CORNELL AGRICULTURAL ECONOMICS STAFF PAPER

THE FINANCIAL MODEL IN THE

ADVANCED UTILITY SIMULATION MODEL

(AUSM)

by

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March 1983 No. 83-4

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This paper describes work which is supported by the U.S. Environmental Protection Agency under assistance agreement No. 808514-03-0 with the University of Illinois, Carnegie-Mellon University, and Cornell University. However, this paper has not been subjected to administrative and peer review, and is for agency use and distribution only. Comments recieved will be helpful to the review process, and should be addressed to Kathleen Cole or Duane Chapman, 212 Warren Hall, Cornell University, Ithaca, New York, 14853. Cole is a graduate research assistant and Chapman is Professor of Resource Economics at Cornell. The authors wish to thank Lucrezia Herman and Judith Watkins for their assistance.

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The Financial Model in the Advanced Utility Simulation Model

by Kathleen Cole and Duane Chapman*

I. Introduction

The financial model described here is part of the Advanced Utility Simulation Model. This model, abbreviated AUSM, is being developed by the Universities Research Group on Energy for the Environmental Protection Agency. The Universities Group includes principal investigators at the University of Illinois and Carnegie-Mellon and Cornell Universities. The AUSM as an operational model is under the responsibility of Professor James Stukel and Caroline Badger at the University of Illinois. Analytical description of the AUSM, and, ultimately, the model itself may be obtained there.

This paper describes the analytical basis of the financial model. Mark Younger, also at Cornell University, is preparing a separate report on programming documentation for the financial model in AUSM.

A. Background and Development

The primary function of the financial model is to provide quantitative responses to this kind of question: how much will air quality control costs affect rates and usage for consumers of electricity, and how will it affect the financial condition of electric utilities? Developing reasonably accurate estimates of these effects is important because both consumers and utilities have had difficulty adjusting to the era of greatly increased energy costs that began in 1973. Business and residential consumers, facing higher energy bills and economic recession, responded in part by using less electricity, particularly in the industrial Midwest. At the same time, many utilities had begun large construction projects in times of great demand growth, and struggled to complete these projects in a period of extremely high interest rates and inflation. Further, in the industrial regions of the country, the cost

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*The computer program was written by Kathleen Cole, and this paper was written by her with Chapman's assistance.

of these expensive new plants is being spread over fewer units of electricity demanded, resulting in even higher rates. Thus, a financial model needs to compute the revenue requirement by which regulators determine rates, and the financial statements which measure a utility's economic health. Ideally, the model should be embedded in an annually recursive model which captures the feedback effects between prices, demand, fuel use, air pollution emissions, and future planning.

The acid precipitation problem particularly requires this kind of approach, since states often identified as major sources of pollutant precursors have been severely affected by economic recession and by declining demand, and have many utilities in financial difficulty. This is analysed in a recent report prepared for the Office of Technology Assessment.[1] That report, which examined financial data on utilities and simple estimates of pollution control costs, could identify states or regions which might have particular difficulty bearing these costs, but it could not accurately estimate the magnitude of these effects on consumer rates or on a utility's financial status. This suggests the value of a model which not only calculates incremental costs of pollution control strategies but also integrates them into a utility's existing financial and regulatory situation.

The two principal existing utility models are the Utility Simulation Model (USM), developed by Teknekron Research, Inc., and the Coal and Electric Utility Model (CEUM), developed by ICF, Inc. The CEUM was inadequate to these tasks, partly because it aggregated to a multi-state level and was therefore unable to reflect the differences in state policies that determine electric rates. Our state survey of these policies illustrates their complexity and diversity.[2] It does not use actual state financial data or the revised corporate income tax.

The USM did perform its national and regional aggregations from state-level analyses; it also provided detailed financial data and performed well in predicting late-1970's values of utility financial statements. However,

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[1] Financial and Regulatory Factors Affecting the State and Regional Economic Impact of Sulfur Oxide Emissions Control, by Kathleen Cole, Duane Chapman, and Clifford Rossi, A.E. Res. 82-40, Cornell University (October 1982).

[2] State Regulatory Policies for Privately Owned Electric Utilities in 1981, by Sally Hindman, Duane Chapman, and Kathleen Cole, A.E. Res. 82-31, Cornell University (October 1982).

the data base and the treatment of income taxation needed updating.

Most significantly, the Teknekron financial model would have required complete restructuring to operate in annual interactions with demand and planning information.

We decided, therefore, to develop an AUSM financial model. It is based in part upon plant-level models we had constructed earlier to compute the costs of service of different types of generating facilities under various options for tax and regulatory policies.[3] These models compute the facility's annual increment to the cost of service over its operating life. The price computation is set out clearly, and policy options may be specified exogenously. The models also provide some financial measures such as the cash flow and profit attributable to the facility. These early Cornell plant models provide the basis for regulatory determination of revenue requirements in the AUSM financial model. The tax and financial statements modelling originated as part of the AUSM.

B. The Place of the Financial Model in AUSM

The financial model in AUSM has two major subroutines. FINANC analyses revenue requirements and is part of the annually recursive interactive AUSM cycle. This is shown in Figure 1, taken from the Urbana report on AUSM.[4]

The second major financial subroutine is R602; this issues the financial reports and makes various financial analyses which follow from the interactive cycle.

In AUSM, the DEMAND model determines many of the initial conditions of the other models and therefore executes first. It uses information from FINANC to set new electric rates. Using these rates and information on fuel prices and other economic conditions, it estimates electricty demand for that year and adjusts electricity sales to reflect losses and transfers. It passes revenues, based on the rates and estimated sales, and purchased power costs

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[3]See Duane Chapman, "Federal Tax Incentives Affecting Coal and Nuclear Power Economics," _Natural Resources Journal_ 22 (April 1982), 361-378; Duane Chapman, _Nuclear Economics: Taxation, Fuel Cost and Decommissioning_, California Energy Commission, November 1980; and Kathleen Cole, _Tax Subsidies and Comparative Costs for Utilities and Residential Heating in New York_, M.S. thesis, Cornell University Department of Agricultural Economics, 1981.

[4]From Universities Research Group on Energy, _The Advanced Utility Simulation Model: Background, Status, and Plans for Completion_, March 1983, Professor James Stukel, University of Illinois, Urbana, Illinois.

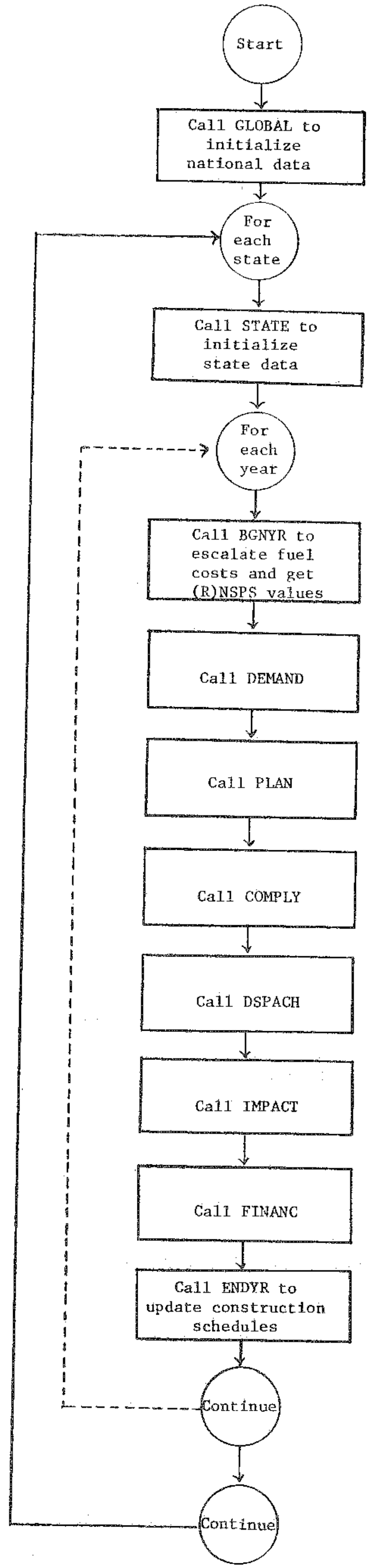

Figure 1
AUSM LOGIC FLOW

to FINANC; it passes generation and peak load net of transfers to DSPACH. It also predicts the system load 10 years in the future and passes this information to PLAN. The PLAN module develops the utilities' construction schedules--their cost and timing--and it may modify these schedules based on the discrepancies between old and new sales forecasts received from DEMAND. It supplies construction costs and data for new generating facilities to FINANC, COMPLY and DSPACH. The CONTROL module chooses pollution control strategies and passes their costs and other characteristics to FINANC. DSPACH determines the amount of electricity supplied by each facility and thus the fuel and other operating costs for the year. IMPACT produces estimates of the environmental effects of these decisions.

Thus, FINANC receives purchased power costs, construction costs for new generating facilities, construction costs for new pollution control equipment, and fuel and operating expenses. From these, it computes revenue requirement: the amount of revenue a state regulatory commission will allow its utilities to earn in that year. R602 uses the actual yearly revenues from DEMAND, together with many of the variables from FINANC, to compute entries for the standard financial reports--income statement, balance sheet, and funds flow--and for detailed statements on retained earnings, the corporate income tax, and the components of revenue requirement. It also computes interest coverage and profitability measures and in the last simulation year prints these reports, samples of which are interspersed in this text. FINANC passes its calculated revenue requirement to DEMAND, where it helps determine next year's electricity rate schedule.

FINANC distinguishes 12 different categories of assets, including new and retrofitted pollution control equipment. It can accept data on individual units, plants or even aggregations of plants as long as the aggregations are of the same type of asset, come on-line in the same year, and (in the case of new plants) have the same construction period. The major accounting variables are developed on an asset-by-asset basis. Thus, although the model currently assumes that a state applies policies uniformly to all utilities, specific regulatory policy options could be linked to particular assets to model a utility, state or region with nonuniform policies.

II. FINANC and the Determination of Revenue Requirement

Regulatory determination of allowed revenues and cost of service has become increasingly complex. This is primarily because of the growing complexity of investment incentives in the Internal Revenue Code, and the regulatory response in determining the distribution of those tax benefits over time and between customers, investors, lenders, and management. The following discussion assumes a prior knowledge of utility economics in general and cost of service and tax normalization in particular.[5]

To understand how the revenue requirement is determined in the model, we might begin with the equation for it:

$$REVRQ_t = SUM_t + RD_t + RC_t + RP_t + RBDP_t + TF_t + TS_t \qquad (1)$$

This is the basic outline of the revenue allowance in Table 1 following. SUM is the total of purchased power costs, fuel costs, operating and maintenance expenses, and non-income taxes. RD, RC and RP are allowed returns to debt and to common and preferred equity. RD, for example, is computed by

$$RD_t = ADJRBS_t * ROD_t * DTPC \qquad (2)$$

where ADJRBS is the adjusted rate base, ROD is the embedded interest rate for old and new debt issues (the rate of return allowed for debt), and DTPC is the percentage share of debt in the utility's capital structure. RP and RC are computed analogously except that the allowed rate of return for common equity is not an embedded rate but a current rate which is determined anew at each rate hearing. RBDP is straight-line depreciation of the unadjusted rate base; it equals the sum over all assets of each asset's book value divided by its book life. TF and TS are allowances for the utility's federal and state corporate income tax expense.

(Appendix A is a glossary of program variable names referred to in this report. Absence of a time subscript in an equation indicates that the value

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[5]Introductory discussion of the revenue requirement concept and its relationship to customer rates and taxation with numerical illustrations is available in Chapter 12 of Energy Resources and Energy Corporations (Ithaca: Cornell University Press, forthcoming May 1983) by Duane Chapman, and other sources.

Table 1. AUSM Regulatory Economics

SCENARIO: URGE SCENARIO TEST001 - SIP UNITS CONTINUE TO EMIT AT 1980 LEVELS
BASE CASE

82/10/27 (82/10/31)

AUSM REPORT - 602: FINANCIAL SUMMARY

ILLINOIS (17)

REGULATORY ECONOMICS (ALL VALUES IN MILLIONS OF CURRENT DOLLARS)

	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989
GRSS RATE BASE	11455.400	12171.225	13543.987	16321.269	18833.440	22146.136	22146.136	22146.136	22146.136	22540.876
RATE BASE ADJS										
CUM DEPREC	4200.313	4602.612	5045.160	5574.974	6181.900	6890.977	7600.053	8309.130	9018.207	9743.731
CUM DEF ITC	474.400	474.400	515.891	647.292	742.247	868.743	868.743	868.743	868.743	905.382
CUM DEF TAXES	1519.968	1666.491	1816.628	2035.875	2335.296	2676.038	3046.085	3381.836	3692.770	3985.584
TOTAL	6194.682	6743.503	7377.679	8258.142	9259.443	10435.758	11514.882	12559.709	13579.720	14634.697
NET RATE BASE	5260.718	5427.722	6166.309	8063.128	9573.996	11710.378	10631.254	9586.427	8566.416	7906.179
REVENUE ALLOWANCE										
FD INC TX ALL	406.938	421.275	458.100	574.122	695.946	875.464	805.335	737.434	671.145	629.791
ST INC TX ALL	36.860	38.159	41.495	52.004	63.039	79.299	72.947	66.797	60.792	57.046
RETURN-DEBT	415.071	428.247	486.522	636.181	755.388	923.949	838.806	756.369	675.890	623.798
RETURN-COMMON	300.334	309.869	352.035	460.324	546.579	668.545	606.938	547.289	489.057	451.364
RETURN-PREF	101.006	104.212	118.393	154.812	183.821	224.839	204.120	184.059	164.475	151.799
DEPRECIATION	381.847	402.299	442.548	529.814	606.926	709.077	709.077	709.077	709.077	725.524
PROPERTY TAX	214.751	224.031	273.991	365.902	404.471	446.613	425.347	404.082	382.816	373.996
OTHER TAXES	47.179	55.009	61.089	68.160	75.655	85.827	100.263	113.109	125.508	144.225
FUEL-COAL	1074.912	1287.753	1294.210	1133.733	1281.165	1351.731	1623.631	1945.464	2322.700	2717.010
FUEL-NUCLEAR	231.219	251.733	329.298	522.331	638.424	776.044	871.425	981.205	1106.651	1248.573
FUEL-DIST OIL	42.902	27.328	125.368	.967	.213	2.630	104.295	25.170	329.999	1044.894
FUEL-RES. OIL	325.942	394.857	365.001	233.850	256.723	322.939	570.042	910.723	1362.850	1973.304
FUEL-NAT. GAS	47.918	53.534	48.184	16.395	14.180	20.164	64.198	131.905	226.353	581.565
FUEL-OTHER	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
PLANT MAINT	235.769	254.640	274.364	244.343	260.118	281.455	335.202	387.726	467.242	566.936
P. C. MAINT	0.000	13.716	26.833	25.554	27.678	29.522	34.054	38.719	44.018	50.148
OTHER MAINT	379.850	410.618	450.745	501.698	565.442	643.303	736.424	848.320	981.904	1137.653
ADMIN,OTH EXP	580.405	627.419	688.732	766.588	863.987	982.958	1125.246	1296.221	1500.336	1738.318
TOTAL	5009.794	5521.375	6077.315	6554.137	7537.527	8762.992	9620.553	10525.983	12113.297	14785.219

of the term is constant throughout the simulation period.)

Certain components of required revenue account for most of the model's computations and need further explanation: rate base (unadjusted and adjusted) and the tax allowance terms.

A. CWIP in the Rate Base and Original Cost Valuation

The unadjusted rate base in the model consists of those assets that are "used and useful" (roughly, those currently in service), valued at their original cost. In most states, this definition is accurate, but a few in the Acid Rain Mitigation Study (ARMS) region adjust the value of the rate base for inflation, and a number have begun to allow the inclusion of some or all of construction-work-in-progress (CWIP) in the rate base. Of the 32 ARMS region states, 25 have at times allowed CWIP in the rate base: 11 routinely allow 100% and 14 permit a smaller percentage, usually on a case-by-case basis.[6] Obviously, only the first of these two categories can be easily modelled. We presently plan to include variable fractions of CWIP in the rate base in the final version of this model.

Given the extremely long lead time for new plants and the high interest rates of recent years, earning a return on a project while it is still under construction is a considerable boon to utilities. Critics charge that this kind of policy removes incentives for the utility to complete projects in reasonable periods of time and to keep costs down.

B. Allowance for Funds Used During Construction (AFUDC)

If it is not included in the rate base until it comes on line, the "original cost" of an asset consists of actual or "direct" construction costs and also an allowance, called AFUDC, which compensates utilities for the costs of the funds provided by both debt and equity holders to construct the plant. Thus, AFUDC is an accounting concept with an equity component, which appears on a utility's income statement under "other income," and a debt component, which reduces actual interest expense in the computation of net income. These items therefore increase the utility's net income, but they do not repre-

[6] Sally Hindman, Duane Chapman, and Kathleen Cole, State Regulatory Policies for Privately Owned Electric Utilities in 1981, A.E. Res. 82-31, Cornell University, (October 1982).

sent monies that the company has actually received in that year.

In the model, AFUDC is computed near the beginning of FINANC in the section which obtains and processes new construction cost data for the year and also in the section following, which deals with construction work in progress during the base year. In both cases, AFUDC is computed by multiplying the portion of the year's assumed construction costs financed by debt/equity by the rate of return to debt/equity. In the method used by most states, AFUDC is computed cumulatively, i.e. on the basis of accumulated construction costs including previous AFUDC for the plant. In other states, the basis for computing AFUDC does not include previously earned AFUDC. The model allows either option, signalled by a state-specific flag variable.

While AFUDC increases the rate base, it is excluded from the basis on which tax depreciation is computed.

1. AFUDC for New Construction

More specifically, the new construction cost portion of the model obtains data on that year's costs and on previous years' accumulated accounts on a plant-by-plant basis, adjusts the current year's costs for inflation, and then computes cumulative AFUDC as follows:

$$AFDCE_t = (CONEXP_t + CWP_{t-1}) * RADCE_t \tag{3}$$

$$AFDCD_t = (CONEXP_t + CWP_{t-1}) * RADCD_t. \tag{4}$$

Non-cumulative AFUDC is computed

$$AFDCE_t = (CONEXP_t + VEST_{t-1}) * RADCE_t \tag{5}$$

$$AFDCD_t = (CONEXP_t + VEST_{t-1}) * RADCD_t. \tag{6}$$

In either case,

$$CWP_t = CWP_{t-1} + AFDCE_t + AFDCD_t + CONEXP_t \tag{7}$$

$$VEST_t = VEST_{t-1} + CONEXP_t. \tag{8}$$

In these equations AFDCE and AFDCD are the equity and debt portions of AFUDC; CWP is construction work in progress and VEST is accumulated direct construction cost (CONEXP) (all for that particular plant). RADCE and RADCD are weighted average returns to debt and equity and are computed as follows:

$$RADCE_t = ROE_t * EQPC \tag{9}$$

$$RADCD_t = ROD_t * DTPC\ (1 - ETXR) \text{ or}$$

$$RADCD_t = ROD_t * DTPC. \tag{10}$$

ROD and ROE are the allowed rates of return to debt and equity. DTPC and EQPC are the shares of debt and equity in the capital structure (and sum to one). EXTR is the combined effective federal and state corporate income tax rate. Here again is another policy option that reflects differences in states' computation of AFUDC. Some use a return that reflects the tax deductibility of interest, others do not. (This option is signalled by a state-specific flag variable when RADCD and RADCE are computed in the first simulation year.)

Once the values are computed for a particular plant they are added into the aggregative AFUDC and CWIP accounts for that simulation year:

$$AFUDCE_t = AFUDCE_t + AFDCE_t \tag{11}$$

$$AFUDCD_t = AFUDCD_t + AFDCD_t \tag{12}$$

$$CWIPE_t = CWPE_t + CWPP_t \tag{13}$$

$$VSTE_t = VSTE_t + VEST_t \tag{14}$$

Here, CWPE and CWPP are accumulations of generating plant and pollution control equipment CWIP. The plant-specific cumulative variables (CWP and VEST) are then stored in a data group to be retrieved in future years of the construction period.

2. AFUDC for Base Year Construction in Progress

The next section of FINANC handles the accumulation of construction work in progress that already exists in a state in the first simulation year. It is treated as a fossil-fuel generating facility of five units, one of which comes on line in each of the first five simulation years. In the first year, one-fifth of this CWIP comes on line; in the second year, one-fourth of the remaining CWIP; in the third year, one-third of the remaining CWIP; etc. The units incur no new construction expenses, but each year the portion of the plant not yet "in use" continues to accrue AFUDC. The equations are similar to those presented above except that the basis for computing AFDCD and AFDCE does not include CONEXP. Also, the plant-level AFUDC accounts are computed separately for the portion of CWIP which will come on line in the next year and the portion that will not come in use until later years. AFDCD and AFDCE for both portions are added into that year's aggregate accounts for all plants (AFUDCD and AFUDCE). However, only the plants that will come on line in the next year are added into the model's aggregate CWIP and investment accounts (CWIPE and VSTE).

C. Gross Plant and Depreciation Accounts

In the year before a plant comes on line, the program calls the subroutine DEPREC to compute yearly and accumulated book depreciation, tax depreciation and deferred tax accounts for the new asset. When these values are returned, FINANC adds them to the appropriate aggregate arrays, beginning with the next simulation year. In addition, the final value of CWP for the asset is added to the aggregate gross electric plant account GRSSPE, and the final value of VEST to the aggregate tax basis array TBASE. Thus, as noted above, only actual construction costs, exclusive of AFUDC, enter into the basis for tax depreciation.

The values of GRSSPE and TBASE to which new assets are added are those for "historical plant"--facilities in service as of the first simulation year. These initial values are set at the beginning of the subroutine in the section which is executed only in the first year. The actual state value for historical plant (which includes AFUDC) is assigned to the variable GRSSPE, gross electric plant.

The proportion of gross plant which is due to direct construction costs is the initial value of the estimated tax basis, TBASE.

Detailed accumulated tax depreciation data are not available for existing generation, transmission, and distribution plant. Therefore, the model approximates depreciation accounts for historical plant. First, it assumes it to be a fossil fuel plant (the most prevalent type of historical plant and close in operating and tax lives to transmission and distribution plant). Second, it gets depreciation accounts for this plant from the subroutine. Third, it solves for an age of the plant such that its computed accumulated tax and book depreciation accounts closely match the exogenous base year values for these variables. When the historical plant's age is determined, its depreciation accounts from that year onward are entered into the model's aggregate depreciation accounts.

D. Unadjusted Rate Base

Finally, the unadjusted rate base in a given year (TOTRBS) equals GRSSPE minus accumulated straight-line depreciation (ADPRBE). Annual straight-line depreciation for one asset (DSL1) equals its final CWP value divided by its operating life; annual aggregate straight-line depreciation (RBDP or DNORME) is the sum of these values for all assets; and ADPRBE is the accumulation of DNORME over the years.

The rate base may be subject to further adjustments, depending on how the state regulatory commission treats utilities' use of certain corporate income tax deductions and credits. There is thus a close link between the tax allowance equations, TF and TS, and the equation for adjusted rate base, ADJRBS.

E. Tax Depreciation

In computing the actual corporate income tax paid by utilities, the model makes the most advantageous use of the federal income tax provisions for accelerated depreciation and the investment tax credit. Unlike straight-line depreciation, which provides equal deductions in each year of an asset's entire operating life, accelerated depreciation allows larger deductions in the early years and smaller ones later. In present value terms it is the preferred method. The two means of accomplishing such a depreciation schedule are (1) tax lives that are shorter than operating lives and (2) a depreciation rate that is greater than the straight-line rate. The Internal Revenue Service has allowed a variety of lives and rate formulas over the past few decades.

For assets in service before January 1, 1981--essentially the historical base-year plant--the program takes maximum advantage of the old version of the Internal Revenue Code. This specifies a range of allowable tax lives for each type of asset in the Asset Depreciation Range (ADR) System. The Code permits a depreciation rate as much as twice the straight-line rate. Thus, for historical plant, tax depreciation deductions are computed as follows for the first half of an asset's life:

$$TXDP_t = (DBLR_t/LIFT) * DB1_t * CCO \tag{15}$$

TXDP is tax depreciation for a particular asset (which is then added to the aggregate variable TXDEPR); DBLR, the declining balance rate, equals 2; LIFT is the shortest life allowed under the ADR System; DB1 is a fraction which adjusts the original cost of the asset exclusive of AFUDC (CCO) to reflect depreciation deductions already taken. When half of the tax life is completed it becomes advantageous to depreciate the remaining basis on a straight-line basis.

Major changes in this part of the Internal Revenue Code, enacted in 1981, significantly shorten the tax lives for public utility assets: from 22.5 to 15 years for steam generation plants (fossil-fired); from 24 to 15 for transmission and distribution facilities; from 40 to 15 for hydroelectric generating plant; and from 16 to 10 for nuclear generating facilities. In the initial version of the new law the depreciation rate was 1.5 times the straight-line rate for assets placed in service 1981-84, 1.75 in 1985 and 2.0 after 1985 (i.e., DBLR in Equation (15) could be 1.5, 1.75 or 2.0). A switch to the sum-of-the-years-digits method[7] was allowed as soon as it became advantageous. Revisions to the Code in September 1982 have simplified the possibilities: the rates for the 1981-84 dates apply for later years as well. An additional change requires the original basis for tax depreciation to be reduced by 50% of the investment tax credit (or, alternatively, the ITC rate to be reduced by two percentage points). The model will be revised to incorporate these changes.

Conveniently, the Code now provides depreciation rate schedules for each new asset life: fractions for each year that can be multiplied by the original value of the asset to get that year's tax depreciation. The model avoids a great deal of complicated computations by obtaining these rates as data and choosing the appropriate set to pass to the depreciation subroutine so that

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[7]The sum-of-the-years-digits method of accelerated depreciation applies a changing fraction each year to the original basis of the asset. The denominator of the fraction is the sum of the numbers which represent each year of the life of the asset (i.e., if the life equals n, the denominator = 1 + 2 + ... + n-1 + n); the numerator each year is the number of years remaining useful life.

$$TXDP_t = DPRATE_t * CCO. \tag{16}$$

F. Investment Tax Credit

The investment tax credit (ITC) is another major tax benefit available to corporations. It amounts to 10% of eligible investment in plant and equipment. An additional amount may be claimed for a corporation's employee stock ownership plan (ESOP): before 1983 it was 1% of eligible investment plus an additional 0.5% if employees contributed a matching amount to the plan. Now the extra 1.5% will be based on compensation paid to employees under the plan and is scheduled to terminate entirely after 1986.

Approximately 95% of the investment cost of a typical electric generating facility is eligible for the credit. However, the eligibility of pollution control equipment retrofitted to older plants is complex.

G. Pollution Control Equipment, the Investment Tax Credit, and Tax Depreciation[8]

The first differentiation in ITC eligibility for pollution control equipment depends upon whether the equipment investment is financed by tax-exempt bonds. If not, the following rules apply:

(1) For equipment in service before 1977, no ITC is allowed on the portion of costs that is eligible for the 60 month rapid amortization;

(2) For equipment added in 1977 or 1978 on utility plant in service before 1976, a maximum of 50% of the rapid amortization basis is eligible for ITC;

(3) For devices acquired or constructed after 1978 for utility plant in service before 1976, 100% of the value of the asset is eligible for ITC provided the equipment has at least a 5 year useful life (if less than 5 years, 1/3 is eligible).

If the equipment is financed by tax-free bonds, more complex rules apply which in effect allow a lower eligibility for ITC even on devices installed after

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[8] This discussion is based on "Treatment of Depreciation and Investment Tax Credit for Pollution Control Facilities," memorandum, Bruce Williamson, Cornell University, July 1981.

1978. Since retrofitted devices in the model will be installed after 1978, have 20 year lives, and are assumed not to be financed by tax exempt bonds, 100% of their construction cost (exclusive of AFUDC) is assumed eligible for the ITC.

Pollution control equipment built with new plants can be depreciated as part of the utility plant under whatever approved system the utility uses for tax purposes.

Depreciation rules available for certain retrofitted pollution control devices are more complex, however. If the device is for a generating facility in existence before January 1, 1976, the utility may depreciate it on a straight line basis over 60 months, beginning as early as the month following acquisition or installation of the device. Two conditions determine the depreciable basis of the equipment.

(1) If its useful life exceeds 15 years then the portion of costs eligible for the rapid 5 year amortization equals 15/L, where L is the actual useful life. The remaining fraction is amortized over the full life.

(2) If the useful life is 15 years or less, then the full cost of the equipment is eligible for 60 month amortization.

Since the model assumes a 20 year operating life for pollution control devices, it computes straight line depreciation over 5 years for 3/4 (15/20) of a retrofitted asset's value and straight line over 20 years for the remaining 1/4.

H. Actual Corporate Tax Paid

Thus, the actual federal corporate income tax paid by a utility would be computed as

$$FITX_t = ((OPREVE_t - SUM_t - SITX_t - TXDEPR_t - OTHINT_t - LTDEXP_t) * FTXR_t) - TC_t \quad (17)$$

Where OPREVE is operating revenues actually received, SUM is business and operating expenses as noted above, SITX is state corporate income tax paid,[9] TXDEPR is the depreciation deduction defined above (TXDP aggregated over all

[9]The state corporate income tax computation is identical to that for the federal tax except that state income tax is not a deduction, the tax rate is different, and there is no investment credit.

assets), LTDEXP plus OTHINT is interest paid, FTXR is the federal corporate income tax rate, and TC is the investment tax credit.

The current federal income tax report is shown in Table 2.

I. Tax Accounting Options and Adjusted Rate Base

Regulatory commissions, however, may assume different values for the components of the tax allowance equations TF and TS than those used by the utility in computing its actual tax. Specifically, regulatory treatment of the tax benefits of accelerated depreciation and the investment tax credit may differ in two ways from their actual incidence on the utility. First, in setting rates, a commission may ignore all or part of certain tax benefits that accrue to the utility so that required revenues (and thus rates) are higher than if all of these benefits were recognized. Second, a commission may recognize tax benefits for rate-making during a period other than that in which they were earned by the utility by using normalized rather than flow-through accounting.

Flow-through accounting passes tax savings on to customers in the year they were earned by the utility so that in the tax allowance equation,

$$TF_t = ((RC_t + RP_t + RBDP_t - REGDPE_t) * \frac{FTXR}{1-FTXR}), \tag{18}$$

REGDPE is equal to TXDEPR. In addition, flow-through accounting further reduces TF by $(TC * \frac{1}{1-FTXR})$, the full amount of the investment tax credit.

In normalized accounting, REGDPE differs from TXDEPR and the investment tax credit factor is not subtracted from TF. Therefore, the tax allowance that enters into revenue requirement for that year may be lower or higher than the utility's actual tax expense. However, the difference between the tax allowance calculated by the commission and the actual tax expense is credited to a reserve which is subtracted from the utility's rate base. In effect, the utility is allowed the immediate use of these tax savings. However, since they are essentially monies contributed by ratepayers, deducting them from the rate base precludes the utility from earning a return on them and returns them to the customer over time.

The present version of the model allows three different tax accounting options: flow-through, full normalization, and partial normalization.

The flow-through option has been described above.

In the full normalization option, the tax allowance equation uses a

Table 2. AUSM Federal Income Tax, Current

SCENARIO: URGE SCENARIO TEST001 - SIP UNITS CONTINUE TO EMIT AT 1980 LEVELS
BASE CASE

82/10/27 (82/10/31)

AUSM REPORT - 602: FINANCIAL SUMMARY

ILLINOIS (17)

FEDERAL INCOME TAX, CURRENT (ALL VALUES IN MILLIONS OF CURRENT DOLLARS)

	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989
TAXABLE INCOME										
TOT OPER REV	4717.855	5500.948	6108.894	6816.014	7565.484	8582.667	10026.319	11310.904	12550.834	14422.476
(DIR OP EXPS)	3286.962	3733.690	4057.593	3952.324	4475.056	5055.094	6209.282	7414.902	9306.053	12171.079
(ACCEL DEPR)	689.362	626.080	686.952	926.229	1142.068	1282.263	1343.112	1271.899	1220.370	1197.369
(GR REC TAX)	35.384	41.257	45.817	51.120	56.741	64.370	75.197	84.832	94.131	108.169
(PROP TAX)	214.751	224.031	273.991	365.902	404.471	446.613	425.347	404.082	382.816	373.996
(ST INC TAX)	-9.889	2.130	4.385	21.594	20.329	32.335	45.724	51.104	26.880	-16.660
(OTHER TAXES)	47.179	55.009	61.089	68.160	75.655	85.827	100.263	113.109	125.508	144.225
(ADM,OTH EXP)	580.405	627.419	688.732	766.588	863.987	982.958	1125.246	1296.221	1500.336	1738.318
(INTERST EXP)	891.990	984.435	1111.817	1177.325	1201.821	1179.784	1118.850	1192.381	1268.386	1444.807
TOTAL	-237.328	51.116	105.237	518.249	487.890	776.036	1097.365	1226.496	645.120	-399.843
(INV TX CRED)	164.828	150.385	65.452	24.259	7.186	14.615	86.793	132.550	184.687	262.490
TOTAL TAX PD	-273.999	-126.871	-17.043	214.135	217.244	342.361	417.995	431.638	112.069	-446.418

	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999
TAXABLE INCOME										
TOT OPER REV	17380.290	21827.556	26114.169	30704.625	35421.906	39140.767	42196.455	44552.911	46159.203	47366.848
(DIR OP EXPS)	15267.471	17786.850	21263.492	24672.245	26662.115	27663.662	27982.480	28147.362	30573.869	32173.902
(ACCEL DEPR)	1092.829	1596.680	1857.516	1948.012	2264.109	2892.764	3754.921	4454.536	4610.443	4473.604
(GR REC TAX)	130.352	163.707	195.856	230.285	265.664	293.556	316.473	334.147	346.194	355.251
(PROP TAX)	478.370	563.677	629.479	729.863	873.367	1083.675	1323.038	1555.362	1602.540	1656.053
(ST INC TAX)	-31.871	12.268	19.145	39.330	108.214	167.376	228.581	279.529	264.735	269.839
(OTHER TAXES)	173.803	218.276	261.142	307.046	354.219	391.408	421.965	445.529	461.592	473.668
(ADM,OTH EXP)	2008.621	2307.939	2640.163	3003.752	3395.200	3811.766	4244.393	4679.151	5096.581	5469.415
(INTERST EXP)	1728.305	1989.168	2340.340	2871.843	3470.263	3948.426	4149.681	4244.592	3707.274	3378.319
TOTAL	-764.902	294.425	459.490	943.928	2597.144	4017.033	5485.939	6708.705	6353.646	6476.132
(INV TX CRED)	295.764	498.226	651.929	684.519	653.859	458.098	379.264	139.826	66.265	0.000
TOTAL TAX PD	-647.619	-362.790	-440.564	-250.312	540.827	1389.737	2144.268	2946.178	2856.412	2979.021

depreciation deduction that reflects neither a shorter tax life nor an accelerated rate: REGDPE is straight-line depreciation of the tax basis of an asset (direct investment cost exclusive of AFUDC) over its book life. In addition, TF is not reduced by (TC * $\frac{1}{1-FTXR}$), the investment tax credit. Thus the utility is allowed immediate use of the full value of these tax savings, but these savings are accumulated in separate accounts and are subtracted from the rate base over the life of each asset. The account for deferred tax savings from accelerated depreciation is

$$ADFRGE_t = ADFRGE_{t-1} + (TXDEPR_t - REGDPE_t) * ETXR \tag{19}$$

The account for the investment tax credit adjustment (ACITC) is derived by computing for each asset

$$TOTITC_t - (AITC * t) \tag{20}$$

and summing these values over all assets for each year. ($TOTITC_1$ equals the total amount of investment tax credit attributable to that asset, AITC equals ($TOTITC_1$/operating life), and t = 1, ..., operating life.) Thus in full normalization

$$ADJRBS_t = GRSSPE_t - ADPRBE_t - ADFRGE_t - ACITC_t \tag{21}$$

where the last two terms reflect the full value of these tax savings.

In the partial normalization option the commission normalizes part and flows through the remaining part of the tax savings from accelerated depreciation. It also normalizes part of the investment tax credit but allows the utility to retain the rest permanently. In this option, which is used in New York and some other states, REGDPE is computed with the accelerated depreciation rate (twice the straight line rate) but using the book life (LIFN) rather than the shorter tax life of the assets. Thus,

$$REGDPE_t = (DBLR_t/LIFN) * CCO \tag{22}$$

This should be compared with Equation (15) for TXDP. ADFRGE is computed as above but with this different value of REGDPE so that, in effect, the tax savings due to the accelerated rates are flowed through.

Because the 1981 and 1982 tax law provisions for depreciation may be used only if the tax savings are fully normalized, the partial normalization option partially normalizes depreciation for historical plant but fully normalizes depreciation for new plant. It uses partial normalization of the ITC for all assets.

As in full normalization, (TC * $\frac{1}{1-FTXR}$) is not subtracted from TF. However, only a fraction of ACITC (8/ZITCR, where ZITCR equals the investment tax credit rate of 10 to 11.5%) is deducted from the rate base; the remainder is retained by the utility. As in full normalization, adjusted rate base, $ADJRBS_t$ equals $GRSSPE_t$ - $ADPRBE_t$ - $ADFRGE_t$ - $ACITC_t$, but the last term does not represent the full value of the tax savings earned from the investment tax credit. Also, for historical plant, the deferred tax account ADFRGE reflects only those tax savings due to shorter tax lives, the rest having been flowed through to consumers.

In fact, ADJRBS in the flow-through case is defined by the same Equation (21), but the last two terms equal zero because the tax benefits were "flowed-through" to customers in the year received. Consequently, there is no subsequent rate base adjustment for these two terms.

This discussion has mentioned several ways in which utilities and regulatory commissions can affect the size of revenue requirement and thus the rates that the company will be allowed to charge. The commission controls its size principally by determining the rate of return allowed on common equity, by allowing or disallowing CWIP in the rate base, and by normalizing or flowing through the company's corporate income tax savings. The company affects the magnitude of the capital portion of the revenue requirement mainly by its investment in new plants and their ultimate construction cost.

The value that determines the financial health of the company is, finally, not the revenue it is allowed to earn but the revenue it actually earns. If demand is sufficiently elastic, the higher rates caused by a large construction program may reduce the revenue received rather than increase it, or result in revenues that are less than expected. This will make it more difficult for the utility to finance its ongoing projects.

To allow for such possibilities, AUSM contains a demand module which structures REVRQ into a rate schedule. It then determines the next year's demand for electricity and actual revenue earned from electricity sales. The latter variable is an important input to the subroutine, R602.

III. R602 and the Financial Reports

This second financial subroutine, R602, computes the standard financial statements and ratios and prints the reports shown in this section.

A. The Income Statement

The computing of income statement items begins with interest expense, which is based on January 1 long term debt. Although utilities have short term debt as well, its amount is quite small relative to its long term debt, and it is exogenous and constant in the model.

Computing interest on January 1 debt before new debt is issued or any debt is retired is unrealistic. Some new debt (that issued in the first half of the year) may add to that year's interest expense, since interest is often paid every six months on long term bonds. On the other hand, a full-year's interest would not be due on all of the long term debt retired that year. To some extent these effects will cancel, although accelerating inflation will give greater weight to the new issue effect, and so interest expense may be somewhat underestimated in such periods. Nevertheless, this assumption greatly simplifies the model and in particular avoids recomputations to balance certain of the financial statements. The interest rate is a weighted average of those from current and previous years.

Having completed the interest expense determination, the program then calculates actual federal and state income tax paid (see Equation (17)). The components of this calculation comprise one of the tables printed in the report, "Federal Income Tax, Current," shown several pages above.

Net income, in Table 3 is

$$NETINC_t = OPREVE_t - EXPTOT_t + OTHINC_t - TOTINT_t. \quad (23)$$

$OPREVE_t$ is the actual revenue from electric sales passed from the demand subroutine. Total operating expenses EXPTOT are defined by

$$EXPTOT_t = DNORME_t + GRTX_t + SSOTX_t + PTX_t + ITXR_t + DOEXP_t, \quad (24)$$

where DNORME is the annual straight line depreciation of gross electric plant;

Table 3. AUSM Income Statement

SCENARIO: URGE SCENARIO TEST001 - SIP UNITS CONTINUE TO EMIT AT 1980 LEVELS
BASE CASE

82/10/27 (82/10/31)

AUSM REPORT - 602: FINANCIAL SUMMARY

ILLINOIS (17)

INCOME STATEMENT (ALL VALUES IN MILLIONS OF CURRENT DOLLARS)

	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989
ELEC OPER REV	4717.855	5500.948	6108.894	6816.014	7565.484	8582.667	10026.319	11310.904	12550.834	14422.476
DIR ELEC OP EXP:										
PURCH POWER	167.489	195.289	216.872	241.975	268.582	304.693	355.945	401.549	445.567	512.013
FUEL,COAL	1074.912	1287.753	1294.210	1133.733	1281.165	1351.731	1623.631	1945.464	2322.700	2717.010
FUEL,NUCLEAR	231.219	251.733	329.298	522.331	638.424	776.044	871.425	981.205	1106.651	1248.573
FUEL,DIST OIL	42.902	27.328	125.368	.967	.213	2.630	104.295	25.170	329.999	1044.894
FUEL,RES. OIL	325.942	394.857	365.001	233.850	256.723	322.939	570.042	910.723	1362.850	1973.304
FUEL,NAT. GAS	47.918	53.534	48.184	16.395	14.180	20.164	64.198	131.905	226.353	581.565
FUEL,OTHER	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
ADMIN,CUST	580.405	627.419	688.732	766.588	863.987	982.958	1125.246	1296.221	1500.336	1738.318
PLANT MAINT	235.769	254.640	274.364	244.343	260.118	281.455	335.202	387.726	467.242	566.936
P. C. MAINT	0.000	13.716	26.833	25.554	27.678	29.522	34.054	38.719	44.018	50.148
OTHER MAINT	379.850	410.618	450.745	501.698	565.442	643.303	736.424	848.320	981.904	1137.653
DEPRECIATION	381.847	402.299	442.548	529.814	606.926	709.077	709.077	709.077	709.077	725.524
OPER TAX EXP:										
INC TAX PAID	-283.888	-124.741	-12.659	235.729	237.572	374.696	463.719	482.742	138.949	-463.078
INC TAX DEF	184.879	146.522	150.137	219.247	299.422	340.742	370.047	335.751	310.934	292.814
INC TAX ADJ	164.828	150.385	65.452	24.259	7.186	14.615	86.793	132.550	184.687	262.490
INC TX REP	65.819	172.166	202.931	479.235	544.180	730.053	920.558	951.043	634.569	92.226
GROSS REC TAX	35.384	41.257	45.817	51.120	56.741	64.370	75.197	84.832	94.131	108.169
PROPERTY TAX	214.751	224.031	273.991	365.902	404.471	446.613	425.347	404.082	382.816	373.996
SOC SEC,OTHER	47.179	55.009	61.089	68.160	75.655	85.827	100.263	113.109	125.508	144.225
TOTAL OPER EXP	4031.941	4628.452	5083.969	5446.556	6163.027	7091.034	8439.725	9677.044	11252.155	13615.219
AFUDC-EQUITY	394.546	490.623	475.749	357.445	226.215	16.890	124.848	253.067	440.991	685.061
INCOME TX CRED	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
TOT OTHER INC	394.546	490.623	475.749	357.445	226.215	16.890	124.848	253.067	440.991	685.061
L TERM INT EXP	891.990	984.435	1111.817	1177.325	1201.821	1179.784	1118.850	1192.381	1268.386	1444.807
OTHER INTEREST	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
(AFUDC-DEBT)	211.530	263.040	255.066	191.639	121.282	9.056	66.936	135.678	236.431	367.285
TOTAL INT EXP	680.460	721.395	856.751	985.686	1080.539	1170.729	1051.914	1056.703	1031.955	1077.522
NET INCOME	400.001	641.724	643.923	741.216	548.133	337.795	659.528	830.223	707.714	414.797

GRTX is the gross receipts tax. Social security and other taxes, SSOTX, are fixed percentages of OPREVE. Property tax, PTX, is a fixed percentage of that year's aggregate tax depreciation basis (TBASE). ITXR is reported income tax and equals actual state and federal corporate tax paid plus that year's tax savings from accelerated depreciation[10] and the tax savings from the investment credit:

$$ITXR_t = ITXP_t + DFTXBK_t + TC_t. \tag{25}$$

Direct operating expense, DOEXP, equals the sum of purchased power, fuel, and operating and maintenance expenses. Other income, OTHINC, includes the investment tax credit, TC (cancelling its effect on ITXR). It also includes the equity portion of AFUDC. TOTINT is equal to LTDEXP, the interest expense on long term debt, plus the exogenous OTHINT for short term debt, minus the debt portion of AFUDC. Thus both AFUDC components augment net income.

Retained earnings are seen in the report in Table 4. At the end of the year, they equal their earlier January 1 value for the year plus net income, and minus preferred and common stock dividends. Preferred stock dividends are computed by applying a percentage (a weighted average of current and past dividend rates on preferred stock issues) to the amount of preferred equity at the beginning of the year. Common stock dividends are a fixed percentage of January 1 retained earnings but equal zero if net income minus preferred dividends is not greater than zero.

Once retained earnings are determined, the model can compute the amount of external funds (FNEEDS) the utility needs to raise that year.

$$\begin{aligned} FNEEDS_t = {} & GRSSPE_t - ADRPBE_t + CWIPE_t + ACCTR_t + OTHASS_t \\ & - (CEQTOT_{t-1} + PEQTOT_{t-1} + LTDTOT_{t-1} - DRETIR_t \\ & + LIACAO_t + ACTCT_t + ADFBK_t + RETERN_t) \end{aligned} \tag{26}$$

Essentially, the amount of external funds is chosen to equate assets and

[10] Whatever method of tax accounting the state uses for regulation, deferred taxes in the standard financial statements equal the tax rate times the difference between tax depreciation (accelerated rate and shorter life) and straight line depreciation (operating life).

Table 4. AUSM Retained Earnings

SCENARIO: URGE SCENARIO TEST001 - SIP UNITS CONTINUE TO EMIT AT 1980 LEVELS
BASE CASE

82/10/27 (82/10/31)

AUSM REPORT - 602: FINANCIAL SUMMARY

ILLINOIS (17)

RETAINED EARNINGS (ALL VALUES IN MILLIONS OF CURRENT DOLLARS)

	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989
JANUARY 1 BAL	947.200	886.646	1067.863	1205.975	1359.200	1275.074	1001.642	1118.301	1378.788	1433.148
NET INCOME	400.001	641.724	643.923	741.216	548.133	337.795	659.528	830.223	707.714	414.797
(PREF DIVIDS)	223.755	238.845	238.845	286.497	292.458	292.458	292.458	290.161	308.657	351.588
(COM DIVIDS)	236.800	221.661	266.966	301.494	339.800	318.769	250.411	279.575	344.697	358.287
DECEMBR 31 BAL	886.646	1067.863	1205.975	1359.200	1275.074	1001.642	1118.301	1378.788	1433.148	1138.070

	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999
JANUARY 1 BAL	1138.070	493.555	544.748	1133.172	2115.042	3782.842	5252.835	6627.203	7361.020	7687.383
NET INCOME	-223.939	658.638	1294.123	1964.014	3041.036	3376.537	3648.411	3351.452	3127.451	2477.017
(PREF DIVIDS)	420.576	484.056	569.512	698.852	844.475	960.834	960.834	960.834	960.834	960.834
(COM DIVIDS)	0.000	123.389	136.187	283.293	528.760	945.711	1313.209	1656.801	1840.255	1921.846
DECEMBR 31 BAL	493.555	544.748	1133.172	2115.042	3782.842	5252.835	6627.203	7361.020	7687.383	7281.720

liabilities on the balance sheet. Assets are GRSSPE minus its accumulated book depreciation; the exogenous other assets (OTHASS); accounts receivable (ACCTR); and construction work in progress (CWIPE). On the liabilities side are the January 1 values of debt and equity ($CEQTOT_{t-1}$, $PEQTOT_{t-1}$ and $LTDTOT_{t-1}$) less debt to be retired that year (DRETIR); accumulated deferred taxes and investment credits (ACTCT and ADFBK); current and other liabilities (LIACAO); and retained earnings (RETERN).

If FNEEDS is less than zero, i.e., the utility has excess funds, the model first uses the funds to retire debt; when there is no debt left to retire, a variable $CASH_t$ is augmented. CASH is set to zero at the beginning of the next year, since the excess money is used and not simply accumulated over the years. (The sole function of this variable is as a yearly repository for these excess funds.) Retiring debt, however, is not often a sensible financial policy, especially in times of rising interest rates. This may be changed to an option in a future version of the program.

If FNEEDS is greater than zero, external funds must be raised. The program first increases FNEEDS to account for financing costs so that

$$FNEEDS_t = FNEEDS_t \; (1 + (RINT_t \; (1 - ETXR)) * DTPC + CRET_t * CEQPC + PRET_t * PEQPC)) \tag{27}$$

where RINT, CRET and PRET are that year's current debt and equity rates of return; DTPC, CEQPC and PEQPC are the shares of debt and equity in the capital structure; and ETXR is the combined state and federal corporate income tax rate.

The model then determines amounts of new debt as well as needed new common and preferred stock. The object is to retain the state's base-year capitalization ratios. The amount of new debt issued is

$$NWDT_t = DTPC * (CAPTOT_{t-1} - DRETIR_t + FNEEDS_t) - (LTDTOT_{t-1} - DRETIR_t) \tag{28}$$

where

$$CAPTOT_{t-1} = COMTOT_{t-1} + LTDTOT_{t-1} + PEQTOT_{t-1}. \tag{29}$$

CAPTOT is total capitalization, COMTOT is common equity, including retained earnings, LTDTOT is long term debt, and PEQTOT is total preferred equity. If FNEEDS becomes positive after a long period of excess funds (and, therefore, debt retirements), FNEEDS are met by new debt alone until the old capitalization ratio is approached. In the model, if NWDT as computed by Equation (28) is greater than or equal to FNEEDS, then NWDT = FNEEDS.

The debt issued is assumed to be 20 year bonds with a yearly coupon and the principal due at the end of the term. The model, therefore, augments the debt retirement account (DRETIR) 20 years hence:

$$DRETIR_{t+20} = NWDT_t + DRETIR_{t+20}. \tag{30}$$

The first financial subroutine has already initialized DRETIR with a retirement schedule for debt outstanding before the first simulation year. Because disaggregated data on outstanding debt issues are not readily available, this schedule for "historical" debt repays principal as it would be repaid in a mortgage.

Unless all-debt financing is used, the model then computes new preferred and common equity issues using equations exactly analogous to (28). At this point, total values for debt and equity are computed for the balance sheet.

First "old" values are computed--

$$OLDT_t = LTDTOT_{t-1} - DRETIR_t \tag{31}$$

$$OLDPEQ_t = PEQTOT_{t-1} \tag{32}$$

$$OLDCEQ_t = CEQTOT_{t-1} \tag{33}$$

--and then

$$LTDTOT_t = OLDT_t + NWDT_t \tag{34}$$

$$PEQTOT_t = OLDPEQ_t + NWPEQ_t \tag{35}$$

$$CEQTOT_t = OLDCEQ_t + NWCEQ_t. \tag{36}$$

Note that CEQTOT includes only stock issued, not the value of retained earnings.

This section of the program will, in a future version, adjust the current year rates of return to debt and equity for inflation. The program as now structured then adjusts the embedded rates for debt and preferred equity to reflect the new marginal values. For example, next year's embedded rate for debt,

$$RINT_{t+1} = (OLDT_t * RINT_t + NWDT_t * RINTM_t)/(LTDTOT_t), \tag{37}$$

where RINTM is the current interest rate. The equation for PRET is analogous. For common equity the current rate only is relevant, so

$$CRET_{t+1} = CRETM_t. \tag{38}$$

B. The Balance Sheet

The balance sheet report (Table 5) follows. New electric plant, which equals gross plant (GRSSPE) minus accumulated straight line depreciation (ADPRBE), is added to construction work in progress (CWIPE) to define total electric plant. CASH plus the exogenous ACCTR (accounts receivable) equal current and other assets (ASSCAO). The exogenous non-electric plant OTHASS completes the asset side of the balance sheet. On the liabilities side, prior common equity issues (OLDCEQ), new issues ($NWCEQ_t$) and retained earnings equal total common equity (COMTOT). Preferred equity is broken down into new and prior issues. The long term debt total excludes next year's debt retirements (these are included under current and other liabilities). Accumulated deferred taxes from depreciation (ADFBK) and the accumulated investment tax credit (ACTTC) complete the liabilities side. If total assets and total liabilities are not equal, the difference (CORR) is added to total liabilities as a correction.

The program then calculates working capital as the difference between current assets and liabilities:

$$WCAP_t = ASSCAO_t - LIACAO_t. \tag{39}$$

C. Cash Flow

The funds flow statement items are essentially changes in the balance sheet components from one year to the next. The next report (Table 6) shows that funds provided are

Table 5. AUSM Balance Sheet

SCENARIO: URGE SCENARIO TEST001 - SIP UNITS CONTINUE TO EMIT AT 1980 LEVELS
BASE CASE

82/10/27 (82/10/31)

AUSM REPORT - 602: FINANCIAL SUMMARY

ILLINOIS (17)

BALANCE SHEET (ALL VALUES IN MILLIONS OF CURRENT DOLLARS)

	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989
ASSETS:										
ELEC UTIL PLT	11455.400	12171.225	13543.987	16321.269	18833.440	22146.136	22146.136	22146.136	22146.136	22540.876
(ACCUM DEPR)	4200.313	4602.612	5045.160	5574.974	6181.900	6890.977	7600.053	8309.130	9018.207	9743.731
NET ELEC PLT	7255.087	7568.613	8498.827	10746.295	12651.540	15255.159	14546.083	13837.006	13127.929	12797.145
CWIP	5358.300	7184.685	6966.870	5234.425	3312.696	247.344	1828.281	3705.913	6457.875	10032.039
TOT ELEC PL	12613.387	14753.298	15465.697	15980.720	15964.236	15502.504	16374.364	17542.919	19585.804	22829.183
OTHER ASSETS	1737.500	1893.875	2064.324	2250.113	2452.623	2673.359	2913.961	3176.218	3462.078	3773.665
CURR. ASSETS	1412.500	1412.500	1412.500	1412.500	1412.500	1412.500	1412.500	1412.500	1412.500	1412.500
TOTAL ASSETS	15763.387	18059.673	18942.521	19643.333	19829.359	19588.363	20700.825	22131.637	24460.382	28015.348
TOTAL CAPITALIZATION, LIABILITIES, CREDITS:										
PRIOR COM EQ	3846.100	4313.800	4313.800	4095.058	4064.368	4064.368	4064.368	4227.304	4443.948	4957.121
NEW COM EQ	467.700	0.000	-218.742	-30.690	0.000	0.000	162.936	216.645	513.173	1188.863
RETAINED EARN	886.646	1067.863	1205.975	1359.200	1275.074	1001.642	1118.301	1378.788	1433.148	1138.070
TOT COM EQ	5200.446	5381.663	5301.033	5423.568	5339.442	5066.010	5345.605	5822.736	6390.269	7284.054
PRIOR PREF EQ	1491.700	1592.300	1592.300	1909.982	1949.722	1949.722	1949.722	1934.408	2057.711	2343.920
NEW PREF EQ	100.600	0.000	317.682	39.740	0.000	0.000	-15.315	123.303	286.209	459.921
TOT PREF EQ	1592.300	1592.300	1909.982	1949.722	1949.722	1949.722	1934.408	2057.711	2343.920	2803.841
LONG TERM DT	6554.193	7393.391	7818.598	7968.662	7865.229	7458.999	7949.207	8455.906	9632.047	11357.946
CURR LIABILS	1532.707	1551.427	1581.663	1625.141	1625.141	1625.141	1625.141	1625.141	1625.141	1789.230
ACCUM DEF ITC	474.400	474.400	514.617	640.365	714.528	812.452	800.380	788.307	776.234	794.693
AC DEF INC TX	1519.968	1666.491	1816.628	2035.875	2335.296	2676.038	3046.085	3381.836	3692.770	3985.584
TOT LIABILS	15763.387	18059.673	18942.521	19643.333	19829.359	19588.363	20700.825	22131.637	24460.382	28015.348

Table 6. AUSM Funds Provided and Applied

SCENARIO: URGE SCENARIO TEST001 - SIP UNITS CONTINUE TO EMIT AT 1980 LEVELS
BASE CASE

82/10/27 (82/10/31)

AUSM REPORT - 602: FINANCIAL SUMMARY

ILLINOIS (17)

FUNDS PROVIDED AND APPLIED (ALL VALUES IN MILLIONS OF CURRENT DOLLARS)

	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989
FUNDS PROVIDED										
NET INCOME	400.001	641.724	643.923	741.216	548.133	337.795	659.528	830.223	707.714	414.797
DEPRECIATION	381.847	402.299	442.548	529.814	606.926	709.077	709.077	709.077	709.077	725.524
DEFERRED TAX	184.879	146.522	150.137	219.247	299.422	340.742	370.047	335.751	310.934	292.814
(AFUDC-EQ)	394.546	490.623	475.749	357.445	226.215	16.890	124.848	253.067	440.991	685.061
(AFUDC-DEBT)	211.530	263.040	255.066	191.639	121.282	9.056	66.936	135.678	236.431	367.285
NEW LT DEBT	616.300	857.919	455.442	193.542	0.000	0.000	490.208	506.699	1176.141	1889.987
NEW COM STOCK	467.700	0.000	-218.742	-30.690	0.000	0.000	162.936	216.645	513.173	1188.863
NEW PREF STCK	100.600	0.000	317.682	39.740	0.000	0.000	-15.315	123.303	286.209	459.921
OTHER,MISC	499.140	608.684	66.510	-334.647	-247.975	-181.816	-677.465	-290.434	-320.400	-457.216
TOT FDS PROV	2044.390	1903.485	1126.686	809.139	859.008	1179.851	1507.232	2042.519	2705.427	3462.344
FUNDS APPLIED:										
ADDNS,UTIL PL	1592.542	1452.992	632.390	234.390	79.839	162.394	964.363	1472.782	2052.073	2916.558
ADDNS,POL CON	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
ADDNS,COAL FU										
ADDNS,NUC FU										
DEBT RETIREMT	0.000	8.707	18.720	30.236	146.911	406.230	0.000	0.000	0.000	0.000
PREF STK DIVS	223.755	238.845	238.845	286.497	292.458	292.458	292.458	290.161	308.657	351.588
COM STK DIVS	236.800	221.661	266.966	301.494	339.800	318.769	250.411	279.575	344.697	358.287
NOTES RETIRMT										
OTH EXPS,INV										
CHG,WORK CAP	-8.707	-18.720	-30.236	-43.478	0.000	0.000	0.000	0.000	0.000	-164.089
TOT FDS APPL	2044.390	1903.485	1126.686	809.139	859.008	1179.851	1507.232	2042.519	2705.427	3462.344

$$FDPROV_t = NETINC_t + DNORME_t + DFTXBK_t - AFUDCE_t - AFUDCD_t + NWDT_t + NWCEQ_t + NWPEQ_t. \tag{40}$$

I.e., funds provided equals net income plus normal depreciation, deferred taxes, and new issues of debt and equity, minus the non-cash AFUDC items. Funds applied:

$$FDAPPL_t = ADDE_t + ADPP_t + DRETIR_t + PDIV_t + CDIV_t + CHWCAP_t + SOURCO_t, \tag{41}$$

where ADDE and ADDP are the direct construction costs for generation facilities and pollution control equipment, and $CHWCAP_t$ equals $WCAP_t - WCAP_{t-1}$. SOURCO is other sources of funds and is used to balance the statement, that is,

$$SOURCO_t = FDAPPL_t - FDPROV_t. \tag{42}$$

D. Summary Financial Statistics

Finally , R602 computes two sets of ratios that provide measures of a utility's financial health to its debtors and equity holders: interest coverage and profitability ratios. (These are shown on Table 7, another report from the full AUSM.) Electric utilities have a variety of non-cash items in their income statements, all of which may be large in magnitude because of their capital intensity, especially for companies with construction programs: AFUDC augments net income, book depreciation decreases it, and deferred taxes from accelerated depreciation decrease it, although they are temporarily available for use to utilities with normalized accounting. A useful measure of earnings for these ratios must take account of these factors, and so the model computes several alternative measures.

The interest coverage ratio measures the number of times earnings will cover interest expense. The denominator is therefore

$$DEN1_t = LTDEXP_t + OTHINT_t,$$

the year's interest expense for long and short term debt. The first measures,

Table 7. AUSM Interest Coverage and Profitability Ratios

SCENARIO: URGE SCENARIO TEST001 - SIP UNITS CONTINUE TO EMIT AT 1980 LEVELS
BASE CASE

AUSM REPORT - 602: FINANCIAL SUMMARY 82/10/27 (82/10/31)

ILLINOIS (17)

INTEREST COVERAGE RATIOS	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989
OPER INCOME	.769	.886	.922	1.163	1.167	1.264	1.418	1.370	1.024	.559
OP INC+INC TX	.843	1.061	1.104	1.570	1.620	1.883	2.241	2.168	1.524	.623
OPER INCOME + INC TX&DEPREC	1.271	1.470	1.502	2.020	2.125	2.484	2.875	2.763	2.083	1.125
INC BEFORE INT	1.211	1.385	1.350	1.467	1.355	1.279	1.530	1.582	1.372	1.033
PROFITABILITY RATIOS										
NET INCOME DIV BY EQUITY	.059	.092	.089	.101	.075	.048	.091	.105	.081	.041
ADJ NET INCOME DIV BY EQUITY	-.003	.005	.009	.056	.069	.093	.115	.099	.039	-.034
PRE INT NET INC DIV BY RBASE	.149	.180	.177	.161	.129	.099	.118	.136	.133	.117
ADJ PRE INT NET INC DIV BY RBASE	.091	.100	.108	.130	.125	.120	.130	.133	.105	.057

$$COV1_t = (OPREVE_t - EXPTOT_t)/DEN1_t, \tag{43}$$

excludes AFUDC from earnings but does not take account of the availability of funds from depreciation and deferred taxes. The second ratio, based on pretax operating income, is

$$COV2_t = (OPREVE_t - EXPTOT_t + ITXR_t)/DEN1_t. \tag{44}$$

It therefore accounts for the availability of deferred taxes and the investment tax credit. The third measure, based on pretax cash flow, accounts as well for funds from depreciation:

$$COV3_t = (OPREVE_t - EXPTOT_t + ITXR_t + DNORME_t)/DEN1_t. \tag{45}$$

These three measures allow one to see the effects of each non-cash item on the interest coverage ratio. The final measure is a more standard one, based on net income before interest payments:

$$COV4_t = (OPREVE_t - EXPTOT_t + OTHINC)/DEN1_t. \tag{46}$$

It includes, as part of earnings, the equity portion of AFUDC; does not take account of funds from depreciation; and includes the investment tax credit (but not deferred taxes) as sources of funds.

The profitability measures show the earnings available for stockholders normalized to the size of the firms involved. One logical denominator would seem to be total equity, the stockholders' contribution, and two measures are computed with the denominator

$$DEN2_t = COMTOT_t + PEQTOT_t. \tag{47}$$

The first is based simply on net income:

$$PROF1_t = NETINC_t/DEN2_t. \tag{48}$$

Because of the importance of non-cash items in utilities' income statements, a second measure accounts for the largest of these by excluding AFUDC and adding back deferred taxes:

$$PROF2_t = (NETINC_t - AFUDCD_t - AFUDCE_t + DFTXBK_t)/DEN2_t. \quad (49)$$

Under some circumstances, however, the denominator DEN2 may provide misleading measures of profitability because it includes retained earnings. For example, over a period of declining profitability, retained earnings and therefore DEN2 will increase more slowly or may even decline, so that PROF1 or PROF2 may overstate the company's profitability. The model therefore computes two more profitability measures with net plant in the denominator:

$$DEN3_t = NETPE_t = GRSSPE_t - ADPRBE_t. \quad (50)$$

These measures are of overall returns to both debt and equity holders. The first is pre-interest net income (with no adjustments for the non-cash items);

$$PROF3_t = (NETINC_t + TOTINT_t + AFUDCD_t)/DEN3_t \quad (51)$$

The final measure excludes the debt and equity portions of AFUDC from earnings and accounts for funds from deferred taxes:

$$PROF_t = (NETINC_t + TOTINT_t - AFUDCE + DFTXBK_t)/DEN3_t. \quad (52)$$

The importance of these differing concepts is evident in the financial summary, where interest coverage and profitability ratios not only differ in magnitude but also in positive or negative values.

In addition to printing the standard financial reports (income statement, statement of retained earnings, balance sheet, and funds flow) and the coverage and profitability ratios, the R602 subroutine also prints the tables showing the components of required revenue and items in the federal corporate income tax calculation in the preceding section.

IV. Data

The exogenous data required for the financial model in AUSM are of two types: numerical and logical. The data were collected earlier as part of an extensive review of state regulatory practices.[11]

The Table 8 excerpt, for example, shows that almost all states used full normalization of tax benefits for the investment tax credit. However, the four states that flowed-through part of the credit included California and New York. The financial model, as explained above, is written to permit full or partial normalization or flow-through regulation according to the actual practices of a state.

The Table 9 excerpt shows state income and other tax rates for electric utilities.

Finally, the Table 10 excerpt shows the exogenous financial data used for the model.

Table 11 summarizes the data acquired in the review of regulatory practices.

[11] Hindman, Chapman, and Cole, op. cit.

Reproduced from State Regulatory Policies for Privately Owned Electric Utilities in 1981

Table 8. 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 8 (continued). Normalization Versus Flow-Through Treatment of the Investment Tax Credit[a]

State	Amount Normalized	Amount Flowed-Through	Rate Base	Cost of Service (Ratable Flow-Through	Not Specified or Unclear[c]
			NORMALIZATION METHOD[b]		
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 8 (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.

Reproduced from State Regulatory Policies for Privately Owned Electric Utilities in 1981

Table 9. 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 9 (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	5%		6%	
LA			2%	8%	
ME		5%		6.93%	State franchise tax - $1.50/$1000 capital and undivided profits. Corporation fee - insignificant.

Table 9 (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%		6.5%	Capital stock tax-varies.
MA				2.35%	
MI		Use tax - 4%.		12%	Local franchise tax - varies.
MN	Local - varies	5%		4%	State franchise tax - $2.50/$1000. Local
MS		5% with exemption of residential customers.			
MO		3.125%	Varies - 3/8 - 1%.	5%	State franchise tax - 1/20 of 1% of assets.
MT				6.75%	Consumer council tax - .09%. Consumer advocate - .000075%. PSC-.0003%.
NV	State franchise tax - 2% gross revenues mill assessments.				
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 9 (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 9 (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.

Reproduced from State Regulatory Policies for Privately Owned Electric Utilities in 1981

Table 10.

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

Table 10 (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

Table 11. State Data for the AUSM Financial Model in _State Regulatory Policies for Privately Owned Electric Utilities in 1981_

Percentage of Construction Work in Progress Allowed in Rate Base During Construction

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

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

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

Allowance for Funds Used During Construction Accumulation Method Allowed

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

Rate Base Adjustment for Inflation

Non-FERC Methods of Calculating Allowance for Funds Used During Construction

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

Average Service Lives Used to Depreciate Utility Assets

Recent Rates of Return Allowed on Common Equity and the Rate Base

Investment Tax Credit Rates Utilized by Most Utilities

Electric Utilities Claiming 1 or 1.5 Percent Additional Investment Tax Credit for Employee Stock Ownership Plans

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

Major State Taxes on Electric Utilities

State Income Tax Rates for Electric Utilities

Average Number of Months Necessary for Rate Decisions

Policies Toward Use of Fuel Price Adjustment Clauses

Regulatory Policies Toward Allowance of Fuel Procurement Investments in the Rate Base

Decommissioning Accounting Data for Privately Owned Nuclear Power Plants

Table 11 (continued).

Publicly Owned Electricity Generation by State 1980

Regulatory Commission Responsibility for Publicly Owned Electric Utilities

Financial Data Tables for all Utilities in a State

V. Sample Analysis: A New York "Stand Alone" Case

As part of our work in understanding the interactions of utility finance with pollution control, dispatching, and customer demand, we use a "stand alone" model which combines these four models. It excludes the coal supply and capacity planning models, and only examines least-cost dispatching and sulfur oxide emissions.

One case being studied is the possibility of New York's two nuclear plants not being allowed to generate electricity. As the following two tables show, non-operation of the Shoreham and Nine Mile 2 plants increases fuel expenses, primarily because of the increased dispatching of existing oil fired plants. Table 12 shows in 1989, for example, $4.8 billion in fuel oil cost, while Table 13 shows $6.0 billion for increased oil which replaces the two nuclear plants.[12]

Although the plants add $7 billion (approximately one-third) to the New York rate base, their net effect may be a reduction in total costs. When this "stand alone" analysis is complete,[13] it will show how these possible savings are affected by various fuel inflation assumptions and rate base allowances, and also how sulfur oxide emissions vary from the changes in fuel use and demand.

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[12]The specific fuel price assumptions in this case are from the U.S. DoE MEFS Model Report, December 1981, Series C, the high prices. As the text indicates, our study examines variation in fuel price assumptions.

[13]D. Chapman, T. Mount, M. Czerwinski, and M. Younger, "Emission Control for Acid Precipitation: Utility Finance and Demand Forecasting," to be presented at the American Association for the Advancement of Science Meeting, May 29, 1983, Detroit, Michigan.

Table 12. New York Income Statement with Shoreham and Nine Mile 2 Operating

INCOME STATEMENT

	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989
ELEC OPER REV	6616.273	7066.180	7651.852	8360.488	9192.105	10514.891	11727.859	12785.953	14315.004	15558.746
OTHER OPER REV	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
TOTAL OPER REV	6616.273	7066.180	7651.852	8360.488	9192.105	10514.891	11727.859	12785.953	14315.004	15558.746
DIR ELEC OP EXP:										
PURCH POWER	543.385	580.335	628.437	686.635	754.935	863.573	963.193	1050.092	1175.671	1277.818
FUEL,COAL	269.205	330.351	392.803	456.152	493.700	641.273	714.444	746.799	825.459	912.942
FUEL,OIL	990.232	1285.058	1628.793	2027.354	2206.632	2310.502	2930.268	3547.321	4128.191	4840.258
FUEL,NAT. GAS	369.541	483.540	621.260	783.469	973.500	1195.044	1235.635	808.875	967.382	1149.273
FUEL,NUCLEAR	90.053	96.626	104.793	114.694	139.952	155.596	173.781	221.598	249.455	280.996
FUEL,OTHER	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
MAINT	292.379	320.334	350.645	383.323	448.612	483.906	519.307	601.140	649.157	701.865
DEPRECIATION	409.426	415.153	421.569	428.759	533.448	581.538	581.538	728.228	728.228	728.228
OPER TAX EXP:										
INC TAX PAID	297.848	218.190	144.360	144.411	160.026	374.093	542.424	697.633	916.557	1055.046
INC TAX DEF	328.731	286.730	252.379	220.893	228.016	262.446	248.914	280.864	340.892	292.356
INC TAX ADJ	33.368	63.905	99.765	66.794	34.541	20.272	10.711	0.000	0.000	0.000
INC TX REP	659.947	568.825	496.504	432.097	422.583	656.812	802.049	978.497	1257.449	1347.402
GROSS REC TAX	49.622	52.996	57.389	62.704	68.941	78.862	87.959	95.895	107.363	116.691
NON-INCOME TAX	564.158	552.354	540.204	527.739	626.879	674.853	644.938	776.225	740.751	705.278
ADMIN, OTH EXP	580.790	634.833	693.831	757.547	925.768	893.867	966.238	1046.279	1129.541	1221.921
TOTAL OPER EXP	4818.766	5320.402	5936.223	6660.465	7494.930	8535.812	9619.328	10600.934	11958.633	13282.652
AFUDC-EQUITY	272.636	340.073	442.381	528.326	359.797	282.126	325.976	0.000	0.000	0.000
INCOME TX CRED	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
TOT OTHER INC	272.636	340.073	442.381	528.326	359.797	282.126	325.976	0.000	0.000	0.000
L TERM INT EXP	1104.675	1161.059	1217.644	1280.250	1332.667	1355.393	1314.353	1249.719	1093.609	907.731
OTHER INTEREST	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
(AFUDC-DEBT)	122.932	153.340	199.471	238.224	162.233	127.212	146.984	0.000	0.000	0.000
TOTAL INT EXP	981.742	1007.719	1018.172	1042.026	1170.433	1228.181	1167.370	1249.719	1093.609	907.731
NET INCOME	1088.401	1078.131	1139.637	1186.323	886.539	1033.023	1267.138	935.300	1262.762	1368.362

RETAINED EARNINGS

	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989
JANUARY 1 BAL	2554.700	2719.636	2814.229	2931.603	3049.722	2824.800	2796.641	3009.637	2837.546	3035.937
NET INCOME	1088.401	1078.131	1139.837	1186.323	886.539	1033.023	1267.138	935.300	1262.762	1368.362
(PREF DIVIDS)	284.790	303.629	318.906	335.303	349.031	354.982	354.982	354.982	354.982	354.981
(COM DIVIDS)	638.675	679.909	703.557	732.901	762.430	706.200	699.160	752.409	709.386	758.984
DECEMBR 31 BAL	2719.636	2814.229	2931.603	3049.722	2824.800	2796.641	3009.637	2837.546	3035.937	3290.331

Table 13. New York Income Statement with Prohibition of Shoreham and Nine Mile 2 Operations

INCOME STATEMENT

	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989
ELEC OPER REV	6616.273	7066.180	7651.852	8360.488	9192.105	10713.219	12008.902	13110.102	15095.586	16549.230
OTHER OPER REV	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
TOTAL OPER REV	6616.273	7066.180	7651.852	8360.488	9192.105	10713.219	12008.902	13110.102	15095.586	16549.230
DIR ELEC OP EXP:										
PURCH POWER	543.385	580.335	628.437	686.635	754.935	879.862	986.275	1076.714	1239.781	1359.166
FUEL,COAL	269.205	330.351	392.803	456.152	520.791	670.824	746.093	826.872	916.971	963.372
FUEL,OIL	990.232	1285.058	1628.793	2027.354	2483.808	2607.243	3200.020	4169.250	4878.055	6026.930
FUEL,NAT. GAS	369.541	483.540	621.260	783.469	973.500	1195.044	1278.411	1123.680	1224.702	1222.644
FUEL,NUCLEAR	90.053	96.626	104.793	114.694	126.470	140.267	156.235	174.526	195.297	218.709
FUEL,OTHER	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
MAINT	292.379	320.334	350.645	383.323	418.200	448.120	481.519	503.857	534.200	569.547
DEPRECIATION	409.426	415.153	421.569	428.759	533.448	581.538	581.538	728.228	728.228	728.228
OPER TAX EXP:										
INC TAX PAID	297.848	218.190	144.360	144.411	40.254	327.220	523.663	430.950	798.969	941.327
INC TAX DEF	328.731	286.730	252.379	220.893	228.015	262.446	248.914	280.864	340.892	292.356
INC TAX ADJ	33.368	63.905	99.765	66.794	34.541	20.272	10.711	0.000	0.000	0.000
INC TX REP	659.947	568.825	496.504	432.097	302.810	609.938	783.288	711.813	1139.862	1233.683
GROSS REC TAX	49.622	52.996	57.389	62.704	68.941	80.349	90.057	98.326	113.217	124.119
NON-INCOME TAX	564.188	552.354	540.204	527.739	625.879	674.853	644.938	776.225	740.751	705.278
ADMIN, OTH EXP	580.790	634.833	693.831	757.547	825.768	891.406	960.917	1037.991	1113.683	1197.340
TOTAL OPER EXP	4818.766	5320.402	5936.223	6660.465	7635.531	8779.426	9905.285	11227.465	12824.730	14348.996
AFUDC-EQUITY	272.636	340.073	442.381	528.326	359.797	282.126	325.976	0.000	0.000	0.000
INCOME TX CRED	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
TOT OTHER INC	272.636	340.073	442.381	528.326	359.797	282.126	325.976	0.000	0.000	0.000
L TERM INT EXP	1104.675	1161.059	1217.644	1280.250	1332.667	1365.136	1327.462	1260.401	1146.125	965.369
OTHER INTEREST	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
(AFUDC-DEBT)	122.932	153.340	199.471	238.224	152.233	127.212	146.984	0.000	0.000	0.000
TOTAL INT EXP	981.742	1007.719	1018.172	1042.026	1170.433	1237.925	1180.478	1260.401	1146.125	965.369
NET INCOME	1088.401	1078.131	1139.837	1186.323	745.938	977.995	1245.115	622.236	1124.730	1234.865

RETAINED EARNINGS

	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989
JANUARY 1 BAL	2554.700	2719.636	2814.229	2931.603	3049.722	2684.199	2633.609	2862.788	2411.793	2576.041
NET INCOME	1088.401	1078.131	1139.837	1186.323	745.938	977.995	1245.115	622.236	1124.730	1234.865
(PREF DIVIDS)	284.790	303.629	318.906	335.303	349.031	357.534	357.534	357.534	357.534	357.533
(COM DIVIDS)	638.675	679.909	703.557	732.901	762.430	671.050	658.402	715.697	602.948	644.010
DECEMBR 31 BAL	2719.636	2814.229	2931.603	3049.722	2684.199	2633.609	2862.788	2411.793	2576.041	2809.362

Table 14. Effect of Operation of Shoreham and Nine Mile 2 on New York Regulatory Economics

REGULATORY ECONOMICS

	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989
GRSS RATE BASE	14329.898	14530.348	14754.934	15006.562	18187.543	19870.676	19870.676	24271.371	24271.371	24271.371
RATE BASE ADJS										
CUM DEPREC	4094.255	4509.406	4930.969	5359.723	5893.164	6474.695	7056.227	7784.457	8512.676	9240.902
CUM DEF ITC	202.546	206.778	210.679	214.251	325.180	400.880	386.224	551.025	530.181	509.338
CUM DEF TAXES	178.063	329.236	461.480	576.854	700.326	865.933	1036.191	1215.579	1474.392	1702.939
TOTAL	4474.859	5045.418	5603.121	6150.824	6918.665	7742.504	8478.637	9551.059	10517.246	11453.176
NET RATE BASE	9855.027	9484.922	9151.805	8855.730	11266.867	12128.164	11392.031	14720.305	13754.117	12818.187
REVENUE ALLOWANCE										
FD INC TX ALL	487.469	454.167	502.245	511.881	746.775	846.177	817.695	1131.832	1084.646	1038.393
ST INC TX ALL	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
OTHER TAX	564.188	552.354	540.204	527.739	626.879	674.853	644.938	776.225	740.751	705.278
RETURN-DEBT	682.953	657.304	634.219	613.701	780.931	840.480	789.466	1020.114	953.157	888.297
RETURN-COMMON	639.034	615.035	593.435	574.236	730.713	786.432	738.699	954.516	891.865	831.176
RETURN-PREF	178.869	172.151	166.105	160.731	204.529	220.125	206.764	267.172	249.635	232.648
DEPRECIATION	409.426	415.153	421.569	428.759	533.448	581.538	581.536	728.228	726.228	728.228
PURCH POWER	543.385	580.335	628.437	686.635	754.935	863.573	963.193	1050.092	1175.671	1277.818
FUEL-COAL	269.205	330.351	392.803	456.152	493.700	641.273	714.444	746.799	825.459	912.942
FUEL-OIL	990.232	1285.058	1628.793	2027.354	2206.632	2310.502	2930.268	3547.321	4128.191	4840.258
FUEL-NAT. GAS	369.541	483.540	621.260	783.469	973.500	1195.044	1235.635	808.875	967.382	1149.273
FUEL-NUCLEAR	90.053	96.626	104.793	114.694	139.952	155.596	173.781	221.598	249.455	280.996
FUEL-OTHER	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
MAINT EXPENSE	292.379	320.334	350.645	383.323	448.612	483.906	519.307	601.140	649.157	701.865
ADMIN,OTH EXP	580.790	634.833	693.831	757.547	825.769	893.867	966.238	1046.279	1129.541	1221.921
TOTAL	6122.211	6664.113	7307.801	8058.715	9504.691	10535.848	11327.832	12952.410	13828.898	14869.043

Table 15. Prohibition of Shoreham and Nine Mile 2 Operation: Effect on Regulatory Economics

REGULATORY ECONOMICS

	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989
GRSS RATE BASE	14329.898	14530.348	14754.934	15006.562	18187.543	19870.676	19870.676	24271.371	24271.371	24271.371
RATE BASE ADJS										
CUM DEPREC	4094.255	4509.406	4930.969	5359.723	5893.164	6474.695	7056.227	7784.457	8512.676	9240.902
CUM DEF ITC	202.546	206.778	210.679	214.251	325.180	400.880	386.224	551.025	530.181	509.338
CUM DEF TAXES	178.063	329.236	461.480	576.854	700.326	865.933	1036.191	1215.579	1474.392	1702.939
TOTAL	4474.859	5045.418	5603.121	6150.824	6918.668	7742.504	8478.637	9551.059	10517.246	11453.176
NET RATE BASE	9855.027	9484.922	9151.805	8855.730	11268.867	12128.164	11392.031	14720.305	13754.117	12818.187
REVENUE ALLOWANCE										
FD INC TX ALL	487.469	494.167	502.245	511.881	746.775	846.177	817.895	1131.832	1084.646	1038.393
ST INC TX ALL	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
OTHER TAX	564.188	552.354	540.204	527.739	626.879	674.853	644.938	776.225	740.751	705.278
RETURN-DEBT	682.953	657.304	634.219	613.701	780.931	840.480	789.465	1020.114	953.157	888.297
RETURN-COMMON	639.034	615.035	593.435	574.236	730.713	785.432	738.699	954.516	891.865	831.176
RETURN-PREF	178.869	172.151	166.105	160.731	204.529	220.125	206.764	267.172	249.635	232.648
DEPRECIATION	409.426	415.153	421.569	428.759	533.448	581.538	581.538	728.228	728.228	728.228
PURCH POWER	543.385	580.335	528.437	686.635	754.935	879.862	986.275	1076.714	1239.781	1359.166
FUEL-COAL	269.205	330.351	392.803	456.152	520.791	670.824	746.093	826.872	916.971	963.372
FUEL-OIL	990.232	1285.058	1628.793	2027.354	2483.808	2607.243	3200.020	4169.250	4878.055	6026.930
FUEL-NAT. GAS	369.541	483.540	621.260	783.469	973.500	1195.044	1278.411	1123.680	1224.702	1222.644
FUEL-NUCLEAR	90.053	96.626	104.793	114.694	126.470	140.267	156.235	174.526	195.297	218.709
FUEL-OTHER	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
MAINT EXPENSE	292.379	320.334	350.645	383.323	418.200	448.120	481.519	503.857	534.200	569.547
ADMIN,OTH EXP	580.790	634.833	693.831	757.547	825.769	891.406	960.917	1037.991	1113.683	1197.340
TOTAL	6122.211	6664.113	7307.801	8058.715	9766.117	10826.016	11635.684	13846.805	14810.691	16046.422

VI. Conclusions and Revisions

Certain areas in the financial model will be revised. The 1982 Tax Act amendments to the Internal Revenue Code must be incorporated. This will simply involve eliminating the depreciation rate schedules for 1985 and beyond and adjusting the tax depreciation basis by half of the amount of the investment tax credit.

Currently, rates of return for debt and equity stay the same from year to year. Since the AUSM model uses both real and nominal future dollars, we wish to make these rates of return reflect changes in inflation.

Another area for work is the treatment of historical plant. In brief, treating it as a single plant of a particular age does not produce tax and book depreciation accounts that are both in accord with the exogenous, base-year values. The effect of this inaccuracy on the model's results is likely to be small in some states where the value of historical plant will be small in comparison with the very expensive construction projects that will come on line during the simulation period. However, if time permits, we plan to approach this depreciation problem by use of sets of schedules for plant of different types and ages to see if we can more closely approach the actual reported values of both the accumulated straight line and accumulated tax depreciation accounts for the base year.

Allowing part or all of CWIP to be included in the rate base for states where this is permitted is another desirable addition to the model. Also it would be more accurate to make debt retirement an optional rather than required strategy.

In a sense, it is premature to offer a conclusion in early 1983. The major objective of the financial model in the AUSM is to provide the best possible empirical representation of actual financial circumstances in each state for the interactive, recursive AUSM. Much of our effort this year is focused upon the validation and testing of the AUSM and its component models, and the validation of each model-to-model interface.

Our overall goal for the URGE project is to achieve the best possible model for use by the EPA, the utility industry, Congress, universities, and environmental organizations in the study of air pollution emissions. If this year's work is successful, substantive analysis and conclusions will be possible a year from now.

The results of the "New York Stand Alone" study described above indicate the potential. Two new nuclear plants are examined as they affect dispatching, fuel costs and regulatory economics. The preliminary analysis above showed such considerable fuel savings that operations of the two plants reduce New York customer costs by $1 billion per year.

This "stand alone" case is a limited subset of the full AUSM, and links utility finance and demand models from Cornell with pollution control and dispatching models from Carnegie-Mellon. It indicates the potential interactions of the financial model in the full AUSM.

Appendix A

Glossary of Variable Names

(NOTE: all units are million dollars unless otherwise specified)

ACCTR(YR) = accounts receivable

ACITC(YR) = accumulated investment tax credits for regulatory commission purposes (for deduction from the rate base); may be only a fraction of total accumulated investment tax credit from electric investment

ACTCT(YR) = accumulated total investment tax credits for all kinds of investments: electric and non electric

ADDE(YR) = total direct construction costs and afudc charges for electric plant in a given year (excludes pollution control equipment)

ADDP(YR) = total direct construction costs and afudc charges for pollution control equipment in a given year

ADFBK(YR) = accumulated total deferred income taxes for book purposes; equals accumulation of accelerated depreciation (construction cost, tax life)

ADFRGE(YR) = accumulated deferred income taxes for deduction from rate base; equals accumulation of TXDEPR minus REGDPE times the tax rate; electric only; accumulated over assets as well as over time

ADJRBS(YR) = adjusted rate base; TOTRBS minus accumulated deferred taxes (ADFRGE) and accumulated investment tax credits (ACITC) in the normalization case; for flow-through accounting, ADJRBS equals TOTRBS

ADPRBE(YR) = accumulated straight line depreciation, electric; based on construction cost plus afudc and operating life; accumulated over all facilities and over time

AFDCD(ASSTYP,PLTNO) = afudc-debt for a particular asset in a given year

AFDCE(ASSTYP,PLTNO) = afudc-equity for a particular asset in a given year

AFUDCD(YR) = afudc-debt accumulated over all projects under construction in a given year

AFUDCE(YR) = afudc-equity accumulated over all assets under construction in a given year

AITC = yearly amortization of the accumulated investment tax credit on electric plant that is deducted from rate base in normalized accounting

ASSCAO(YR) = current and other assets on balance sheet; equals ACCTR + CASH

CAPTOT(YR) = total capitalization; equals COMTOT + PEQTOT + LTDTOT; on balance sheet

CASH(YR) = the repository for excess funds; is set to zero at the beginning of each year

CCO = the final value of VEST for a particular asset

CDIV(YR) = dividends paid on common stock

CEQPC = fraction of capitalization that is common equity; fraction

CEQTOT(YR) = total common stock issued; equals OLDCEQ + NWCEQ

CHWCAP(YR) = change in working capital during a year; if it is the first year of the simulation CHWCAP(YR) equals WCAP(YR) - BSWCAP; if it is a later year in the simulation CHWCAP(YR) equals WCAP(YR) - WCAP(LSTYR)

COMTOT(YR) = total common stock equity; equals CEQTOT + RETERN

CONEXP(ASSTYP,PLTNO) = direct construction expense for a particular asset in given year

CORR = the correction to total liabilities made to balance the balance sheet

COV1(YR)...COV4(YR) = interest coverage ratios; each of the four is computed by dividing a different definition of income by interest expense

CRET(YR) = rate of return to common stock; fraction

CRETM(YR) = current rate of return to common stock; fraction

CWIPE(YR) = construction work in progress (construction cost plus afudc); electric; equals CWPE + CWPP

CWP(ASSTYP,PLTNO) = construction work in progress; accumulated direct construction costs plus afudc for a particular asset as of a given year

CWPE(YR) = construction work in progress (construction cost plus afudc) for all non-pollution control electric assets under construction in a given year

CWPP(YR) = construction work in progress (construction cost plus afudc) for all pollution control assets under construction in a given year

DB1(YR) = fraction of tax basis not yet depreciated

DEN1(YR) = the denominator used in the computation of interest coverage ratios; equals LTDEXP + OTHINT (if this sum = zero, then denom = 1)

DEN2(YR) = The denominator used in the computation of profitability ratios one and two; equals COMTOT + PEQTOT

DEN3(YR) = the denominator used in the computation of profitability ratios three and four; equals NETPE

DFTXBK(YR) = deferred tax for income statement; equals accelerated (construction cost, tax life) minus straight line depreciation (construction cost, operating life) times tax rate for all assets

DNORME(YR) = straight line (construction cost plus afudc, operating life) depreciation on all electric assets in YR

DOEXP(YR) = direct operating expenses, electric; equals PP plus fuel costs plus MAINT plus OPEXPO

DPRATE(YR) = the depreciation rate schedule under the new tax law for a particular asset. Fraction.

DRETIR(YR) = debt to be retired in YR (assumes 20 year bonds)

DSL1(YR) = straight line depreciation (construction cost plus afudc, operating life) for a particular asset in a given year; passed from depreciation subroutine

DTPC = fraction of capitalization that is debt; fraction

EQPC = fraction of capitalization that is equity; equals CEQPC + PEQPC; fraction

ETXR = combined effective federal and state corporate income tax rate; equals FTXR + (1 - STXR) + STXR. Fraction.

EXPTOT(YR) = total operating expenses; equals DOEXP + DNORME + ITXR + GRTX + SSOTX + PTX

FDAPPL(YR) = funds applied; for funds flow statement

FDPROV(YR) = funds provided; for funds flow statement

FITX(YR) = actual federal income tax expense

FNEEDS(YR) = financial needs

FTXR = federal corporate income tax rate, marginal; fraction

GRSSPE(YR) = electric utility plant in service, gross

GRTX(YR) = gross receipts tax

ITXP(YR) = income tax paid; equals FITX plus, for some states, the state corporate income tax as well; on income statement

ITXR(YR) = income tax reported; equals ITXP + DFTXBK + TC; on income statement

LIACAO(YR) = notes and other current liabilities

LIFN = operating life in years; for depreciation subroutine input; REAL

LIFT = tax life in years; for depreciation subroutine input; REAL

LTDEXP(YR) = interest expense on long term debt; equals RINT * LTDTOT

LTDTOT(YR) = total long term debt; equals OLDT + NWDT

MAINT(YR) = maintenance expense, electric; input data from dispatch subroutine

NETINC(YR) = net income for income statement

NWCEQ(YR) = new common stock issued in YR

NWDT(YR) = new long term debt issued in YR

NWPEQ(YR) = new preferred stock issued in YR

OLDCEQ(YR) = common stock issued prior to YR

OLDPEQ(YR) = preferred stock issued prior to YR

OLDT(YR) = total outstanding debt as of YR; equals LTDTOT(LSTYR) - DRETIR(YR)

OPEXPO(YR) = administrative, customer and other costs, electric

OPREVE(YR) = operating revenues, electric; input from demand subroutine

OTHASS(YR) = assets owned by the utility other than those related to the generation, distribution and sale of electricity; assumed to be equal to the base year value for each subsequent year

OTHINC(YR) = other income, total; for income statement; equals AFUDCE + TC

OTHINT(YR) = other interest, i.e., on short term debt

PDIV(YR) = dividends paid on preferred stock

PEQPC = fraction of capitalization that is preferred stock; fraction

PEQTOT(YR) = total preferred stock; equals OLDPEQ + NWPEQ

PP(YR) = cost of purchased and interchanged electric power; input from dispatch subroutine

PRET(YR) = rate of return to preferred stock (weighted average); fraction

PRETM(YR) = current rate of return to preferred stock; fraction

PROF1...PROF4 = profitability ratios; computed by dividing different definitions of income by total equity for PROF1 and PROF2; or dividing income by net plant for PROF3 and PROF4.

PTX(YR) = property taxes

RADCD = afudc-debt rate; equals ROD * DTPC; fraction

RBDP(YR) = straight line depreciation (construction cost plus afudc, operating life), used in revenue requirement determination

RC(YR) = allowed return to common equity for revenue requirement determination

RD(YR) = allowed return to debt for revenue requirement determination

REGDPE(YR) = depreciation deduction for regulatory commission tax allowance; equals accelerated depreciation for all electric assets using construction costs and operating life

RETERN(YR) = retained earnings, end of year

REVRQ(YR) = revenue requirement for price determination

RINT(YR) = interest rate on long term debt (weighted average); fraction

RINTM(YR) = current interest rate on long term debt

ROD = interest rate on long term debt for afudc and required revenue calculations; equals RINT(YR); fraction

RP(YR) = allowed return on preferred equity for revenue requirement determination

SITX(YR) = state income tax due in a given year

SOURCO(YR) = other funds provided: equals FDAPPL(YR) - FDPROV(YR)

SSOTX(YR) = social security and other taxes

SUM(YR) = for revenue requirement determination; sum of fuel costs, operating costs and non-income taxes for electricity

TBASE(YR) = basis for tax depreciation and property tax; equals sum of VEST for all plants on line; for historical plant equals GRSSPE + GRSSPO times TBSPC

TBSPC = fraction of historical gross plant exclusive of afudc; fraction

TC(YR) = investment tax credit earned during the year; sum of ZITC for each asset type and plant number for that year

TF(YR) = federal income tax allowance for required revenue determination

TOTINT(YR) = total interest expense for income statement; equals LTDEXP + OTHINT - AFUDCD

TOTITC(ASSTYP,PLTNO) = accumulated investment tax credit earned by a particular asset

TOTRBS(YR) = rate base: construction costs plus afudc on electric plant in service

TS(YR) = state income tax allowance for REVRQ(YR) determination

TXDEPR(YR) = accelerated depreciation (construction cost, tax life) in YR on total assets

TXDP(YR) = actual income tax depreciation deduction (accelerated depreciation (construction cost, tax life)) for a particular asset in a given year; passed from depreciation subroutine

VEST(ASSTYP,PLTNO) = accumulated direct construction cost for a particular asset

VSTE(YR) = total accumulated direct construction costs, electric generation

VSTP(YR) = total accumulated direct construction costs, pollution control

WCAP(YR) = working capital; equals ASSCAO - LIACAO

ZITCR = investment tax credit rate; fraction