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STATE REGULATORY POLICIES FOR PRIVATELY OWNED ELECTRIC UTILITIES IN 1981

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UNIVERSITY RESEARCH GROUP ON ENERGY

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The authors were all at Cornell University when this study was undertaken. Hindman was a Research Specialist, and Chapman is a Professor of Resource Economics while Cole is a Graduate Research Assistant.

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I. INTRODUCTION

A. The University Research Group on Energy

The data reported here were collected to provide state-specific financial and economic parameters for the analysis of the effect of air pollution control policies on utilities and their customers. Since there has been considerable interest in these statistics, this report provides the information gathered.

The work is part of the University Research Group on Energy's analysis of electric utilities, air pollution emissions, and control. The Group has, as principal investigators, James Stukel (project director) and Clark Bullard at the University of Illinois, Ed Rubin and Sarosh Talukdar at Carnegie-Mellon University, and Timothy Mount and Duane Chapman at Cornell University.[1] The areas of responsibility are coordination and system integration (Urbana), capacity planning (Urbana), coal supply (Urbana), pollution control and emissions (Carnegie-Mellon), plant operations and dispatching (Carnegie-Mellon), demand and conservation (Cornell), and finance (Cornell).

The major objective of the Group is to develop an integrated, annually recursive simulation model which can be used by the Environmental Protection Agency in its acid rain research and policy analysis programs.

This report is representational rather than inferential. State practices and data are reported here as gathered for use in the simulation model. Analysis will be the domain of future work.

These data do not supplant the continuing efforts of the National Association of Regulatory Utility Commissioners or of investment analysis groups. It must be emphasized that the data are collected for use in a computer simulation model, and are issued here to provide these data to interested persons and organizations.[2]

The data were collected and analyzed by Sally Hindman with the assistance of Kathleen Cole in technical areas, and under the supervision of Duane Chapman. The report is prepared by Hindman and Chapman.

B. State Regulatory Practices and Air Pollution

In a related publication, Kathleen Cole studies "Financial and Regulatory Factors Affecting the State and Regional Economic Impact of Sulfur Oxide Emissions Control."[3] While Cole's work explores the implications of regulation, the significance of the economic environment as it affects the impact of air pollution policies is evident with a simple example.

Consider a hypothetical Consolidated Electric Corporation. The Corporation has 2,000 MW of coal capacity, and is operating at an average 69% capacity utilization. With an average 9% energy loss, it generates 12.1 billion kWh and sells 11 billion kWh annually.

Its capacity is entirely sold to retail customers. Although demand is declining slightly, the company is in a sound position with respect to fully utilized plant.

Now suppose it has been required to install retrofit flue gas desulfurization facilities at an average current-dollar cost of $175 per kW, and that this is the last year of a three-year construction program. Payment is made to the contractor as the work concludes.

Variations in state regulatory practice will have a considerable impact on the effects of pollution control investment on utility economics and customers. In this example, states are categorized as "A" states and "F" states according to the relative favorability of their regulatory climates. "A" states are those deemed most favorable toward companies from the standpoint of investor/lender evaluators. "F" states' regulatory climates are considered least favorable. Many investment companies rank state regulatory commissions in a manner analogous to their evaluation of bond quality. Just as a good bond rating indicates a judgment that default on bond payment liabilities is improbable, so a good state rating indicates that the evaluator expects the regulatory commission to allow reasonable or high earnings for shareholders.

An "A" state is likely to use one or more of these policies: fair value inflation adjustment of rate base, construction work in progress (CWIP) in the rate base, a high rate of return, and full normalization of tax benefits.

At the other position, an "F" state would be likely to use original cost, allowance for funds used during construction (AFUDC) with no rate base CWIP, a low rate of return and flow-through of tax benefits. Such variations are evident in following sections of this paper.

The regulatory data in Table 1 give one possible representation of these contrasting policies. The "A" state gives a 30% inflation adjustment to net plant in service and allows full pollution control CWIP in the rate base. In this state, Consolidated Electric has a \$1.560 billion rate base without the FGD (flue gas desulfurization) system, and \$1.910 billion with the system. Depreciation is being changed to an economic depreciation basis in this year and is assumed to be one-fifteenth of the rate base value of plant in service, or \$104 million. Allowed return on rate base is 12%, a value appropriate to mid-1981.

This state follows full normalization, and bases its tax allowance on

Table 1. Regulatory Data (million dollars), Third Year of Three-year FGD Installation Period

	The "A" State		The "F" State	
	Without FGD Investment	With FGD investment	Without FGD Investment	With FGD Investment
Plant in Service, Original Cost	1700	1700	1700	1700
Accumulated Depreciation	500	500	500	500
Net Plant in Service, Original Cost	1200	1200	1200	1200
Inflation Adjustment	360	360	0	0
Pollution Control Cost	0	350	0	350
Pollution Control CWIP in Rate Base	0	350	0	0
AFUDC for Income Statement	0	0	0	32
Rate Base	1560	1910	1200	1200
Allowed Return on Rate Base, %	12%	12%	8%	8%
Amount of Allowed Return	187	229	96	96
Depreciation for Revenue Allowance	104	104	40	40
Depreciation for Tax Allowance	40	40	120	120
Tax Allowance	146	166	-54	-135
Operating Expense	300	300	300	300
Cost of Service Revenue	737	799	382	301
Average Price per kWh	6.7¢	7.3¢	3.5¢	2.7¢

Table 2. Income Statement Data (million dollars),
Third Year of Three-year FGD Installation period

	The "A" State		The "F" State	
	Without FGD Investment	With FGD Investment	Without FGD Investment	With FGD Investment
Revenue	737	799	386	301
Operating Cost				
Operating expense	300	300	300	300
Depreciation	40	40	40	40
Income tax on statement	146	166	-17	-63
(actual paid)	(109)	(94)	(-54)	(-135)
(deferred)	(37)	(37)	(37)	(37)
(credit)	(0)	(35)	(0	(35)
Total Operating Cost	486	506	323	277
Operating Income	251	293	59	24
Other Income				
Investment Credit	0	35	0	35
AFUDC - equity	0	0	0	19
Total Other Income	0	35	0	54
Income before Interest Charges	251	328	59	78
Interest Charges				
AFUDC - debt	0	0	0	(13)
Interest Payment	80	98	80	98
Total Interest Charges	80	98	80	85
Net Income	171	230	-21	-8
Adjusted Net Income (actual tax, no AFUDC)	208	267	16	30

normal straight line depreciation. Consequently, the tax allowance is $145 million with no FGD and $166 million with the system.[4] As part of its normalization policy, the state determines its tax allowance without reference to the investment tax credit.

Of course, this simplifies the tax treatment. Most normalization states will, in succeeding years, reduce the rate base by the amount of tax benefits which have accrued to the corporation. Since Tables 1 and 2 deal only with a single year, it may be assumed that this aspect of normalization becomes operative in subsequent years.

Operating expense is a constant $300 million in all cases. Cost of service revenue is the sum of allowed return, allowed depreciation, the tax allowance, and operating expenses. The result is allowed revenue of $736 million without FGD and $799 million with the system. Customer cost rises from 6.7 ¢/kWh to 7.3 ¢/kWh.

The "F" state is rather less helpful in providing increased revenue or satisfactory revenue. It gives no inflation adjustment or pollution control CWIP in the rate base. (It does, however, allow a 9% AFUDC on the pollution investment cost. In the following year, this $32 million would be added to the rate base when placed in service. It will also appear below in this year's income statement.) Rate base totals $1.2 billion with or without the FGD installation. The allowed rate of return is a much lower 8%. Depreciation in the cost of service calculation is normal straight line depreciation.

In the "F" state tax policy, all tax benefits are flowed-through. The depreciation figure in the tax allowances is identical to actual depreciation for tax purposes. The tax allowance is negative: -$54 million without FGD and -$135 with FGD[5]. The large difference in the tax allowance arises from two factors: the investment tax credit and interest payments. This is discussed below. It should be emphasized that the "F" state requires the tax allowance to equal the tax actually paid.

Operating expense remains the same $300 million.

Now, cost of service revenue is $382 million without FGD and $301 million with FGD. For the "F" state, the tax benefits are all passed on immediately to customers. This means that, in the last year of installing FGD when--in this illustration--payment is made, the tax benefits are large enough to reduce tax payments below zero. Theoretically, negative tax payments could be flowed-through to customers in several ways. The use of carry-back provisions may allow Consolidated Electric to re-estimate previous years' tax returns to obtain refunds. Alternatively, certain new tax leasing provisions might permit the tax benefits to be sold. Third, if Consolidated Electric is an operating subsidiary of a utility holding company, the benefits from Consolidated can shelter income from other companies operated by the holding company.

In reality, most flow-through commissions would adopt some form of modified normalization in the face of vary large negative tax allowances. However, as Table 1 indicates, tax benefits from investment are so large that flow-through can reduce revenue requirements in very early years.

Note the change in average customer price: in this year, the customer price is actually reduced by the FGD installation. (Of course, in later years, the price will be higher. This is explained below.)

The illustration makes the point needed. Given the same physical assumptions and purchase costs, regulatory policies in the "F" state cause customer prices to be one-half the prices in the "A" state. Further, the $350 million paid for FGD increases price in the "A" state, but, because of the tax benefits captured for customers, the FGD cost reduces customer price in the "F" state.

But, the advantage gained by customers is at a serious cost to Consolidated Electric. Net income is negative in the "F" state. Adjusting net income so that tax expense is actual tax paid and excluding AFUDC still leaves net income unacceptably low. This is of course expected, and explains why many states changed policy in 1980-82.

Perhaps the surprise is that the $350 million FGD adds a positive amount to net income in both states for this specific year. Yet, since it is of course the purpose of fair regulation to increase the magnitude of net income to reward greater useful shareholder investment, this is after all expected.

It must be emphasized that Tables 1 and 2 are for a specific year. The time paths of customer cost and net income varies considerably for normalized and flow-through accounting.

Figure 1 shows that customer prices are much higher with normalization in early years, but, as tax benefits are returned to consumers over the lifetime of a facility, normalization customer charges are less over most of a facility's life. Although Figure 1 is based upon a nuclear plant, similar analysis of a coal facility with FGD gives similar results.

Figure 2 shows a tax and profit analysis for a coal plant with FGD over the construction and operating periods. Normalization actually requires the

FIGURE I. AVERAGE PRICES WITH FLOW-THROUGH AND NORMALIZATION REGULATION (Hypothetical Nuclear Plant, 1980 dollars)

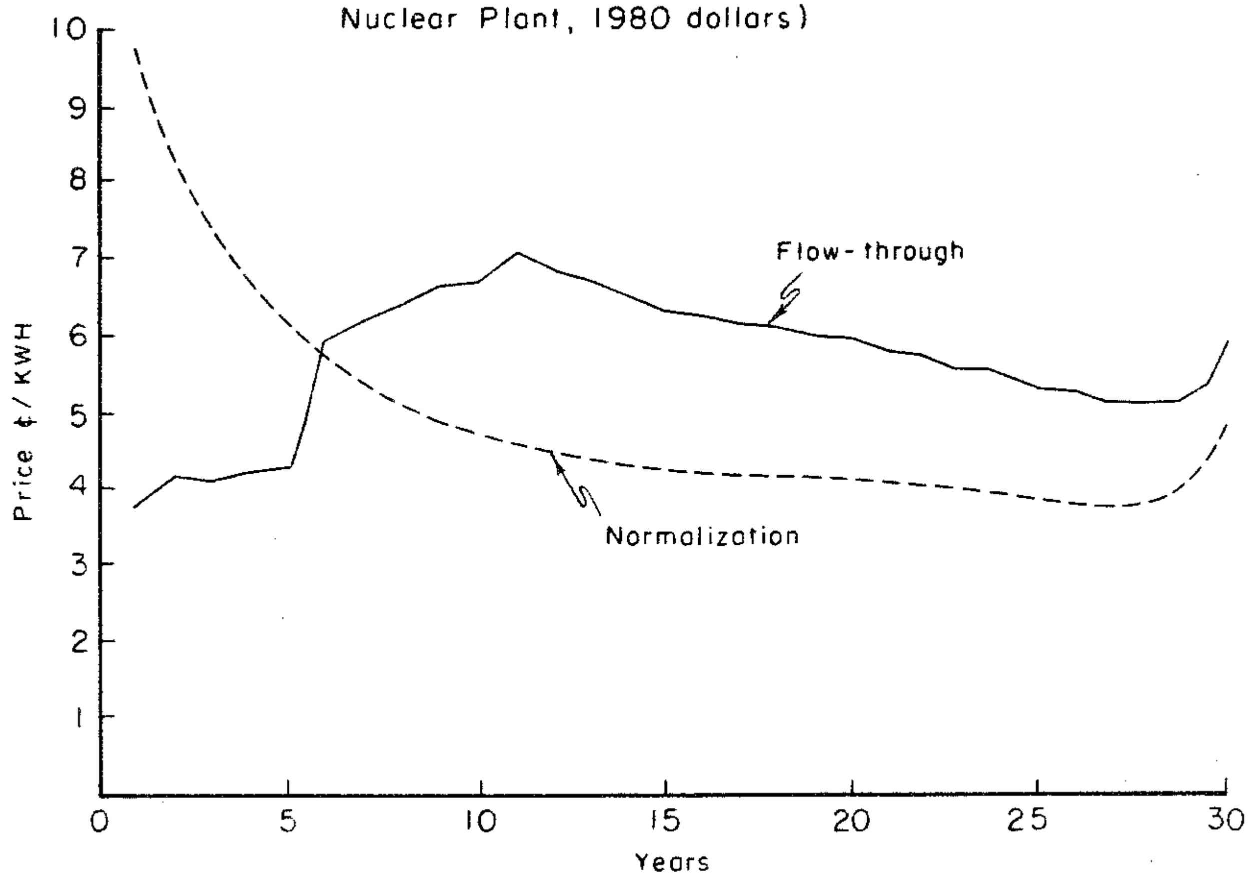
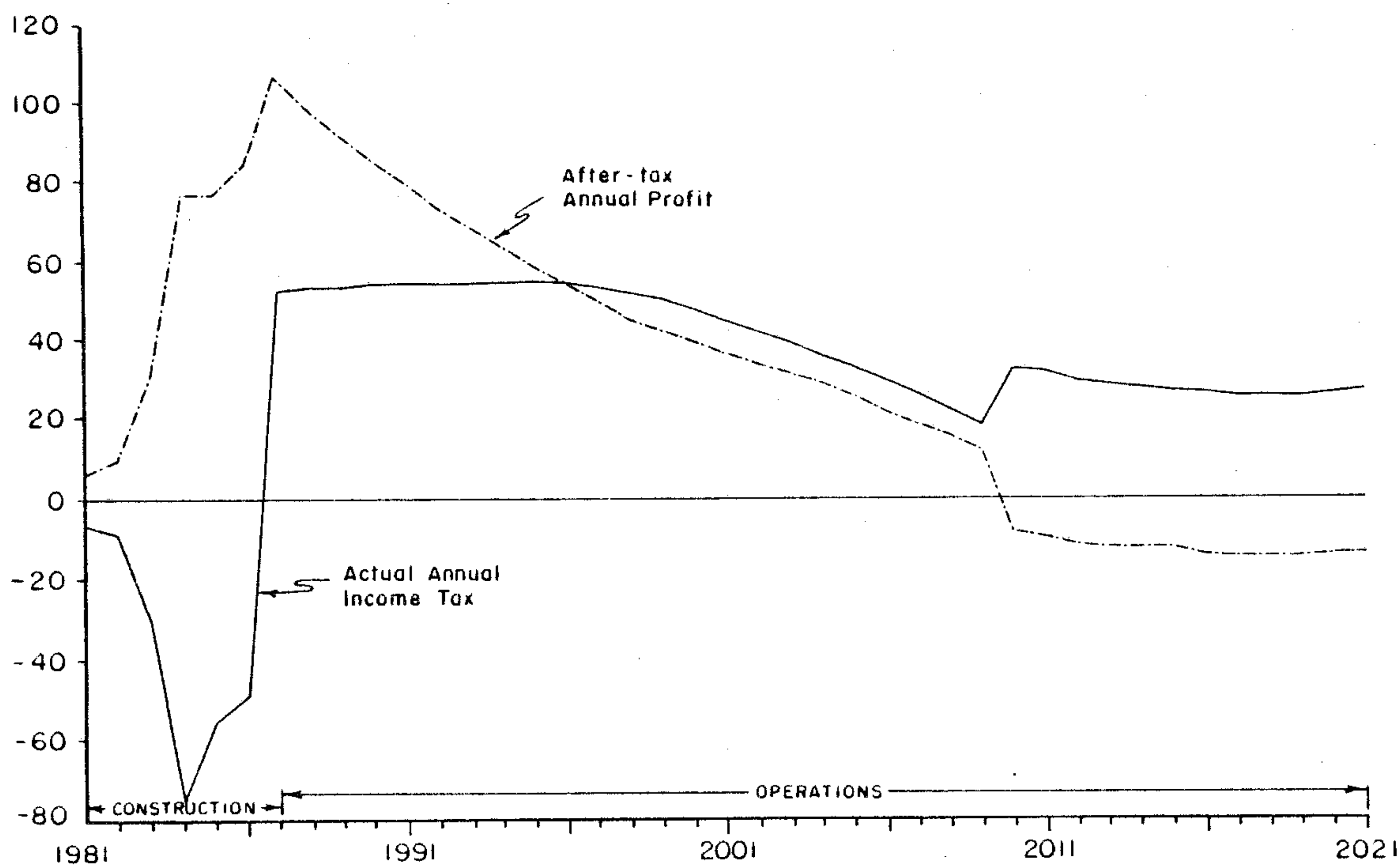


FIGURE 2. ANNUAL TAXATION AND PROFIT: REPRESENTATIVE PENNSYLVANIA COAL PLANT ($ MILLIONS)



plant to operate at an after-tax loss in the last third of its operating period.

The Economic Recovery Tax Act of 1981 further increases tax benefits for new power plants, but requires those benefits to be wholly normalized.[6] The 1982 Tax Act slightly modifies the accelerated depreciation-investment tax credit provisions of the 1981 Act, but leaves intact the statutory requirement of normalization as a precondition for new tax benefits.

The hypothetical example used here assumed that, at a cost of $350 million, flue gas desulfurization equipment was retrofitted to 2,000 MWe of existing coal capacity. Further, assume that the company uses 5.8 million tons of 2% sulfur coal. This yields 232,000 tons of sulfur oxide at a rate of 3.65 lb $SO_2/\overline{M}Btu$. The FGD system is 90% effective, reducing emissions to 23.2 thousand tons of SO_2. While the focus of this report is financial practices in the states as they influence the financial impact of air pollution policies, it should be remembered that one of the purposes of air pollution control is, simply, to reduce sulfur emissions.

In future work the URGE group will utilize the Advanced Utility Simulation Model to study forms of air pollution policy, examining the interaction of costs, finance, emissions, and demand over a 20 or 30 year period. Financial impact will be examined through the Cornell financial model which will incorporate the knowledge and data acquired through this report. Again, reference is made to the Cole analysis cited earlier which was prepared for the Congressional Office of Technology Assessment.

C. Questionnaire and Methodology

The questionnaire (Appendix A) investigates items allowed in the rate base, rates of return, tax treatment, and other financial and accounting information. These data have, as noted, been utilized in constructing the financial sub-model of the URGE Advanced Utility Simulation Model.

Several reports currently available deal with some questions of relevance to the URGE group. For example, Salomon Brothers, Goldman Sachs, Shearson and Value Line provide some similar information.[7] The National Association of Regulatory Utility Commissioners (NARUC) Annual Report 1980 also contains regulatory data.[8] However, the information in these sources is necessarily limited in quantitative detail and as a result cannot be used as a basis for numerical modelling.

The questionnaire was carried out using a combination of techniques. Initially, commission staff people were contacted to ensure their cooperation. The questionnaire was then mailed to commissions. The first mailing achieved responses from 26 states. A follow up questionnaire brought answers from an additional 11 states. A second follow up mailing in combination with telephone calls achieved responses from the remaining 13 states.

Additional telephone calls were made to all commissions in order to clarify the information previously received. The process took place during an eight month period between April and October of 1981.

The state of Nebraska was omitted from the inquiry because it has no privately owned electric utilities. All other states and Washington, D.C. were included.

This effort collected over 1500 data entries and achieved a response rate of about 98 percent. Still, the questionnaire was not without weaknesses. Several of the questions were open-ended in the information they requested. Responses to these inquiries were consequently varied and generally less complete than those seeking specific information (e.g. question II.A. on items allowed in the rate base, and section III on rates of return suffered from this problem).

Another problem arose from the detail sought in some questions. State commission staff people have only limited time to work on questionnaires and some of the information sought required considerable research by them. Questions like IV.B.2.b. regarding the normalization method for tax deferrals from accelerated depreciation achieved a lower response rate than others.

Overall, this approach has been useful in acquiring data for use in the Advanced Utility Simulation Model. For other purposes, some other ongoing mechanism is needed.

A final note: as part of the financial data needed for simulation modelling and analysis, we summarized the basic balance sheet and tax statistics for the privately owned utilities in each state. These data are given as 31 variables or terms in Appendix C.

II. RATE BASE

A. Items Allowed in the Rate Base Other Than Direct Investment and AFUDC

Items typically included in a utility's rate base are, along with direct investment and allowance for funds used during construction (AFUDC): allowance for working capital; materials and supplies; plant or property held for future use; land held for future use; fuel inventories; pollution control; construction work in progress; advance payments; contributions in aid of construction; acquisition adjustments; and minimum bank balances. Items typically deducted from the rate base are: accumulated deferred taxes and credits; depreciation; and customer advances for construction.

B. Treatment of Pollution Control and Conservation Expenditures

1. Pollution Control

Electric utility air pollution control investments consist primarily of electrostatic precipitators for oil and coal plants and sulfur oxide scrubbers for new coal plants. Such expenditures are generally a great deal more costly for coal burning units than they are for oil fired generating plants.

Forty-five commissions questioned said pollution control equipment was included in utilities' rate bases. One, Louisiana, said because there was relatively little coal in the state such expenditures were not included.[9] Presumably, pollution control investment might be considered if it existed.

The NARUC 1980 Annual Report shows that Alaska, Minnesota and Oklahoma disallow pollution equipment from the rate base.[10] All three of these commissions when responding to the URGE questionnaire said that pollution control was allowed in company rate bases.

2. Company and Customer Conservation Expenditures

a. company expenditures

Company conservation expenditures improve the efficiency of utilities' own systems or buildings.

Table 3 presents results on state treatment of company conservation expenditures. Answers provided were categorized according to whether such cases were heard or not typically heard before commissions.

Of 20 states where such cases were heard, fifteen indicated that

Table 3. Regulatory Treatment of Company Conservation Expenditures[a]

State	Heard Before Commission: Allowed in Rate Base	Heard Before Commission: Case by Case	Not Typically Heard Before Commission: Would be Allowed	Not Typically Heard Before Commission: Large or Long Term Expenditures:Rate Base Short Term or Small:Expensed	Not Typically Heard Before Commission: Expensed	Other
AL[b]		√				
AK			√			
AZ	√					
AR				√		
CA	√					
CO[c]						√
CT	√					
DC			√			
DE			√			
FL			√			
GA	√					
HI	√					
ID					√	
IL	√					
IN[d]					√	
IA	√					
KS[e]		√				
KY[f]						√
LA				√		
ME[g]		√				
MD[h]		√				
MA			√			
MI	√					
MN	√					
MS				√		
MO			√			
MT[i]						√
NV[j]				√		
NH	√					
NJ					√	

Table 3 (Continued). Regulatory Treatment of Company Conservation Expenditures[a]

	Heard Before Commission		Not Typically Heard Before Commission			Other
State	Allowed in Rate Base	Case by Case	Would be Allowed	Large or Long Term Expenditures:Rate Base Short Term or Small:Expensed	Expensed	
NM[i]						√
NY	√					
NC[g]						√
ND	√					
OH			√			
OK	√					
OR	√					
PA[g]						√
RI			√			
SC			√			
SD	√					
TN[i]						√
TX				√		
UT[k]				√		
VT				√		
VA[i]						√
WA			√			
WV				√		
WI[l]		√				
WY					√	

[a]Company conservation expenditures are defined as in-house investments which utilities make to improve the energy efficiency of their own buildings or equipment.

[b]Items are allowed depending on whether or not they are deemed retirement units.

[c]Generic hearings are presently being held regarding the treatment of company conservation expenditures.

Table 3 (Continued). Regulatory Treatment of Company Conservation Expenditures[a]

[d]These could be included in the rate base.

[e]Decisions are based on the size of them.

[f]No cases like this have gone before the commission.

[g]If an item is deemed used and useful it is allowed in the rate base.

[h]An 80-90 percent chance exists for an item to be allowed in the rate base.

[i]This state's answer was unclear to the authors.

[j]These expenditures do not go before the commission. Major expenditures could be allowed in the rate base.

[k]Equipment is allowed in the rate base. Labor is considered an expense item.

[l]If a capital improvement is made to increase the life of the plant it is allowed in the rate base.

these investments were allowed in the rate base. Five said they were allowed on a case by case basis.

Twenty-two commissions did not typically hear such cases. Of these, company conservation expenditures would be allowed in ten. In eight states, larger or long term expenditures would be allowed rate base treatment while short term or small amounts would be expensed. Four states said company conservation expenditures were expensed. Eight either provided no answers to this question or had unique methods of handling them.

b. customer conservation expenditures

Customer related conservation expenditures help customers improve the energy efficiency of their homes or buildings, primarily in compliance with the National Energy Conservation Policy Act, which requires utilities to set up energy audit programs for residential buildings.

Table 4 presents results on state treatment of customer conservation expenditures. Fifteen states (30 percent) included at least part of utilities' customer conservation program costs in the rate base. Ten commissions allowed companies to expense part and allow part in the rate base. In such cases, it is common for large capital expenditures (e.g. equipment) to be allowed rate base treatment while smaller expenditures are expensed. Four states (Arkansas, Minnesota, Mississippi, and Texas) mentioned utility pilot programs which were included in the rate base. Twenty-three state commissions indicated that customer conservation expenditures were treated as expense items. Four states said their commissions are presently having generic hearings on this subject. Alaska and California said their state energy offices handled their customer conservation programs.

Table 4. Historical Treatment of Customer Related Conservation Expenditures[a]

State	Have Been Allowed in Rate Base	Never Allowed in Rate Base
AL		√
AK[b]		√
AZ		√
AR	√	
CA[b]		
CO		√
CT	√	
DC[c]		√
DE		√
FL[c]		√
GA		√
HI		√
ID	√	
IL		√
IN		√
IA		√
KS[c]		
KY		√
LA		√
ME	√	
MD		√
MA		√
MI	√	
MN	√	
MS	√	
MO		√
MT	√	
NV		√
NH[c]		
NJ		√
NM[f]		
NY	√	
NC		√
ND		√
OH		√
OK		√
OR	√	
PA[d]		
RI	√	
SC		√

Table 4 (Continued). Historical Treatment of Customer Related Conservation Expenditures[a]

State	Have Been Allowed in Rate Base	Never Allowed in Rate Base
SD	√	
TN[e]		
TX	√	
UT	√	
VT		√
VA[f]		
WA	√	
WV		√
WI		√
WY		√

[a]Customer related conservation expenditures are defined as any costs incurred by utilities in helping customers improve the energy efficiency of their buildings and equipment.

[b]These expenditures are handled by the state energy office.

[c]The commission is now looking at the treatment of these expenditures.

[d]The commission hasn't yet addressed the issue of whether conservation expenditures should be allowed in the rate base.

[e]This question is not relevant for Tennessee.

[f]No answer.

C. Percentage of CWIP Allowed in the Rate Base

Construction Work in Progress (CWIP) is any work on utility plant which is in the process of construction but has not yet been placed into service. CWIP traditionally had not been allowed rate base treatment until completed. In recent years, however, a pattern toward increased inclusion of CWIP has developed.

State policies toward allowance of CWIP in the rate base were found to fall into four major categories:

1. No CWIP allowed.
2. Allowance of a small portion of CWIP (less than ten percent).
3. Allowance of CWIP in varying amounts on a case by case basis.
4. 100 percent allowed.

Table 5 lists the percentage of CWIP allowed in the rate base during construction. Results showed that 17 states allowed no CWIP (34 percent) and eight states (16 percent) allowed a small portion of CWIP. Amounts permitted varied in 11 states (22 percent) since CWIP allowed was determined case by case. Fourteen states allowed all of CWIP (28 percent). Ohio was the only state which did not fall into any of these categories.

States allowing a small percentage of CWIP in the rate base permitted one of four or five loose categories of expenses. Two states said non-revenue producing CWIP was allowed; two said non-interest bearing items were permitted with AFUDC offset; one said production and transmission items, and one said renovations and construction. The combined number of states allowing no CWIP and a small percentage of CWIP in the rate base was 25, half.

Table 6 lists reasons mentioned for inclusion of CWIP in the rate base

Table 5. Percentage of Construction Work in Progress Allowed in the Rate Base During Construction

State	None	A Small Percent (Under 10%)	Amount Varies	100%
AL				✓
AK		✓		
AZ			✓	
AR[a]				✓
CA		✓		
CO			✓	
CT	✓			
DC		✓		
DE				✓
FL			✓	
GA			✓	
HI	✓			
ID	✓			
IL			✓	
IN[b]	✓			
IA	✓			
KS	✓			
KY				✓
LA				✓
ME	✓			
MD				✓
MA	✓			
MI				✓
MN				✓
MS			✓	
MO	✓			
MT	✓			
NV	✓			
NH	✓			
NJ			✓	
NM	✓			
NY[c]		✓		
NC				✓
ND[a]				✓
OH[d]			✓	
OK		✓		
OR	✓			
PA		✓		
RI	✓			
SC				✓

Table 5 (Continued). Percentage of Construction Work in Progress Allowed in the Rate Base During Construction.

State	None	A Small Percent (Under 10%)	Amount Varies	100%
SD	√			
TN				√
TX			√	
UT			√	
VT		√		
VA				√
WA		√		
WV			√	
WI	√			
WY[e]				√

[a]CWIP to be in service within one year is allowed.

[b]CWIP has been included very rarely.

[c]Under extreme financial conditions more can be included.

[d]Up to 20% of CWIP allowed. Included projects must be 75 percent complete.

[e]CWIP that will be operational at a given date, usually the date of the hearing is allowed.

Table 6. Reasons for Inclusion of Construction Work in Progress in the Rate Base Before Project Completion

State	Reason
AZ	CWIP included to grant adequate cash flow.
CO	Currently, PSC of Colorado is being allowed to earn on CWIP up to 40%. This allowance is one specific plant.
IL	Contingent upon the demonstrated necessity for cash flow.
KS	Only allowed if utility has a severe financial problem.
MS	Larger utility, 80-90% oil, more CWIP tends to be allowed; smaller utility, Miss. Power 80-90% coal, not as much allowed.
NJ	The level of CWIP depends on the nature of CWIP, the financial condition of the company, etc.
NY	Under extreme financial hardship, e.g. cash flow problems, varied amounts allowed.
TX	Percentage allowed is dependent upon how much is necessary to ensure a utility company's financial integrity. A specific procedure is followed to determine CWIP.
WV	Primarily allowed where return on capital wouldn't generate enough cash flow.

before project completion. Of the 11 states which permitted varying amounts of CWIP in the rate base, the financial health of the company was most frequently cited as a factor affecting how much CWIP was allowed. Five out of ten states mentioned this. Size of the utility was reported as significant, smaller companies being allowed a greater portion of CWIP in their rate bases than large ones. Fuel use was also cited as a factor in decisions regarding allowance of CWIP.

Three states indicated that although CWIP had not traditionally been permitted in the rate base, recently some CWIP was allowed to be included.

Of the 14 states allowing 100 percent inclusion of CWIP, two allowed only CWIP which would be in service within 12 months (Table 5).

When CWIP is given rate base treatment before construction is completed Allowance for Funds Used During Construction is usually offset (see page 26 for discussion of this term). This was specified by five commissions. In Kentucky AFUDC is offset "unless the utility requests otherwise."

In Ohio, at the discretion of the commission, up to 20 percent of CWIP is allowed though included projects must be 75 percent complete.

Inclusion of CWIP in the rate base before construction is completed means that utilities are allowed to earn a return on their investments before they are in use. This provides funds for utilities in the midst of construction programs.

The effect of utilities being permitted CWIP in the rate base on their ability to deal with pollution control expenditures is positive. Companies receive a return on their investment sooner.

Eight of the 14 states allowing 100 percent of CWIP in the rate base before project completion were questioned regarding policies for rate base and tax depreciation. All of the six states which understood the question and provided clear answers regarding utility policy toward rate base depreciation said companies wait until a plant is "used and useful" for depreciation to begin (Table 7). All seven clearly responding as to policy toward tax depreciation followed this practice (Table 8).

D. Simple Versus Compound Accumulation of AFUDC and its Relationship to CWIP in the Rate Base

Allowance for Funds Used During Construction (AFUDC) represents the amount credited for the cost of funds used in constructing a new plant and is based generally on expenditures to date on the project.[11] It can be calculated as a flat rate multiplied by accumulated annual construction expenses with no adjustments allowed or it can be compounded in the same way banks compound savings so that AFUDC can be earned on AFUDC.

Table 9 shows that 31 states (62 percent) allowed compounding of AFUDC and 19 states (38 percent) used simple accumulation.

Relationships between states' treatment of CWIP and their methods of accumulating AFUDC are illustrated in Table 10. Eleven states (22 percent) responding to this question permitted no CWIP in the rate base and allowed compounding. Seven additional states (14 percent) allowed a small amount of CWIP in the rate base and compounding. These 18 states totalled 36 percent. In all, seven states allowed a small amount or no CWIP in the rate base

Table 7. Utility Policy Toward Rate Base Depreciation in States Allowing Construction Work in Progress in the Rate Base

State	Policy: Wait Until Plant Comes in Service for Rate Base Depreciation	Other/Comments
AL		
AR		
DE	√	
LA	√	
KY		
MD	√	
MI	√	
MN	√	
NC	√	
ND		
SC		Depreciation is computed on CWIP
TN		
VA		Offset AFUDC all the time plant under construction.
WY		

Table 8. Utility Policy Toward Tax Depreciation in States Allowing Construction Work in Progress in the Rate Base

State	Policy: Wait Until Plant Comes in Service for Tax Depreciation	Other/Comments
AL	√	
AR		
DE	√	
KY		
LA		Not sure.
MD	√	
MI		
MN	√	
NC	√	Varies. By and large, when plant in service.
ND		
SC	√	
TN		
VA	√	
WY		

Table 9. Allowance for Funds Used During Construction Accumulation Method Allowed [a]

State	Compounding	Simple	State	Compounding	Simple
AL	√		MO		√
AK		√	MT		√
AZ		√	NV		√
AR	√		NH	√	
CA	√		NJ[c]		√
CO		√	NM		√
CT	√		NY	√	
DC	√		NC	√	
DE	√		ND	√	
FL		√	OH	√	
GA		√	OK	√	
HI	√		OR	√	
ID	√		PA	√	
IL	√		RI	√	
IN	√		SC[b]	√	
IA	√		SD	√	
KS	√		TN		√
KY	√		TX	√	
LA[b]	√		UT	√	
ME	√		VT	√	
MD	√		VA		√
MA		√	WA[b]	√	
MI		√	WV		√
MN		√	WI		√
MS		√	WY		√

[a]Compounding of AFUDC is carried out in much the same way that banks compound savings. Simple accumulation is carried out using a flat rate multiplied by accumulated annual construction expenses with no adjustments allowed.

[b]Method chosen by utilities varies but state allows compounding.

[c]A majority of utilities in this state follow the method indicated although one or more companies do not.

Table 10. Policies Toward Allowance of Construction Work in Progress in the Rate Base and Method of Accumulating Allowance for Funds Used During Construction

Amount of CWIP	AFUDC Accumulation Method Compound	Simple
None	CT	MA
	HI	MO
	ID	MT
	IN	NV
	IA	NM
	KS	WI
	ME	
	NH	
	OR	
	RI	
	SD	
Small Amount[a]	CA	AK
	DC	
	NY	
	OK	
	PA	
	VT	
	WA	
Varied Amount	IL	AZ
	OH	CO
	TX	FL
	UT	GA
		MS
		NJ
		WV
100%	AL	MI
	AR	MN
	DE	TN
	KY	VA
	LA	WY
	MD	
	NC	
	ND	
	SC	

[a] A small amount means less than 10%.

during construction and simple accumulation of AFUDC.

Nine states (18 percent) allowed all of CWIP in the rate base during construction and compounding of AFUDC. Four states (eight percent) permitted varying amounts of CWIP and allowed compounding. These 13 states totalled 26 percent. Five states (ten percent) allowed all of CWIP in the rate base and simple accumulation of AFUDC. Seven permitted varying amounts of CWIP and simple accumulation. These 12 states totalled 24 percent.

E. Rate Base Adjustment for Inflation

Inflation is one of several factors which utilities and state regulatory agencies view as contributing to attrition, the erosion of a company's potential earnings. Therefore, some public service commissions allow electric utilities to incorporate an inflation adjustment mechanism. These mechanisms are not necessarily explicitly associated with inflation rates.

Variations on three major methods are used to correct for inflation: 1. The overall return allowed can be increased. 2. A year end rate base can be utilized. 3. CWIP can be allowed in the rate base during construction. Table 11 illustrates inflation adjustment mechanisms utilized by commissions.

When asked whether the rate base was adjusted for inflation, 40 states said no adjustment was made. Ten indicated that at least occasionally adjustments were permitted.

Louisiana indicated that company rate bases were adjusted to correct for inflation or that an attrition allowance was computed. Three additional states, Florida, Idaho and Maine, said attrition allowances had

Table 11. Rate Base Adjustment for Inflation

State	Adjustment
CT	Not generally. Occasionally a prospective adjustment will be made if plant is expected to enter rate base.
FL	Not directly. An attrition allowance, however, may be allowed which would serve this purpose.
ID	Not generally. However, a .57% attrition allowance was allowed in the most recent rate case.
IL	Fair value is the regulatory standard for ratemaking purposes in Illinois. The commission is obliged to consider reproduction cost new-depreciation or current value of plant and property together with original cost-depreciation and other pertinent factors in arriving at its fair value rate base.
IN	No annual inflation factor. However, plant reassessed for present day value. Rate base adjusted on fair value basis.
KY	Year end rate base can be adjusted for additions looking at what kind of income generated. Generally not adjusted.
LA	In rate cases an attrition allowance is computed, if rate of return allowed wasn't enough. Rate base adjusted to cover inbalance.
ME	No except in cases where an attrition allowance is computed.
NJ	New Jersey Board of Public Utilities uses test year end rate base, and permits filings based upon partial forecasted test year. This would be updated to actual prior to board decision.
NY	The rate base in an historic test year presentation is not normally adjusted for inflation. However, in a forecast test year presentation most elements of rate base may include some measure of inflation since the starting point is historic information. The mechanics of an inflation allowance, when applied, vary from case to case depending on each company's forecasting methodology.

been permitted.

Two states, Kentucky and New Jersey, mentioned company utilization of year end rate bases. New Jersey and New York said that permitting forecasted test year presentations helped in correcting for inflation.

Both Illinois and Indiana indicated that companies in their states used a fair value rate base which increases the rate base by an inflation adjustment factor. However, the NARUC report lists several other states which use a fair value rate base. Answers provided may have differed in specificity due to the wording of this question.

F. Utilization of the Federal Energy Regulatory Commission Method in Calculating AFUDC

The Federal Energy Regulatory Commission (FERC) method of computing AFUDC uses the after-tax cost of debt to arrive at the debt portion of AFUDC. The after-tax cost of debt is the interest rate times one minus the corporate tax rate (Int X (1-Tax Rate)).[12] The earlier alternative method of computing the debt portion of AFUDC uses the before-tax cost of debt, i.e. simply the interest rate. The FERC method gives a net of tax AFUDC rate; the alternative method, a gross AFUDC rate.

In response to this question, 35 state commissions said the FERC method was used by electric utilities in their state. No state reported regular use of the earlier gross AFUDC rate. Fifteen states said a variation on FERC or a method other than FERC was used. Table 12 lists non-FERC methods of calculating AFUDC. Of these, three states mentioned allowing use of the overall rate of return in calculating the AFUDC rate. Four commissions said a variation on the FERC method was utilized by at least some companies

Table 12. Non-FERC Methods of Calculating Allowance for Funds Used During Construction[a]

State	Method
CO	For book purposes the FERC method is used. For ratemaking all AFUDC is credited to income.
FL	AFUDC is calculated using the following components on a period end basis: 1. long term debt. 2. common equity. 3. preferred stock. 4. customer deposits. 5. deferred taxes. 6. short term debt. Overall cost of capital determined from these components is the AFUDC rate.
LA	AFUDC is normally computed using the overall cost of capital. However, adjustments are made to assure that company can meet interest coverage requirements. Decide between net and gross of tax depending on what the company has been using. Net used more than gross.
ME	The allowed rate of return is utilized.
MA	The Department of Public Utilities has not yet issued policy on this question.
MI	The FERC method had been used. The rate now used for large utilities is the overall authorized rate of return.
NV	The FERC formula or the overall rate of return is used, whichever is lowest.
NH	One utility uses net of AFUDC.
NJ	This is determined case by case. After tax cost of capital is a key determining factor.
NY	AFUDC is calculated similar to the FERC method and, in fact, some electric utilities have applied for and received permission to follow the FERC method.
NC	The FERC method is not utilized. Cost free capital is not included in the capital structure.
SC	The FERC method is used to establish the maximum rate, however, all companies don't use the maximum rate.
TX	For interstate companies, AFUDC calculated using the FERC method. Certain intrastate utilities use some variation which yields a result less than permitted under FERC. The commission usually allows maximum flexibility in computing AFUDC, however, utilities aren't allowed more than FERC would give them.

Table 12 (Continued). Non-FERC methods of Calculating Allowance for Funds Used During Construction[a]

State	Method
WA	Two companies use FERC as a guideline but differentiate a bit taking slightly less than FERC. Puget Power uses FERC, then since CWIP is allowed in the rate base, reduce this 20%.
WI	A 7% AFUDC rate is utilized.

[a]FERC = Federal Energy Regulatory Commission

in their states. Nevada, Washington, and Texas said a rate somewhat lower than determined utilizing FERC was allowed. In Washington, one utility used FERC to compute the AFUDC rate, then since 20 percent of CWIP was allowed in the rate base, the company reduced this rate by 20 percent. Louisiana computed AFUDC using the overall cost of capital. However, adjustment was made to assure that companies could meet interest coverage requirements. Decision is made between net and gross of tax depending on what the company has been using.

G. Time Sequence for Inclusion of AFUDC in the Rate Base

Table 13 describes exceptions to including AFUDC in the rate base upon project completion. When asked when AFUDC was allowed in the rate base, 34 state commissions (68 percent) responded that AFUDC was included upon project completion. Sixteen commissions (32 percent) replied to the contrary. Of these 16, 11 said AFUDC was included during construction or when it was booked. Five said AFUDC was allowed upon project completion or when CWIP was allowed depending on whether and how much CWIP was allowed in the rate base.

H. Type of Depreciation and Average Service Lives Used to Depreciate Assets in the Rate Base

For book purposes straight line depreciation is generally used to depreciate assets in the rate base. Results showed this to be true. Forty-seven states responding to this question said that straight line depreciation was used.

The average service life is the expected life of an asset used for accounting purposes in the depreciation schedule for all items allowed in the rate base.

Table 13. Exceptions to Including Allowance for Funds Used During Construction in Rate Base Upon Project Completion

State	Time Sequence for Including AFUDC
AL	AFUDC is computed on a monthly basis for book purposes, the total balance being included in the rate base.
AK	When not already allowed in rate base, upon project completion.
AR	AFUDC is allowed in the rate base when it is included in CWIP that will be completed within 12 months after the test year. (Any AFUDC same way. Calculated from inception of project until project goes on line.)
CO	When it is booked.
FL	AFUDC is allowed if it was accumulated in CWIP prior to the test period when CWIP allowed. If CWIP not allowed - AFUDC allowed upon project completion.
GA	When CWIP is allowed. In Georgia AFUDC is capitalized as part of CWIP. When they allow CWIP they offset AFUDC by crediting it by related income in order to avoid a double return on money.
IL	Usually, the AFUDC which is capitalized to a particular plant item or product becomes a part of the rate base when its construction is completed and the item is cleared from CWIP to plant in service. The exception would be the inclusion of an increment of CWIP in the rate base which would include its related AFUDC.
LA	Included in CWIP.
MI	As it is computed (or booked). The utility does not have to wait for project completion before including AFUDC.
MT	During construction.
NJ	AFUDC is allowed as part of CWIP during construction and later transferred to plant in service upon completion of project.
OH	Always upon completion, may be included in CWIP.
OK	During construction for the portion of CWIP allowed in rate base.

Table 13 (Continued). Exceptions to Including Allowance for Funds Used During Construction in Rate Base Upon Project Completion

State	Time Sequence for Including AFUDC
SC	AFUDC is computed on CWIP and CWIP is considered a rate base component in rate cases along with plant in service and other previously mentioned items. Upon project completion AFUDC is discontinued when the plant is commercial.
TN	During the time of construction.
VA	As accrued on the books. Most capitalized AFUDC based on FERC is accrued monthly while a unit is under construction. It is put into CWIP during construction and shows up in net income.

Several publications available list information equivalent to the average service lives for major assets. A FERC publication, <u>Electric Utility Depreciation Practices</u>, includes this information through 1976.[13] This data is, therefore, somewhat outdated. Another publication, <u>A Survey of Depreciation Statistics</u>, by the AGA Depreciation and EEI Accounting committees includes this data for about 75 percent of the class A and B electric utilities.[14] This can not be used to determine average figures for states since major companies' assets are not included. The information gained through this questionnaire, although varying greatly in its detail and overall accuracy from state to state, represents the most complete compilation of this data currently available.

Table 14 lists average service lives used to depreciate utility assets. Results showed that for the 44 states answering this question average service lives for nuclear facilities ranged between 23-35 years; coal or steam production plants 24-40 years; oil and gas baseload units 24-50 years; oil and gas peaking units 15-38 years; hydro units 32-100 years; transmission plants 29-66 years; distribution plants 25-49 years; and other significant items (general plants) 10-56 years.

III. RATES OF RETURN

A. <u>Rates of Return Allowed on Common Equity and the Rate Base</u>

Regulated electric utilities are allowed to earn a rate of return on common equity and their rate base. Rates of return are generally expressed as percentages.

Table 15 lists rates of return allowed on common equity and the rate base

Table 14. Average Service Lives Used to Depreciate Utility Assets (years)[a]

State	Nuclear	Coal	Oil and Gas Baseload	Oil and Gas Peaking	Hydro	Transmission	Distribution	Other or General Plant
AL	26	30	–	15	67	42	28	25
AK	–	~35	–		50		33	13
AZ	–	33	33	28	50	30	23	18
AK	31	30	34	22	69	43	30	31
CA	35	40		20	60	45	30	30
CO	32	29	29	25	62	40	30	
CT	35	–	37	26	78	35		33
DC	–	30	30		–			
DE	31	29	29	24	–	44	34	31
FL	31	–	30	30	–	38	38	30
GA	27	30	–	12	40	40	30	20
HI	–	–	35	25	40	40	36	28
ID	–	33	–	26	74	50	39	52
IL	25	33	25	25	32	29	29	28
IN	–	27	–	25	44	45	25	34
IA	25	26	26	22	40	36	27	15
KS	33	30	35	35	–	35	35	
KY	–	30	–	–	50	30	30	29
LA	–	–	28	15	–	35	30	20
ME	30	–	30	20	50	34	28	17
MD	32	31	30	25	50	41	33	29
MA								
MI	36	35	35	25	54	47	34	25
MN	29	29	29	27	72	38	29	24
MS	–	24	24	–		52	34	35
MO	–	35	–	25	100	40	32	
MT	–	35	–	30	55	35	25	25

Table 14 (continued). Average Service Lives Used to Depreciate Utility Assets (years)[a]

State	Nuclear	Coal	Oil and Gas Baseload	Oil and Gas Peaking	Hydro	Transmission	Distribution	Other or General Plant
NV	-	38	50	-	100	35	30	35
NH								
NJ	30	43	43	25	50	48	28	30
NM	-							
NY	23	34	34	25	44	46	37	56
NC	25	28	-	20	77	46	31	22
ND	30	36	-	32	75			33
OH	34	31	-	38	-	44	38	38
OK	-				-			
OR	28	35	25	-	50	40	30	45
PA	35	40	40	25	58	40	40	40
RI								
SC	25	28	30	20	66	66	29	28
SD	28	33	-	30	-	35	35	-
TN	-	-	-	-	-	35	29	33
TX	-	33	35	30	75	30	30	10
UT	-	35	35	30	50	48	38	35
VT	26	30	28	30	55	30	28	32
VA	31	30	-	20	60	49	49	42
WA	25	33		19	64	49	36	25
WV	-	34	-	-	50	31	31	23
WI	25	32		20	54	34	29	29
WY	-							

[a]Information provided in this table varies greatly in its preciseness. Answers ranged from rough guesses by commission staff people to exact calculations based on figures for individual utilities.

Table 14 (continued). Average Service Lives Used to Depreciate Utility Assets (years)[a]

In cases where depreciation rates were given this figure was inverted and multiplied by 100 to arrive at the average service life. For some states, average service life is calculated as mean per company per state. These states are: Idaho, Michigan, Minnesota, New Hampshire, Vermont, and Washington.

Slash marks designate states which do not have this asset. Blank spaces indicate that no answer was provided for this asset or that the answer was unclear to the authors.

In some cases although a state had very few assets of a specific type, an answer was provided and thus has been listed.

"Other production" as categorized by utilities has been classified as "oil and gas peaking". "Steam production" has been classified as "coal" and "oil and gas baseload".

Table 15. Recent Rates of Return Allowed on Common Equity and the Rate Base[a]

(percent)

State	Range Common Equity	Range Rate Base	Average Common Equity	Average Rate Base	Most Recent Common Equity	Most Recent Rate Base
AL	11.70-14.0	9.85-10.49	12.85	10.17		
AK					14.5-15	17.5
AZ	12.5 -14	7.5 - 9	13.25	8.25		
AR					15	10.5
CA	12.21-14.95	9 -11.75	13.58	10.38		
CO					15.45	10.19
CT	14.5 -15.1	10.25-11.3	14.7	10.68		
DC					13.25	9.38
DE			15	10.75		
FL	14.5 -16.5	8.08-10.76	14.88	10.6		
GA	12.25-14.4	9.36-11.13	13.23	10.14		
HI	14.75-15	10.25-10.95	14.88	10.6		
ID					15.75	11.49
IL	15.5 -17.5	11.47-11.88	16.5	11.68		
IN	14.91-16.75	7.5 - 7.9	15.83	7.7		
IA	12.5 -14.2	8.5 -10.0	13.35	9.25		
KS	13.71-14.0	8.61- 9.36	13.91	9.03		
KY	13.5 -15	10 -11	14.25	10.5		
LA	13.75-14.9	10.56-11.78	14.24	10.98		
ME	13.75-16.5	10.65-12.49	14.72	11.38		
MD					14	9.94
MA	12.61-16		13.5			
MI	13 -13.5	8.5 -10	13.25	9.25		
MN	13.5 -14.5	10 -11	14.0	10.5		
MS	10.39-15.3	8.85-9.88	12.85	9.37		
MO	13.02-14.4	8.26- 9.39	13.71	9.06		
MT	13.75-14.25	10.25-11	14.01	10.63		
NV		11.75-12.25	15	12	15.2	11.7
NH	14.5 -15		15.13		15.9	10.49
NJ	13.0 -15	9 -11.5	14	10.25		
NM	14 -16	10 -12	15	11		
NY	14.1 -16.9	10.58-12.24	15.55	11.44		
NC	13.59-14.15	10.66-10.88	13.94	10.78		
ND					13.90	10.40
OH	15.5 -16.22	11.15-11.76	15.83	11.49		
OK					15.25	10.52

Table 15 (Continued). Recent Rates of Return Allowed on Common Equity and the Rate Base[a]

(percent)

State	Range		Average		Most Recent	
	Common Equity	Rate Base	Common Equity	Rate Base	Common Equity	Rate Base
OR		11.34-12.65		12.0	16.25	
PA	15.25-16	10.23-11.53	15.56	10.91		
RI	13.5 -14.75	11 -12	14.13	11.5		
SC	13.75-14	10.5 -10.75	13.88	10.63		
SD	12.7 -14.1	10.1 -10.6	13.4	10.35		
TN					14.0	12.14
TX	14.1 -18.0	10.55-11.76	16.05	11.16		
UT			16.80	11.87		
VT					14.5	10.6
VA	14.5 -15.5	10.4 -10.7	15.0	10.55	15.0	10.68
WA	13.75-15.25	10.10-11.71	14.75	11.02		
WV	13 -15	9 -11	14	10		
WI	10.69-14.75	9.57-11.37	12.72	10.47		
WY			13.3	10.5		

[a]Figures represent returns allowed 1980-1981.

These returns are ranges, averages and example cases cited by commissions. They are not standardized and do not necessarily represent exact ranges or averages currently allowed.

by state regulatory commissions. Recent rates of return granted on common equity varied between 10.0 and 18.0 percent. These were in Mississippi and Texas respectively. The mean low and high rates determined were 12.7% and 16.8%. Mean rates of return allowed on equity were evenly distributed among the three classes 13.0%-13.9%, 14.0%-14.9%, and 15.0%-15.9%. All but six states fit into these categories.

Overall rates of return allowed varied between 7.5% and 12.7%. Low returns were granted in Arizona and Indiana; high returns in Oregon. Nineteen states' mean overall rates of return fell between 10.0%-10.9%; nine between 11.0%-11.9%; and six between 9.0%-9.9%. This was all but four states.

B. How Rates of Return are Determined

State regulatory commission responses to this question varied greatly in their specificity. This was probably due to the open ended nature of the question. Some states made no distinction between the way in which returns on common equity and the rate base were determined. Others discussed both in detail.

In general, in determining the allowed return on equity, commonly used methods are: discounted cash flow, earnings to price ratios, comparable earnings, risk premium analysis and trend analysis. In arriving at the rate of return on the rate base the weighted average cost of capital is utilized including: common stock equity, short and long term debt, preferred stock equity, customer deposits, investment tax credits and deferred taxes.

C. Frequency of Revisions

Forty-seven regulatory commissions responding to this question said rates of return are adjusted every rate case.

IV. TAX TREATMENT

A. Investment Tax Credit

1. Company Utilization of Additional Investment Tax Credits for Employee Stock Ownership Plans

The investment tax credit (ITC) provides a basic 10% tax credit for qualified investment expenditures. Prior to 1981, an additional one percent credit was allowed for stock contributed by an employer to an Employee Stock Ownership Plan (ESOP). An additional 1/2 percent was possible if employees matched the employer's additional 1/2 percent. Electric utilities were, therefore, ordinarily entitled to a maximum 11.5 percent investment tax credit.[15]

Table 16 lists investment tax credit rates utilized by most utilities. Thirty-five commissions (70 percent) said the 11 or 11.5 percent tax credit rates were utilized by most companies in their states.[16] Thirteen commissions (26 percent) said the ten percent tax credit rate was used by most companies.

Table 17 lists the number of utilities per state claiming additional ITC's for ESOP. A total of 168 utilities were listed as claiming the 1 or 1.5 percent additional ITC's available. This represents 82 percent of the class A and B privately owned electric utilities in the country.[17] Three regulatory commissions, Alaska, West Virginia, and Mississippi, said no

Table 16. Investment Tax Credit Rates Utilized by Most Utilities[a]

State	10%	11 or 11 1/2%	State	10%	11 or 11 1/2%
AL		√	MO	√	
AK	√		MT		√
AZ		√	NV		√
AR	√		NH	√	
CA	√		NJ		
CO		√	NM		
CT		√	NY		√
DC		√	NC		√
DE		√	ND		√
FL		√	OH		√
GA		√	OK	√	
HI		√	OR	√	
ID		√	PA		√
IL		√	RI	√	
IN		√	SC		√
IA		√	SD		√
KS		√	TN	√	
KY		√	TX		√
LA		√	UT	√	
ME		√	VT		√
MD		√	VA		√
MA	√		WA		√
MI		√	WV	√	
MN		√	WI		√
MS	√		WY		√

[a]Blank spaces indicate question was not answered.

Table 17. Electric Utilities Claiming 1 or 1.5 Percent Additional Investment Tax Credit for Employee Stock Ownership Plans[a]

State	Number of Utilities	State	Number of Utilities	State	Number of Utilities
AL	–	KY	2	OH	7
AK	0	LA	4	OK	2
AZ	2	ME	4	OR	2
AR[b]	12	MD	5	PA[c]	11
CA	2	MA	∿4	RI	0
CO[c]	2	MI[c]	8	SC	3
CT	3	MN	5	SD	6
DC	1	MS	0	TN	0
DE	1	MO	8	TX	11
FL	4	MT	3	UT	1
GA	2	NV	2	VT	3
HI	3	NH	1	VA	–
ID	2	NJ	–	WA	2
IL[b]	∿8	NM	–	WV	0
IN	3	NY	4	WI	4
IA[c]	6	NC	2	WY	6
KS	4	ND	3		

[a]Slash marks indicate that this question was not answered.

[b]It is assumed that this was answered including all regulated utilities in the state since the number given exceeded the number of class A and B electric utilities in the state listed in: D.O.E., EIA, Statistics of Privately Owned Electric Utilities in the United States - 1980. (Washington, D.C.: Energy Information Administration, 1981.)

[c]This state answered either: "all major utilities," "most if not all" or "a majority of utilities." Therefore, the number listed is the number of class A & B electric utilities in the state listed in the publication cited above.

utilities in their states had ESOP.

Although 168 utilities have adopted an ESOP, whether or not a company is able to take advantage of the additional ITC in a specific year often depends on the financial health of the utility. Therefore, it cannot be assumed that the number of companies currently taking available tax credits is this high.

The Economic Recovery Tax Act of 1981 repeals the current ESOP investment tax credit for property acquired after December 31, 1982 and this property-based system is replaced by a payroll-based corporate income tax credit for ESOP contributions after 1982. According to Price Waterhouse and Company, "the credit, subject to certain limitations with respect to contributions made on behalf of highly compensated individuals, is limited to 1/2 of 1 percent of compensation paid to employees under the plan for calendar years 1983 and 1984, and 3/4 of 1 percent of compensation paid in 1985 through 1987, at which time the credit expires. For many utilities the change from a property to a payroll-based credit will result in a significant reduction in the amount of contributions paid into existing ESOPs."[18]

Thus, although the large number of utilities participating in ESOP has a significant financial impact on the U.S. electric utility industry currently, this benefit to companies will soon decrease.

2. Normalization Versus Flow-Through Treatment of the Investment Tax Credit

As defined in the preceding section, the investment tax credit (ITC) provides a credit generally equal to 10 percent of the cost of qualified depreciable property purchased by businesses.[19]

The Revenue Act of 1971 provided three options to public utilities for treatment of the ITC: 1. rate base normalization, 2. ratable flow-through or cost of service normalization, 3. immediate flow-through. Appendix B-1 reproduces a Kiefer discussion of the options.

Results pertaining to state treatment of the ITC are contained in Table 18. According to findings, 43 states (86 percent) normalize 100 percent of the ITC. Of these, 27 (54 percent) did not specify their normalization method and 15 (30 percent) use cost of service normalization. One said it uses rate base normalization.

In Washington, D.C., companies normalize six percent of the ITC and flow-through four percent using cost of service normalization. Five states, Arizona, California, Nevada, Tennessee, and Washington, report having individual companies using the 100 percent flow-through option. A total of six utilities were named since the two major privately owned utilities in Nevada both use flow-through.

Five states mentioned having companies using varying accounting methods. Of states with utilities using flow-through, California said two companies use cost of service normalization with 6% normalized and 4% flowed-through; Arizona and Washington said utilities in their states normalize 100 percent, not specifying the method. In Connecticut, some companies use 6% normalization, 4% flow-through cost of service normalization, while others normalize 100 percent. In New York, all companies but one use the 6% normalization, 4% flow-through cost of service method. One utility normalizes 100 percent.

Table 18. Normalization Versus Flow-Through Treatment of the Investment Tax Credit[a]

State	Amount Normalized	Amount Flowed-Through	NORMALIZATION METHOD[b] Rate Base	NORMALIZATION METHOD[b] Cost of Service (Ratable Flow-Through)	NORMALIZATION METHOD[b] Not Specified or Unclear[c]
AL	All				✓
AK	All				✓
AZ[d]	Varies				✓
AR	All			✓	
CA[d]	6% Portion	4% Portion		✓	
CO	All			✓	
CT[e]	6% Portion	4% Portion			✓
DC	6% Portion	4% Portion		✓	
DE	All				✓
FL[f]	All				✓
GA	All			✓	
HI	All				✓
ID[g]	All				✓
IL	All			✓	
IN	All				✓
IA	All			✓	
KS	All				✓
KY	All				✓
LA	All				✓
ME	All			✓	
MD	All			✓	
MA	All				✓
MI	All			✓	
MN	All				✓
MS	All				✓
MO[h]	All				✓
MT	All				✓
NV[i]	All				✓

Table 18 (continued). Normalization Versus Flow-Through Treatment of the Investment Tax Credit[a]

State	Amount Normalized	Amount Flowed-Through	NORMALIZATION METHOD[b] Rate Base	Cost of Service (Ratable Flow-Through	Not Specified or Unclear[c]
NH	All			✓	
NJ	All				✓
NM[f]	All			✓	
NY[e]	6% Portion	4% Portion		✓	
NC	All				
ND	All				
OH	All				✓
OK	All			✓	
OR	All			✓	
PA[f]	All			✓	
RI	All				✓
SC	All				✓
SD	All			✓	
TN		All			
TX	All			✓	
UT[h]	All				✓
VT	All				✓
VA	All				✓
WA[j]	Varies				
WV	All			✓	
WI	All				✓
WY	All				✓

[a]Information presented represents accounting methods applying to assets new prior to the Economic Recovery Tax Act of 1981.

Table 18 (continued). Normalization Versus Flow-Through Treatment of the Investment Tax Credit[a]

[b]Definitions of normalization methods are taken from: Kiefer, D.W. Accelerated Depreciation and the Investment Tax Credit in the Public Utility Industry: A Background Analysis. (Columbus, Ohio: The National Regulatory Research Institute, Ohio State University, 1979.)

[c]Unclear answers are those which the authors had difficulty in interpreting. This does not mean that information provided was in any way inadequate.

[d]One utility flows-through 100 percent of the investment tax credit.

[e]One utility normalizes 100 percent of the investment tax credit.

[f]Greater than 90 percent is normalized. Most major utilities use ratable flow-through.

[g]One utility uses the ratable flow-through method.

[h]Greater than 90 percent is normalized.

[i]Two large utilities flow-through 100 percent.

[j]Of three major utilities, one flows-through 100 percent; one normalizes 100 percent and ratably flows-through 100 percent of the investment tax credit.

B. Accelerated Depreciation

1. Methods of Depreciation Permitted for Tax Purposes

Commission responses regarding methods of depreciation permitted for tax purposes varied from the informal response, "any they can get away with!" to "any methods are approved which are allowed by the Internal Revenue Code." Nonetheless, the overall pattern was consistent. All answers indicated that accelerated methods of depreciation were allowed according to those permitted under the Internal Revenue Code (IRC).

Methods then allowed under the IRC are the straight-line method, and liberalized depreciation including the double declining balance and sum of the years' digits method. (See the conclusion of the next section as it indicates applicable depreciation for post-1980 assets.)

2. Normalization Versus Flow-Through Treatment of Tax Deferrals from Accelerated Depreciation

The Economic Recovery Tax Act of 1981 introduced a major revision in the depreciation system used to recover the cost of original investment. This is known as the accelerated cost recovery system (ACRS), and specifies mandatory tax lives and depreciation percentages.

Prior to 1981, the Asset Depreciation Range (ADR) system is applicable.

Both systems can be generally categorized as "accelerated depreciation": they permit, for tax purposes, full depreciation before useful life ends, and more rapid depreciation in early years than occurs under normal straight line depreciation.[20]

However, both the ACRS and ADR systems create tax deferrals. Results pertaining to state treatment of tax deferrals from accelerated depreciation are contained in Table 19. Findings showed that 35 states (70 percent) fully normalized the tax deferrals from accelerated depreciation prior to the Economic Recovery Tax Act of 1981. Eight states' treatment were split, with some companies permitting full normalization and others using alternative methods. A total of 43 states (86 percent) allowed companies to fully normalize tax deferrals.

In the eight states which did not allow full normalization, other methods were utilized. Arkansas normalizes the tax savings due to the difference between actual tax depreciation and straight line depreciation using the tax life (this amounts to about 60 percent of the tax savings). Illinois allows utilities to normalize the difference between tax and book lives. In New York, the difference on a straight line basis between book lives and ADR lives is normalized and the tax effects related to liberalized depreciation are flowed-through. North Carolina allows normalization of differences due to accelerated rates.

Three states allow utilities to flow-through tax deferrals from accelerated depreciation: California, Tennessee, and Vermont.

The Economic Recovery Tax Act of 1981 applies to utility investments after 1980 and contains two provisions related to depreciation practices which affect electric utilities. First, it shortens the "recovery" periods for depreciable assets to 3, 5, 10, and 15 years.[21] Second, in order for companies to utilize these benefits, it requires that all tax deferrals from accelerated depreciation by fully normalized.[22]

When asked how they planned to treat tax benefits available under the

Table 19. Normalization Versus Flow-Through Treatment of Tax Deferrals from Accelerated Depreciation[a]

State	Amount Normalized	Amount Flowed-Through
AL	All	
AK	All	
AZ	Difference from accelerated to straight line - 80% normalized 20% flowed-through - 1 company; All - 2 companies.	
AR	Difference between actual tax depreciation and straight line depreciation using tax life - about 60% of the depreciation benefit.	
CA		All
CO	All	
CT	All - major utilities.	
DC	All	
DE	All	
FL	All	
GA	All	
HI	All	
ID	All - 2 companies.	All - 1 company.
IL	Difference between tax and book lives.	
IN	All	
IA	All - 4 companies.	Difference between straight line tax life and straight line, book life - 2 companies.
KS	All	
KY	All	
LA	All	
ME	All - 1 company. Difference between ADR and book lives - 2 companies.	
MD	All	
MA	All	
MI	All	
MN	All	
MS	All	
MO	All	
MT	All	
NV	All - 1 company.	
NH	All	
NJ	All - major utilities.	

Table 19 (Continued). Normalization Versus Flow-Through Treatment of Tax Deferrals from Accelerated Depreciation[a]

State	Amount Normalized	Amount Flowed-Through
NM	All	
NY	Difference on a straight line basis between book lives and ADR lives.	Tax effects related to liberalized depreciation.
NC	Differences due to accelerated rates - 1 company. All - 3 companies.	
ND	All	
OH	All	
OK	All	
OR	Difference between ADR and book lives - 1 company. Answer unclear - 1 company.	
PA	All	
RI	All	
SC	All - 2 companies. Difference between tax straight line and tax accelerated - 1 company.	
SD	All	
TN		All
TX	All	
UT	All - 1 company. Difference between tax depreciation and ADR lives - 60% of benefits - 1 company.	
VT		All. 1 utility under another jurisdiction differs.
VA	All - major utilities.	
WA	All - 1 company. Difference between ADR + book lives - 1 company.	
WV	All - major utilities.	
WI	All	
WY	All	

[a]Information presented represents accounting methods applying to assets new prior to the Economic Recovery Tax Act of 1981.

Economic Recovery Tax Act of 1981, all states responded that at least for the time being they would fully normalize benefits as stipulated. Many of the states questioned had not seriously considered the new law since conversations regarding this issue took place between July and October 1981, very close to the time the law was passed.

C. State Taxation

1. Types of Taxation and Tax Rates Levied on Electric Utilities

Some states reported every tax imposed on utilities, while others included only major taxes. A number of commissions included municipal and county taxes.

Table 20 lists the four major types of taxation imposed on electric utilities according to the tax base. These bases are: gross receipts, state sales, local sales, and income. Franchise and other taxes have been categorized as miscellaneous. Because property tax rates vary greatly within individual states, the commissions were not able to report useful state data for the questionnaire.

A gross receipts tax, generally based on gross revenues, is imposed in 36 states. The maximum rate is 7 percent in New Jersey.

A sales tax, based generally on total revenues from electricity sales, is imposed on the state level in 25 states. Rates vary from three percent in several states to six percent in Rhode Island. Local sales taxes were listed by six states. These varied from 3/8 of 1 percent in some areas of Missouri to 3 percent in Juneau, Alaska.

Table 20. Major State Taxes on Electric Utilities (1981)[a]

State	Gross Receipts[b]	State Sales[c]	Local Sales[c]	Income[d]	Miscellaneous
AL	Municipal and local license tax 2 1/2% electric revenues.	4%	2%	5%	Rental tax-some cities - 4%. Corporate franchise $3 per mill based on par value of common and preferred stock. Public utility license - 2.2% State regulatory comm. fee - .5% Hydro tax - .25$/kwh.
AK			3% Juneau and Douglas 1% Outside corporate limits.	9.4%	Juneau city use tax 1% for items purchased outside of Juneau.
AZ	Regulatory assessment 2/10 of 1% of gross receipts.	4%		10.5%	
AR	3%			6%	
CA				State franchise tax 9.6%	
CO		3%		5%	
CT	5%			10%	
DC	6%			State franchise tax - 9.9%	Business license fee - insignificant.
DE	Gross receipts tax - .1%. License tax 2% on gross revenues excluding residential and resale.			8.7%	State franchise tax - maximum $100,000 on assets and shares of stock. Public utility tax - 5%. Regulatory tax - .2% of intrastate operating revenue. Use tax 2% on leases of tangible property.

Table 20 (continued). Major State Taxes on Electric Utilities (1981)[a]

State	Gross Receipts[b]	State Sales[c]	Local Sales[c]	Income[d]	Miscellaneous
FL	Utility assessment fee - 1/8 of 1% of gross operating revenues from intrastate business. Gross receipts tax - 1.5%.	4% residential electricity sales exempt and purchases toward oil conversion.		5%	
GA		3%	Some cities have a supplement to state sales tax.	6%	State franchise tax - 4%.
HI	Public utility fee - 1/4 of 1% of gross revenues.			6.435%	Local franchise tax - 2 1/2% counties and cities Public service company tax up to 8.2%.
ID				6.5%	
IL	Gross receipts tax - 5%. Public utility tax on gross receipts .008%.	5%		State income tax - 4%. Personal property replacement tax on income - 2.85%	State franchise tax 1.2%. Personal property replacement tax on investment .8%.
IN	1.35%	4%		3%	
IA				10%	
KS	State corporation commission tax - maximum of 1/5% of gross operating revenues.			6.75%	
KY	Millage rate			6%	
LA		5%	2%	8%	State franchise tax - $1.50/$1000 capital and undivided profits.
ME		5%		6.93%	Corporation fee - insignificant.

Table 20 (continued). Major State Taxes on Electric Utilities (1981)[a]

State	Gross Receipts[b]	State Sales[c]	Local Sales[c]	Income[d]	Miscellaneous
MD	2%	5%			Capital stock tax-varies.
MA				6.5%	
MI		Use tax - 4%.		2.35%	
MN	Local - varies	5%		12%	Local franchise tax - varies.
MS		5% with exemption of residential customers.		4%	State franchise tax - $2.50/$1000. Local
MO		3.125%	Varies - 3/8 - 1%.	5%	State franchise tax - 1/20 of 1% of assets.
MT				6.75%	Consumer council tax - .09%.
NV	State franchise tax - 2% gross revenues mill assessments.				Consumer advocate - .000075%. PSC-.0003%.
NH	PUC tax - .0013 of gross revenues of state.			State franchise tax - 9%.	
NJ	7%	Insignificant - about 1% of taxes 1979.			State franchise tax - 5% of assets. General assessment tax - about .9% of taxes 1979.
NM	Gross receipts tax - 3.5%. Inspection and supervision fee .5% of gross revenues.		2% of total revenues earned in any city.	$90,000 + 6% of increment	
NY	Gross earning tax .75% from in state sources and 4.5% on dividends paid/year above 4% of amount paid in capital employed in state.			Gross income tax - 3% exclusive of sales for resale.	

Table 20 (continued). Major State Taxes on Electric Utilities (1981)[a]

State	Gross Receipts[b]	State Sales[c]	Local Sales[c]	Income[d]	Miscellaneous
NC	6%			6%	
ND					
OH	4%	4%			Highway use - insign.
OK	2%	Varies - 2-4%.		4%	$1.25 per mill of invested capital maximum tax $20,000.
OR	PUC fee .15% per dollar of gross Oregon revenue. DOE fee .05% per dollar gross Oregon revenues.			Cities - overall about 1.75% of gross income. State income tax - 7.5%.	
PA	4.5% of all revenues.			10.5%	Capital stock tax - 1% applies to capital stock value.
RI	4%	State sales tax - 6% residential exempt.			
SC	.3%	4%		6%	Generation tax - .5%/kw.
SD	.1% on gross retail revenues.	4%			
TN	3%			Excise tax - 6%	State franchise tax - .15%. Franchise tax works as a credit against gross receipts.
TX	.167% of gross revenues.	State sales tax 5% residential exempt.			
UT	Less than 1%.	4%			
VT	Gross receipts tax - 4%. Public service tax .0040 of gross operating revenues.	3%		$17,150 + 7.5% of excess over $250,000.	Generation tax - 1.9% of asset's appraised value.

Table 20 (continued). Major State Taxes on Electric Utilities (1981)[a]

State	Gross Receipts[b]	State Sales[c]	Local Sales[c]	Income[d]	Miscellaneous
VA	1.125% of 1st $100,000; 2.6% on remainder. Special commission tax - .11% of revenues.				
WA	Business tax - 3.6% of revenues intrastate.	State Sales tax - 5%. Utility and transmission fee - .8% of sales to ultimate consumer.			Franchise and occupational fee - 1.0% (about). Generation tax - .44% net generation. Corporation license - insignificant.
WV	4%			State income tax - 6% - offset by gross receipts tax.	
WI	Remainder assessment .102% of revenue.	4%		7.9%	
WY	Maximum 0.3% on gross intrastate revenues.				

[a]This table lists reported variations, qualifications, exclusions, deductions, and highest stage rates for taxes as provided by states. Marginal tax rates listed are generally applicable to class A utilities. Property taxes have not been included. All taxes when possible have been categorized according to their base. Others have been placed in the miscellaneous column. These taxes are as reported for 1981.

[b]Gross receipts tax is based on gross revenues. Gross revenues have also been referred to as: total receipts and total revenues.

[c]State and local sales taxes are based on total revenues from electricity sales.

[d]Income tax is based on net income unless specified otherwise.

Note: Percentages and fractions of percentages may be incorrectly interpreted.

State and local franchise taxes are imposed in 15 states with bases varying.

2. Variations in State Income Tax Rates

In addition to the Federal Corporate Income Tax, many states impose a corporate income tax on electric utilities. Several states also impose a franchise tax and other taxes based on income. The base of these taxes is generally taxable income. Table 21 lists state income tax rates. Results show that a total of 39 states impose an income tax on electric utilities while 11 do not. Three of these states have a franchise tax and one has an excise tax.

Tax rates range between two and twelve percent. The largest numbers of states' taxes fall in the range of 6.0-6.9 percent of taxable income (Figure 3). This includes 13 states.

V. RATE CASE DURATION, FUEL ADJUSTMENT AND PROCUREMENT, NUCLEAR PLANT DECOMMISSIONING, REGULATION OF PUBLIC UTILITIES

A. Average Number of Months Necessary for Rate Decisions

The length of time from the date that a utility files a proposed rate revision to the date that a state regulatory commission issues a formal response varies greatly between states. Results showed that time required for rate decisions ranged from an average of 4.5 months in Texas to 21 months in Vermont (Table 22). The mean number of months necessary was 8.5. Twenty states indicated that a statutory deadline existed for such decisions. Wisconsin was the only state which said there was no requirement for the length of time which might be involved in a decision.

Table 21. State Income Tax Rates for Electric Utilities[a] (percent)

State	Rate	State	Rate
AL	5.0	MO	5.0
AK	9.4	MT	6.75
AZ	10.5	NV	-
AR	6.0	NH	9.0[b]
CA	9.6[b]	NJ	-
CO	5.0	NM	6.0
CT	10.0	NY	3.0[c]
DC	9.9[b]	NC	6.0
DE	8.7	ND	7.0
FL	5.0	OH	-
GA	6.0	OK	4.0
HI	6.435	OR	7.5
ID	6.5	PA	10.5
IL	4.0	RI	-
IN	3.0	SC	6.0
IA	10.0	SD	-
KS	6.75	TN	6.0[c]
KY	6.0	TX	-
LA	8.0	UT	2.0
ME	6.93	VT	7.5
MD	-	VA	-
MA	6.5	WA	-
MI	2.35	WV	6.0
MN	12.0	WI	7.9
MS	4.0	WY	-

[a]All variations, qualifications, exclusions, deductions, and initial rates have been omitted. Marginal tax rates shown in this table are applicable to most class A utilities.

Slash marks denote states with no income tax or with no such tax on electric utilities.

Taxes are categorized according to their base, net income, and not by their title. New York was the only state which listed its tax as based on gross income. Taxes listed, unless otherwise specified, are state corporate income taxes.

[b]This is a state franchise tax.

[c]This is an excise tax.

FIGURE 3. STATE INCOME TAX RATES FOR ELECTRIC UTILITIES

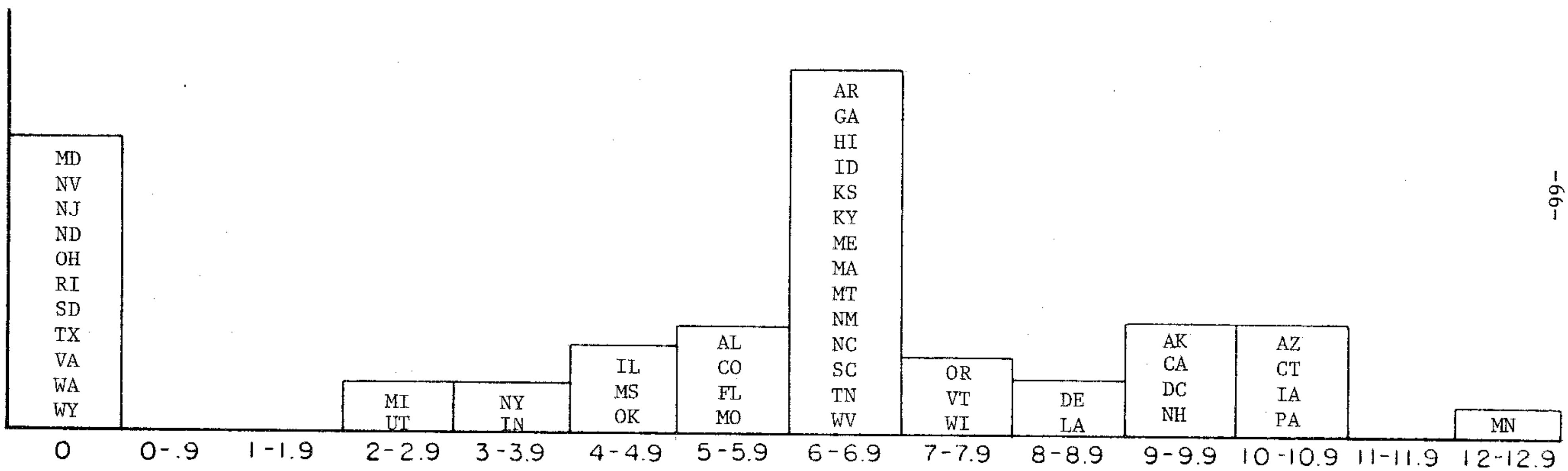


Table 22. Average Number of Months Necessary for Rate Decisions[a]

State	Month	State	Month
AL	6	MO	11
AK	6.5	MT	8.5
AZ	6	NV	6
AR	10	NH	6
CA	12	NJ	8
CO	10	NM	6.5
CT	5	NY	11
DC	16	NC	7
DE	7	ND	8
FL	8	OH	9
GA	6	OK	8.5
HI	9	OR	6
ID	5	PA	9
IL	11	RI	8
IN	6	SC	12
IA	12	SD	6
KS	8	TN	6
KY	10	TX	4.5
LA	12	UT	8
ME	9	VT	21
MD	7	VA	5
MA	6	WA	5
MI	9	WV	10
MN	12	WI	8.5
MS	6	WY	10

[a]For states where a legal maximum time period was listed this has been assumed average. When time periods have been differentiated between large and small utilities, the average for the large companies is utilized.

B. Policies Toward Fuel Price Adjustment Clauses

The fuel price adjustment clause is any mechanism which allows an electric utility to adjust its charges above or below the base amount included in its rates, based on changes in costs of fuel for generation of electricity, purchased power, or purchased gas.[23] An automatic fuel price adjustment clause differs in that it allows for increases or decreases or both in energy costs incurred by a utility without prior hearing.[24]

Adjustments for fuel price changes are made, according to commission guidelines or statutes: monthly, quarterly, three times per year, and bi-annually. This occurs both in states with automatic adjustment and in states without.

Three basic processes are used for adjustment: electric utilities can be allowed automatic adjustment for changes with no hearings required; they can be required to file a notification or report with commissions with no hearings necessary; or hearings can be mandatory for any changes in the fuel adjustment factor.

The facilitation of fuel cost recovery is one of the major aspects of fuel adjustment clauses. However, this is difficult to determine without comprehensive knowledge of state policy in this area. For example, the stipulation that a utility must file a notification or request with the state commission can serve merely as a technicality or may cause a company's rate change request to be subjected to a rigorous review process. Therefore, it is important that information presented in the following table be carefully scrutinized before any conclusions are drawn.

Table 23 lists policies toward use of fuel price adjustment clauses. Questionnaire results showed that 30 states allow automatic adjustment for fuel price changes. Eleven of these require utilities to file with commissions

Table 23. Policies Toward Use of Fuel Price Adjustment Clauses[a]

State	Adjustment Automatic[b] Yes	No	Frequency of Adjustment	Frequency of Hearings	Other Provisions
AL		√	Quarterly	Same[c]	
AK	√		Irregular	Same	Must file with commission
AZ	√		Triggered by .1 percent change in fuel costs	Irregular	Clause reviewed annually
AR	√		Monthly		
CA	√		Quarterly		Must file with commission
CO	√		Monthly	Quarterly	File with commission
CT	√		Monthly		Formal hearings for specific items - as necessary
DC	√		Monthly		Recalculated annually
DE	√		Monthly		Recalculated annually
FL	√		Monthly	Biannually	
GA		√	Quarterly[d]	Same	Recalculated annually
HI	√		Irregular	Same	
ID		√			Surcharges allowed upon application with commission
IL	√		Irregular	Annually	File with commission
IN		√	Quarterly[e]	Same	
IA	√		Monthly		
KS	√		Monthly		Must file with commission
KY	√		Monthly	Biannually & biennially	Must file with commission
LA		√	Monthly		
ME		√	Quarterly[f]	Same	Recalculated annually
MD	√		Monthly[g]		Received biannually
MA		√	Quarterly[h]	Same	
MI		√	Monthly	Same	Recalculated annually for over and under recovery
MN	√		Monthly		Recalculated annually[i]
MS	√		Monthly		Continuous Monitoring of Expenses by PSC
MO					No adjustment clause
MT		√	Biannually[j]	Same	File with commission opposite quarters
NV		√	Biannually[e]	Same	Deferred energy accounting utilized

Table 23 (continued). Policies Toward Use of Fuel Price Adjustment Clauses[a]

State	Adjustment Automatic[b] Yes	No	Frequency of Adjustment	Frequency of Hearings	Other Provisions
NH		✓	Quarterly and monthly	Same	
NJ		✓	Irregular	Same	Recalculated annually
NM	✓		Monthly		
NY	✓		Monthly		File with commission
NC	✓		3 times/ year	Same	
ND	✓		Biannually		Recalculated biennially
OH		✓	Biannually	Same	
OK	✓		Monthly		File with commission
OR	✓		Quarterly[j]		File with commission
PA	✓		Annually[i]		File with commission
RI	✓		Quarterly		
SC		✓	Biannually	Same	
SD	✓				
TN					No adjustment clause
TX	✓		Monthly		
UT	✓				Balancing account used
VT					No adjustment clause for large utilities[k]
VA		✓	Biannually	Same	
WA					No adjustment clause
WV		✓	Biannually	Same	
WI	✓		Monthly	Annually	
WY	✓		Quarterly Monthly		File with commission

[a]The fuel price adjustment clause as defined by the Oklahoma Corporation Commission is "any mechanism which allows a public utility to automatically adjust its charges above or below the base amount included in its rates, based on charges above or below the base amount included in its rates, based on changes in costs of fuel for generation of electricity, purchased power or purchased gas." This is from Oklahoma Statute Title 17 S 250.

Blank spaces indicate information not provided or which was unclear to the author.

Practices generally applicable for retail electric operations to fuel costs of power generated by utilities.

Table 23 (continued). Policies Toward Use of Fuel Price Adjustment Clauses[a]

[b]Automatic adjustment refers to provisions in a rate schedule which provide for increases or decreases or both without prior hearing in energy costs incurred by an electric utility. This definition is from North Dakota Public Service Commission, "Automatic Adjustment Clauses."

[c]Hearings are not necessarily required for all quarterly adjustments. They are held quarterly at a maximum.

[d]As needed as a result of increased or decreased fuel costs.

[e]At maximum.

[f]Reviewed and almost always changed.

[g]At a minimum. As much as a five percent per month increase is possible without the permission of the commission.

[h]If a ten percent over recovery occurs hearings are required for interim adjustment. Such hearings also can be necessary for under recovery.

[i]At minimum.

[j]One utility follows this practice.

[k]Fuel adjustment policies in Vermont vary by utility. Some companies can adjust monthly, others quarterly upon filing with the state commission. The large utilities are not allowed fuel price adjustment clauses.

before making adjustments. Sixteen states do not permit automatic adjustment and require companies to undergo hearings in order to make adjustments for fuel price changes.

Of the states allowing automatic adjustment, 18 permit adjustment monthly; one, North Carolina, allows adjustment three times per year; three permit alterations quarterly; and one, North Dakota, allows adjustment biannually. Arizona's adjustment is apparently triggered by a 1 mill/kWh change in fuel costs. Pennsylvania and Alaska allow alterations due to fuel price changes as necessary.

Of states mandating hearings in order for changes to be implemented, six states require these biannually; five commissions quarterly; and three states monthly. One state, New Jersey, holds hearings irregularly as adjustments are made.

Three states, Washington, Tennessee and Missouri, have no adjustment clauses. Vermont only allows its small and medium size utilities such clauses and does not permit large companies to use them. In Missouri, according to a commission staff person, utilities can file for interim rate relief if absolutely necessary but this is very infrequently done. Tennessee of course has no privately owned generating capacity.

C. Policies Toward Inclusion of Fuel Procurement Investments in the Rate Base

Fuel procurement investments are defined as direct investments by utilities in coal mines, natural gas fields, nuclear fuel facilities, or any other fuel obtainment related operations. Such investments are made by companies for several reasons, one being to obtain fuel below market prices. For accounting purposes, fuel procurement investments are generally included as part of the cost of fuel or allowed in the rate base.

Table 24 lists state regulatory policies toward fuel procurement investments. When asked whether these investments were allowed in the rate base, eight states (16 percent) answered "yes." Six commissions (12 percent) said such ventures were included on a case by case basis. Six states indicated that investments were allowed on exception. Fourteen regulatory commissions (28 percent) said these were not permitted in the rate base. Twelve states (24 percent) said they had no such schemes.

D. Privately Owned Nuclear Power Plant Decommissioning Accounting Practices

The URGE questionnaire attempted to obtain detailed information on decommissioning accounting practices for the 58 privately owned, presently operable reactors.[25] Data were collected on: (1) accounting methods; (2) the estimated cost of decommissioning; (3) funds accrued to date; (4) cost of original investment; (5) number of units; (6) power ratings; and (7) median year of expected decommissioning. This information is summarized by state and contained in Table 25.

Privately owned nuclear power plants exist in 24 states. Nuclear construction programs have been most ambitious in Illinois (six reactors); and in Pennsylvania, South Carolina and Virginia (four reactors). A number of states, however, still have only one plant.

Total state power ratings vary from 343 MWe in Colorado to 5508 in Illinois. Privately owned plants total 45,643 MWe of capacity.

The median year of expected decommissioning varies from 2002 to 2016.

Table 24. Regulatory Policies Toward Allowance of Fuel Procurement Investments in the Rate Base[a]

State	Allowed	Case by Case	Exceptions Allowed	Not Allowed	Not Applicable No Such Investments	Answer Unclear[b]
AL	√					
AK		√				
AZ					√	
AR			√			
CA	√					
CO				√		
CT				√		
DC					√	
DE					√	
FL				√		
GA					√	
HI					√	
ID	√					
IL		√				
IN						√
IA			√			
KS					√	
KY					√	
LA	√					
ME					√	
MD		√				
MA					√	
MI				√		
MN				√		
MS				√		
MO			√			
MT		√				
NV			√			
NH					√	
NJ		√				

Table 24 (Continued). Regulatory Policies Toward Allowance of Fuel Procurement Investments in the Rate Base[a]

State	Allowed	Case by Case	Exceptions Allowed	Not Allowed	Not Applicable No Such Investments	Answer Unclear[b]
NM				√		
NY		√				
NC				√		
ND			√			
OH			√			
OK	√					
OR	√					
PA				√		
RI	√					
SC				√		
SD				√		
TN					√	
TX						√
UT	√					
VT					√	
VA						√
WA				√		
WV				√		
WI						√
WY				√		

[a]Fuel procurement investments are defined as company investments in coal mines, natural gas fields, nuclear fuel facilities, etc.

[b]This column lists answers which were unclear to the author.

Table 25. Decommissioning Accounting Data for Privately Owned Nuclear Power Plants (by state)[1]

State	Number of Units	Power Rating (MW)[3]	Median Year of Expected Decommissioning[4]	Decommissioning Fund Accounting Method[5]	Cost of Original Investment (million $)[6]	1981 Estimated Cost of Decommissioning (million $)[7]	Funds Accrued to Date (million $)
AL	2	1768.0	2016	UDR	734.5[14]	68.4	unknown
AR	2	1861.3	2015	UDR	254.0[15]	69.4	1.2
CA[2]	1	450.0	2003	UDR	181.6	64.0	~10.0
CO	1	343.0	2014	ESF	---	35.0	2.1
CT	3	2172.3	2008	UDR	728.7	243.0	9.5
FL	4	2459.0	2010	UDR	1138.7	236.6	22.1
GA	2	1700.0	2014	UDR	4.5[16]	64.0	---
IL[2]	6	5508.0	2008	UDR	1116.2[17]	370.0[21]	65.3[25]
IA	1	597.0	2010	none	232.3	none	none
ME	1	810.0	2007	UDR[8]	237.8	62.7	none
MD	2	1829.0	2012	UDR	777.7	64.8	6.2[26]
MA	2	863.0	2002	split[9]	310.7	45.6	[27]
MI[2]	4	3157.0	2008	split[10]	1220.2	355.0[22]	3.0[28]
MN	3	1755.0	2008	UDR	551.7	151.3	---
NJ	2	1720.0	2007	UDR	851.0[18]	232.6	[29]
NY	3	2172.1	2006	UDR	686.5[19]	147.5	[30]
NC	2	1733.4	2012	UDR	714.9	331.2[23]	10.1
OH	1	962.0	2012	UDR	635.1	53.5	unknown
OR	1	1216.0	2011	UDR[11]	466.4	8.5	2.8
PA[2]	4	3227.0	2010	ESF[12]	1389.9	155.4	[31]
SC	4	3570.7	2008	UDR	586.1	310.3[24]	[32]
VT	1	540.0	2007	none[13]	198.8	73.0	none
VA	4	3622.0	2010	UDR	1201.7[20]	82.8	8.8
WI	3	1607.6	2007	UDR	380.9	129.4	~20.0

Note: See footnotes and detailed explanation of definitions and assumptions in Appendix B-2.

Specifically, a total of 35 reactors are expected to come to term and require decommissioning between 2005 and 2009. In ten years between 2003 and 2012, 51 reactors will need to be decommissioned.[26]

Two major decommissioning accounting alternatives are utilized by companies, the "unsegregated depreciation reserve" (UDR) and the "external sinking fund" (ESF). These methods are described in footnote 5, Appendix B-2. According to Wood, the external sinking fund method has a much greater chance of assuring the availability of funds for decommissioning than the unsegregated reserve.[27]

Plants in 19 states (79 percent of states with privately owned reactors) use unsegregated depreciation reserve accounting. Plants in three states (Colorado, Massachusetts, and Pennsylvania) have external sinking funds. Four states have plants for which no accounting method has been chosen.

Individually, 48 plants (83 percent of these plants) use UDR accounting; five (9 percent) have ESF's; and five have no established accounting methods.[28]

Cost of original investment as of 1978 varied by state between $4.5 million and $1.4 billion depending on the number, size, and age of plants. The 1978 total cost of investment for 53 plants was $14.6 billion. For states with privately owned reactors, this is an average of $610 million.

The total 1981 estimated cost of decommissioning varies greatly between states. Values range from $8.5 million in Oregon to $370 million in Illinois. The total estimated cost of decommissioning all privately owned reactors is $3.4 billion (1981 $). This is an average of $140 million per state and $58 million per plant.

Funds accrued to date range from none in Iowa, Maine, and Vermont to

$22.1 million in Florida. It is difficult to determine any total figure for funds accrued to date since a number of utilities themselves are unsure of the exact amount. From information provided, total funds accrued to date for all 58 plants fall between an estimated $170-190 million ($ 1981).

State ratios of the total 1981 estimated cost of decommissioning to the 1978 original cost of investment show considerable variation. Values range from estimated decommissioning costs of 1.8 percent of the cost of orginal investments in Oregon to 52.9 percent of the cost in South Carolina. The average state ratio is 24.4 percent. (Such ratios, of course, must be kept in perspective as being significantly increased by the use of 1978 investment values. Both inflation and added expenses due to plant completions, and equipment additions and improvements to existing plants may have increased plant costs above 1978 values, thus lowering these ratios. Of course, estimated decommissioning costs have also increased markedly since 1978.)

Nuclear plant decommissioning cost estimates show considerable variability. The Battelle Pressurized Water Reactor Study estimated the 1978 cost of decommissioning a 1175 MW plant at $42 million.[29] The California Energy Commission has assumed decommissioning costs at ten percent of the cost of construction.[30] Skinner, studying the Elk River and Sodium-Reactor Experiment decommissionings, estimated decommissioning costs at 24 percent of the investment cost.[31] Finally, Chapman has asserted that the cost of decommissioning for damaged reactors with serious contamination problems could be as high as 100 percent of a plant's original cost.[32]

If the estimated decommissioning costs in Table 25 should be experienced at the dates indicated, then the financial impact upon states and utilities will be minimal. However, if the costs are much higher, and are experienced earlier, the financial impact would become significant. Although this is usually viewed as unlikely, it must be recognized that such a development would severely limit the ability of certain states and utilities to finance major new air pollution control programs.

E. Regulation of Publicly Owned Electric Utilities by State Regulatory Commissions

State regulatory agencies were generally unable to provide exact figures for the percentage of publicly owned electricity produced in their states. Several regulatory agencies referred the author to their state energy offices for this information. It is likely that such data does not fall within the jurisdiction of regulatory commissions. This information as derived from the Edison Electric Institute (EEI) Yearbook 1980 is contained in Table 26.

A total of 22.0 percent of U.S. electricity is produced by publicly owned utilities.[33] Five states have greater than 75 percent and 26 states have less than ten percent of their electricity produced by these utilities.

Table 27 describes regulatory commission responsibility for publicly owned utilities. Twenty six state commissions (52 percent) indicated no such responsibility. Twenty commissions (40 percent) indicated that they had at least some regulatory authority over publicly owned utilities.

Four commissions named municipals as utilities which they regulated; seven cited R.E.A. Co-ops. Twelve state commissions did not specify which utilities they had authority over.

Appendix C provides two sources of state comparative data on private and public utilities.

Table 26. Publicly Owned Electricity Generation by State 1980[a]
(percent)

State	Generation	State	Generation
AL	50.0	MO	26.7
AK	97.2	MT	32.4
AZ	81.9	NV	16.4
AR	12.0	NH	-
CA	26.9	NJ	1.0
CO	44.9	NM	2.3
CT	.2	NY	30.8
DC	-	NC	1.9
DE	7.5	ND	96.3
FL	14.5	OH	1.0
GA	3.4	OK	10.4
HI	-	OR	63.3
ID	29.8	PA	-
IL	3.2	RI	.1
IN	3.4	SC	20.9
IA	6.5	SD	67.0
KS	15.4	TN	98.6
KY	59.8	TX	12.3
LA	9.5	UT	4.7
ME	.2	VT	3.4
MD	.3	VA	1.7
MA	1.5	WA	87.5
MI	6.0	WV	-
MN	4.1	WI	12.0
MS	12.1	WY	5.0

[a]These results are preliminary for 1980. Slash marks denote states with less than .1 percent publicly owned generation.

Source: EEI Statistical Year Book of the Electric Utility Industry 1980 (Washington, D.C.: Edison Electric Institute. 1980): 24-25, Tables 15 and 16.

Table 27. Regulatory Commission Responsibility for Publicly Owned Electric Utilities[a]

State	No Responsibility	Regulatory Responsibility: Municipals	R.E.A. Coops	Other (unspecified)
AL	✓			
AK		✓	✓	
AZ			✓	
AR			✓	
CA	✓			
CO			✓	
CT	✓			
DC	✓			
DE				✓
FL				
GA	✓			
HI	✓			
ID	✓			
IL[b]	✓			
IN		✓		✓
IA		✓	✓	
KS				✓
KY				✓
LA	✓			
ME				✓
MD				✓
MA				✓
MI	✓			
MN	✓			
MS				
MO	✓			
MT	✓			
NV	✓			
NH	✓			
NJ		✓		
NM				
NY	✓			
NC	✓			
ND	✓			
OH	✓			

Table 27 (continued). Regulatory Commission Responsibility for Publicly Owned Electric Utilities[a]

State	No Responsibility	Regulatory Responsibility: Municipals	R.E.A. Coops	Other (unspecified)
OK				√
OR				
PA	√			
RI	√			
SC	√			
SD	√			
TN	√			
TX				√
UT			√	
VT				√
VA				√
WA	√			
WV	√			
WI				√
WY			√	

[a]Check marks indicate that some or all electric utilities in these categories are regulated. Blank spaces indicate that this question was not answered. No distinction has been made between power buying and power generating utilities.

[b]Illinois regulates service area boundaries, not financial accounting or rates.

F. Financial Regulations Overlooked by the Questionnaire

Forty three commissions responded that no significant financial regulations had been overlooked. Table 28 describes answers provided by the remaining seven states.

Seven state commissions (14 percent) listed regulations or areas which the questionnaire missed. Four states mentioned information regarding securities approval or issuing stocks and bonds; Nevada cited new regulations related to the State Consumer Advocate Office; Oklahoma mentioned state regulatory approval of actions by utility affiliates; and Georgia discussed utilization of the projected test year in rate cases and utilities providing refunds to customers when necessary.

Table 28. Major Final Regulations Not Dealt with in Questionnaire

State	Financial Regulations not Mentioned
GA	Senate Bill 29 - Must use projected test year in rate cases for electric utilities. When electric plant is sold, company must refund to customers their amounts contributed.
ME	Long term debt has to be approved by commission.
NV	New regulations pending before the Nevada legislature. Consumer Advocate office to work on utility rates.
NH	All financings require approval by the PUC with the exception of short term borrowings up to 10 percent of the net asset value.
NJ	Issuing bonds, common stock, leasing property.
OK	State regulatory commission must approve electric utility (only) securities issues.
WI	Affiliate interests - approval of any actions if they provide services to the parent.

APPENDICES

APPENDIX A

URGE State Regulatory Policy Questionnaire

I. Rate Base

A. What items may be included in the rate base (RB) other than direct investment and AFUDC?

B. Can pollution control and conservation expenditures be included in the RB? Please distinguish between customer related and company conservation expenditures.

C. What percentage, if any, of CWIP is allowed in the RB?

D. For book purposes (not tax), what type of depreciation (i.e., SL, DDB, SYD) and asset lives are used to depreciate various assets in the RB?

1. nuclear plants

2. coal plants

3. oil and gas units

4. hydro

5. transmission and distribution equipment

6. other significant parts of the RB

E. Is the RB adjusted for inflation? If yes, how is the adjustment made?

F. Is AFUDC calculated by the FERC method? If not, how is it calculated?

G. When is AFUDC allowed in the RB? Upon project completion?

H. Can AFUDC be earned on accumulated AFUDC which is not in the RB?

II. Rates of Return

A. What rates of return are allowed on: 1) common equity; 2) the rate base?

1. How are these numbers determined?

2. How often are they revised?

III. Tax Treatment

A. Investment Tax Credit (ITC)

1. What ITC rate is used by most utilities in the state? (i.e. 10%, 11%, or 11-1/2%.)

2. What percentage of the ITC is normalized, flowed-through? Please describe in detail your method of normalization.

3. How many utilities in your state claim the additional 1-1/2% ITC for employee stock ownership plans?

B. Accelerated Depreciation

1. Which method(s) of depreciation are permitted for tax purposes?

2. What percentage of tax deferrals from accelerated depreciation are normalized and what percentage are flowed-through?

a. Please distinguish between deferrals from accelerated depreciation and deferrals from the asset depreciation range differing from an investment's actual expected life.

b. Please describe in detail your method of normalization, if different from that applied to the ITC.

C. State Taxation

1. What types of taxation (corporate income, gross receipts, sales, property, etc.) does the state levy on electric utilities? Please list types of taxation and tax rates.

2. If your state has a corporate income tax, how does it differ from the federal corporate income tax?

IV. Miscellaneous

A. Does your state have an automatic fuel price adjustment clause? If so, please describe it.

B. Are companies who operate nuclear power plants required to contribute to an account which will be used to decommission these plants? Please describe the required contributions.

C. How many months on an average does it take to make a decision on requested rate increases?

D. How are fuel procurement investments treated? By fuel procurement investment, I mean direct investment in coal mines, natural gas fields, nuclear fuel facilities, etc.

E. What percentage of electric power in your state is produced by non-investor owned utilities? Do you regulate these utilities directly?

F. Are there any significant state financial regulations that I have not mentioned?

APPENDIX B-1

Options for Treatment of the Investment Tax Credit

This discussion is taken directly from: Donald W. Kiefer, Accelerated Depreciation and the Investment Tax Credit in the Public Utility Industry: A Background Analysis (Columbus, OH: Ohio State Univ., 1979) p. 3.

"The first option - which the statute labels the "general rule" but which might more descriptively be named "rate base normalization: permits (but does not require) a reduction in the utility's rate base to reflect the investment tax credit (or a portion thereof) so long as the amount of the reduction is restored to the rate base not less than ratably over the useful life of the asset for book purposes. Under this option, any adjustment to the utility's cost of service for ratemaking purposes, including an adjustment which would result from reducing the depreciable basis of assets by the amount of the credit, is expressly prohibited.

The second option called "ratable flow-through" or "cost of service normalization" permits a ratable reduction in the utility's cost of service for ratemaking purposes but prohibits any adjustment to the utility's rate base. The prohibited adjustments include any accounting treatment of the credit which would affect the utility's permitted profit on investment.

Under these options if a regulatory agency requires a greater adjustment in the rate base or the cost of service than is permitted, then the investment tax credit is to be disallowed with regard to the affected property.

Under the third option, which the statute appropriately terms "immediate flow-through", the entire amount of the investment tax credit may be flowed-through immediately to rates by an equivalent reduction in the Federal income tax element of the utility's cost of service. However, this option could be elected only by a utility which uses accelerated depreciation and flow-through accounting for its post-1969 property, and the election was supposed to be made without regard to the requirements of any regulatory agency."

APPENDIX B-2

Footnotes for Table 25: Decommissioning Accounting Data for Privately Owned Nuclear Power Plants

1 Information provided in this table unless indicated represents state totals for practices current in December 1981. It does not include data for publicly owned, decommissioned or inoperable reactors. Information has been compiled from data collected for individual reactors. Those interested can obtain reactor-specific data from: Sally Hindman, c/o Duane Chapman, 212 Warren Hall, Cornell University, Ithaca, New York, 14853. Unobtainable information is indicated by "---".

2 The following reactors are presently inoperable or have been decommissioned: CA - Humboldt Bay 3; IL - Dresden 1; MI - Fermi 1; NY - Indian Point 1; PA - Peach Bottom 1, Three Mile Island 1, Three Mile Island 2; SD - Pathfinder. Commercial reactors with power ratings under 50 electrical megawatts have been omitted.

3 Power ratings are in electrical megawatts.

4 This has been calculated using an average service life of 35 years from the plant start-up date. It does not take into consideration factors which might affect the shutdown date such as accidents, faulty technology or extensions in estimated average service lives. It assumes that sister reactors will undergo "double" or simultaneous decommissioning due to economies of scale associated with this practice.

5 UDR = Unsegregated Depreciation Reserve. This is also referred to as an unfunded reserve. It is an accounting procedure generally using negative net salvage value depreciation, which allows estimated decommissioning costs to be accumulated over the life of the facility. ESF = External Sinking Fund. This reserve requires a prescribed amount of funds to be set aside annually in some manner such that the fund, plus any accumulated interest would be sufficient to pay for costs at the estimated time of decommissioning. The fund could be invested in high-grade corporate securities, in state or municipal tax-free securities, in federal debt obligations, or other assets. The fund would be administered separately from the utility's assets. Source of definitions: R.S. Wood, Assuring the Availability of Funds for Decommissioning Nuclear Facilities (Washington, D.C.: U.S. Nuclear Regulatory Commission, October 1980) pp. 9-13.

6 Cost of investment includes: land and land rights, structures and improvements, and equipment through December 1978. The source is: U.S. Department of Energy, Energy Information Administration, Steam Electric Plant Construction Cost and Annual Production Expenses - 1978 (Washington, D.C.: U.S.

DOE/EIA, 1980). Plants for which this information has not been provided were incomplete or nonexistent at the time the data were gathered. Values have been rounded to $^{1}/10$ of 1 million dollars.

7 Values listed in pre-1981 dollars have been converted to 1981 dollars using a multiplier based on the Consumer Price Index (All Items). Numbers in post-1981 dollars were adjusted using a multiplier based on a constant seven percent inflation rate. The source of Consumer Price Indices was: James E. Carter, Economic Report of the President (Washington, D.C.: U.S. Government Printing Office, January 1981) p. 289.

8 No funds were being accrued for Maine Yankee's wholesale plant operations as of November 1981. Wholesale power exports comprise a major portion of the company's sales. Funds are currently unsegregated, but, according to plant officials, a segregated trust fund is scheduled for use pending FERC approval of decommissioning plans.

9 Pilgrim 1 has no accounting system for decommissioning funds. Yankee Rowe has an external sinking fund.

10 Donald C. Cook has no established accounting system for decommissioning funds. Decommissioning practices were to be determined in a rate case pending as of March 1982. Both Big Rock Point 1 and Palisades 1 have "unsegregated depreciation reserves."

11 Funds for Trojan 1 are segregated internally by Portland General Electric through use of an "internal sinking fund." Other utilities may also use this accrual method but have not indicated this specifically. Use of an internal sinking fund does not significantly affect the long-term protection or availability of funds for decommissioning as found with other unsegregated reserves. Footnote 5 describes the two major accounting methods.

12 Ohio Edison, with 35 percent ownership of Beaver Valley 1, uses an unsegregated depreciation reserve.

13 As of March 1982 no decommissioning funds had been accrued for Vermont Yankee. The utility planned to wait until the plant debt was paid off before setting aside funds. In lieu of debt payments, monies were to be set aside for decommissioning for the last six years of the unit's life. Vermont Yankee Nuclear Power Co. has been involved in a precedent-setting legal case related to taxation of funds which would be used for decommissioning.

14 This does not include costs for Farley 2.

15 This does not include costs for Arkansas Nuclear 2.

16 This does not include costs for Edwin I Hatch 2.

17 This includes costs for Dresden 1 which is now inoperable.

18 This does not include costs for Salem 2.

19 This includes costs for Indian Point 1 which is now inoperable.

20 This does not include costs for North Anna 2.

21 Commonwealth Edison, the principal owner of Illinois' nuclear facilities, is using a decommissioning cost range in estimating funds needed. The state total using the low range value would be $320 million. The value listed in this table is the total using the high range numbers.

22 The decommissioning method which will be used for Donald C. Cook 1 and 2 has not yet been made final. The value listed in this table assumes the highest cost method, "entombment and dismantlement," will be chosen. If the lowest cost method, "mothballing," is used the state total estimated cost of decommissioning would be $196.79 million.

23 These estimates are new and have recently been approved by the North Carolina commission. Approval, as of March 1982, had not been obtained by South Carolina P.S.C., but was anticipated.

24 The estimate for one plant in this state, H.B. Robinson 2, is new and as of March 1982 had not yet been approved by South Carolina P.S.C. However, commission approval was anticipated.

25 This includes funds for Iowa-Illinois Gas and Electric's 25 percent share of Quad Cities 1 and 2.

26 This is through 2/28/82.

27 No funds have been accrued for Pilgrim 1. One mill per kWh is accrued for Yankee Rowe.

28 August 1980 the state regulatory commission disallowed the accrual of funds for decommissioning the Big Rock Point and Palisades plants until generic hearings are held on the subject of decommissioning.

29 Public Service Electric and Gas has accrued $27 million for all four of its units (three under construction and one existing). Accrued funds for Oyster Creek were $4,167,700 through January 1981.

30 Indian Point 2 - $5 million / year; Nine Mile Point 1 - $2.48 million / year; Ginna 1 - $3.13 million / year.

31 Beaver Valley 1 - Ohio Edison's share - $121,540 / year; Duquesne Light's share - $7.65 million to date. Peach Bottom 2 and 3 - Philadelphia Electric's share - $2.2 million / year.

32 H.B. Robinson 2 - $1.2 million; Oconee 1, 2, and 3 - amount unknown.

APPENDIX C

URGE State Financial Data— ARMS Region

ITEMS	UNITS	AL	AR	CT	DE
Common Equity Portion of Capitalization	Fraction	.321	.312	.356	.353
Debt Portion of Capitalization	Fraction	.581	.534	.510	.509
Preferred Stock Portion of Capitalization	Fraction	.098	.154	.134	.138
Accumulated Investment Tax Credit	Million $	54.9	32.3	48.9	38.8
Property Tax and Other Taxes	Fraction	.018	.013	.042	.019
State Income Tax Rate[a]	Fraction	.050	.060	.100	.087
Base Year Accumulated Investment Tax Credit	Million $	54.9	32.3	48.9	38.8
AFUDC Accumulation Method[b]	0=Simple 1=Compound	1	1	1	1
AFUDC Calculation Method[c]	0=After Taxes 1=Other	0	0	0	0
Rate of Return to Common Stock[d]	Fraction	.129	.150	.147	.150
Electric Plant in Service	Million $	4009.0	2220.0	2936.0	1252.3
Net Plant Electric	Million $	2922.7	1773.1	1798.5	970.0
Construction Work in Progress-Electric	Million $	1147.8	285.1	865.2	102.7
Accumulated Direct Construction Costs-Electric	Million $	918.24	228.1	692.2	82.2
Construction Work in Progress-Pollution Control	Million $	97.3	42.5	11.0	25.6
Accumulated Direct Construction Costs-Pollution Control	Million $	77.8	34.0	8.8	20.5
Total Outstanding Debt	Million $	1998.5	875.4	1485.5	524.7
Prior Common Stock Issuance	Million $	380.3	516.4	1089.7	387.7
Prior Preferred Stock Issuance	Million $	381.9	222.3	369.9	125.0
Retained Earnings	Million $	105.2	93.8	405.5	130.6
Total Current and Accrued Liabilities	Million $	395.9	253.1	729.9	97.4
Total Current and Accrued Assets	Million $	402.0	116.8	496.5	154.1
Net Working Capital	Million $	6.1	-136.4	-233.4	56.7
New Preferred Stock Issued	Million $	-----	50.3	54.7	30.0
New Common Stock Issued	Million $	-----	35.8	32.2	7.7

APPENDIX C (Continued)

ITEMS	UNITS	AL	AR	CT	DE
New Long Term Debt	Million $	255.9	70.0	121.5	45.0
Total Assets and Other Debits	Million $	4769.5	2278.7	3992.1	1386.0
EEI 1980-Total Revenues Electric Utility Industry	Million $	2038.7	875.1	1304.4	325.2
EEI 1980-Total Revenues Investor Owned Utilities	Million $	1309.1	696.5	1252.7	281.4
DOE 1980-Total Revenues from Sales to Ultimate Consumers, Private Utilities	Million $	1297.1	623.7	1250.5	378.0
DOE 1980-Total Revenues from Sales of Electricity, Private Utilities	Million $	1550.9	811.8	1379.1	436.9

APPENDIX C (Continued)

ITEMS	UNITS	FL	GA	IL	IN
Common Equity Portion of Capitalization	Fraction	.367	.320	.346	.369
Debt Portion of Capitalization	Fraction	.523	.577	.526	.510
Preferred Stock Portion of Capitalization	Fraction	.110	.103	.128	.121
Accumulated Investment Tax Credit	Million $	451.7	237.1	474.4	343.8
Property Tax and Other Taxes	Fraction	.033	.017	.037	.013
State Income Tax Rate[a]	Fraction	.050	.060	.040	.030
Base Year Accumulated Investment Tax Credit	Million $	451.7	237.1	474.4	343.8
AFUDC Accumulation Method[b]	0=Simple 1-Compound	0	0	1	1
AFUDC Calculation Method[c]	0=After Taxes 1=Other	1	0	0	0
Rate of Return to Common Stock[d]	Fraction	.152	.132	.165	.158
Electric Plant in Service	Million $	8662.6	4997.2	11455.4	7760.1
Net Plant Electric	Million $	6554.4	3754.3	7443.3	5658.8
Construction Work in Progress-Electric	Million $	1472.4	813.6	5358.3	2219.9
Accumulated Direct Construction Costs-Electric	Million $	1177.9	650.9	4286.6	1775.2
Construction Work in Progress-Pollution Control	Million $	79.2	88.4	403.5	198.9
Accumulated Direct Construction Costs-Pollution Control	Million $	63.4	70.7	322.8	159.1
Total Outstanding Debt	Million $	3212.6	2407.7	5946.6	3349.3
Prior Common Stock Issuance	Million $	2502.6	1377.1	3846.1	2722.7
Prior Preferred Stock Issuance	Million $	773.3	445.4	1491.7	890.7
Retained Earnings	Million $	1115.6	239.9	947.2	613.3
Total Current and Accrued Liabilities	Million $	838.4	426.7	1524.0	978.6
Total Current and Accrued Assets	Million $	1011.4	860.7	1412.5	1074.9
Net Working Capital	Million $	173.3	434.0	-111.5	96.3
New Preferred Stock Issued	Million $	10.0	0	100.6	50.0
New Common Stock Issued	Million $	121.3	0	467.7	142.1

APPENDIX C (continued)

ITEMS	UNITS	FL	GA	IL	IN
New Long Term Debt	Million $	524.1	75.0	616.3	606.5
Total Assets and Other Debits	Million $	9528.4	5591.4	15951.6	9966.6
EEI 1980-Total Revenues Electric Utility Industry	Million $	4687.7	2129.0	4728.3	2167.0
EEI 1980-Total Revenues Investor Owned Utilities	Million $	3821.6	1652.8	4505.3	1900.5
DOE 1980-Total Revenues from Sales to Ultimate Consumers, Private Utilities	Million $	3804.9	1652.2	4463.9	2032.9
DOE 1980-Total Revenues from Sales of Electricity, Private Utilities	Million $	4093.5	1914.2	4662.9	2805.0

APPENDIX C (Continued)

ITEMS	UNITS	IA	KY	LA	ME
Common Equity Portion of Capitalization	Fraction	.346	.372	.320	.366
Debt Portion of Capitalization	Fraction	.530	.516	.543	.505
Preferred Stock Portion of Capitalization	Fraction	.124	.112	.137	.129
Accumulated Investment Tax Credit	Million $	172.2	130.9	194.2	45.4
Property Tax and Other Taxes	Fraction	.022	.017	.013	.017
State Income Tax Rate[a]	Fraction	.100	.060	.080	.070
Base Year Accumulated Investment Tax Credit	Million $	172.2	130.9	194.2	45.4
AFUDC Accumulation Method[b]	0=Simple 1=Compound	1	1	1	1
AFUDC Calculation Method[c]	0=After Taxes 1=Other	0	0	1	1
Rate of Return to Common Stock[d]	Fraction	.134	.143	.142	.147
Electric Plant in Service	Million $	3072.3	2209.8	3976.9	1100.6
Net Plant Electric	Million $	2256.6	1555.1	2719.8	666.1
Construction Work in Progress-Electric	Million $	588.4	600.9	2448.7	164.1
Accumulated Direct Construction Costs-Electric	Million $	470.7	480.7	1959.0	131.3
Construction Work in Progress-Pollution Control	Million $	63.4	129.1	292.5	6.1
Accumulated Direct Construction Costs-Pollution Control	Million $	50.7	103.3	234.0	4.9
Total Outstanding Debt	Million $	1540.3	868.9	2079.6	466.2
Prior Common Stock Issuance	Million $	1011.3	695.8	1386.9	324.7
Prior Preferred Stock Issuance	Million $	336.2	208.0	511.5	98.2
Retained Earnings	Million $	294.7	237.5	354.5	91.9
Total Current and Accrued Liabilities	Million $	467.9	294.4	483.9	196.1
Total Current and Accrued Assets	Million $	408.8	333.7	355.8	179.8
Net Working Capital	Million $	-59.1	39.4	-128.1	-16.3
New Preferred Stock Issued	Million $	38.5	20.0	143.0	25.0
New Common Stock Issued	Million $	36.8	64.4	141.4	24.7

APPENDIX C (Continued)

ITEMS	UNITS	IA	KY	LA	ME
New Long Term Debt	Million $	65.9	183.6	514.3	16.3
Total Assets and Other Debits	Million $	3980.3	2704.4	5885.4	1293.2
EEI 1980-Total Revenues Electric Utility Industry	Million $	1073.1	1552.8	2029.0	419.4
EEI 1980-Total Revenues Investor Owned Utilities	Million $	875.8	852.4	1860.2	409.3
DOE 1980-Total Revenues from Sales to Ultimate Consumers, Private Utilities	Million $	941.4	780.6	2071.4	404.1
DOE 1980-Total Revenues from Sales of Electricity, Private Utilities	Million $	983.1	909.9	2266.5	605.4

APPENDIX C (Continued)

ITEMS	UNITS	MD & DC	MA	MI	MN
Common Equity Portion of Capitalization	Fraction	.390	.403	.438	.410
Debt Portion of Capitalization	Fraction	.497	.514	.465	.472
Preferred Stock Portion of Capitalization	Fraction	.113	.083	.097	.118
Accumulated Investment Tax Credit	Million $	200.6	140.0	9551.3	130.0
Property Tax and Other Taxes	Fraction	.032	.047	.019	.032
State Income Tax Rate[a]	Fraction	-----	.065	.024	.120
Base Year Accumulated Investment Tax Credit	Million $	200.6	140.0	9551.3	130.0
AFUDC Accumulation Method[b]	0=Simple 1=Compound	1	0	0	0
AFUDC Calculation Method[c]	0=After Taxes 1=Other	0	1	1	0
Rate of Return to Common Stock[d]	Fraction	.140	.135	.133	.140
Electric Plant in Service	Million $	5485.2	4450.8	8372.8	3374.9
Net Plant Electric	Million $	3912.5	3072.8	6251.9	2422.4
Construction Work in Progress-Electric	Million $	791.8	875.9	3250.1	242.1
Accumulated Direct Construction Costs-Electric	Million $	633.4	700.7	2600.1	193.7
Construction Work in Progress-Pollution Control	Million $	232.8	65.6	978.6	17.7
Accumulated Direct Construction Costs-Pollution Control	Million $	186.2	52.5	782.9	14.2
Total Outstanding Debt	Million $	2472.3	1885.4	4394.5	1214.5
Prior Common Stock Issuance	Million $	2004.1	1541.8	4084.4	1058.6
Prior Preferred Stock Issuance	Million $	553.6	305.5	764.7	308.7
Retained Earnings	Million $	565.3	241.3	801.1	349.3
Total Current and Accrued Liabilities	Million $	514.5	887.6	1333.1	376.3
Total Current and Accrued Assets	Million $	743.3	799.4	1548.4	310.2
Net Working Capital	Million $	228.8	-88.2	215.3	-66.1
New Preferred Stock Issued	Million $	41.5	15.0	196.2	0
New Common Stock Issued	Million $	56.3	8.4	243.6	14.5

APPENDIX C (Continued)

ITEMS	UNITS	MD & DC	MA	MI	MN
New Long Term Debt	Million $	152.0	90.6	887.4	20.5
Total Assets and Other Debits	Million $	6415.0	5415.5	12460.3	3504.4
EEI 1980-Total Revenues Electric Utility Industry	Million $	2037.1	2169.6	3329.0	1293.0
EEI 1980-Total Revenues Investor Owned Utilities	Million $	1971.2	1982.1	3073.5	983.4
DOE 1980-Total Revenues from Sales to Ultimate Consumers, Private Utilities	Million $	1967.3	2008.6	3075.9	981.6
DOE 1980-Total Revenues from Sales of Electricity, Private Utilities	Million $	2075.6	3388.2	3287.9	1110.9

APPENDIX C (Continued)

ITEMS	UNITS	MS	MO	NH	NJ
Common Equity Portion of Capitalization	Fraction	.347	.363	.408	.406
Debt Portion of Capitalization	Fraction	.556	.505	.418	.476
Preferred Stock Portion of Capitalization	Fraction	.097	.132	.174	.118
Accumulated Investment Tax Credit	Million $	50.2	293.0	25.8	164.8
Property Tax and Other Taxes	Fraction	.025	.036	.016	.068
State Income Tax Rate[a]	Fraction	.040	.050	.090	-----
Base Year Accumulated Investment Tax Credit	Million $	50.2	293.0	25.8	164.8
AFUDC Accumulation Method[b]	0=Simple 1=Compound	0	0	1	0
AFUDC Calculation Method[c]	0=After Taxes 1=Other	0	0	1	1
Rate of Return to Common Stock[d]	Fraction	.129	.137	.151	.140
Electric Plant in Service	Million $	1423.4	4873.3	610.8	6613.4
Net Plant Electric	Million $	991.5	3512.4	434.2	4626.9
Construction Work in Progress-Electric	Million $	40.6	1669.7	672.6	1860.6
Accumulated Direct Construction Costs-Electric	Million $	32.5	1335.5	538.1	1488.5
Construction Work in Progress-Pollution Control	Million $	.3	216.8	30.6	489.6
Accumulated Direct Construction Costs-Pollution Control	Million $	.2	173.4	24.5	391.7
Total Outstanding Debt	Million $	502.3	2109.3	363.6	3433.7
Prior Common Stock Issuance	Million $	329.0	1626.8	342.5	2924.3
Prior Preferred Stock Issuance	Million $	91.6	605.6	113.7	876.3
Retained Earnings	Million $	94.0	459.6	84.4	932.9
Total Current and Accrued Liabilities	Million $	197.5	536.9	234.2	1328.2
Total Current and Accrued Assets	Million $	269.7	620.6	123.0	1074.6
Net Working Capital	Million $	72.2	83.7	-111.2	-253.6
New Preferred Stock Issued	Million $	0	25.0	60.0	20.0
New Common Stock Issued	Million $	0	108.9	64.6	151.3

APPENDIX C (Continued)

ITEMS	UNITS	MS	MO	NH	NJ
New Long Term Debt	Million $	25.0	303.9	53.0	174.0
Total Assets and Other Debits	Million $	1337.0	5935.5	1314.9	9961.5
EEI 1980-Total Revenues Electric Utility Industry	Million $	996.7	1752.0	369.9	3406.3
EEI 1980-Total Revenues Investor Owned Utilities	Million $	592.4	1400.3	347.8	3372.5
DOE 1980-Total Revenues from Sales to Ultimate Consumers, Private Utilities	Million $	592.0	1641.5	353.9	3372.5
DOE 1980-Total Revenues from Sales of Electricity, Private Utilities	Million $	810.0	1795.1	414.7	3392.2

APPENDIX C (Continued)

ITEMS	UNITS	NY	NC	OH	PA
Common Equity Portion of Capitalization	Fraction	.417	.366	.341	.360
Debt Portion of Capitalization	Fraction	.462	.500	.527	.502
Preferred Stock Portion of Capitalization	Fraction	.121	.134	.132	.138
Accumulated Investment Tax Credit	Million $	301.2	315.7	342.2	526.5
Property Tax and Other Taxes	Fraction	980.2	.022	.014	.025
State Income Tax Rate[a]	Fraction	.030	.060	-----	.105
Base Year Accumulated Investment Tax Credit	Million $	301.2	315.7	342.2	526.5
AFUDC Accumulation Method[b]	0=Simple 1=Compound	1	1	1	1
AFUDC Calculation Method[c]	0=After Taxes 1=Other	0	1	0	0
Rate of Return to Common Stock[d]	Fraction	.156	.139	.158	.156
Electric Plant in Service	Million $	14330.0	7156.3	13131.9	13328.9
Net Plant Electric	Million $	10180.3	4724.0	9715.5	9891.9
Construction Work in Progress-Electric	Million $	3680.6	4392.5	4207.8	4627.5
Accumulated Direct Construction Costs-Electric	Million $	2944.5	3514.0	3366.3	3702.0
Construction Work in Progress-Pollution Control	Million $	652.1	112.5	916.6	366.8
Accumulated Direct Construction Costs-Pollution Control	Million $	521.7	90.0	733.3	293.4
Total Outstanding Debt	Million $	7364.5	3859.4	6764.0	6779.1
Prior Common Stock Issuance	Million $	6641.6	2944.7	4563.3	5042.2
Prior Preferred Stock Issuance	Million $	1824.0	1051.5	1661.5	1879.9
Retained Earnings	Million $	2554.7	617.3	1094.6	1187.2
Total Current and Accrued Liabilities	Million $	1623.0	792.5	1887.0	1244.4
Total Current and Accrued Assets	Million $	2011.0	552.4	1730.2	1555.8
Net Working Capital	Million $	388.0	-240.1	-156.8	311.4
New Preferred Stock Issued	Million $	200.3	124.0	244.4	200.1
New Common Stock Issued	Million $	339.4	273.6	353.0	378.6

APPENDIX C (Continued)

ITEMS	UNITS	NY	NC	OH	PA
New Long Term Debt	Million $	375.9	537.2	827.9	786.3
Total Assets and Other Debits	Million $	19406.4	10702.7	17212.7	17672.3
EEI 1980-Total Revenues Electric Utility Industry	Million $	6729.0	2268.3	4720.5	4842.5
EEI 1980-Total Revenues Investor Owned Utilities	Million $	6258.6	1819.1	4447.9	4748.8
DOE 1980-Total Revenues from Sales to Ultimate Consumers, Private Utilities	Million $	6255.0	2355.1	4427.2	4742.4
DOE 1980-Total Revenues from Sales of Electricity, Private Utilities	Million $	6755.0	2782.6	5168.1	4919.6

APPENDIX C (Continued)

ITEMS	UNITS	RI	SC	TN	TX
Common Equity Portion of Capitalization	Fraction	.335	.340	.577	.430
Debt Portion of Capitalization	Fraction	.529	.542	.423	.459
Preferred Stock Portion of Capitalization	Fraction	.136	.118	0	.111
Accumulated Investment Tax Credit	Million $	8.9	75.6	.2	791.4
Property Tax and Other Taxes	Fraction	.097	.019	.065	.023
State Income Tax Rate[a]	Fraction	-----	.060	.060	-----
Base Year Accumulated Investment Tax Credit	Million $	8.9	75.6	.2	791.4
AFUDC Accumulation Method[b]	0=Simple 1=Compound	1	1	0	1
AFUDC Calculation Method[c]	0=After Taxes 1=Other	0	1	0	0
Rate of Return to Common Stock[d]	Fraction	.141	.139	.134	.161
Electric Plant in Service	Million $	408.0	1169.9	86.3	12130.9
Net Plant Electric	Million $	267.0	853.7	34.1	9212.9
Construction Work in Progress-Electric	Million $	3.5	582.9	1.2	4317.9
Accumulated Direct Construction Costs-Electric	Million $	2.8	466.3	1.0	3454.3
Construction Work in Progress-Pollution Control	Million $	.1	1.5	0	88.7
Accumulated Direct Construction Costs-Pollution Control	Million $	.1	1.2	0	71.0
Total Outstanding Debt	Million $	113.4	708.3	0	4855.6
Prior Common Stock Issuance	Million $	84.1	461.8	19.1	4614.2
Prior Preferred Stock Issuance	Million $	34.3	150.9	0	1108.6
Retained Earnings	Million $	14.9	133.0	3.4	1384.6
Total Current and Accrued Liabilities	Million $	63.0	141.2	11.7	1399.6
Total Current and Accrued Assets	Million $	67.1	161.9	7.3	927.9
Net Working Capital	Million $	4.0	20.7	-4.4	-451.7
New Preferred Stock Issued	Million $	0	20.0	0	179.2
New Common Stock Issued	Million $	.3	30.2	0	390.8

APPENDIX C (Continued)

ITEMS	UNITS	RI	SC	TN	TX
New Long Term Debt	Million $	20.0	76.6	14.0	486.8
Total Assets and Other Debits	Million $	341.9	1809.5	45.4	14824.2
EEI 1980-Total Revenues Electric Utility Industry	Million $	339.6	1313.1	2379.0	7069.0
EEI 1980-Total Revenues Investor Owned Utilities	Million $	338.7	1064.3	40.1	5998.5
DOE 1980-Total Revenues from Sales to Ultimate Consumers, Private Utilities	Million $	341.5	451.4	46.3	5926.7
DOE 1980-Total Revenues from Sales of Electricity, Private Utilities	Million $	341.5	476.8	46.3	6433.9

APPENDIX C (Continued)

ITEMS	UNITS	VT	VA	WV	WI
Common Equity Portion of Capitalization	Fraction	.349	.336	.362	.431
Debt Portion of Capitalization	Fraction	.535	.543	.563	.457
Preferred Stock Portion of Capitalization	Fraction	.116	.121	.075	.112
Accumulated Investment Tax Credit	Million $	9.9	108.2	27.7	193.5
Property Tax and Other Taxes	Fraction	.030	.021	.027	.022
State Income Tax Rate[a]	Fraction	.075	-----	.060	.079
Base Year Accumulated Investment Tax Credit	Million $	9.9	108.2	27.7	193.5
AFUDC Accumulation Method[b]	0=Simple 1=Compound	1	0	0	0
AFUDC Calculation Method[c]	0=After Taxes 1=Other	0	0	0	1
Rate of Return to Common Stock[d]	Fraction	.145	.150	.140	.127
Electric Plant in Service	Million $	4030.4	5032.7	3643.4	4030.4
Net Plant Electric	Million $	3807.8	3800.1	2781.8	2373.5
Construction Work in Progress-Electric	Million $	61.9	1451.0	110.5	438.0
Accumulated Direct Construction Costs-Electric	Million $	49.5	1160.8	88.4	350.4
Construction Work in Progress-Pollution Control	Million $	.6	46.9	9.7	59.0
Accumulated Direct Construction Costs-Pollution Control	Million $	.5	37.5	7.8	47.2
Total Outstanding Debt	Million $	227.5	2627.8	1425.6	1216.2
Prior Common Stock Issuance	Million $	154.7	1794.5	1023.6	1346.4
Prior Preferred Stock Issuance	Million $	43.5	677.3	216.0	331.5
Retained Earnings	Million $	32.8	390.5	119.5	509.3
Total Current and Accrued Liabilities	Million $	94.4	413.2	430.8	474.2
Total Current and Accrued Assets	Million $	82.8	519.4	398.5	607.5
Net Working Capital	Million $	-11.6	106.2	-32.3	133.3
New Preferred Stock Issued	Million $	8.0	0	0	24.9
New Common Stock Issued	Million $	.8	79.1	20.0	31.0

APPENDIX C (Continued)

ITEMS	UNITS	VT	VA	WV	WI
New Long Term Debt	Million $	10.8	401.8	198.1	245.0
Total Assets and Other Debits	Million $	608.7	6526.1	3484.6	4048.1
EEI 1980-Total Revenues Electric Utility Industry	Million $	159.6	2369.5	710.4	1541.6
EEI 1980-Total Revenues Investor Owned Utilities	Million $	135.5	2176.9	707.2	1372.2
DOE 1980-Total Revenues from Sales to Ultimate Consumers, Private Utilities	Million $	126.8	1848.7	1019.8	1410.6
DOE 1980-Total Revenues from Sales of Electricity, Private Utilities	Million $	317.9	2057.9	1420.7	1577.8

APPENDIX C (Continued)

URGE State Financial Data— Non-ARMS Region

ITEMS	UNITS	AK	AZ	CA	CO
Common Equity Portion of Capitalization	Fraction	.427	.436	.398	.394
Debt Portion of Capitalization	Fraction	.547	.458	.458	.471
Preferred Stock Portion of Capitalization	Fraction	.026	.106	.144	.135
Accumulated Investment Tax Credit	Million $	1.0	59.1	190.8	100.3
Property Tax and Other Taxes	Fraction	.006	.031	.010	.020
State Income Tax Rate[a]	Fraction	.094	.105	.096	.050
Base Year Accumulated Investment Tax Credit	Million $	1.0	59.1	190.8	100.3
AFUDC Accumulation Method[b]	0=Simple 1=Compound	0	0	1	0
AFUDC Calculation Method[c]	0=After Taxes 1=Other	0	0	0	1
Rate of Return to Common Stock[d]	Fraction	.148	.133	.136	.155
Electric Plant in Service	Million $	22.2	3029.0	13422.4	1493.8
Net Plant Electric	Million $	15.0	2372.7	9195.8	1087.0
Construction Work in Progress-Electric	Million $	.4	1253.5	5838.3	446.0
Accumulated Direct Construction Costs-Electric	Million $	.32	1002.8	4670.6	356.8
Construction Work in Progress-Pollution Control	Million $	-----	46.4	607.1	66.0
Accumulated Direct Construction Costs-Pollution Control	Million $	-----	37.1	485.7	52.8
Total Outstanding Debt	Million $	3.4	1364.6	6892.4	710.7
Prior Common Stock Issuance	Million $	.6	980.9	3595.8	436.0
Prior Preferred Stock Issuance	Million $	.3	338.6	2273.1	204.4
Retained Earnings	Million $	4.0	402.0	2594.7	133.4
Total Current and Accrued Liabilities	Million $	4.0	315.0	2875.3	237.0
Total Current and Accrued Assets	Million $	1.6	277.5	2990.4	265.3
Net Working Capital	Million $	-2.4	-37.5	115.1	28.3
New Preferred Stock Issued	Million $	-----	48.0	200.1	25.0
New Common Stock Issued	Million $	-----	153.3	543.0	95.3

APPENDIX C (Continued)

ITEMS	UNITS	AK	AZ	CA	CO
New Long Term Debt	Million $	3.0	303.9	968.9	87.0
Total Assets and Other Debits	Million $	18.0	4386.4	20699.3	2119.4
EEI 1980-Total Revenues Electric Utility Industry	Million $	125.3	1317.2	8997.8	847.4
EEI 1980-Total Revenues Investor Owned Utilities	Million $	8.9	832.5	7253.5	635.9
DOE 1980-Total Revenues from Sales to Ultimate Consumers, Private Utilities	Million $	5.9	855.7	7197.0	603.2
DOE 1980-Total Revenues from Sales of Electricity, Private Utilities	Million $	5.9	985.7	7521.6	645.8

APPENDIX C (Continued)

ITEMS	UNITS	HI	ID	KS	MT
Common Equity Portion of Capitalization	Fraction	.405	.378	.477	.408
Debt Portion of Capitalization	Fraction	.485	.562	.427	.458
Preferred Stock Portion of Capitalization	Fraction	.110	.060	.096	.134
Accumulated Investment Tax Credit	Million $	28.7	33.6	87.1	18.2
Property Tax and Other Taxes	Fraction	.051	.012	.015	.019
State Income Tax Rate[a]	Fraction	.064	.065	.068	.068
Base Year Accumulated Investment Tax Credit	Million $	28.7	33.6	87.1	18.2
AFUDC Accumulation Method[b]	0=Simple 1=Compound	1	1	1	0
AFUDC Calculation Method[c]	0=After Taxes 1=Other	0	0	0	0
Rate of Return to Common Stock[d]	Fraction	.149	.158	.139	.140
Electric Plant in Service	Million $	793.7	1235.5	2061.7	605.2
Net Plant Electric	Million $	557.8	1032.4	1548.5	481.4
Construction Work in Progress-Electric	Million $	79.0	107.7	550.5	98.4
Accumulated Direct Construction Costs-Electric	Million $	63.2	86.2	440.4	78.7
Construction Work in Progress-Pollution Control	Million $	-----	10.3	66.5	19.4
Accumulated Direct Construction Costs-Pollution Control	Million $	-----	8.2	53.2	15.5
Total Outstanding Debt	Million $	269.6	571.0	875.4	338.3
Prior Common Stock Issuance	Million $	125.8	230.0	695.1	247.0
Prior Preferred Stock Issuance	Million $	56.1	61.5	242.2	69.0
Retained Earnings	Million $	88.5	107.9	392.9	15.5
Total Current and Accrued Liabilities	Million $	77.8	105.2	174.7	113.2
Total Current and Accrued Assets	Million $	88.1	47.0	222.0	67.5
Net Working Capital	Million $	10.3	-58.2	47.3	-45.7
New Preferred Stock Issued	Million $	8.5	-----	-----	30.0
New Common Stock Issued	Million $	16.5	33.6	66.1	36.5

APPENDIX C (Continued)

ITEMS	UNITS	HI	ID	KS	MT
New Long Term Debt	Million $	16.0	-----	204.4	-----
Total Assets and Other Debits	Million $	775.5	1254.8	3029.5	931.8
EEI 1980-Total Revenues Electric Utility Industry	Million $	446.2	354.1	943.5	186.9
EEI 1980-Total Revenues Investor Owned Utilities	Million $	446.2	327.7	696.5	138.5
DOE 1980-Total Revenues from Sales to Ultimate Consumers, Private Utilities	Million $	429.1	214.2	631.6	110.6
DOE 1980-Total Revenues from Sales of Electricity, Private Utilities	Million $	429.1	252.5	720.6	186.5

APPENDIX C (Continued)

ITEMS	UNITS	NV	NM	ND	OK
Common Equity Portion of Capitalization	Fraction	.386	.342	.363	.399
Debt Portion of Capitalization	Fraction	.477	.492	.496	.505
Preferred Stock Portion of Capitalization	Fraction	.137	.166	.141	.096
Accumulated Investment Tax Credit	Million $	44.9	63.9	39.8	153.0
Property Tax and Other Taxes	Fraction	.017	.010	.016	.024
State Income Tax Rate[a]	Fraction	-----	.060	.070	.040
Base Year Accumulated Investment Tax Credit	Million $	44.9	63.9	39.8	153.0
AFUDC Accumulation Method[b]	0=Simple 1=Compound	0	0	1	1
AFUDC Calculation Method[c]	0=After Taxes 1=Other	1	0	0	0
Rate of Return to Common Stock[d]	Fraction	.150	.150	.139	.153
Electric Plant in Service	Million $	958.1	783.7	521.4	3037.9
Net Plant Electric	Million $	740.5	627.4	361.3	2376.8
Construction Work in Progress-Electric	Million $	154.5	667.5	238.0	265.7
Accumulated Direct Construction Costs-Electric	Million $	123.6	534.0	190.4	212.6
Construction Work in Progress-Pollution Control	Million $	10.5	120.1	49.3	.6
Accumulated Direct Construction Costs-Pollution Control	Million $	8.4	96.1	39.4	.48
Total Outstanding Debt	Million $	395.7	442.7	295.5	2198.0
Prior Common Stock Issuance	Million $	176.3	275.8	157.3	738.9
Prior Preferred Stock Issuance	Million $	94.0	146.0	79.2	229.8
Retained Earnings	Million $	132.1	87.2	69.6	189.0
Total Current and Accrued Liabilities	Million $	129.2	176.4	114.2	262.9
Total Current and Accrued Assets	Million $	111.7	85.2	110.6	263.0
Net Working Capital	Million $	-17.5	-91.2	-3.6	.1
New Preferred Stock Issued	Million $	29.8	50.0	23.0	-----
New Common Stock Issued	Million $	47.9	13.8	32.0	13.6

APPENDIX C (Continued)

ITEMS	UNITS	NV	NM	ND	OK
New Long Term Debt	Million $	36.5	136.3	63.0	190.0
Total Assets and Other Debits	Million $	1150.7	1473.0	949.1	3042.0
EEI 1980-Total Revenues Electric Utility Industry	Million $	404.6	453.6	182.7	1119.9
EEI 1980-Total Revenues Investor Owned Utilities	Million $	379.9	372.2	124.6	902.9
DOE 1980-Total Revenues from Sales to Ultimate Consumers, Private Utilities	Million $	393.9	242.3	156.1	936.0
DOE 1980-Total Revenues from Sales of Electricity, Private Utilities	Million $	404.1	304.1	165.4	1221.6

APPENDIX C (Continued)

ITEMS	UNITS	OR	SD	UT	WA
Common Equity Portion of Capitalization	Fraction	.376	.255	.406	.385
Debt Portion of Capitalization	Fraction	.523	.503	.470	.507
Preferred Stock Portion of Capitalization	Fraction	.101	.242	.124	.108
Accumulated Investment Tax Credit	Million $	13.0	16.3	88.4	59.6
Property Tax and Other Taxes	Fraction	.015	.018	.014	.022
State Income Tax Rate[a]	Fraction	.075	-----	.020	-----
Base Year Accumulated Investment Tax Credit	Million $	13.0	16.3	88.4	59.6
AFUDC Accumulation Method[b]	0=Simple 1=Compound	1	1	1	1
AFUDC Calculation Method[c]	0=After Taxes 1=Other	0	0	0	1
Rate of Return to Common Stock[d]	Fraction	.163	.134	.168	.148
Electric Plant in Service	Million $	4057.0	322.8	2025.4	1658.4
Net Plant Electric	Million $	3300.4	256.2	1691.1	1332.4
Construction Work in Progress-Electric	Million $	854.5	45.1	164.2	459.9
Accumulated Direct Construction Costs-Electric	Million $	683.6	36.1	131.4	367.9
Construction Work in Progress-Pollution Control	Million $	22.0	6.5	35.1	119.6
Accumulated Direct Construction Costs-Pollution Control	Million $	17.6	5.2	28.1	95.7
Total Outstanding Debt	Million $	1941.6	148.9	794.4	939.9
Prior Common Stock Issuance	Million $	1250.6	81.8	489.2	450.3
Prior Preferred Stock Issuance	Million $	434.7	36.1	225.0	169.3
Retained Earnings	Million $	187.6	24.4	161.6	175.6
Total Current and Accrued Liabilities	Million $	703.8	31.3	107.1	146.4
Total Current and Accrued Assets	Million $	334.1	31.3	224.6	142.8
Net Working Capital	Million $	-369.7	0	117.5	-3.6
New Preferred Stock Issued	Million $	2.8	-----	-----	30.0
New Common Stock Issued	Million $	203.2	1.7	73.5	90.5

APPENDIX C (Continued)

ITEMS	UNITS	OR	SD	UT	WA
New Long Term Debt	Million $	329.9	0	59.3	0
Total Assets and Other Debits	Million $	5182.7	362.4	2097.4	2107.7
EEI 1980-Total Revenues Electric Utility Industry	Million $	876.7	180.8	453.5	964.8
EEI 1980-Total Revenues Investor Owned Utilities	Million $	739.9	116.8	408.1	453.9
DOE 1980-Total Revenues from Sales to Ultimate Consumers, Private Utilities	Million $	931.6	84.3	479.9	435.6
DOE 1980-Total Revenues from Sales of Electricity, Private Utilities	Million $	1086.7	87.9	599.6	504.4

APPENDIX C (Continued)

ITEMS	UNITS	WY
Common Equity Portion of Capitalization	Fraction	.537
Debt Portion of Capitalization	Fraction	.463
Preferred Stock Portion of Capitalization	Fraction	-----
Accumulated Investment Tax Credit	Million $	1.2
Property Tax and Other Taxes	Fraction	.034
State Income Tax Rate[a]	Fraction	-----
Base Year Accumulated Investment Tax Credit	Million $	1.2
AFUDC Accumulation Method[b]	0=Simple 1=Compound	0
AFUDC Calculation Method[c]	0=After Taxes 1=Other	0
Rate of Return to Common Stock[d]	Fraction	.133
Electric Plant in Service	Million $	20.0
Net Plant Electric	Million $	14.4
Construction Work in Progress-Electric	Million $	.2
Accumulated Direct Construction Costs-Electric	Million $	.16
Construction Work in Progress-Pollution Control	Million $	-----
Accumulated Direct Construction Costs-Pollution Control	Million $	-----
Total Outstanding Debt	Million $	6.3
Prior Common Stock Issuance	Million $	3.0
Prior Preferred Stock Issuance	Million $	0
Retained Earnings	Million $	3.7
Total Current and Accrued Liabilities	Million $	10.9
Total Current and Accrued Assets	Million $	5.7
Net Working Capital	Million $	-5.2
New Preferred Stock Issued	Million $	-----
New Common Stock Issued	Million $	-----

APPENDIX C (Continued)

ITEMS	UNITS	WY
Net Long Term Debt	Million $	0
Total Assets and Other Debits	Million $	28.1
EEI 1980-Total Revenues Electric Utility Industry	Million $	145.2
EEI 1980-Total Revenues Investor Owned Utilities	Million $	96.3
DOE 1980-Total Revenues from Sales to Ultimate Consumers, Private Utilities	Million $	9.5
DOE 1980-Total Revenues from Sales of Electricity, Private Utilities	Million $	9.5

[a] See page 64 of text for further discussion of state corporate income taxes.

[b] See page 26 of text for further discussion of AFUDC.

[c] See page 33 of text for specific methods used.

[d] See page 39 of text for further discussion of rates of return. Figures utilized were taken from Table 15.

Sources: Edison Electric Institute. EEI Yearbook 1980. Washington, D.C.: Edison Electric Institute, 1980. U.S. Department of Energy, Energy Information Administration. Statistics of Privately Owned Electric Utilities in the United States 1980 Annual. Washington, D.C.: U.S. Department of Energy, Energy Information Administration, 1981.

Note: The EEI data are revenue from sales to ultimate customers and apparently include only intra-state revenue. For the DOE data, revenue from out of state sales may be included in both items, and sales to other utilities may be included only in the last item. EEI may include a larger number of utilities than does DOE.

FOOTNOTES

[1]The URGE Project Office coordinates the group, and is led by its director, James Stukel. Address inquiries to Professor James Stukel, University Research Group on Energy, University of Illinois, 901 South Mathews Avenue, Urbana, Illinois, 61801.

[2]The utility finance model is described in URGE Project Office, First-Year Progress Report of the University Research Group on Energy, Appendix B and pp. 4-4 to 4-19.

[3]Prepared for the Office of Technology Assessment (OTA), U.S. Congress. The analysis will be available from the OTA, or from Cornell University, 212 Warren Hall, Ithaca, New York, 14853.

[4]For this illustration, the tax allowance equals (.46/(1 - .46))*(Allowed Return + (Depreciation for Revenue Allowance - Depreciation for Tax Allowance) - Interest Expense). Interest expense without FGD is assumed to be an embedded average 10% on a debt of $800 million, or $80 million. The addition of FGD adds $18 million to this year's interest payments.

[5]For the flow-through "F" State, the tax allowance is changed to (.46/(1 - .46))*(Allowed Return + Normal Depreciation - Tax Depreciation - Interest Payments) - Credits/(1 - .46).

[6]Analyzed in D. Chapman, "The 1981 Tax Act and the Economics of Coal and Nuclear Power," Hearings, Nuclear Fuel Cycle Policy and the Future of Nuclear Power, U.S. House Interior Committee, Subcommittee on Oversight and Investigations, 1981. Also Cornell Department of Agricultural Economics Staff Paper No. 81-26.

[7]Mark D. Luftig and Jennifer Proga, Stock Research: Industry Analysis - Electric Utility Regulation (New York: Salomon Brothers, 1982); Ernest Liu, "Public Utility Survey" (New York: Goldman Sachs, Inc., August 1982); Daniel L. Tulis, "Equity Research - Monthly Utility Service" (New York: Shearson/American Express, Inc., March 1982); A. Bernhard, The Value Line Investment Survey, Part 3, Ratings and Reports (New York: A. Bernhard, 1982), pp. 180, 701, 1719.

[8]Geneva Beierlein, ed., 1980 Annual Report on Utility and Carrier Regulation (Washington, D.C.: National Association of Regulatory Utility Commissioners, 1981).

[9]According to the Inventory of Power Plants in the United States 1980 Annual, Louisiana has one 519 MW coal unit.

[10]Beierlein, pp. 454-455, Table 14.

[11]Edison Electric Institute, Glossary of Electric Utility Terms (Washington, D.C.: Edison Electric Institute, 1980), p. 47.

[12]This method, then, recognizes the fact that interest costs are tax deductible.

[13]Federal Energy Regulatory Commission, Electric Utility Depreciation Practices 1976 (Washington, D.C.: Federal Energy Regulatory Commission, 1980).

[14]AGA Depreciation Committee and EEI Accounting Committee, "A Survey of Depreciation Statistics 1980-1981," 1981. (Mimeographed).

[15]See, for example, Christopher P. Davis, "Federal Tax Subsidies for Electric Utilities: An Energy Policy Perspective," Harvard Environmental Law Review, Vol. 4, No. 2 (1980), pp. 317-318.

[16]State commissions were inaccurate in distinguishing which utilities were involved in 1 percent ESOP and which took the additional 1/2 percent available. Therefore, 11 and 11 1/2 percent answers have been combined in one category.

[17]According to Statistics of Privately Owned Electric Utilities - 1980 Annual there are 205 class A and B electric utilities in the U.S.

[18]Price Waterhouse and Company, The Economic Recovery Tax Act of 1981: A Summary and Analysis (New York, N.Y.: Price Waterhouse and Company, 1981).

[19]Davis, p. 317.

[20]Price Waterhouse and Company.

[21]Ibid.

[22]Ibid.

[23]Oklahoma Statute Supplement 17 1977 Section 250 E.T.-SEQ., and Rules 6 and 12 of Commission Order Number 125207, Cause Number 26134.

[24]North Dakota Public Service Commission. Automatic Adjustment Clauses (unpublished).

[25]Information current through December 1981.

[26]This, of course, assumes no major problems will arise forcing early retirement of plants.

[27]R. S. Wood, Assuring the Availability of Funds for Decommissioning Nuclear Facilities, Draft Report, NUREG-0584 Rev. 2 (Washington, D.C.: U.S. Nuclear Regulatory Commission, 1980), pp. 14-16.

[28]Beaver Valley 1 is counted as having an external sinking fund since 65 percent of its funds are accrued using this method. (Pennsylvania utilities are required to use the external sinking method and Beaver Valley is 65 percent owned by Pennsylvania companies.)

[29]R. I. Smith, G. J. Konzek and W. E. Kennedy, Jr., Technology, Safety and Costs of Decommissioning a Reference Pressurized Water Reactor Power Station, NUREG 1CR-0130 (Washington, D.C.: U.S. Nuclear Regulatory Commission, August 1979).

[30]Duane Chapman, Nuclear Economics: Taxation, Fuel Cost and Decommissioning, Consultant Report (Sacramento, CA: California Energy Commission, November 1980), p. 55.

[31]Smith, Konzek and Kennedy, p. 3-3.

[32]Chapman, pp. 55-57.

[33]Edison Electric Institute, EEI Yearbook 1980 (Washington, D.C.: Edison Electric Institute, 1980), pp. 20-23.

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