are well within the range of 5.5 to 20 percent.

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[4]For example, see Ernst and Ernst, Costs of Capital and Rates of Return for Industrial Firms and Class A & B Electric Utility Firms, Washington, D.C., June 1979.

Incremental Cash Flows

The cash flows of each of the payer groups are briefly described below in the context of three time periods:

- Planning and construction
- Year of cancellation
- Cost amortization.

The cash flow model employed assumes that all of the project's outlay costs occur in the 10-year period preceding the year of cancellation and that cancellation occurs in the middle of the eleventh year. Present values are all referenced to this cancellation date.

Planning and Construction

During the planning and construction period the utility's incremental cash flows consist of the following components:

U1: Planning and construction outlay costs

U2: Tax savings from investment tax credits created by the project and used to reduce the utility's income taxes (credit)

U3: Tax savings from deductions of interest payments on the project's debt financing (credit)

U4: Reduced returns earned due to the deduction from rate base of the deferred taxes created by the project.[5]

Note that the interest and the common and preferred stock dividend payments associated with the financing of the project are not included in the utility cash flows. Their effects are entirely accounted for by the choice of discount rate used in calculating the project's present value to the utility and by the accrual of Allowance for Funds Used During Construction (AFUDC), since the analysis assumes that the utility is not allowed to include its construction work in progress (CWIP) into the rate base.

Because of the aforementioned assumption regarding CWIP, ratepayers are affected during the construction period only by the following incremental cash flow components:

R1: Reduced returns earned due to the deduction from rate base of deferred taxes created by the project (credit)

R2: Tax savings due to the reduced returns (credit).

Note that although the income taxes referred to here are based on the utility's earnings, the ratepayers actually pay them (or, in the case of a tax saving, are relieved of paying them) because the ratemaking process treats income taxes as a cost of service item.

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[5]These deferred taxes occur because the tax savings from the debt financing of the planning and construction outlays are not flowed through to current ratepayers but are instead acccumulated for future amortization over the life of the completed project.

Finally, government income tax revenues are affected by the following components:

G1: Tax savings from investment tax credits created by the project and used to reduce the utility's income taxes

G2: Tax savings from deductions of interest payments on the project's debt financing

G3: Tax savings due to the reduced returns.

Cancellation Year

In the year the plant is cancelled the utility incurs a liability for prematurely cancelling unfulfilled contracts. Although this liability is neither fully paid nor fully determined for some months or years after the cancellation, this analysis assumes that the present value-equivalent of these costs is fully paid out at the time of plant cancellation. The salvage value of the plant and equipment is similarly treated even though the proceeds of such sales will be received over a period of months or years. Finally, the total cost outlays associated with the plant are written off as an extraordinary loss, thereby reducing the utility's income tax liability. For tax purposes, accrued AFUDC is not recognized as part of the plant cost; thus only cash outlays can be deducted.

Other cash flow components are as described above for the planning and construction period, with one exception. In theory, the tax savings from interest deductions should only be accrued as deferred taxes up to the date of cancellation. Thereafter these tax savings should be flowed through to the ratepayers; however, this analysis assumes that, due to regulatory lag, the tax savings in the cancellation year are entirely retained by the utility.

The utility's incremental cash flows in the cancellation year are:

U5: Contract cancellation costs

U6: Plant salvage value (credit)

U7: Tax saving from write-off of extraordinary loss (credit)

U8: Tax saving from deduction of interest payments on the project's debt financing (credit)

U9: Reduced return earned due to deferred taxes deducted from rate base.

In the year of cancellation, the ratepayer's cash flow components are:

R3: Reduced return earned due to deferred taxes deducted from rate base (credit)

R4: Tax saving due to the reduced return (credit).

Incremental reductions in income tax revenues lost in the cancellation year consist of the following:

G4: Tax saving from write-off of extraordinary loss

G5: Tax saving from deduction of interest payments on the project's debt financing

G6: Tax saving due to the reduced return.

Cost Amortization

The cash flow relationships developed here are sufficiently general to allow the use of any arbitrary length of amortization; however, the computer program written to quantify the costs is dimensioned to accommodate a maximum amortization period of 30 years. During the period of cost amortization, the utility recovers, through higher rates, the plant's abandonment cost net of the one-time tax saving realized on the write-off in the cancellation year. Over this same period, it amortizes to rates (i.e., refunds to ratepayers in equal annual installments) the investment tax credits and deferred income taxes which accumulated on the project prior to its cancellation. These two items partially offset the incremental revenues required from ratepayers to recover the abandonment cost. All of the utility's other cash flow components have been previously explained.

The utility's incremental cash flows during the period of cost amortization consist of the following components:

U10: After-tax cost amortization revenues (credit)

U11: Amortized investment tax credits

U12: Amortized deferred taxes

U13: Reduced returns earned due to deferred taxes deducted from rate base.

During the amortization period, the ratepayers' incremental cash flows are as follows:

R5: After-tax cost amortization revenues

R6: Amortized investment tax credits (credit)

R7: Amortized deferred taxes (credit)

R8: Income taxes on amortization revenues and investment tax credits

R9: Tax savings from deductions of interest payments on the project's debt financing (credit)

R10: Reduced returns earned due to deferred taxes deducted from rate base (credit)

R11: Tax savings due to reduced returns (credit).

Finally, governments' incremental income tax revenues during the amortization period are:

G7: Income taxes on the amortization revenues and investment tax credits (credit)

G8: Tax savings from deductions of interest payments on the projects' debt financing

G9: Tax savings due to reduced returns.

The symmetry of these cash flows, shown in Table C2, reveals that most of the incremental cash flows associated with the project represent transfer payments among the three groups. Thus, the only economic resource costs associated with the project are the cash outlays during planning and construction, U1, the cancellation costs, U5, and the salvage value, U6. The present value of these three items as of the date of cancellation equals the plant's abandonment cost borne by the utility and, ultimately, its investors.

The specific accounting equations for each of the cash flow components defined above are described in the following section.

Mathematical Description of Cash Flow Model

Planning and Construction Years

The first substantive calculation performed by the computer-based cash flow model consists of distributing the project's planning and construction expenditures, i.e., cash outlays excluding allowance for funds used during constructions (AFUDC), among the 10 years prior to cancellation. The underlying assumption is that the cash outlays in each of these years is a fixed percentage of the total cash outlays accumulated in prior years; thus:

$$OUTLAY_t = A \cdot \sum_{n=1}^{t-1} OUTLAY_n \quad , \qquad \text{(C4)}$$

where: $OUTLAY_t$ = cash outlays during year t of the planning and construction period, and
A = a constant.

The reader may recongnize equation (C4) as being the discrete approximation to exponential growth. This relationship was adopted because it offers a good fit to the cash outlay pattern assumed in the CONCEPT-5 model, which estimates the construction costs of nuclear and coal-fired steam power plants.[6]

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[6]C.R. Hudson II, CONCEPT-5 User's Manual, ORNL-5470, Oak Ridge National Laboratory, Oak Ridge, Tennessee; January 1979.

Table C2. Cash Flows Among Major Payer Groups for a Project Cancellation When Option 1 Cost Recovery is Employed[a]

Project Status	Payer Group: Utility	Ratepayer	Government
Construction ...	U1	--	--
	-U2	--	G1 (= U2)
	-U3	--	G2 (= U3)
	U4	-R1 (= -U4)	--
	--	-R2	G3 (= R2)
Cancellation ...	U5	--	--
	-U6	--	--
	-U7	--	G4 (= U7)
	-U8	--	G5 (= U8)
	U9	-R3 (= -U9)	--
	--	-R4	G6 (= R4)
Amortization ...	-U10	R5 (= U10)	--
	U11	-R6 (= -U11)	--
	U12	-R7 (= -U12)	--
	--	R8	-G7 (= -R8)
	--	-R9	G8 (= R9)
	U13	-R10 (= -U13)	--
	--	-R11	G9 (= R11)

[a]Cash flows are presented from a cost perspective; i.e., outflows are positive, inflows are negative.

Next, the cash flow model calculates the amount of construction work in progress (CWIP) and the AFUDC accrued at mid-year for each of the 10 planning/construction years and for the cancellation year. The following equations are employed:
For the first year (t=1):

$$AFDC_t = [(OUTLAY_t)/2] \cdot [(RAFDC_t)/4] \quad , \tag{C5}$$

and

$$CWIP_t = (OUTLAY_t/2) + AFDC_t \quad . \tag{C6}$$

For subsequent years (t=2 through t=11):

$$\begin{aligned} AFDC_t = {} & CWIP_{t-1} \cdot (RAFDC_{t-1} + RAFDC_t)/2 \\ & + [(OUTLAY_{t-1})/2] \cdot [(RAFDC_{t-1})/4 + (RAFDC_t)/2] \\ & + [(OUTLAY_t)/2] \cdot [(RAFDC_t)/4] \quad , \end{aligned} \tag{C7}$$

and

$$CWIP_t = CWIP_{t-1} + AFDC_t + (OUTLAY_{t-1})/2 + (OUTLAY_t)/2 \quad , \tag{C8}$$

where: $AFDC_t$ = AFUDC accrued from the mid-year of t-1 (or from the start of the project if t=1) to mid-year of t;

$RAFDC_t$ = AFUDC rate applicable in year t; and

$CWIP_t$ = Construction Work in Progress accumulated at mid-year in year t, including the addition of all AFUDC accrued up to that point in time.

Equations (C5) through (C8) are based on several simplifying assumptions which introduce minor inaccuracies into the calculation but yield acceptable approximations:

- Cash outlays in any year are uniformly distributed throughout that year.
- AFUDC is compounded annually at mid-year.
- The AFUDC rate is set at the start of each year and remains constant until reset.

The model calculates next the utility's income tax savings during the planning and construction years due to investment tax credits (ITC) and interest payments on the debt financing of the project. It is assumed that ITC are used in the same year they are earned, as progress payments are made to contractors, thus:

$$ITC_t = OUTLAY_t \cdot RITC_t \quad , \tag{C9}$$

where: ITC_t = the income tax reduction in year t due to the investment tax credits earned (and used) in that year, and

$RITC_t$ = the ITC rate applicable to capital outlays in year t.

Interest payments made in year t are estimated on the basis of the average value of the CWIP during the year, which in turn is approximated by the value of CWIP at mid-year:

$$INT_t = CWIP_t \cdot RINT_t \cdot RDEBT_t \quad , \tag{C10}$$

where: INT_t = interest paid during year t,

$RINT_t$ = interest rate on the debt financing the project in year t, and

$RDEBT_t$ = percent of the project CWIP financed by debt in year t.

The corresponding tax saving is then:

$$TAXSAVI_t = INT_t \cdot RTAX_t \quad , \tag{C11}$$

where: $RTAX_t$ = utility's marginal income tax rate in year t, including the effect of Federal, State, and local income taxes.

The tax saving, $TAXSAVI_t$, is normalized, i.e., retained by the utility in a deferred taxes account and used to pay income taxes in later years. Thus, the amount in this deferred tax account in year t is:

$$TAXDEF_t = \sum_{n=1}^{t-1} TAXSAVI_n \quad . \tag{C12}$$

The regulatory process prohibits the utility from earning a return on these funds; therefore, the deferred tax account is subtracted from the rate base, reducing the utility's return in year t as follows:

$$REDRTN_t = ROR_t \cdot TAXDEF_t \quad , \tag{C13}$$

where: ROR_t = rate of return allowed on the rate base in year t.

The reduced return to the utility also reduces its income taxes which are flowed through to rate payers; thus, the total decrease in revenue paid by ratepayers in year t is the sum of the two components:

$$\Delta REV_t = REDRTN_t + TXSAVR_t \quad , \tag{C14}$$

where:

$$TXSAVR_t = \Delta REV_t \cdot RTAX_t \quad . \tag{C15}$$

Thus,

$$TXSAVR_t = (REDRTN_t \cdot RTAX_t) / (1 - RTAX_t) \quad . \qquad (C16)$$

Based on the above equations, the cash outflows of the utility, ratepayers, and governments during planning and construction are shown below:

For utilities,

$$CASHF1_t = OUTLAY_t + REDRTN_t - TXSAVI_t - ITC_t \quad . \qquad (C17)$$

For ratepayers,

$$CASHF2_t = -REDRTN_t - TXSAVR_t \quad . \qquad (C18)$$

For governments,

$$CASHF3_t = TXSAVI_t + TXSAVR_t + ITC_t \quad . \qquad (C19)$$

Cancellation Year

In the year of cancellation the utility realizes its loss for accounting purposes by writing off the sunk cost of the plant in mid-year. Before income taxes, this cost is:

$$PTCOST = \sum_{n=1}^{10} (OUTLAY_n + AFDC_n) + CANCEL - SALVGE \quad , \qquad (C20)$$

where: PTCOST = pre-tax costs initially incurred by the utility in cancelling the project,

CANCEL = cost of cancelling incompleted contracts, and

SALVGE = salvage value of the project's components.

Since this cost write-off creates an income tax deduction, the utility receives a tax saving which partially offsets its loss. However, for tax purposes, accrued AFUDC is not recognized as a cost. Thus, the tax saving and associated after-tax cost is:

$$TXSAVL = (PTCOST - \sum_{n=1}^{10} AFDC_t) \cdot RTAX_{11} \quad , \qquad (C21)$$

and

$$ATCOST = PTCOST - TXSAVL \quad . \qquad (C22)$$

It is assumed that during the planning and construction period the utility uses short-term borrowings (e.g., lines of credit or "bridge" loans) for the debt-funded portion of the project. This was done primarily to simplify the calculation of the interest payments associated with the project in these years, since it avoids having to vintage the imbedded interest rates as they change from year to year. Also, much of the debt financing of construction projects is done with bank lines of credit to accommodate the disbursement funds on a progress payment basis.

At the start of the cancellation year it is assumed that short-term debt underlying the after-tax portion of the project is replaced with long-term debt which matures at the end of project amortization. The interest on this debt during the amortization year is thus:

$$INTRST = ATCOST \cdot RDEBT_{11} \cdot RINT_{11} \quad . \qquad (C23)$$

The corresponding tax saving is then:

$$TXSAVI_{11} = INTRST \cdot RTAX_{11} \quad . \qquad (C24)$$

The entire tax saving incurred in the cancellation year is assumed to be deferred because of regulatory lag. Thus:

$$TAXDEF_{12} = TAXDEF_{11} + TXSAVI_{11} \quad , \qquad (C25)$$

and

$$REDRTN_{11} = TAXDEF_{11} \cdot ROR_{11} \quad . \qquad (C26)$$

The cash outflows of the utility, ratepayers, and governments in the cancellation year are shown below.

For utilities,

$$CASHF1_{11} = CANCEL - SALVGE - TXSAVL + REDRTN_{11} - TXSAVI_{11} \quad . \qquad (C27)$$

For ratepayers,

$$CASHF2_{11} = -REDRTN_{11} - TXSAVR_{11} \quad , \qquad (C28)$$

$$TXSAVR_{11} = RTAX_{11} \cdot (REDRTN_{11} + TXSAVR_{11}) \quad , \qquad (C29)$$

and

$$CASHF2_{11} = (-REDRTN_{11})/(1 - RTAX_{11}) \quad . \qquad (C30)$$

For governments,

$$CASHF3_{11} = TXSAVL + TXSAVI_{11} + TXSAVR_{11} \quad . \qquad (C31)$$

Amortization years

Over the amortization period of N years, the cost components included in the incremental amortization revenues are as follows:

$$AMTITC = 1/N \cdot \sum_{n=1}^{10} ITC_n \quad , \tag{C32}$$

$$AMTCST = 1/N \cdot ATCOST \quad , \tag{C33}$$

$$AMTDTX = 1/N \cdot DEFTAX_{12} \quad , \tag{C34}$$

and

$$AMTREV_t = AMTITC + AMTCST + AMTDTX \quad . \tag{C35}$$

To these must be added the incremental income taxes to which the cost amortization gives rise:

$$TAXAMT_t = (AMTREV_t \cdot RTAX_t) / (1 - RTAX_t) \quad . \tag{C36}$$

In addition, the long-term debt financing of the project must be correspondingly amortized if the utility is to maintain a constant debt-equity ratio based on book values. This may be the result of bond repurchases in the open market or merely reallocating the debt to new projects. In either case, the impact of this on project cash flows is that the tax deductions from the interest payments on the remaining balance decrease linearly. While this approach potentially yields capital gains or losses on the bonds which are appropriately assigned to the cancelled project, the cash flow model ignores these effects since they are likely to be small.

At mid-year of amortization year t, the fraction of the unamortized balance remaining is given by:

$$UNAMRT_t = 1 - [(t - 12 + 0.5)/N] \quad . \tag{C37}$$

The corresponding tax saving is then:

$$TXSAVI_t = UNAMRT_t \cdot INTRST \cdot RTAX_t \quad . \tag{C38}$$

As the deferred tax account is amortized by the flow-through of AMTDTX:

$$TAXDEF_t = TAXDEF_{12} \cdot [1 - (t-12)/N] \quad . \tag{C39}$$

The reduced return resulting from the subtraction of this account from rate base is thus:

$$REDRTN_t = ROR_t \cdot TAXDEF_t \quad , \qquad \text{(C40)}$$

and

$$TXSAVR_t = (REDRTN_t \cdot RTAX_t) \ / \ (1 - RTAX_t) \quad . \qquad \text{(C41)}$$

The cash outflows of the utility, ratepayers, and governments during the amortization years are shown below.

For utilities,

$$CASHF1_t = -AMTREV_t + REDRTN_t \quad . \qquad \text{(C42)}$$

For ratepayers,

$$CASHF2_t = AMTREV_t - REDRTN_t + TAXAMT_t - TXSAVR_t - TXSAVI_t \quad . \qquad \text{(C43)}$$

For governments,

$$CASHF3_t = -TAXAMT_t + TXSAVR_t + TXSAVI_t \quad . \qquad \text{(C44)}$$

Present Value Calculations

Each of the cash outflows for years prior to cancellation ($t<11$) are compounded forward to the cancellation year using the respective discount rates for each ratepayer class, e.g., for $CASHF1_t$:

$$PVFAC1_t = \prod_{n=t}^{10} (1 + RDISC1_n) \quad . \qquad \text{(C45)}$$

$RDISC2_n$ and $RDISC3_n$ are similarly used for $CASHF2_t$ and $CASHF3_t$.

In a parallel fashion the cash outflows for the amortization years are discounted back to the cancellation year, e.g., for $CASHF1_t$:

$$PVFAC1_t = \prod_{n=11}^{t} (1 + RDISC1_n)^{-1} \quad , \qquad \text{(C46)}$$

and similarly for $CASHF2_t$ and $CASHF3_t$.

Finally, note that:

$$PVFAC1_{11} = PVFAC2_{11} = PVFAC3_{11} = 1 \quad . \qquad \text{(C47)}$$

Numerical Evaluation

The computer program described above was employed to perform the present value calculations. With this program, a hypothetical nuclear power plant cancellation was analyzed for varying amortization periods, ranging from 2 to 30 years. The analysis employed the following assumptions:

- The plant is cancelled in July 1983.
- Project sunk costs recorded in the cost accounts on the date of cancellation are $720 million (including $220 million in AFUDC).
- Additional contract cancellation costs of $100 million are incurred.
- A salvage value of $50 million is realized.
- The abandonment costs are amortized over N years (varying from 2 to 30) with no return earned on the unamortized balance.
- Deferred taxes accrued due to AFUDC are deducted from rate base and amortized over the N years.
- Accrued investment tax credits are amortized over the N years (i.e., "ratable flowthrough" option is employed).
- The utility's effective income tax rate is 48.7 percent through the entire period and includes the effects of Federal, state, and local taxes.

The relative allocation of costs obtained from this parametric analysis was presented earlier in Section 3.0 of this report. Detailed results for the 10-year amortization case are shown in Tables C3 through C8. Table C9 shows a detailed listing of the FORTRAN computer program used to perform the the calculations.

Table C3. Annual Cash Flows for a Utility Associated with a Hypothetical Nuclear Power Plant Cancellation

Year	Utility Outlay Costs and Revenues (Millions of Dollars)				
	Construction Outlays	Tax Savings from Debt Financing	Investment Tax Credit	Reduced Return Due to Deferred Taxes	AFDC Accrued Each Year
1	15.036	0.144	1.504	0.0	0.136
2	18.795	0.491	1.880	0.011	1.171
3	23.494	1.148	2.349	0.048	2.722
4	29.368	1.993	2.937	0.154	5.082
5	36.710	2.771	3.671	0.325	8.336
6	45.887	3.696	4.589	0.587	12.494
7	57.359	5.564	5.736	0.926	18.074
8	71.699	8.537	7.170	1.429	24.992
9	89.623	14.629	8.962	2.252	34.186
10	112.029	23.272	11.203	3.897	48.024
	Contract Cancellation Costs, Less Salvage		Tax Savings from Write-off		
11[a]	50.000	19.808	267.850	6.380	64.940
	Abandonment Cost Amortization	Deferred Tax Amortization	Accrued Investment Tax Credit Amortization		
12	50.215	7.215	5.000	7.576	--
13	50.215	7.215	5.000	6.980	--
14	50.215	7.215	5.000	6.349	--
15	50.215	7.215	5.000	5.682	--
16	50.215	7.215	5.000	4.978	--
17	50.215	7.215	5.000	4.239	--
18	50.215	7.215	5.000	3.463	--
19	50.215	7.215	5.000	2.651	--
20	50.215	7.215	5.000	1.804	--
21	50.215	7.215	5.000	0.920	--

[a]Year of cancellation.

Table C4. Annual Cash Flows for Ratepayers Associated with a Hypothetical Nuclear Power Plant Cancellation

	Ratepayer Revenue Requirements (Millions of Dollars)				
Year	Reduced Return Due to Deferred Tax	Income Tax on Reduced Return	Amortization Revenues	Income Tax on Amortization Revenues	Tax Savings from Debt Financing
1	0.0	0.0	0.0	0.0	0.0
2	0.011	0.010	0.0	0.0	0.0
3	0.048	0.046	0.0	0.0	0.0
4	0.154	0.146	0.0	0.0	0.0
5	0.325	0.308	0.0	0.0	0.0
6	0.587	0.557	0.0	0.0	0.0
7	0.926	0.879	0.0	0.0	0.0
8	1.429	1.357	0.0	0.0	0.0
9	2.252	2.138	0.0	0.0	0.0
10	3.897	3.700	0.0	0.0	0.0
11	6.380	6.057	0.0	0.0	0.0
12	7.576	7.192	38.000	36.074	18.818
13	6.980	6.627	38.000	36.074	16.837
14	6.349	6.027	38.000	36.074	14.856
15	5.682	5.394	38.000	36.074	12.875
16	4.978	4.726	38.000	36.074	10.895
17	4.239	4.024	38.000	36.074	8.914
18	3.463	3.288	38.000	36.074	6.933
19	2.651	2.517	38.000	36.074	4.952
20	1.804	1.712	38.000	36.074	2.971
21	0.920	0.873	38.000	36.074	0.990

Table C5. Annual Income Tax Revenues Associated with a Hypothetical Nuclear Power Plant Cancellation

Year	Foregone Income Tax Revenues (Millions of Dollars)				
	Investment Tax Credit	Tax Savings from Debt Financing	Reduced Return Due to Deferred Tax	Abandonment Cost Write-off	Amortization Revenues
1	1.504	0.144	0.0	0.0	0.0
2	1.880	0.491	0.010	0.0	0.0
3	2.349	1.148	0.046	0.0	0.0
4	2.937	1.993	0.146	0.0	0.0
5	3.671	2.771	0.308	0.0	0.0
6	4.589	3.696	0.557	0.0	0.0
7	5.736	5.564	0.879	0.0	0.0
8	7.170	8.537	1.357	0.0	0.0
9	8.962	14.629	2.138	0.0	0.0
10	11.203	23.272	3.700	0.0	0.0
11	0.0	19.808	6.057	267.850	0.0
12	0.0	18.818	7.192	0.0	-36.074
13	0.0	16.837	6.627	0.0	-36.074
14	0.0	14.856	6.027	0.0	-36.074
15	0.0	12.875	5.394	0.0	-36.074
16	0.0	10.895	4.726	0.0	-36.074
17	0.0	8.914	4.024	0.0	-36.074
18	0.0	6.933	3.288	0.0	-36.074
19	0.0	4.952	2.517	0.0	-36.074
20	0.0	2.971	1.712	0.0	-36.074
21	0.0	0.990	0.873	0.0	-36.074

Table C6. Allocations Among Major Payer Groups of Costs Associated with a Hypothetical Nuclear Power Plant Cancellation for a Ratepayer Discount of 5.0 to 5.5 Percent

	Project Cost Allocation Among Major Parties (Millions of Dollars)					
	Utility		Ratepayers		Government	
Year	Cash Outlays	Present Value	Cash Outlays	Present Value	Cash Outlays	Present Value
1 ...	13.389	38.435	0.0	0.0	1.648	3.616
2 ...	16.435	43.198	-0.021	-0.035	2.381	4.935
3 ...	20.046	48.155	-0.094	-0.145	3.543	6.839
4 ...	24.592	53.502	-0.300	-0.437	5.076	9.157
5 ...	30.592	60.069	-0.633	-0.873	6.750	11.498
6 ...	38.190	67.861	-1.145	-1.496	8.842	14.259
7 ...	46.985	75.672	-1.805	-2.236	12.179	18.403
8 ...	57.421	83.489	-2.786	-3.271	17.064	23.708
9 ...	68.284	89.148	-4.390	-4.886	25.729	32.404
10 ...	81.452	93.889	-7.597	-8.015	38.175	42.920
11[a] ...	-231.278	-231.278	-12.437	-12.437	293.715	293.715
12 ...	-30.424	-27.481	40.489	38.378	-10.064	-9.258
13 ...	-31.020	-24.937	43.630	39.200	-12.610	-10.511
14 ...	-31.651	-22.655	46.841	39.891	-15.191	-11.478
15 ...	-32.318	-20.563	50.123	40.460	-17.805	-12.175
16 ...	-33.022	-18.676	53.475	40.916	-20.454	-12.658
17 ...	-33.761	-16.972	56.898	41.265	-23.136	-12.957
18 ...	-34.537	-15.433	60.390	41.515	-25.854	-13.103
19 ...	-35.349	-14.041	63.953	41.672	-28.605	-13.120
20 ...	-36.196	-12.780	67.587	41.744	-31.391	-13.030
21 ...	-37.080	-11.637	71.291	41.736	-34.210	-12.851
Net Present Values	--	236.963	--	372.947	--	340.311

[a]Year of cancellation.

Table C7. Allocations Among Major Payer Groups of Costs Associated with a Hypothetical Nuclear Power Plant Cancellation for Ratepayer Discount Rates Equal to the Project Discount Rates

	Project Cost Allocation Among Major Parties (Millions of Dollars)					
	Utility		Ratepayers		Government	
Year	Cash Outlays	Present Value	Cash Outlays	Present Value	Cash Outlays	Present Value
1 ...	13.389	38.435	0.0	0.0	1.648	3.616
2 ...	16.435	43.198	-0.021	-0.056	2.381	4.935
3 ...	20.046	48.155	-0.094	-0.227	3.543	6.839
4 ...	24.592	53.502	-0.300	-0.653	5.076	9.157
5 ...	30.592	60.069	-0.633	-1.243	6.750	11.498
6 ...	38.190	67.861	-1.145	-2.034	8.842	14.259
7 ...	46.985	75.672	-1.805	-2.907	12.179	18.403
8 ...	57.421	83.489	-2.786	-4.050	17.064	23.708
9 ...	68.284	89.148	-4.390	-5.731	25.729	32.404
10 ...	81.452	93.889	-7.597	-8.757	38.175	42.920
11[a] ...	-231.278	-231.278	-12.437	-12.437	293.715	293.715
12 ...	-30.424	-27.481	40.489	36.572	-10.064	-9.258
13 ...	-31.020	-24.937	43.630	35.074	-12.610	-10.511
14 ...	-31.651	-22.655	46.841	33.528	-15.191	-11.478
15 ...	-32.318	-20.563	50.123	31.891	-17.805	-12.175
16 ...	-33.022	-18.676	53.475	30.243	-20.454	-12.658
17 ...	-33.761	-16.972	56.898	28.604	-23.136	-12.957
18 ...	-34.537	-15.433	60.390	26.986	-25.854	-13.103
19 ...	-35.349	-14.041	63.953	25.403	-28.605	-13.120
20 ...	-36.196	-12.780	67.587	23.863	-31.391	-13.030
21 ...	-37.080	-11.637	71.291	22.374	-34.210	-12.851
Net Present Values	--	236.963	--	256.444	--	340.311

[a]Year of cancellation.

Table C8. Allocations Among Major Payer Groups of Costs Associated with a Hypothetical Nuclear Power Plant Cancellation for a Ratepayer Discount of 20 Percent

	Project Cost Allocation Among Major Parties (Millions of Dollars)					
	Utility		Ratepayers		Government	
Year	Cash Outlays	Present Value	Cash Outlays	Present Value	Cash Outlays	Present Value
1 ...	13.389	38.435	0.0	0.0	1.648	3.616
2 ...	16.435	43.198	-0.021	-0.110	2.381	4.935
3 ...	20.046	48.155	-0.094	-0.406	3.543	6.839
4 ...	24.592	53.502	-0.300	-1.076	5.076	9.157
5 ...	30.592	60.069	-0.633	-1.890	6.750	11.498
6 ...	38.190	67.861	-1.145	-2.849	8.842	14.259
7 ...	46.985	75.672	-1.805	-3.743	12.179	18.403
8 ...	57.421	83.489	-2.786	-4.813	17.064	23.708
9 ...	68.284	89.148	-4.390	-6.321	25.729	32.404
10 ...	81.452	93.889	-7.597	-9.117	38.175	42.920
11[a] ...	-231.278	-231.278	-12.437	-12.437	293.715	293.715
12 ...	-30.424	-27.481	40.489	33.741	-10.064	-9.258
13 ...	-31.020	-24.937	43.630	30.299	-12.610	-10.511
14 ...	-31.651	-22.655	46.841	27.107	-15.191	-11.478
15 ...	-32.318	-20.563	50.123	24.172	-17.805	-12.175
16 ...	-33.022	-18.676	53.475	21.491	-20.454	-12.658
17 ...	-33.761	-16.972	56.898	19.055	-23.136	-12.957
18 ...	-34.537	-15.433	60.390	16.854	-25.854	-13.103
19 ...	-35.349	-14.041	63.953	14.874	-28.605	-13.120
20 ...	-36.196	-12.780	67.587	13.099	-31.391	-13.030
21 ...	-37.080	-11.637	71.291	11.514	-34.210	-12.851
Net Present Values	--	236.963	--	169.443	--	340.311

[a]Year of cancellation.

Table C9. Computer Program for Calculating the Present Values of Abandonment Costs Allocated Among Three Major Payer Groups

```
//JH3UZZZ1 JOB (6434,FOR,1,10),'ZEBU',TIME=(0,05)
//STEP1 EXEC PROC=FORTGCLG
//FORT.SYSIN DD *
C NAME OF PROGRAM: ZEBU
C AUTHOR: ROBERT REED
C DATE OF PROGRAM: OCTOBER 1982
C
      DIMENSION AFDC(11),RAFDC(11)
      DIMENSION TXSAVI(41),RTAX(41),RINT(41)
      DIMENSION REDRTN(41),ROR(41),CASHF1(41),CASHF2(41)
      DIMENSION CASHF3(41),RDISC1(41),RDISC2(41),RDISC3(41)
      DIMENSION PVFAC1(41),PVFAC2(41),PVFAC3(41),PV1(41)
      DIMENSION PV2(41),PV3(41),RITC(41)
      REAL ITC(11)
      REAL INTRST,INIBAL
      REAL NPV1,NPV2,NPV3
      DIMENSION RDEBT(41),OUTLAY(42),CWIP(42)
      DIMENSION AMTREV(41),TAXAMT(41),TXSAVR(41)
      DIMENSION SUBTOT(10)
C
C     READ INPUT DATA
C
C     READ RUN-SPECIFIC DATA
C
C     WRITE ECHO REPORT OF RUN-SPECIFIC DATA
C
      WRITE(6,50)
50    FORMAT(12X,'RECAPITULATION OF RUN-SPECIFIC INPUT DATA')
      READ(10,*,ERR=3000,END=2000) NCASES
      WRITE(6,70)NCASES
70    FORMAT(1H0,'NCASES = ',I3)
      READ(10,*,ERR=3000,END=2000) (RITC(I),I=1,11)
      WRITE(6,77) (I,RITC(I),I=1,11)
77    FORMAT(1H0,'RITC(',I2,')= ',F7.4)
      READ(10,*,ERR=3000,END=2000) (RINT(I),I=1,41)
      WRITE(6,78) (I,RINT(I),I=1,41)
78    FORMAT(1H0,'RINT(',I2,')= ',F7.4)
      READ(10,*,ERR=3000,END=2000) (RDISC1(I),I=1,41)
      WRITE(6,79) (I,RDISC1(I),I=1,41)
79    FORMAT(1H0,'RDISC1(',I2,')= ',F7.4)
      READ(10,*,ERR=3000,END=2000) (RDISC2(I),I=1,41)
      WRITE(6,80) (I,RDISC2(I),I=1,41)
80    FORMAT(1H0,'RDISC2(',I2,' )=',F7.4)
      READ(10,*,ERR=3000,END=2000) (RDISC3(I),I=1,41)
      WRITE(6,81) (I,RDISC3(I),I=1,41)
81    FORMAT(1H0,'RDISC3(',I2,')= ',F7.4)
C
C     INITIALIZE PLANT COUNT
```

ble C9. Computer Program for Calculating the Present Values of Abandonment Costs Allocated Among Three Major Payer Groups (continued)

```
C
       NCASE=0
 90    NCASE= NCASE +1
C
C      READ PLANT SPECIFIC DATA
C
       READ(10,*,ERR=3000,END=2000)CONEXP,AFUDC,CANCEL,
      1SALVGE,N,A
C
C      WRITE ECHO REPORT OF PLANT-SPECIFIC DATA
C
       WRITE(6,45) CONEXP,AFUDC,CANCEL,SALVGE,N,A
 45    FORMAT(F12.3,5X,F12.3,5X,F12.3,5X,F12.3,5X,I3,5X,F12.3)
       READ(10,*,ERR=3000,END=2000)(RAFDC(I),I=1,11)
       WRITE(6,82) (I,RAFDC(I),I=1,11)
 82    FORMAT(1H0,'RAFDC(',I2,')=',F7.4)
       READ(10,*,ERR=3000,END=2000)(RTAX(I),I=1,41)
       WRITE(6,83) (I,RTAX(I),I=1,41)
 83    FORMAT(1H0,'RTAX(',I2,')=',F7.4)
       READ(10,*,ERR=3000,END=2000)(ROR(I),I=1,41)
       WRITE(6,84)(I,ROR(I),I=1,41)
 84    FORMAT(1H0,'ROR(',I2,')=',F7.4)
       READ(10,*,ERR=3000,END=2000)(RDEBT(I),I=1,41)
       WRITE(6,85)(I,RDEBT(I),I=1,41)
 85    FORMAT(1H0,'RDEBT(',I2,')=',F7.4)
       WRITE(6,95)
 95    FORMAT('0')
       WRITE(6,91)
 91    FORMAT('0')
       WRITE(6,92)
 92    FORMAT('0')
       IF(N.LT.1) GO TO 4000
C
C      DISTRIBUTE TOTAL CONSTRUCTION OUTLAYS TO YEARS
C      IN THE CONSTRUCTION PERIOD.
C
       SUBTOT(10)=CONEXP
       SUM=0.0
C
       DO 100 I=1,10
           J=10-I+1
           OUTLAY(J)=A*SUBTOT(J)
           SUBTOT(J-1)=SUBTOT(J)-OUTLAY(J)
           SUM=SUM+OUTLAY(J)
 100   CONTINUE
       RATIO=CONEXP/SUM
       DO 150 I=1,10
           OUTLAY(I)=RATIO*OUTLAY(I)
```

Table C9. Computer Program for Calculating the Present Values of Abandonment Costs Allocated Among Three Major Payer Groups (continued)

```
150   CONTINUE
      OUTLAY(11)=0.0
C
C     CALCULATE THE AVERAGE CONSTRUCTION WORK IN PROGRESS
C     AFUDC ACCRUALS AND INVESTMENT TAX CREDITS FOR EACH
C     YEAR IN THE CONSTRUCTION PERIOD AND FOR THE
C     CANCELLATION YEAR.
C
      TOTITC=0.0
      TOTOUT=0.0
      TOTAFD=0.0
C
C     AFDC(I) IS ASSUMED TO BE COMPOUNDED AND ADDED
C     AT MID-YEAR I.
C
      AFDC(1)=(OUTLAY(1)*RAFDC(1))/8
      CWIP(1)=.5*OUTLAY(1)+AFDC(1)
      DO 200 I=1,10
          AFDC(I+1)=CWIP(I)*.5*(RAFDC(I)+RAFDC(I+1))+
     1    .5*OUTLAY(I)*(.25*RAFDC(I)+.5*RAFDC(I+1))+
     1    .5*OUTLAY(I+1)*.25*RAFDC(I+1)
          CWIP(I+1)=CWIP(I)+.5*(OUTLAY(I)+OUTLAY(I+1))
     1    +AFDC(I+1)
          ITC(I)=OUTLAY(I)*RITC(I)
          TOTITC=TOTITC+ITC(I)
          TOTOUT=TOTOUT+OUTLAY(I)
          TOTAFD=TOTAFD+AFDC(I)
200   CONTINUE
C
      TOTAFD=TOTAFD+AFDC(11)
C
C     DETERMINE YEARLY CASH FLOWS
C     DURING CONSTRUCTION PERIOD:
C
C     CALCULATE INCOME TAXES SAVED FROM DEDUCTABILITY
C     OF DEBT FINANCING.  ALSO, IT IS ASSUMED THAT
C     SHORT TERM FINANCING IS USED TO FUND CONSTRUCTION
C     AND INTEREST RATES ARE ADJUSTED ANNUALLY.
C     ALSO CALCULATE DEFERRED TAXES ACCRUED AND REDUCTIONS
C     IN ALLOWED RETURN DUE TO SUBTRACTING DEFERRED TAXES
C     TAXES FROM THE RATE BASE.
C
      TAXDEF=0.0
C
      DO 300 I = 1,10
C
```

Table C9. Computer Program for Calculating the Present Values of Abandonment Costs Allocated Among Three Major Payer Groups (continued)

```
              TXSAVI(I)=CWIP(I)*RDEBT(I)*RINT(I)*RTAX(I)
              REDRTN(I)=ROR(I)*TAXDEF
              TAXDEF=TAXDEF+TXSAVI(I)
C
C       FOR UTILITY:
C
               CASHF1(I)=OUTLAY(I)-TXSAVI(I)+REDRTN(I)-ITC(I)
C
C       FOR RATEPAYER:
C
               TXSAVR(I)=REDRTN(I)*RTAX(I)/(1.0-RTAX(I))
               CASHF2(I)=-REDRTN(I)-TXSAVR(I)
C
C       FOR TAXPAYER:
C
               CASHF3(I)=TXSAVI(I)+ITC(I)+TXSAVR(I)
C
300     CONTINUE
C
C       DETERMINE CASH FLOWS IN YEAR OF CANCELLATION.
C
C
C       CALCULATE PRE-TAX AND AFTER-TAX ABANDONMENT
C       COST TO UTILITY AT TIME OF CANCELLATION.
C
        PTCOST=CONEXP+AFUDC+CANCEL-SALVGE
        TXSAVL=(PTCOST-AFUDC)*RTAX(11)
        ATCOST=PTCOST-TXSAVL
C
C       IN CANCELLATION YEAR THE DEBT PORTION OF THE AFTER
C       TAX ABANDONMENT COST IS REFUNDED USING LONG TERM
C       BONDS WITH MATURITIES EQUAL TO THE PERIOD OF
C       AMORTIZATION.
C
        INTRST=ATCOST*RDEBT(11)*RINT(11)
        TXSAVI(11)=INTRST*RTAX(11)
C
C       TAX SAVINGS ARE ONLY DEFERRED IN FIRST HALF OF
C       YEAR WHILE AFUDC ACCRUES. HOWEVER, UTILITY
C       STILL RETAINS THESE SAVINGS;
C
        REDRTN(11)=ROR(11)*TAXDEF
        TAXDEF=TAXDEF+.5*TXSAVI(11)
        INIBAL=TAXDEF
```

Table C9. Computer Program for Calculating the Present Values of Abandonment Costs Allocated Among Three Major Payer Groups (continued)

```
C
C     FOR UTILITY:
C
      CASHF1(11)=CANCEL-SALVGE-TXSAVL-TXSAVI(11)+REDRTN(11)
C
C     FOR RATEPAYER:
C
      TXSAVR(11)=REDRTN(11)*RTAX(11)/(1.0-RTAX(11))
C
      CASHF2(11)=-REDRTN(11)-TXSAVR(11)
C
C     FOR TAXPAYER:
C
      CASHF3(11)=TXSAVL+TXSAVI(11)+TXSAVR(11)
C
C     DETERMINE CASH FLOWS DURING AMORTIZATION PERIOD
C
      LASTYR=N+11
C
C     CALCULATE COMPONENTS OF AMORTIZATION
C     REVENUES
C
      AMTITC=TOTITC/N
      AMTCST=ATCOST/N
      AMTDTX=INIBAL/N
C
      DO 350 I = 12,LASTYR
C
          AMTREV(I)=AMTCST-AMTDTX-AMTITC
          TAXAMT(I)=AMTREV(I)*RTAX(I)/(1.0-RTAX(I))
C
C
C     TAX SAVINGS FROM DEBT FINANCING ARE ENTIRELY FLOWED
C     THROUGH TO RATEPAYERS DURING AMORTIZATION PERIOD.
C     ALSO DURING THIS PERIOD THE DEBT IS RETIRED PRO
C     RATA FROM AMORTIZATION REVENUES. CAPITAL GAINS AND
C     LOSSES DUE TO BOND PRICES AT A PREMIUM OR DISCOUNT
C     ARE ASSUMED TO BE OF SECOND ORDER; THUS ARE
C     IGNORED.
C
          UNAMRT=1.0-((I-12+.5)/N)
          TXSAVI(I)=INTRST*UNAMRT*RTAX(I)
          TAXDEF=INIBAL*(1.0-(I-12.0)/N)
          REDRTN(I)=ROR(I)*TAXDEF
          TXSAVR(I)=REDRTN(I)*RTAX(I)/(1.0-RTAX(I))
C
```

Table C9. Computer Program for Calculating the Present Values of Abandonment Costs Allocated Among Three Major Payer Groups (continued)

```
C
C     FOR UTILITY:
C
C
            CASHF1(I)=-AMTREV(I)+REDRTN(I)
C
C     FOR RATEPAYER:
C
            CASHF2(I)=AMTREV(I)+TAXAMT(I)-REDRTN(I)-TXSAVR(I)-
     1      TXSAVI(I)
C
C
C     FOR TAXPAYER:
C
            CASHF3(I)=-TAXAMT(I)+TXSAVR(I)+TXSAVI(I)
C
350   CONTINUE
C
C     PRESENT VALUE FACTORS ARE DEFINED TO BE 1.0 IN YEAR OF
C     PLANT CANCELLATION.
C
      PVFAC1(11)=1.0
      PVFAC2(11)=1.0
      PVFAC3(11)=1.0
C
C     CALCULATE PRESENT VALUE FACTORS FOR CONSTRUCTION PERIOD.
C
      DO 400 J=1,10
            I=10-J+1
            PVFAC1(I)=(1.0+RDISC1(I))*PVFAC1(I+1)
            PVFAC2(I)=(1.0+RDISC2(I))*PVFAC2(I+1)
            PVFAC3(I)=(1.0+RDISC3(I))*PVFAC3(I+1)
400   CONTINUE
C
C     CALCULATE PRESENT VALUE FACTORS FOR AMORTIZATION PERIOD.
C
      DO 425 I =12,LASTYR
            PVFAC1(I)=PVFAC1(I-1)/(1.0+RDISC1(I))
            PVFAC2(I)=PVFAC2(I-1)/(1.0+RDISC2(I))
            PVFAC3(I)=PVFAC3(I-1)/(1.0+RDISC3(I))
425   CONTINUE
C
C     CALCULATE THE YEARLY CONTRIBUTIONS TO NET PRESENT VALUE
C     OF CASH FLOWS AND CUMULATIVE TOTALS.
C
      NPV1 =0.0
      NPV2 =0.0
      NPV3 =0.0
C
```

Table C9. Computer Program for Calculating the Present Values of Abandonment Costs Allocated Among Three Major Payer Groups (continued)

```
      DO 450 I =1,LASTYR
            PV1(I)=CASHF1(I)*PVFAC1(I)
            PV2(I)=CASHF2(I)*PVFAC2(I)
            PV3(I)=CASHF3(I)*PVFAC3(I)
            NPV1=NPV1+PV1(I)
            NPV2=NPV2+PV2(I)
            NPV3=NPV3+PV3(I)
450   CONTINUE
C
C     WRITE RESULTS:
C
      PRINT 1100
1100  FORMAT('1',25X,'ITC RATES,BOND INTEREST RATES,DISCOUNT ',
     1'RATES,PRESENT VALUE FACTORS')
      PRINT 1109
1109  FORMAT('0')
      PRINT 1115
1115  FORMAT('0')
      PRINT 1110
1110  FORMAT('0','YEAR',42X,'UTILITY',17X,'RATEPAYER',
     116X,'GOVERNMENT')
      PRINT 1116
1116  FORMAT('0')
      PRINT 1120
1120  FORMAT('0',10X,'INVESTMENT',5X,'UTILITY',10X,'DISCOUNT',2X,'PV'
     1,13X,'DISCOUNT',2X,'PV',13X,'DISCOUNT',2X,'PV')
      PRINT 1130
1130  FORMAT(' ',10X,'TAX CREDIT',5X,'BOND INTEREST',4X,'RATE',6X,
     1'FACTOR',9X,'RATE',6X,'FACTOR',9X,'RATE',6X,'FACTOR')
      PRINT 1140
1140  FORMAT('0')
      DO 1160 I=1,10
      WRITE(6,1150) I,RITC(I),RINT(I),RDISC1(I),PVFAC1(I),
     1RDISC2(I),PVFAC2(I),RDISC3(I),PVFAC3(I)
1150  FORMAT(' ', 1X,I3,10X,F7.4,3X,F7.4,10X,F7.4,3X,
     1F7.4,8X,F7.4,3X,F7.4,8X,F7.4,3X,F7.4)
1160  CONTINUE
      WRITE(6,1161)
1161  FORMAT('0')
      WRITE(6,1162) RITC(11),RINT(11),RDISC1(11),PVFAC1(11),
     1RDISC2(11),PVFAC2(11),RDISC3(11),PVFAC3(11)
1162  FORMAT('0',1X,'CANC.YR',6X,F7.4,3X,F7.4,10X,
     1F7.4 ,3X,F7.4,8X,F7.4,3X,F7.4,8X,
     1F7.4,3X, F7.4)
      PRINT 1165
```

Table C9. Computer Program for Calculating the Present Values of Abandonment Costs Allocated Among Three Major Payer Groups (continued)

```
1165  FORMAT('0')
      DO 1180 I=12,LASTYR
      WRITE(6,1170) I,RITC(I),RINT(I),RDISC1(I),PVFAC1(I),
     1RDISC2(I),PVFAC2(I),RDISC3(I),PVFAC3(I)
1170  FORMAT(' ',1X,I3,10X,F7.4,3X,F7.4,10X,F7.4,3X,F7.4,8X,
     1F7.4,3X,F7.4,8X,F7.4,3X,F7.4)
1180  CONTINUE
      WRITE(6,1195)
1195  FORMAT('1 ')
      WRITE(6,1196)
1196  FORMAT('0')
      WRITE(6,1200)
1200  FORMAT(' ',20X,'UTILITY OUTLAY COSTS AND REVENUES-$MILLIONS')
      WRITE(6,1202)
1202  FORMAT('0')
      WRITE(6,1204)
1204  FORMAT(' ','YEAR',10X,'CONSTRUCTION',6X,'TAX SAVINGS FROM',
     123X,'REDUCED RETURN DUE',5X,'AFDC ACCRUED')
      WRITE(6,1206)
1206  FORMAT(' ',14X,'OUTLAYS',11X,'DEBT FINANCING',13X,
     1'ITC',9X,'TO DEFERRED TAXES',7X,'EACH YEAR')
      WRITE(6,1208)
1208  FORMAT('0')
      DO 1215 I=1,10
      WRITE(6,1210) I,OUTLAY(I),TXSAVI(I),ITC(I),REDRTN(I),AFDC(I)
1210  FORMAT(1X,I3,10X,F10.3,10X,F10.3,10X,F10.3,10X,F10.3,10X,F10.3)
1215  CONTINUE
      WRITE(6,1218)
1218  FORMAT('0')
      WRITE(6,1220)
1220  FORMAT('0','CANCELN YR',3X,'CONTRACT CANCELN',24X,'TAX SAVINGS
     1')
      WRITE(6,1221)
1221  FORMAT(14X,'COSTS LESS SALVAGE',22X,'FROM WRITEOFF')
      WRITE(6,1222)
1222  FORMAT(' ')
      C1=CANCEL-SALVGE
      WRITE(6,1224) C1,TXSAVI(11),TXSAVL,REDRTN(11),AFDC(11)
1224  FORMAT('0',13X,F10.3,10X,F10.3,10X,F10.3,10X,F10.3,10X,F10.3)
      WRITE(6,1226)
1226  FORMAT('0')
      WRITE(6,1230)
1230  FORMAT('0','YEAR',10X,'ABANDONMENT',11X,'DEFERRED TAX',6X,
     1'ACCRUED ITC')
      WRITE(6,1232)
1232  FORMAT('0',17X,'COST',15X,'AMORTIZATION',6X,'AMORTIZATION')
      WRITE(6,1233)
```

Table C9. Computer Program for Calculating the Present Values of Abandonment Costs Allocated Among Three Major Payer Groups (continued)

```
 1233 FORMAT(14X,'AMORTIZATION')
      WRITE(6,219)
 219  FORMAT('0')
      DO 1235 I=12,LASTYR
      WRITE(6,1234)I,AMTCST,AMTDTX,AMTITC,REDRTN(I)
 1234 FORMAT('0',I3,10X,F10.3,10X,F10.3,10X,F10.3,10X,F10.3)
 1235 CONTINUE
      WRITE(6,1237)
 1237 FORMAT('0')
      WRITE(6,1250)
 1250 FORMAT(' ')
      WRITE(6,1252)
 1252 FORMAT(25X, 'RATEPAYER REVENUE REQUIREMENTS-$MILLIONS')
      WRITE(6,1254)
 1254 FORMAT('0')
      WRITE(6,1256)
 1256 FORMAT('0','YEAR',8X,'REDUCED RETURN DUE',3X,'INCOME TAX ON',
     17X,'AMORTIZATION',10X,'INCOME TAX ON',6X,'TAX SAVINGS FROM')
      WRITE(6,1258)
 1258 FORMAT(13X,'TO DEFERRED TAX',6X,'REDUCED RETURN',
     16X,'REVENUES',14X,'AMORT.REVENUES',5X,'DEBT FINANCING')
      WRITE(6,1260)
 1260 FORMAT('0')
      DO 1270 I=1,LASTYR
      T4=TXSAVI(I)
      IF(I.LE.11) T4=0.0
      IF(I.LT.12) AMTREV(I)=0.0
      IF(I.LT.12) TAXAMT(I)=0.0
      WRITE(6,1265) I,REDRTN(I),TXSAVR(I),AMTREV(I),TAXAMT(I),T4
 1265 FORMAT(1X,I3,10X,F10.3,10X,F10.3,10X,F10.3,10X,F10.3,10X,F10.3)
 1270 CONTINUE
      WRITE(6,1272)
 1272 FORMAT('0')
      WRITE(6,1274)
 1274 FORMAT('0')
      WRITE(6,1300)
 1300 FORMAT(' ')
      WRITE(6,1302)
 1302 FORMAT(25X,'FOREGONE INCOME TAX REVENUES-$MILLIONS')
      WRITE(6,1304)
 1304 FORMAT('0')
      WRITE(6,1306)
 1306 FORMAT(1X,'YEAR',13X,'ITC',11X,'TAX SAVINGS FROM'
     1,6X,'REDUCED RETURN',8X,'ABANDONMENT',10X,'AMORTIZATION')
      WRITE(6,1308)
 1308 FORMAT(32X,'DEBT FINANCING',8X,'ON DEFERRED TAX',6X
     1,'COST WRITEOFF',11X,'REVENUES')
      WRITE(6,1310)
```

ble C9. Computer Program for Calculating the Present Values of Abandonment Costs Allocated Among Three Major Payer Groups (continued)

```
 1310 FORMAT('0')
      DO 1325 I = 1,LASTYR
      T1=0.0
      T2=0.0
      T3=ITC(I)
      IF(I.EQ.11) T1=TXSAVL
      IF(I.GT.11) T2=-TAXAMT(I)
      IF(I.GE.11) T3=0.0
      WRITE(6,1350)I,T3,TXSAVI(I),TXSAVR(I),T1,T2
 1350 FORMAT(1X,I3,10X,F10.3,10X,F10.3,10X,F10.3,10X,F10.3,10X
     1,F10.3)
 1325 CONTINUE
      WRITE(6,1400)
 1400 FORMAT('0')
      WRITE(6,1402)
 1402 FORMAT('0')
      WRITE(6,1470)
 1470 FORMAT('0')
      WRITE(6,1480)
 1480 FORMAT('0')
      PRINT 1495
 1495 FORMAT(' ',25X,'PROJECT COST ALLOCATION AMONG MAJOR PARTIES
     1-$MILLIONS')
      WRITE(6,1496)
 1496 FORMAT('0')
      WRITE(6,1505)
 1505 FORMAT('0')
      PRINT 1510
 1510 FORMAT('0','YEAR',27X,'UTILITY',31X,'RATEPAYERS'
     1,16X,'GOVERNMENT')
      WRITE(6,1511)
 1511 FORMAT('0')
      PRINT 1520
 1520 FORMAT('0',25X,'CASH',7X,'PRESENT',22X,'CASH',
     18X,'PRESENT',8X,'FOREGONE',4X,'PRESENT')
      PRINT 1530
 1530 FORMAT(' ',25X,'OUTLAYS',6X,'VALUE',21X,
     1'OUTLAYS',6X,'VALUE',11X,'REVENUES',4X,'VALUE')
      WRITE(6,1551)
 1551 FORMAT('0')
      DO 1550 I=1,10
      WRITE (6,1540) I,CASHF1(I),PV1(I),CASHF2(I),PV2(I),CASHF3(I),
     1PV3(I)
 1540 FORMAT(1X,I3,18X,F10.3,2X,F10.3,18X,F10.3,2X,
     1F10.3,6X,F10.3,2X,F10.3)
 1550 CONTINUE
      WRITE(6,1555)
```

Table C9. Computer Program for Calculating the Present Values of Abandonment Costs Allocated Among Three Major Payer Groups (continued)

```
1555 FORMAT('0')
     WRITE (6,1560) CASHF1(11),PV1(11),CASHF2(11),PV2(11),
    1CASHF3(11),PV3(11)
1560 FORMAT('0',1X,'CANCELLATION YEAR',3X,F10.3,
    12X,F10.3,18X,F10.3,2X,F10.3,6X
    1F10.3 ,2X,F10.3)
     PRINT 1570
1570 FORMAT('0')
     DO 1600 I=12,LASTYR
     WRITE (6,1580) I,CASHF1(I),PV1(I),CASHF2(I),PV2(I),
    1CASHF3(I),PV3(I)
1580 FORMAT(' ',1X,I3,17X,F10.3,2X,F10.3,18X,F10.3,2X,
    1F10.3,6X,F10.3,2X,F10.3)
1600 CONTINUE
     WRITE(6,1700)
1700 FORMAT('0')
     WRITE(6,1900) NPV1,NPV2,NPV3
1900 FORMAT(1X,'NET PRESENT VALUES',15X,F10.3,30X,F10.3,18X,F10.3)
     WRITE(6,1910)
1910 FORMAT('0')
     IF(NCASE.LT.NCASES) GO TO 90
     STOP
2000 WRITE(6,2010)
2010 FORMAT(1H,'READ ERROR: END OF FILE FOUND')
     STOP
3000 WRITE(6,3010)
3010 FORMAT(' ','READ ERROR IN TRANSMISSION.')
4000 WRITE(6,4010)
4010 FORMAT(' ','READ ERROR: AMORTIZATION PERIOD LESS THAN ONE')
C
     STOP
     END
```


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