Electricity Finance and Pricing Submodule

Model Documentation

<u>Model Description</u>

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Introduction

Purpose of the Report

The purpose of this report is to define the objectives of the model, describe its basic approach, and provide detail on how it works. This documentation is intended as a reference document for model analysts, users, and the public. EIA has a legal obligation to provide adequate documentation in support of its models (Public Law 93-275).

Model Summary

The EFP is a regulatory accounting model that projects electricity prices. The model first solves for revenue requirements[1] by building up a rate base[2], calculating a return on rate base, and adding the allowed expenses. Average revenues (prices) are calculated based on assumptions regarding regulatory lag and customer cost allocation methods. The model then solves for the internal cash flow and analyzes the need for external financing to meet necessary capital expenditures. Finally, the EFP builds up the financial statements.

The EFP is used in conjunction with the National Energy Modeling System (NEMS). Inputs to the EFP include the forecast generating capacity expansion plans, operating costs, regulatory environment, and financial data. The outputs include forecasts of income statements, balance sheets, revenue requirements, and electricity prices.

Model Archival Citation and Model Contact

The EFP will be archived as a part of the National Energy Modeling System. The model contact is Art Holland (202-586-2026).

[1]Revenue requirements are the costs that a ratemaking authority allows a regulated utility to recover from ratepayers.

[2]The ratebase is the total value (original cost less accumulated straight line depreciation and excluded tax deferrals) of all capitalized assets on which the regulated utility is allowed by a ratemaking authority to earn a return.

Model Purpose

Model Objectives

The Electricity Finance and Pricing Submodule (EFP) is a component of the Electricity Market Module (EMM), which is part of the National Energy Modeling system. As a component of NEMS, the EFP forecasts financial information for electric utilities on an annual basis given a set of inputs and assumptions concerning forecast capacity expansion plans, operating costs, regulatory environment, and financial data. The outputs of the model include electricity prices by end use sectors for North American Electric Reliability (NERC) and Census regions, financial statements, revenue requirements[3], and financial ratios for each stage of production (generation, transmission and distribution.)

Electricity prices are determined by allocating projected revenue requirements to each customer class and dividing by the corresponding sales. Because the EFP is an aggregated model, the revenue requirements are allocated according to a representative rate structure for an entire region. The EFP simulates the traditional original-cost or rate-of-return regulatory method where electric utilities have their rates set by local, State, and Federal regulatory commissions. Utilities have rates set so as to allow them to recover their operating costs and earn a rate of return equal to their cost of capital.

The EFP determines the revenues that the aggregated utility requires in order to operate and earn its allowed profit using an average cost based algorithm. Revenues required for wholesale trades, including generation that is provided by nonutilities[4], are determined in separate submodules of the Electricity Market Module (EMM) of the National Energy Modeling System (NEMS) and transferred to the EFP as expense items.

There are three exceptions to the use of traditional rate of return regulation for determining revenue requirements in the EFP. These exceptions are sales-leaseback transactions[5], phase-in plans for new generating units[6], and disallowances[7]. These exceptions are modeled by exogenously adjusting the

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[3]Revenue requirements are the costs that a ratemaking authority allows a regulated utility to recover from ratepayers.

[4]Nonutility generators are companies that generate electric power to be sold at wholesale rates to utilities who will in turn sell the power to ultimate consumers. Nonutility generators are nonregulated in that ratemaking commissions generally do not use the exhaustive cost based determination of electricity rates that are used for traditional regulated utilities. Instead, alternate methods for setting their rates have been developed such as a utility avoided cost method for cogenerators, and competitive bidding for independent power producers (IPPs).

[5]A sales-leaseback transaction in the electric power industry generally involves the sale by the utility of a newly completed power plant to a group of investors with the understanding that the utility will then operate the plant through a lease arrangement. The advantage to the utility of such an arrangement is that rate shock can be avoided because there is a quick recovery of the costs of building the plant (through the sale proceeds). Payments by the utility for the use of the plant may then be levelized by the lease payments.

[6]A phase-in plan also serves to reduce rate shock caused by a new plant entering service. A new plant is introduced into rates in phases to raise rates gradually over time. In many cases, the ratemaking authority will allow the utility to earn a compounded return on the unrecovered portion of the plant, but recovery of these returns is deferred

forecasted revenue requirements to comply with known information. The revenue that the aggregated utility will actually receive is modeled by adjusting the revenue requirement by a function to simulate regulatory lag[8]. The model solves for internal cash flow and determines the need for external financing in order to meet capital expenditures.

Revenue requirements are allocated to each of four customer classes: residential, commercial, industrial, and transportation. The allocation process is carried out in three steps. First, all costs are functionalized. That is, they are sorted by stage of production into generation, transmission, and distribution. Second, the functionalized costs are classified according to the service characteristics to which they are related. The four service characteristics are fuel costs, variable operation and maintenance (O&M) costs, fixed O&M costs, and capital related costs[9]. Third, these functionalized and classified costs are allocated to the four customer classes and the average revenue for each customer class in each region is determined. In addition to determining customer average revenues on a regional basis, the EFP builds financial statements and ratios using accounting methods that simulate standard industry accounting practice.

Alternative regulatory and financial treatments that can be simulated in the EFP are flow-through versus normalized accounting[10], construction work in progress (CWIP) versus allowance for funds used during construction (AFUDC)[11], alternate levels of allowed rates of return, and varying periods of regulatory lag.

The type of ownership (investor-owned or public) is specified to allow for more precise historic data inputs, varying regulatory, financial, and accounting conditions between ownership types as well as to allow for enhanced analysis flexibilities and capabilities.

The EFP can be used as a quantitative tool to examine a wide variety of policy issues and options. The following are some of the types of studies in which the EFP's predecessor, the National Financial Statements model (NUFS), has been used in the past to analyze impacts on electricity prices and electric

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until a later date as part of the phase-in plan.

[7]A disallowance occurs when a ratemaking authority refuses to allow a utility to recover the costs of building a plant or a portion of a plant through the rates it charges consumers. Grounds for a disallowance could be that the utility has built more generating capacity than it needs, or the ratemaking authority judges that the utility's management was imprudent in some aspect of the manner in which the building project was undertaken.

[8]Regulatory lag is the effect that is caused by any time-related deviation in the assumptions that underlie the calculations of electricity prices, such as the differences between forecasted electricity sales and actual sales. The time variable in the EFP controls the period of time that passes before the realization of the change in assumptions.

[9]Capital related costs include all costs of production other than operation and maintenance (O&M, including fuel) and all wholesale trade expenses. The return on the ratebase, annual depreciation expenses, and all taxes are three examples of capital related costs.

[10]In flow-through accounting the tax advantages of accelerated depreciation and investment tax credits are passed on directly to ratepayers by way of a reduction in the regulated utility's revenue requirements. In normalized accounting, these tax advantages are amortized over a period of time - usually the useful life of the asset that generated the tax advantage.

[11]In the CWIP scenario, construction costs are added to the ratebase for an immediate return on investment as they are accrued. In the AFUDC scenario, construction costs are not added to the utility's ratebase until construction is completed and the new asset is operational. Financing costs are accrued in the AFUDC accounts and amortized over the life of the asset.

utility financial performance:

- Allowing alternative levels of CWIP in rate base
- Examining the impacts of Federal income tax reform proposals
- Recovering costs associated with canceled nuclear plants
- Analyzing price impacts of proposed acid rain legislation
- Analyzing alternative regulatory or financial environments such as normalization versus flow-through accounting, changes in interest rates or allowed rates of return, and varying regulatory lag
- Analyzing alternative rates of future electricity demand growth
- Examining financial feasibility of least-cost optimal capacity expansion plans
- Implementing alternative capacity expansion plans under different assumptions of cost escalation.

Relationship to Other Models

Inputs

The EFP is a submodule of the NEMS. As such, there are several inputs to the EFP which come from other NEMS components[12]. The capacity expansion plan is provided by the Electricity Capacity Planning (ECP) submodule. This includes the year the plant enters service, capacity (megawatts), and cost (dollars per kilowatt). The EFP uses this information to calculate the cost of construction as well as when and how these construction costs are incorporated into electricity rates.

The fuel, and operation and maintenance (O&M) costs come from the Electricity Fuel Dispatch (EFD) submodule. The EFP uses these data to calculate the revenues that are needed by electric utilities. The revenue requirements are used to calculate electricity prices to be charged to consumers. Each customer class's contribution to peak load comes from the Load and Demand Side Management (LDSM) submodule. The EFP uses these data to allocate costs to customer classes for pricing retail electricity.

Electricity demand comes from the end-use sector demand modules. The EFP uses electricity demand forecasts in its average revenue calculations[13].

The amount of power purchased from industrial and commercial cogeneration facilities and refineries (kilowatthours) and the amount paid by utilities is passed from the Electricity Fuel Dispatch (EFD) submodule. The EFP includes this information in its average revenue calculations.

Information on firm interregional and international power transfers comes from the Electricity Capacity Planning (ECP) submodule.

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[12]Appendix C includes a detailed listing of all EFP input variables.

[13]In order to calculate average revenues the EFP will calculate revenue requirements and divide the result by total sales in kilowatthours.

Interest rates on bonds rated AA are passed to the EFP from the Macroeconomic Activity Module. These interest rates are used to determine the forecasted costs of capital in the EFP.

Outputs

There are also several outputs from the EFP which are passed to other NEMS components[14]. Electricity price forecasts by customer class are passed to the electricity demand modules. The demand modules use this price information to calculate changes in the demand for electricity.

The utility cost of capital is used by the Electricity Capacity Planning (ECP) submodule in its capital budgeting algorithm.

[14]Appendix C includes a detailed listing of all EFP output variables and their calculations.

Model Overview and Rationale

Theoretical Approach

The EFP has four functions:

1. Electricity pricing,
2. Accounting,
3. Determining the cost of capital for electric utilities,
4. Determining the costs of transmission and distribution services.

The EFP is an accounting system that models regulatory practice and is completely deterministic. It has solution algorithms for the generation, transmission, and distribution stages of production. Pricing mechanisms are implemented for the generation and transmission stages of production to enhance the model's flexibility in simulating emerging pricing techniques used in the electric power industry. There are many pricing mechanisms that could be used for this purpose. The one that has been included initially in this submodule is the traditional cost of service method. The modular design of this submodule will allow the user to plug in additional pricing methods as they are needed in the future.

The first step in calculating generation and transmission transfer prices and distribution average revenues is the determination of the revenue requirement. The revenue requirement, the costs that a ratemaking authority allows a regulated utility to recover from ratepayers, is the sum of the fixed and variable costs of production. The fixed costs include the return on the ratebase, fixed operation and maintenance (O&M) costs, and the annual depreciation expense (the recovery of invested capital). Revenue requirements are determined for generation, transmission, and distribution independently for each region. In the case of generation and transmission, the term revenue requirement is used loosely and is not meant to infer that, in the future, these stages are assumed to be regulated under a cost of service arrangement.

Fixed Costs

The **ratebase** is the total value (original cost less accumulated straight line depreciation and excluded tax deferrals) of all capitalized assets on which the regulated utility is allowed by a ratemaking authority to earn a return. The ratebase for the first modeled year is based on historical data from the previous year with additions or deletions determined by the modeled costs of capacity additions. Additions to the generation ratebase are determined in the Electricity Capacity Planning submodule. Transmission ratebase additions are determined in the EFP as a function of generation capacity expansion. Additions to the distribution ratebase are determined in the EFP as a function of sales. the EFP also determines the fixed O&M for the three stages of production.

The forecasted **rate of return** is a function of the interest rate on AA rated utility bonds. This rate of return is the weighted average cost of capital for each region. In the first year of the simulation, the long-term debt rate for each region is the weighted average of the actual long-term debt rates for electric utilities in that region. After that, it is a function of the national utility long-term debt rate (from the Macroeconomic Activity Module). The regional cost of equity is a function of the previous year's regional return on equity and debt, and the current year's regional debt rate. The cost of preferred stock is a function of the average of the regional debt rates.

Variable Costs

Fuel costs and variable operation and maintenance costs (O&M) for generation are determined by the Electricity Fuel Dispatch (EFD) submodule. Transmission and distribution related variable O&M costs are determined in the EFP based on historic data as is the rest of the data for the calculation of the revenue requirements.

Cost Allocation and Retail Average Revenues

After the revenue requirements for all three stages of production have been aggregated, costs are allocated to the four customer classes. Costs are summed into four groups - capital related, fixed operation and maintenance (O&M), variable O&M, and fuel - for each stage of production for the purpose of allocation to customer classes. Several methods for allocating costs are available in the EFP. The choice as to which method to use for which type of costs (capital, fixed O&M, variable O&M, and fuel) for each stage of production is a user option.

The selection of the method used for the allocation of each type of cost (in each stage of production) should result in costs being allocated according to which customer class is responsible for the cost of service. For example, some costs, such as variable O&M, can be confidently allocated on the basis of the level of electricity sales to each customer class. Others, such as fuel costs, are allocated on the basis of each customer class's contribution to the system peak load at the time of peak load (coincident peak method). The justification for this is that, for the purposes of allocating costs, it is assumed that electric utilities burn more expensive fuel as demand on the system increases. Therefore, the customer class most responsible for the system peak is most responsible for the burning of the most expensive fuels. Allocating fuel costs on the basis of the customer class's contribution to the peak load (using the coincident peak or probability of contribution to peak method) provides a method that is consistent with that assumption. Other costs, such as the cost of building new generating plants, are incurred to meet peak load requirements as well as for fuel diversity and other reasons. Allocation methods that recognize the multiple reasons for these costs have been developed in the utility industry and are available in the EFP (two versions of the average and excess demand method).

Following are the cost allocation methods available in the EFP:

Sales method. Costs are allocated on the basis of the proportion of electricity sales, in kilowatthours, to each of the four customer classes. This method will be used most frequently to allocate variable O&M costs for all three stages of production (generation, transmission, and distribution).

Coincident peak method. Costs are allocated on the basis of each customer class's contribution to the system peak at the time of the system peak[15].

Probability of contribution to peak (PCP) method. The proportion of each class's load in each of the

[15]The system, or coincident peak, is the highest point on the system load curve. That is where the greatest demand on the system exists. Non-coincident peaks, on the other hand, are where individual customer class demands are greatest.

highest twenty peaking hours of each year (from the Load and Demand Side Management - LDSM - submodule) is determined. Each customer class's proportions are averaged for each year and used as the weight for allocating costs. That is, costs are allocated on the basis of system peak data to time periods and customer classes.

Non-coincident peak (NCP) method. The residential, commercial, industrial, and transportation peaks are summed. Costs are allocated on the basis of the proportion of each customer class's individual peak load to the sum of the individual peak loads. This method will be used most frequently to allocate distribution fixed O&M and capital costs, and will be used with the **average and excess demand using probability of contribution to peak (AED-PCP) method** (discussed below) to allocate transmission fixed O&M and capital costs.

Average and excess demand method using the probability of contribution to peak (AED-PCP) or coincident peak (AED-CP). This cost allocation method recognizes that capital additions are not made solely for peak demands. Sometimes capital additions are needed for fuel cost savings or other sales oriented reasons. Customer class peaks and system load factors are both used in allocating costs. In this method costs are first divided into those that will be allocated on the basis of average demand and those that will be allocated on the basis of "excess" or peak load demand. Those costs to be allocated on the basis of average demand are allocated first. This is done by calculating the ratio of the class average demand to the sums of the class average demands. Then, the remaining costs are allocated on the basis of the demand in excess of the system load factor. This is done by calculating each customer class's contribution to the system peak using either the probability of contribution to peak method or the coincident peak method.

Retail electricity average revenues are calculated for each ownership type (investor owned and public utilities) and across ownership categories (investor owned and public utilities combined) for each NERC region and selected subregions. That is, each region will have an average revenue calculation for investor owned utilities, public utilities, and a combination of the two. The calculation of average revenues for a given region and customer class is the revenue requirement that has been allocated to that customer class divided by the total sales (kilowatthours) to that customer class, or:

$$\text{Average Revenue}_{ij} = \text{Total Revenue}_{ij} / \text{Sales}_{ij}$$

where:

$\text{Average Revenue}_{ij}$ = average revenue (retail price) of electricity for customer class i and region j

$\text{Total Revenue}_{ij}$ = revenue requirement allocated to customer class i and region j

Sales_{ij} = sales to customer class i and region j.

Stage of production and industry-wide financial statements are generated for each region and nationally. Financial statements are standard accounting statements such as Balance Sheets and Income Statements. The industry-wide financial statements aggregate the three stages of production into a single set of financial statements to represent a vertically integrated industry.

Fundamental Assumption

The fundamental assumption is that standard cost of service regulation will continue. That is, utilities will recover their expenses plus a return on their investments equal to their cost of capital.

Alternative Approaches and Reasons for Selection

The National Utility Financial Statements model (NUFS) is the predecessor to the EFP as the financial and electricity pricing component of EIA's intermediate term energy modeling system. The EFP replaces NUFS to account for two broad based changes in the industry that are occurring or could occur in the next decade. These two changes are: (1) industry structural changes, and (2) capital investment changes.

Changes Related to Industry Structure

The structure of the electric power industry today, in which vertically integrated franchise monopolies[16] dominate, was influenced in large part by the Public Utility Holding Company Act of 1935 (PUHCA). This act was passed by Congress as part of the New Deal legislation to break up the large monopoly holding companies that dominated the electric power industry. These holding companies were structured in such a way as to impede regulatory oversight.

This vertical integration of the electric power industry may be breaking down as a result of policy initiatives such as reform of the PUHCA and efforts to increase competition in the power generation arena to increase efficiency by encouraging the emergence of nonutility generators. In many cases, wholesale rates for nonutility generators are set by means other than the traditional cost of service approach. Competitive bidding and other mechanisms that produce market based rates[17] are currently being used by regulated utilities to select nonutilities (NUGs) as suppliers of wholesale power.

As a result of this potential disintegration[18], separate companies working within distinct regulatory frameworks could be involved in each of the three primary stages of production of the industry: generation, transmission, and distribution[19]. Therefore these three stages of production are modeled separately. Transfer prices are calculated for generation and transmission. The purpose of these transfer prices is to transfer the costs of each of these stages to the distribution stage so that total costs for all of these stages can be included in the calculation of average revenues. In the case of a vertically integrated electric utility,

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[16]In a franchise monopoly, an electric utility (investor-owned or public) operates in a defined service territory at the exclusion of all other electric utilities.

[17]The term, market based rates, is a general term here that refers to prices established in whole or part by market transactions. Examples include competitive bidding by IPP's to build and operate generating capacity and price caps set by the Federal Energy Regulatory Commission (FERC) for wholesale electricity rates.

[18]Vertical disintegration and unbundling are synonymous terms.

[19]Within each stage of production - generation, transmission, and distribution - representations are made of the various ownership categories, regulatory considerations, and economic assumptions that exist now or are likely to exist in the future.

the generation and transmission transfer prices represent the flow of costs (as between divisions within a corporation) that become components of the retail pricing mechanism (which calculates average revenues for distribution). This technique will facilitate an analysis of industry structural change, allow for independent assumptions for each of the three stages of production with regard to regulatory and tax treatment, and will allow the analyst to use a variety of costing mechanisms with varying underlying economic assumptions for these stages of production.

Separate financial statements are provided for each of these stages of production on a regional and national basis so that an independent analysis of each will be feasible. (Financial statements are provided on an industry-wide basis as well. In these reports, the three stages of production are combined at the regional and national levels to represent a regional vertically integrated utility.)

The pricing technique used for **retail distribution** continues to be the average cost based method used by NUFS. An assumption of the EFP is that retail electricity rates will continue to be regulated on a cost of service basis. Average revenues continue to be calculated for the four customer classes represented in NUFS: residential, commercial, industrial, and transportation. An improved cost allocation algorithm has been implemented so that these customer class average revenues are more meaningful in terms of the actual forecasted cost of service. That is, cost allocation methods in the EFP may use peak load data generated by the Load and Demand Side Management submodule (LDSM) as the basis for the allocation of some costs of service so that costs may be more accurately allocated to the customer class responsible for those costs.

Changes Related to Capital Expenditures

The second broad based change has to do with investment emphasis. In the 1970's and 1980's, most capital expenditures were for construction projects. However, over the next ten years, a sizable amount of capital expenditures will be for purposes other than for new construction. They include demand side management (DSM) costs, nuclear decommissioning costs, life extension costs, post operational capital expenditures, and costs and revenues associated with the Clean Air Act Amendments of 1990 (CAA). Since many of the accounting and rate-making issues dealing with these expenditures will be different in the future, the EFP is designed so that an accurate representation of these issues can be made.

Cost and performance information for DSM programs will be developed in the Load and Demand-Side Management Submodule of the EMM in NEMS while their penetration and impacts will be represented in the individual demand models. The EFP accounts for these direct costs, whether expensed or capitalized, and includes them in the pricing function. In the electric power industry, it is necessary to compensate utilities for the reduction in revenues that results from DSM programs through revenue adjustment mechanisms because the rates that they charge are based on historic test periods that reflect a higher demand for electricity. Lost revenues (and profits) which can result from utility investments in DSM programs are captured in the EFP because it calculates average revenues (prices) based on demand after adjustment for DSM impacts. The EFP is also able to capture the adjustments to allowed rates of return that some states are offering to utilities as incentives for implementing DSM programs through adjustments to the model's return on equity component of average revenues.

Several other electric utility models that contain a financial component have been examined:

- Electric Generation Expansion Analysis System (AGEAS), from the Electric Power Research Institute (EPRI) and Stone and Webster

- Load Management Strategy Testing Model (LMSTM), Version 4.0, from EPRI and Electric Power Software, Inc.

- Integrated Utility Planning and Analysis System (PROSCREEN II), from Energy Management Associates, Inc.

- Integrated Utility Planning System (UPLAN III), from LCG Consulting

- Electric and Gas Utility Modeling System (EGUMS), from RCG/Hagler, Bailly, Inc.

Model Usage

The most important consideration that must be made in a comparison of the capabilities of these models to the capabilities of the EFP is that, with the exception of EGUMS, these models are designed to represent the operations of a single utility. This is significant because a single utility model can incorporate very specific information about accounting practices and load characteristics that an aggregate model does not have. There are two issues where this becomes manifest. First, the single utility model is capable of using very specific information concerning customer load characteristics in allocating costs to customer classes. The EFP uses less detailed aggregate customer load data that covers an entire NERC Region instead of just a utility service area. Second, a single utility model can take advantage of utility-specific data in its determination of marginal costs. In particular it has available to it refined data on (1) the probability of a given generating unit being the marginal unit of production, (2) the variable costs of generation for specific generating plants, as opposed to aggregate data on the typical generating plant of a specific type that must be used in an aggregate model, and (3) customer load characteristics.

While EGUMS is an aggregate model, its purpose is entirely different from that of the EFP. The EFP is designed for policy analysis and forecasting for a broad range of regulatory and legislative possibilities, and must be very flexible with many policy handles[20]. EGUMS is designed specifically to aid in the analysis of the role that demand side management (DSM) can play in pollution abatement. EGUMS will not be used in the analysis of regulations dealing with taxes, financial management, or accounting so it does not need the explicit revenue requirement calculation, phase-in, sale-leaseback, and disallowance capabilities that are required of the EFP. EGUMS calculates marginal energy and capacity costs for use by the DSM algorithm, but it has no need for the transfer prices that will be used by the EFP. It also uses a fixed shares algorithm for allocating costs to the various customer classes.

Revenue Requirements

LMSTM, PROSCREEN II, and UPLAN III all use a detailed calculation of revenue requirements in much the same way as the EFP. The ratebase and expenses are calculated to determine the revenue requirements. PROSCREEN II and UPLAN III use an iterative process, adjusting the revenue requirements up or down until user specified criteria have been reached. This change in revenue requirements corresponds to a rate case where a rate change has been approved. The decision criteria could be a specified return on common equity, a return on the ratebase, or other measures. The EFP does not

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[20]A policy handle is a point in the model's code where changes in assumptions may be inserted. These assumption changes could be of a financial, regulatory, tax, industry, or political nature. This policy handle feature is a primary purpose for the National Energy Modeling System.

explicitly model rate cases because it is a regional model instead of single utility model. An exception to this is that rate case decisions that include phase-ins or disallowances are modeled in the EFP if there is a significant impact on revenues at the regional level.

EGEAS uses customer rates to determine total revenues. It minimizes total revenue requirements subject to a capacity expansion plan in much the same fashion as the EFP. However, in EGEAS, all of the non-generation costs for the utility are user inputs.

Cost Allocation

In the LMSTM, generation and distribution capacity revenue requirements are distributed to customer classes and rating periods using a percent-of-peak load allocation mechanism. The model allocates the revenue requirements to each kilowatt served in a manner such that the amount allocated is dependent on the fraction of the load in the hour divided by the load in the peak hour. As in the EFP, all assets and costs are assigned to functional categories (generation, transmission, and distribution). There is a rates submodule in which the user indicates the method for allocating costs in each functional category to customer classes (the user inputs a rate schedule) which indicates a customer, demand, and energy charge.

In PROSCREEN II, the user classifies costs into demand, customer, and energy components and a rate schedule is input into the model. One or more rate classes may be defined with others allowed to "float" to achieve a target return. Several allocation methods are available including coincident peak demand, noncoincident peak demand, average and excess demand, kilowatthour energy sales, number of customers, and weighted number of customers. Options are available to simulate dynamic forces and to equalize the calculation of total revenues to the sum of revenues for each customer class. These options include:

- revenue requirements equal the class cost of service including a specified rate of return on the ratebase, which may vary by class;

- same as above except there are class specific caps expressed as a multiple of the average percentage increase with the revenue in excess of the cap allocated to other classes;

- specific user input percentage increases by class;

- specific user supplied rates.

In UPLAN III end use prices are calculated to include both time-differentiated and non time-differentiated rates for up to twelve customer classes. Rates are generated by customer classes for peak, off-peak, and shoulder hours. In AGEAS input customer class rates are altered if one class's revenues are reduced by a DSM program. In this scenario, the other classes subsidize the fixed costs previously allocated to that class. In the EFP, costs are allocated after the effects of all DSM programs have been identified in terms of the cost of service, customer class average demands, and customer class load shapes.

Market Based Rates

Both LMSTM and UPLAN III expressly model market based rates. LMSTM uses an override feature which bypasses the cost of service calculation. Instead, the model uses a rate input by the user; either an absolute price per kilowatthour or annual escalation. UPLAN III calculates an hourly rate and cost that are set as the purchase price for energy and capacity by a grid company or by the dispatcher of a pool organization. The calculation of the hourly rate is based on the specifications for the United Kingdom grid policy:

Rate = Marginal Energy Cost + LOLP * Value of Capacity + Other Costs

Marginal Energy Cost: the highest incremental cost of any unit operating in any particular hour

LOLP: the loss of load probability as calculated based on the reliability in any hour

Value of Capacity: the difference between the value of the lost load and the marginal cost. Set to zero if the number is negative.

Other Costs: Any other economic parameter set by the user.

Solution Algorithm and Key Computations

Overview

The purpose of this chapter is to describe the solution algorithm used within EFP. The discussion in this chapter is organized into two sections. The first section, 1. Forecasting Revenue Requirements, describes the method used to forecast annual revenue requirements. In order to forecast the revenue requirement, one must first forecast the components of the rate base and the expenses. This section will describe the algorithms used to calculate and forecast these items. With all of these items forecast, one has nearly all the necessary components to forecast the financial statements and ratios. The second section, 2. Remaining Algorithms, describes the process of using these items to yield forecasts of electric revenue, prices, taxes (both actual and for financial purposes), and financial ratios.

1. Forecasting Revenue Requirements

The EFP method of forecasting revenue requirements duplicates the regulatory process. The EFP forecast of revenue requirements in any given year is that which allows the utilities to earn a rate of return equal to the cost of capital and also recover their operating costs. Formally, the forecast for revenue requirements in any given year is:

$$ERRVRQ = (ERRB * ESRR) + ERTFLN + ERTOMN + ERBDE + GENREG + STAREG + FEDREG - EROFFS + ESLLPN - EPIND$$

where:[21]

ERRVRQ	=	revenue requirement[22]
ERRB	=	rate base
ESRR	=	rate of return
ERTFLN	=	fuel costs
ERTOMN	=	operation and maintenance expenses, excluding fuel costs
ERBDE	=	book depreciation expense
GENREG	=	general taxes (gross receipts, property, sales) for regulatory purposes
STAREG	=	State income taxes for regulatory purposes
FEDREG	=	Federal income taxes for regulatory purposes
EROFFS	=	AFUDC offset

[21] The variable names used in this description are the same as those found in the computer code of EFP. There are some conventions used in variable naming, as follows. A prefix of ER denotes variables containing results aggregated to the total system level. A prefix of ES denotes a ratio or fraction. A prefix of EO denotes variables related to assets existing before the first forecast year. Finally, a prefix of EB denotes a variable related to an individual plant build.

[22] For accounts that describe `flows' (e.g., fuel expense, depreciation expense), the value refers to the period January 1 to December 31 of the given year. For accounts that describe `stocks' (e.g., rate base, utility plant), except when otherwise stated, the value refers to the end of the given year value, i.e., value on December 31 of the given year.

ESLLPN = net lease payment associated with sales/leaseback transactions
EPIND = net deferred phase-in revenues for year.

Note that, except where specifically stated, the variables are calculated in nominal dollars. Nominal dollars, rather than real dollars, are required to simulate the regulatory process effectively. Once nominal electricity prices are determined, they are reported in both nominal and real dollars. Each of the eleven variables on the right-hand side of the revenue requirement equation above is discussed in separate sections labeled 1.1 through 1.11. More detailed and involved discussions are needed to fully describe the solution algorithms. To aid in the continuity of this presentation, these discussions are separated into their own sections and are labeled 1.12 through 1.17. The discussions in Sections 1.1 through 1.11 sometimes refer to these later sections.

1.1 Calculation of Rate Base (ERRB)

The formula used to calculate the rate base is:

ERRB = ERTUP + ERRCWP + ERWC + ERNFSN - ERABDE - ERPRDF - (ERCNBV - ERCNAD) - ESLNDG - EDISNT

where:

ERRB = rate base
ERTUP = total utility plant
ERRCWP = CWIP allowed in rate base
ERWC = working capital
ERNFSN = nuclear fuel stock
ERABDE = accumulated book depreciation
ERPRDF = provision for deferred income taxes
ERCNBV = book value of canceled projects whose unamortized balance is not allowed in rate base
ERCNAD = accumulated depreciation (or amortization) of canceled projects whose unamortized balance is not allowed in rate base
ESLNDG = net deferred gain from sale/leaseback transactions
EDISNT = net disallowed plant.

As calculated above, ERRB is the year-end rate base. Another option in EFP is to calculate revenue requirements using the average value of the rate base over the year. The analyst may choose either option. The formulas used to calculate the average rate base are:

ERRBAQ = (ERRB + ERRBB) / 2.0

ERRBB = $ERRB_{t-1}$ + ERDLRB

where:

ERRBA = average year rate base
ERRB = end of year rate base
ERRBB = beginning year rate base
$ERRB_{t-1}$ = end of year rate base from proceeding year
ERDLRB = book value of new plants that come on line this year.

The average-year rate base is calculated as the simple average of the beginning-and end-of-year rate base. The beginning-of-year rate base is calculated as the rate base at the end of the previous year plus the book value of any new plants that come on line in the given year. (The calculation of the book value of new assets is described in Section 1.13)

When the end-of-year rate base option is chosen, an additional adjustment to the calculation of rate base is made. When plants come on line in the middle of a given year, they continue to accrue AFUDC for those months until the plant is actually in service. To avoid earning an excess return (AFUDC plus a full-year cash return) on such plants, the end-of-year rate base is lowered so that the total return (AFUDC plus cash return) on the plant is appropriate.

The values of ERCNBV and ERCNAD are calculated by summing the costs of all canceled projects. For projects canceled before the first year of the forecast horizon, the costs are specified by the analyst through inputs. For projects canceled after the first year of the forecast horizon, the analyst specifies which projects are to be canceled and at what point in time, and the costs of the projects are based on costs incurred up to the cancellation date (as simulated within the model).

ERRCWP is discussed in Section 1.13. ERABDE and ERPRDF are discussed in Section 1.14. ESLNDG is discussed in Section 1.16. EDISNT is discussed Section 1.17. Each of the remaining components of the rate base equation is discussed below.

1.1-a Total Utility Plant (ERTUP)

Total Utility Plant (ERTUP) is calculated as:

$$ERTUP = \sum_{\text{all } k} (EOBKVL_k) + \sum_{\text{all } k} (ERBVYE_k) - ERBTIR$$

where:

$EOBKVL_k$ = book value of assets existing in the base year (old assets) of type k (i.e., distribution)

$ERBVYE_k$ = book value of assets completed in the forecast horizon (new assets) of type k which are completed as of the year of forecast

ERBTIR = book value of all assets which have been retired during the forecast horizon as of the year of forecast.

The book value of existing assets in the base year is an input that can be derived from historical financial statements such as the FERC Form 1 or Form EIA-412. The calculation of ERBTIR is discussed in Section 1.14. $ERBVYE_k$ is calculated by summing the book values of each individual new asset of type k which is completed as of the year of forecast. The calculation of the book value of individual new assets is discussed in Section 1.13.

1.1-b Working Capital (ERWC)

Working capital is calculated within EFP using what is known as the 1/8 method. In general, this method arrives at working capital by summing the following: materials and supplies excluding fuel stocks; a percentage of operating and maintenance expenses, usually 1/8, representing a 45-day net lag in revenues and expenses; and other adjustments unique to a jurisdiction. The 1/8 method is based on the assumption that an average monthly billing utility has a net lag of 45 days between the payment of expenses and collection of revenues. This method of estimating working capital does have some drawbacks. The implicit assumption behind the 1/8 method is that there is a positive working capital need. The 1/8 method does not give any recognition to the availability of working capital resulting from the accrual of interest or tax expenses prior to the time of their payment. Items such as these constitute sources of working capital that are not considered using the 1/8 method. In addition, under circumstances of unusually fast receipt of customer payments and extended delay in paying suppliers, there can actually be a negative working capital requirement for a utility. The 1/8 method also assumes that all utilities have the same experience with regard to receipt of payment from customers and employ the same payment policies.

The calculation for working capital is:

$$ERWC = .125 * (ERTOMN + ERTFLN)$$

where:

ERTOMN = operation and maintenance costs, excluding fuel
ERTFLN = fuel costs

The calculation of ERTOMN is discussed in Section 1.4. ERTFLN is discussed in Section 1.3.

1.1-c Nuclear Fuel Stock (ERNFSN)

The nuclear fuel stock in any given year is calculated as a function of the amount of fuel actually used in the year.

$$ERNFSN = 3.5 * EFPNUC * ESGNPD$$

where:

ERNFSN = Nuclear fuel stock
EFPNUC = Real dollar nuclear fuel expense
ESGNPD = inflation index to convert real dollars to nominal dollars

1.2 Rate of Return (ESRR)

The rate of return is calculated as a weighted average of the cost of long term debt, short term debt, common equity, and preferred stock. The equation is:

$$ESRR = ESPRLT * ESEMDT + ESPRST * ESRTST + ESPRCE * ESRTCE + ESPRPS * ESEMPS$$

where:

ESPRLT = fraction of capital structure made up by long term debt
ESPRST = fraction of capital structure made up by short term debt
ESPRCE = fraction of capital structure made up by common equity
ESPRPS = fraction of capital structure made up by preferred stock
ESEMDT = embedded cost of long term debt
ESRTST = cost of short term debt
ESRTCE = allowed return on common equity
ESEMPT = embedded cost of preferred stock.

With the exception of ESEMDT, ESEMPT, and ESRTCE all of the above values are inputs into EFP.

1.2-a Embedded Cost of Long Term Debt (ESEMDT)

The embedded cost of long-term debt in any year is a function of several quantities including the cost of new debt, the cost of existing debt, and the timing and quantity of retirements and issues of new debt:

ESEMDT = (ESEMDL * ERBNDL - ESEMDB * RETIRE + ESRTLT * (ERBOND - ERBNDL + RETIRE))/ERBOND

ERBOND = ERAMD * ESPRLT

RETIRE = maximum of: ESPRLT * ERBDE; and EROBL

EROBE = EROBL - RETIRE

ESRTLT = UTBRRG1 + (UTBRRG2 * MC_RMPUAANS)

where:

ERBOND	=	total long-term debt outstanding in current year
ERBNDL	=	total long-term debit outstanding from previous year
EROB	=	long-term debt outstanding in current year that was issued before the first year of the forecast period
EROBL	=	long-term debt outstanding in previous year that was issued before the first year of the forecast period
RETIRE	=	amount of debt that is retired in current year
ESRTLT	=	cost of new long-term debt issued
ERAMD	=	assets minus deferrals (i.e., amount that must be financed)
ESPRLT	=	fraction of capital structure made up by long-term debt
ERBDE	=	book depreciation expense
ESEMDL	=	embedded cost of long-term debt in previous year
ESEMDB	=	embedded cost of long-term debt in the year previous to the first forecast year.
MC_RMPUAANS	=	the cost of new AA rated utility bonds
UTBRRG	=	regression coefficients

The algorithm calculates the embedded cost of debt as a weighted average of: i) the embedded cost in the previous year (ESEMDL); ii) the embedded cost in the base year (ESEMDB); and iii) the cost of new long term debt issued in the current year (ESRTNB). Only debt issued before the forecast period is assumed to be retired. This is appropriate, given the mid-range forecast period over which EFP forecasts. EROBL for a given year is equal to EROB from the previous year. ESRTNB, ESEMDB, EROBL (for first forecast year), and ESPRLT are user inputs in this algorithm. ERAMD and ERBDE are discussed in Sections 1.7-b and 1.14, respectively.

1.2-b Embedded Cost of Preferred Stock (ESEMPS)

The embedded cost of preferred stock is calculated in an algorithm similar to that used for the embedded cost of long-term debt above.

ESEMPS = (ESEMPL * ERPRFL - ESEMPB * RETIRE + ESRTPS * (ERPREF - ERPRFL +

RETIRE))/ERPREF

ERPREF = ERAMD * ESPRPS

RETIRE = maximum of: ESPRPS * ERBDE; AND ERPFL

ERPF = ERPFL - RETIRE

ESRTPS = PSRCF1 + (PSRCF2 * ESRTDA)

where:

ERPREF	=	total preferred stock in current year
ERPRFL	=	total preferred stock from previous year
ERAMD	=	assets minus deferrals (see Section 1.7-b)
ESPRPS	=	fraction of capital structure made up by preferred stock (user input)
RETIRE	=	amount of preferred stock that is retired in current year
ERBDE	=	book depreciation expense
ERPF	=	preferred stock outstanding in current year that was issued before the first year of the forecast period
ERPFL	=	preferred stock outstanding in previous year that was issued before the first year of the forecast period
ESRTDA	=	the average cost of new long term debt
ESRTPS	=	cost of new preferred stock issued
ESEMPL	=	embedded cost of preferred stock from previous year
ESEMPB	=	embedded cost of preferred stock from the year previous to the first forecast year
PSRCF	=	regression coefficients

ERPFL for a given year is equal to ERPF from the previous year. The values of ESEMPB and ERPFL (for the first forecast year) are input into EFP. These values can be derived from historical financial statements such as the FERC Form 1.

1.2-c Cost of Common Equity (ESRTCE)

The cost of common equity is a function of the previous year's cost of equity, the cost of new long term debt, and the cost of new debt in the previous year:

ESRTCE = ARRCF1 + (ARRCF2 * ESRTCL) + (ARRCF3 * ESRTLT) + (ARRCF4 * ESRTDL)

where:

ESRTCE	=	the cost of common equity
$ARRCF_n$	=	regression coefficients
ESRTCL	=	the cost of equity in the previous forecast year
ESRTLT	=	the cost of new debt
ESRTDL	=	the cost of new debt in the previous forecast year

1.3 Fuel Costs (ERTFLN)

Fuel costs in each forecast year are derived from the results of the dispatch exercise.

ERTFLN = (EFPFL + BLKSUM) * ESGNPD

where:

ERTFLN	=	nominal dollar fuel cost
EFPFL	=	real dollar fuel costs as determined by the dispatch model
BLKSUM	=	real dollar wholesale purchase costs (includes imports, exports, purchases from NUGs and inter-regional transfers) determined by the dispatch model
ESGNPD	=	inflation index to convert real dollars to nominal dollars

1.4 Operation and Maintenance (O&M), Excluding Fuel (ERTOMN)

As with fuel costs, operation and maintenance costs are input to EFP from other modules being used to drive EFP. Again, if necessary, these costs are inflated each year by a user-defined inflation rate. Operation and maintenance costs are calculated differently for generation, transmission, and distribution.

1.4-a Generation O&M

ERTOMN = (ERTOM + OVERPR + ERTOMF + OMLE) * ESGNPD

where:

ERTOM	=	real dollar production related variable operation and maintenance expenses
ESGNPD	=	inflation index to convert real dollars to nominal dollars.
ERTOMF	=	real dollar production related fixed O & M expenses
OVERPR	=	real dollar production and maintenance expenses allocated to the production function. (eg. general and administrative)
OMLE	=	real dollar O & M expenses associated with the life extension of the generating units

1.4-b Transmission O&M

ERTOMN = (ERTOMT + OVERTR) * ESGNPD

where:

ERTOMT	=	real dollar transmission operation and maintenance expenses
ESGNPD	=	inflation index to convert real dollars to nominal dollars.
OVERTR	=	real dollar overhead-related O & M expenses allocated to transmission. (eg. general administration).

1.4-c Distribution O&M

Operation and maintenance costs are input to EFP from the distribution model being used to drive EFP. If necessary, these costs are inflated each year by a user-defined inflation rate.

ERTOMN = (ERTOMD + OVERDS) * ESGNPD

where:

ERTOMD = real dollar operation and maintenance expenses associated with distribution
ESGNPD = inflation index to convert real dollars to nominal dollars.
OVERDS = real dollar overhead related O & M expenses allowed to distribution. (eg. general administration).

1.5 Depreciation (ERBDE)

Discussion of the book depreciation expense may be found in Section 1.14.

1.6 General Taxes for Regulatory Purposes (GENREG)

General taxes encompass all taxes except State and Federal income taxes. Among these taxes are gross receipts, FICA, payroll, property, and sales.

It is assumed that these taxes each year will be a constant percentage of revenue requirements.

$$GENREG = EGTXRT * ERRVRQ + ERPRTX + ERSLTX$$

where:

EGTXRT = gross receipts tax rate
ERRVRQ = revenue requirement
ERPRTX = property taxes
ERSLTX = sales tax

The gross receipts tax rate is an input which is calculated from base-year data (e.g., FERC Form 1, Form EIA-412). Including ERRVRQ on the right-hand side of the equation appears to make this discussion circular (i.e., ERRVRQ is a function of GENREG and GENREG is a function of ERRVRQ). This is resolved in Section 1.12.

ERPRTX is modeled as an input fraction of book value and ERSLTX is modeled as an input fraction of construction expenditures.

1.7 State Income Taxes for Regulatory Purposes (STAREG)

STAREG is equal to State taxable income for regulatory purposes multiplied by the State income tax rate:

$$STAREG = (ERRVRQ - ERTFLN - ERTOMN - ERTDWO - ERTIEX - ESLLP) * ESSTXR$$

where:

ERRVRQ = revenue requirement
ERTFLN = fuel expense
ERTOMN = operation and maintenance expense, excluding fuel costs
ERTDWO = depreciation for tax purposes, without acceleration
ERTIEX = interest expense
ESLLP = lease payment associated with sale/leaseback transactions

ESSTXR = State income tax rate

ERRVRQ on the right-hand side of this equation is discussed in Section 1.12. ERTFLN and ERTOMN were discussed in Sections 1.4 and 1.4, respectively. ERTDWO is discussed in Section 1.14-b. ESLLP is discussed in Section 1.16. ESSTXR is a user input. ERTIEX is now discussed.

1.7-a Interest Expenses (ERTIEX)

The total interest expense depends on the cost of debt and on the average amount of debt outstanding during the year.

$$ERSIEX = ESRTST * ESPRST * \frac{(ERAMD + ERAMDL - ESLPRC)}{2}$$

$$ERLIEX = ESEMDT * ESPRLT * \frac{(ERAMD + ERAMDL - ESLPRC)}{2}$$

$$ERTIEX = ERSIEX + ERLIEX$$

where:

ERSIEX = short-term interest expense
ERLIEX = long-term interest expense
ERTIEX = total interest expense
ESRTST = cost of short-term debt
ESEMDT = embedded cost of long-term debt
ESPRST = fraction of capital structure made up by short-term debt
ESPRLT = fraction of capital structure made up by long-term debt
ERAMD = assets minus deferrals (equals amount that must be financed through debt or equity)
ERAMDL = assets minus deferrals from previous year
ESLPRC = net of tax sales proceeds from sale/leaseback transactions

ESRTST, ESPRST, and ESPRLT are user inputs. ESEMDT was discussed in Section 1.2-a. ERAMDL for a given year is equal to ERAMD from the previous year. ERAMD is discussed below. ESLPRC is discussed in Section 1.16.

1.7-b Assets Minus Deferrals (ERAMD)

ERAMD is the amount that must be financed by debt or equity.

$$ERAMD = ERTUP + ERBCWP + ERWC + ERNFSN + EPIDEF - ERABDE - ERPRDF - ERDITC - EDISNT - ESLNDG$$

where:

ERTUP = total utility plant (see 1.1-a)
ERBCWP = booked construction work in progress (see 1.13)
ERWC = working capital (see 1.1-b)
ERNFSN = nuclear fuel stock (see 1.1-c)

EPIDEF	=	cumulative deferred phase-in revenues (see 1.17)
ERABDE	=	accumulated book depreciation (see 1.14)
ERPRDF	=	provision for deferred income taxes (see 1.14)
ERDITC	=	deferred investment tax credits (see 1.14)
EDISNT	=	net disallowed plant (see 1.17)
ESLNDG	=	net deferred gain from sale/leaseback transactions (see 1.16)

1.8 Federal Income Taxes for Regulatory Purposes (FEDREG)

FEDREG is equal to Federal taxable income (for regulatory purposes) multiplied by the Federal income tax rate, adjusted by several accounts reflecting timing differences between actual income taxes paid and regulatory income taxes:

$$FEDREG = (ERRVRQ - ERTFLN - ERTOMN - GENREG - STAREG - ERTDRG - ERTIEX + ERCIDC - ESLLP) * ESFTXR - ERFITC - ERAITC - ERFFDC - ERAFDC - EREDTF$$

where:

ERRVRQ	=	revenue requirement
ERTFLN	=	fuel expense (see 1.3)
ERTOMN	=	operation and maintenance expense, excluding fuel costs (see 1.4)
GENREG	=	general taxes for regulatory purposes (see 1.6)
STAREG	=	State income taxes for regulatory purposes (see 1.7)
ERTDRG	=	tax depreciation expense for regulatory purposes (see 1.14)
ERTIEX	=	interest expenses (see 1.7a)
ERCIDC	=	interest expenses capitalized for purposes of calculating Federal income taxes for regulatory purposes (see 1.13-e)
ESLLP	=	lease payment associated with sale/leaseback transactions (see 1.16)
ESFTXR	=	Federal income tax rate
ERFITC	=	generated ITC that is flowed through (see 1.15)
ERAITC	=	amortization of deferred ITC (see 1.15)
ERFFDC	=	generated tax savings from the debt portion of AFUDC that is flowed through (see 1.13)
ERAFDC	=	amortization of deferred tax savings from the debt portion of AFUDC (see 1.13)
EREDTF	=	excess deferred taxes flowed back to ratepayers (see 1.14-c).

ERRVRQ on the right side of the equation is discussed in 1.12. ESFTXR is a user-supplied input. FEDREG includes the effects of the ITC or the tax savings due to the debt portion of AFUDC. These effects are captured with the variables ERFITC, ERAITC, ERFEDC, and ERAFDC.

1.9 AFUDC Offset (EROFFS)

See Section 1.13.

1.10 Net Lease Payments Associated with Sale/Leaseback Transactions (ESLLPN)

See Section 1.16.

1.11 Net Deferred Phase-in Revenues (EPIND)

See Section 1.17.

1.12 Resolution of ERRVRQ "Circular" Argument

The following four equations have been presented:

(i)ERRVRQ = . . . + GENREG + STAREG + FEDREG
(ii)GENREG = EGTXRT * ERRVRQ + . . .
(iii)STAREG = (ERRVRQ - . . .) * ESSTXR
(iv)FEDREG = (ERRVRQ - . . . - STAREG - GENREG) * ESFTXR

In the somewhat linear presentation of Sections 1.1 through 1.11, the above equations seem to present a circular argument. (ERRVRQ is a function of GENREG, STAREG, and FEDREG, but also the later variables depend on ERRVRQ.) This specification, of course, is not really a problem. The above is just a system of four linear equations with four unknowns. Using the method known as algebraic substitution, one can solve for the value of ERRVRR, as follows:

First, the above equations (ii), (iii), and (iv) can be substituted into equation (i) to yield:

ERRVRQ = . . . + ERRVRQ * EGTXRT + (ERRVRQ - . . .) * ESSTXR
+ (ERRVRQ - . . . - STAREG - GENREG) * ESFTXR

Next, substituting equations (ii) and (iii) into the above equation and gathering like terms yields:

ERRVRQ = . . . + ERRVRQ * EGTXRT * (1 - ESFTXR) + (ERRVRQ - . . .) * ESSTXR * (1 - ESFTXR) + (ERRVRQ - . . .) * ESFTXR

Next, moving all terms on the right hand side of the equation that contain the variable ERRVRQ to the left hand side yields:

ERRVRQ * (1 - EFTXRT * (1 - ESFTXR) - ESSTXR * (1 - ESFTXR) - ESFTXR)
= . . . + (- . . .) * ESSTXR * (1 - ESFTXR)
+ (- . . .) * ESFTXR

Finally, dividing the equation on both sides by the constant on the left hand side yields:

ERRVRQ = (. . .
+ (- . . .) * ESSTXR * (1 - ESFTXR)
+ (- . . .) * ESFTXR)
/ (1 - EGTXRT * (1 - ESFTXR) - ESSTXR * (1 - ESFTXR) - ESFTXR)

This equation yields a unique value for ERRVRQ. This value can then be substituted back into equations (ii), (iii), and (iv) to yield values for the remaining variables.

1.13 Construction Work in Progress (CWIP)

For regulatory purposes, EFP is able to simulate three alternative treatments of construction work in progress: 1) CWIP in rate base; 2) CWIP not in rate base; or 3) the offset method. When CWIP is allowed in rate base for ratemaking purposes, the utility is allowed to earn a current cash return on all construction outlays. If CWIP is not allowed in rate base (i.e., AFUDC is capitalized) the utility is allowed to include an annual estimate of the net cost, for the period of construction, of funds used for construction purposes. These "allowances" are accumulated over the construction period of the project and are brought into the rate base as an addition to the value of the completed investment once the investment becomes operational. The third alternative of dealing with construction work in progress is the capitalized AFUDC offset method. For this procedure, CWIP is allowed in rate base and AFUDC is capitalized, but there is a corresponding offset to the return on rate base equal to the amount of the capitalized AFUDC. If the AFUDC rate is equal to the allowed rate of return on rate base and if the utility is allowed to compound the effects of AFUDC then this method is essentially equivalent to not allowing CWIP in rate base.

The regulatory treatment of CWIP is decided upon a case-by-case basis by most public utility commissions. In general, at the multi-utility aggregation level at which EFP is run, all of the treatments are used to some degree. To account for this, EFP allows the analyst to input the percentage of CWIP that is to be allowed in rate base. The remainder of the CWIP is then assumed either not to be in rate base or to be handled under the offset method (depending on another user input).

The treatment of CWIP affects quite a few variables. These effects will now be discussed. All of the discussions will assume only one plant is being built. This is for ease in presentation only, and going to the "n" plant case presents no conceptual problems. For the presented algorithms, the following values are input to EFP:

Variable	**Description**	**Source**
EBPCAP	Capacity of build	Distribution Planning Model
EBPCST	Real dollar cost per unit of capacity (real dollars/capacity), not including any financing costs incurred during construction	Distribution Planning Model
EBSYR	Year plant comes on line	Distribution Planning Model
ESLCP	Length (in years) of construction period (including first year of operation)	User
$ESCPRF_j$	Direct (i.e., not including financing charges) construction expenditures (in real dollars) in year j as a fraction of total direct construction costs (in real dollars)	User
$ESGNPD_j$	Inflation escalation index used to convert real dollars to current year j dollars, expressed as the ratio of current year j dollars to real dollars	User
$CWPPER_j$	Percentage (expressed as a fraction) of CWIP allowed in rate base, year j	User

Variable	Description	Source
ESRBAF	0 Remainder of CWIP (i.e., 1.0 - CWPPER) not in rate base) 1 Remainder of CWIP is under AFUDC offset	User
ESCGRW	Annual escalation rate used to escalate costs over and above the inflation rate	User
ESBKLF	Book life of plant	User

The algorithms to calculate the CWIP related variables in EFP are executed in five basic steps:

1) Calculate the AFUDC rate (Section 1.13-a)

2) Calculate annual direct construction expenditures in current year dollars (Section 1.13-b)

3) Calculate year by year CWIP accounts and the resulting book value of the new plant (Section 1.13-c)

4) Calculate tax basis of plant (Section 1.13-d)

5) Calculate several AFUDC related accounts (Section 1.13-e).

Each step is now discussed in detail.

1.13-a Step 1

Step 1 is to calculate the AFUDC rate. EFP simulates a pre-tax AFUDC rate. EFP calculates the pre-tax AFUDC rate as:

ESAFDC = TEMPD + TEMPE

where:

TEMPD = ESPRLT * ESEMDL + ESPRST * ESRTST
TEMPE = ESPRCE * ESRTCE + ESPRPS * ESEMPL

All of the right-hand variables above are discussed in Section 1.2. An additional value used below is the fraction of AFUDC representing debt costs.

ESWACD = TEMPD/ESAFDC

where:

ESWACD = fraction of AFUDC representing debt costs.

1.13-b Step 2

Step 2 is to calculate direct construction expenditures by year, in nominal dollars. This is done for each year j, where j ranges from the first year of construction (i.e., EBSYR - ESLCP + 1) to the first year of operation (i.e., EBSYR).

$$EBYCWP_j = EBPCAP * EBPCST * ESCPRF_j * ESGNPD_j * CAPESC_j$$

for j = (EBSYR - ESLCP + 1) to EBSYR

where:

$EBYCWP_j$	=	nominal dollar direct construction expenditures, year j
EBPCAP	=	capacity of build
EBPCST	=	real dollar cost per unit of capacity
$ESCPRF_j$	=	real dollar direct construction expenditures, in year j, as a fraction of total direct construction expenditures
$ESGNPD_j$	=	inflation index to convert real dollars to current year j dollars
$CAPESC_j$	=	escalation index to escalate construction costs over and above inflation
EBSRY	=	year plant comes on line
ESLCP	=	length (in years) of construction period (including first year of operation).

EBPCAP, EBPCST, ESCPRF, ESGNPD, EBSYR, and ESLCP are inputs to EFP. CAPESC is calculated from the input values of ESCGRW (see description above of user inputs).

1.13-c Step 3

This step includes calculation of the major CWIP-related accounts for each year j during the construction period. This includes year by year: CWIP allowed in rate base, booked CWIP, booked AFUDC, and the AFUDC offset. Also calculated is the book value of the new plant.

CWIP allowed in rate base is calculated as:

$$EBRCWP_j = (EBBCWP_j + EBYCWP_j) * [CWPPER_j + ESRBAF * (1.0 - CWPPER_j)]$$

where:

$EBRCWP_j$	=	CWIP allowed in rate base, year j
$EBBCWP_{j-1}$	=	booked CWIP, year j-1
$CWPPER_j$	=	percentage of CWIP allowed in rate base, year j
$EBYCWP_j$	=	nominal dollar direct construction expenditures, year j
ESRBAF	=	0 if no AFUDC offset, and 1 if AFUDC offset.

Booked AFUDC in year j is calculated as:

$$AFUDC_j = (EBBCWP_{j-1} + .5 * EBYCWP_j) * (1-CWPPER_j) * ESAFDC_j$$

where:

$AFUDC_j$	=	booked AFUDC, year j
$EBBCWP_{j-1}$	=	booked CWIP, year j-1
$EBYCWP_j$	=	nominal dollar direct construction expenditures, year j

$CWPPER_j$ = percentage of CWIP allowed in rate base, year j
$ESAFDC_j$ = AFUDC rate, year j

Note that in the calculation of AFUDC the average level of CWIP over the calendar year is used. This is why $EBYCWP_j$ is multiplied by one-half (the construction takes place evenly over the year so the average balance should include only half of this amount). The calculation of CWIP in rate base, however, uses an end-of-year CWIP balance. Adjustments to this value to make it an average level over the year are made only if the user requests an average-year rate base.

ESAFDC and EBYCWP were calculated above in Steps 1 and 2, respectively. The calculation of EBBCWP is shown below.

Booked CWIP in year j is calculated as:

$EBBCWP_j$ = 0 for j = EBSYR - ESLCP (i.e., year before construction begins

= $EBBCWP_{j-1} + EBYCWP_j + AFUDC_j$

for j = (EBSYR - ESLCP + 1) to EBSYR (i.e., construction period)

where:

$EBBCWP_j$ = booked CWIP, year j
$EBYCWP_j$ = nominal dollar direct construction expenditures, year j
$AFUDC_j$ = booked AFUDC, year j

The AFUDC offset is calculated as:

$EROFFS_j = AFUDC_j * ESRBAF$

where:

$EROFFS_j$ = AFUDC offset, year j.

The book value of the new plant when it comes on line is:

$EBBKVL = EBBCWP_j$

where:

j = EBSYR (the first year of operation)
EBBKVL = book value of new plant

This equation assumes that the new plant comes on line January 1 of year EBBSYR. EFP can also simulate plants coming on line after January 1, using similar equations.

1.13-d Step 4

The fourth step is to calculate the tax basis for the investment. Previous to the Tax Reform Act (TRA) of 1986, the tax basis was the sum over all years of the nominal dollar direct construction expenditures

(EBYCWP) calculated in Step 2 (adjusted for investment tax credits as described in 1.14-b.). However, any asset coming on line after 1986, that is not grand-fathered under the provision must capitalize interest during construction.

$EBASVL_j$	=	0	for j =	EBSYR - ESLCP (i.e., year before construction begins)
		$= EBASVL_{j-1} + EBYCWP_j + AVDINT_j$		
			for j =	(EBSYR - ESLCP+1) to EBSYR (i.e., construction period)
		$= EBASVL_{EBSYR}$	for j =	EBSYR to (EBSRY + ESBKLF) (i.e., during service life)

where:

EBASVL	=	tax basis, year j
$EBYCWP_j$	=	nominal dollar direct construction expenditures, year j
$AVDINT_j$	=	interest capitalized for tax basis (avoided interest), year j

No interest is capitalized for the tax basis unless the plant is covered under the TRA. The applicability of the TRA to a given plant is determined by a user-defined test based on the year the plant came on line and first year of construction. When the new tax law does apply, the capitalized interest is calculated as:

$$AVDINT_j = (EBASVL_{j-1} + .5 * EBYCWP_j) * ESRTNB_j$$

where:

$AVDINT_j$	=	interest capitalized for tax basis (avoided interest), year j
$EBASVL_{j-1}$	=	tax basis, year j-1
$EBYCWP_j$	=	nominal dollar direct construction expenditure, year j
$ESRTNB_j$	=	cost of new debt, year j.

1.13-e Step 5

The fifth step is to calculate several accounts related to AFUDC.

It is important to separate AFUDC into that financed by debt and that financed by equity:

$$ERFDCD_j = ESWACD_j * AFUDC_j$$

$$ERFDCE_j = (1-ESWACD_j) * AFUDC_j$$

where:

$ERFDCD_j$	=	debt financed portion of AFUDC, year j
$ERFDCE_j$	=	equity financed portion of AFUDC, year j
$ESWACD_j$	=	fraction of AFUDC representing debt costs, year j (see step 1)

While a plant is under construction, various interest expenses associated with construction of the plant accrue. For those plants not covered under the TRA, this interest expense provides a tax savings to the utility because interest is a deductible expense. The regulatory process attempts to capture this savings for ratemaking purposes and either flow it through immediately to ratepayers or defer it to a later period when the asset is in service. This is done by using the concept of the tax savings due to the debt portion of AFUDC.

$$ERFFDC_j = ERFDCD_j * ESFTXR * ESFPDB$$

$$ERXFDC_j = ERFDCD_j * ESFTXR * (1- ESFPDB)$$

$$DAFDC_j = \sum_{i=k}^{j} ERXFDC_i$$

for j = K to EBSYR where K = EBSYR - ESLCP + 1

where:

$ERFFDC_j$	=	generated tax savings from the debt portion of AFUDC that is flowed through, year j
$ERFXFDC_j$	=	generated tax savings from the debt portion of AFUDC that is deferred (normalized), year j
$DAFDC_j$	=	deferred tax savings from the debt portion of AFUDC, year j
$ERFDCD_j$	=	debt-financed portion of AFUDC, year j, (see above)
ESFTXR	=	Federal tax rate (user input)
ESFPDB	=	flow through percentage (expressed as a fraction) for AFUDC tax savings.

ESFPDB reflects the regulatory policy towards the tax savings and is a user input. The tax savings is generated while the plant is under construction. When the plant begins service, the deferred taxes, if any, are amortized over the service life of the plant.

$$EBAFDC = DAFDC_{EBSYR}/ESBKLF$$

$$DAFDC_j = DAFDC_{j-1} - EBAFDC \text{ for } j = EBSYR \text{ to } (EBSYR + ESBKLF - 1)$$

(i.e., over service life of plant)

where:

EBAFDC	=	annual amortization of deferred savings from the debt portion of AFUDC
$DAFDC_j$	=	deferred tax savings from the debt portion of AFUDC, year j
ESBKLF	=	book life of plant

Again, the calculations above pertaining to the tax savings from the debt portion of AFUDC relate only to plants not covered under the TRA of 1986. For plants covered under the TRA of 1986, there is no tax savings because interest must be capitalized for tax purposes. The interest capitalized for the purposes of calculating Federal income taxes for regulatory purposes is therefore:

$$ERCIDC_j = ERXFDC_j + AVDINT_j$$

where:

$ERCIDC_j$	=	interest capitalized for the purposes of calculating Federal income taxes for regulatory purposes, year j
$ERXFDC_j$	=	generated tax savings from the debt portion of AFUDC that is deferred, year j
$AVDINT_j$	=	interest capitalized for tax basis, year j (see Step 4 above).

1.14 Depreciation

Depreciation expenses are calculated separately for financial (or book) and for tax purposes). Financial and tax depreciation differ for several reasons. First, book depreciation is calculated using the straight-line method while tax depreciation uses an accelerated method. The accelerated method yields higher depreciation in the early years of an asset's life followed by lower depreciation in later years than does the straight-line method (assuming all else equal). Second, capitalized AFUDC is depreciated for book purposes but not for tax purposes. Similarly, interest capitalized during construction for tax purposes is not depreciated for book purposes, but is for tax purposes. Finally, the depreciation base for tax purposes must be lowered by one-half of the total investment tax credit earned during construction of the plant. The depreciation base for book purposes is not adjusted in this way.

The following discussion applies to a new plant with the following input characteristics:

EBSYR	=	year plant comes on line
ESBKLF	=	book life of plant
ESDEPR	=	depreciation rate for financial purposes (usually 1/ESBKLF)

The methodology presented here is easily expanded to the "n" plant case and to existing plants.

1.14-a Depreciation for Financial Purposes (ERBDE)

Book depreciation is calculated using the straight-line method (net book value divided by remaining life):

$$ERBDE_j = (EBBKVL - EBABDE_{j-1})/(ESBKLF - (J-EBSYR))$$

and

$$EBABDE_j = \sum_{i = EBSYR}^{j} ERBDE_i$$

for j = EBSYR to EBSYR + ESBKLF - 1
(i.e., over service life of asset)

where:

$ERBDE_j$	=	book depreciation, year j
$EBABDE_j$	=	accumulated book depreciation, year j
EBBKVL	=	book value of plant (includes any AFUDC).

The derivation of EBBKVL is discussed in section 1.11.c. When the plant retires (year EBSYR + ESBKLF), its book value is added to account ERBTIR and subtracted from EBABDE. This has the effect of removing the plant from the books. (See Section 1.1-a.)

1.14-b Depreciation for Tax Purposes

For tax purposes, depreciation is accelerated (i.e., allowed to be greater in early life of plant and less in later life) by two forces. First, utilities may depreciate the plant over a shorter period of time than the service life used for financial purposes. Second, an accelerated depreciation rate is used instead of a straight-line constant rate. The effect of this is to lower tax liability in the earlier years of the plant life and raise them in the later years, compared to the straight-line method.

There are three different options in EFP when determining tax depreciation rates: i) use those prescribed in the Tax Reform Act (TRA) of 1986; ii) use those prescribed in the 1981 Economic Recovery Tax Act (ERTA); or iii) use the sum-of-years digit method. The method used for a particular asset is based on a user-specified test, which is a function of the year the construction of asset begins and the year the asset comes on line. The sum-of-years digit method is used for any asset that comes on line before 1981. Because the first two methods are the most applicable approaches, they are discussed below.[23]

Under ERTA and TRA, tax depreciation schedules (now more properly called tax recovery schedules) are specified. The tax base, as modified under the Tax Equity and Fiscal Responsibility Act of 1982 (TEFRA), is reduced by one half of the investment tax credit (discussed in Section 1.15) earned during the construction of the asset. For a given asset, the relevant recovery schedule is determined based on when the asset comes on line and on what service life class the asset belongs. Most assets in EFP are depreciated over 15 years (some 10) under ERTA, and 20 years (some 15) under TRA. Then, for the remaining years of the book life, tax depreciation is zero.

$$ERTDE_j = EXTXRS_j * (EBASVL - .5 * EBDITC)$$

for j = EBSYR to EBSYR + ESBKLF - 1
(i.e., during the service life of the plant)

where:

$ERTDE_j$	=	depreciation expense for tax purposes, year j
EBASVL	=	tax basis of asset
$EXTXRS_j$	=	depreciation rate prescribed by ERTA or TRA, year j
EBDITC	=	investment tax credits generated.

EBASVL is discussed in Section 1.13-c. EBDITC is described in Section 1.15.

Absent accelerated depreciation, tax depreciation would be:

$$ERTDWO_j = ESDEPR * (EBASVL - 0.5*EBDITC)$$

for j = EBSYR to EBSYR + ESBKLF - 1
(i.e., during the service life of the plant)

[23] The approach for the sum-of-years digit method is identical to that described except that the tax base is not reduced by one-half the investment tax credit.

where:

$ERTDWO_j$ = depreciation for tax purposes, without acceleration, year j
ESDEPR = straight-line depreciation rate.

The difference between $ERTDWO_j$ and $ERTDE_j$ leads to tax savings in the early years of service followed by increased taxes in the later years. The regulatory authority determines the treatment of this difference for ratemaking purposes.

$$ERTDRG_j = ERTDWO_j * (1 - ESFLPR) + ERTDE_j * (ESFLPR)$$

for j = EBSYR to EBSYR + ESBKLF - 1
(i.e., during the service life of the plant)

where:

$ERTDRG_j$ = tax depreciation expense for regulatory purposes, year j
ESFLPR = percentage of tax savings due to acceleration depreciation that is flowed through

When the tax effects of accelerated depreciation are flowed through for regulatory purposes (ESFLPR = 1.0), ERTDRG is equal to ERTDE. In this case, revenue requirements directly show the effects of the acceleration. However, when the tax effects are normalized (ESFLPR = 0.0), then ERTDRG is equal to ERTDWO and thus the revenue requirements show no effects of the acceleration. Thus, in a flow-through scenario, revenue requirements are lower in the early years of the plant's service and higher in the later years, compared to revenue requirements in a normalized scenario (all else equal). This effect comes about because ERTDRG affects Federal income taxes for regulatory purposes, which in turn affects revenue requirements.

Other useful quantities relating to this tax effect are:

$$ERATSF_j = ESFTXR * (ERTDE_j - ERTDWO_j) * ESFLPR$$
$$ERATSD_j = ESFTXR * (ERTDE_j - ERTDWO_j) * (1-ESFLPR)$$

$$DAD_j = \sum_{i = EBSYR}^{j} ERATSD_i \quad \text{for } j = EBSYR \text{ to } EBSYR + ESBKLF - 1$$

where:

$ERATSF_j$ = tax savings resulting from accelerated depreciation that are flowed through, year j
$ERATSD_j$ = tax savings resulting from accelerated depreciation that are deferred, year j
DAD_j = provision for deferred taxes due to accelerated tax depreciation, year j
ESFTXR = Federal income tax rate.

1.14-c Excess Deferred Income Taxes Flowed Back to Ratepayers (EREDTF)

The 1986 Tax Reform Act (TRA) lowered the marginal Federal income tax rate from 46 percent to 40 percent in 1987 and to 34 percent thereafter. One effect of the decrease in the marginal tax rate is to lower future reductions in deferred income taxes that will occur as assets complete their service lives.

As described in Section 1.14-b, accelerated depreciation allowed for tax purposes leads to deferred income taxes for regulated utilities. Over the life of an individual asset the level of deferred income taxes will increase in its early years and finally decrease to zero at the end of its service life. A complication arises, however, when the marginal tax rate decreases during the service life of an asset. The deferred taxes have been booked at the higher marginal tax rate, but will now be paid at the lower tax rate. The difference between deferred income taxes now booked (under the 46-percent marginal tax rate) and what will ultimately be paid under the 34-percent marginal rate is referred as excess deferred income taxes.

These excess deferred taxes should be flowed through to the ratepayers. EFP can flow back these taxes over the remaining lives of the assets or over any user-defined schedule of years.

The first step is to calculate the amount of deferred taxes that have accrued:

$$EXCESS = \sum_{j = EBSYR}^{IYREDT} (ERTDE_j - ERTDWO_j) * (ESFTXR_j - ESFTXR_{IYREDT})$$

where:

EXCESS	=	total excess deferred income taxes
ERTDE	=	depreciation expense for tax purposes, year j (see 1.14-b)
ERTDWO	=	depreciation for tax purposes, without acceleration, year j (see 1.14-b)
$ESFTXR_j$	=	Federal income tax rate, year j (user input)
EBSYR	=	first year of service
IYREDT	=	year in which excess taxes are to be calculated (user input)

Now the amount of excess deferred income taxes flowed back to ratepayers in each year can be calculated:

$$EREDTF_j = \begin{cases} 0.0 & \text{if } j < IYREDT \\ EXCESS/REMLIF & \text{if } j \geq IYREDT \end{cases}$$

where:

EREDTF	=	excess deferred taxes flowed back to ratepayers each year
EXCESS	=	total excess deferred income taxes
REMLIF	=	remaining years of life for asset (ESBKLF - (IYREDT-EBSYR)).

The above equation flows back the excess deferred income taxes over the remaining life of the investment. Within EFP, it can also be flowed back over any user-defined schedule of years.

1.14-d Provision for Deferred Income Taxes (ERPRDF)

The provision for deferred income taxes is the sum of the values of all deferred income taxes or deferred tax savings (excluding investment tax credits). For purposes of EFP, this includes the deferred taxes from accelerated depreciation and the deferred tax savings from the debt portion of AFUDC on assets not affected by the TRA of 1986.

$$ERPRDF = DAD + DAFDC - EREDTF$$

where:

ERPRDF	=	provision for deferred income taxes
DAD	=	deferred income taxes due to accelerated depreciation (see Section 1.14-b)
DAFDC	=	deferred tax savings from the debt portion of AFUDC (see Section 1.13-d)
EREDTF	=	excess deferred taxes flowed back to ratepayers (see Section 1.14-c).

1.15 Investment Tax Credit

The investment tax credit was established by Congress to encourage certain kinds of investments. The effect of the investment tax credit is to reduce the Federal tax liability by the amount of the credit. The credit is generated during each year of the construction period for the plant. Previous to the Tax Reform Act of 1986 (TRA), the value of the credit each year was a percentage of construction expenses (excluding AFUDC) for that year. The investment tax credit was repealed under TRA. However, many assets currently under construction when the TRA was passed were grand-fathered under the provision and will continue to receive the credit. For these assets, the effective investment tax credit rate will decrease over time. Within EFP, assets that receive the credit are determined by a user-specified test that is a function of the year in which the construction of the asset began and the year in which the asset enters service (i.e., any asset for which construction began before a user-specified year and which enters service before a user-specified year, will continue to receive the credit). This test allows the capability to examine alternative assumptions regarding grand-fathering.

The regulatory treatment of this tax savings is decided by the new regulatory commission. The credit can be flowed through immediately to lower the revenue requirement in the year it was generated or deferred and then amortized over the life of the plant. EFP handles any combination of these two treatments.

$$ERFITC_j = EBYCWP_j * ESRITC_j * ESFLPR$$

$$XITCD_j = EBYCWP_j * ESRITC_j * (1 - ESFLPR)$$

$$EBDITC_j = \sum_{i=K}^{j} XITCD_i \qquad \text{for } j = K \text{ to } EBSYR \quad \text{where } K = EBSYR - ESLCP + 1$$

where:

$ERFITC_j$	=	generated ITC that is flowed through, year j
$XITCD_j$	=	generated ITC that is deferred, year j
$EBDITC_j$	=	deferred ITC, year j
EBYCWP	=	construction expenses, net of AFUDC, year j (see 2.1.13-b)
$ESRITC_j$	=	investment tax credit rate, year j
ESFLPR	=	percentage of tax savings flowed through
ESLCP	=	length (in years) of construction period (including first year of operation)

When the plant begins service, any deferred ITC is amortized over the life of the plant.

$$ERAITC = EBDITC_{EBSYR}/ESBKLF$$
$$EBDITC_j = EBDITC_{j-1} - ERAITC \quad \text{for } j = EBSYR \text{ to } EBSYR + ESBKLF - 1$$

where:

ERAITC	=	amortization of deferred investment tax credit
$EBDITC_j$	=	deferred ITC, year j, (see 1.13-c)
ESBKLF	=	service life of plant (user input).

Note that the investment tax credit is generated only on the direct construction expense, not on capitalized AFUDC.

1.16 Sale/Leaseback Transactions

The sale and leaseback of an electric power plant is essentially a financial transaction that affects the timing of cost recovery, and frequently the capital cost, associated with the plant. It generally does not change the utility's responsibilities for operating and maintaining the plant or for selling the electricity it generates. Attractive for a variety of reasons, the sale/leaseback may be a creative way for a utility to circumvent constraints imposed by regulatory authorities, competition, bond indemnifications, or its tax position, benefiting both investors and ratepayers.

In the simplest form of a sale or leaseback, the utility sells a power plant to an institutional investor, then leases the plant back from the investor for equal semiannual rents over a term that is typically between 25 and 30 years. Regulators treat the rental payment as operating expenses, and the utility's revenue requirement no longer includes the return on capital or depreciation expense associated with the plant. The result is a flat revenue requirement over time, lower than conventional cost recovery in the short term, and higher toward the end of the lease.

For the algorithm presented below, the following values are input in EFP for each sale/leaseback transaction to be modeled:

Variable	Description
IBYRSL	Year transaction is completed
SLPROC	Gross proceeds from transaction
BKGAIN	Gross gain on book value
SLTAXS	Utility income taxes on transaction
SLLP	Annual lease payment
SLTERM	Lease term

The methodology presented here applies to one transaction and is easily expanded to the "n" transaction case.

The first step is to calculate the book value of the plant sold, the net gain from the transaction,and the tax basis of the plant sold:

$$SLBKVL = SLPROC - BKGAIN$$
$$SLGAIN = BKGAIN - SLTAXS$$

SLASVL	=	SLPROC - SLTAXS/ESFTXR

where:

SLBKVL	=	book value of plant sold
SLPROC	=	gross proceeds from transaction (input)
BKGAIN	=	gross gain on book value (input)
SLGAIN	=	net gain on book value
SLTAXS	=	utility income taxes on transaction (input)
SLASVL	=	tax basis of plant sold
ESFTXR	=	federal income tax rate (input).

The book value of the plant is removed from utility plant in service and the tax basis is removed from the utility tax accounts. This is done within the EFP by creating an asset with a negative book value and tax basis equal in absolute value to that calculated above. This has the effect of removing the plant from utility books.

The remaining quantities are now calculated:

ESLPRC	=	SLPROC - SLTAXS
ESLLP	=	SLLP
ESLAGN	=	SLGAIN/SLTERM
$ESLNDG_j$	=	SLGAIN - j * ESLAGN for j = 1, SLTERM
ESLLPN	=	ESLLP - ESLAGN

where:

ESLPRC	=	net of tax sales proceeds
ESLLP	=	annual lease payment
ESLAGN	=	amortization of gain
ESLNDG	=	net deferred gain from transaction
ESLLPN	=	net least payment
SLPROC	=	gross proceeds from transaction (input)
SLTAXS	=	utility income taxes on transaction (input)
SLLP	=	annual lease payment (input)
SLGAIN	=	net gain on book value
SLTERM	=	lease term.

1.17 Rate Phase-in Plans

Almost all electric utilities in the United States have their electricity rates set by regulatory commissions at the local, State, or Federal level (or any combination of these three). The most common method used by regulators to determine the appropriate rates is often referred to as original-cost, rate-of-return regulation. Under this methodology, the utility is able to charge rates that allow it to recover its operating and capital costs. Under this scheme, the rate impacts of the capital costs of a new asset coming on line are greatest in its first year of service and decline thereafter over the life of the asset. Historically, the large increase in capital costs associated with a new plant were substantially, if not totally, offset by the lower operating costs obtained by utilizing the new unit.

In recent years, however, many situations have arisen where, under traditional regulation, substantial rate increases would occur as new plants com eon line. This has been caused by two major forces. First, the costs of new power plants have risen substantially. This widely discussed phenomenon has caused the capital costs of the plant to be substantially higher. Second, at the same time, the savings derived from lower operating costs of the new plants have not been very great. This is due to lower energy commodity prices as well as the power generation technologies leveling out in terms of efficiency. Additionally, many areas of the country were over-built with capacity, again lowering the savings derived from the new plants. In many cases, a single utility has brought on line a new plant whose total costs make up a large fraction of its total assets, thus amplifying the two forces just described.

Given this pressure for dramatic increases in rates, alternative regulatory approaches were necessary. Even if a regulatory commission were to allow the large rate increases, the potential reaction of customers, particularly large customers, forbids such rate increases. The prospect of these customers leaving the service territory or bypassing the local utility through cogeneration or transmission wheeling is very real. Any exit of these customers requires the rates of remaining customers to increase even more, and ever-increasing rates and ever-declining sales become a possibility. In the interests of both the utilities and the ratepayers, a common approach to deal with this problem has emerged and is referred to as rate phase-in plans.

The idea of a rate phase-in plan is straightforward. For a number of years, rates are to be set at a level lower than would have been the case under traditional ratemaking. This is followed by a number of years in which rates are higher than they would have been in order to allow the company to make up for the early years. In practice, each rate phase-in plan is at least somewhat unique in response to the particulars of the situation.

For the algorithm presented below, the following values are input for each rate phase-in plan to be modeled:

Variable	Description
IBYRPI	Year rate phase-in plan begins
PIBKVL	Book value of phase-in plant
DISPER	Fraction of phase-in plant disallowed
LIP	Length of phase-in plan
$PIDFS_j$	Cumulative fraction of total cost to be phase-in in year j
$PIRCS_j$	Fraction of remaining deferred revenues to be recovered in year j
IRDPI	Logical variable indicating whether capitalized return is earned on deferred costs
PIBKLF	Book life of phase-in plant
PITXBS	Tax basis as a fraction of book basis for phase-in plant

The methodology presented here applies to one rate phase-in plan and is easily expanded to the "n" plan case.

The first step is to calculate the total revenue requirement associated with the phase-in plant under traditional regulation for each year of the phase-in plan:

$$RR_j = PIBKVL * (1.0 - DISPER) * (1.0 - j/PIBKLF) * ESPR/(1.0 - ESFTXR) + PIBKVL / PIBKLF * (1.0 + (1.0 - PITXBS) * ESFTXR/(1.0 - ESFTXR)))$$

for j = 1, LPI

where:

RR_j	=	traditional revenue requirement of phase-in plant, year j
PIBKVL	=	book value of phase-in plant (input)
DISPER	=	fraction of phase-in plant disallowed (input)
PIBKLF	=	book life of phase-in plant (input)
ESRR	=	rate of return (see Section 1.2)
ESFTXR	=	federal income tax rate (input)
PITXBS	=	tax basis as a fraction of book basis for phase-in plant (input)
LPI	=	length of phase-in plan (input)

Next, the costs to be deferred in each year are calculated:

$$EPIND_j = RR_j * (1.0 - PICFS_j) * (1.0 - ESFTXR) - PIRCS_j * EPIDEF_{j-1}$$

for j = 1, LPI

where:

$EPIND_j$	=	pre-tax deferred costs, year j
RR_j	=	traditional revenue requirement of phase-in plant, year j
$PIDFS_j$	=	cumulative fraction of total cost to be phased-in in year j (input)
ESFTXR	=	federal income tax rate (input)
$PIRCS_j$	=	fraction of remaining deferred revenues to be recovered in year j (input)
$EPIDEF_{j-1}$	=	cumulative deferred costs, year j-1 (see below).

Note that $EPIND_j$, calculated above, will be positive during the initial period of the phase-in and will be negative during the final period of the phase-in. A negative value represents recovery from rate payers of deferred costs.

Next, the capitalized deferred return is calculated, if necessary (depends on value of IRDPI, an input described above):

$$EPIRET_j = (EPIDEF_{j-1} + .5 * EPIND_j) * ESAFDC \quad \text{for } j = 1, LPI$$

where:

$EPIRET_j$	=	capitalized return on deferred costs, year j
$EPIDEF_{j-1}$	=	cumulative deferred costs, year j-1 (see below)
$EPIND_j$	=	pre-tax deferred costs, year j
ESAFDC	=	AFUDC rate (see Section 1.13-a)

Next, cumulative deferred costs are calculated:

$$EPIDEF_j = EPIDEF_{j-1} + EPIND_j + EPIRET_j$$

for j = 1, LPI

where:

$EPIDEF_j$	=	cumulative deferred costs, year j

$EPIND_j$ = pre-tax deferred costs, year j
$EPIRET_j$ = capitalized return on deferred costs, year j

EPIDEF begins year 1 with a value of 0.0.

Finally, the net value of disallowed plant is calculated:

$$EDISNT_j = PIBKVL * DISPER * (1.0 - j/PIBKLF)$$

for j = 1, PIBKLF

where:

$EDISNT_j$ = net disallowed plant, year j
PIBKVL = book value of phase-in plant (input)
DISPER = fraction of phase-in plant disallowed (input)
PIBKLF = book life of phase-in plant (input).

1.18 Nuclear Decommissioning

The cost of decommissioning is read into the EFP and adjusted for assumed rates of inflation to calculate the decommissioning cost in the year of retirement:

$$NDCost = NDCost * (1+Inflation)^{**}RetireDate$$

where:

NDCost = the cost to retire the plant in the retirement year
Inflation = the average annual inflation rate to the retirement year
RetireDate = the year of retirement and decommissioning

The funds needed at the time of retirement are calculated as:

$$QAmt = NDCost * NDCostF - [NDFund * (1+NetInt)^{**}(Period+1)]$$

where:

QAmt = the funds needed at the time of retirement that have not been collected
NDCostF = escalation assumption for the decommissioning costs
NDFund = current fund balance
NetInt = return on fund balance (rate of return)
Period = number of years to decommissioning

The annual addition to the fund is calculated as:

$$QAmt = QAmt * NetInt / ((1 + NetInt) ^{**} (Period + 1) - 1) / (1 - Adminpct)$$

where:

QAmt = the annual (levelized) additions to the fund (sinking fund)
AdminPct = the cost of administering the fund as a percentage of the fund balance

The total additions with the cost of administering the fund:

QAmt = QAmt / (1 - AdminPct)

where:

QAmt = the annual contribution to the fund including the cost of administering it

Finally, the ending balance in the decommissioning fund is expressed as:

NDFund = [NDFund * (1 + Interest) * (1 + Inflation)] + QAmt * NDCollectF

where:

NDFund = the ending balance for the decommissioning fund
NDCollectF = an assumed regulatory factor expressed as a percentage of the necessary funds that regulators allow the utility to collect - 1 (100%) for AEO'94

2. Remaining Algorithms

Section 1 described in the EFP algorithms to forecast the major components of revenue requirements. This section describes the remaining algorithms which are used to yield forecasts of electric revenues, the price of electricity, taxes (both current and for financial purposes), financial ratios, and other miscellaneous items.

2.1 Electric Revenues

Electric revenues are a function of revenue requirements and the regulatory lag. Regulatory lag can result from the situation where electric utility rates (and thus revenues) are based on costs from a historical test year rather than on costs from the period during which the rates are in effect. EFP calculates electric revenues under five different assumptions: i) no lag, ii) 1-year lag, iii) one-quarter-year lag, iv) one-half-year lag, and v) three-quarter-year lag.

In a no-lag scenario, rates are based on current year experiences and rate base so that electric revenues are equal to the revenue requirements calculated in Section 1:

ERRVLG = ERRVRQ

where:

ERRVLG = electric revenues
ERRVRQ = revenue requirements

In a 1-year lag scenario, electric revenues are calculated as follows:

$$ERRVLG_t = [(ERRB'_{t-1} * ESRR_t) + ERTOMN_{t-1} + ERBDE_{t-1} + GENREG_{t-1} + STAREG_{t-1} + FEDREG_{t-1} - EROFFS_{t-1} + ESLLPN_{t-1} - EPIND_{t-1}] * EQTLSL_t / EQTLSL_{t-1} + ERTFLN_t$$

where variables are same as in Section 1, except:

$$ERRB'_{t-1} = ERRB_{t-1} + (EBRCWP_t - EBRCWP_{t-1})$$

$$EQTLSL_t = \text{total sales of electricity, year t.}$$

This equation is similar to the equation for revenue requirements presented in Section 1. However, the right-hand variables are lagged by 1 year, with some exceptions. First, the rate base used differs from the previous year's rate base by the difference in the amount of CWIP allowed in rate base. This reflects the fact that the amount of CWIP in rate base is determined by order in each rate case and does not reflect an historically observed value. Similarly, the rate of return on rate base is not the previous year's value, but instead reflects the regulatory commission's current finding on the appropriate return. Next, a factor equal to the ration of current-year sales to previous-year sales is present because the rates are based on historical expenses and sales, but will be collected on the current year sales. Finally, fuel costs are not lagged, but instead recovered as they are incurred. The overall approach is that the price of electricity is comprised of two parts — a fuel cost (recovered through an instantaneously adjusting fuel adjustment clause) and base rates set in rate hearings.

Weighted averages of the revenues under the no-lag and 1-year lag case are used in the other scenarios (e.g., one-half-year lag).

Forecast sales of electricity are passed to EFP from the dispatch module being used to drive EFP.

2.2 Allocation of Costs to Customer Classes

Costs are functionalized by stage of production and classified as capital related, fixed O&M, variable O&M, or fuel for each modeled region. Each of these categories may be allocated to the various customer classes using any of the following methods:

2.2-a Sales Method

Costs are allocated on the basis of the proportion of total sales to the class as follows:

$$DEMFAC1_j = SALCLS_j/SALTOT$$

where:

$DEMFAC_n$ = the factor for allocating costs to customer class j
SALCLS = the total sales of electricity to class j
SALTOT = the total sales of electricity to all classes

2.2-b Coincident Peak Method

Costs are allocated on the basis of each customer class's contribution to the system peak load:

$$DEMFAC5_j = SECANNUALPEAK1_j/TOTAL$$

where:

$SECANNUALPEAK1_j$ = the load attributable to customer class j at the time of the system peak
TOTAL = the total load on the system at the time of system peak

2.2-c Probability of Contribution to Peak

Costs are allocated on the basis of the average contribution to system peak of the customer class over a number of previous model years:

$$DEMFAC6_j = SECANNPEAAVPCP_j/TOTAL$$

where:

$SECANNPEAAVPCP_j$ = the average contribution to the system peak of customer class j over a number of previous model years
TOTAL = the sum of the average contributions to the system peaks of all customer classes over a number of previous model years

2.2-d Non-Coincident Peak Method

In this method, costs are allocated on the basis of the proportion of the load of each customer class at the time of the customer class peak, divided by the sum of the customer class peaks:

$$DEMFAC7_j = SECANNUALPEAK2_j/TOTAL$$

where:

$SECANNUALPEAK2_j$ = the load of customer class j at the time of the peak load of customer class j
TOTAL = the sum of the customer class loads at the time of the peak for each individual customer class (non-coincident peak)

2.2-e Average and Excess Demand Using Coincident Peak

Costs are allocated using a combination of the sales method (average demand) and the coincident peak (excess demand). The proportion of costs equal to the level of the system load factor is allocated on the basis of the sales method. The remaining costs are allocated on the basis of the coincident peak method:

$$DEMFAC8_j = (SYSTEMLF * DEMFAC1) + [(1 - SYSTEMLF) * DEMFAC5]$$

where:

SYSTEMLF = the system load factor

2.2-f Average and Excess Demand Using Probability of Contribution to Peak

This method is the same as that described above except that the proportion of costs in excess of the system load factor is allocated on the basis of the probability of contribution to peak instead of the coincident peak method:

$$DEMFAC9_j = (SYSTEMLF * DEMFAC1) + [(1 - SYSTEMLF) * DEMFAC6]$$

2.2-g Allocation of Costs to Customer Classes

Finally, all of the methods used for allocating each cost category (each cost type - capital, fuel, etc.- by stage of production) are summed for each of those cost categories:

$$COSTFC_{kjl} = \sum DEMFAC_{nj} * TECFAC_{nkl}$$

where:

$COSTFC_{kjl}$ = the sum of all allocation proportions for cost type k, customer class j, and stage of production l
$DEMFAC_{nj}$ = allocation proportion using method n for customer class j
$TECFAC_{kjl}$ = the proportion of cost type k to be allocated using method n for stage of production l

and revenues are allocated to the class:

$$REV_{jl} = COSTFC_{kjl} * COST_{kl}$$

where:

REV_{jl} = the revenues allocated to customer class j for stage of production l
$COST_{kl}$ = the cost type k (classified cost) for stage of production l (fuctionalized cost)

2.3 Price of Electricity

With electric revenues forecast and allocated, the forecast price of electricity is straightforward:

2.3-a Price Calculation

$$EPRICE_{jl} = REV_{jl}/SALCLS_j$$

where:

$EPRICE_{jl}$ = the price of electricity for customer class j and stage of production l
REV_{jl} = electric revenues allocated to customer
SALCLS = sales to customer

2.3-b Benchmark/Subsidization Calculation

Once the price of electricity has been calculated for each customer class and region at the distribution stage of production, the computed prices for residential, commercial, and transportation are compared to historic prices for benchmarking and subsidy calculation[24]. The prices for transportation are not benchmarked because (1) there is no relevant historic price for off-peak electric vehicles, and (2) the proportion of costs allocated to this class is very small. Differences in the modelled prices and historic prices may be due to differences between the modelled allocation techniques and those being used in practice, and they may be due to customer class cross-subsidization where one customer class's cost allocation is increased or decreased for the purpose of accommodating another class. This benchmarking/subsidization routine is as follows:

First, the historic and modelled proportions of revenues to each of the three classes are determined. Historic proportions are:

$$REVHPCT_{jy} = REV\mathit{Y}_j/REVHRCI_y$$

where:

$REVHPCT_j$	=	the actual proportion of revenues allocated to customer class j in year y
$REV\mathit{Y}_j$	=	the actual revenues allocated to customer class j in year y
$REVHRCI_y$	=	the actual total revenues allocated to all three classes in year y

The modelled proportions are:

$$REVPCT_{jy} = REV_{jy}/REVRCI_y$$

where:

$REVPCT_{jy}$	=	the modelled proportion of revenues allocated to customer class j in year y
REV_y	=	the modelled revenues allocated to customer class j in year y
$REVRCI_y$	=	the modelled total revenues allocated to all three classes in year y

The historic proportion of sales attributable to each customer class is:

$$SLSHPCT_{jy} = SAL\mathit{Y}_j/SLSHRCI_y$$

where:

$SLSHPCT_{jy}$	=	the actual proportion of sales to customer class j
$SAL\mathit{Y}_j$	=	the actual sales to customer class j in year y
$SLSHRCI_y$	=	the actual sales to all three classes in year j

The modelled proportion of sales is:

$$SLSPCT_{jy} = SALCLS_{jy}/SLSRCI_y$$

where:

[24] This benchmarking/subsidization technique is not used for the generation or transmission transfer price calculations.

$SLSPCT_{jy}$ = the modelled proportion of sales to customer class j
$SALCLS_{jy}$ = the modelled sales to customer class j in year y
$SLSRCI_{y}$ = the modelled sales to all three classes in year j

These ratios are then used to calculate the implied subsidy to be used to benchmark/subsidize customer class prices while controlling for differences in the level of actual sales to each customer class and modelled sales to each customer class.

$$SUBPCT_j = (REVHPCT_j - SLSHPCT_j) - (REVPCT_j - SLSPCT_j)$$

2.3-c Calculation of Prices with Benchmarking and Subsidization

After the benchmarking/subsidization proportion has been calculated, it is multiplied times the total revenues allocated to the three benchmarked/subsidized customer classes to determine the revised allocation to each class. This revised allocation is again divided by sales to the class to determine the revised price:

$$EPRICE_j = (REV_j + (REVRCI * SUBPCT_j)) / (SALCLS_j)$$

where:

$EPRICE_j$ = the benchmarked/subsidized price of electricity to customer class j
REV_j = the costs (revenues) allocated to customer class j before the benchmarking/subsidization routine
REVRCI = total costs allocated to the three customer classes
$SUBPCT_j$ = benchmarking/subsidy percent for customer class j
$SALCLS_j$ = electricity sales to customer class j

2.4 Taxes

EFP calculates two categories of taxes: general taxes and income taxes.

2.4-a General Taxes

General taxes encompass all taxes except the State and Federal income taxes. Among these taxes are gross receipts, FICA, capitalized payroll, property and sales.

The assumption is made that these taxes each year will be a constant percentage of revenues.

$$GENTAX = EGTXRT * ERRVLG + ERPRTX + ERSLTX$$

where:

GENTAX = actual general taxes
EGTXRT = general tax rate (user input)
ERRVLG = electric revenues (see Section 2.1)
ERPRTX = property taxes (see Section 1.6)
ERSLTX = sales tax (see Section 1.6)

ERPRTX is modeled as an input fraction of the book value of property, and ERSLTX is modeled as an input fraction of the construction expenditures.

2.4-b Income Taxes

Current income taxes are those actually paid by the utility in a given year. Because of the regulatory and financial treatment of certain tax savings (e.g., investment tax credits, accelerated depreciation), this is not, in general, what is booked on the income statement as income tax expense.

CITAX = (ERRVLG - ERTFLN - ERTOMN - ERTDWO - GENTAX - (ERTIEX - AVDINT) - ESLLP) * ESFTXR + STTAX - (ERFITC + XITCD) - (ERATSF + ERATSD)

where:

CITAX	=	current income taxes
ERRVLG	=	electric revenues (see Section 2.1)
ERTFLN	=	fuel costs (see Section 1.3)
ERTOMN	=	operation and maintenance expenses, excluding fuel (see Section 1.4)
ERTDWO	=	depreciation for tax purposes, without acceleration (see Section 1.14-b)
GENTAX	=	actual general taxes (see Section 2.3-a)
ERTIEX	=	interest expenses (see Section 1.7-a)
AVDINT	=	interest capitalized on assets during construction (see Section 1.13-d)
ESLLP	=	annual lease payment associated with sale/leaseback transactions
ESFTXR	=	Federal income tax rate (user input)
STTAX	=	State income taxes, including Federal income tax benefits (see below)
ERFITC	=	generated ITC which is flowed through (see Section 1.15)
XITCD	=	generated ITC that is deferred (see Section 1.15)
ERATSF	=	tax savings from accelerated depreciation that is flowed through (see Section 1.14-b)
ERATSD	=	tax savings from accelerated depreciation that is deferred (see Section 1.14-b).

Now, booked income tax expense is current taxes, plus deferrals, minus amortizations:

BKITAX = CITAX + (XITCD - ERAITC) + (ERXFDC - ERAFDC) + ERATSD - EREDTF

where:

BKITAX	=	booked income tax expense
ERAITC	=	amortization of deferred ITC (see Section 1.15)
ERXFDC	=	generated tax savings from debt portion of AFUDC that is deferred (see Section 1.13-d)
ERAFDC	=	amortization of deferred tax savings from the debt portion of AFUDC (see Section 1.13-d)
EREDTF	=	excess deferred taxes flowed back to rate payers.

The only remaining tax variable to be explained is STTAX (State income taxes including Federal income tax benefits):

STTAX = (ERRVLG - ERTFLN - ERTOMN - ERTDWO - ERTIEX - ESLLP) *

ESSTXR * (1 - ESFTXR)

where:

ESSTXR = State income tax rate (user input).

State income taxes are deductible in calculating Federal taxable income so the net effect of State income taxes upon total income taxes is STTAX.

2.5 Financial Ratios

The output of EFP includes the forecasted values of several financial ratios. These ratios are standard indicators of a utility company's financial health. However, financial analysts disagree over the exact formula to be used in some cases. For EFP, the following definitions are used:

i) Interest Coverage. Interest coverage is calculated and printed under four alternative formulas. In all formulas, the denominator is total interest expenses. For pre-tax interest coverage, less AFUDC, the numerator is operating income plus booked income taxes. For pre-tax interest coverage, with AFUDC, the numerator is operating income, plus booked income taxes, plus AFUDC. For post-tax interest coverage, less AFUDC, the numerator is operating income. For post-tax interest coverage, with AFUDC, the numerator is operating income plus AFUDC.

ii) Actual Return on Common Equity. This ratio is calculated as earnings available for common equity divided by the year-average book value of common equity (common stock plus retained earnings).

iii) AFUDC as a Percentage of Earnings Available for Common. This ratio is calculated AFUDC divided by earnings available for common equity.

iv) Internal Cash Flow as a Percent of Construction Expenditures. This ratio is calculated as total internally generated funds divided by construction expenditures (excluding AFUDC).

v) CWIP as a Percentage of Net Plant. This ratio is calculated as total CWIP divided by net plant. Net plant includes both plant in service and CWIP.

vi) Effective Tax Rate. This rate is calculated as booked income taxes divided by booked pre-tax income. Pre-tax income is the sum of operating income and booked income taxes.

vii) Safety Margin. This ratio is calculated as net income plus booked income taxes, minus AFUDC, all divided by electric revenues.

Appendix A
Listing of Subroutines and Subroutine Functions[25].

The following list provides a brief description of the subroutines in the EFP. Line numbers from the code are included to help the user find appropriate subroutines and make changes as necessary. Also, this section provides insights for a better understanding of the operation of the EFP.

```
   1.          SUBROUTINE ELEFP

  71.          SUBROUTINE INICON

  73.    C****************************************************************
  74.    C     THIS SUBROUTINE READS IN THE RUN FILE, WHICH
  75.    C     CONTAINS THE CONTROL OPTIONS FOR REPORT WRITING
  76.    C****************************************************************

 156.          SUBROUTINE ELREAD

 158.    C******************************************************************
 159.    C   THIS SUBROUTINE READS INPUT DATA FROM FLAT FILES,
 160.    C   CALLS ELEA TO SPREAD AGGREGATE VINTAGE YEAR DATA ACROSS THE
 161.    C   VINTAGE YEARS, AND WRITES OUT DIRECT ACCESS FILES FOR THREE
 162.    C   CATEGORIES OF DATA:
 163.    C       1) INFORMATION THAT DOES NOT VARY BY REGION OR YEAR
 164.    C          (ONE RECORD)
 165.    C       2) INFORMATION THAT VARIES BY REGION BUT NOT BY YEAR
 166.    C          (RECORDS INDEXED BY REGION)
 167.    C       3) INFORMATION THAT VARIES BY BOTH REGION AND YEAR
 168.    C          (RECORDS INDEXED BY REGION AND YEAR)
 169.    C******************************************************************

 418.          SUBROUTINE COMENT(NN)

 420.    C*******************************************************************
 421.     C    THIS SUBROUTINE SKIPS OVER COMMENT LINE IN DATA INPUT FILES.
 422.     C    A COMMENT BEGINS WITH AN ASTERISK (*) IN COLUMN 1
 423.    C*******************************************************************

 631.          SUBROUTINE ELRDPI

 633.    C****************************************************************
 634.    C      THIS SUBROUTINE READS IN THE PHASE-IN DATABASE
 635.    C****************************************************************

 730.          SUBROUTINE ELRDSL

 732.    C**************************************************************
 733.    C THIS SUBROUTINE READS IN THE SALES LEASEBACK DATABASE
 734.    C**************************************************************
```

[25]All listings of code in this section are from CN6005.PRJ.NEMS.FORTRN.UEFP.D1123931.

```
      SUBROUTINE TREAS

C***************************************************************
C  THIS SUBROUTINE READS IN A FILE CONTAINING TAX CHANGES TO
C  BE SIMULATED.  IT ALSO INITIALIZES SOME NEW VARIABLES.
C***************************************************************

      SUBROUTINE RDALLO

C**************************************************************
C THIS SUBROUTINE READS IN THE DEMAND QUALITIES (WHICH WILL
C EVENTUALLY BE PASSED BY THE LDSM MODULE) AND THE ALLOCATION
C TECHNIQUES FOR EACH OPERATING COMPONENT (GENERATION,
C TRANSMISSION, AND DISTRIBUTION) THERE ARE 4 CLASSES:
C     1 = RESIDENTIAL
C     2 = COMMERCIAL
C     3 = INDUSTRIAL
C     4 = TRANSPORTATION
C**************************************************************

      SUBROUTINE ELRDTD

C*******************************************************************
C             THIS SUBROUTINE READS TRANSMISSION DATA
C*******************************************************************

      SUBROUTINE ELRDDD

C*******************************************************************
C               THIS SUBROUTINE READS DISTRIBUTION DATA
C*******************************************************************

      SUBROUTINE ELEA

C********************************************************************
C  THIS SUBROUTINE CALCULATES ACCOUNTS FOR EXISTING ASSETS INCLUDING
C  BOOK VALUE, ASSET VALUE, ACCUMULATED BOOK DEPRECIATION, AMORTI-
C  ZATION OF DEFERRED INVESTMENT TAX CREDITS, AND AMORTIZATION
C  OF DEFERRED TAX SAVINGS FROM THE DEBT PORTION OF AFUDC
C********************************************************************

      SUBROUTINE EFP(NRGN)

C*******************************************************************
C     THIS SUBROUTINE IS THE MAIN ROUTINE FOR CONTROL OVER THE
C     THREE OPERATING COMPONENTS OF EFP.  ALL VARIABLE
C     INITIALIZATION IS PERFORMED PRIOR TO CALLING THE ROUTINES
C     RESPONSIBLE FOR EACH OPERATING COMPONENT.  THUS THE VARIABLES
C     ARE MANAGED IN THIS ROUTINE, AND EACH OPERATING COMPONENT IS
C     CALLED WITH THE PROPER SET UP . IN ADDITION INFORMATION
C     FLOWING OUT OF THE COMPUTATIONS PERFORMED FOR EACH
C     OPERATING COMPONENT ARE ALSO MANAGED BEFORE PROCEEDING TO THE
C     NEXT OPERATING COMPONENT.
C*******************************************************************

      SUBROUTINE ALLFAC(NRGN)

C**************************************************************
C THIS SUBROUTINE CALCULATES THE ALLOCATION FACTORS FOR EACH
C OF THE PRE-DEFINED ALLOCATION TECHNIQUES.  THE ALLOCATION
```

```
C FACTORS ARE A FUNCTION OF THE DEMAND CHARACTERISTICS OF EACH
C CLASS.  THE ALLOCATION TECHNIQUES ARE:
C    1 = SALES
C    2 = MARGINAL FUEL
C    3 = EMBEDDED FUEL
C    4 = CUSTOMER
C    5 = CP
C    6 = PCP
C    7 = NCP
C    8 = AED - CP
C    9 = AED - PCP
C**************************************************************

      SUBROUTINE ELGLTR(NRGN,ICALL)

C*******************************************************************
C         THIS SUBROUTINE TRANSFERS GLOBAL TO LOCAL VARIABLES
C*******************************************************************

      SUBROUTINE ELLGTR(NRGN,ICALL)

C*******************************************************************
C         THIS SUBROUTINE TRANSFERS LOCAL TO GLOBAL VARIABLES
C*******************************************************************

      SUBROUTINE CAPCOST(NRGN,ICALL,CURIYR,CURITR,N)

C*******************************************************************
C        THIS SUBROUTINE CALCULATES THE COST OF CAPITAL
C*******************************************************************

      SUBROUTINE ELDIST(NRGN)

C*******************************************************************
C       THIS SUBROUTINE DETERMINES THE COST OF CONSTRUCTION AND
C                MAINTENANCE OF DISTRIBUTION EQUIPMENT
C*******************************************************************

      SUBROUTINE ELTRAN(NRGN)

C*******************************************************************
C       THIS SUBROUTINE DETERMINES THE COST OF CONSTRUCTION AND
C                MAINTENANCE OF TRANSMISSION EQUIPMENT
C*******************************************************************

      SUBROUTINE GL(NRGN,ICALL)

C*****************************************************************
C    THIS SUBROUTINE GATHERS INFORMATION NEEDED FROM THE
C    DISPATCH PART OF NEMS
C*****************************************************************

      SUBROUTINE GENERA(NRGN,ICALL)

C******************************************************************
C THIS SUBROUTINE INVOKES GENERATION ACCOUNTING COMPUTATIONS
C*******************************************************************

      SUBROUTINE AVRPRC(NRGN,ICALL)
```

```
C*****************************************************************
C  THIS SUBROUTINE INVOKES AVERAGE COST PRICING COMPUTATIONS
C*****************************************************************

      SUBROUTINE ELADCR

C******************************************************************
C     THIS SUBROUTINE CALCULATES THE AFUDC RATE TO BE USED IN
C                        THE CURRENT YEAR
C******************************************************************

      SUBROUTINE ELCWIP(NRGN,ICALL)

C******************************************************************
C    THIS SUBROUTINE CALCULATES THE FINANCIAL ACCOUNTS RELATED
C                 TO CONSTRUCTION WORK IN PROGRESS
C******************************************************************

      SUBROUTINE ELBKDP

C*******************************************************************
C        THIS SUBROUTINE CALCULATES BOOK DEPRECIATION AND TAX
C                 DEPRECIATION WITHOUT ACCELERATION.
C*******************************************************************

      SUBROUTINE ELTXDP

C*******************************************************************
C    THIS SUBROUTINE CALCULATES TAX DEPRECIATION USING:
C            1) THE SUM-OF-THE-YEARS METHOD,
C            2) ERTA MODIFIED BY TEFRA METHOD,
C            3) TRA METHOD.
C*******************************************************************

      SUBROUTINE ELITC

C******************************************************************
C     THIS SUBROUTINE CALCULATES THE ACCOUNTS RELATING TO THE
C                  INVESTMENT TAX CREDIT
C******************************************************************

      SUBROUTINE ELTSAF

C*******************************************************************
C     THIS SUBROUTINE CALCULATES THE ACCOUNTS RELATING TO THE TAX
C               SAVINGS FROM THE DEBT PORTION OF AFUDC
C*******************************************************************

      SUBROUTINE ELEDT(NRGN)

C*******************************************************************
C CALCULATE EXCESS DEFERRED TAXES FROM ACCELERATED DEPRECIATION
C THAT RESULT FROM THE LOWERING OF THE FEDERAL INCOME TAX RATE.
C ALSO CALCULATE HOW MUCH OF THIS EXCESS SHOULD BE FLOWED THRU TO
C CUSTOMERS IN EACH YEAR OF THE FORECAST PERIOD.
C*******************************************************************

      SUBROUTINE SYD(ICYOS,DEPR,TXLF,BKLF,EXCESS,FT,NYRSFT,FTPER)

C*******************************************************************
```

```
C THE PURPOSE OF THIS SUBROUTINE IS TO CALCULATE THE AMOUNT OF
C 'EXCESS' DEFERRED TAXES WHICH MUST BE FLOWED BACK TO RATE PAYERS.
C THE 'EXCESS' DEFERRED TAXES ARE THOSE WHICH WERE BOOKED AT 46%
C BUT WILL NEVER BE AMORTIZED OTHERWISE BECAUSE OF THE LOWERED TAX
C RATE.  THIS ROUTINE IS FOR THOSE ASSETS WHICH HAVE USED SUM OF
C THE YEARS DIGITS.
C*******************************************************************

      SUBROUTINE ERTA(ICYOS,DEPR,IPTYP,EXCESS,BKLF,FT,NYRSFT,FTPER)

C*******************************************************************
C THE PURPOSE OF THIS SUBROUTINE IS TO CALCULATE THE AMOUNT OF
C 'EXCESS' DEFERRED TAXES WHICH MUST BE FLOWED BACK TO RATE PAYERS.
C THE 'EXCESS' DEFERRED TAXES ARE THOSE WHICH WERE BOOKED AT 46%
C BUT WILL NEVER BE AMORTIZED OTHERWISE BECAUSE OF THE LOWERED TAX
C RATE.  THIS ROUTINE IS FOR THOSE ASSETS WHICH HAVE USED THE ERTA
C TAX SCHEDULES.
C*******************************************************************

      SUBROUTINE CONDRS(ICYOS,DEPR,J,EXCESS,BKLF,FT,NYRSFT)

C*******************************************************************
C THE PURPOSE OF THIS SUBROUTINE IS TO CALCULATE THE AMOUNT OF
C 'EXCESS' DEFERRED TAXES WHICH MUST BE FLOWED BACK TO RATE PAYERS.
C THE 'EXCESS' DEFERRED TAXES ARE THOSE WHICH WERE BOOKED AT 46%
C BUT WILL NEVER BE AMORTIZED OTHERWISE BECAUSE OF THE LOWERED TAX
C RATE.  THIS ROUTINE IS FOR THOSE ASSETS WHICH HAVE USE THE NEW
C TRA TAX SCHEDULES.
C*******************************************************************

      SUBROUTINE FTEDT(EXCESS,LYEAR,NRGN,FT,NYRSFT)

C*******************************************************************
C THE PURPOSE OF THIS SUBROUTINE IS TO CALCULATE YEAR BY YEAR
C AMOUNTS OF 'EXCESS' DEFERRED INCOME TAXES TO BE FLOWED BACK TO
C CUSTOMERS.  THE 'EXCESS' RESULTS FROM THE LOWERING OF THE INCOME
C TAX RATE.
C*******************************************************************

      SUBROUTINE ELPHIN(NRGN)

C*******************************************************************
C                               - ELPHIN -
C THIS SUBROUTINE CALCULATES THE IMPACT OF PHASE-IN/DISALLOWANCE
C PLANS OF NEW CAPACITY.  SINCE THE REST OF THE MODEL HAS
C CALCULATED COMPONENTS OF REVENUE REQUIREMENTS ASSUMING
C TRADITIONAL REGULATORY TREATMENT OF THESE PLANTS, THIS ROUTINE
C ONLY CALCULATES THE CHANGE IN THE COMPONENTS CAUSED BY THE PHASE
C IN PLAN, RELATIVE TO TRADITIONAL REGULATION.
C*******************************************************************

      SUBROUTINE ELPIPY(I,IPI)

C*******************************************************************
C                             -ELPIPY-
C THIS SUBROUTINE CALCULATES THE IMPACT OF PHASE-IN/DISALLOWANCE
C PLANS OF NEW CAPACITY FOR YEARS BEFORE THE MODEL STARTS.  THIS
C SUBROUTINE WORKS EXACTLY THE SAME WAY AS THE SUBROUTINE ELPHIN
C WHICH CALLS THIS SUBROUTINE.
********************************************************************
```

```
      SUBROUTINE ELSL(NRGN)

C*******************************************************************
C THIS SUBROUTINE ADJUSTS THE RESULTS OF EFP FOR THE IMPACT OF
C SALES AND SUBSEQUENT LEASEBACK OF UTILITY PLANT.  IN ORDER TO
C CONSERVE SPACE AND NOT PRODUCE ANY ADDITIONAL BUILDS, THE MOST
C RECENT DISTRIBUTION BUILD IS ADJUSTED TO REFLECT IMPACT.  THIS
C SUBROUTINE RELIES ON 2 SIMPLIFICATIONS:
C    (1) EVEN THOUGH THE ALGORITHM ASSUMES THAT PROCEEDS FROM SALE
C        ARE USED TO RETIRE HIGH COST DEBT AND EQUITY, NO SPECIAL
C        ADJUSTMENTS ARE MADE TO THE EMBEDDED INTEREST RATES,
C    (2) THE TAX ON THE GAIN IS NOT REFLECTED IN THE CURRENT INCOME
C        TAX CALCULATIONS, BUT RATHER THE ALGORITHM USES THE
C        AFTER TAX GAIN (THIS STILL PRODUCES CORRECT RESULTS).
C*******************************************************************

      FUNCTION ELCEXP(JYR,LCP)

C**********************************************************
C   THIS FUNCTION COMPUTES THE PERCENTAGE OF THE
C   TOTAL CONSTRUCTION EXPENDITURE THAT WILL OCCUR DURING
C   THE GIVEN YEAR IN THE CONSTRUCTION PERIOD.
C**********************************************************

      SUBROUTINE ELXPNS(NRGN,ICALL)

C*******************************************************************
C    THIS SUBROUTINE CALCULATES NOMINAL FUEL AND O&M EXPENSES, AND
C    WORKING CAPITAL
C*******************************************************************

      SUBROUTINE ELINEX(NRGN)

C*******************************************************************
C              THIS SUBROUTINE CALCULATES INTEREST EXPENSE
C*******************************************************************

      SUBROUTINE ELREVS

C*******************************************************************
C    THIS SUBROUTINE SOLVES FOR THE REVENUE REQUIREMENTS AND THEN
C      DETERMINES ALLOWED REVENUES BASED ON THE REGULATORY LAG.
C*******************************************************************

      SUBROUTINE STMTS(NRGN,ICALL)

C*****************************************************************
C THIS SUBROUTINE PREPARES THE FINANCIAL STATEMENTS.
C*****************************************************************

      SUBROUTINE ELRATE(ICALL,NRGN)

C******************************************************************
C THIS SUBROUTINE CONTROLS THE CALCULATION OF RATES BY SECTOR.
C IT UTILIZES 3 SUBROUTINES:
C       FUNCTN:  FUNCTIONALIZES TOTAL COSTS INTO CATEGORIES
C       ALLOCT:  ALLOCATES CATEGORY COSTS TO CLASSES
C       RATES:   CALCULATES AVERAGE PRICE FOR EACH CLASS
C*******************************************************************
```

```
      SUBROUTINE FUNCTN(ISECT,NRGN)

C******************************************************************
C THIS SUBROUTINE FUNCTIONALIZES THE REVENUE REQUIREMENT INTO
C PRE-DEFINED COST CATEGORIES.  THE CATEGORIES ARE:
C         COST(1) = FUEL COSTS
C         COST(2) = VARIABLE O&M
C         COST(3) = FIXED O&M
C         COST(4) = CAPITAL COSTS
C******************************************************************

      SUBROUTINE ALLOCT(ISECT)

C******************************************************************
C THIS SUBROUTINE CALCULATES REVENUES ALLOCATED TO EACH CLASS
C******************************************************************

      SUBROUTINE RATES(ISECT,NRGN)

C******************************************************************
C THIS SUBROUTINE CALCULATES AVERAGE PRICE BY SECTOR.  AVERAGE
C PRICE IS CALCULATED AS REVENUES ALLOCATED TO THE CLASS
C DIVIDED BY SALES TO THE CLASS
C******************************************************************

      SUBROUTINE TRANSM(NRGN,ICALL)

C******************************************************************
C THIS SUBROUTINE INVOKES TRANSMISSION ACCOUNTING COMPUTATIONS
C******************************************************************

      SUBROUTINE DISTRI(NRGN,ICALL)

C******************************************************************
C THIS SUBROUTINE INVOKES DISTRIBUTION ACCOUNTING COMPUTATIONS
C******************************************************************

      SUBROUTINE GETEB(NRGN,ICALL)

C******************************************************************
C THIS SUBROUTINE CREATES ARRAYS (THE EB ARRAYS) WHICH CONTAIN
C PARAMETERS DESCRIBING EACH BUILD APPLICABLE TO THE CURRENT
C REGION AND OPERATING COMPONENT (TRANS, DIST, OR GENERATION).
C******************************************************************

      SUBROUTINE STREB(NRGN,ICALL)

C******************************************************************
C THIS SUBROUTINE CREATES ARRAYS (THE EB ARRAYS) WHICH CONTAIN
C PARAMETERS DESCRIBING EACH BUILD APPLICABLE TO THE CURRENT
C REGION AND OPERATING COMPONENT (TRANS, DIST, OR GENERATION).
C******************************************************************

      SUBROUTINE ELSET

C******************************************************************
C   THIS SUBROUTINE ASSIGNS ELECTRICITY PRICES BY SECTOR AND REGION
C    USING A MAPPING FROM NERC TO CENSUS REGIONS
C******************************************************************
```

```
      SUBROUTINE REPORT(NRGN,INDOC)
c*******************************************************************
C       THIS SUBROUTINE CONTROLS WHICH OUTPUT REPORTS ARE PRINTED
C       LARGE OR SMALL REPORT CAN BE PRINTED
C*******************************************************************

      SUBROUTINE TMPSET(IT,NRGN,IC)

C*******************************************************************
C       THIS SUBROUTINE SETS UP TEMPORARY ARRAYS OF REPORT DATA
C       FOR THE GIVEN REGION AND TYPE
C*******************************************************************

      SUBROUTINE ADDUP(NRGN)

C*******************************************************************
C     THIS SUBROUTINE SUMS UP THE REGIONAL RESULTS TO YIELD
C     TOTALS ACROSS OPERATING COMPONENT AND OWNERSHIP TYPES
C*******************************************************************

      SUBROUTINE REAL$(ITYPE)

C*******************************************************************
C     THIS SUBROUTINE CONVERTS ALL DOLLARS FROM NOMINAL TO REAL
C     DOLLARS.  THIS IS DONE ONLY WHEN REQUESTED (WHEN IREAL$=1)
C*******************************************************************

      SUBROUTINE REPLAR(ITYPE)

C********************************************************************
C          THIS SUBROUTINE PRINTS THE LARGE REPORT
C********************************************************************

      SUBROUTINE REPSML(ITYPE,NRGN,INDOC)

C*******************************************************************
C          THIS SUBROUTINE PRINTS THE SMALL REPORT
C*******************************************************************

      SUBROUTINE ELRDND(IN)

C********************************************************************
C                             -ELRDND-
C This subroutine reads in the nuclear decommissioning data.
C********************************************************************

      SUBROUTINE ELND(NRGN,ICALL)

C******************************************************************
C                                 -ELND-
C This subroutine calculates the qualified amount for each year as
C well as the new fund balance and total administrative costs.  The
C totals are in current year dollars.
C*******************************************************************

      SUBROUTINE ANEWBLD(NRGN)

C*******************************************************************
C       THIS SUBROUTINE CREATES A NEW BUILD FOR PURPOSES OF RECORDING
C                THE COSTS OF CAPITAL ADDITIONS, PHASE-INS, AND SALE-
```

```
C                LEASEBACKS, AND LIFE EXTENSIONS
C*******************************************************************

      SUBROUTINE ELRDLE(IN)

C*******************************************************************
C                          -ELRDLE-
C This subroutine reads in the LIFE EXTENSION  data.
C*******************************************************************
```

Appendix B
Listing of Computations[26]

The following section shows the calculations used in the EFP. Line numbers are included and may be cross referenced with the previous section listing the subroutines to aid the user in finding particular bits of code for future changes.

COST OF CAPITAL

AA BOND RATE ADJUSTMENT (Please note that this is a temporary fix for the macroeconomic side cases in the Annual Energy Outlook 1994).

```
 2141.     C  THESE CALCULATIONS SHOULD BE USED ONLY FOR YEARS IN WHICH THE
 2142.     C  COST OF CAPITAL THAT WAS READ IN IS TO BE OVERWRITTEN -
 2143.     C  1ST ITERATION ONLY
 2144.
 2145.           IF (CURIYR .GT. 3) THEN
 2146.            IF (CURITR .EQ. 1) THEN

 2151.     C  APPLY ADJUSTMENT TO UTILITY BOND RATE IN MACRO CASE SINCE FEEDBACK
 2152.     C   FOR CAPITAL INVESTMENT NOT LIKED
 2153.
 2154.                 UTAART = MC_RMPUAANS(CURIYR)
 2155.               IF(CURIYR.GE.8)
 2156.          +       UTAART = MC_RMPUAANS(CURIYR) + UAAADJ(MMAC)
```

NEW LONG TERM (LT) DEBT

```
 2147.           ESRTLT(1)=(UTBRRG(1,NRGN)+(UTBRRG(2,NRGN)*MC_RMPUAANS(CURIYR)))
 2148.          1          /100
 2149.
 2150.           ESRTLT(2)=(BRMCF(1)+(BRMCF(2)*MC_RMPUAANS(CURIYR)))/100
```

COMMON STOCK

```
 2154.            ESRTCE(1)=ARRCF(1,NRGN)+(ARRCF(2,NRGN)*ESRTCL(N,NRGN,ICOM))+
 2155.          1          (ARRCF(3,NRGN)*ESRTLT(N))+
 2156.          2          (ARRCF(4,NRGN)*ESRTDL(N,NRGN,ICOM))
 2157.

 2161.            ESRTCE(2)=ESRTLT(2)
```

NEW PREFERRED STOCK

```
 2165.            ESRTPS(1)=PSRCF(1)+PSRCF(2)*ESRTDA(ICOM)
 2166.            ESRTPS(2)=0
```

NEW SHORT TERM (ST) DEBT

```
 2170.            ESRTST(N)=ESRTLT(N)
```

ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION (AFUDC) RATE

DEBT CONTRIBUTION

```
 2674.                 TEMPD = (ESPRLT(N)*ESEMDL(N)) + (ESPRST(N)*ESRTST(N))
```

EQUITY PORTION

[26] All listings of code are from CN6005.PRJ.NEMS.FORTRN.UEFP.D1123931 except **AA BOND RATE ADJUSTMENT** which is from CN6005.PRJ.NEMS.FORTRN.UEFP.D1217931.

```
 2669.                  TEMPE = (ESPRCE(N)*ESRTCE(N)) + (ESPRPS(N)*ESEMPL(N))
```

PRE-TAX AFUDC RATE

```
 2676.                  ESAFDC(N) = TEMPD + TEMPE
```

DEBT PORTION

```
 2679.                     ESWACD(N) = TEMPD/ESAFDC(N)
```

DIRECT CAPITAL EXPENDITURES

GENERATION

```
 2864.                           EBYCWP(I,N) = CONPER*EBPCAP(I,N)*EBPCST(I)
 2865.          1                                 *MC_PGDP(CURIYR)

 2945.                           EBYCWP(EBNUM,N) = EBYCWP(EBNUM,N) + CAPAD
```

TRANSMISSION

```
  971.     C      UTEMCP = TRANSMISSION ENERGY-MILE CAPITAL COST

  997.                  READ(IN,*)UTEMCP(I,N)

 1747.                  ETEMCP = UTEMCP(CURIYR,NRGN)
```

DISTRIBUTION

```
 2317.            DCP = (DSTSLP*EQTLSL(1)) + DSTCON
 2318.            DCP = DCP/ESTSHR(1)
```

BOOKED AFUDC

CONSTRUCTION WORK IN PROGRESS (CWIP) IN RATEBASE

```
 2880.                              EBRCWP(I,N) = (CWIPWA*CWPPER) +
 2881.          1                                 (CWIPWA*(1.0 - CWPPER)*
 2882.          2                                 ESRBAF(N))
```

BOOKED AFUDC
(PLANT NOT ENTERING SERVICE THIS YEAR)

```
 2874.                              AFUDC = (EBBCWP(I,N) + (0.5*EBYCWP(I,N)))*
 2875.          1                           (1.0 - CWPPER)*ESAFDC(N)
```

(PLANT ENTERING SERVICE THIS YEAR)

```
 2892.                              AFUDC = (EBBCWP(I,N) + (0.5*EBYCWP(I,N)))*
 2893.          1                           (1.0 - CWPPER)*(1.0 - EBSERP(I))*
 2894.          2                           ESAFDC(N)
```

AFUDC OFFSET

```
 2911.                           EROFFS(N) = (AFUDC*ESRBAF(N)) + EROFFS(N)
```

BOOKED CWIP

```
 2878.                              EBBCWP(I,N) = CWIPWA + AFUDC
```

TAX BASIS (TAX REFORM ACT OF 1986 - TRA - ONLY)

AVOIDED INTEREST

(PLANT NOT ENTERING SERVICE THIS YEAR)

```
 2876.                              AVDINT = (ELASVL + (0.5*EBYCWP(I,N)))*
 2877.          1                            ESRTLT(N)
```

(PLANT ENTERING SERVICE THIS YEAR)

```
 2896.                             AVDINT = (ELASVL + (0.5*EBYCWP(I,N)))*
 2897.          1                           ESRTLT(N)*(1.0 - EBSERP(I))
```

TAX BASIS

```
 2868.                          EBASVL(I,N) = EBASVL(I,N) + EBYCWP(I,N)
```

ADD AVOIDED INTEREST

```
 2915.                             EBASVL(I,N) = EBASVL(I,N) + AVDINT
```

ADD POST OPERATIONAL CAPITAL EXPENDITURES

```
 2961.                             EBASVL(EBNUM,N) = EBASVL(EBNUM,N) + CAPAD
```

ADD LIFE EXTENSION

```
 2970.                            EBASVL(EBNUM,N) = EBASVL(EBNUM,N) + CAPLE(N,NRGN,CURIYR)
```

LOWER BY HALF OF DEFERRED INCOME TAX CREDIT (DITC) IF ASSETS ARE POST TEFRA

```
 3432.                                EBASVL(I,N) = EBASVL(I,N) -
 3433.          1                                   0.5*EBDITC(I,N)
```

ADJUST FOR SALES/LEASEBACK

```
 4428.                      EBASVL(EBNUM,I) = EBASVL(EBNUM,I) - ASVL
```

AFUDC ACCOUNTS

DEBT PORTION OF AFUDC

```
 2910.                          ERFDCD(N) = DEBTAF + ERFDCD(N)
```

EQUITY PORTION OF AFUDC

```
 2908.                          ERFDCE(N) = (AFUDC*WACE) + ERFDCE(N)
```

CAPITALIZED INTEREST DURING CONSTRUCTION

(CAPITALIZE)

```
 2916.                             ERCIDC(N) = ERCIDC(N) + AVDINT
```

(DO NOT CAPITALIZE)

```
 2920.                             ERCIDC(N) = ERCIDC(N) + DEBTAF
```

BOOK DEPRECIATION

```
 3065.                             BDE = (EOBKVL(IYR,J,N) - EOABDE(IYR,J,N))
 3066.          1                          /(NRETIR - CURIYR)
 3067.                             ERBDE1(N) = BDE + ERBDE1(N)

 3084.                          BDE = (EBBKVL(I,N)/ESBKLF(J,N))*EBSERP(I)

 3095.                             BDE = EBBKVL(I,N) - EBABDE(I,N)

 3100.                             BDE = (EBBKVL(I,N) - EBABDE(I,N))
 3101.          1                        /(ESBKLF(J,N) - (CURIYR - EBSYR(I) +
 3102.          2                        EBSERP(I) - 1))

 3111.                       ERBDE2(N) = BDE + ERBDE2(N)

 3117.                 ERBDE(N) = ERBDE2(N) + ERBDE1(N)
```

STRAIGHT LINE TAX DEPRECIATION

EXISTING ASSETS

```
 3063.                             ERTDW1(N) = EODEPR(J,N)*EOASVL(IYR,J,N) +
 3064.          1                                ERTDW1(N)
```

NEW ASSETS

```
 3116.                  ERTDWO(N) = ERTDW1(N)

 3309.                           ERTDW2(N) = EBASVL(I,N)*ESDEPR(J,N) + ERTDW2(N)

 3325.                  ERTDWO(N) = ERTDWO(N) + ERTDW2(N)
```

ACCELERATED TAX DEPRECIATION

EXISTING ASSETS

(ERTA MODIFIED BY TEFRA IF VINTAGE YEAR IS 1981 TO 1984)

```
 3246.                           IF (K .LE. ESTXRP(L)) ERTDE1(N) = ESTXRS(L,K)*
 3247.         1                                       (0.95*EOASVL(IYR,J,N)) +
 3248.         2                                       ERTDE1(N)
```

(USE SYD IF VINTAGE IS BEFORE 1981)

```
 3255.                           ERTDE1(N) = SYDTDR*EOASVL(IYR,J,N) + ERTDE1(N)
```

NEW ASSETS

(USE SYD)

```
 3282.                              ERTDE2(N) = (TEMP1/TEMP2)*EBASVL(I,N) +
 3283.         1                                ERTDE2(N)
```

(USE SENATE/HOUSE CONFEREE DEPREC. METHOD IF START YR. IN RANGE)

```
 3294.                                 ERTDE2(N) = ERTDE2(N) +
 3295.         1                                   CONDR(ICURYR,ICONTP(J))*
 3296.         2                                   EBASVL(I,N)
```

(USE ERTA MODIFIED BY TEFRA)

```
 3301.                                 IF (K .LE. ESTXRP(L)) ERTDE2(N) =
 3302.         1                                               ESTXRS(L,K)*
 3303.         2                                               EBASVL(I,N) +
 3304.         3                                               ERTDE2(N)

 3326.                  ERTDE(N) = ERTDE1(N) + ERTDE2(N)
```

RATEMAKING DEPRECIATION

```
 3332.                  ERTDRG(N) = ERTDWO(N)*(1.0 - ESFLPR(N)) +
 3333.         1                    ERTDE(N)*ESFLPR(N)
```

OTHER DEPRECIATION RELATED QUANTITIES

TAX SAVINGS DUE TO ACCEL. DEPREC. FLOWED THROUGH

(EXISTING ASSETS WITH ADJUSTMENT IF CUM. DEFERRALS ARE GREATER THAN 0)

```
 3265.                     ERATSF(N) = ESFTXR(N)*(ERTDE1(N) - ERTDW1(N))*
 3266.         1                       (ESFLPR(N))
```

(NEW ASSETS)

```
 3327.                  ERATSF(N) = (ESFTXR(N)*(ERTDE2(N) - ERTDW2(N)))*
 3328.         1                    ESFLPR(N) + ERATSF(N)
```

DEFERRED TAX SAVINGS DUE TO ACCELERATED DEPRECIATION

(OLD ASSETS)

```
 3263.                     ERATSD(N) = ESFTXR(N)*(ERTDE1(N) - ERTDW1(N))*
 3264.         1                       (1 - ESFLPR(N))
```

(NEW ASSETS)

```
3329.                 ERATSD(N) = (ESFTXR(N)*(ERTDE2(N) - ERTDW2(N)))*
3330.          1                  (1 - ESFLPR(N)) + ERATSD(N)
```

PROVISION FOR DEFERRED TAXES DUE TO ACCEL. DEPREC. AND DEBT AFUDC

(TAX SAVINGS DUE TO ACCELERATED DEPRECIATION)

```
3331.                 ERPRDF(N) = ERPDFL(N) + ERATSD(N)
```

(TAX SAVINGS DUE TO THE DEBT PORTION OF AFUDC)

```
3524.                    ERPRDF(N) = ERPRDF(N) + ERXFDC(N) - ERAFDC(N)
```

(DELETE DEFERRED AMOUNT FLOWED THROUGH THIS YEAR)

```
3713.                 ERPRDF(N) = ERPRDF(N) - EREDTF(N)
```

ANNUAL INVESTMENT TAX CREDIT (ITC)

ANNUAL ITC FLOWED THROUGH

```
3426.                             ERFITC(N) = GITC*ESFLPR(N) + ERFITC(N)
```

ANNUAL ADDITION TO DEFERRED ITC

```
3429.                             XITCD = XITCD + XITCDP
```

ANNUAL ITC AMORTIZATION

(ITC FROM NEW ASSETS)

```
3428.                             EBDITC(I,N) = EBDITC(I,N) + XITCDP
```

AMORTIZATION PER YEAR OF DEFERRED ITC

(DEFERRED ITC FROM EXISTING ASSETS)

```
3409.                          IF (CURIYR .LT. NRETIR) ERAITC(N) =
3410.          1                                       EOAITC(IYR,J,N) +
3411.          2                                       ERAITC(N)
```

(DEFERRED ITC FROM NEW ASSETS)

```
3428.                             EBDITC(I,N) = EBDITC(I,N) + XITCDP
```

AMORT'D. AMT. (3434:LOWERED TAX BASIS FOR POST TEFRA AND 3441:OTHERS)

```
3434.                                ERAITC(N) = EBDITC(I,N)/ESBKLF(J,N) +
3435.          1                                 ERAITC(N)

3441.                             ERAITC(N) = EBDITC(I,N)/ESBKLF(J,N) +
3442.          1                              ERAITC(N)
```

TOTAL ACCRUED EXCESS DEFERRED TAXES (EDT)

EXCESS DEPRECIATION AS A FRACTION OF THE TAX BASIS

```
3776.                 EXCESS = (AD*(0.46 - TXRTYR(IYREDT))*(1.0 - FTPER)) +
3777.          1               EXCESS

3779.                 EXCESS = (AD*(TXRTYR(JYR - IBASE + 1) - TXRTYR(IYREDT))*
3780.          1               (1.0 - FTPER)) + EXCESS

3938.              EXCESS = (CONDR(JYR,ICONTP(J)) - DEPR)*(TXRTYR(KYR) -
3939.          1            TXRTYR(IYREDT)) + EXCESS
```

AMOUNT OF EXCESS DEFERRED TAXES FLOWED THROUGH THIS YEAR

```
4002.                 UREDTF(NRGN,IYREDT) = UREDTF(NRGN,IYREDT) + EXCESS

4007.                    UREDTF(NRGN,JYR) = UREDTF(NRGN,JYR) + YREX
```

```
 4018.                   UREDTF(NRGN,JYR) = UREDTF(NRGN,JYR) +
 4019.          1                           (EXCESS*FREDTF(K))

 4028.                   UREDTF(NRGN,JYR) = UREDTF(NRGN,JYR) + (EXCESS*FT(K))
```

PROVISION FOR DEFERRED TAXES

```
 3524.                   ERPRDF(N) = ERPRDF(N) + ERXFDC(N) - ERAFDC(N)

 3713.                ERPRDF(N) = ERPRDF(N) - EREDTF(N)
```

IMPACT OF PHASE-IN AND DISALLOWANCE

TRADITIONAL REVENUE REQUIREMENT FOR PHASED-IN PLANT

```
 4156.                           RR = PIBKVL(IPI)*(1.0 - DISPER(IPI))
 4157.          1                     *(1.0 - ((YRPI - AVERB)/PIBKLF))
 4158.          2                     *(((ESPRLT(I)*ESEMDL(I)) +
 4159.          3                     (ESPRST(I)*ESRTST(I)))
 4160.          4                     + (((ESPRCE(I)*ESRTCE(I)) +
 4161.          5                     (ESPRPS(I)*ESEMPL(I)))/
 4162.          6                     (1.0 - ESFTXR(I)))) +
 4163.          7                     ((PIBKVL(IPI)/PIBKLF)
 4164.          8                     *(1.0 + (((1.0 - PITXBS)*ESFTXR(I))/
 4165.          9                     (1.0-ESFTXR(I)))))
```

ANNUAL DEFERRED COST OF PHASE-IN

(DEFERRED AMOUNT THIS YEAR)

```
 4166.                           DEFCST = RR*(1.0 - PIDFS(IYRPI,IPI))*
 4167.          1                         (1.0 - ESFTXR(I))
```

RECOVERY OF PAST DEFERRED COSTS

```
 4317.                   DEFCST = DEFCST - (PIRCS(IYRPI,IPI)*
 4318.          1                PIDEF(IPI))
```

CUMULATIVE DEFERRED COST

```
 4184.                           EPIDEF(I) = EPIDEF(I) + PIDEF(IPI)
```

NET VALUE OF DISALLOWED PLANT

```
 4190.                           EDISNT(I) = EDISNT(I) + ((PIBKVL(IPI)*
 4191.          1                            (1.0 - (YRPI/PIBKLF)))*
 4192.          2                            DISPER(IPI))
```

SALE/LEASEBACK REVENUE

BOOK VALUE OF PLANT SOLD

```
  774.          SLBKVL(NSL) = SLPROC(NSL) - BKGAIN
```

NET GAIN ON BOOK VALUE

```
  775.          SLGAIN(NSL) = BKGAIN - SLTAXS(NSL)
```

ASSET VALUE OF SALES/LEASEBACK PLAN

```
 4424.                              ASVL = SLPROC(ISL) - SLTAXS(ISL)/ESFTXR(I)
```

(IF FEDERAL INCOME TAXES EQUAL 0)

```
 4426.                              ASVL = SLBKVL(ISL)
```

PROCEEDS NET OF TAXES

```
 4429.                           ESLPRC(I) = ESLPRC(I) + SLPROC(ISL) -
 4430.          1                            SLTAXS(ISL)
```

AMORTIZATION OF GAIN

```
 4434.                          AMOR = SLGAIN(ISL)/SLTERM(ISL)
 4435.                          ESLAGN(I) = ESLAGN(I) + AMOR
```

NET DEFERRED GAIN

```
 4436.                          ESLNDG(I) = ESLNDG(I) + SLGAIN(ISL) - AMOR*YRSL
```

LEASE PAYMENT

```
 4433.                          ESLLP(I) = ESLLP(I) + SLLP(ISL)
```

TOTAL FUEL COSTS IN NOMINAL DOLLARS

```
 4506.                 ERTFLN(I) = EFPFL + BLKSUM
 4507.                 ERTFLN(I) = ERTFLN(I) * ESTSHR(I) * MC_PGDP(CURIYR)
```

OPERATION AND MAINTENANCE (O&M) EXPENSES

GENERATION O&M

```
 2563.              EFPOM = ERTOM(1) + ERTOM(2)
 2565.     C ADD IN PRODUCTION ALLOCATED GNA
 2566.              EFPOM = EFPOM + OVERPR(NRGN)*(EQTLSL(1) + EQTLSL(2))
```

FIXED COMPONENT

```
 2568.              EFPOM = EFPOM + 8.5*(EQTLSL(1) + EQTLSL(2))
```

TRANSMISSION O&M

```
 2487.           ERTOMT = ETEMTL*ETEMOM

 2572.              IF (ICALL .EQ. 'T') THEN
 2573.                 EFPOM = ERTOMT
 2574.     C ADD IN TRANSMISSION ALLOCATED GNA
 2575.                 EFPOM = EFPOM + OVERTR(NRGN)*(EQTLSL(1) + EQTLSL(2))
```

DISTRIBUTION O&M

```
 2577.     C CALCULATE O&M FOR DISTRIBUTION EQUIPMENT
 2578.                 EFPOM = OMDMLT(NRGN)*(EQTLSL(1) + EQTLSL(2))
 2579.     C ADD IN DISTRIBUTION ALLOCATED GNA
 2580.                 EFPOM = EFPOM + OVERDS(NRGN)*(EQTLSL(1) + EQTLSL(2))
```

NOMINAL O&M

```
 4516.     C CALCULATE NOMINAL O&M COSTS
 4517.                 ERTOMN(I) = (EFPOM*ESTSHR(I))*MC_PGDP(CURIYR)
```

GENERAL TAXES (ALL TAXES OTHER THAN FEDERAL INCOME TAXES)

```
 5118.                 ERGNTX(N) = ERRVLG(N)
 5119.          1                  *EGTXRT(N) + ERPRTX(N) + ERSLTX(N)
```

INTEREST EXPENSE

SHORT TERM

```
 4653.                 ERSIEX(I) = ESRTST(I)*(ERAMD(I)*ESPRST(I) + ERAMDL(I)*
 4654.          1                  ELPRST(I) - ESLPRC(I)*ESPRST(I))/2.0
```

LONG TERM

```
 4651.                 ERLIEX(I) = ESEMDT(I)*(ERAMD(I)*ESPRLT(I) + ERAMDL(I)*
 4652.          1                  ELPRLT(I) - ESLPRC(I)*ESPRLT(I))/2.0
```

TOTAL

```
 4655.                 ERTIEX(I) = ERLIEX(I) + ERSIEX(I)
```

ASSETS MINUS DEFERRALS (AMOUNT TO BE FINANCED)

```
                  ERAMD(I) = ERTUP(I) + ERBCWP(I) + ERWC(I) - ERABDE(I) -
        1                    ERPRDF(I) - ERDITC(I) + ERNFSN(I) -
        2                    EDISNT(I) + EPIDEF(I) - ESLNDG(I)
```

FEDERAL INCOME TAX

```
                     STFTAX = (ERRVLG(N) - ERTFLN(N) - ERTOMN(N) - ERQAMT(N) -
        1                      ESLLP(N) - ERBDE(N) - ERGNTX(N) - DEDINT +
        2                      ERFDCE(N))*ESFTXR(N)
```

RATEBASE

TOTAL UTILITY PLANT

```
                  ERTUP(N) = ERBL(1,N) + ERBL(2,N) + ERBL(3,N) + ERBL(4,N)
```

WORKING CAPITAL

```
                  ERWC(I) = 0.125*(ERTOMN(I) + ERTFLN(I))
```

NUCLEAR FUEL STOCK

```
                  ERNFSN(I) = 3.5*EFPNUC*ESTSHR(I)*MC_PGDP(CURIYR)
```

RATEBASE

```
                  ERRB(I) = ERTUP(I) + ERRCWP(I) + ERWC(I) - ERABDE(I) -
        1                   ERPRDF(I) + ERNFSN(I) - (ERCNBV(I) -
        2                   ERCNAD(I)) - ESLNDG(I)
      C DEDUCT DEFERRED ITC, IF REQUESTED
                  IF ((OPITCRB(I) .EQ. 2) .AND. (ESFTXR(I) .NE. 0.0))
        1            ERRB(I) = ERRB(I) - ERDITC(I)
      C CALCULATE RATE BASE
                  IF (OPAVRB(I) .EQ. 2) THEN
                     ERRBRR(I) = ERRB(I) - ERAFDL(I)
                  ELSE
      C CALCULATE RATE BASE AS YEAR AVERAGE
                     RBLAST = ERRBL(I)
                     IF (CURIYR .EQ. FIRSYR) RBLAST = RBLAST + ERWC(I) +
        1                                             ERNFSN(I)
                     ERRBRR(I) = (RBLAST + ERDLRB(I) + ERRB(I))/2.0
                  ENDIF
      C CALCULATE RATE BASE AS YEAR END
      C SUBTRACT OUT OF RATE BASE THE NET DISALLOWED PLANT
                  ERRBRR(I) = ERRBRR(I) - EDISNT(I)
```

RATE OF RETURN

LONG TERM (LT) DEBT

(DEBT RETIREMENTS)

```
                     RETIRE = ESPRLT(I)*ERBDE(I)
```

(LT DEBT OUTSTANDING)

```
                     EROB(I) = EROBL(I)-RETIRE
                     IF (EROB(I) .LE. 0.0) THEN
                        RETIRE = RETIRE + EROB(I)
                        EROB(I) = 0.0
                     ENDIF
```

(NEW LT DEBT)

```
                     ERBOND(I) = ERAMD(I)*ESPRLT(I)
```

(EMBEDDED COST OF LT DEBT)

```
                     IF (ERBOND(I) .GT. 0.0) ESEMDT(I) = (ESEMDL(I)*
        1                                                 ERBNDL(I) -
```

```
     2                                                   ESEMDB(I)*
     3                                                   RETIRE +
     4                                                   ESRTLT(I)*
     5                                                   (ERBOND(I) -
     6                                                   ERBNDL(I) +
     7                                                   RETIRE))/
     8                                                   ERBOND(I)
            ENDIF
```

PREFERRED STOCK

(PREFERRED STOCK RETIREMENTS)

```
               IF (ERPF(I) .LE. 0.0) THEN
                  RETIRE = RETIRE + ERPF(I)
                  ERPF(I) = 0.0
               ENDIF
```

(PREFERRED STOCK OUTSTANDING)

```
               ERPF(I) = ERPFL(I)-RETIRE
```

(NEW PREFERRED STOCK)

```
               ERPREF(I) = ERAMD(I)*ESPRPS(I)
```

(EMBEDDED COST OF PREFERRED STOCK)

```
               IF (ERPREF(I) .NE. 0.0) THEN
                  ESEMPS(I) = (ESEMPL(I)*ERPRFL(I) - ESEMPB(I)*
     1                        RETIRE + ESRTPS(I)*(ERPREF(I) -
     2                        ERPRFL(I) + RETIRE))/ERPREF(I)
               ENDIF
```

RATE OF RETURN (WEIGHTED AVERAGE COST OF CAPITAL)

```
            ESRR(I) = ESPRLT(I)*ESEMDT(I) + ESPRST(I)*ESRTST(I) +
     1                ESPRCE(I)*ESRTCE(I) + ESPRPS(I)*ESEMPS(I)
```

REVENUE REQUIREMENT

```
C CALCULATE THE REVENUE REQUIREMENT. THE EQUATION SHOWN BELOW
C IS THE SOLUTION TO 4 SIMULTANEOUS EQUATIONS INVOLVING THE
C REVENUE REQUIREMENTS.
            ERRVRQ(I) = (ERRBRR(I)*ESRR(I) + ERTFLN(I) + ERTOMN(I) +
     A                  ERQAMT(I) +
     1                  ERBDE(I) - ERAITC(I) - ERFITC(I) -
     2                  ERAFDC(I) - ERFFDC(I) - EROFFS(I) -
     3                  EREDTF(I) - EPIND(I) + ESLLP(I) -
     4                  ESLAGN(I) + (ERPRTX(I) + ERSLTX(I))*
     5                  (1.0 - ESFTXR(I)) + (ERTFLN(I) + ERTOMN(I) +
     6                  ERTDWO(I) + ERTIEX(I) + ESLLP(I) + ERQAMT(I))*
     7                  ((-1.0*ESSTXR(I)) + ESSTXR(I)*ESFTXR(I)) +
     8                  (ERTFLN(I) + ERTOMN(I) + ERTDRG(I) + ERQAMT(I) +
     9                  (ERTIEX(I) - ERCIDC(I)) + ESLLP(I))*
     *                  ((-1.0*ESFTXR(I))))/(1.0 - EGTXRT(I) -
     1                  ESSTXR(I) - ESFTXR(I) + EGTXRT(I)*
     2                  ESFTXR(I) + ESSTXR(I)*ESFTXR(I))
```

ELECTRIC REVENUES

```
C CALCULATE ELECTRIC REVENUES AS A FUNCTION OF REVENUE REQUIREMENTS
C AND THE REGULATORY LAG SCENARIO.
C NO LAG TO 1 YEAR LAG IN INCREMENTS OF 1/4 YEAR
            LAG = EILAG(I)
            IF ((LAG .GE. -1) .AND. (LAG .LE. 5) .AND. (LAG .NE. 0))
     1         THEN
               IF (LAG .EQ. -1) THEN
C EILAG IS -1 -- EARNED RETURN ON EQUITY IS INPUT
                  ERRVLG(I) = (ERAVCE(I)*ESERCE(I) + ERPSDV(I) +
     1                        EDISYR(I) - EPIND(I) - EPIRET(I) -
     2                        ERFDC(I) + ERTIEX(I) + ERTFLN(I) +
     3                        ERTOMN(I) + ERBDE(I) - ERAITC(I) +
```

```
 4826.          3                        ERQAMT(I) -
 4827.          4                        ERFITC(I) - ERAFDC(I) - ERFFDC(I) -
 4828.          5                        ERATSF(I) - EREDTF(I) + ESLLP(I) -
 4829.          6                        ESLAGN(I) + (ERPRTX(I) + ERSLTX(I))*
 4830.          7                        (1.0 - ESFTXR(I)) + (ERTFLN(I) +
 4831.          8                        ERTOMN(I) + ERTDWO(I) + ERTIEX(I) +
 4832.          8                        ERQAMT(I) +
 4833.          9                        ESLLP(I))*((-1.0*ESSTXR(I)) +
 4834.          *                        ESSTXR(I)*ESFTXR(I)) + (ERTFLN(I) +
 4835.          1                        ERTOMN(I) + ERTDWO(I) + (ERTIEX(I) -
 4836.          2                        ERCIDC(I)) + ESLLP(I) + ERQAMT(I))*
 4837.          3                        ((-1.0*ESFTXR(I))))/(1.0 - EGTXRT(I) -
 4838.          4                        ESSTXR(I) - ESFTXR(I) + EGTXRT(I)*
 4839.          5                        ESFTXR(I) + ESSTXR(I)*ESFTXR(I))
 4863.                          IF (LAG .EQ. 3) THEN
 4864.     C EILAG IS 3 -- 1/2 YEAR REGULATORY LAG
 4865.                             ERRVLG(I) = (0.5*ELRVRQ(I)) +
 4866.          1                                (0.5*ERRVRQ(I))
 4867.                          ELSE
 4868.                             IF (LAG .EQ. 4) THEN
 4869.     C EILAG IS 4 -- 3/4 YEAR REGULATORY LAG
 4870.                                ERRVLG(I) = (0.75*ELRVRQ(I)) +
 4871.          1                                   (0.25*ERRVRQ(I))
 4872.                             ELSE
 4873.                                IF (LAG .EQ. 5) THEN
 4874.     C EILAG IS 5 -- 1 YEAR REGULATORY LAG
 4875.                                   ERRVLG(I) = ELRVRQ(I)
 4876.                                ELSE
 4877.     C EILAG IS 2 -- 1/4 YEAR REGULATORY LAG
 4878.                                   ERRVLG(I) = (0.25*ELRVRQ(I)) +
 4879.          1                                      (0.75*ERRVRQ(I))
 4880.                                ENDIF
 4881.                             ENDIF
 4882.                          ENDIF
 4883.                       ELSE
 4884.     C EILAG IS 1 -- NO REGULATORY LAG
 4885.                          ERRVLG(I) = ERRVRQ(I)
```

LAST YEARS ACTUAL REVENUES

```
 4844.                          ELRVRQ(I) = ((ELRB(I)*ESRR(I) + ELTOMN(I) +
 4845.          1                           ERQAMT(I) +
 4846.          1                           ELBDE(I) - ELAITC(I) - ELFITC(I) -
 4847.          2                           ELAFDC(I) - ELFFDC(I) - ELOFFS(I) -
 4848.          3                           EREDTF(I) - EPIND(I) + ELLLP(I) -
 4849.          4                           ELLAGN(I) + (ELPRTX(I) +
 4850.          5                           ELSLTX(I))*(1.0 - ESFTXR(I)) +
 4851.          6                           (ELTOMN(I) + ELTDWO(I) +
 4852.          7                           ELTIEX(I) + ELLLP(I) + ERQAMT(I))*
 4853.          8                           ((-1.0*ESSTXR(I)) + ESSTXR(I)*
 4854.          9                           ESFTXR(I)) + (ELTOMN(I) +
 4855.          *                           ERTDRG(I) + ERQAMT(I) + (ELTIEX(I) -
 4856.          1                           ELCIDC(I)) + ELLLP(I))
 4857.          2                           *((-1.0*ESFTXR(I))))*EQTLSL(I)/
 4858.          3                           ELTLSL(I) + ERTFLN(I)*(1.0 -
 4859.          4                           ESSTXR(I))*(1.0 - ESFTXR(I)))/
 4860.          5                           (1.0 - EGTXRT(I) - ESSTXR(I) -
 4861.          6                           ESFTXR(I) + EGTXRT(I)*ESFTXR(I) +
 4862.          7                           ESSTXR(I)*ESFTXR(I))
```

ELECTRICITY PRICES

PROBABILITY OF CONTRIBUTION TO PEAK

```
 1639.              PCP(ICLS) = SECANNPEAAVPCP(NRGN,ICLS)

 1642.              DEMFAC(6,ICLS) = SECANNPEAAVPCP(NRGN,ICLS)/TOTAL
```

NON COINCIDENT PEAK

```
 1648.              NCP(ICLS) = SECANNUALPEAK(NRGN,ICLS,2)

 1651.              DEMFAC(7,ICLS) = SECANNUALPEAK(NRGN,ICLS,2)/TOTAL
```

ANNUAL AND EXCESS DEMAND WITH PROBABILITY OF CONTRIBUTION TO PEAK

```
              DEMFAC(9,ICLS) = SYSTEMLF(NRGN)*DEMFAC(1,ICLS) +
     1                         (1.0 - SYSTEMLF(NRGN))*DEMFAC(6,ICLS)
```

COST ALLOCATION FACTORS

```
                    COSTFC(ICOST,ICLS,ISECT) = (DEMFAC(ITECH,ICLS)
     1                                  *(TECFAC(ITECH,ICOST,ISECT)/100.0))
     2                                  + COSTFC(ICOST,ICLS,ISECT)
```

CUSTOMER CLASS REVENUE ALLOCATION

```
                 REV(ICLS,ISECT) = REV(ICLS,ISECT) +
     1                             COSTFC(ICOST,ICLS,ISECT)*
     1                       COST(ICOST,ISECT)
```

CUSTOMER CLASS PRICES

```
                 EPRICE(ICLS,ISECT,NRGN) = REV(ICLS,ISECT)/
     1                                     SALCLS(NRGN,ICLS)
```

"SUBSIDIZED" PRICES

```
C DETERMINE TOTAL REVENUES AND SALES TO RES, COM, AND IND
C BASED ON HISTORIC DATA AND MODEL OUTPUT

                IF (CURIYR .EQ. 1) THEN
                 REVHRCI=REVHRCI+REV90(ICLS,NRGN)
                 SLSHRCI=SLSHRCI+SAL90(ICLS,NRGN)
                ELSE
                 REVHRCI=REVHRCI+REV91(ICLS,NRGN)
                 SLSHRCI=SLSHRCI+SAL91(ICLS,NRGN)
                ENDIF
                 REVRCI=REVRCI+REV(ICLS,4)
                 SLSRCI=SLSRCI+SALCLS(NRGN,ICLS)

C CALCULATE PROPORTION OF REVENUES AND SALES TO RES,COM,AND IND
C BASED ON HISTORIC DATA AND MODEL OUTPUT
                 REVPCT(ICLS)=REV(ICLS,4)/REVRCI
                IF (CURIYR .EQ. 1) THEN
                 REVHPCT(ICLS)=REV90(ICLS,NRGN)/REVHRCI
                 SLSHPCT(ICLS)=SAL90(ICLS,NRGN)/SLSHRCI
                ELSE
                 REVHPCT(ICLS)=REV91(ICLS,NRGN)/REVHRCI
                 SLSHPCT(ICLS)=SAL91(ICLS,NRGN)/SLSHRCI
                 SLSPCT(ICLS)=SALCLS(NRGN,ICLS)/SLSRCI

C CALCULATE THE DIFFERENCE BETWEEN THE PROPORTION OF REVENUES AND
C THE PROPORTIONS OF SALES ALLOCATED TO EACH CLASS BASED ON
C HISTORIC DATA AND MODEL OUTPUT
                DIFFPCT(ICLS)=REVPCT(ICLS)-SLSPCT(ICLS)
                DIFFHPCT(ICLS)=REVHPCT(ICLS)-SLSHPCT(ICLS)

C DETERMINE IMPLIED SUBSIDY OF HISTORIC DATA -
C THE SUBSIDY IS THE PERCENT OF RESIDENTIAL,COMMERCIAL, AND
C INDUSTRIAL REVENUES TO BE REALLOCATED - A NEGATIVE SUBSIDY
C MEANS THAT THAT PARTICULAR CUSTOMER IS SUBSIDIZING OTHERS
           SUBPCT(ICLS,NRGN,CURIYR)=DIFFHPCT(ICLS)-DIFFPCT(ICLS)

C RECALCULATE THE CUSTOMER CLASS PRICES WITH SUBSIDIES

            EPRICE(ICLS,4,NRGN)=(REV(ICLS,4)+
     1                          (REVRCI*SUBPCT(ICLS,NRGN,CURIYR)))/
     2                             SALCLS(NRGN,ICLS)
```

Appendix C
Indices and Input/Output Variables

Following are the abbreviations used in the tables:

Units:

87 $/kw	1987 dollars per kilowatt
87 10^6$	million 1987 dollars
KWH	kilowatthours
MM $	thousands of dollars
MM $/EM	thousand dollars per energy mile
MW	megawatts
N/A	not applicable or not available
$/KW	dollars per kilowatt

Submodules, Models:

MACRO	Macroeconomic Activity Module
MAIN	Main calling routine of the National Energy Modeling System
UDAT	Common Utility Data File
UECP	Electricity Capacity Expansion submodule
UEFD	Electricity Fuel Dispatch submodule
ULDSM	Load and Demand Side Management submodule

Input File Names:

EFPALL	CN6005.PRJ.EFPALL.*scenario.datekey*
EFPCNTL	CN6005.PRJ.EFPCNTL.*scenario.datekey*
EFPTAX	CN6005.PRJ.EFPTAX.*scenario.datekey*
ETRANS	CN6005.PRJ.ETRANS.*scenario.datekey*
FINREG	CN6005.PRJ.FINREG.*scenario.datekey*
PHASEIN	CN6005.PRJ.PHASEIN.*scenario.datekey*
SALELB	CN6005.PRJ.UEFP.SALELB.*scenario.datekey*

Sources for Table 4:

EIA	Assumptions made by analysts at the Energy Information Administration (EIA).
EIA412	Energy Information Administration Form 412 and Rural Electrification

	Administration Form 7
ERTA	Economic Recovery Tax Act of 1981
FORM 1	Federal Energy Regulatory Commission (FERC) Form 1
RRA	*Regulatory Focus*, Regulatory Research Associates, Inc., Various Issues
S&PIS	Standard and Poors Industry Surveys, Utilties-Electric, Current Analysis, May 6, 1993, Page U5.
TRA	Tax Reform Act of 1986

References under "Block" (Table 2), "Common Block" (Table 4), or "Output To" (Table 5) are members of the partitioned data set CN6005.PRJ.NEMS.COMMON.PDS.*datekey*.

Table 1 Variable Indices

INDEX	DESCRIPTION	VALUES
EBNUM	NUMBER OF BUILDS	UP TO 300
EIPROD	NUMBER OF EFP PRODUCTION PLANT TYPES	12
EOVYRS	NUMBER OF VINTAGE YEARS	34
MNUMCR	NUMBER OF CENSUS REGIONS (INCLUDES TOTAL)	8
MNUMNR	NUMBER OF NERC REGIONS (INCLUDES TOTAL)	13
NCLASS	NUMBER OF CUSTOMER CLASSES	4
NCOMP	NUMBER OF OPERATING COMPONENTS	3
NCOST	NUMBER OF COST CATEGORIES	4
NERTA	NUMBER OF ERTA DEPRECIATION SCHEDULES	3
NOCAP	NUMBER OF PLANT TYPE REPORTS	UP TO 16
NOPREG	NUMBER OF PRINT REGIONS	UP TO 44
NOWN	NUMBER OF OWNERSHIP CATEGORIES (1=PRIVATE 2=PUBLIC)	2
NPI	NUMBER OF PHASE-IN PLANS	UP TO 125
NPTYP	NUMBER OF EFP PLANT TYPES	16
NSCHED	NUMBER OF TRA DEPRECIATION SCHEDULES	2
NSL	NUMBER OF SALE/LEASEBACK TRANSACTIONS	UP TO 30
NTECH	NUMBER OF ALLOCATION TECHNIQUES	9
NUMCAP	# OF PLANT TYPES IN EACH PLANT TYPE REPORT	UP TO 16
NYRCON	NUMBER OF YEARS IN TRA DEPRECIATION SCHEDULE	50
NYRCP	NUMBER OF YEARS IN CONSTRUCTION PROFILE	15
NYREDT	NUMBER OF YEARS TO FLOW BACK EXCESS DEFERRED TAXES	UP TO 20
NYRERT	NUMBER OF YEARS IN ERTA DEPRECIATION SCHEDULE	15
NYRPI	NUMBER OF YEARS IN PHASE-IN PLANS	UP TO 20
UNYEAR	NUMBER OF YEARS FOR MODEL TO SOLVE	21

Table 2 Input Variables From Other EMM Submodules					
VARIABLE	DESCRIPTION	INDICES	UNITS	SUBMOD.	BLOCK
EBPCAP	CAPACITY ASSOCIATED WITH EACH BUILD	EBNUM,NOWN	MW	UECP	EFPBLD
EBPCST	CAPITAL COST ASSOCIATED WITH EACH BUILD	EBNUM	87 $/KW	UECP	EFPBLD
EBPTYP	PLANT TYPE FOR EACH BUILD	EBNUM	N/A	UECP	EFPBLD
EBSERP	% OF YEAR PLANT IS IN SERVICE DURING THE FIRST YEAR	EBNUM	FRACTION	UECP	EFPBLD
EBSYR	YEAR WHICH PLANT COMES ON LINE	EBNUM	YEAR	UECP	EFPBLD
EOMW	VINTAGE CAPACITY EXISTING IN BASE YEAR	EOVYRS,NPROD, NOWN,MNUMNR	MW	UDAT	EFPIN
ERFFL(19)	NUCLEAR FUEL COSTS IN REAL DOLLARS	NONE	87 10^6$	UEFD	DISPOUT
ERTFL	TOTAL FUEL COSTS IN REAL DOLLARS	NOWN	87 10^6$	UEFD	DISPOUT
ERTOM	TOTAL PRODUCTION OPERATION & MAINTENANCE COSTS IN REAL DOLLARS	NOWN	87 10^6$	UEFD	DISPOUT
ETDMDE	REVENUES FROM ECONOMY POWER SALES	NONE	87 10^6$	UEFD	DISPOUT
ETDMDF	REVENUES FROM FIRM POWER SALES	NONE	87 10^6$	UECP	DISPOUT
ETDMME	ECONOMY POWER SALES	NONE	KWH	UEFD	DISPOUT
ETDMMF	FIRM POWER SALES	NONE	KWH	UECP	DISPOUT
ETEXPD	EXPORTED POWER (CANADA/MEXICO) REVENUES	NONE	87 10^6$	UEFD	DISPOUT
ETEXPE	EXPORTED POWER (CANADA/MEXICO) - ECONOMY	NONE	KWH	UEFD	DISPOUT
ETEXPF	EXPORTED POWER (CANADA/MEXICO) - FIRM	NONE	KWH	UECP	DISPOUT
ETGEN	TOTAL EWG GENERATION	NONE	KWH	UEFD	DISPOUT
ETIMPD	IMPORTED POWER (CANADA/MEXICO) COSTS	NONE	87 10^6$	UEFD	DISPOUT
ETIMPE	IMPORTED POWER (CANADA/MEXICO) - ECONOMY	NONE	KWH	UEFD	DISPOUT
ETIMPF	IMPORTED POWER (CANADA/MEXICO) - FIRM	NONE	KWH	UECP	DISPOUT

Table 2 Input Variables From Other EMM Submodules

VARIABLE	DESCRIPTION	INDICES	UNITS	SUBMOD.	BLOCK
EWGOWN	EWG - OWN USE	NONE	KWH	UEFD	DISPOUT
EWGRCC	EWG POWER COSTS	NONE	87 10^6$	UEFD	DISPOUT
EWGREV	EWG POWER COSTS	NONE	87 10^6$	UEFD	DISPOUT
EWGRIC	EWG POWER COSTS	NONE	87 10^6$	UEFD	DISPOUT
EWGRMW	EWG POWER COSTS	NONE	87 10^6$	UEFD	DISPOUT
MNUMCR	NUMBER OF CENSUS REGIONS (INCLUDES TOTAL)	NONE	YEARS	UDAT	PARAMETR
MNUMNR	NUMBER OF NERC REGIONS (INCLUDES TOTAL)	NONE	YEARS	UDAT	PARAMETR
SECANNUALPEAK	NON-COINCIDENT ANNUAL PEAK BY CUSTOMER CLASS	UNRGN,NCLS,2	MW	ULDSM	DSMTFEFP
SECANNUALPEAK	COINCIDENT ANNUAL PEAK BY CUSTOMER CLASS	UNRGN,NCLS,1	MW	ULDSM	DSMTFEFP
SYSTEMLF	ANNUAL SYSTEM LOAD FACTOR	UNRGN	MW	ULDSM	DSMTFEFP
TOTSECLOAD	SALES BY CUSTOMER CLASS	UNRGN,NCLS	MWH	ULDSM	DSMTFEFP

Table 3 Variables From Other NEMS Models

VARIABLE	DESCRIPTION	INDICES	UNITS	MODEL	BLOCK
CURIYR	CURRENT YEAR INDEX	NONE	NUMBER	MAIN	NCNTRL
MC_PGDP	GENERAL INFLATION INDEX (1987=1.0)	UNYEAR	NOM.RATE	MACRO	MACOUT
MC_RMPUAANS	NATIONAL YIELD ON NEW AA UTILITY BONDS	UNYEAR	NOM.RATE	MACRO	MACOUT
UNYEAR	NUMBER OF YEARS	NONE	NUMBER	MAIN	ECONTROL

Table 4 Input Variables From External Sources

VARIABLE	DESCRIPTION	INDICES	UNITS	DATA SOURCE*	COMMON BLOCK	INPUT FILE NAME
BKGAIN	BOOK GAIN ON SALE/LEASEBACK	NONE	MM $	RRA	NONE	SALELB
CAPTIT	PLANT TYPE NAMES FOR REPORT HEADERS	NOCAP	NONE	EIA	NAME	EFPCNTL
CONDR	TAX DEPRECIATION SCHEDULES UNDER TAX REFORM ACT OF 1986	NYRCON, NSCHED	FRACTION	TRA	TAX	EFPTAX
DISPER	FRACTION OF PLANT TOTALLY DISALLOWED	NPI	FRACTION	RRA	PHASIN	PHASEIN
DISPR1	FRAC. OF EXCESS CAPACITY DISALLOWANCE TO TREAT AS DISALLOW.	NONE	FRACTION	EIA	NONE	PHASEIN
DISPR2	FRAC. OF IMPRUDENCE DISALLOWANCE TO TREAT AS DISALLOW.	NONE	FRACTION	EIA	NONE	PHASEIN
DISPRU	IMPRUDENCE DISALLOWANCE	NONE	FRACTION	RRA	NONE	PHASEIN
DISXCS	EXCESS CAPACITY DISALLOWANCE	NONE	FRACTION	RRA	NONE	PHASEIN
EDIVRT	DIVIDEND PAYOUT RATIO	NOWN	FRACTION	FORM1/EIA	EFPRCY	FINREG
EGTXRT	GENERAL TAX RATE	NOWN	FRACTION	FORM1	EFPRC	FINREG
EIDIST	INDEX OF DISTRIBUTION BUILD	NONE	N/A	EIA	EFPGEN	NONE
EILAG	REGULATORY LAG (0 TO 1 YRS BY .25; VAL = 1 TO 5 BY 1)	NOWN	NONE	EIA	EFPRCY	FINREG
EINUC	NUCLEAR PLANT TYPE INDEX	NONE	N/A	EIA	EFPGEN	NONE
EITRAN	PLANT CODE FOR TRANSMISSION CAPITAL	NONE	N/A	EIA	EFPGEN	NONE
EOBKLF	BOOK LIFE FOR OLD ASSETS BY PLANT TYPE	NPTYP,NOWN	YEARS	EIA	EFPGEN	FINREG

Table 4 Input Variables From External Sources

VARIABLE	DESCRIPTION	INDICES	UNITS	DATA SOURCE*	COMMON BLOCK	INPUT FILE NAME
EOBKVL	BOOKED VALUE OF EXISTING ASSETS	EOVYRS, NPTYP,NOWN	MM $	FORM 1 EIA412	EFPTMP	FINREG
EODEPR	BOOK DEPRECIATION RATE FOR OLD ASSETS BY PLANT TYPE	NPTYP,NOWN	FRACTION	EIA	EFPGEN	FINREG
EOTXLF	TAX LIFE FOR OLD ASSETS	NPTYP,NOWN	YEARS	EIA	EFPGEN	FINREG
EOVYRS	NUMBER OF VINTAGE YEARS	NONE	YEARS	EIA	EFPGEN	FINREG
ERCCA	COST OF POST SERVICE CAPITAL EXPENDITURES	NPROD	$/KW	EIA	EFPR	FINREG
ESBKLF	BOOK LIFE FOR NEW ASSETS BY PLANT TYPE	NPTYP,NOWN	YEARS	EIA	EFPGEN	FINREG
ESCPRF	CONSTRUCTION PROFILE FOR EACH PLANT TYPE	NPTYP, NYRCP	FRACTION	EIA	EFPGEN	FINREG
ESCWPP	% CWIP IN RATE BASE FOR EACH YEAR	NOWN	FRACTION	EIA	EFPRCY	FINREG
ESDEPR	DEPRECIATION RATE FOR BOOK PURPOSES	NPTYP,NOWN	FRACTION	EIA	EFPGEN	FINREG
ESEMDB	EMBEDDED COST OF LONG TERM DEBT - BASE YEAR	NOWN	FRACTION	FORM 1 EIA412	EFPRC	FINREG
ESEMPB	EMBEDDED COST OF PREFERRED STOCK - BASE YEAR	NOWN	FRACTION	FORM 1	EFPRC	FINREG
ESFLPR	PERCENT OF DEFERRED TAX FLOWED THROUGH	NOWN	FRACTION	EIA	EFPRC	FINREG
ESFPDB	% FLOW THROUGH OF DEBT PORTION OF AFUDC	NOWN	FRACTION	EIA	EFPRC	FINREG

Table 4 Input Variables From External Sources

VARIABLE	DESCRIPTION	INDICES	UNITS	DATA SOURCE*	COMMON BLOCK	INPUT FILE NAME
ESLCP	LENGTH OF THE CONSTRUCTION PERIOD FOR EACH BUILD	NPTYP	YEARS	EIA	EFPGEN	FINREG
ESPRCE	PERCENT OF CAPITALIZATION FROM COMMON EQUITY	NOWN	FRACTION	FORM 1	EFPRCY	FINREG
ESPRLT	PERCENT OF CAPITAL OBTAINED WITH LONG TERM DEBT	NOWN	FRACTION	FORM 1	EFPRCY	FINREG
ESPRPS	PERCENT OF CAPITALIZATION FROM PREFERED STOCK	NOWN	FRACTION	FORM 1	EFPRCY	FINREG
ESPRST	PERCENT OF CAPITAL OBTAINED WITH SHORT TERM DEBT	NOWN	FRACTION	FORM 1	EFPRCY	FINREG
ESRBAF	% OF AFUDC/CWIP WHICH RECEIVES OFFSET TREATMENT	NOWN	FRACTION	EIA	EFPRC	FINREG
ESRITC	INVESTMENT TAX CREDIT RATE	NPTYP	FRACTION	ERTA	TAX	EFPTAX
ESRTCE	COST OF COMMON EQUITY - FOR EACH YEAR 1990-92	NOWN	FRACTION	S&PIS	EFPRCY	FINREG
ESRTLT	COST OF NEW LONG TERM DEBT - FOR EACH YEAR 1990-92	NOWN	FRACTION	FORM 1 EIA412	EFPRCY	FINREG
ESRTPS	COST OF PREFERED STOCK - FOR EACH YEAR 1990-92	NOWN	FRACTION	FORM 1	EFPRCY	FINREG
ESRTST	COST OF NEW SHORT TERM DEBT - FOR EACH YEAR 1990-92	NOWN	FRACTION	FORM 1 EIA412	EFPRCY	FINREG
ESSLTX	SALES TAX RATE	NOWN	FRACTION	EIA	EFPRC	FINREG
ESTSHR	PRIVATE/PUBLIC GENERATION SHARE	NOWN	FRACTION	FORM 1/EIA	EFPRCY	FINREG
ESTXLF	TAX LIFE FOR NEW ASSETS UNDER SYD METHOD	NPTYP,NOWN	YEARS	EIA	EFPGEN	FINREG

Table 4 Input Variables From External Sources

VARIABLE	DESCRIPTION	INDICES	UNITS	DATA SOURCE*	COMMON BLOCK	INPUT FILE NAME
ESTXRC	TAX RECOVERY CLASS (ERTA) FOR NEW ASSETS BY PLANT TYPE	NPTYP,NOWN	N/A	ERTA	EFPGEN	FINREG
ESTXRP	TAX RECOVERY PERIOD (ERTA) FOR EACH RECOVERY CLASS	NERTA	YEARS	ERTA	TAX	EFPTAX
ESTXRS	TAX RECOVERY SCHEDULE (ERTA) FOR EACH RECOVERY CLASS	NERTA, NYRERT	FRACTION	ERTA	TAX	EFPTAX
ETEMOM	TRANSMISSION ENERGY-MILE O&M COSTS	UNYEAR, MNUMNR	MM $/EM	EIA	TRANS	ETRANS
FRACRG	FRACTIONS TO AGGREGATE/DISAG INPUT REG'S TO PRINT REG'S	MNUMNR, NOPREG	N/A	EIA	RUN	EFPCNTL
FREDTF	FRACTION OF TOTAL FLOWED BACK IN EACH YEAR (IF IEDT = 2)	NYREDT	FRACTION	EIA	TAX	EFPTAX
IASMPT	ASSUMPTION CODE FOR EACH PHASE-IN	NONE	1-3	RRA	NONE	PHASEIN
IASSMP	LOWEST ASSUMPTION CODE TO USE IN THIS RUN (SCREENING VAR.)	NONE	1-3	RRA	NONE	PHASEIN
IBYRPI	1ST YEAR OF PHASE-IN PERIOD	NPI	YEAR	RRA	PHASIN	PHASEIN
IBYRSL	YEAR OF SALE/LEASEBACK PLAN	NSL	YEAR	RRA	SALELB	SALELB
ICAPYR	YEAR IDC PROPOSAL IS IMPLEMENTED	NONE	YEAR	TRA	TAX	EFPTAX
IEDT	METHOD USED FOR FLOW BACK OF EXCESS DEFERRED TAXES	NONE	1,2	EIA	TAX	EFPTAX
IPCOMP	FLAGS INDICATING THE OPERATING COMPONENTS TO PRINT	NCOMP+1	0,1	EIA	RUN	EFPCNTL
IPOWN	FLAGS INDICATING WHICH OWNERSHIP CLASSES TO PRINT	NOWN+1	0,1	EIA	RUN	EFPCNTL

Table 4 Input Variables From External Sources

VARIABLE	DESCRIPTION	INDICES	UNITS	DATA SOURCE*	COMMON BLOCK	INPUT FILE NAME
IPREG	FLAGS INDICATING THE REGIONS TO BE PRINTED	NOPREG+1	0,1	EIA	RUN	EFPCNTL
IPRPT	FLAGS INDICATING WHICH REPORTS (LARGE/SMALL) TO PRINT	2	0,1	EIA	RUN	EFPCNTL
IRDPI	CAPITALIZE RETURN ON DEFERRED COST? (1=YES,2=NO)	NPI	1,2	RRA	PHASIN	PHASEIN
IREAL$	FLAG INDICATING IF REPORTS ARE IN REAL OR NOMINAL $	NONE	0,1	EIA	RUN	EFPCNTL
IROPI	OWNERSHIP TYPE OF PHASE-IN PLAN	2,NPI	1,2	RRA	PHASIN	PHASEIN
IROPI	REGION OF PHASE-IN PLAN	1,NPI	1-14	RRA	PHASIN	PHASEIN
IROSL	OWNERSHIP TYPE OF SALE/LEASEBACK	2,NSL	1,2	RRA	SALELB	SALELB
IROSL	REGION OF SALE/LEASEBACK	1,NSL	1-14	RRA	SALELB	SALELB
IRSYP	FIRST YEAR IN WHICH NEW GEN. PLANT USES TRA DEPREC. SCHED.	NONE	YEAR	TRA	TAX	EFPTAX
IRSYTD	FIRST YEAR IN WHICH NEW T&D PLANT USES TRA DEPREC. SCHED.	NONE	YEAR	TRA	TAX	EFPTAX
IYREDT	FIRST YEAR IN WHICH EXCESS SHOULD BE FLOWED BACK	NONE	YEAR	TRA	TAX	EFPTAX
IYRITC	YEAR ITC PROPOSAL IS IMPLEMENTED	NONE	YEAR	TRA	TAX	EFPTAX
IYRRL$	YEAR IN WHICH TO REPORT REAL DOLLARS	NONE	YEAR	EIA	RUN	EFPCNTL
JYRITC	FIRST START YEAR OF EFFECTED PLANTS	NONE	YEAR	TRA	TAX	EFPTAX

Table 4 Input Variables From External Sources

VARIABLE	DESCRIPTION	INDICES	UNITS	DATA SOURCE*	COMMON BLOCK	INPUT FILE NAME
LPI	LENGTH OF PHASE-IN PLAN	NPI	YEARS	RRA	PHASIN	PHASEIN
NAME3	REPORT TITLE	NONE	N/A	EIA	NAME	EFPCNTL
NCOST	NUMBER OF COST CATEGORIES	NONE	N/A	EIA	CA	EFPALL
NOCAP	# OF PLANT TYPE REPORTS	NONE	N/A	EIA	RUN	EFPCNTL
NOPREG	NUMBER OF PRINT REGIONS	NONE	N/A	EIA	RUN	EFPCNTL
NPI	TOTAL NUMBER OF PHASE-IN PLANS	NONE	N/A	RRA	PHASIN	PHASEIN
NSL	TOTAL NUMBER OF SALE/LEASEBACK TRANSACTIONS	NONE	N/A	RRA	SALELB	SALELB
NTECH	NUMBER OF ALLOCATION TECHNIQUES	NONE	N/A	EIA	CA	EFPALL
NUMCAP	# OF PLANT TYPES IN EACH PLANT TYPE REPORT	NOCAP	N/A	EIA	RUN	EFPCNTL
NYREDT	NUMBER OF YEARS TO FLOW BACK (IF IEDT=2)	NONE	YEARS	EIA	TAX	EFPTAX
PIBKLF	BOOK LIFE OF PHASED-IN PLANT	NONE	YEARS	EIA	PHASIN	PHASEIN
PIBKVL	BOOK VALUE OF PLANT TO BE PHASED-IN	NPI	MM $	RRA	PHASIN	PHASEIN
PIDFS	CUMULATIVE FRACTION OF TOTAL COST PHASED-IN BY YEAR	NYRPI,NPI	FRACTION	RRA	PHASIN	PHASEIN
PIRCS	FRAC. OF REMAINING DEFERRED REV'S. TO BE RECOVERED BY CLASS	NYRPI,NPI	FRACTION	RRA	PHASIN	PHASEIN
PITXBS	TAX BASIS AS A FRACTION OF BOOKED COST OF PHASE-IN PLANT	NONE	FRACTION	EIA	PHASIN	PHASEIN

Table 4 Input Variables From External Sources

VARIABLE	DESCRIPTION	INDICES	UNITS	DATA SOURCE*	COMMON BLOCK	INPUT FILE NAME
REVHRCI	THE TOTAL REVENUES ALLOCATED TO THE RESIDENTIAL, COMMERCIAL, AND INDUTRIAL CLASSES	NONE	MM $	FORM1 EIA412	EFPINT	N/A
SAL90 SAL91	THE SUM OF THE SALES TO THE RESIDENTIAL, COMMERCIAL, AND INDUSTRIAL CLASSES IN 1990 AND 1991	ICLS,NRGN	KWH	FORM1 EIA412	EFPINT	N/A
SLLP	ANNUAL LEASE PAYMENT	NSL	MM $	RRA	SALELB	SALELB
SLPROC	GROSS SALE PROCEEDS	NSL	MM $	RRA	SALELB	SALELB
SLTAXS	INCOME TAXES ON SALES/LEASEBACK TRANSACTIONS	NSL	MM $	RRA	SALELB	SALELB
SLTERM	TERM OF THE LEASE (YEARS)	NSL	YEARS	RRA	SALELB	SALELB
TRABDE	TOTAL ACCUMULATED BOOK DEPRECIATION - BASE YEAR	NOWN	MM $	FORM 1 EIA412	NONE	FINREG
TRAMD	TOTAL ASSETS MINUS DEFERRALS - BASE YEAR	NOWN	MM $	FORM 1 EIA412	NONE	FINREG
TRCS	TOTAL COMMON STOCK - BASE YEAR	NOWN	MM $	FORM 1	NONE	FINREG
TRDITC	ACCUMULATED DEFERRED ITC - BASE YEAR	NOWN	MM $	FORM 1	NONE	FINREG
TROB	TOTAL LONG TERM DEBT - BASE YEAR	NOWN	MM $	FORM 1 EIA412	NONE	FINREG
TRPRDF	TOTAL DEFERRED TAXES - BASE YEAR	NOWN	MM $	FORM 1	NONE	FINREG
TRPS	TOTAL PREFERRED STOCK - BASE YEAR	NOWN	MM $	FORM 1	NONE	FINREG

Table 4 Input Variables From External Sources						
VARIABLE	DESCRIPTION	INDICES	UNITS	DATA SOURCE*	COMMON BLOCK	INPUT FILE NAME
TRRE	TOTAL RETAINED EARNINGS - BASE YEAR	NOWN	MM $	FORM 1	NONE	FINREG
TRRVRQ	ELECTRIC REVENUES - BASE YEAR	NOWN	MM $	FORM 1	NONE	FINREG
TRST	TOTAL SHORT TERM DEBT - BASE YEAR	NOWN	MM $	FORM 1	NONE	FINREG
TRWC	WORKING CAPITAL	NOWN	MM $	FORM 1	NONE	FINREG
TXRTYR	FEDERAL STATUTORY TAX RATE	UNYEAR	FRACTION	TRA/EIA	TAX	EFPTAX
UTEMCP	TRANSMISSION ENERGY-MILE CAPITAL COST	UNYEAR, MNUMNR	MW/EM	EIA	TRANS	ETRANS

Table 5 Output Variables Calculated Within The EFP

VARIABLE	DESCRIPTION	INDICES	UNITS	SUBROUTINE OR FUNCTION	OUTPUT TO
BALSHT	BALANCE SHEET REPORT	26	MM $	STMTS	REPORT
CANPLT	CANCELED PLANT REPORT	3	MM $	STMTS	REPORT
CAPREQ	CAPITAL REQUIREMENTS REPORT	NOCAP,6	MM $	STMTS	REPORT
COST	COMPONENTS OF COST	NCOST,NCOMP	MM $	STMTS	REPORT
COSTFC	FACTORS TO ALLOCATE COST POOLS TO RATE CLASSES	NCOST,NCLASS, NCOMP	FRACTION	ALLOCT	EFPRP2
CSTCAP	COST OF CAPITAL REPORT	11	FRACTION	STMTS	REPORT
DEMFAC	FACTORS FOR SECTOR SPLITS BY ALLOCATION TECHNIQUE	NTECH,NCLASS	FRACTION	ALLFAC	CA
DISPER	FRACTION OF PLANT TOTALLY DISALLOWED	NPI	FRACTION	ELRDPI	PHASIN
EBAFDC	AMORITIZATION OF AFUDC TAX SAVINGS FROM NEW ASSETS	NOWN,IBNUM	MM $	ELCWIP	EFPBLD
EBASVL	TAX BASIS OF ASSETS	NOWN,IBNUM	MM $	ELCWIP	EFPBLD
EBBKVL	BOOK VALUE OF ASSETS	NOWN,IBNUM	MM $	ELCWIP	EFPBLD
EBDITC	DEFERRED ITC FROM NEW ASSETS	NOWN,IBNUM	MM $	ELITC	EFPBLD
EBRCWP	CWIP IN RATE BASE BY BUILD	NOWN,IBNUM	MM $	ELCWIP	EFPBLD
EBYCWP	ANNUAL CONSTRUCTION EXPENDITURES BY PLANT	NOWN,IBNUM	MM $	ELCWIP	EFPBLD
EDISNT	NET DISALLOWED PLANT FOR YEAR	NOWN	MM $	ELPHIN	EFPINT
EDISYR	GROSS PLANT DISALLOWED IN THIS YEAR	NOWN	MM $	ELPHIN	EFPINT
EPAFDC	BOOKED AFUDC IN CURRRENT YEAR	NPTYP,NOWN	MM $	ELCWIP	EFPINT
EPIDEF	TOTAL CUMULATIVE DEFERRED PHASE-IN REVENUES	NOWN	MM $	ELPHIN	EFPINT
EPIND	NET-DEFERRED PHASE-IN REVENUES FOR YEAR	NOWN	MM $	ELPHIN	EFPINT

Table 5 Output Variables Calculated Within The EFP

VARIABLE	DESCRIPTION	INDICES	UNITS	SUBROUTINE OR FUNCTION	OUTPUT TO
EPIRET	CAPITALIZED RETURN ON DEFERRED REVENUES FOR YEAR	NOWN	MM $	ELPHIN	EFPINT
EPONLN	BOOK VALUE OF CAPACITY COMPLETED IN CURRENT YEAR	NPTYP,NOWN	MM $	ELCWIP	EFPINT
EPRICE	PRICES PASSED TO NEMS REPORT WRITER	NCLASS,NSECT, MNUMNR	MM $	RATES	EFPRP2
EPYCWP	DIRECT CONSTRUCTION EXPENDITURES FOR YEAR (NO AFUDC)	NPTYP,NOWN	MM $	ELCWIP	EFPINT
ERABDE	ACCUMULATED BOOK DEPRECIATION ALL ASSETS	NOWN	MM $	ELBKDP	EFPINT
ERAFDC	AMORTIZATION OF AFUDC TAX SAVINGSFOR ALL ASSETS	NOWN	MM $	ELTSAF	EFPINT
ERAFDL	RATE BASE ADJ. FOR PLTS. COMING ON IN MID YR. (EOY RB. ONLY)	NOWN	MM $	ELCWIP	EFPINT
ERAITC	AMORTIZATION/YEAR OF DEFERRED ITC	NOWN	MM $	ELITC	EFPINT
ERAMD	TOTAL VALUE OF ASSETS TO BE FINANCED	NOWN	MM $	ELINEX	EFPINT
ERATSD	ACCELERATED DEPRECIATION TAX SAVINGS - DEFERRED	NOWN	MM $	ELTXDP	EFPINT
ERATSF	ACCELERATED TAX DEPRECIATION SAVINGS - FLOWED THROUGH	NOWN	MM $	ELTXDP	EFPINT
ERAVCE	AVERAGE COMMON EQUITY BALANCE IN CURRENT YEAR	NOWN	MM $	ELINEX	EFPINT
ERBCWP	TOTAL BOOKED CWIP (INCLUDES AFUDC)	NOWN	MM $	ELCWIP	EFPINT
ERBDE	BOOK DEPRECIATION FOR ALL ASSETS	NOWN	MM $	ELBKDP	EFPINT
ERBDED	DEPRECIATION EXPENSE FOR DISALLOWED PLANT	NOWN	MM $	ELPHIN	EFPINT

Table 5 Output Variables Calculated Within The EFP

VARIABLE	DESCRIPTION	INDICES	UNITS	SUBROUTINE OR FUNCTION	OUTPUT TO
ERBNDL	LAST YEARS LONG TERM DEBT	NOWN	MM $	ELINEX	EFPINT
ERBOND	NEW LONG TERM DEBT	NOWN	MM $	ELINEX	EFPINT
ERBTIR	BOOK VALUE OF ALL RETIREMENTS	NOWN	MM $	ELBKDP	EFPINT
ERCIDC	CAPITALIZED INTEREST DURING CONSTRUCTION FOR TAXES	NOWN	MM $	ELCWIP	EFPINT
ERCNAD	ACCUMULATED AMORTIZATION FOR CANCELED PLANT	NOWN	MM $	ELBKDP	EFPINT
ERCNBV	BOOK VALUE OF CANCELED PLANT	NOWN	MM $	ELBKDP	EFPINT
ERDLRB	CHANGE IN RATE BASE DUE TO BUILDS GOING INTO RB ON JAN.1	NOWN	MM $	ELCWIP	EFPINT
EREDTF	AMOUNT OF EXCESS TO BE FLOWED THROUGH THIS YEAR	NOWN	MM $	ELEDT	EFPINT
ERFDC	TOTAL ANNUAL AFUDC	NOWN	MM $	ELCWIP	EFPINT
ERFDCD	DEBT PORTION OF TOTAL AFUDC	NOWN	MM $	ELCWIP	EFPINT
ERFDCE	EQUITY PORTION OF TOTAL AFUDC	NOWN	MM $	ELCWIP	EFPINT
ERFFDC	AMOUNT OF AFUDC TAX SAVINGS FLOWED THROUGH	NOWN	MM $	ELCWIP	EFPINT
ERFFDC	AMOUNT OF AFUDC TAX SAVINGS FLOWED THROUGH	NOWN	MM $	ELCWIP	EFPINT
ERFITC	AMOUNT OF ITC FLOWED THROUGH FOR RATEMAKING	NOWN	MM $	ELITC	EFPINT
ERLIEX	LONG TERM INTEREST EXPENSE	NOWN	MM $	ELINEX	EFPINT
ERNFSN	NUCLEAR FUEL STOCK IN NOMINAL DOLLARS	NOWN	MM $	ELCEXP	EFPINT
ERNITC	TOTAL DEFERRED ITC NET OF AMORITIZED DEFERRALS	NOWN	MM $	ELITC	EFPINT
EROB	OUTSTANDING BONDS	NOWN	MM $	ELINEX	EFPINT

Table 5 Output Variables Calculated Within The EFP

VARIABLE	DESCRIPTION	INDICES	UNITS	SUBROUTINE OR FUNCTION	OUTPUT TO
EROBL	LAST YEARS OUTSTANDING BONDS	NOWN	MM $	ELINEX	EFPINT
EROFFS	TOTAL AFUDC OFFSET	NOWN	MM $	ELCWIP	EFPINT
ERPF	TOTAL OUTSTANDING PREFERRED STOCK ISSUED BEFORE BASE YEAR	NOWN	MM $	ELINEX	EFPINT
ERPRDF	PROVISION FOR DEFERRED TAXES	NOWN	MM $	ELTXDP	EFPINT
ERPREF	TOTAL NEW PREFERRED STOCK	NOWN	MM $	ELINEX	EFPINT
ERPRTX	PROPERTY TAX ON BOOK VALUE OF PLANTS	NOWN	MM $	ELCWIP	EFPINT
ERPSDV	TOTAL PREFERRED STOCK DIVIDENDS IN CURRENT YEAR	NOWN	MM $	ELINEX	EFPINT
ERRB	RATE BASE	NOWN	MM $	ELREVS	EFPINT
ERRBRR	RATE BASE USED FOR SETTING REVENUE REQUIREMENTS	NOWN	MM $	ELREVS	EFPINT
ERRCWP	TOTAL CWIP IN RATE BASE	NOWN	MM $	ELCWIP	EFPINT
ERRVLG	ACTUAL REVENUES DEPENDING ON LAG SCENARIO	NOWN	MM $	ELREVS	EFPINT
ERRVRQ	REVENUE REQUIREMENTS FOR CURRENT YEAR	NOWN	MM $	ELREVS	EFPINT
ERSIEX	SHORT TERM INTEREST EXPENSE	NOWN	MM $	ELINEX	EFPINT
ERSLTX	SALES TAX ON YEARLY CWIP EXPENDITURES	NOWN	MM $	ELCWIP	EFPINT
ERTDRG	TAX DEPRECIATION USED FOR REGULATORY PURPOSES	NOWN	MM $	ELTXDP	EFPINT
ERTDWO	TAX DEPRECIATION W/O ACCELERATION FOR ALL ASSETS	NOWN	MM $	ELBKDP	EFPINT
ERTFLN	TOTAL FUEL COSTS IN NOMINAL DOLLARS	NOWN	MM $	ELCEXP	EFPINT
ERTIEX	TOTAL INTEREST EXPENSE	NOWN	MM $	ELINEX	EFPINT

Table 5 Output Variables Calculated Within The EFP

VARIABLE	DESCRIPTION	INDICES	UNITS	SUBROUTINE OR FUNCTION	OUTPUT TO
ERTOMN	TOTAL O&M IN NOMINAL DOLLARS	NOWN	MM $	ELCEXP	EFPINT
ERTOMT	TOTAL TRANSMISSION RELATED O&M EXPENSES REAL DOLLARS	NOWN	MM $	ELTRAN	EFPINT
ERTUP	TOTAL UTILITY PLANT IN SERVICE	NOWN	MM $	ELBKDP	EFPINT
ERWC	WORKING CAPITAL	NOWN	MM $	ELCEXP	EFPINT
ERXFDC	DEFERRED AFUDC TAX SAVINGS	NOWN	MM $	ELCWIP	EFPINT
ERYCWP	TOTAL YEARLY CWIP W/O AFUDC	NOWN	MM $	ELCWIP	EFPINT
ESAFDC	AFUDC RATE	NOWN	FRACTION	ELADCR	EFPINT
ESEMDT	EMBEDDED COST OF DEBT	NOWN	FRACTION	ELINEX	EFPINT
ESEMPS	EMBEDDED COST OF PREFERRED STOCK	NOWN	FRACTION	ELINEX	EFPINT
ESLAGN	TOTAL REGIONAL AMORTIZATION OF GAIN FROM SALE/LEASEBACK	NOWN	MM $	ELSL	EFPINT
ESLLP	TOTAL REGIONAL LEASE PAYMENT	NOWN	MM $	ELSL	EFPINT
ESLNDG	TOTAL REGIONAL NET DEFERRED GAIN	NOWN	MM $	ELSL	EFPINT
ESLPRC	NET OF TAX SALES PROCEEDS	NOWN	MM $	ELSL	EFPINT
ESRR	RATE OF RETURN (WEIGHTED AVERAGE COST OF CAPITAL)	NOWN	FRACTION	ELREVS	EFPINT
ESRTCE	COST OF COMMON EQUITY	NOWN	FRACTION	CAPCOST	EFPINT
ESRTLT	COST OF NEW LONG TERM DEBT	NOWN	FRACTION	CAPCOST	EFPINT
ESRTPS	COST OF NEW PREFERRED STOCK	NOWN	FRACTION	CAPCOST	EFPINT
ESRTST	COST OF SHORT TERM DEBT	NOWN	FRACTION	CAPCOST	EFPINT
ESWACD	DEBT FRACTION OF AFUDC	NOWN	FRACTION	ELADCR	EFPINT
FUNDS	SOURCES/USES OF FUNDS REPORT	21	MM $	STMTS	REPORT
PIDEF	TOTAL CUMULATIVE DEFERRED REVENUES	NPI	MM $	ELRDPI	PHASIN

Table 5 Output Variables Calculated Within The EFP

VARIABLE	DESCRIPTION	INDICES	UNITS	SUBROUTINE OR FUNCTION	OUTPUT TO
REV	REVENUES BY RATE CLASS AND STAGE OF PRODUCTION	NCLASS, NCOMP+1	MM $	ALLOCT	EFPRP2
REVREQ	REVENUE REQUIREMENTS REPORT	24	MM $	STMTS	REPORT
SALES	SALES REPORT	2	MM $	STMTS	REPORT
SLGAIN	NET OF TAX GAIN OVER BOOK VALUE FROM SALE	NSL	MM $	ELRDSL	SALELB
TAXINC	TAX INCOME REPORT	19	MM $	STMTS	REPORT
TBALSH	TEMPORARY BALANCE SHEET REPORT	UNYEAR,26	MM $	TMPSET	EFPWRT
TCANPL	TEMPORARY CANCELED PLANT REPORT	UNYEAR,3	MM $	TMPSET	EFPWRT
TCAPRE	TEMPORARY CAPITAL REQUIREMENTS REPORT	UNYEAR,NOCAP, 6	MM $	TMPSET	EFPWRT
TCSTCA	TEMPORARY COST OF CAPITAL REPORT	UNYEAR,11	MM $	TMPSET	EFPWRT
TFUNDS	TEMPORARY SOURCES/USES OF FUNDS REPORT	UNYEAR,21	MM $	TMPSET	EFPWRT
TREVRE	TEMPORARY REVENUE REQUIREMENTS REPORT	UNYEAR,24	MM $	TMPSET	EFPWRT
TSALES	TEMPORARY SALES REPORT	UNYEAR,2	MM $	TMPSET	EFPWRT
TTAXIN	TEMPORARY TAX INCOME REPORT	UNYEAR,19	MM $	TMPSET	EFPWRT
TXINCS	TEMPORARY INCOME STATEMENT REPORT	UNYEAR,20	MM $	TMPSET	EFPWRT
UOABDE	ACCUM BOOK DEP FOR EXISTING ASSETS BY VINTAGE YEAR	EOVYRS,NPTYP, NOWN	MM $	ELEA	EFPR
UOAFDC	AMORT OF AFDC BY PLANT, REGION, AND OWNERSHIP *	EOVYRS,NPTYP, NOWN	MM $	ELEA	EFPR
UOAITC	AMORITIZATION OF DEFERRED ITC FROM EXISTING ASSETS	EOVYRS,NPTYP, NOWN	MM $	ELEA	EFPR

Table 5 Output Variables Calculated Within The EFP

VARIABLE	DESCRIPTION	INDICES	UNITS	SUBROUTINE OR FUNCTION	OUTPUT TO
UOASVL	ASSET VALUE OF EXISTING ASSETS BY VINTAGE YEAR	EOVYRS,NPTYP, NOWN	MM $	ELEA	EFPR
UOBKVL	BOOKED VALUE OF EXISTING ASSETS BY VINTAGE YEAR	EOVYRS,NPTYP, NOWN	MM $	ELEA	EFPR
UREDTF	SAME AS EREDTF, BUT BY YEAR AND REGION	MNUMNR, UNYEAR	MM $	ELEDT	EFPINT
XINCST	INCOME STATEMENT REPORT	20	MM $	STMTS	REPORT

Appendix D
Bibliography

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Appendix E
Model Abstract

Model name:	Electricity Finance and Pricing Submodule
Model Acronym:	EFP
Description:	The EFP is a regulatory accounting model that projects electricity prices. The model first solves for revenue requirements[27] by building up a ratebase[28], calculating a return on rate base, and adding the allowed expenses. Average revenues (prices) are calculated based on assumptions regarding regulatory lag and customer cost allocation methods. The model then solves for the internal cash flow and analyzes the need for external financing to meet necessary capital expenditures. Finally, the EFP builds up the financial statements.
Purpose of Model:	The EFP is used in conjunction with the National Energy Modeling System (NEMS). Inputs to the EFP include the forecast generating capacity expansion plans, operating costs, regulatory environment, and financial data. The outputs include forecasts of income statements, balance sheets, revenue requirements, and electricity prices.
Model Update Information:	Updated for the Annual Energy Outlook, 1994, December 17, 1993
Part of Another Model:	Electricity Market Module
Model Interface References:	Electricity Market Module of the National Energy Modeling System
Official Model Representative	
Office:	Office of Integrated Analysis and Forecasting
Division:	Energy Supply and Conversion Division
Branch:	Nuclear and Electricity Analysis Branch
Model contact person:	Art Holland
Phone number:	(202)596-2026
Documentation References:	Draft Documentation Dated March 21, 1994

[27]Revenue requirements are the costs that a ratemaking authority allows a regulated utility to recover from ratepayers.

[28]The **ratebase** is the total value (original cost less accumulated straight line depreciation and excluded tax deferrals) of all capitalized assets on which the regulated utility is allowed by a ratemaking authority to earn a return.

Archive Media and Installation Manual:
Archived as Part of the National Energy Modeling System

Energy System Described by the Model:
Financial impacts of electric utilities' plans and operations

Coverage	
Geographic:	National and regional
Time unit Frequency:	Annual
Product:	Electricity
Economic Sectors:	Residential, Commercial, Industrial, Transportation
Modeling Features	
Model Structures:	Finance and Accounting
Modeling Technique:	Deterministic
Input Data	
Non-DOE:	*Regulatory Focus* Regulatory Research Associates, Inc. Various Issues
	Rural Electrification Administration Form 7, *Statistical Report, Rural Electric Borrowers*
	Standard and Poors Industry Surveys *Utilities-Electric, Current Analysis* May 6, 1993
DOE:	Federal Energy Regulatory Commission Form1, "Annual Report of Major electric Utilities, Licensees and Others"
	Energy Information Administration Form 412, "Annual Report on Public Electric Utilities"
Computing Environment:	FORTRAN on an IBM mainframe computer

Independent Expert Reviews Conducted:
Howard Thompson (University of Wisconsin)
Doug Bohi (Resources for the Future)

Status of Evaluation Efforts Conducted by the Model's Sponsor: None to Date.

Appendix F
Data Quality and Estimation

This section describes the quality of the data used in the EFP and the estimation techniques used to prepare the data for use in the model. The individual data items are listed in Table 4 of Appendix C along with their sources. The quality of the sources is discussed in this section.

Regulatory Focus, Regulatory Research Associates, Inc. (RRA), Various Issues

These data items include those that pertain to rate phase-in plans, regulatory disallowances, and sales/leaseback arrangements made by electric utilities. These data items are entered on a case by case basis from accounts of rate cases. That is, data items are gleaned by analysis from specific textual descriptions of rate phase-in plans, regulatory disallowances, and sales-leaseback plans as described in accounts of rate cases that are published weekly by RRA in the publication Regulatory Focus. RRA reports include detailed coverage of eighty major investor-owned electric utilities.

Imprudence and excess capacity disallowances are generally reported directly in these accounts, as is the cost of new generating plants so that the fraction of the plant disallowed may be calculated. For data items related to sales-leaseback and rate phase-in plans, most are reported either directly or may be calculated from the data provided. These items include:

- book gain on sale/leaseback (sales price - utility cost to build),
- first year of phase-in period,
- year of sale/leaseback plan,
- capitalize return on deferred cost (yes or no),
- ownership type (public or private) and region of the rate phase-in or sales/leaseback plan,
- length of phase-in plan,
- book value of plant to be phased in,
- all data items regarding the rate at which total costs and deferred costs are to be phased into rates (cumulative),
- annual lease payments,
- gross sales proceeds,
- income taxes on the proceeds, and
- terms (in years) of leases.

The remaining data items concerning sales-leaseback and rate phase-in plans - assumption code for each phase-in, lowest assumption code to use in this run, and the total number of rate phase-in and sales/leaseback transactions - are judgements concerning the analyst's confidence in each record (data from each specific rate case), how to treat these assumptions in the NEMS run, and simple summations respectively.

Economic Recovery Act of 1981 (ERTA) and the Tax Reform Act of 1986 (TRA)

All of the data items from both of these sources are specified in the legislation. Data from these sources includes:

- tax depreciation schedules,
- investment tax credit rate,
- tax recovery periods, and
- first year to flow back excess deferred taxes.

Standard and Poors Industry Surveys (S&PIS), Utilities-Electric Current Analysis, Standard and Poors Corporation, May 6, 1993

This source is used for one data item, the cost of common equity, for each year 1990 through 1992. These are national numbers read in directly from the text on page U5.

Energy Information Administration Form 412 (EIA412), the Rural Electrification Administration Form 7 (REA7), and the Federal Energy Regulatory Commission (FERC) Form 1 (FORM1)

These data sources are discussed together because the same data items come from these sources for both investor-owned and publicly-owned utilities unless specifically mentioned below. Input data for investor-owned electric utilities comes from the FERC Form1. Input data for Federal power projects and municipal power authorities (publicly-owned) comes from the EIA412, and data inputs for cooperatives (publicly-owned) comes from the REA7. All data items are aggregated to the Electricity Market Module by mapping routines before being input into the model or used to calculate the following data inputs.

The FERC Form 1 is the survey, "Annual Report of Major Electric Utilities, Licensees and Others". Respondents are discussed in detail in the Financial Statistics of Selected Investor Owned Electric Utilities, 1993 published by the Energy Information Administration. The EIA Form 412 is the "Annual Report of Public Electric Utilities" survey. The data for cooperatives is from the "Statistical Report, Rural Electric Borrowers". The respondents to the Rural Electrification Administration Form 7 and the EIA Form 412 are described in the Financial Statistics of Selected Publicly Owned Electric Utilities, 1993. Unless specific calculations are shown below, all of the data items used from the Form 1 and EAI412 are read in directly from data maintained by EIA's Office of Coal, Nuclear, Electricity and Alternate Fuels, and all of the data items from the Rural Electrification Administration (REA) Form 7 are read in from data maintained by the REA.

The dividend payout ratio and all data items related to common or preferred stock are from the FERC Form 1 only (because stock is only relevant to investor-owned utilities). All other data items come from all three sources. Again, details of the data items including variable names, descriptions, indices used in the model, units of measure, and storage within the model data framework are described in Table 4 of Appendix C. Following are the calculated data items from these three sources:

Dividend Payout Ratio

EDIVRT	=	CSDIV/NTERN

where:

EDIVRT	=	dividend payout ratio
CSDIV	=	common stock dividends
NTERN	=	net earnings

General Tax Rate

EGTXRT	=	(TXOTH + TXINC)/ELREV

where:

EGTXRT	=	general tax rate
TXINC	=	income taxes other than Federal income taxes
TXOTH	=	other taxes
ELREV	=	total electric revenues

Embedded Cost of Long Term Debt - Base Year

ESEMDB	=	LDINT/LD

where:

ESEMDB	=	embedded cost of long term debt - base year
LDINT	=	long term debt interest expense - end of year
LD	=	total long term debt

Embedded Cost of Preferred Stock - Base Year

ESEMPB	=	PSDIV/PSISS

where:

ESEMPB	=	embedded cost of preferred stock - base year
PSDIV	=	preferred stock dividends
PSISS	=	total preferred stock issued

Percent of Capitalization from Common Equity

ESPRCE	=	(PRCAP - PSISS)/(PRCAP + LD + CALIAB)

where:

ESPRCE	=	percent of capitalization from common equity
PRCAP	=	total proprietary capital
CALIAB	=	total current and accrued liability

Percent of Capital Obtained with Long Term Debt

ESPRLT = LD/(PRCAP + LD + CALIAB)

where:

ESPRLT = percent of capital obtained with long term debt

Percent of Capital Obtained with Preferred Stock

ESPRPS = PSISS/(PRCAP + LD + CALIAB)

where:

ESPRPS = percent of capital obtained with preferred stock

Percent of Capital Obtained with Short Term Debt

ESPRST = CALIAB/(PRCAP + LD + CALIAB

where:

ESPRST = percent of capital obtained with short term debt

Assumptions made by analysts at the Energy Information Administration (EIA)

All of these data items are assumptions based on judgement by analysts at EIA. They may be decisions regarding the organization of output data items (such as the plant type names for report headers), policy assumptions (such as the percentage of CWIP allowed in the ratebase), or simplifying assumptions made in lieu of accurate data (such as the transmission energy-mile operation and maintenance costs). This later category is an indicator of future efforts to improve the quality of data inputs into the EFP. All of the data items that fall under the assumptions category are described in Table 4 of Appendix C with the source designation "EIA".