ENERGY 2020
Documentation

Volume 5

Electric Sector
Code Description

Systematic Solutions, Inc.
534 E. Dayton-Yellow Springs Rd.
Fairborn, Ohio 45324
(513) 878-8603

Policy Assessment Corp.
14604 West 62nd Place
Arvada, Colorado 80004
(303) 467-3566

Volume 5

Electric Sector Code Description

Volume 5
Electric Sector Code Description

INTRODUCTION

This chapter explains the electric utility supply sector code in detail. ENERGY 2020 simulates the forecasting of capacity needs, and the planning, construction, operation, and retirement of utility plants. Each step is financed in the model by revenues, debt, and the sale of stock. The model, like the utility, pays taxes and generates a complete set of accounting books. The utility sector of ENERGY 2020, at an aggregate level, describes all the major considerations of an entire integrated utility.

Overview

Before the electric utility sector dispatches the plants to meet its load, it must know what that load is. Therefore, the first step in the dispatch procedure is the development of a forecast for the short term demand for electricity. The length of the forecast depends on the length of time it takes to build the type of plant that is needed. Using the forecasted demand, ENERGY 2020 will then determine the capacity needed, based on future construction and retirements. Plant construction is initiated, and both the physical and financial components of the construction process are tracked. If there are any nuclear plants, the decomissioning costs of retiring those plants are also calculated.

Plants are dispatched on the basis of costs and exogenously specified constraints. Other loading orders are possible such as dispatch to meet pollution requirements. In addition to own utility generation, purchased power, qualified facilities and emergency power are also dispatched in order of increasing costs in the basic version of the model.

Similar to the way the generation capacity was determined, the model updates the transmission and distribution capacity. The model will construct new capacity and retire old capacity as needed.

This sector performs all utility financial calculations. Fuel costs, operation and maintenance costs, and pollution costs are endogenously calculated. Utility assets - transmission, distribution, generation, nuclear, conservation and other - are updated and shifted through their age categories. Revenues and taxes paid are computed and all cash flows are tracked.

To determine the price of electricity, ENERGY 2020 uses a test year. Using a forecast of next year's sales and capacity, the plants are dispatched and costs are determined exactly as they are during normal simulation. The prices are then determined using a contribution to peak methodology for the allocation of fixed costs and a standard rate-base rate of return methodology overall. The calculated prices are sent to the demand sector used in the following period's calculation of demand.

The following section lists and briefly describes each procedure used in the simulation of the electric utility sector.

DESCRIPTION OF PROCEDURES

1. **COSTCAPITAL** - This procedure calculates the weighted cost of capital. The weighted cost of capital is used in regulatory matters such as rate determination and in the AFUDC calculation. The costs of capital reflects the amount of company debt and equity as well as the respective rates of return.
2. **LOADFORECAST** - The utility sector forecasts future demand for electricity. From the forecast it projects the future capacity required to meet future demand by taking into account retirement and construction currently in progress.
3. **EXPANSION** - This procedure determines the amount of generating capacity, both base and peak, that needs to be initiated in the next time period to maintain desired reserve margins. Corrections are made for retirements, different forecasting times, firm power purchases, qualified facilities and capacity under construction.
4. **PJCOSTS** - This procedure determines the costs of the initiated projects. Depletion, capital, pollution, fuel and marginal costs are calculated.
5. **RANKORDER** - This procedure is one of the five options one can choose to determine the methodology used to build new capacity. This procedure awards contracts for new capacity based on perfect knowledge of the marginal cost of energy.
6. **MARKETSHARE** - This procedure is one of the five option procedures one can choose to determine the methodology Energy 2020 uses to builds plants. This procedure awards contracts for new capacity using consumer choice theory with non-price factors and imperfect information entering into the decision process along with marginal costs.
7. **FUTMARKETSHARE** - This procedure is one of the five option procedures one can choose to determine the methodology Energy 2020 uses to builds plants. This procedure awards contracts for new capacity based on a user specified desired market share. The process of achieving the desire market shares differs from GCFRINITIATION. In FUTMARKETSHARE, the criteria is based on some desired future market shares such as 80% of **all new** capacity will be coal-fired. In GCFRINITIATION, it is the desired total market share that provides the target - e.g. 50% of **all** capacity will be coal fired.
8. **SUPPLYCURVE** - This procedure is one of the five option procedures one can choose to determine the methodology Energy 2020 uses to builds plants. This procedure awards contracts for new capacity based on a user specified supply curve. The supply curve can be ordered on the basis of marginal cost or any other user specified criteria (such as emissions). As additional capacity is needed, the model moves up the supply curve and selects the next plant. Since this plant procedure is often used when intermittent renewable resources are to be selected, an algorithm for providing battery backup is also included.
9. **GCFRINITIATION** - This procedure is one of the five option procedures one can choose to determine the methodology Energy 2020 uses to builds plants. This procedure awards contracts for new capacity based on a user specified desired total market share.

Total market share is the share of the total plant capacity from both new and existing resources of a particular type.

10. **INITIATION** - In this procedure, one of the five new capacity selection procedures is chosen and the plants are set for construction.
11. **CONSTRUCTION** - In this procedure, the construction cost of each plant (in a particular construction level) is determined. Then the plants under construction and the plants newly initiated above are shifted through their construction levels.
12. **PRODUCTION** - While construction is a function of estimated long-term demand, power production is controlled by current demand. The utility tries to satisfy demand with its least expensive plant capacity, but situations may arise where expensive plants must be run, or power must be purchased from other utilities. The procedure simulates these contingencies.
13. **TRANSDISTR -** Transmission and distribution facilities are added when forecasted peak demand indicates additional T&D capacity is needed. This procedure calculates the cost of maintaining transmission and distribution facilities sufficient to handle the utility's generation.
14. **FUELCOSTS** - In the production procedure, the plants, purchase power and qualified facilities were dispatched. With the knowledge of each plants hours of operation and heat rate, ENERGY 2020 can now determine the total cost of fuel use in this procedure.
15. **OMCOSTS** - This procedure calculates the operation and maintenance costs based on the production of each plant.
16. **DECOMMISSION** - This procedure calculates the decomissioning costs of the nuclear plants
17. **POLLUTION** - This procedure determines the cost of pollution based on plant production.
18. **ASSETS** - This procedure updates all of the asset categories*: transmission, distribution, generation, nuclear, conservation and other* by moving the assets through three age categories*: new, middle and old*.
19. **REVENUE** - This procedure calculates revenu and allowance for funds used during construction.
20. **TAXES** - At this point, revenues, costs and assets have been determined. With this information in hand, ENERGY 2020 is ready to calculate the various taxes. This procedure will determine the property and revenue tax, the municipal property tax, the interest on short term debt, the taxable income, income tax before and after credits, investment tax credits, deferred investment tax credits and deferred taxes.
21. **INCOME -** This procedure determines the operating expenses, operating income, income before interest, net income and income available to common stockholders.
22. **DIVIDENDS -** The common stock dividend rate and the common stock are calculated by one of several methods. The methods for computing common stock dividends include a

dividend payout ratio, a dividend payout ratio with growth constraints, and exogenous specification of the common stock dividends or common stock dividend rate.

23. **FUNDS -** This procedure calculates the funds from operations, funds available to common stockholders, funds from business, common stock dividends reinvested, prefered stock sinking fund and the external financing required.

24. **LIMITS -** This procedure determines debt coverage by using operating and non-operating earnings to compute net earnings and the net earnings certificate ratio (the ratio of net earnings to interest on long-term debt). The second part of the procedure establishes limits on new debt, selling preferred stock, and purchasing common stock.

25. **FINANCE -** This procedure determines how the utility will finance its expansion plans if outside financing is required. If there are excess funds to be distributed, this procedure determines how they will be used.

26. **CAPITAL -** This procedure computes the principal and embedded interest for long range debt, principal for intermediate range debt, the dollar value of preferred and common stock, the book value, market value, and number of shares of common stock, retained earnings, and the dollar value of government bonds held by the utility.

27. **CASH** - This procedure contains the financing loop which calls multiple procedures to resolve all financing requirements. The calculations need to be performed at least twice because net income is a function of indebtedness, which is a function of cash requirements, which are a function of income. The loop is performed until the results converge.

28. **TESTYEAR -** The regulatory process centers around a test year, either historical or one year forward, when the proposed rates will go into effect. The future or historical test year can change from year to year as a policy. If a future test year is used, the utility forecasts test year sales and peak demand by season and class. The test year sales are used to determine average revenue while the test year peaks are used to determine the class-specific responsibility for the system peak and thereby allocate generation capacity responsibility. The regulatory procedures (TESTYEAR and PRICE) use allowed rates-of-return and test year costs and demands to determine allowed revenues.

29. **PRICE -** The price of electricity is calculated in this procedure as the sum of three separately determined components. First, generation fuel costs are allocated by customer class according to sales. Second differential charges attempt to capture energy-related cost-to-serve differences between classes and, to some extent, policy-related "external" adjustments of electricity prices across customer classes. Third, operating costs are allocated by customer class on a contribution to peak basis.

30. **DSMPOST -** This procedure calculates market revenue and expenses for DSM evaluation. Market revenue is the revenue the utility would earn in a competitive market if it received the allowed rate of return. Rate-based conservation costs are calculated and used in computing the total conservation cost to the utility.

31. **POSTPROCESS -** In this procedure, additional output variables, including primary generating capacity by fuel and primary energy consumption are derived from other model calculated variables. Generally these variables are aggregates of variables calculated and used separately in the model.

PROCEDURE COSTCAPITAL

This procedure calculates the weighted cost of capital. The weighted cost of capital (WCC) is used in regulatory matters such as rate determination and in the AFUDC calculation. The costs of capital reflect the amount of company debt and equity as well as the respective rates of return.

If the region being simulated contains IOUs and manicipal utilities, then some assets are owned by a municipality, and those assets are treated and taxed differently. Therefore a Municipal Asset Fraction (MAF) must be calculated and used to separate the assets when different treatments are required. The following equation calculates the Municipal Asset Fraction (MAF). It is the ratio of municipal debt (determined by an exogenously specified debt fraction (MDF)) to total assets.

MAF=(DB+ID)*MDF/(DB+ID+PS+CS+RE)

Where:

DB - Long Term Debt (M$)
ID - Intermediate Debt (M$)
MDF - Municipal Debt Fraction ($/$)
PS - Preferred Stock (M$)
CS - Common Stock (M$)
RE - Retained Earnings (M$)

The allowed return on equity (AROE) is based on the smoothed inflation rate (INSM) and an exogenously specified “risk premium” (CSPR). The risk premium captures the real rate of return required to retain capital investment and is used in the weighted cost of capital equation to determine the recoverable return on common stock.

AROE=INSM+CSPR

Where:

AROE: Allowed Return on Equity (1/YR)
INSM: Smoothed Inflation Rate (1/YR)
CSPR: Common Stock Risk Premium (1/YR)

In a similar fashion, the interest rate on government bonds (SIIR), preferred stock dividend rate (PSDVR), interest rate on new debt (DBIR) and interest rate on intermediate debt (IDIR) are all functions of their respective risk premiums (SIPR, PSPR, DBPR, & IDPR) and the smoothed inflation rate (INSM).

SIIR=INSM+SIPR
PSDVR=INSM+PSPR
DBIR=INSM+DBPR

IDIR=INSM+IDPR

Where

SIIR: Interest Rate of Government Bonds (1/YR)
SIPR: Government Bonds Risk Premium (1/YR)
PSDVR: Preferred Stock Dividend Rate (1/YR)
PSPR: Preferred Stock Risk Premium (1/YR)
DBIR: Interest Rate on New Debt (1/YR)
DBPR: Long Term Debt Risk Premium (1/YR)
IDIR: Interest Rate on Intermediate Debt (1/YR)
IDPR: Intermediate Debt Risk Premium (1/YR)
ID: Intermediate Debt (M$)

The value of the preferred stock dividends (PSDV) and the value of the interest on intermediate debt (IDIN) are equal to the number of shares outstanding (PS & ID) multiplied by their respective interest rate.

PSDV=PS*PSDVR
IDIN=ID*IDIR

Where:

PSDV: Preferred Stock Dividends (M$/YR)
IDIN: Interest on Intermediate Debt (M$/YR)

The weighted cost of capital (WCC) is a fraction representing the annual cost of utility capital investment. It is derived from the ratio of interest payments (DBIN + IDIN) plus preferred stock dividends (PSDV) and the imputed return on equity (AROE*(CS+RE)), to the total amount of debt (DB+ID) and equity (PS+CS+RE). The variable WCC is the weighted cost of capital is relevant only for the IOU portion of the region; therefore, the cost of servicing any municipal debt (1-MDF) is removed.

WCC=((DBIN+IDIN) * (1-MDF)+PSDV+AROE*(CS+RE)) / ((DB+ID)*(1-MDF)+PS+CS+RE)

Where:

PSDV: Preferred Stock Dividends (M$/YR)
IDIN: Interest on Intermediate Debt (M$/YR)
DBIN: Debt Interest on Long Term Debt (M$/YR)
IDIN: Interest on Intermediate Debt (M$/YR)
MDF: Municipal Debt Fraction (DLESS) ($/$)
CS: Common Stock (M$)
RE: Retained Earnings (M$)
ID: Intermediate Debt (M$)
DB: Long Term Debt (M$)
WCC: Weighted Cost of Capital(1/YR)

The following cost of capital equation calculates a pseudo after tax weighted cost of capital. It is NOT an after tax WCC in the traditional sense. Rather, it is the increase in revenue requirements (including the impact of taxes) needed to maintain the nominal allowed rate of return. The equation is similar to WCC except that the (1-TAXR) term is included in the denominator of the equation. Since the tax rate (TAXR) is less than 1 (more specifically, 0<TAXR<1), WCCTX will be greater than WCC.

Deleted: ¶

WCCTX=((DBIN+IDIN)*(1-MDF)+(PSDV+AROE*(CS+RE))/(1-TAXR))/
((DB+ID)*(1-MDF)+PS+CS+RE)

Where:

WCCTX: After Tax Weighted Cost of Capital (1/YR)

To determine the allowed rate of return, regulators are concerned with the average cost of all the capital the firm has raised. For this reason, WCC is calculated using the historical or embedded costs of the utility, rather than the cost of new funds. It is important to note that, outside the electric utility industry, there is a key difference in the definition of "weighted average cost of capital." Traditionally, in financial management terms, the WaCC implies the weighted average cost of acquiring new funds. In other words, WaCC is equal to the "marginal" costs of new funds to be raised during the planning period. We designate the term WMCC to this concept. Think of it as the weighted "marginal" cost of capital.

TCAP=DB+ID+PS+CS+RE
WMCC=DBIR*((DB+ID)/TCAP)+PSDVR*(PS/TCAP)+AROE*((CS+RE)/TCAP)

Where:

TCAP: Total Capitalization ($/M)
WMCC: Marginal Cost of Capital (1/YR)

PROCEDURE LOADFORECAST

The utility sector forecasts future demand for electricity. From the forecast it projects the future capacity required to meet future demand by taking into account retirement and construction currently in progress. If future electricity requirements are forecasted to exceed existing capacity and capacity under construction, then construction of additional capacity is initiated. Several options are available to project the future value of the peak demand (FPDP), the average demand (FADP), and the minimum demand (FMDP).

Forecasting Time

A forecasted load curve is modeled by calculating average growth values for minimum, average, and peak power (MDP, ADP, and PDP) and extrapolating those values into the future. The time horizon (FT) over which the values are projected depends on the estimated construction time and the type of plant needed. For example, if the next plant is a coal plant requiring a 4 year construction period, then the load forecast must be for 4 years in the future. The forecasting time (FT) is different for each plant type (POWER: peaking, intermediate, baseload). For peaking plants the construction time (CD) of the peaking plants is used. For intermediate plants, the construction time (CD) of the intermediate plants is used. For baseload plants, the construction time (CD) of the baseload plants is used. The construction time (CD) is an utility-specific exogenously specified variable.

Deleted: ¶

FT(HZ)=SUM(P)(CD(P)*GCFR(P))

Where:

FT(HORIZON): Forecast Time (YEARS)
CD(PLANT): Construction Delay (YRS)
GCFR(PLANT): Fraction of New capacity by Plant Type (MW/MW)

Several forecasting methods depend on smoothing functions. The following equations update the intermediate values of the smoothing functions for the peak load (PDPSM), the average load (ADPSM), and the minimum load (MDPSM) using the smoothing constants (USMT, HAT). The default values for the exogenously specified USMT and HAT can vary by region but HAT (Historical Averaging Time) is larger than USMT (Smoothing Time). Therefore, the changes to demand are smaller with the level two values.

```
PDPSM(HZ,1)=PDPSM(HZ,1)+DT*(PDP-PDPSM(HZ,1))/USMT(HZ)
PDPSM(HZ,2)=PDPSM(HZ,2)+DT*(PDP-PDPSM(HZ,2))/HAT(HZ)
ADPSM(HZ,1)=ADPSM(HZ,1)+DT*(ADP-ADPSM(HZ,1))/USMT(HZ)
ADPSM(HZ,2)=ADPSM(HZ,2)+DT*(ADP-ADPSM(HZ,2))/HAT(HZ)
MDPSM(HZ,1)=MDPSM(HZ,1)+DT*(MDP-MDPSM(HZ,1))/USMT(HZ)
MDPSM(HZ,2)=MDPSM(HZ,2)+DT*(MDP-MDPSM(HZ,2))/HAT(HZ)
```

Where:

PDPSM(HORIZON,LV2): Smoothed PDP for Extrapolation Macro (MW)
PDP: Annual Peak Load (MW)
USMT(HORIZON): Smoothing Time (Year)
HAT(HORIZON): Historical Averaging Time (YRS)
ADPSM(HORIZON,LV2): Smoothed ADP for Extrapolation (MW)
MDPSM(HORIZON,LV2): Smoothed MDP for Extrapolation Macro (MW)
AOP: Average Demand for Power (MW)
MDP: Minimum Demand for Power (MW)

Extrapolation

There are four methods of forecast extrapolation. The first three are based on alternative smoothing functions and the last method is based on an exogenous forecast. All definitions of the variable names for methods 1 through 3 appear in the method 3 section.

Method 1

Based on the smoothing functions (PDPSM, ADPSM, MDPSM) and a smoothing constant (USMT) a growth rate is computed for the peak load (PDPGR), the average load (ADPGR), and the minimum load (MDPGR).

```
PDPGR(HZ)=(PDP/PDPSM(HZ,1)-1)/USMT(HZ)
ADPGR(HZ)=(ADP/ADPSM(HZ,1)-1)/USMT(HZ)
MDPGR(HZ)=(MDP/MDPSM(HZ,1)-1)/USMT(HZ)
```

The load forecast (FPDP, FADP, FMDP) is equal current value (PDP, ADP, MDP) times one plus the growth rate (PDPGR, ADPGR, MDPGR) raised to the number of years in the forecast (FT) - standard compound growth rate.

```
FPDP(HZ)=PDP*((1+PDPGR(HZ))**FT(HZ))
FADP(HZ)=ADP*((1+ADPGR(HZ))**FT(HZ))
FMDP(HZ)=MDP*((1+MDPGR(HZ))**FT(HZ))
```

Method 2

Based on both sets of smoothing functions (PDPSM, ADPSM, MDPSM) and both smoothing constant (USMT and HAT) a growth rate is computed for the peak load (PDPGR), the average load (ADPGR), and the minimum load (MDPGR).

```
PDPGR(HZ)=(PDPSM(HZ,1)/PDPSM(HZ,2)-1)/(HAT(HZ)-USMT(HZ))
ADPGR(HZ)=(ADPSM(HZ,1)/ADPSM(HZ,2)-1)/(HAT(HZ)-USMT(HZ))
MDPGR(HZ)=(MDPSM(HZ,1)/MDPSM(HZ,2)-1)/(HAT(HZ)-USMT(HZ))
```

The load forecast (FPDP, FADP, FMDP) is equal to the smoothed value (PDPSM, ADPSM, MDPSM) times e to the power of the growth rate (PDPGR, ADPGR, MDPGR) times the number of years in the forecast (FT) plus the number of years in the smoothing period (USMT).

```
FPDP(HZ)=PDPSM(HZ,1)*EXP(PDPGR(HZ)*(FT(HZ)+USMT(HZ)))
FADP(HZ)=ADPSM(HZ,1)*EXP(ADPGR(HZ)*(FT(HZ)+USMT(HZ)))
FMDP(HZ)=MDPSM(HZ,1)*EXP(MDPGR(HZ)*(FT(HZ)+USMT(HZ)))
```

Method 3

Based on the ratios of both sets of smoothing functions (PDPSM, ADPSM, MDPSM) and the difference between both smoothing constants (USMT and HAT) a growth rate is computed for the peak load (PDPGR), the average load (ADPGR), and the minimum load (MDPGR).

```
PDPGR(HZ)=(PDPSM(HZ,1)/PDPSM(HZ,2)-1)/(HAT(HZ)-USMT(HZ))
ADPGR(HZ)=(ADPSM(HZ,1)/ADPSM(HZ,2)-1)/(HAT(HZ)-USMT(HZ))
MDPGR(HZ)=(MDPSM(HZ,1)/MDPSM(HZ,2)-1)/(HAT(HZ)-USMT(HZ))
```

Where:

PDPGR(HORIZON): Peak Load Growth Rate (1/YR)
ADPGR(HORIZON): Growth Rate in Average Demand (1/YR)
MDPGR(HORIZON): Minimum Load Growth Rate (1/YR)
PDPSM(HORIZON,LV2): Smoothed PDP for Extrapolation (MW)
ADPSM(HORIZON,LV2): Smoothed ADP for Extrapolation (MW)
MDPSM(HORIZON,LV2): Smoothed MDP for Extrapolation (MW)
USMT(HORIZON): Smoothing Time (Year)
HAT(HORIZON): Historical Averaging Time (YRS)
FT(HORIZON) Forecast Time (YEARS)
FPDP(HORIZON) Future Peak Demand for Power (MW)

The load forecast (FPDP, FADP, FMDP) is equal to the smoothed value (PDPSM, ADPSM, MDPSM) times e to the power of the natural log of one plus the growth rate (PDPGR, ADPGR, MDPGR) times the number of years in the forecast (FT) plus the number of years in the smoothing period (USMT).

```
FPDP(HZ)=PDPSM(HZ,1)*EXP(LN(1+PDPGR(HZ))*(FT(HZ)+USMT(HZ)))
FADP(HZ)=ADPSM(HZ,1)*EXP(LN(1+ADPGR(HZ))*(FT(HZ)+USMT(HZ)))
FMDP(HZ)=MDPSM(HZ,1)*EXP(LN(1+MDPGR(HZ))*(FT(HZ)+USMT(HZ)))
```

Where:

FPDP(HORIZON): Future Peak Demand for Power (MW)
FADP(HORIZON): Future Average Demand for Power (MW)
FMDP(HORIZON): Future Minimum Demand for Power (MW)

Method 4

This method is based on an exogenous forecast adjusted to reflect the differences between the exogenous forecast and the actual load values. The difference in loads (PDPDIF, ADPDIF, MDPDIF) is equal to the actual loads (PDP, ADP, MDP) and the exogenous forecasted loads (XFPDP, XFADP, XFMDP).

```
PDPDIF=PDP-XFPDP
ADPDIF=ADP-XFADP
MDPDIF=MDP-XFMDP
```

Where:

PDPDIF(YEAR):	*PDP Different than XPDP (MW)*
ADPDIF(YEAR):	*ADP Different than XADP (MW)*
MDPDIF(YEAR):	*MDP Different than XMDP (MW)*
XFPDP:	*PDP of "Control Forecast, (MW)*
XFADP:	*ADP of "Control Forecast, (MW)*
XFMDP:	*MDP of "Control Forecast, (MW)*

The load forecast (FPDP, FADP, FMDP) is equal to the exogenous load forecast in the future period (XFPDP, XFADP, XFMDP) plus the difference in loads (PDPDIF, ADPDIF, MDPDIF). The future period is the current period plus the number of years in the forecast (FT).

```
FUTYR=XMIN(CURRENT+FT,FINAL)
FPDP=XFPDP+PDPDIF
FADP=XFADP+ADPDIF
FMDP=XFMDP+MDPDIF
```

Where:

FPDP(HORIZON):	*Future Peak Demand for Power (MW)*
FADP(HORIZON):	*Future Average Demand for Power (MW)*
FMDP(HORIZON):	*Future Minimum Demand for Power (MW)*

PROCEDURE EXPANSION

The forecasted future capacity needs determine the incremental capacity needs (IPGC). These may be small, large, or even negative. Negative needs signal projected over-capacity, and no new construction is initiated. The model continuously converts changing incremental future needs into discrete construction initiation (GCCI) and completed plants. This procedure determines the amount of generating capacity, both base and peak, that needs to be initiated in the next time period to maintain desired reserve margins. Corrections are made for retirements, different forecasting times, firm power purchases, qualified facilities and capacity under construction.

Maximum Demand Satisfied by Power Type

The forecast of the maximum demand satisfied by each power type (peak, intermediate, baseload) is a function of the forecast of the load duration curve (FPDP, FADP, FMDP) and the minimum number of hours for each power type (MILD). The value in megawatts that "MILD" represents on the load curve (MILP) is the load that must be satisfied by base- or intermediate-load plants.

```
FMDS(PW,HZ)=FMDP(HZ)+(FPDP(HZ)-FMDP(HZ)) * (1-MILD(PW)/8760)**XMAX(0,(FPDP(HZ) -
        FADP(HZ)) / (FADP(HZ)-FMDP(HZ)))
```

Where:

FMDS(POWER,HORIZON):	*Forecast of Maximum Demand (MW)*
FMDP(HORIZON):	*Future Minimum Demand for Power (MW)*

FPDP(HORIZON):	*Future Peak Demand for Power (MW)*
MILD(POWER):	*Maximum Base Load Power Duration (HOURS/YR)*
FADP(HORIZON):	*Future Average Demand for Power (MW)*

The future capacity requirements (FGCRQ) for each power type are equal to the maximum demand to be satisfied by the power type (FMDS) times the desired reserve margin (DRM). After the first (baseload) power type, the capacity requirements (FGCRQ) are the difference between the maximum demand for the current power type (FMDS(PW,PW) and the maximum demand of the previous power type (FMDS(PW-1,PW)).

Baseload

FGCRQ(PW)=(FMDS(PW,HZ)-FMDS(PW+1,HZ))*(1+DRM(PW))

Where:

FGCRQ(POWER)	*Future Generation capacity Requirements (MW)*
FMDS(POWER,HORIZON):	*Forecast of Maximum Demand (MW)*
DRM(POWER)	*Desired Reserve Margin (MW/MW)*

Peaking

FGCRQ(PW)=FMDS(PW,HZ)*(1+DRM(PW))

Calculate New Capacity

For each power type (peak, intermediate, baseload), the amount of new capacity required is calculated by comparing the capacity available and the capacity requirements for the forecast period. The final year of the forecast period (FUTYR) is defined as the current year (CURRENT) plus the forecasting time (FT), but not past the last year of model calculations (FINAL).

FUTYR=XMIN(CURRENT+FT,FINAL)

Where:

FUTYR Year for capacity Planning Horizon (YEAR)

The current amount of installed generating capacity (TGC) is the sum over the plant types for each power type of the generating capacity (GC) adjusted by the winter/summer ratio (WSRATIO).

TGC(PW)=SUM(P)(GC(P)/WSRATIO(P))

Where:

TGC(POWER):	*Total Generating capacity (MW)*
WSRATIO(PLANT):	*Winter to Summer capacity Ratio (Fraction)*

If the power type is peak, then pumped storage, if available, is included.

TGC=TGC+PSGC

Where:

PSGC: Pumped Storage capacity (MW)

The capacity under construction (TCUC) is the sum over plant types for each power type of the capacity under construction (CUC) plus any exogenous capacity additions (XGCCI) set by the user during the forecast period (FUTYR), all adjusted by the winter/summer ratio (WSRATIO).

TCUC(PW)=SUM(P)(PCUC(P)/WSRATIO(P))+SUM(P,Y)(XGCCI(P,Y)/WSRATIO(P))

Where:

TCUC(POWER): *Total capacity under Construction (MW)*
PCUC(PLANT): *Capacity under Construction (MW)*
XGCCI(PLANT,YEAR): *Generation capacity Initial Rate (MW/YR)*

Determine the capacity retired (FCR) during forecast period

FCR(PW)=SUM(P,Y)(GCR(P,Y)/WSRATIO(P))

Where:

FCR(POWER): *Forecast of Generating Cap. Retirements (MW)*
GCR(PLANT,YEAR): *Generation Cap. Retirements (MW/YR)*

Miscellaneous types of both baseload and peaking capacity (FMGC) available in the future (FUTYR) includes firm power purchases (PPGC), qualified facilities (QFGC), excess regional power (RIC), and interruptible load (SILGC) for peak power (PEAK):

Base Load Capacity

FMGC(PW)=RIC(PW,FUTYR)+SUM(PP)(PPGC(PP,FUTYR))+SUM(T)(XQFGC(T,FUTYR))

Where:

FMGC(POWER): *Future Misc. Generating capacity (MW)*
RIC(POWER,YEAR): *Regional Interchange capacity (MW)*
PPGC(PP,YEAR): *Purchase Power capacity (MW)*
XQFGC(TECH,YEAR): *Historical QF Generating capacity (MW)*

Peaking Capacity

FMGC(PW)=FMGC(PW)+MAX(M)(SILGC(M,FUTYR))

Where:

XQFGC(TECH,YEAR): *Historical QF Generating capacity (MW)*
SILGC(MONTH,YEAR): *MONTH Interruptible Load Effective Generation capacity (MW)*

The total amount of capacity available in the future (FGC) is the existing capacity (TGC) less the future retirements (FCR) plus capacity under construction (TCUC) plus the miscellaneous future capacity (FMGC).

FGC=TGC-FCR+TCUC+FMGC

Where:

FGC(POWER): *Future Generation capacity (MW)*
TGC(POWER): *Total Generating capacity (MW)*
FCR(POWER): *Forecast of Generating Cap. Retirements (MW)*
TCUC(POWER): *Total capacity under Construction (MW)*
FMGC(POWER): *Future Misc. Generating capacity (MW)*

The estimate of gross new capacity requirements (GPGC) is equal to the forecasted capacity requirements (FGCRQ) minus the forecasted capacity available (FGC).

GPGC=FGCRQ-FGC

Where:

GPGC(POWER: *Gross New capacity Requirements (MW)*
FGCRQ(POWER): *Future Generation capacity Requirements (MW)*

Due to flexibility between power types (e.g. coal plants can cycle, oil-fired peaking can be run at higher capacity factors), new capacity is not constructed unless the system as a whole needs capacity. The net new capacity requirements (NPGC) is equal to the sum of the gross requirements, but not less than zero.

NPGC=XMAX(SUM(PW)(GPGC(PW)),0)

Where:

NPGC: New Capacity Requirements

The net capacity requirements are distributed based on the size of the gross requirements. The power type with the greatest need is satisfied first.

IPGC=XMAX(XMIN(GPGC,NPGC),0)
NPGC=XMAX(NPGC-IPGC,0)

Where:

IPGC(POWER,YEAR): *Indicated Planned Generation Cap. (MW)*
GPGC(POWER): *Gross New capacity Requirements (MW)*
NPGC(POWER): *New capacity Requirements (MW)*

PROCEDURE PJCOSTS

This procedure determines the costs of the initiated projects. Depletion, capital, pollution, fuel and marginal costs are calculated.

Depletion Cost Impacts

The depletion multiplier (DM, *where 0< DM <=1*) is a function of the resource base, the generating capacity and the capacity under construction of a particular plant type. The depletion multiplier reflects the fact that some generation technologies require scarce resources (land or water, for example) for their implementation. As we build these technologies up to their limit (RESI), the depletion multiplier approaches zero.

DM(P)=XMAX(1E-20,(RESI(P)-GC(P)-PCUC(P)))/RESI(P)

Where:

DM(PLANT): *Depletion Multiplier (DLESS) ($/$)*
RESI(PLANT): *Resource Base (GJ)*
GC(PLANT): *Generation capacity (MW)*
PCUC(PLANT): *capacity under Construction (MW)*

Capital Cost

The generation capital cost is a function of the normal GCCC (GCCCN), the policy GCCC multiplier (GCCCM), inflation (INFLA) and the depletion multiplier (DM).

GCCC(P)=GCCCN(P)*GCCCM(P)*INFLA(Y)/DM(P)

Where:

GCCC(PLANT):	*Generation capacity Capital Costs ($/KW)*
GCCCN(PLANT):	*Generation capacity Capital Cost Normal ($/KW)*
GCCCM(PLANT):	*Capital Cost Multiplier ($/$)*
INFLA(YEAR):	*Inflation Index*

Pollution Control Costs

The pollution control capital cost (PCCC) for each plant type is equal to the ***minimum*** of **either** the capital cost of installing the pollution control device **or** purchasing a credit.

PCCC(P)=SUM(POLL)(XMIN(PCCCN(P,POLL),PCREDIT(POLL)))

Where:

PCCC(PLANT):	*Pollution Control Capital Costs ($/KW/YR)*
PCCCN(PLANT,POLL):	*Pollution Control Capital Real Costs ($/KW/YR)*
PCREDIT(POLL):	*Pollution Credits Cost ($/KW)*

Marginal Cost

The project fuel price (PJFP) is set equal to the fuel price (FP)

PJFP=FP

The capital charge rate is the annualization of capital expenses to account for taxes, tax credits, return of principal, return on investment, and interest during construction. The CCR equation is:

CCR=(1-DIVTC/(1+WCC+DRISK+INSM) - TAXR *
(2/(GCPL*0.8))/(WCC+DRISK+INSM+2/(GCPL*0.8))) * (WCC+DRISK)/(1-
(1/(1+WCC+DRISK))**GCPL)/(1-TAXR)

Where:

CCR:	*Capital Charge Rate*
DIVTC:	*Device Investment Tax Credit ($/$)*
WCC:	*Weighted Cost of Capital (1/YR)*
DRISK:	*Device Risk Premium*
INSM:	*Smoothed Inflation Rate (1/YR)*
TAXR:	*Income Tax Rate*
GCPL(PLANT):	*Generation capacity Physical Life (YRS)*

The project environmental cost (PJEC) per kWh is a function of the project type (PJ), project pollution (PJPCX), heat rate (PJHRT) and the societal cost of pollution (POCSTR)

PJEC(PJ)=SUM(POLL)(PJPCX(PJ,POLL)*PJHRT(PJ)*POCSTR(POLL)*INFLA(Y))/1E9

Where:

PJEC(PJ):	*Project Environmental Costs (MILLS/KWH)*
PJPCX(PJ,POLL):	*Project Pollution Coefficients (TONS/TBTU)*

PJHRT(PJ): Project Heat Rate (BTU/KWH)
POCSTR(POLL): Societal Cost of Pollution ($/TON)

The busbar cost or marginal cost of energy (MCE) is the sum of the capital (GCCC), fuel (PJFP*HRTM), other O&M direct (UFOMC,UOMC), and environmental (PJEC) costs.

```
MCE=CCR*(GCCC+PCCC+UFOMC)+(UOMC/1000*INFLA+PJFP * HRTM/1E6 + PJEC *
        PJECSW/1000)*8760*DLF
```

The next five procedures, RANKORDER, MARKETSHARE, FUTMARKETSHARE, SUPPLYCURVE, and GCFRINITIATION, are plant selection procedures. Only one procedure, selected by the user, is used to build new generation plants. RANKORDER builds plants on the basis of the marginal cost of energy - the true marginal cost of new generation. MARKETSHARE builds generation using logic similar to consumer choice theory. The marginal cost of energy is again the basic criterion for selection, but it is modified to reflect imperfect information and (unspecified) non-price factors. FUTMARKETSHARE and GCFRINITIATION build plants to satisfy an exogenous user specified desired market share. In the former, the criteria is a user specified new market shares; in the latter, the desired market share of new and existing plant combined is the target. SUPPLYCURVE selects plants from a predetermined generation supply curve that can be based on costs or any other criteria desired by the user.

PROCEDURE RANKORDER

This procedure is one of the five option procedures one can choose to determine the methodology Energy 2020 uses to builds plants. This procedure awards contracts for new capacity based on perfect knowledge of the marginal cost of energy.

The projects (PJ) are first sorted based on the busbar costs (MCE):

```
SORT ASCENDING PJ USING MCE
```

The amount of capacity awarded to each project (PJCI) is based on the amount of power needed (IPGC) and the maximum (PJMAX) and minimum (PJMNPS) project sizes.

```
PJCI=XMAX(XMIN(IPGC,PJMAX),0)
```

Where:

PJCI(PJ): Capacity of Projects Initiated (MW/YR)
IPGC(POWER,YEAR): Indicated Planned Generation Cap. (MW)
PJMAX(PJ): Maximum Project Size (MW)

The amount of capacity (PJCI) needed is rounded into an integer number of projects. The 0.4999 term is part of a programming technique which recognizes the fact that PJCI is an integer and that a new plant should be built whenever PJCI is positive.

```
PJCI=ROUND(PJCI/PJMNPS+0.499)*PJMNPS
```

Where:

PJMNPS(PJ): Minimum Project Size (MW)

The capacity awarded (PJCI) is subtracted from capacity needs (IPGC)

```
IPGC=IPGC-PJCI
```

Where:

IPGC(POWER,YEAR) 'Indicated Planned Generation Cap. (MW)

Finally, the market share of each project (PJMS) is computed.

PJMS(PJ)=PJCI(PJ)/SUM(P)(PJCI(P))

Where:

PJMS(PJ): Project Market Share of capacity Needs (MW/MW)

PROCEDURE MARKETSHARE

This procedure is the second of the five option procedures one can choose to determine the methodology Energy 2020 uses to builds plants. This procedure awards contracts for new capacity using logic similar to consumer choice theory with non-price factors and imperfect information entering into the decision process along with marginal costs..

The first step is to compute the project allocation weight (PJMAW). This weight calculation is based on the marginal cost of energy (MCE) modified by non-price factors and a variance factor to capture imperfect price information.

PJMAW=(MCE**PJVF)*PJMSM

Where:

PJMAW(PJ):	*Project Marginal Allocation Weight ($/$)*
MCE(PJ,POWER):	*Marginal Cost of Energy ($/KW/YR)*
PJVF:	*Project Variance Factor*
PJMSM(PJ):	*Project Market Share Non Price Factors*

The total allocation weight (PJTAW) is the sum of the project allocation weights (PJMAW) for the selected projects.

PJTAW=SUM(P)(PJMAW(P))

Where:

PJTAW: Total Project Allocation Weight ($/$)

The amount of capacity awarded to each project (PJCI) is computed from the amount of capacity needed (IPGC), the allocation weight and the maximum (PJMAX) project sizes.

PJCI=XMAX(XMIN(IPGC*PJMAW/PJTAW,PJMAX),0)

Where:

PJCI(PJ):	*Capacity of Projects Initiated (MW/YR)*
IPGC(POWER,YEAR):	*Indicated Planned Generation Cap. (MW)*
PJMAW(PJ):	*Project Marginal Allocation Weight ($/$)*
PJTAW:	*Total Project Allocation Weight ($/$)*
PJMAX(PJ):	*Maximum Project Size (MW)*

The amount of capacity (PJCI) is rounded into an integer number of projects. The 0.4999 term is part of a programming technique which recognizes the fact that PJCI is an integer and that a new plant should be built whenever PJCI is positive.

PJCI=ROUND(PJCI/PJMNPS+0.499)*PJMNPS

Where:

PJMNPS(PJ): Minimum Project Size (MW)

Capacity awarded (PJCI) is subtracted from capacity needs (IPGC):

IPGC=IPGC-PJCI

Where:

IPGC(POWER,YEAR) Indicated Planned Generation Cap. (MW)

For the plant type initiated, the marginal allocation (PJMAW) weight is subtracted from the total allocation weight (PJTAW).

PJTAW=PJTAW-PJMAW

Where:

PJMAW(PJ): Project Marginal Allocation Weight ($/$)
PJTAW: Total Project Allocation Weight ($/$)

Then the market share of each project (PJMS) is computed as a function of the initiated projects.

PJMS(PJ)=PJCI(PJ)/SUM(P)(PJCI(P))

Where:

PJMS(PJ): Project Market Share of Capacity Needs (MW/MW)
PJCI(PJ): Capacity of Projects Initiated (MW/YR)

PROCEDURE FUTMARKETSHARE

This procedure is the third of the five option procedures one can choose to determine the methodology Energy 2020 uses to builds plants. This procedure awards contracts for new capacity based on a user specified desired market share. The process of achieving the desire market shares differs from GCFRINITIATION. In FUTMARKETSHARE, the criteria is based on some desired future market shares such as 80% of **all new** capacity will be coal-fired. In GCFRINITIATION, it is the desired total market share that provides the target - e.g. 50% of **all** capacity will be coal fired.

The current market share (GCCIAR) of each project type is subtracted from the desired market share (GCDMS) to determine the project type that has the largest market share defect (GCMSD). Then the PROJECT type that has the largest market share defect is selected.

GCMSD(PJ)=GCDMS(PJ)-GCCIAR(PJ)

Where:

GCMSD(PJ): Current Expansion Market Share Deficit
GCDMS(PJ): Desired Expansion Plan Market Share
GCCIAR(PJ): Cumulative Expansion Plan Market Share

The amount of capacity (PJCI) is rounded into an integer number of projects. The 0.4999 term is part of a programming technique which recognizes the fact that PJCI is an integer and that a new plant should be built whenever PJCI is positive.

PJCI=ROUND(IPGC/PJMNPS+0.499)*PJMNPS

Where:

PJCI(PJ): *Capacity of Projects Initiated (MW/YR)*
IPGC(POWER,YEAR): *Indicated Planned Generation Cap. (MW)*
PJMNPS(PJ): *Minimum Project Size (MW)*

The project type (PJCI) with the largest market share defect is initiated first. The smallest plant size (PJMNPS) available is selected. The capacity awarded (PJMNPS) is subtracted from capacity needs (IPGC);

IPGC=IPGC-PJMNPS

Where:

IPGC(POWER,YEAR): *Indicated Planned Generation Cap. (MW)*
PJMNPS(PJ): *Minimum Project Size (MW)*

and added to the cumulative capacity awarded (GCCIAC):

GCCIAC=GCCIAC+PJMNPS

Where:

GCCIAC(PJ): *Current Cumulative megawatts Developed*
PJMNPS(PJ): *Minimum Project Size (MW)*

The current megawatts of capacity developed (GCCIAC) are added to the cumulative megawatts of capacity developed (GCCIA).

GCCIA=GCCIA+GCCIAC

Where:

GCCIA(PJ): *Cumulative Megawatts Developed (MW)*
GCCIAC(PJ): *Current Cumulative megawatts Developed*

Finally, the new cumulative expansion plan market share (GCCIAR) is calculated and will be used in the next plant initiation:

GCCIAR(PJ)=GCCIA(PJ)/SUM(PPJ)(GCCIA(PPJ))

Where:

GCCIA(PJ): *Cumulative Megawatts Developed (MW)*
GCCIAR(PJ): *Cumulative Expansion Plan Market Share*

PROCEDURE SUPPLYCURVE

This procedure is the forth of the five option procedures one can choose to determine the methodology Energy 2020 uses to builds plants. This procedure awards contracts for new capacity based on a user specified supply curve. The supply curve can be ordered on the basis of marginal cost or any other user specified criteria (such as emissions). As additional capacity is needed, the model moves up the supply curve and selects the next plant. Since this plant procedure is often used when intermittent renewable resources are to be selected, an algorithm for providing battery backup is also included.

The amount of capacity awarded to each project (PJCI) is based on the amount of power needed (IPGC) and the amount of capacity available. The amount of capacity available is the difference between the maximum capacity (SCGC) and the capacity already developed (SCGCCI).

PJCI=XMAX(XMIN(IPGC,SCGC-SCGCCI),0)

Where:

PJCI(PJ): *Capacity of Projects Initiated (MW/YR)*
IPGC(POWER,YEAR): *Indicated Planned Generation Cap. (MW)*
SCGCCCM(RESOURCE): *Project Capital Costs Multiplier ($/$)*
SCGCCI(RESOURCE): *Cumulative capacity Initiated (MW)*

The amount of capacity (PJCI) is rounded into an integer number of projects. The 0.4999 term is part of a programming technique which recognizes the fact that PJCI is an integer and that a new plant should be built whenever PJCI is positive.

PJCI=ROUND(PJCI/SCMPS+0.499)*SCMPS

Where:

PJCI(PJ): *Capacity of Projects Initiated (MW/YR)*
SCMPS(RESOURCE): *Minimum Project Size (MW)*

If this resource requires back-up capacity (SCBACKUP), then the back-up capacity in the form of a battery is initiated.

PJCI(BATTERY)=PJCI(BATTERY)+PJCI*SCBACKUP

Where:

PJCI(PJ): *Capacity of Projects Initiated (MW/YR)*
SCBACKUP(RESOURCE): *Project Back-up Power Requirements (0=None,1=Battery)*

The capital cost multiplier (GCCCM) is set equal to the project capital cost multiplier.

GCCCM=SCGCCCM

Where:

GCCCM(PLANT): *Capital Cost Multiplier ($/$)*
SCGCCCM(RESOURCE): *Project Capital Costs Multiplier ($/$)*

The capacity awarded (PJCI) is subtracted from capacity needs (IPGC)

IPGC=IPGC-PJCI

Where:

IPGC(POWER,YEAR): *Indicated Planned Generation Cap. (MW)*
PJCI(PJ): *Capacity of Projects Initiated (MW/YR)*

The new capacity (PJCI) is added to the cumulative capacity initiated (SCGCCI)

SCGCCI=SCGCCI+PJCI

Where:

SCGCCI(RESOURCE): *Cumulative capacity Initiated (MW)*
PJCI(PJ): *Capacity of Projects Initiated (MW/YR)*

If the remaining capacity (SCGC-SCGCCI) is not positive, then the resource pointer (SCPOINTER) is incremented to the next resource.

SCPOINTER=SCPOINTER+1

Where:

SCPOINTER(POWER) *Pointer to Current Resource Option*

PROCEDURE GCFRINITIATION

This procedure is the last of the five option procedures one can choose to determine the methodology Energy 2020 uses to builds plants. This procedure awards contracts for new capacity based on a user specified desired total market share. Total market share is the share of the total plant from both new and existing resources of a particular type.

The current market share (GCFRAC) is calculated for each plant type.

LOC1=SUM(P)(PCUC(P)+XGCCI(P,Y))
GCFRAC(P)=(PCUC(P)+XGCCI(P,Y))/LOC1

Where:

GCFRAC(PLANT): *Distribution of Capacity Under Construction (Fraction)*
PCUC(PLANT): *Capacity Under Construction (MW)*
XGCCI(PLANT,YEAR): *Generation Capacity Initial Rate (MW/YR)*

If the current market share (GCFRAC) is less than the desired fraction (GCFR) for each plant type, then projects (PJCI) are initiated to satisfy the need for new capacity (IPGC). XMAX is used to make sure PJCI is greater or equal to zero.

PJCI(P)=XMAX(0,IPGC(PW))

Where:

PJCI(PJ): *Capacity of Projects Initiated (MW/YR)*
IPGC(POWER,YEAR): *Indicated Planned Generation Cap. (MW)*

The amount of capacity (PJCI) is rounded into an integer number of projects. The 0.4999 term is part of a programming technique which recognizes the fact that PJCI is an integer and that a new plant should be built whenever PJCI is positive.

PJCI=ROUND(PJCI/PJMNPS+0.499)*PJMNPS

Where:

PJCI(PJ): *Capacity of Projects Initiated (MW/YR)*
PJMNPS(PJ): *Minimum Project Size (MW)*

Capacity awarded (PJCI) is subtracted from capacity needs (IPGC):

IPGC(PW)=IPGC(PW)-PJCI(PJ)

Where:

IPGC(POWER,YEAR): *Indicated Planned Generation Cap. (MW)*
PJCI(PJ): *Capacity of Projects Initiated (MW/YR)*

Then the market share of each project (PJMS) is computed:

PJMS(PJ)=PJCI(PJ)/SUM(P)(PJCI(P))

Where:

PJMS(PJ): *Project Market Share of capacity Needs (MW/MW)*
PJCI(PJ): *Capacity of Projects Initiated (MW/YR)*

PROCEDURE INITIATION

In this procedure, one of the 5 plant selection procedures is chosen and the plants are set for construction.

Use the project selection switch (PJSW) to choose a project selection procedure.

RANKORDER
MARKETSHARE
FUTMARKETSHARE
SUPPLYCURVE
GCFRINITIATION

If power is needed and was unanticipated by the forecasting procedure, purchased power is used to fill the gap. Endogenous purchase power contracts (both capacity and energy) are calculated wherever the plant construction time (CTIME) is greater than the lag in demand - new demand is never left unserved. Historical purchased power (XPPGC), if it exists, is included but cannot be used to fill the gap..

PPGCEN(HYDRO,Y)=PPGCEN(HYDRO,Y-1)+PJCI(PPHYDRO)
PPGCEN(ECPP,Y)=PPGCEN(ECPP,Y-1)+PJCI(PPCOAL)
PPGCEN(OGCT,Y)=PPGCEN(OGCT,Y-1)+PJCI(PPOTHER)
PPGC=XPPGC+PPGCEN

Where:

PPGCEN(PP,YEAR):	*Endogenous Purchase Power Contracts (MW)*
PJCI(PJ):	*Capacity of Projects Initiated (MW/YR)*

If demand has not been underforecast and existing plant is adequate purchase power capacity (PPGC) is set equal to the historical firm purchases (XPPGC).

PPGC=XPPGC

Where:

PPGC(PP,YEAR):	*Purchase Power capacity (MW)*
XPPGC(PP,YEAR):	*Historical Firm Purchases capacity (MW)*

The new utility plants (GCCI) are equal to the utility projects initiated (PJCI(PJPLANT)) plus any new utility plant exogenously specified (XGCCI).

GCCI(P)=PJCI(PJPLANT(P))+XGCCI(P)

Where:

GCCI(PLANT):	*Generation Capacity Initial Rate (MW/YR)*
PJCI(PJ):	*Capacity of Projects Initiated (MW/YR)*
PJPLANT(PLANT):	*Map between PJ and PLANT*
XGCCI(PLANT,YEAR):	*Generation Capacity Initial Rate (MW/YR)*

PROCEDURE CONSTRUCTION

In this procedure, the construction cost of each plant (in a particular construction level) is determined. Then the plants under construction and the plants newly initiated above are shifted through their construction levels (LV12). The exact number of construction levels is equal to the construction delay (CD). For example, a coal plant with a construction period of two years

would be on line in year three and have two construction levels. The construction of new plants not only entails physical processes but also financial concerns such as construction costs and the allowance-for-funds-used-during-construction (AFC). AFC is based on the various costs of capital—the weighted cost of capital used for regulatory matters and the net-of-tax rate on construction funds. Gross assets are increased by completed construction (CW) and the associated allowance for funds used during construction (AFC)..

Construction Cost

For each plant, the fraction of the total cost of construction (FF) at the current construction level (LV12) is calculated. The fractional part of the construction delay (FRCD) depends on the particular construction level where "LV12:S" is the PROMULA syntax for the value of the "LV12" index. Construction costs are not normally the same in each year the plant is under construction. The construction cost fraction table (TABFF) determines the approximate costs incurred as a function of the portion (fraction) of the plant that is built. The construction cost fraction (FF) is then normalized using the construction delay normalization factor (TFF).

```
FRCD=LV12:S
FRCD=(FRCD-.5)/CD(P)
FF=TABFF(FRCD)
TFF=SUM(LV12)(FF(LV12))
FF=FF/TFF
```

Where:

FRCD:	*Fractional Part of Construction Delay*
CD(PLANT):	*Construction Delay (YRS)*
FF(LV12):	*Cost Fraction in Lth construction level*
TABFF(FFX,FFY):	*Construction Cost Fraction Table*
TFF	*Construction Delay Normalization Factor*

To calculate the allowance for funds used during construction (AF), if allowed, requires values for the gross and net rates for AFUDC (AFGSR and AFNTR, respectively).. The gross rate for AFUDC (AFGSR) is a function of the cost of new capital (WMCC) and the exogenously specified gross rate for AFUDC multiplier (AFGSM) if the rate is different from the WMCC. The net rate of AFUDC (AFNTR) is equal to the gross rate (AFGSR) minus taxes on municipal property, if any.

```
AFGSR=WMCC*AFGSM
AFNTR=AFGSR*(1-AFDBF*TAXR*NMAF)
```

Where:

AFGSR:	*Gross Rate for AFUDC (1/YR)*
WMCC:	*Weighted Marginal Cost of Capital (1/YR)*
AFGSM:	*Gross Rate for AFUDC Multiplier (1/YR)*
AFNTR:	*Net Rate for AFUDC (1/YR)*
AFDBF:	*Fraction of AFUDC from Debt Funds ($/$)*
TAXR(AA):	*Municipal Property Tax Rate (1/YR)*
NMAF:	*Switch for Tax Effect of AFUDC*

The construction work in progress (CW, in millions of dollars), for each plant at each level, is a function of the capacity under construction in the previous period (CUC), the cost fraction level calculated above (FF) and the generation capacity capital cost (GCCC). The accumulated

construction work in progress (CWAC, in millions of dollars), for each plant, is summed from the previous level.

```
CW(P,L)=CUC(P,L)*FF(L)*GCCC(P)/1000
CWAC(P,L)=CWAC(P,L)+DT*CW(P,L)
```

Where:

CW(PLANT,LV12):	*Construction Work in Progress (M$/year)*
CUC(PLANT,LV12):	*Capacity Under Construction in previous period (MW)*
FF(LV12):	*Cost Fraction in Lth construction level ($/$)*
GCCC(PLANT):	*Generation Capacity Capital Costs ($/KW)*
CWAC(PLANT,LV12):	*Construction Work in Progress Accumulated (M$)*

Utilities, in general, cannot collect a return on funds used for construction until after the plant is completed. The allowance for funds used during construction (AF) equals the return-on-investment for "CWAC" that "should" have occurred in the current year plus the "interest" on the accumulated AFC from previous years. Because the funds will be added to realized income after the plant is on-line, the "AF" is accumulated at a net-of-tax rate (AFNTR). (The "AF" is REPORTED as income for the year it is incurred.) More specifically, the allowance for funds used during construction (AF) is a function of the net rate for AF (AFNTR), the fraction of construction work in progress (CWIP) that is not in the rate base (1-FCWRB), the construction work in progress (CWIP)that is not municipally owned [CWAC*(1-MAF)] and the accumulated allowance for funds under construction (AFAC). Occasionally construction work in progress (CWIP) is allowed in the rate base before the plant comes on line. If that is the case then those dollars must be subtracted from AF to avoid a double return. Since the tax treatment of CWIP and AFC differs, the model keeps track of both types of assets separately

The gross allowance for funds used during construction (AFGS) is calculated in a fashion similar to AF and is a function of the gross rate for AF (AFGSR) and the sum of the construction levels for the fraction of CWIP that is not in the rate base (1-FCWRB), the construction work in progress (CWAC) and the accumulated AF (AFAC). Finally, the allowance for funds used during construction is added to AFAC to accumulate the AFUDC.

```
AF(P,L)=AFNTR*(1-FCWRB)*(CWAC(P,L)*(1-MAF)+AFAC(P,L))
AFGS(P)=AFGSR*SUM(L)((1-FCWRB)*(CWAC(P,L)+AFAC(P,L)))
AFAC(P,L)=AFAC(P,L)+DT*AF(P,L)
```

Where:

AF(PLANT,LV12):	*Allow. for Funds Used During Construction. (M$/YR)*
AFNTR:	*Net Rate for AFUDC (1/YR)*
FCWRB:	*Fraction of CWIP in Rate Base ($/$)*
MAF:	*Municipal Asset Fraction ($/$)*
AFAC(PLANT,LV12):	*Accumulated AFUDC (M$)*
AFGS(PLANT):	*Gross Allow. Funds Used During Construction. (M$/YR)*
AFGSR:	*Gross Rate for AFUDC (1/YR)*

Construction level shifting

The plants, once initiated, must now be shifted through their construction levels. However, if the current construction level is equal to the construction delay, then the plant is fully constructed is removed from the construction levels, goes “on line” and is entered into the ratebase.

When the plant is fully constructed, the capacity under construction from the previous period (CUC) is added to the generation capacity completion rate (GCCR, the term "rate" is used here because capacity is completed in megawatts per year). Then the accumulated construction work in progress (CWAC) is added to the construction work into gross assets (CWGA). Finally, the accumulated AFUDC (AFAC) is added to AFUDC into gross assets (AFGA).

```
GCCR(P)=GCCR(P)+CUC(P,L)
CWGA(P)=CWGA(P)+CWAC(P,L)
AFGA(P)=AFGA(P)+AFAC(P,L)
```

Where:

GCCR(PLANT):	*Generation capacity Completion Rate (MW/YR)*
CUC(PLANT,LV12):	*Cap. Under Construction. in Previous Period (MW)*
CWGA(PLANT):	*Construction Work into Gross Assets (M$)*
CWAC(PLANT,LV12):	*Construction. Work in Progress Accumulated (M$)*
AFGA(PLANT):	*AFUDC into Gross Assets by Plant (M$)*
AFAC(PLANT,LV12):	*Accumulated AFUDC (M$)*

If the construction level is less than the construction delay, the construction level is incremented by one. For each plant, the capacity under construction in the previous period (CUC), the accumulated construction work in progress (CWAC) and the accumulated AFUDC (AFAC) are all shifted to the next level.

```
CUC(P,L+1)=CUC(P,L)
CWAC(P,L+1)=CWAC(P,L)
AFAC(P,L+1)=AFAC(P,L)
```

Begin Construction of New Plants

Capacity under construction for each plant at construction level 1 [CUC(P,1)] is set equal to the generating capacity initiated (the XMAX function assures CUC is never negative).

```
CUC(P,1)=XMAX(0,GCCI(P))
```

Where:

CUC(PLANT,LV12):	Cap. Under Construction. in Previous Period (MW)
GCCI(PLANT):	Generation capacity Initial Rate (MW/YR)

Because of their unique sizes, hydro projects' generating capacity completion rate (GCCR) are determined exogenously. Once that has been established, Construction work into gross assets (CWGA) is a function of the completion rate (GCCR) and the capital cost (GCCC) as with the other project types.

```
GCCR(HYDRO)=XGCCR(HYDRO)
CWGA(HYDRO)=GCCR(HYDRO)*GCCC(HYDRO)/1000
```

Where:

GCCR(PLANT):	*Generation capacity Completion Rate (MW/YR)*
XGCCR(PLANT):	*Generation Cap. Construction Completion Rate (MW/YR)*
CWGA(PLANT):	*Construction Work into Gross Assets (M$)*
GCCC(PLANT):	*Generation capacity Capital Costs ($/KW)*

The total capacity under construction (PCUC) is the sum of all the initial projects in all construction levels. The total accumulated construction costs are the total overnight construction costs (CWAC) plus the accumulated AFUDC (AFAC).

PCUC(P)=SUM(LV)(CUC(P,LV))
TCWAC(P)=SUM(LV)(CWAC(P,LV)+AFAC(P,LV))

Where:

PCUC(PLANT):	*Capacity under Construction (MW)*
CUC(PLANT,LV12):	*Cap. Under Construction. in Previous Period (MW)*
TCWAC(PLANT):	*CWIP plus AFUDC Accumulated (M$)*
CWAC(PLANT,LV12):	*Construction. Work in Progress Accumulated (M$)*
AFAC(PLANT,LV12):	*Accumulated AFUDC (M$)*

Plant conversions are handled next. The generating capacity converted from oil to coal (GCCV) is added to the generating capacity completion rate of coal plants [GCCR(COAL)]. The capacity converted to coal (GCCV) and the cost of conversion from oil to coal (GCCVCST) are added to construction work into gross assets of coal [CWGA(COAL)].

GCCR(COAL)=GCCR(COAL)+GCCV
CWGA(COAL)=CWGA(COAL)+GCCV*GCCVCST*INFLA/1000

Where:

GCCR(PLANT):	*Generation capacity Completion Rate (MW/YR)*
GCCV :	*Generationcapacity Converted from Oil to Coal (MW)*
CWGA(PLANT):	*Construction Work into Gross Assets (M$)*
GCCVCST:	*Generation capacity Oil to Coal Conversion Costs ($/KW)*

The generating capacity converted from oil to gas (OGCV) is added to the generating capacity completion rate of gas plants [GCCR(GCC)].

GCCR(GCC)=GCCR(GCC)+OGCV

Where:

OGCV:	*Generation capacity Converted from Oil to Gas (MW)*

Total generating capacity by plant type (GC) is adjusted with the current periods capacity additions (GCCR), retirements (GCR) and fuel conversions (GCFCV).

GC=GC+DT*(GCCR-GCR+GCFCV)

Where:

GC(PLANT):	*Generation capacity (MW)*
GCCR(PLANT):	*Generation capacity Completion Rate (MW/YR)*
GCR(PLANT,YEAR):	*Generation Cap. Retirements (MW/YR)*
GCFCV(PLANT):	*Fuel Conversion (MW)*

The generating capacity capital cost per kW by plant type (GCCOST, in dollars per kW) is a function of the construction work into gross assets (CWGA) AFUDC into gross assets (AFGA) and the amount of capacity completed (GCCR).

GCCOST=(CWGA+AFGA)/GCCR*1000

Where:

GCCOST(PLANT):	*Generating capacity Capital Cost ($/KW)*
CWGA(PLANT):	*Construction Work into Gross Assets (M$)*
AFGA(PLANT):	*AFUDC into Gross Assets by Plant (M$)*
GCCR(PLANT):	*Generation capacity Completion Rate (MW/YR)*

Plant capital additions (GCAD, in millions of dollars) is a function of the plant capital cost (GCCC), the generating capacity (GC) and the plant unit capital addition fraction (GCAC).

```
GCAD=GC*GCCC*GCAC/1000
```

Where:

GCAD(PLANT): Plant Capital Additions (M$)
GC(PLANT): Generation capacity (MW)
GCCC(PLANT): Generation capacity Capital Costs ($/KW)
GCAC(PLANT): Plant Unit Capital Additions (%)
GCAD(PLANT): Plant Capital Additions (M$)

The generating plant construction expenditure (TCW) for the current period is a function of the total construction work in progress [sum(plant,lv)(CW(plant,lv))], total plant capital additions [sum(p)(GCAD(p))], construction work into gross assets for hydro [CWGA(HYDRO)], life extension costs [GCEXST], total fuel conversion costs [sum(plant)(GCFCST(plant))] and oil to coal conversion costs [GCCCV*GCCCVST].

```
TCW=SUM(PLANT,LV)(CW(PLANT,LV)) + SUM(P)(GCAD(P)) + CWGA(HYDRO) +
        (GCEXCST+SUM(PLANT)(GCFCST(PLANT)))*INFLA + GCCV*GCCVCST*INFLA/1000
```

Where:

TCW: Generating Plant Construction Expenditures (M$/YR)
CW(PLANT,LV12): Construction Work in Progress (M$/YR)
GCAD(PLANT): Plant Capital Additions (M$)
CWGA(PLANT): Construction Work into Gross Assets (M$)
GCEXCST: Life Extension Costs (M$)
GCFCST(PLANT): Fuel Conversion Costs (M$)
GCCV : Generation capacity Converted from Oil to Coal (MW)
CWGA(PLANT): Construction Work into Gross Assets (M$)
GCCVCST: Generation capacity Oil to Coal Conversion Costs ($/KW)

In some cases, not all new plant is allowed in the ratebase immediately. Some of it may be deferred pending a “used and useful” determination. These plants are usually nuclear plants with very high construction costs and long construction delays. AFUDC from the deferred rate base (AFAF) is a function of the construction work portion of the deferred rate base (CWDFRB), the AFUDC portion of the deferred rate base (AFDFRB) and the gross rate for AFUDC (AFGSR).

```
AFAF=(CWDFRB+AFDFRB)*AFGSR
```

Where:

AFAF: AFUDC from the Deferred Rate Base (M$/YR)
CWDFRB: CW portion of Deferred Rate Base (M$/YR)
AFDFRB: AFUDC portion of Deferred Rate Base (M$/YR)
AFGSR: Gross Rate for AFUDC (1/YR)

Nuclear construction work into gross assets [CWGA(NUCLEAR)] is added into the CW portion of the deferred rate base (CWDFRB) and nuclear AFUDC into gross assets is added into the AFUDC portion of the deferred rate base (AFDFRB).

```
CWDFRB=CWDFRB+CWGA(NUCLEAR)
AFDFRB=AFDFRB+AFGA(NUCLEAR)+AFAF
```

Where:

CWDFRB:	*CW portion of Deferred Rate Base (M$/YR)*
AFDFRB:	*AFUDC portion of Deferred Rate Base (M$/YR)*
CWGA(PLANT):	*Construction Work into Gross Assets (M$)*
AFGA(PLANT):	*AFUDC into Gross Assets by Plant (M$)*

The fraction of nuclear costs that can go into the rate base (NUCRB) starts out as an exogenously specified input. Then NUCRB becomes the lesser of either itself or the CW portion of the deferred rate base (CWDFRB) and the AFUDC portion of the deferred rate base (AFDFRB). The CW portion of nuclear costs that go into the rate base (CWRB) is a function of NUCRB and the CW portion of the deferred rate base as a percent of the total deferred rate base [CWDFRB/(CWDFRB+AFDFRB)].

```
LOC1=CWDFRB+AFDFRB
NUCRB=XMIN(NUCRB,LOC1)
CWRB=NUCRB*CWDFRB/(CWDFRB+AFDFRB)
AFRB=NUCRB-CWRB
```

Where:

CWDFRB:	*CW portion of Deferred Rate Base (M$/YR)*
AFDFRB:	*AFUDC portion of Deferred Rate Base (M$/YR)*
NUCRB(YEAR):	*raction of Nuclear Plant Allowed in Rate Base*
CWRB:	*CW portion of Nuclear Costs into Rate Base (M$/YR)*
AFRB:	*AFUDC portion of Nuclear Costs into Rate Base (M$/YR)*

The CW portion of nuclear costs that go into the rate base (CWRB) is removed from the CW portion of the deferred rate base (CWDFRB). Remove the AFUDC portion of nuclear costs that go into the rate base (AFRB) from the AFUDC portion of the deferred rate base (AFDFRB).

```
CWDFRB=CWDFRB-CWRB
AFDFRB=AFDFRB-AFRB
```

Where:

CWDFRB:	*CW portion of Deferred Rate Base (M$/YR)*
CWRB:	*CW portion of Nuclear Costs into Rate Base (M$/YR)*
AFDFRB:	*AFUDC portion of Deferred Rate Base (M$/YR)*
AFRB:	*AFUDC portion of Nuclear Costs into Rate Base (M$/YR)*

PROCEDURE PRODUCTION

While construction is a function of estimated long-term demand, power production is controlled by current demand. The utility tries to satisfy demand with its least expensive plant capacity, but situations may arise where expensive plants must be run, or power must be purchased from other utilities.

The production subsector uses an adjusted derating method to dispatch plants. The derating method uses the scheduled (SOR) and unscheduled outage rates (UOR) in any arbitrary time interval to develop an effective firm generating capacity (EGC) for each plant type during that time interval. These time intervals typically represent climatic seasons but may represent hours of the year. This sector also simulates power purchases when economic or necessary. Plant availability and generation for four plant types—coal, nuclear, hydroelectric, and oil/gas—are currently considered. Base versus peak loading distinctions are made. Must-run, pumped storage, firm purchases, interruptable load, and qualified facilities are also dispatched.

Effective generating capacity

Initialize the average (ADPM), minimum (MDPM), and peak (PDPM) loads.

```
ADPM(M)=MONOUT(M)/HOURS(M)*1000
MDPM(M)=MINLD(M)
PDPM(M)=PKLOAD(M)
```

Where:

ADPM(MONTH):	*Avg. Demand modified by Pumped Storage Hydro (MW)*
MONOUT(MONTH):	*Monthly Output (gWh/month)*
MDPM(MONTH):	*Minimum Demand as Modified by Pumped Storage (MW)*
MINLD(MONTH):	*Monthly Minimum Load (MW/month)*
PDPM(MONTH):	*Peak Demand as Modified by Pumped Storage (MW)*
PKLOAD(MONTH):	*Monthly Peak Load (MW/month)*

Plants have scheduled maintenance outages and a history of unscheduled outages. The plant availability factor (PAF) is a function of both the scheduled outage rate (SOR) and the unscheduled outage rate (UOR) of each plant type. The same is true for the ability to dispatch from a particular plant. The dispatch plant availability factor (DPAF) is a function of the scheduled outage rate (DSOR) and the unscheduled outage rate (DUOR) of each dispatch type.

```
PAF(P,M)=(1-UOR(P))*(1-SOR(P,M))
DPAF(D,M)=(1-DUOR(D))*(1-DSOR(D,M))
```

Where:

PAF(PLANT,MONTH):	*lant Availability fraction. (MW/MW)*
UOR(PLANT):	*nscheduled Outage Rate (Fraction)*
SOR(PLANT,MONTH):	*cheduled Outage Rate (Fraction)*
DPAF(DISPATCH,MONTH):	*Plant Availability Fraction. (MW/MW)*
DUOR(DISPATCH):	*Unscheduled Outage Rate by Dispatch (Fraction)*
DSOR(DISPATCH,MONTH):	*Scheduled Outage Rate by Dispatch*

If the fractional year the new plant can be operated (OPFR) is greater than or equal to the fractional number of hours left in the year, then the effective generating capacity (EGC) is a function of the generating capacity (GC) and the plant availability factor (PAF).

```
DO IF OPFR(P) GE LOC1
        EGC(DD,M)=GC(PLANT)*PAF(DD,M)
```

Where:

EGC(DISPATCH,MONTH):	*Effective Generating capacity (MW)*
GC(PLANT):	*Generation capacity (MW)*
PAF(PLANT,MONTH):	*Plant Availability Fraction. (MW/MW)*
OPFR(PLANT):	*Fractional Year New Plant is Operational*

Otherwise, the fractional year the new plant can be operated (OPFR) is less than the fractional number of hours left in the year. Then the effective generating capacity (EGC) is a function of the generating capacity (GC) and the plant availability factor (PAF) less the new capacity (GCCR). If the plant is coal fired, this periods conversion from oil to coal (GCCV) is removed from the effective generating capacity (EGC).

```
ELSE
        EGC(DD,M)=(GC(PLANT)-GCCR(PLANT))*PAF(DD,M)
        DO IF PLNKEY EQ "COAL"
                EGC(DD,M)=(GC(PLANT)-GCCV)*PAF(DD,M)
```

The *effectual* must run oil and gas capacity [MROIL(y)*PAF(OILG,M)] is removed from the effective generating capacity of oil and gas [EGC(OILG,M)]. The effective generating capacity of must run oil and gas [EGC(MROIL,M)] is equal to the generating capacity (MROIL) multiplied by its availability factor (MRPAF).

```
EGC(OILG,M)=EGC(OILG,M)-MROIL(Y)*PAF(OILG,M)
EGC(OILMR,M)=MROIL(Y)*MRPAF(M)
```

Where:

MROIL(YEAR): *Must Run Oil & Gas (MW)*
MRPAF(MONTH): *Must Run Oil & Gas Availability Factor*

The effective generating capacity for qualified facilities [(EGC,QF,M)] is a function of the historical generating capacity (XQFGC) and the availability factor (QFPAF) summed over all technologies.

```
EGC(QF,M)=SUM(T)(XQFGC(T,Y)*QFPAF(T,M))
```

Where:

XQFGC(TECH,YEAR): *Historical QF Generating capacity (MW)*
QFPAF(TECH,MONTH): *QF Availability Factor (Fraction)*

The effective generating capacity of the purchased power dispatch [EGC(PPPMAP(PP))] is a function of the purchased power generating capacity (PPGC) and its availability factor((PPAF).

```
DD=PPMAP(PP)
EGC(DD,M)=PPGC(PP,Y)*PPAF(PP,M)
```

Where:

PPMAP(PP): *urchase Power Map between PP and DISPATCH Sets*
PPGC(PP,YEAR): *Purchase Power capacity (MW)*
PPAF(PP,MONTH): *Purchase Power Availability Factor (Fraction)*

The effective generating capacity of the economy purchase power [EGC(ECPP,M)] is a function of the excess regional generating capacity (EXCAP) and the average demand modified by pumped storage (ADPM)

```
EGC(ECPP,M)=EXCAP*ADPM(M)
```

Where:

EXCAP: *xcess Regional Generating capacity (MW)*
ADPM(MONTH): *Avg. Demand modified by Pumped Storage Hydro (MW)*

The effective generating capacity of emergency purchase power [EGC(EMPP)] is not constrained and is set equal to the peak demand (PDPM). The effective generating capacity of the interruptable load dispatch ([EGC(interrupt)] is set equal to the capacity of the interruptable load. The effective generating capacity of pumped storage [EGC(psload)] is a function of its generating capacity (PSGC) and availability factor (PSPAF).

```
EGC(EMPP,M)=PDPM(M)
EGC(INTERRUPT,M)=SILGC(M,Y)
EGC(PSLOAD,M)=PSGC*PSPAF(M)
```

Where:

PDPM(MONTH): *Peak Demand as Modified by Pumped Storage (MW)*
SILGC(MONTH,YEAR): *MONTH Interruptible Load Effective Generation capacity (MW)*

PSGC: *Pumped Storage capacity (MW)*
PSPAF(MONTH): *Pumped Storage Availability Factor*

The pumped storage electricity dispatched [EGP(psload)] is a function of its effective generating capacity [EGC(psload)] and its usage rate (PSUSE).

EGP(PSLOAD,M)=EGC(PSLOAD,M)*PSUSE*HOURS(M)/1000

Where:

EGP(DISPATCH,MONTH): *Electricity Dispatched (GWH/YR)*
PSUSE: *Pumped Storage Usage Rate (Fraction.)*

Pumped storage is used to exchange base-load generation for peaking generation. Pumped storage "generation" assumes that utility operating procedures limit the fraction of the time (PSUSE) pumped storage can be used. PS generation reduces the peak load (PDPM) that the other plants on the system must serve. It increases the average load (ADPM) because of energy losses (PSEF) associated with filling the PS reservoir. The minimum load (MDPM) is increased by a fraction (PSMINF) of the PS load [EGC(PS)/PSEF], to correspond to the extra base generation needed to fill the reservoir when PS is NOT being used.

ADPM(M)=ADPM(M)+EGP(PSLOAD,M)*(1/PSEF-1)/HOURS(M)*1000
MDPM(M)=MDPM(M)+EGC(PSLOAD,M)/PSEF*PSMINF
PDPM(M)=XMAX(ADPM(M),PDPM(M)-EGC(PSLOAD,M))

Where:

ADPM(MONTH): *Avg. Demand modified by Pumped Storage Hydro (MW)*
PSEF: *Pumped Storage Efficiency (KWH/KWH)*
MDPM(MONTH): *Minimum Demand as Modified by Pumped Storage (MW)*
PSMINF: *Pumped Storage change in Minimum Demand Fraction*
PDPM(MONTH): *Peak Demand as Modified by Pumped Storage (MW)*

The average demand (modified by pumped storage, ADPM) is adjusted by interchange power (delivered, IDEL, and received, IREC).

ADPM(M)=ADPM(M)+(IDEL-IREC)*1000/8760

Where:

IDEL: *Interchanged Power Delivered (GWh)*
IREC: *Interchanged Power Received (GWh)*

The maximum load that can be satisfied by baseload generating capacity (MILP) is calculated from the load curve equations and the flexibility of baseload plants to follow load and serve intermediate and peaking needs (MILD).

MILP=MDPM+(PDPM-MDPM)*(1-MILD/8760)**XMAX(0,(PDPM-ADPM)/(ADPM-MDPM))

Where:

MILP(MONTH): *Maximum Base Load Power (MW)*
MDPM(MONTH): *Minimum Demand as Modified by Pumped Storage (MW)*
PDPM(MONTH): *Peak Demand as Modified by Pumped Storage (MW)*
MILD(POWER): *Maximum Base Load Power Duration (HOURS/YR)*

Baseload plants are limited by MILP (LIMIT). Nuclear plants are limited by minimum load constraints (NUMLCFR). Peaking (and intermediate) plants are limited only by the system peak (PDPM).

LIMIT(*base*)=MILP
LIMIT(NUCLEAR)=XMIN(MILP,MDPM*NUMLCFR)
LIMIT(*peak*)=PDPM

Where:

LIMIT(DISPATCH,MONTH):	*Upper Limit for Dispatch (MW)*
MILP(MONTH):	*Maximum Base Load Power (MW)*
MDPM(MONTH):	*Minimum Demand as Modified by Pumped Storage (MW)*
NUMLCFR:	*Nuclear Min. Load Constraint Fraction*
PDPM(MONTH):	*Peak Demand as Modified by Pumped Storage (MW)*

Dispatch plants

Given the calculated effective generating capacity, ENERGY 2020 dispatches plants and purchases power in the order of increasing costs. For example, nuclear power will be dispatched before coal power; available coal power from the grid will be purchased before oil-fired plants are dispatched. Base load plants can follow loads up to the "MILP" point discussed above. Thereafter, peaking plants and peak purchases are used to satisfy demand. Firm purchase (FPGC) and interruptable load (ILGC) are exogenously specified to the model. They are dispatched as ordinary generation.

Dispatch Units and Subtract Generation From Load Curve (loop)

ENERGY 2020 will “loop” through the dispatch types (plants) in the order of increasing costs. All of the PROMULA code in this section will be executed for each plant dispatched. After each plant is dispatched and the resultant capacity is removed from the load curve, ENERGY 2020 selects the next dispatch plant and repeats the code in this section. When all of the plants (and purchases etc.) have been dispatched, ENERGY 2020 resumes in the following section.

For each dispatch type, the total effective generating capacity (TEGC) is equal the lesser of itself or the dispatch limit (LIMIT). Remember, we are traversing through the dispatch types, from least expensive to most expensive. Before the traversing started, TEGC was set equal to zero. Then, the total effective generating capacity (TEGC) for the first dispatch type simply becomes zero. Before the next dispatch type is reached, TEGC is updated (this is shown below). The upper limit for the particular dispatch type (LIMIT) is the maximum of either *(i):* the difference between it and the total effective generating capacity (LIMIT-TEGC), or *(ii):* the average demand (ADPM). The maximum demand satisfied by dispatch type (MDS) becomes the minimum of either *(i):* the effective generating capacity taking into account the operational outage rate [EGC*(1-OOR)], or *(ii):* the peak demand (PDPM).

TEGC=XMIN(LIMIT,TEGC)
LIMIT=XMAX((LIMIT-TEGC),ADPM)
MDS=XMIN(EGC*(1-OOR),PDPM)

Where:

TEGC(DISPATCH,MONTH):	*Total Effective Generating capacity (MW)*
LIMIT(DISPATCH,MONTH):	*Upper Limit for Dispatch (MW)*
ADPM(MONTH):	*Avg. Demand modified by Pumped Storage Hydro (MW)*
MDS(DISPATCH,MONTH):	*Max. Demand Satisfied by Plant (MW)*
EGC(DISPATCH,MONTH):	*Effective Generating capacity (MW)*
OOR(DISPATCH):	*Operational Outage Rate (Fraction)*

PDPM(MONTH): *Peak Demand as Modified by Pumped Storage (MW)*

After a plant is dispatched, its generation is removed from the load curve (shown below). When the load curve changes, peak, average and minimum demands (PDPM, ADPM and MDPM, respectively) change as well. Then, ALPHA, BETA and GAMMA, the parameters for the load duration curve, must be re-calculated.

```
ALPHA=XMAX(0,(PDPM-ADPM)/(ADPM-MDPM))
BETA=(1+ALPHA)/ALPHA
GAMMA=ALPHA/ALPHA*(PDPM-MDPM)**(1/(ALPHA+1))
```

Where:

ALPHA(MONTH): *Shape Parameter for Load Curve*
BETA(MONTH): *Load Curve Parameter*
GAMMA(MONTH): *Load Curve Parameter*

Using the new load curve parameters (ALPHA, BETA and GAMMA, modified above), the electricity dispatched (EGP) is calculated. The generation is the integral of the load duration curve from MDS(D) to MDS(D+1).

```
EGP=HOURS/1000*(MDS-(XMAX(0,MDS-MDPM)/GAMMA)**BETA/BETA)
EGP=XMIN(EGP,ADPM*HOURS/1000)
```

Where:

EGP(DISPATCH,MONTH): *Electricity Dispatched (GWH/YR)*
MDS(DISPATCH,MONTH): *Max. Demand Satisfied by Plant (MW)*
MDPM(MONTH): *Minimum Demand as Modified by Pumped Storage (MW)*
ADPM(MONTH): *Avg. Demand modified by Pumped Storage Hydro (MW)*

As mentioned above, the electricity dispatched must be removed from the load curve. The effective generating capacity (EGC) is from the plant dispatched above. Peak, average and minimum demand for power (PDPM, ADPM and MDPM) are then recalculated. Total effective generating capacity (TEGC) is calculated as the minimum of either *(i):* the LIMIT or *(ii):* effective generating capacity is added to it.

```
EGC=DTYPE*EGC+(1-DTYPE)*XMIN(EGC,ADPM)
MDPM=XMAX(0,MDPM-EGC)
ADPM=XMAX(0,ADPM-EGP/HOURS*1000)
PDPM=XMAX(0,ADPM,PDPM-EGC)
TEGC=XMIN(LIMIT,TEGC+EGC)
```

Where:

DTYPE(DISPATCH): *Dispatch Type (0=Normal,1=Peak)*
EGC(DISPATCH,MONTH): *Effective Generating capacity (MW)*
TEGC(DISPATCH,MONTH): *Total Effective Generating capacity (MW)*
LIMIT(DISPATCH,MONTH): *Upper Limit for Dispatch (MW)*

At this point, ENERGY 2020 selects the next dispatch plant and re-executes all of the code in this section. If ENERGY 2020 is finished dispatching all of the plants, it resumes at the following section calculating the reserve margin and system totals.

Reserve margin and system totals

The total generating capacity (CAPACITY) is equal to the generating capacity of all the plants [sum(p)(GC(p))] corrected for winter/summer capability (WSRATIO) plus the pumped storage

generating capacity (PSGC), the generating capacity of the qualified facilities [sum(t)(XQFGC(t))], purchased power [sum(pp)(PPGC(pp))] and the effective capacity of the interruptable load. The reserve margin is initially calculated as ratio of capacity to peak demand minus one. An "extended" reserve margin, including interchange power is also calculated in a similar fashion. The final reserve margin is the higher of the initial reserve margin and either the extended reserve margin or the desired margin, whichever is less. This allows interchange power to count toward the reserve margin only up to the desired reserve margin value. Interchange power cannot cause excess reserve margins; excess capacity can.

```
CAPACITY=SUM(P)(GC(P)/WSRATIO(P)) + PSGC + SUM(T)(XQFGC(T)) + SUM(PP)(PPGC(PP)) +
        MAX(M)(SILGC(M,Y))
RMARGIN=CAPACITY/PDP-1
ERMARGIN=(CAPACITY+SUM(PW)(RIC(PW)))/PDP-1
RMARGIN=XMAX(RMARGIN,XMIN(ERMARGIN,DRM(PEAK)))
```

Where:

CAPACITY:	*Generating capacity including QF and purchased power*
GC(PLANT):	*Generation capacity (MW)*
WSRATIO(PLANT):	*Winter to Summer capacity Ratio (Fraction)*
PSGC:	*Pumped Storage capacity (MW)*
XQFGC(TECH,YEAR):	*Historical QF Generating capacity (MW)*
PPGC(PP,YEAR):	*Purchase Power capacity (MW)*
SILGC(MONTH,YEAR):	*MONTH Interruptible Load Effective Generation capacity (MW)*
RIC(POWER,YEAR):	*Regional Interchange capacity (MW)*
RMARGIN:	*Reserve Margin Inc. Pool Sales (Fraction.)*
ERMARGIN:	*Extended Reserve Margin (Fraction.)*
DRM(POWER):	*Desired Reserve Margin (MW/MW)*

System totals are generated by calculating the electricity generated (EG, in GWhs by plant type), qualified facility electricity generated (QFEG), purchased power electricity generated (PPEG), total electricity generated (TEG), interruptable load electricity generated (ILEG), total electricity available (TEA), load factor (LF) and plant capacity factor (PCF). Most of these equations are simply sums the exceptions being the load and plant capacity factors. The load factor is the ratio of average demand to peak demand. An "improving" load factor moves closer to unity. The plant capacity factor captures the percent of actual electricity generated to the total possible. Note that care is taken to count new generation only for the months it was on line.

```
EG(P)=SUM(M)(EGP(P,M))
EG(OGCT)=EG(OGCT)+SUM(M)(EGP(PGAS,M))
EG(GCC)=EG(GCC)+SUM(M)(EGP(IFO2,M))
EG(OILG)=EG(OILG)+SUM(D,M)(EGP(D,M))
EG(COAL)=EG(COAL)+SUM(M)(EGP(CLEMR,M)+EGP(BCLE,M))
QFEG(T)=(XQFGC(T)*QFPAF(T,WINTER)) * SUM(M)(EGP(QF,M))/SUM(TECH)(XQFGC(TECH) *
        QFPAF(TECH,WINTER))
PPEG(PP)=SUM(M)(EGP(PPMAP(PP),M))
TEG=SUM(P)(EG(P))
ILEG=SUM(M)(EGP(INTERRUPT,M))
TEA=TEG+SUM(T)(QFEG(T))+SUM(PP)(PPEG(PP)) - SUM(M)(EGP(PSLOAD,M)) * (1/PSEF-
        1)+(IREC-IDEL)
LF=ADP/PDP
PCF=EG/((GC-GCCR*(1-OPFR))*8760/1000)
```

Where:

EG(PLANT):	*Electricity Generated (GWH/YR)*
EGP(DISPATCH,MONTH):	*Electricity Dispatched (GWH/YR)*
QFEG(TECH):	*QF Electricity Generated (GWH/YR)*
XQFGC(TECH,YEAR):	*Historical QF Generating capacity (MW)*
QFPAF(TECH,MONTH):	*QF Availability Factor (Fraction)*
PPEG(PP):	*Purchase Power Purchases (GWH)*
PPMAP(PP):	*Purchase Power Map between PP and DISPATCH Sets*
TEG:	*Total Electricity Generated (GWH/YR)*
ILEG(YEAR):	*Interruptible Load Generation (MW)',*
LF:	*Load Factor (MW/MW)*
ADP:	*Annual Average Load*
PDP:	*Annual Peak Load*
PCF(PLANT):	*Plant capacity Factor (1/YR)*
GC(PLANT):	*Generation capacity (MW)*
GCCR(PLANT):	*Generation capacity Completion Rate (MW/YR)*
OPFR(PLANT):	*Fractional Year New Plant is Operational*

PROCEDURE TRANSDISTR

Transmission and distribution facilities are added when forecasted peak demand indicates additional T&D capacity is needed.This procedure calculates the cost of maintaining transmission and distribution facilities sufficient to handle the utility's generation.

The transmission and distribution retirement rate (TDRR, in MW/year) is set equal the transmission and distribution generating capacity (TDGC) divided by the transmission and distribution plant lifetime (TDPL). The indicated transmission and distribution construction rate (TDICR, in MW/year) for each class is a function of the class' contribution to the peak (CTP), the T&D reserve margin (TDRM), the T&D generating capacity (TDGC), and the T&D construction completion rate (TDCT). Then the T&D retirement rate (TDRR) is added to the indicated T&D construction rate because at least what is retired must be replaced {if the indicated T&D construction rate turns out to be negative, then it is set equal to zero [XMAX(TDICR,0)]}.

```
TDRR=TDGC/TDPL
TDICR(C,TD)=MAX(M)(CTP(C,M))*(1+TDRM(C,TD))-TDGC(C,TD)-TDCR(C,TD)
TDICR=XMAX(TDICR,0)+TDRR
```

Where:

TDRR(CLASS,TD):	*Trans. and distribution. Retirement Rate (MW/YR)*
TDGC(CLASS,TD):	*Transmission and Distribution capacity (MW)*
TDPL(TD):	*Transmission and Distribution Plant Life (YRS)*
TDICR(CLASS,TD):	*Indicated T&D Construction Rate (MW/YR)*
TDCR(CLASS,TD):	*T&D Construction Completion Rate (MW/YR)*
TDCT(TD):	*T&D Construction Time (YRS)*
CTP(CLASS,MONTH):	*Contribution to Electric Peak Load (MW)*
TDRM(CLASS,TD):	*Transmission and Distribution Reserve Margin (MW/MW)*

The transmission and distribution construction rate (TDCR) in the current period (year) is a function of last year's T&D construction rate, the indicated construction rate (TDICR), and the construction time (TDCT). The transmission and distribution to be financed (TDTBF) is a function of the construction rate (TDCR) and the capital cost (TDCC). The financing of T&D is assumed to occur on the last year of construction as the new lines are completed. Capital cost is

exogenous to the model. The T&D generating capacity (TDGC) is updated from the previous years value with construction and retirements (TDCR & TDRR, respectively).

```
TDCR=TDCR+DT*(TDICR-TDCR)/TDCT
TDTBF(C,TD)=TDCR(C,TD)*TDCC(C,TD)*INFLA(Y)
TDGC=TDGC+DT*(TDCR-TDRR)
```

Where:

TDTBF(CLASS,TD): *Trans. and Distribution. to be Financed (M$/YR)*
TDGC(CLASS,TD): *Transmission and Distribution capacity (MW)*

Electricity production costs are internally calculated in terms of operating and maintenance costs, and fuel costs. Specifically, production costs are the sum of facility operating and maintenance costs, general and administrative costs, operational costs of the transmission and distribution facilities, and fuel costs.

FUELCOSTS

This procedure determines the cost of fuel for the plants dispatched above.

The fuel prices used in these calculations come from the supply sector(s). Fuel prices for each plant type are determined based on the map between prices and plant-type (PRPLMAP).

```
EUFP(PLANT)=SUM(PRICES)(FP(PRICES)*PRPLMAP(PLANT,PRICES))
```

Where:

EUFP(PLANT): *Fuel Price for Electric Utility ($/MBTU)*
FP(PRICES): *Delivered Fuel Price ($/GJ)*
PRPLMAP(PLANT,PRICES): *Map between PLANT and PRICES*

Oil/gas plants are dual fuel plants that can switch between natural gas and oil fuels (generally distillate) as economics justify. The fraction of generation using oil (OILFR) is calculated as a market share process based on relative prices with parameters estimated from historical data. Engineering constraints (EUOFM) on the oil/gas switching are also historical estimated but are assumed to be minimal in future years. The effective price of fuel (EUFP) in the plants burning oil and gas is determined by multiplying the fraction of fuel from oil (OILFR) by the oil price and adding to it one minus the oil/gas fraction times the gas price. The variance factor used in this calculation captures the imperfect price information available to the utility.

```
OILFR=1/(1+(FP(EU_GAS)/(EUOFM*FP(EU_RESID)))**EUFVF)
EUFP(OILG)=(FP(EU_RESID)*OILFR+FP(EU_GAS)*(1-OILFR))
```

Where:

OILFR: *Fraction of Oil/Gas which is Oil (FRAC.)*
EUOFM: *OIL Fraction multiplier. (Fraction)*
EUFVF: *Fungible Market Share Variance Factor (DLESS)*
EUFP(PLANT): *Fuel Price for Electric Utility ($/MBTU)*
FP(PRICES): *Delivered Fuel Price ($/GJ)*

The embodied fuel requirements (EFRQ) are the integral of new capacity (GCCR) times the marginal heat rate less any retirements (GCR). Retirements assume the average heat rate.

The embedded fuel requirement (EFRQ, by plant) is equal to the previous periods value [$EFRQ_{t-1}$] plus the fuel required for the new capacity [(GCCR+GCFCV)*HRTM] less the fuel required for the retirements [GCR/GCL*EFRQ].

EFRQ=EFRQ+(GCCR+GCFCV)*HRTM/1000-DT*GCR/GCL*EFRQ

Where:

EFRQ(PLANT):	*Embodied Fuel Requirement (MBTU/HOUR)*
GCCR(PLANT):	*Generation capacity Completion Rate (MW/YR)*
GCFCV(PLANT):	*Fuel Conversion (MW)*
HRTM(PLANT):	*Marginal Heat Rate (BTU/KWH)*
GCR(PLANT,YEAR):	*Generation Cap. Retirements (MW/YR)*
GCL(PLANT):	*Generation capacity (MW)*
HRTM(PLANT)	*Marginal Heat Rate (BTU/KWH)*

Marginal plant heat rates (HRTM) are exogenous to the model. The model calculates an average heat rate (HRTA) for each plant type as the ratio of embodied fuel requirements (the energy needed if the plants where at full operation)(EFRQ) and the on-line capacity (GC). The second term of the equation [(1-EFRQ/EFRQ)*HRTM] will be zero for any non-zero value for EFRQ. If the embodied fuel requirements are zero, (i.e., the generation capacity is zero) the average heat rate (HRTA) will then equal the marginal heat rate (HRTM).

HRTA=EFRQ/(GC/1000)+(1-EFRQ/EFRQ)*HRTM

Where:

HRTA(PLANT):	*Average Heat Rate (BTU/KWH)*
HRTM(PLANT):	*Marginal Heat Rate (BTU/KWH)*

The utility's demand for fuel (EUDMD, by plant) is a function of the electricity generated (EG), the average heat rate (HRTA) sometimes adjusted by a multiplier (EUODM not equal to 1) that captures losses and other fuel demands, if any.

EUDMD=EG*HRTA/1E6*EUODM

Where:

EUDMD(PLANT):	*Utility Fuel Demand (TBTU/YR)*
EG(PLANT):	*Electricity Generated (GWH/YR)*
HRTA(PLANT):	*Average Heat Rate (BTU/KWH)*
EUODM(PLANT):	*Electric utility fuel multiplier*

Qualified facility fuel demand (QFDMD) is a function of the electricity generated by the QFs (GFEG) and the QF heat rate (QFHRT)

QFDMD=QFEG*QFHRT/1E6

Where:

QFDMD(TECH):	*Fuel Demand from QF (TBTU/YR)*
QFEG(TECH):	*QF Electricity Generated (GWH/YR)*
QFHRT(TECH):	*QF Heat Rate*

The fuel demanded for purchased power (PPDMD, by plant) is a function of the electricity purchased (PPEG) and the heat rate (HRTA). Given the purchased power type, the PPPLMAP variable points to the appropriate plant type to use its heat rate (HRTA).

PPDMD(PP)=SUM(PLANT)(HRTA(PLANT)*PPPLMAP(PP,PLANT))*PPEG(PP)/1E6

Where:

PPDMD(PP): *Purchase Power Fuel Demand (TBTU/YR)*
HRTA(PLANT): *Average Heat Rate (BTU/KWH)*
PPPLMAP(PP,PLANT): *Map between Purchased Power PLANT*
PPEG(PP): *Purchase Power Purchases (GWH)*

The energy demand can then be calculated by fuel. The energy demand for gas, oil, coal and biomass are calculated by summing the electric utility fuel demand (EUDMD) for each plant type that uses such fuel.

DMDES(GAS)=EUDMD(OGCT)+EUDMD(GCC) + (EUDMD(OGST) + EUDMD(OGCC) + EUDMD(OILG))*(1-OILFR)
DMDES(OIL)=(EUDMD(OGST)+EUDMD(OGCC)+EUDMD(OILG))*OILFR
DMDES(COAL)=EUDMD(COAL)+EUDMD(GCOAL)
DMDES(BIOMASS)=EUDMD(WOODG)+EUDMD(WOODS)

Where:

DMDES(FUEL): *Energy Demand (TBTU/YR)*
EUDMD(PLANT): *Utility Fuel Demand (TBTU/YR)*

The gas fungible energy demand [(FDMDES(GAS)] is equal to oil & gas steam [EUDMD(OGST)], oil and gas combined cycle (OGCC) and oil/gas (OILG) all multiplied by fraction of oil & gas that is gas (1-OILFR).

FDMDES(GAS)=(EUDMD(OGST)+EUDMD(OGCC)+EUDMD(OILG))*(1-OILFR)

Where:

FDMDES(FUEL): *Fungible Energy Demand (TBTU/YR)*
OILFR: *Fraction of Oil/Gas which is Oil (FRAC.)*

The unit fuel cost (UFC in mills/kWh) is a function of the fuel demand (EUFP) and heat rate (HRTA) adjusted by a calibrated operational multiplier (EUOPM) used to capture engineering constraints that cause heat rate fluctuations such as partial valve settings and start-ups/shut-downs.

UFC=EUFP*HRTA*EUOPM/1000

Where:

UFC(PLANT): *Unit Fuel Cost (MILLS/KWH)*
EUFP(PLANT): *Fuel Price for Electric Utility ($/MBTU)*
HRTA(PLANT): *Average Heat Rate (BTU/KWH)*
EUOPM(PLANT): *Operational Multiplier.*

Nuclear unit fuel costs are exogenous.

UFC(NUCLEAR)=XUFC(NUCLEAR)

Where:

XUFC(PLANT): *Historical Unit Fuel Cost (MILLS/KWH)*

Utilities provide funds to a spent fuel disposal costs escrow account (SFAC) based on expected unit spent fuel disposal costs (SFDC) and nuclear generation (EG). Specifically, the spent fuel

disposal costs escrow account (SFAC) is equal to last periods value ($SFAC_{t-1}$) plus the new spent fuel disposal costs [$SFDC*EG_{nuclear}$] adjusted for inflation.

SFAC=SFAC+DT*(SFDC*EG(NUCLEAR)*INFLA)

Where:

SFAC: *Spent Fuel Disposal Costs Escrow Account (M$)',*
SFDC: *Spent Fuel Disposal Costs (MILLS/KWH)',*
EG(PLANT): *Electricity Generated (GWH/YR)',*

The total fuel cost by plant (FC) is a function of the electricity generated (EG) and the unit fuel costs (UFC). The total fuel cost (TFC) sums the plants of FC.

FC=EG*UFC/1000
TFC=SUM(PLANT)(FC(PLANT))

Where:

FC(PLANT): *Fuel Cost (M$/YR)*
UFC(PLANT) *Unit Fuel Cost (MILLS/KWH)*
TFC: *Total Fuel Cost (M$/YR)*

PROCEDURE DECOMMISSION

Utilities owning nuclear plants must provide a nuclear plant decommissioning escrow account (DCAC). This procedure calculates decommissioning costs for those utilities with nuclear plants. It tracks contributions to a decommissioning escrow account and yearly subtractions from this account to pay for decommissioning retired nuclear plants.

The nuclear capacity which completes decommissioning (DCGCCR) is a function of the capacity being decommissioned (DCGC) and the time required for decommissioning (DCAT).

DCGCCR=DCGC/DCAT

Where:

DCGCCR: *Decommissioning Completion Rate (MW/yr)*
DCGC: *Generating capacity Being Decommissioned (MW)*
DCAT: *Time Required to Decommission (Years)*

The amount of capacity being decommissioned (DCGC) is equal to the amount undergoing decommissioning in the previous year (DCGC) plus any nuclear capacity retired (GCR(NUCLEAR) in the current year minus the capacity which completes decommissioning (DCGCCR).

DCGC=DCGC+DT*(GCR(NUCLEAR)-DCGCCR)

Where:

DCGC: *Generating capacity Being Decommissioned (MW)*
GCR(PLANT,YEAR): *Generation Cap. Retirements (MW/YR)*
DCGCCR: *Decommissioning Completion Rate (MW/yr)*

The cumulative amount of capacity which has completed decommissioning (DCGCDC) is equal to the value in the previous period (DCGCDC) plus the capacity which has completed decommissioning during the current period (DCGCCR).

DCGCDC=DCGCDC+DT*(DCGCCR)

Where:

DCGCDC: *Generating capacity With Decommissioning Complete (MW)*

The total amount of capacity which will ever be decommissioned (DCTOT) is equal to the existing nuclear capacity (GC(NUCLEAR)) plus the capacity being decommissioned (DCGC) and the capacity already decommissioned (DCGCDC).

DCTOT=(GC(NUCLEAR)+DCGC+DCGCDC)

Where:

DCTOT: *Total capacity Ever Decommissioned (MW*
GC(PLANT): *Generation capacity (MW)*
DCGC: *Generating capacity Being Decommissioned (MW)*

The fraction of decommissioning which is complete (DCFR) is equal to the cumulative amount of capacity which has completed decommissioning (DCGCDC) divided by the total amount of capacity which will ever be decommissioned (DCTOT).

DCFR=DCGCDC/DCTOT

Where:

DCFR: *Fraction of Decommissioning Complete (MW/MW)*
DCGCDC: *Generating capacity With Decommissioning Complete (MW)*

The decommissioning expenses for the current period (DCEXP) are equal to the amount of capacity decommissioned (DCGCCR) times the decommissioning cost per unit (DCUC).

DCEXP=DCGCCR*DCUC*INFLA/1000

Where:

DCEXP: *Current Decommissioning Expenses (M$/YR)*
DCGCCR: *Decommissioning Completion Rate (MW/yr)*
DCUC: *Actual Decommission Cost ($/kW)*

The accumulation of funds within the nuclear decommissioning account (DCA) depends on the fraction of decommissioning complete (DCFR). When the fraction exceeds the threshold (DCFSW), then the allocation of the decommissioning costs depends on the amount in the escrow account.

If the cost of the fraction of decommissioning completed (DCFR) is less than the threshold then the additions to the nuclear decommissioning escrow account (DCA) are equal to the estimated cost of decommissioning (DCEC) times the amount of capacity which requires decommissioning (DCTOT). The GCPL term annualizes the cost over the life of the plant.

DCA=DCEC*INFLA*DCTOT/GCPL(NUCLEAR)

Otherwise, if the fraction of decommissioning complete (DCFR) is greater than or equal to the threshold then the decommissioning is essentially complete and any balance in the escrow account is amortized over the normal plant life.

DCA=(-DCAC)/GCPL(NUCLEAR)

Where:

DCA: *Decommission Annual Cost (M$/yr)*
DCEC: *Estimated Decommission Cost ($/kW)*
DCTOT: *Total capacity Ever Decommissioned (MW)*
GCPL(PLANT): *Generation capacity Physical Life (YRS)*
DCAC: *Decommission Cost Escrow Account (M$)*

The model includes the interest earned on the escrow account (DCINT) by assuming that the account accrues interest equal to that paid on new debt.

DCINT=DCAC*DBIR

Where:

DCINT: Decommission Cost Interest (M$)
DCAC: Decommission Cost Escrow Account (M$)
DBIR: Interest Rate on New Debt (1/YR)

The value of the nuclear decommissioning escrow account (DCAC) is equal to the value in the previous period (DCAC) plus the changes to the account. These changes include funds included in operating expenses (DCA), interest charged to or earned by the escrow account (DCINT), and payments made for the actual decommissioning expenses (DCEXP).

DCAC=DCAC+DT*(DCA+DCINT-DCEXP)

Where:

DCAC: Decommission Cost Escrow Account (M$)
DCA: Decommission Annual Cost (M$/yr)
DCINT: Decommission Cost Interest (M$)
DCEXP: Current Decommissioning Expenses (M$/YR)

PROCEDURE OMCOSTS

Both fixed and variable operation and maintenance costs are calculated. Variable costs are bsed on generation and fixed costs are based on generation capacity in service. The operation and maintenance cost (OMC, by plant) is equal to the variable O&M costs [EG*(UOMC+PUOMC)] plus the fixed O&M costs [GC-GCCR*(1-OPFR)) * (UFOMC+PFOMC)]. The variable O&M costs are broken into non-pollution unit O&M costs (UOMC) and pollution O&M costs (PUOMC), both of which are exogenously specified. The pollution and non-pollution fixed O&M costs (PFOMC and UFOMC, respectively) are calibrated values.

OMC=(EG*(UOMC+PUOMC)+(GC-GCCR*(1-OPFR)) * (UFOMC+PFOMC))/1000*INFLA

Where:

OMC(PLANT): *Operation and Maintenance Costs (M$/YR)*
EG(PLANT): *Electricity Generated (GWH/YR)*
UOMC(PLANT): *Unit O&M Costs (MILLS/KWH)*
PUOMC(PLANT): *Pollution Control Unit O&M Costs ($/KWH)*
GC(PLANT): *Generation capacity (MW)*
GCCR(PLANT): *Generation capacity Completion Rate (MW/YR)*
OPFR(PLANT): *Fractional Year New Plant is Operational*
UFOMC(PLANT): *Unit Fixed O&M Costs ($/KW)*
PFOMC(PLANT): *Pollution Control Fixed O&M Costs ($/KWH)*

Pumped storage generating capacity fixed O&M costs [PSGC*$UFOMC_{hydro}$] are added to the operation and maintenance cost of hydro [OMC_{hydro}]. Decommissioning costs are added to nuclear O&M costs.

```
OMC(HYDRO)=OMC(HYDRO)+PSGC*UFOMC(HYDRO)/1000*INFLA
OMC(NUCLEAR)=OMC(NUCLEAR)+DCA
```

Where:

PSGC: Pumped Storage capacity (MW)
DCA Decommission Annual Cost (M$/yr)

The amount of purchased power required was calculated in the generation and dispatch portion of the model. The unit cost of purchased power (PPUC) is endogenously estimated as an energy cost (UFC) plus wheeling charges (PPWC). The energy cost is calculated as the average of the fuel costs (UFC) the utility would incur if it produced the power from Given the purchased power type, the PPPLMAP variable points to the appropriate plant type.

```
PPUC(PP)=SUM(PLANT)(UFC(PLANT)*PPPLMAP(PP,PLANT))+PPWC(PP)*INFLA
```

Where:

PPUC(PP):	*Purchase Power Unit Cost (MILLS/KWH)*
UFC(PLANT):	*Unit Fuel Cost (MILLS/KWH)*
PPPLMAP(PP,PLANT):	*Map between Purchased Power PLANT*
PPWC(PP):	*Purchase Power Wheeling Charge (MILLS/KWH)*

The purchased power and qualified facility costs (PPCT and QFCT) are equal to the fixed (capacity charge) plus variable costs. The variable costs are equal to the amount purchased (PPEG & QFEG) multiplied by the unit cost (PPUC & QFUC). The capacity cost is equal to the amount of capacity (PPGC & XQFGC) multiplied by the appropriate capacity charge rate (PPCC & QFCC).

```
PPCT=(PPEG*PPUC+PPGC*PPCC*INFLA)/1000
QFCT=(QFEG*QFUC+XQFGC*QFCC)*INFLA/1000
```

Where:

PPCT(PP):	*Purchase Power Cost (M$)*
PPEG(PP):	*Purchase Power Purchases (GWH)*
PPUC(PP):	*Purchase Power Unit Cost (MILLS/KWH)*
PPGC(PP,YEAR):	*Purchase Power capacity (MW)*
PPCC(PP):	*Purchase Power capacity Charges (1975 $/KW)*
QFCT(TECH):	*Qualified Facilities Cost (M$)*
QFEG(TECH):	*QF Electricity Generated (GWH/YR)*
QFUC(TECH):	*QF Purchases Unit Cost (MILLS/KWH)*
XQFGC(TECH,YEAR):	*Historical QF Generating capacity (MW)*
QFCC(TECH):	*Qualified FacilityCapacity Charges ($/KW)*

The capital charge rate is the annualization of capital expenses to account for taxes (TAXR), tax credits (TCR), return of principal (WCC), return on investment, and interest during construction. The CCR equation is:

```
CCR=(1-TCR/(1+WCC)-TAXR*(2*DPRDD(1))/(WCC+2*DPRDD(1)))*WCC/
   (1-(1/(1+WCC))**(1/DPRSL(1)))/(1-TAXR)
```

Where:

CCR: *Capital Charge Rate*
TCR: *Investment Tax Credit Rate ($/$)*
WCC: *Weighted Cost of Capital (1/YR)*
TAXR: *Income Tax Rate (DLESS)*
DPRDD(AA): *Accelerated Depreciation Rate (1/YR)*
DPRSL(AA): *Straight Line Depreciation Rate (1/YR)*

The unit fuel cost of the new plant (MUFC) is equal to the unit fuel cost (UFC) multiplied by the ratio of the marginal to the average heat rate (HRTM/HRTA).

MUFC=UFC/HRTA*HRTM

Where:

MUFC(PLANT): *Marginal Unit Fuel Cost (MILLS/KWH)*
UFC(PLANT): *Unit Fuel Cost (MILLS/KWH)*
HRTA(PLANT): *Average Heat Rate (BTU/KWH)*
HRTM(PLANT): *Marginal Heat Rate (BTU/KWH)*

The avoided cost of electricity for the next year [ACE(NEXT)] is a function of the capital cost of the capacity [CCR*GCCC], the variable and fixed O&M costs [UOMC & UFOMC] and the marginal unit fuel cost of the new capacity [MUFC*GCFR*ACM] summed over all of the plants.

ACE(NEXT)=SUM(P)((CCR*GCCC(P)/8760*1000 + (UOMC(P)/1000 +
UFOMC(P)/(8760*1000))*INFLA(Y) + MUFC(P))*GCFR(P))*ACM

Where:

ACE(YEAR): *Avoided Cost of Electricity (MILLS/KWH)*
CCR : *Capital Charge Rate*
GCCC(PLANT): *Generation capacity Capital Costs ($/KW)*
UOMC(PLANT): *Unit O&M Costs (MILLS/KWH)*
UFOMC(PLANT): *Unit Fixed O&M Costs ($/KW)*
MUFC(PLANT): *Marginal Unit Fuel Cost (MILLS/KWH)*
GCFR(PLANT): *Fraction of New capacity by Plant Type (Fraction)*
ACM : *Avoided Cost of Elec. Multiplier*

The total cost of purchased power (PPUCT) is equal to the cost of purchased power [sum(pp)(PPCT(pp))] plus the QF cost [sum(t)(QFCT(t))] and the net interchange cost [IREC*IRUC-IDEL*IDUC].

PUCT=SUM(PP)(PPCT(PP))+SUM(T)(QFCT(T)) + ((IREC*IRUC-IDEL*IDUC)*INFLA)/1000

Where:

PUCT: *Cost of Purchase Power (M$/YR)*
PPCT(PP): *Purchase Power Cost (M$)'*
QFCT(TECH): *Qualified Facilities Cost (M$)*
IREC: *Interchanged Power Received (GWH)*
IRUC: *Historical Interchanged Power Received Unit Cost (MILLS/KWH)*
IDEL: *Interchanged Power Delivered (GWH)*
IDUC: *Historical Interchanged Power Delivered Unit Cost (MILLS/KWH)*

The total general and administrative O&M costs (TGAOM) is equal to the unit cost (UGAOM, in mills/kWh) multiplied by the amount of electricity (TEA)

TGAOM=TEA*UGAOM*INFLA/1000

Where:

TGAOM :	*Total General and Admin. O&M Costs (M$/YR)*
TEA :	*Total Electricity Available (GWH/YR)*
UGAOM :	*Unit General and Admin. O&M Costs (MILLS/KWH)*

The operation and maintenance costs of T&D capacity is a function of the capacity (TDGC) and the unit O&M costs (TDUMC).

TDOMC(TD)=SUM(C)(TDGC(C,TD))*TDUMC(TD)*INFLA(Y)/1000

Where:

TDOMC(TD):	*T&D Operation and Maintenance Costs (M$/YR)*
TDGC(CLASS,TD):	*Transmission and Distribution capacity (MW)*
TDUMC(TD):	*Trans. & Distribution. Unit O&M Cost ($/KW/YR)*

Total operation and maintenance costs (TOMC) is equal to the operation and maintenance cost summed by plant [sum(p)(OMC(p))], the T&D O&M cost [sum(td)(TDOMC(td)], the total administrative costs [TGAOM], the sum of the sectors of: {[CNEXP], the conservation administrative costs [CONADM] and the load management expenses [LMEXP]} and the oil to gas conversion cost.

TOMC=SUM(P)(OMC(P))+SUM(TD)(TDOMC(TD)) + TGAOM + SUM(S)(CONEXP(S) +
CONADM(S) + LMEXP(S)) + OGCVCST

where:

TOMC:	*Total Operation and Maintenance Costs (M$/YR)*
OMC(PLANT):	*Operation and Maintenance Costs (M$/YR)*
TDOMC(TD):	*T&D Operation and Maintenance Costs (M$/YR)*
CONEXP(SECTOR):	*Conservation Expense ($M/YR)*
CONADM(SECTOR):	*Conservation Administration Costs (M$/YR)*
LMEXP(SECTOR):	*Load management. Expense ($M/YR)*
OGCVCST:	*Generation capacity Oil to Gas Conversion Costs ($M/YR)*

PROCEDURE POLLUTION

The emissions of CO2, CO, VOCs, NOX, SOX and particulates from the burining of fuels at the consumer end-use and energy-supply technology level are calculated in this procedure.

The following three equations calculate the maximum fuel demand (EUDMAX), maximum fuel demand additions (EUDADD) and the maximum fuel demand retirements (EUDRET). The maximum fuel demand is simply the theoretical upper limit of possible fuel demand assuming all of the plants operated continuously. The maximum demand for each fuel (EUDMAX) is a function of the generation capacity (GC) and the average heat rate (HRTA) summed over all of the plants that use such fuel. The maximum fuel demand additions is a function of the new generating capacity [GCCR+GCFCV] and the heat rate of the new plants [HRTM]. The maximum fuel demand of the retired plants is a function of the generation capacity of the retired plants [GCR] and the average heat rate [HRTA].

EUDMAX(F)=SUM(P)(GC(P)*HRTA(P))*8760/1E9
EUDADD(F)=SUM(P)((GCCR(P)+GCFCV(P))*HRTM(P))*8760/1E9
EUDRET(F)=SUM(P)(GCR(P)*HRTA(P))*8760/1E9
PCMM(F,POLL)=SUM(P)(PCM(P,POLL)*GC(P))/SUM(PL)(GC(PL))

Where:

EUDMAX(FUEL):	*Electric utility demand maximum (tBtu)*
EUDADD(FUEL):	*Electric utility demand additions (tBtu)*
EUDRET(FUEL):	*Electric utility demand Retirements (tBtu)*

The pollution control multiplier by fuel (PCMM) is a function of the pollution control multiplier by plant (PCM) weighted by the generating capacity of the plants that use such fuel. PCM is exogenously specified

PCMM(F,POLL)=SUM(P)(PCM(P,POLL)*GC(P))/SUM(PL)(GC(PL))

Where:

PCMM(FUEL,POLL):	*Pollution Control Multiplier by fuel*
PCM(PLANT,POLL):	*Pollution Control Multiplier*

The pollution additions (POEMA, *tons per year*) are equal to the electric utility demand additions (EUDADD) multiplied by the minimum of either the marginal pollution coefficients (POCX) or the pollution standards (POCS). The POCX is an exogenously specified coefficient based on a "typical-use" specification.The pollution retirements (POEMR, *tons per year*) are equal to the electric utility fuel demand retirements (EUDRET) multiplied by the retirement pollution coefficient (POCR). The pollution retrofits (POEMRR, *in tons per year*) are a function of the embodied pollution (POEMLG) and the pollution control multiplier (PCMM). The pollution standards (PSTD, *in tons for each fuel and pollutant*) is a function of the base energy demand (PBASE) and the pollution standards.

POEMA=XMIN(POCX,POCS)*EUDADD
POEMR=POCR*EUDRET
POEMRR=POEMLG*(1-PCMM)
PSTD=PBASE*POCS

Where:

POEMA(FUEL,POLL):	*Pollution Additions (TONS/YR)*
POCX(FUEL,POLL):	*Marginal Pollution Coefficients (TONS/TBTU)*
POCS(FUEL,POLL):	*Pollution Standards (TONS/TBTU)*
EUDADD(FUEL):	*Electric utility demand additions (tBtu)*
POEMR(FUEL,POLL):	*Pollution Retirement (TONS/YR)*
POCR(FUEL,POLL):	*Retirement Pollution Coefficients (Tons/PJ)*
EUDRET(FUEL):	*Electric utility demand Retirements (tBtu)*
POEMRR(FUEL,POLL):	*Pollution Retrofits (Tons/YR)*
POEMLG(FUEL,POLL):	*Embodied Pollution (Tons/YR)*
PCMM(FUEL,POLL):	*Pollution Control Multiplier by fuel*
PSTD(FUEL,POLL):	*Pollution Standards (tons)*
PBASE(FUEL):	*Pollution Base (tBtu)*

The embedded pollution (POEM) is a function of the embodied pollution (POEMLG) plus the net pollution additions [POEMA-(POEMR+POEMRR)]. The average pollution (POCA, *in tons per tBtu*) is a function of the embodied pollution (POEM) and the maximum fuel demand (EUDMAX).

POEM=POEMLG+DT*(POEMA-(POEMR+POEMRR))
POCA=POEM/EUDMAX

Where:

POEM(FUEL,POLL): Embodied Pollution (Tons/year)
POEMLG(FUEL,POLL): Embodied Pollution (Tons/year)
POEMA(FUEL,POLL): Pollution Additions (Tons/year)
POEMR(FUEL,POLL): Pollution Retirement (Tons/year)
POEMRR(FUEL,POLL): Pollution Retrofits (Tons/year)
POCA(FUEL,POLL): Average Pollution Coefficients (TONS/TBTU)
EUDMAX(FUEL): Electric utility demand maximum (tBtu)

The total pollution (TFPOL) is a function of the electric utility fuel demand (EUDMD) and the average pollution coefficient (POCA)

TFPOL=DMDES*POCA

Where:

TFPOL(FUEL,POLL): Energy Sector Pollution (TONS/YR)
EUDMD(PLANT): Utility Fuel Demand (TBTU/YR)
POCA(FUEL,POLL): Average Pollution Coefficients (TONS/TBTU)

LOC1 (a local scratch variable) is set equal to the ratio of purchase power generating capacity (PPGC) to total generating capacity [GC+PPGC], the sum(p) sums all of the plants. For each fuel that corresponds to a purchase power fuel, total pollution (TFPOL) is recalculated as above, adjusted for the purchased power generating capacity (1+LOC1).

LOC1=SUM(PP)(PPGC(PP,Y))/(SUM(P)(GC(P))+SUM(PP)(PPGC(PP,Y)))
TFPOL=DMDES*(1+LOC1)*POCA

Where:

PPGC(PP,YEAR): Purchase Power capacity (MW)
GC(PLANT): Generation capacity (MW)
TFPOL(FUEL,POLL): Energy Sector Pollution (TONS/YR)
DMDES(FUEL): Energy Demand (TBTU/YR)
POCA(FUEL,POLL): Average Pollution Coefficients (TONS/TBTU)

Total pollution (TSPOL, *by pollution type only*) is equal to the energy sector pollution summed by fuel [sum(f)(TFPOL(f))].

TSPOL(L)=SUM(F)(TFPOL(F,L))

Where:

TSPOL(POLL): Energy Sector Pollution (TONS/YR)

Pollution Control/Damage Costs can be exogenously specified on a dollars per ton basis and used to compute a yearly societal cost of pollution.

POCST(F)=SUM(P)(TFPOL(F,P)*POCSTR(P))/1E6*INFLA

Where:

POCST(FUEL): Societal Cost of Pollution ($M/YR)
POCSTR(POLL): Societal Cost of Pollution ($/TON)
TFPOL(FUEL,POLL): Energy Sector Pollution (TONS/YR)

PROCEDURE ASSETS

The utility asset portion of the model keeps track of gross, net, and tax assets. It also calculates the depreciation values used for the income statement and tax obligations. This procedure

updates all of the asset categories*: transmission, distribution, generation, nuclear, conservation and other*. All assets have three age categories*: new, middle and old*.

Gross assets are increased by completed construction (CW) and the associated allowance for funds used during construction (AFC). Since the tax treatment of CWIP and AFC differs, the model keeps track of both types of assets separately. The assets are further divided into two asset types (AA). One set is associated with the flow and storage gas capacity which lasts 30 to 45 years. The other set is associated with the SNG and LPG capacity which only lasts 15 to 25 years. The CW additions to gross assets (CWGAA) include newly completed facilities (CWGA), capacity capital additions (DCAD), T&D construction (DDTBF), and miscellaneous capital expenditures (MISCGA).

The direct construction costs of gross generation assets [CWGAA(GENER)] is a function of the sum of the plants (non-nuclear) construction work into gross assets (CWGA), plant capital additions (GCAD), plant fuel conversions (GCFCST), life extension costs (GCEXCST) and the pollution control costs to be financed (PCTBF). The AFUDC of generation gross assets [AFGA(GENER)] is the sum of the plants (non-nuclear) of AFUDC into gross assets (AFGA, *by plant*).

```
CWGAA(GENER)=SUM(P)(CWGA(P) + GCAD(P) + GCFCST(P)*INFLA) + GCEXCST*INFLA +
        PCTBF
AFGAA(GENER)=SUM(P)(AFGA(P))
```

Where:

CWGAA(AA):	*Direct construction. Costs to Gross Assets (M$)*
CWGA(PLANT):	*Construction Work into Gross Assets (M$)*
GCAD(PLANT):	*Plant Capital Additions (M$)*
GCFCST(PLANT):	*Fuel Conversion Costs (M$)*
GCEXCST:	*Life Extension Costs (M$)*
PCTBF:	*Pollution Control To Be Financed (M$/YR)*
AFGAA(AA):	*AFUDC into Gross Assets (M$)*
AFGA(PLANT):	*AFUDC into Gross Assets by Plant (M$)*

Similar to the above, the direct construction costs of nuclear gross assets [CWGAA(NUCLEAR)] is equal to nuclear construction work into gross assets [CWGA(NUCLEAR)] plus nuclear capacity additions [GCAD(NUCLEAR)]. AFUDC into gross assets for the nuclear asset account [AFGAA(NUCLEAR)] is equal to nuclear AFUDC into gross assets [AFGA(NUCLEAR)] plus AFUDC from the deferred rate base (AFAF).

```
CWGAA(NUCLEAR)=CWGA(NUCLEAR)+GCAD(NUCLEAR)
AFGAA(NUCLEAR)=AFGA(NUCLEAR)+AFAF
```

Where:

AFAF AFUDC from the Deferred Rate Base (M$/YR)

Construction work gross assets of the conservation asset category [CWGAA(CON)] is equal to the sum of the sectors of the capitalized conservation expense (CONCAP), the capitalized load management expense (LMCAP) and the exogenous capitalized conservation expense (XCONCAP *is included only if the exogenous demand adjustment switch is on XDSW=1*).

```
CWGAA(CON)=SUM(S)(CONCAP(S)+LMCAP(S)+(XCONCAP(S)*XDSW))
```

Where:

CWGAA(AA): Direct Construction. Costs to Gross Assets (M$)
CONCAP(SECTOR): Capitalized Conservation Expense ($M/YR)
LMCAP(SECTOR): Capitalized Load Management. Expense ($M/YR)
XCONCAP(SECTOR): Exogenous Capitalized Conservation Expense (M$/YR)
XDSW: Exogenous Demand Adjustment Switch 1 = on',

Transmission and distribution construction work gross assets [CWGA(*TRAN or DIST*)] is equal to the sum of the classes of T&D to be financed [TDTBF(*TRAN or DIST*)]. Construction work gross assets of the "other" category are set equal to the sum of the purchase power types of T&D costs to be financed (PPTBF).

```
CWGAA(TRAN)=SUM(C)(TDTBF(C,TRAN))
CWGAA(DISTR)=SUM(C)(TDTBF(C,DISTR))
CWGAA(OTHER)=SUM(PP)(PPTBF(PP))
```

Where:

TDTBF(CLASS,TD): Trans. and Distribution. to be Financed (M$/YR)
PPTBF(PP): Purchase Power T&D Costs to be Financed ($M)

The miscellaneous additions to gross assets (MISCGA, *for each asset category*) is a function of the amount of gross assets (GA) and the calibrated miscellaneous additions to gross assets fraction (MISCFR). The miscellaneous additions to gross assets for the "other" category [MISGA(OTHER)] is equal to the sum of all gross assets [sum(aa)(GA(aa))] multiplied by the the calibrated miscellaneous additions to gross assets fraction (MISCFR). Miscellaneous additions to gross assetts (MISGA) is then added to the direct construction costs into gross assets (CWGAA).

```
MISCGA(AA)=GA(AA)*MISCFR(AA)
MISCGA(OTHER)=SUM(AA)(GA(AA))*MISCFR(OTHER)
CWGAA=CWGAA+MISCGA
```

Where:

MISCGA(AA): Misc. Additions to Gross Assets (M$)
GA(AA): Gross Assets (M$)
MISCFR(AA): Miscellaneous Additions to Gross Assets Fraction ($/$)

The additions to gross assets are set equal to the construction work into gross assetts (CWGAA) plus AFUDC into gross assets (AFGAA).

```
GAA=CWGAA+AFGAA
```

Where:

GAA(AA): Additions to Gross Assets (M$)',
CWGAA(AA): Direct Construction. Costs to Gross Assets (M$)
AFGAA(AA): AFUDC into Gross Assets (M$)'

The straight line depreciation for all asset categories [SLDP(AA)] is a function of the total assets [GALV + GAA] and the straight line depreciation rate. The second equation in the group assures that the amount of depreciation is not greater than the net assetts (NA) or the additions to gross assets (GAA). The total depreciation (SLDPR) is equal to the sum of the asset categories of the straight line depreciation (SLDP)

```
SLDP(AA)=(SUM(AGE)(GALV(AA,AGE))+GAA(AA))*DPRSL(AA)
SLDP=XMIN(XMAX(GAA,NA),SLDP)
SLDPR=SUM(AA)(SLDP(AA))
```

Where:

SLDP(AA): *Straight Line Depreciation (M$/YR)*
GALV(AA,AGE): *Gross Assets (M$)*
GAA(AA): *Additions to Gross Assets (M$)*
DPRSL(AA): *Straight Line Depreciation Rate (1/YR)*
NA(AA): *Net Assets (M$)*
SLDPR: *Total Straight Line Depreciation (M$/YR)*

If exogeneous retirements are zero (XRGA), then the retiring gross assets from the construction costs (RGA) are a function of the ratio of old gross assets [GALV(aa,old)] to the asset's physical lifetime (GAPL). Otherwise if exogeneous retirements are positive then the retiring gross assets from the construction costs (RGA) are equal to the minum of either the exogeneous retirements or the sum of the age of gross assets (GALV).

```
RGA(AA)=XMAX(0,GALV(AA,OLD))/(GAPL(AA)/3)*(1-XRGA(AA)/XRGA(AA)) +
        XMIN(XRGA(AA),SUM(AGE)(GALV(AA,AGE)))
```

Where:

RGA(AA): *Retire. of GA from Const. Cost (M$/YR)*
GALV(AA,AGE): *Gross Assets (M$)*
GAPL(AA): *Gross Assets Physical Life (YRS)*
XRGA(AA): *Retiring GA from Direct Constr. Cost (M$/YR)*

The utility assets move in discrete units. For computational speed and simplicity, there are only three age classes rather than the sixty it would take to simulate the annual financial unit of measurement. Thus retirements would occur in twenty-year units. To avoid this disruptive and incorrect retirement, the last age class is retired continuously. The pulse parameter moves the assets across the age categories. The interval is established by dividing the lifetime of the variable by the number of internal levels. Then some of the contents of the oldest level are removed in a continuous fashion. Using the pulse, the contents of level one are moved to level two and the contents of level two to level three. Level one is filled the the input from outside the procedure.

```
PULSE=FLOOR(XMAX(0,(CTIME+DT/2-CWOUT+1)))
CWOUT=CWOUT+GAPL/3*PULSE
```

Where:

PULSE(AA): *Pulse to Move Assets Across Age Classes*
CWOUT(AA): *Gross Asset Pulse Parameter (M$)*
GAPL(AA): *Gross Assets Physical Life (YRS)*

The following three equations shift the age classes of the asset categories. The gross assets in the OLD age class [GALV(aa,old)] are equal to the previous period's values less retirements (RGA) plus the gross assets in the middle class [GALV(MID)] that were shifted (PULSE) to the OLD class. The gross assets in the middle (MID) age class are equal to the previous period's value less the assets shifted from middle to old plus the assets shifted from new (NEW) to middle (MID). The gross assets in the new (NEW) class are equal to the previous period's value less the assets shifted from new (NEW) to middle (MID) plus the additions to gross assets (GAA). The last equation sums the age dimension of the gross assets (GALV) to get total gross assets (GA, *by asset accountI*).

```
GALV(AA,OLD)=GALV(AA,OLD)-DT*RGA(AA)+GALV(AA,MID)*PULSE(AA)
GALV(AA,MID)=GALV(AA,MID)*(1-PULSE(AA))+GALV(AA,NEW)*PULSE(AA)
GALV(AA,NEW)=GALV(AA,NEW)*(1-PULSE(AA))+GAA(AA)
GA(AA)=SUM(AGE)(GALV(AA,AGE))
```

Where:

GALV(AA,AGE): Gross Assets (M$)
RGA(AA) : Retire. of GA from Const. Cost (M$/YR)
GAA(AA): Additions to Gross Assets (M$)
GA(AA): Gross Assets (M$)

Two terms with specific functions are also calculated. Accumulated depreciation is calculated so that utility financial statements can be generated.The accumulated depreciation is equal to the last period's value (ACDP) plus this years depreciation (SLDP) and miscellaneous deductions (MISCDED) less the retired gross assets (RGA). Net assets represent the net plant-in-service after allowance for depreciation and are used in the rate base calculations. Net assets (NA) are calculated as gross assets (GA) less the accumulated depreciation (ACDP).

```
ACDP=ACDP+DT*(SLDP+MISCDPR-RGA)
NA=GA-ACDP
```

Where:

ACDP(AA): Accumulated Depreciation (M$)
SLDP(AA): Straight Line Depreciation (M$/YR)
MISCDED(YEAR): Miscellaneous Deductions (M$)
RGA(AA): Retire. of GA from Const. Cost (M$/YR)
NA(AA): Net Assets (M$)
GA(AA): Gross Assets (M$)

Tax assets are increased by completed construction. Specifically, tax assets (TA) of the non-nuclear asset accounts are calculated as last period's value plus the non municipal portion of the construction work into gross assets [CWGAA*(1-MAF)]. The nuclear tax assets [TA(NUCLEAR)] include plant capital additions (GCAD) and construction work into gross assets (CWGA).

```
TA(AA)=TA(AA)+CWGAA(AA)*(1-MAF)
TA(NUCLEAR)=TA(NUCLEAR)+(CWGA(NUCLEAR)+GCAD(NUCLEAR))*(1-MAF)
```

Where:

TA(AA): Tax Assets (M$)
CWGAA(AA): Direct Const. Costs to Gross Assets (M$)
CWGA(PLANT): Construction Work into Gross Assets (M$)
GCAD(PLANT): Plant Capital Additions (M$)

The accelerated depreciation is a function of the tax assets (TA) and the accelerated depreciation rate (DPRDD). In the second equation, if the straight line depreciation (SLDP) is greater than the accelerated depreciation then set the accelerated depreciation equal to the straight line depreciation. The third equation assures the accelerated depreciation is not greater than the tax assets (TA). Total accelerated depreciation (TATDP) sums the asset acccounts of the accelerated depreciation by asset account (ATDP). Finally, the accelerated depriciation (ATDP) is removed from the tax assets (TA).

```
ATDP=TA*DPRDD
ATDP=XMAX(ATDP,SLDP)
```

```
ATDP=XMIN(ATDP,TA)
TATDP=SUM(AA)(ATDP(AA))
TA=TA+DT*(-ATDP)
```

Where:

ATDP(AA):	*Accelerated Tax Depr. (M$/YR)*
DPRDD(AA):	*Accelerated Depreciation Rate (1/YR)*
SLDP(AA):	*Straight Line Depreciation (M$/YR)*
TATDP:	*'Total Accelerated Tax Depr. (M$/YR)*

PROCEDURE REVENUE

The electric price (PE) for each class was calculated in the previous period (year) in the TESTYEAR procedure. ENERGY 2020 then calculated the electricity demand and attendant sales. In this procedure, revenue, allowance for funds used during construction and the operating income are determined.

The electric revenues for each class (RV) is simply equal to the price paid by each class (PE) multiplied by the sales for each class (SALES) adjusted for interruptible load (ILEG). The total electric revenue (REV) sums the classes of revenue by class (RV) and adds the gas revenue (GSREV).

```
RV(C)=PE(C)*(SALES(C,ELECTRIC)-ILEG)/1000
REV=SUM(C)(RV(C))+GSREV*INFLA
```

Where:

RV(CLASS):	*Elect. Revenues by Revenue Class (M$/YR)*
SALES(CLASS,FUEL):	*Annual Sales of Electricity (GWH/YR)*
PE(CLASS,YEAR):	*Price of Electricity (MILLS/KWH)*
ILEG(YEAR)	*Interruptible Load Gen. (MW)*
REV :	*Revenues (M$/YR)*
GSREV:	*Gas Revenues (M$/YR)*

For income reporting purposes, AFC is counted as income. Total AFC (TAF) is the sum, over facility type, of AFGS calculated earlier in the construction process plus the AFUDC from the deferred rate base (AFAF). AFC from debt (AFDB) represents the interest payments the utility would have been given as revenues to "cover" interest payments. AFC from equity represents the return on equity the utility would have been allowed to recover if the facilities under construction were "in-service." The fraction (AFDBF) of TAF that is attributed to debt or equity is used to determine AFDB and AFEQ.

```
TAF=SUM(P)(AFGS(P))+AFAF
AFDB=TAF*AFDBF
AFEQ=TAF*(1-AFDBF)
```

Where:

TAF:	*AFUDC Generated in Current Period (M$/YR)*
AFGS(PLANT):	*Gross Allow. Funds Used During Const. (M$/YR)*
AFAF:	*AFUDC from the Deferred Rate Base (M$/YR)*
AFDB:	*AFUDC from Debt Funds (M$/YR)*
AFEQ:	*AFUDC from Equity Funds (M$/YR)*

AFDBF: *Fraction of AFUDC from Debt Funds*

The utility also receives other income (OTINC) from other investments (SI). ENERGY 2020 assumes that these investments are in government bonds or at least earn the return on bonds (SIIR). Any other income estimated in the historical calibration is also included here.

OTINC=SI*SIIR*(1-TAXR)+IOTHER*INFLA

Where:

OTINC: *Other Income (M$/YR)*
SI: *Government Bonds (M$)*
SIIR: *Interest Rate of Government Bonds*
TAXR: *Income Tax Rate*
IOTHER: *Income from Other Sources (M$/YR)*

PROCEDURE TAXES

At this point, revenues, costs and assets have been determined. With this information in hand, ENERGY 2020 is ready to calculate the various taxes. In this procedure, ENERGY 2020 will determine the property and revenue tax, the municipal property tax, the interest on short term debt, the taxable income, income tax before and after credits, investment tax credits, deferred investment tax credits and deferred taxes.

Total property and revenue tax for the current period (PTAX) is equal to the sum of the asset accounts of the taxes on the non municipally owned net assets [PTAXR*NA*(1-MAF), *tax rate times net assets gives tax amount*] plus the revenue tax [REV*RVTAXR], if any. REVTAXR is a policy variable set equal to zero in the baseline. The total municipal property tax (MTAX) calculation sums the taxes of the asset accounts of the municipally owned portion of the net assets [MTAXR*NA*MAF].

PTAX=SUM(AA)(PTAXR(AA)*NA(AA))*(1-MAF)+REV*RVTAXR
MTAX=SUM(AA)(MTAXR(AA)*NA(AA))*MAF

Where:

PTAX: *Property and Revenue Tax (M$/YR)*
PTAXR(AA): *Property Tax Rate (1/YR)*
NA(AA): *Net Assets (M$)*
MAF: *Municipal Asset Fraction*
REV: *Revenues (M$/YR)*
RVTAXR: *Revenue Tax Rate (Frac.)*
MTAX: *Municipal Property Tax (M$/YR)*
MTAXR(AA): *Municipal Property Tax Rate (1/YR)*

The short term interest payments (SDIN) need to be subtracted from income before the tax rate is applied. SDIN is equal to the short term debt [(DB+ID)*DBFR] plus construction expenditures (TCW) multiplied by the interest rate on new debt (DBIR).

SDIN=(TCW+(DB+ID)*DBFR)*DBIR

Where:

SDIN: *Interest on Short Term Debt (M$/YR)*
TCW: *Generating Plant Construction Expenditures (M$/YR)*
DB: *Long Term Debt (M$)*

ID: Intermediate Debt (M$)
DBFR: Fraction of Debt Interest Adjusted (Fraction)
DBIR: Interest Rate on New Debt (1/YR)

Taxable income is equal to the non municipal net revenues [(REV-TOMC-PUCT-TFC)*(1-MRF)], less depreciation and property taxes (TATDP & PTAX) less the non municipal interest payments [(DBIN+IDIN+SDIN)*(1-MDF)] less gas purchase expenses (GSEXP) less miscelaneous deductions (MISCDED) less the construction cost loss from canceling nuclear plants (CWLS).

TXINC=(REV-TOMC-PUCT-TFC)*(1-MRF)-TATDP-PTAX-(DBIN+IDIN+SDIN)*(1-MDF)-GSEXP*INFLA-MISCDED-CWLS

Where:

TXINC: Taxable Income (M$/YR)
REV: Revenues (M$/YR)
TOMC: Total Operation and Maintenance Costs (M$/YR)
PUCT: Cost of Purchase Power (M$/YR)
TFC: Total Fuel Cost (M$/YR)
MRF: Municipal Revenue Fraction (Dless)
TATDP: Total Accelerated Tax Depr. (M$/YR)
PTAX: Property and Revenue Tax (M$/YR)
DBIN: Debt Interest on Long Term Debt (M$/YR)
IDIN: Interest on Intermediate Debt (M$/YR)
SDIN: Interest on Short Term Debt (M$/YR)
MDF: Municipal Debt Fraction
GSEXP: Gas Purchased for Resale (M$)
MISCDED(YEAR):Miscellaneous Deductions (M$)
CWLS: Construction Losses from Canceling Nuclear Plants (M$)

The income taxes before credits (ITXBC) is a function of the taxable income (TXINC) and the tax rate (TAXR).

ITXBC=TXINC*TAXR

Where:

ITXBC: Income Tax before Credits (M$/YR)
TAXR: Income Tax Rate

Historically, investment tax credits can be claimed at a time other than when the investment first qualified for the credit. As investments enter gross assets (CWGAA), investment tax credits are earned (ERTC) at the tax credit rate (TCR). They are accumulated into an account from which they are claimed (ATC). The utility can claim 85% (MTCR) of its income tax obligation before credits or the level of accumulated credits, whichever is less. The level of credits (ATC) is reduced with claimed tax credits and increased with earned tax credits. The earned investment tax credit multiplies the investment tax credit rate (TCR) by the sum of the asset categories of the non-municipal construction work gross assets [CWGAA*(1-MAF)]. The maximum income tax (ITXMX) is a function of the maximum tax credit fraction (MTCR) and the income tax before credits (ITXBC, *if positive; zero otherwise*). The claimed investment tax credit (CLTC) is the minimum of either the accumulated investment tax credits of the previous period (ATC) or the maximum income tax (ITXMX). The accumulated investment tax credits for the current period (ATC) is equal to last period's value plus the earned income tax credit (ERTC) less the claimed investment tax credit (CLTC).

```
ERTC=SUM(AA)(CWGAA(AA))*(1-MAF)*TCR
ITXMX=XMAX(ITXBC,0)*MTCR
CLTC=XMIN(ATC,ITXMX)
ATC=ATC+ERTC-DT*CLTC
```

Where:

ERTC:	*Earned Investment Tax Credit (M$)*
CWGAA(AA)	*Direct Const. Costs to Gross Assets (M$)*
MAF:	*Municipal Asset Fraction*
TCR:	*Investment Tax Credit Rate ($/$)*
ITXMX:	*Income Tax Maximum (M$)*
MTCR:	*Maximum Tax Credit Fraction*
CLTC:	*Claimed Investment Tax Credit (M$/YR)*
ATC:	*Accumulated Investment Tax Credits (M$)*
ERTC:	*Earned Investment Tax Credit (M$)*

If the normilazitation switch (INMTC) *is* "on," then the deferred investment tax credit (DFITC) is set equal to the claimed investment tax credit (CLTC). The utility can defer tax credits (DFITC) and amortize the claimed credits over a time span of around 30 years (ATTC). It is the amortized amounts (AMTC) that are subtracted from income tax before credit. The ammortized investment tax credit (AMTC) equals the ratio of last period's accumulated deferred investment tax credits (ATDC) to its ammoritization time (ATTC).The accumulated deferred investment tax credits (ATDC) for the current period is equal to last period's value plus the difference in deferred investment tax credits (DFTIC) and the ammortized investment tax credit (AMTC).

```
DFITC=CLTC*NMTC
AMTC=ADTC/ATTC
ADTC=ADTC+DT*(DFITC-AMTC)
```

Where:

DFITC:	*Deferred Investment Tax Credits (M$/YR)*
NMTC:	*Normalization Switch for Tax Credits*
AMTC:	*Amortized Investment Tax Credit (M$/YR)*
ADTC:	*Accum. Deferred Investment Tax Credits (M$)*
ATTC:	*Amortization Time for Inv. Tax Credit (YRS)*

The following equation calculates the net deferred taxes from depreciation (NDFTX) using liberalized depreciation and double declining balance method because in normalized accounting (NMDP), the utility accumulates deferred taxes (ADTX) from using liberalized depreciation (TDDDP) relative to the "level" straight-line depreciation (SLDCW). The difference in total accelerated depreciation and the non-municipal portion of straight line depreciation [*tatdp-sldp**(1-MAF)], the tax rate (TAXR) and the ammortized accumulated deferred taxes from depreciation (*adtx/attc*, *if positive*) are used for the calculation. The accumulated deferred taxes from depreciation (ADTX) for the current period is equal to last period's value net deferred taxes from depreciation (NDFTX).

```
NDFTX = (TATDP-SUM(AA)(SLDP(AA))*(1-MAF))*TAXR*NMDP - (XMAX(0,ADTX)/ATTC)*(1-
        NMDP)
ADTX=ADTX+DT*(NDFTX)
```

Where:

NDFTX: *Net Deferred Taxes from Depreciation (M$/YR)*
TATDP: *Total Accelerated Tax Depr. (M$/YR)*
SLDP(AA): *Straight Line Depreciation (M$/YR)*
MAF: *Municipal Asset Fraction*
TAXR: *Income Tax Rate*
NMDP: *Switch for Liberalized Depreciation*
ADTX: *Accum. Deferred Taxes from Depreciation (M$)*

The following equation calculates the deferred taxes from AFUDC on borrowed funds (AFDTX) using AFUDC from debt funds (AFDB), the tax rate (TAXR) and the tax effect switch (NMAF).

AFDTX=AFDB*TAXR*NMAF

Where:

AFDTX: Tax Effect of AFUDC for Debt Funds (M$/YR)
AFDB: AFUDC from Debt Funds (M$/YR)
NMAF: Switch for Tax Effect of AFUDC

The income tax is equal to the income tax before credits (ITXBC) less the claimed investment tax credit (CLTC). The income tax reported is equal to the calculated income tax (ITX) plus the deferred income tac credits (DFITC) less the ammortized tax credits (AMTC) plus the net deferred taxes from depreciation (NDFTX) plus the tax effect of AFUDC for debt funds (AFDTX) plus the net of tax difference in construction losses and construction losses expensed to ratepayers from canceling a nuclear plant [(CWLS-CNLEX)*TAXR].

ITX=ITXBC-CLTC
ITXRP=ITX+DFITC-AMTC+NDFTX+AFDTX+(CWLS-CNLEX)*TAXR

Where:

ITX: Income Tax (M$/YR)
ITXBC: Income Tax before Credits (M$/YR)
CLTC: Claimed Investment Tax Credit (M$/YR)
ITXRP: Income Tax Reported (M$/YR)
DFITC: Deferred Investment Tax Credits (M$/YR)
AMTC: Amortized Investment Tax Credit (M$/YR)
NDFTX: Net Deferred Taxes from Depreciation (M$/YR)
AFDTX: Tax Effect of AFUDC for Debt Funds (M$/YR)
CWLS: Construction Losses from Canceling Nuclear Plants (M$)
CNLEX: Construction Loss Expensed to Ratepayers (M$/YR)
TAXR: Income Tax Rate

PROCEDURE INCOME

In this procedure, ENERGY 2020 determines the operating expenses, operating income, income before interest, net income and income available to common stockholders.

The operating expenses (OPEXP) are equal to the sum of the current expenses. Operating income is equal to revenues (REV) less expenses (OPEXP).

OPEXP = TOMC + PUCT + TFC + SLDPR + PTAX + MTAX + ITXRP + GSEXP*INFLA + CNLEX + MISCEXP
OPINC = REV - OPEXP

Where:

OPEXP:	*Operating Expenses (M$/YR)*
TOMC:	*Total Operation and Maintenance Costs (M$/YR)*
PUCT:	*Cost of Purchase Power (M$/YR)*
TFC:	*'Total Fuel Cost (M$/YR)*
SLDPR:	*Total Straight Line Depreciation (M$/YR)*
PTAX :	*Property and Revenue Tax (M$/YR)*
MTAX :	*Municipal Property Tax (M$/YR)*
ITXRP:	*Income Tax Reported (M$/YR)*
GSEXP:	*Gas Purchased for Resale (M$)*
CNLEX:	*Construction Loss Expensed to Ratepayers (M$/YR)*
MISCEXP:	*Miscellaneous Expenses (M$)*
OPINC:	*Operating Income (M$/YR)*
REV:	*Revenues (M$/YR)*

The income before interest (INCBI) is equal to the operating income (OPINC) plus the AFUDC from equity funds (AFEQ) and other income (OTINC) less the construction losses from canceling nuclear plants [CWLS*(1-CNLFR)]. Net Income (NTINC) is equal to the income before taxes (INCBI) less the interest payments (DBIN+IDIN+SDIN) plus AFUDC from debt funds (AFDB).

INCBI=OPINC+AFEQ+OTINC-CWLS*(1-CNLFR)
NTINC=INCBI-(DBIN+IDIN+SDIN)+AFDB

Where:

INCBI:	*Income before Interest (M$/YR)*
AFEQ:	*AFUDC from Equity Funds (M$/YR)*
OTINC:	*Other Income (M$/YR)*
CWLS:	*Construction Losses from Canceling Nuclear Plants (M$)*
CNLFR:	*Construction Loss Fraction*
NTINC:	*Net Income (M$/YR)*
INCBI:	*Income before Interest (M$/YR)*
DBIN:	*Debt Interest on Long Term Debt (M$/YR)*
IDIN:	*Interest on Intermediate Debt (M$/YR)*
SDIN:	*Interest on Short Term Debt (M$/YR)*
AFDB:	*AFUDC from Debt Funds (M$/YR)*

The income available to common stockholders before common stock dividend are paid (INCBC) is equal to the net income (NTINC) less the preferred stock dividends (PSDV).

INCBC=NTINC-PSDV

Where:

INCBC:	*Income before CS Dividend Payments (M$/YR)*
NTINC:	*Net Income (M$/YR)*
PSDV:	*Preferred Stock Dividends (M$/YR)*

PROCEDURE DIVIDENDS

Utilities pay common dividends per share (CSDR) as an company operating policy. With revenue, taxes and income calculated, ENERGY 2020 can now determine the dividend payments. If the current year is an historical year, then the dividend rate and divident payments

are set equal to their historical values. Otherwise, ENERGY 2020 will calculate the dividend payments based on available income, if any, the calibrated payout ratio and the input dividend growth rate criterion.

The common stock dividend rate (CSDR) and the common stock dividends (CSDV) are calculated by one of the four following routines. If the criteria for a particular option is not satisfied, then the criteria for the following option is tested. Once the criteria for a particular option is satisfied, the code in the option is executed and ENERGY 2020 resumes after the last option. If the criteria in the first three options is not satisfied, then the last option is executed by default.

Option 1

If the current year is less than the last historical year (i.e., the current year is an historical year) and the common stock dividend rate is greater than zero then set the common stock dividend rate (CSDR) and the common stock dividends (CSDV) equal to their historical values (XCSDR & XCSDV).

```
CSDR=XCSDR
CSDV=XCSDV
```

Where:

XCSDR:	*Historical Common Stock Dividend Rate ($/SHARE/YR)*
XCSDV:	*Historical Common Stock Dividends (M$/YR)*

Option 2

If the common stock dividend rate is greater than zero then set the common stock dividend rate (CSDR) equal to its historical value (XCSDR). The common stock dividends (CSDV, *in millions of dollars*) is equal to the dividend rate (CSDR) multiplied by the value of the common stock outstanding (CSSO) plus the value of common stock shares sold (CSSS, *adjusted for dividend payout timing* CSDVFR). Since common stock is sold on a continuous basis throughout the year, a fraction of new stock issued in a particular year will not render a dividend in such year based on the timing of the dividends. The common stock dividend fraction (CSDVFR), is used to account for this phenomena.

```
CSDR=XCSDR
CSDV=CSDR*(CSSO+CSSS*CSDVFR)
```

Where:

CSSO:	*Common Stock Shares Outstanding (MILLIONS)*
CSSS:	*Shares of Common Stock Sold ($M/YR)*
CSDVFR:	*Dividend Fraction earned by Common Stock sold*

Option 3

This option is a user specified option. The common stock dividends are equal to the income before common stock dividend payments (INCBC) multiplied by the common stock payout ratio (CSPAYO). If the common stock dividends are calculated less than zero, then set them equal to

zero. The common stock dividend rate (CSDR) is equal to the ratio of the dividends paid (CSDV) to the value of the stock [CSSO+CSSS*CSDVFR, *adjusted for dividend payout timing. see discussion in option 2*].

```
CSDV=INCBC*CSPAYO
CSDV=XMAX(CSDV,0)
CSDR=CSDV/(CSSO+CSSS*CSDVFR)
```

Where:

INCBC:	*Income before CS Dividend Payments (M$/YR)*
CSPAYO:	*CS Payout Ratio*

Option 4

If the criteria in any of the first 3 options were not satisfied then this option is executed. The maximum dividend rate (CSDRMAX) is equal to the ratio of common stock dividends paid [INCBC*CSPAYO, *see discussion in option 3*], to the net value of the common stock [CSSO-CSSP+CSSS*CSDVFR]. The minimum dividend rate (CSDRMIN) is set equal to the prior year's dividend rate (CSDRL). The targed dividend rate for common stock (CSDRTG), is based on last year's dividend rate (CSDRL) and the targeted dividend growth rate (CSDRGR). If the targeted dividend rate (CSDRTG) falls inbetween the maximum and minimum dividend rate (CSDRMAX & CSDRMIN), then the actual dividend rate (CSDR) becomes the targeted rate. Otherwise, the actual dividend rate will be constrained by the minimum and maximum.

```
CSDRMAX=(INCBC*CSPAYO)/(CSSO-CSSP+CSSS*CSDVFR)
CSDRMIN=CSDRL
CSDRTG=CSDRL*(1+CSDRGR)
CSDR=XMAX(XMIN(CSDRTG,CSDRMAX),CSDRMIN)
CSDV=CSDR*(CSSO-CSSP+CSSS*CSDVFR)
```

Where:

CSDR:	*Common Stock Dividend Rate*
CSDV:	*Common Stock Dividends (M$/YR)*
CSDVSW:	*CS Dividend Switch Time (YEAR)',*
CSSO:	*Common Stock Shares Outstanding (MILLIONS)*
CSSS:	*Shares of Common Stock Sold ($M/YR)*
CSDVFR:	*Dividend Fraction earned by Common Stock sold*
CSDRMAX:	*Common Stock Maximum Dividend Rate*
CSDRTG:	*CS Target Dividend Rate*
CSDRMIN:	*CS Minimum Dividend Rate*
CSDRL:	*Prior Common Stock Dividend Rate ($/SHARE/YR)*
CSDRGR:	*Common Stock Dividend Rate Growth Rate*
INCBC:	*Income before CS Dividend Payments (M$/YR)*
CSPAYO:	*CS Payout Ratio*
CSSP:	*Shares of CS Re-Purchased ($M/YR)*

The income available to common stockholders after common stock dividends are paid out (INCAC), is equal to the income before common stock dividends are paid (INCBC) less the dividend payments (CSDV).

```
INCAC=INCBC-CSDV
```

Where:

INCAC: Income after CS Dividend Payments (M$/YR)
INCBC: Income before CS Dividend Payments (M$/YR)
CSDV : Common Stock Dividends (M$/YR)

PROCEDURE FUNDS

This procedure controls the cash flows. More specifically, ENERGY 2020 calculates the funds from operations, funds available to common stockholders, funds from business, common stock dividends reinvested, preffered stock sinking fund and the required financing.

The funds from operations (FDOP) are equal to the net income (NTINC) adding back depreciation (SLDPR) and the difference between reported taxes and taxes paid (ITXRP-ITX), less AFUDC from both equity and debt funds (AFEQ & AFDB) plus the construction losses from canceling nuclear plants [CWLS*(1-CNLFR)+CNLEX] plus the annual decomissioning cost (DCA). The funds available for common stock dividends (FDCS) are equal to the funds from operations (FDOP) less the preffered stock dividends (PSDV). Then, the funds from business (FDBS) are equal to the funds available to common stockholders (FDCS) less the common stock dividends (CSDV).

FDOP=NTINC+SLDPR+(ITXRP-ITX)-AFEQ-AFDB+CWLS*(1-CNLFR)+CNLEX+DCA
FDCS=FDOP-PSDV
FDBS=FDCS-CSDV

Where:

FDOP: Funds from Operations (M$/YR)
NTINC: Net Income (M$/YR)
SLDPR: Total Straight Line Depreciation (M$/YR)
ITXRP: Income Tax Reported (M$/YR)
ITX: Income Tax (M$/YR)
AFEQ: AFUDC from Equity Funds (M$/YR)
AFDB: AFUDC from Debt Funds (M$/YR)
CWLS: Construction Losses from Canceling Nuclear Plants (M$)
CNLFR: Construction Loss Fraction (DLESS)
CNLEX: Construction Loss Expensed to Ratepayers (M$/YR)
DCA: Decommission Annual Cost (M$/yr)
FDCS: Funds Available for CS Dividends (M$/YR
PSDV: Preferred Stock Dividends (M$/YR)
FDBS: Funds from Business (M$/YR)
CSDV: Common Stock Dividends (M$/YR)

The common stock dividends reinvested (CSDI) are a user specified fraction of the value of common stock (CSDV).

CSDI=CSDV*CSDIF

Where:

CSDI: Common Stock Dividends Re-invested (M$/YR)
CSDIF: Frac. of CS Dividends Re-invested

The amount of long term and intermediate term debt repaid in the current period (DBRP & IDRP) is equal to the ratio of the value of the debt (DB & ID) to the debt lifetime (DBAL & IDAL). The interest paid on the debt (DBRIN) is equal to either the ratio of debt interest on long

term debt (DBIN) to the debt lifetime (DBAL) or its historical value (XDBRIN) if the current period is a historical year.

DBRP=DB/DBAL
IDRP=ID/IDAL
DBRIN=XDBRIN or DBRIN=DBIN/DBAL

Where:

DBRP: Debt Repaid (M$/YR)
DB: Long Term Debt (M$)
DBAL: Debt Lifetime (YRS)
IDRP: Intermediate Debt Repaid (M$/YR)
ID: Intermediate Debt (M$)
IDAL: Intermediate Debt Average Lifetime (YRS)
DBRIN: Interest on Debt Repaid (M$/YR)
XDBRIN: Historical Interest on Debt Repaid (M$/YR)
DBIN: Debt Interest on Long Term Debt (M$/YR)

Preferred Stock (PS) is increased by the amount funds raised from selling preferred stocks. It is decreased by the amount of preferred stock that enters the preferred stock "sinking fund"

PSSF=PS/PSAL

Where:

PSSF: Preferred Stock Sinking Fund (M$/YR)
PS: Preferred Stock (M$)
PSAL: Preferred Stock Average Lifetime (YEARS)

The utility must finance total construction work in progress, (TCW), debt repayments, purchase power and T&D costs, preferred stock sinking funds (PSSF), and other required financing (MISCGA, MISCFN). Total construction work in progress (TCW) is the sum of CW over facility type and construction schedule, and capacity additions (DCAD) over all sources. The total funding required (FNRQ) is equal to the financing required for various projects [PCTBF, MISCFN, TDTBF and PPTBF], plus plant construction expenditures (TCW), additions to gross assets (MISCGA), debt repaid (DBRP and IDRP) and preferred stock sinking fund (PSSF), less the funds from business (FDBS) and the common stock dividends reinvested (CSDI).

FNRQ = PCTBF + MISCFN + SUM(C,TD)(TDTBF(C,TD)) + SUM(PP)(PPTBF(PP)) + TCW +
SUM(AA)(MISCGA(AA)) + DBRP + IDRP+ PSSF - FDBS - CSDI

Where:

FNRQ: Financing Required (M$)
PCTBF: Pollution Control To Be Financed (M$/YR)
MISCFN: Misc. Projects to be Financed (M$)
TDTBF(CLASS,TD): Trans. and Dist. to be Financed (M$/YR)
PPTBF(PP): Purchase Power T&D Costs to be Financed ($M)
TCW: Generating Plant Construction Expenditures (M$/YR)
MISCGA(AA): Misc. Additions to Gross Assets (M$)
DBRP: Debt Repaid (M$/YR)
IDRP: Intermediate Debt Repaid (M$/YR)
PSSF: Preferred Stock Sinking Fund (M$/YR)
FDBS: Funds from Business (M$/YR)

CSDI: Common Stock Dividends Re-invested (M$/YR)

PROCEDURE LIMITS: FINANCING LIMITS

ENERGY 2020 establishes limits for funding options. Long-term debt is limited by the desired debt fraction and the net earnings certificate ratio. Preferred stock is limited by a desired ratio with long-term debt (PSDBR). No limit is placed on common stock. The basic version of the model allows common stock dilution to occur as necessary. A limit, however, is placed on the repurchase of common stock. No stock can be repurchased if common stock does not at least represent a specified minimum fraction (CSLM) of total capitalization (TCAP). Also a limited fraction of outstanding stock (CSPF) can be purchased per year to avoid excessive market changes in stock prices.

This procedure determines debt coverage by using operating and non-operating earnings to compute net earnings and the net earnings certificate ratio (the ratio of net earnings to interest on long-term debt). If the ratio is less than 1, debt is covered; that is, earnings are sufficient to pay the interest. The second part of the procedure establishes limits on new debt, selling preferred stock, and purchasing common stock. The limit on new debt is computed by two methods, the first based on the desired net-earnings-to-certificate ratio and the second on the allowed debt fraction of total capitalization. The first method value is used for simulating historical years and the smaller of the two values for future years. Limits on common stock purchases are also computed by two methods; the smaller value is used.

Net Earnings Certificate Ratio - Debt Coverage

Operating earnings are composed of revenues minus the costs of O&M, fuel, and purchased power; property and municipal taxes; and the cost of gas purchased for resale, adjusted for inflation.

OPRN=REV-TOMC-TFC-PUCT-PTAX-MTAX-GSEXP*INFLA

where:

GSEXP: Gas Purchased for Resale (M$)
INFLA(YEAR): Inflation Index (DLESS)
MTAX: Municipal Property Tax (M$/YR)
OPRN: Operating Earnings (M$/YR)
PTAX: Property and Revenue Tax (M$/YR)
PUCT: Cost of Purchase Power (M$/YR)
REV: Revenues (M$/YR)
TFC: Total Fuel Cost (M$/YR)
TOMC: Total Operation and Maintenance Costs (M$/YR)

Non-operating earnings are composed of AFUDC from debt and equity funds and other income (minus the income tax).

NOPEN=AFEQ+AFDB+OTINC*(1-TAXR)

where:

AFDB: AFUDC from Debt Funds (M$/YR)

AFEQ: AFUDC from Equity Funds (M$/YR)
NOPEN: Non-Operating Earnings (M$/YR)
OTINC: Other Income (M$/YR)
TAXR: Income Tax Rate (DLESS)

Disallowed earnings are determined by multiplying all earnings (i.e. operating plus non-operating) by the disallowed earnings fraction and subtracting the result from non-operating earnings. Disallowed earnings should not exceed non-operating earnings.

DISEN=NOPEN-DISF*(OPRN+NOPEN)
DISEN=XMIN(NOPEN,DISEN)

where:

DISEN: Disallowed Earnings (M$/YR)
DISF: Disallowed Earnings Fraction (Fraction)
OPRN: Operating Earnings (M$/YR)
NOPEN: Non-Operating Earnings (M$/YR)

Net earnings are operating plus non-operating earnings, minus disallowed earnings.

NETEN=OPRN+NOPEN-DISEN

where:

DISEN: Disallowed Earnings (M$/YR)
NETEN: Net Earnings (M$/YR)
NOPEN: Non-Operating Earnings (M$/YR)
OPRN: Operating Earnings (M$/YR)

The net earnings certificate ratio is based on a measure of earnings available (NETEN) to make interest payments (DBIN):

NCERR=NETEN/DBIN

where:

DBIN: Debt Interest on Long Term Debt (M$/YR)
NCERR: Net Earnings Certificate Ratio (DLESS)
NETEN: Net Earnings (M$/YR)

Financing Limits

Issuing New Debt

Total capitalization is composed of long term and intermediate debt, preferred and common stock, and retained earnings.

TCAP=DB+ID+PS+CS+RE

where:

CS: Common Stock (M$)
DB: Long Term Debt (M$)
ID: Intermediate Debt (M$)
PS: Preferred Stock (M$)
RE: Retained Earnings (M$)
TCAP: Total Capitalization (M$)

To compute the limit on new long term debt by the first method, divide net earnings by the desired net-earnings-to-certificate ratio. This is the limit on total long-term debt interest. Subtract current debt interest (after adjusting for repaid debt) to find the limit on new debt interest, and divide by the interest rate to get the limit on new debt.

DBNLM1=(NETEN/NECRD-(DBIN-DBRIN))/DBIR

where:

DBIN: Debt Interest on Long Term Debt (M$/YR)
DBIR: Interest Rate on New Debt (1/YR)
DBNLM1: Limit on New Long Term Debt (M$)- first method
DBRIN: Interest on Debt Repaid (M$/YR)
NECRD: Net Earnings to Cert. Ratio Desired (DLESS)
NETEN: Net Earnings (M$/YR)

The new debt limit by the second method is the maximum debt fraction of the utility's share of total capitalization (once new financing is added in), plus all of the municipal share of new financing, minus existing long-term and intermediate debt (adjusted for repayments).

DBNLM2=FNRQ*MAF+(TCAP+FNRQ)*(1-MAF)*DBLM-(DB-DBRP+ID-IDRP)

where:

DB: Long Term Debt (M$)
DBLM: Debt Maximum Fraction of Total Capitalization
DBNLM2: Limit on New Long Term Debt (M$)--second method
DBRP: Debt Repaid (M$/YR)
FNRQ: Financing Required (M$)
ID: Intermediate Debt (M$)
IDRP: Intermediate Debt Repaid (M$/YR)
MAF: Municipal Asset Fraction (Dless)
TCAP: Total Capitalization (M$)

Allowing the utility to take on no more than a negative amount of new debt is meaningless, so if the new debt limit computed by the first method (DBNLM1) is negative, it is replaced with 0. The first method value is used for the new debt limit when simulating years for which historical data is available. When simulating future years, the new debt limits computed by both methods and the lower one is used.

In the basic version of ENERGY 2020, the limit for new intermediate debt is set to 0, restricting future financing to long term debt, and the issue of stock.

IDNLM=0

where:

IDNLM: Limit on New Intermediate Debt (M$)

Selling Preferred Stock

The limit on preferred stock issues is found by multiplying the maximum debt (intermediate and long term debt, plus the limits on new intermediate and long term debt) by the preferred-stock-

to-debt ratio, taking the utility's share (1-MAF) of this, and subtracting the value of existing preferred stock.

PSNLM=(DB+ID+DBNLM+IDNLM)*PSDBR*(1-MAF)-PS

where:

DB: Long Term Debt (M$)
DBNLM: Limit on New Long Term Debt (M$)
ID: Intermediate Debt (M$)
IDNLM: Limit on New Intermediate Debt (M$)
MAF: Municipal Asset Fraction (Dless)
PS: Preferred Stock (M$)
PSDBR: Preferred Stock to Debt Ratio ($/$)
PSNLM: Limit on New Preferred Stock (M$)

Purchasing Common Stock

The first method for computing the limit on common stock purchases is simply to multiply the sum of common stock and retained earnings by the exogenously determined fraction of common stock which may be purchased.

CSPLM1=CSPF*(CS+RE)

where:

CS: Common Stock (M$)
CSPF: Fraction of CS which may be Purchased (1/YR)
CSPLM1: Limit on Common Stock Purchased (M$)--first method
RE: Retained Earnings (M$)

The second method multiplies the utility's share of total capitalization by the exogenously determined common stock minimum fraction, and subtracts the result from the the sum of existing common stock plus retained earnings.

CSPLM2=CS+RE-TCAP*CSLM*(1-MAF)

where:

CS: Common Stock (M$)
CSLM: CS Minimum Fraction of Total Capitalization
CSPLM2: Limit on Common Stock Purchased (M$)
MAF: Municipal Asset Fraction (Dless)
RE: Retained Earnings (M$)
TCAP: Total Capitalization (M$)

The smaller of the limits on common stock purchases computed by the two methods is selected. Purchasing a negative amount of stock is meaningless, so the limit is set to 0 if the selected value is negative.

CSPLM=XMIN(CSPLM1,CSPLM2)
CSPLM=XMAX(CSPLM,0)

where:

CSPLM: Limit on Common Stock Purchased (M$)
CSPLM1: Limit on Common Stock Purchased (M$)
CSPLM2: Limit on Common Stock Purchased (M$)

The retained earnings fraction is the ratio of retained earnings to the sum of retained earnings and common stock.

```
REF=RE/(CS+RE)
```

where:

CS: Common Stock (M$)
RE: Retained Earnings (M$)
REF: Retained Earnings Fraction (Fraction)

PROCEDURE FINANCE: FINANCING

This procedure determines how the utility will finance its expansion plans if outside financing is required. If there are excess funds to be distributed, this procedure determines how they will be used.

If financing is required, funds are raised in turn by selling available government bonds, taking on new long term debt and then intermediate debt up to allowable limits, issuing preferred stock up to the allowable limit, and finally issuing common stock to raise any remaining required funds. If instead there are excess funds to be distributed, they are used first to prepay intermediate debt and then to purchase common stock up to the allowable limit. Excess funds still remaining go to buy government bonds.

Financing of Funds Requirements

The code in this section is executed if financing is required, i.e. the amount to be financed, FNRQ, is positive.

```
DO IF FNRQ GT 0
```

where:

FNRQ: Financing Required (M$)

The first step to meeting new financing is to sell bonds to finance other funds, up to the amount needed or the total value of the bonds, whichever is less. Subtract the amount realized from the bonds from the amount required to determine the remaining requirement.

```
SIFD=XMIN(FNRQ,SI)
FNR=FNRQ-SIFD
```

where:

FNR: Financing Funds Remaining (M$)
FNRQ: Financing Required (M$)
SI: Government Bonds (M$)
SIFD: Funds from Selling Government Bonds (M$/YR)

A long-term loan is considered for the remaining amount needed, up to the limit on new long-term debt.

```
DBFD=XMIN(FNR,DBNLM)
```

If the loan amount (DBFD) is negative, it implies that FNR was negative, that is, the required amount has been exceeded. The loan amount is reset to 0.

```
DBFD=XMAX(DBFD,0)
```

The loan amount is then subtracted from the remaining amount required.

```
FNR=FNR-DBFD
```

where:

DBFD: Funds from Debt (M$/YR)
DBNLM: Limit on New Long Term Debt (M$)
FNR: Financing Funds Remaining (M$)

An intermediate-term loan is obtained for the remaining amount needed, up to the limit on new intermediate-term debt. As above, the loan amount is reset to 0 if the requirement has already been met. The loan amount is subtracted from the remaining amount required.

```
IDFD=XMIN(FNR,IDNLM)
IDFD=XMAX(IDFD,0)
FNR=FNR-IDFD
```

where:

FNR: Financing Funds Remaining (M$)
IDFD: Funds from Intermediate Debt (M$/YR)
IDNLM: Limit on New Intermediate Debt (M$)

A block of preferred stock is issued next if necessary, up to the limit on new preferred stock. As above, the loan amount is reset to 0 if the requirement has already been met. The loan amount is subtracted from the remaining amount required.

```
PSFD=XMIN(FNR,PSNLM)
PSFD=XMAX(PSFD,0)
FNR=FNR-PSFD
```

where:

FNR: Financing Funds Remaining (M$)
PSFD: Funds from Preferred Stock (M$/YR)
PSNLM: Limit on New Preferred Stock (M$)

Common stock is then issued equal to the value of any remaining funds required.

```
CSFD=FNR
```

where:

CSFD: Funds from Common Stock (M$/YR)
FNR: Financing Funds Remaining (M$)

Since there are no excess funds available for debt prepayment, repurchasing common stock or purchasing bonds, these amounts are set to 0.

```
IDEP=0
CSPU=0
SIPU=0
```

where:

CSPU: Common Stock Purchased by Company (M$/YR)
IDEP: Intermediate Debt Extra Payments (M$/YR)
SIPU: Funds Used to Purchase Government Bonds (M$/YR)

Distribution of Excess Funds

Perform this section if no financing is required (i.e. the amount to be financed, FNRQ, is negative) but rather there are excess funds to be distributed. The first step is to subtract the financing requirement from 0 to get a positive value for the funds remaining to be distributed (FNR).

FNR=0-FNRQ

where:

FNR: Excess Funds Remaining (M$)
FNRQ: Financing Required (M$)

Payment is first made on intermediate debt. The following equation determines how much debt will remain once the normal payments for the time period has been made.

IDX=ID-DT*IDRP

where:

ID: Intermediate Debt (M$)
IDRP: Intermediate Debt Repaid (M$/YR)
IDX: Intermediate Debt Balance (M$)

Extra debt payments are made up to the balance amount or the amount to be distributed, whichever is less.

IDEP=XMIN(FNR,IDX)

where:

FNR: Excess Funds Remaining (M$)
IDEP: Intermediate Debt Extra Payments (M$/YR)
IDX: Intermediate Debt Balance (M$)

The (positive) extra payment amount is added to the (negative) funds to be distributed (FNRQ). The resulting difference is the excess funds remaining to be distributed. If all excess funds were not used to pay off intermediate range debt, this result will be negative. Therefore the sign is changed to get a positive value for remaining funds.

FNR=FNRQ+IDEP
FNR=0-FNR

where:

FNR: Excess Funds Remaining (M$)
FNRQ: Financing Required (M$)
IDEP: Intermediate Debt Extra Payments (M$/YR)

Next, a buy back of common stock is initiated, up to the amount of remaining funds or the limit on common stock purchases, whichever is less. The difference between stock purchases and

remaining funds is the new remaining amount. If all excess funds were not used to buy stock, this result will be negative.

```
CSPU=XMIN(FNR,CSPLM)
FNR=CSPU-FNR
```

where:

CSPU: Common Stock Purchased by Company (M$/YR)
CSPLM: Limit on Common Stock Purchased (M$)
FNR: Excess Funds Remaining (M$)

Use any funds still remaining to purchase government bonds.

```
SIPU=-FNR
```

where:

FNR: Excess Funds Remaining (M$)
SIPU: Funds Used to Purchase Govt. Bonds (M$/YR)

Because no financing is required, funds from selling bonds, new indebtedness, and issuing stock can all be set to 0.

```
SIFD=0
DBFD=0
PSFD=0
CSFD=0
IDFD=0
```

where:

CSFD: Funds from Common Stock (M$/YR)
DBFD: Funds from Debt (M$/YR)
IDFD: Funds from Intermediate Debt (M$/YR)
PSFD: Funds from Preferred Stock (M$/YR)
SIFD: Funds from Selling Government Bonds (M$/YR)

Total Financing Requirement

Financing for the year is composed of all funds acquired from selling bonds, new indebtedness, or issuing stock, OR all excess funds distributed to extra debt payments or purchasing bonds or common stock. Computing the financing as funds acquired minus funds distributed guarantees that the total financing is positive if additional funds had to be acquired and negative if excess funds were distributed.

```
FN=SIFD+DBFD+PSFD+CSFD+IDFD-IDEP-CSPU-SIPU
```

where:

CSFD: Funds from Common Stock (M$/YR)
CSPU: Common Stock Purchased by Company (M$/YR)
DBFD: Funds from Debt (M$/YR)
FN 'Financing Rate (M$/YR)',
IDEP: Intermediate Debt Extra Payments (M$/YR)
IDFD: Funds from Intermediate Debt (M$/YR)
PSFD: Funds from Preferred Stock (M$/YR)
SIFD: Funds from Selling Government Bonds (M$/YR)
SIPU: Funds Used to Purchase Government Bonds (M$/YR)

PROCEDURE CAPITAL: CAPITAL STRUCTURE

This procedure computes principal and average interest for long range debt, as well as principal for intermediate range debt. It determines the dollar value of preferred and common stock and the book value, market value, and number of shares of common stock; and computes retained earnings. It also computes the dollar value of government bonds held by the utility.

Long Term Debt

Long term debt is new debt principal (funds acquired by going into debt minus any debt repayments) integrated over time. It grows with new borrowings (DBFD) and declines with repayments (DBRP).

DB=DB+DT*(DBFD-DBRP)

where:

DB: Long Term Debt (M$)
DBFD: Funds from Debt
DBRP: Debt Repaid (M$/YR)

Interest on new debt is simply the new debt principal times the new debt interest rate.

DBNIN=DBFD*DBIR

where:

DBFD: Funds from Debt
DBIR: Interest Rate on New Debt (1/YR)
DBNIN: Interest on New Debt (M$/YR)

Interest on long term debt is the integral of net interest (interest on new debt minus any interest that has been repaid).

DBIN=DBIN+DT*(DBNIN-DBRIN)

where:

DBIN: Debt Interest on Long Term Debt (M$/YR)
DBNIN: Interest on New Debt (M$/YR)
DBRIN 'Interest on Debt Repaid (M$/YR)',DISK(EOUTPUT,DBRIN(YEAR))

Divide long term debt interest by long term debt to determine the average interest rate for long term debt.

DBAIR=DBIN/DB

where:

DB: Long Term Debt (M$)
DBAIR: Average Interest Rate on Debt (1/YR)
DBIN: Debt Interest on Long Term Debt (M$/YR)

Intermediate Debt

Intermediate debt is net intermediate indebtedness (funds acquired by going into debt minus any extra payments and any debt repaid) integrated over time.

ID=ID+DT*(IDFD-IDEP-IDRP)

where:

ID: Intermediate Debt (M$)
IDEP: Intermediate Debt Extra Payments (M$/YR)
IDFD: Funds from Intermediate Debt (M$/YR)
IDRP: Intermediate Debt Repaid (M$/YR)

Preferred Stock

The value of preferred stock is funds from the issuance of preferred stock minus funds deposited in the preferred stock sinking fund, integrated over time.

PS=PS+DT*(PSFD-PSSF)

where:

PS: Preferred Stock (M$)
PSFD: Funds from Preferred Stock (M$/YR)
PSSF: Preferred Stock Sinking Fund (M$/YR)

Common Stock

Common Stock Book Value and Market Value

The book value of a share of common stock is calculated by adding retained earnings to the value of all common stock (book value of equity), and dividing by the number of shares outstanding.

CSBV=(CS+RE)/CSSO

where:

CS: Common Stock (M$)
CSBV: Book Value of Common Stock ($/SHARE)
CSSO: Common Stock Shares Outstanding (MILLIONS)
RE: Retained Earnings (M$)

The market value of a share is the book value times the market-to-book-value ratio.

CSMV=CSBV*CSMB

where:

CSBV: Book Value of Common Stock ($/SHARE)
CSMB: CS Market to Book Value Ratio (DLESS)
CSMV: Market Value of Common Stock ($/SHARE)

Common Stock Dollars

The dollar value of common stock is the integral of funds from the sale of common stock plus re-invested dividends, minus any shares purchased by the company which are not included in retained earnings.

CS=CS+DT*(CSFD+CSDI-CSPU*(1-REF))

where:

CS: Common Stock (M$)
CSDI: Common Stock Dividends Re-invested (M$/YR)
CSFD: Funds from Common Stock (M$/YR)
CSPU: Common Stock Purchased by Company (M$/YR)
REF: Retained Earnings Fraction (Fraction)

Number of Shares of Common Stock

The number of shares of common stock can be found by dividing funds from the sale of common stock plus reinvested dividends by the market value per share.

CSSS=(CSFD+CSDI)/CSMV

where:

CSDI: Common Stock Dividends Re-invested (M$/YR)
CSFD: Funds from Common Stock (M$/YR)
CSMV: Market Value of Common Stock ($/SHARE)
CSSS: Shares of Common Stock Sold (MILLIONS)

The number of shares purchased by the company is found by dividing the dollar value of the company's shares by the larger of the book value and market value.

CSSP=CSPU/XMAX(CSBV,CSMV)

where:

CSBV: Book Value of Common Stock ($/SHARE)
CSMV: Market Value of Common Stock ($/SHARE)
CSPU: Common Stock Purchased by Company (M$/YR)
CSSP: Shares of CS Re-Purchased (MILLIONS)

The number of outstanding shares is the integral over time of total shares sold minus those purchased by the company.

CSSO=CSSO+DT*(CSSS-CSSP)

where:

CSSO: Common Stock Shares Outstanding (MILLIONS)
CSSP: Shares of CS Re-Purchased (MILLIONS)
CSSS: Shares of Common Stock Sold (MILLIONS)

Retained Earnings

Retained earnings is the integral of income after dividends are paid minus the retained earnings portion of funds spent to repurchase common stock; plus any miscellaneous additions to retained earnings.

RE=RE+DT*(INCAC-CSPU*REF)+MISRE

where:

CSPU: Common Stock Purchased by Company (M$/YR)
INCAC: Income after CS Dividend Payments (M$/YR)
MISRE: Miscellaneous Additions to Retained Earnings (M$/YR)

RE: Retained Earnings (M$)
REF: Retained Earnings Fraction (Fraction)

Government Bonds

The basic version of ENERGY 2020 does not provide a detailed simulation of utility diversification. Instead it provides an account called short-term investments (SI) where excess funds (SIPU) can be invested. It is assumed these investments achieve the same rate of return as government bonds. These investments are withdrawn (SIFD) to meet future funding needs if necessary. The dollar value of government bonds is the difference between funds spent buying bonds and funds obtained from selling bonds, integrated over time.

SI=SI+DT*(SIPU-SIFD)

where:

SI: Government Bonds (M$)
SIFD: Funds from Selling Government Bonds (M$/YR)
SIPU: Funds Used to Purchase Govt. Bonds (M$/YR)

PROCEDURE CASH: FUNDING/CASH FLOW LOOP

The Financing Loop calls multiple procedures to resolve all financing requirements. Calculations need to be performed at least twice because net income is a function of indebtedness, which is a function of cash requirements, which are a function of income. The loop is performed until the results converge, i.e. until the error is less than an exogenously determined maximum error. Many iterations may be required. If the loop does not converge, a warning appears instructing the user to abort processing.

Initialize the error and the loop count.

FINERR=1
FINCOUNT=0

where:

FINCOUNT: Counter for Financial Loop
FINERR: Error check for Financial Loop

Then perform the financing loop until the error is less than the maximum allowable error, but at least twice.

DO UNTIL (FINERR LE FINMAX) AND (FINCOUNT GT 2)

where:

FINCOUNT: Counter for Financial Loop
FINERR: Error check for Financial Loop
FINMAX: Maximum Error Value for Financial Loop Counter

Error is re-initialized to income before common stock dividends are paid, plus the dividend payments. At the end of the loop, this value will be compared to the same sum.

FINERR=CSDV+INCBC

where:

CSDV: Common Stock Dividends (M$/YR)
FINERR: Error check for Financial Loop
INCBC: Income before CS Dividend Payments (M$/YR)

The following financial procedures, already described, are then performed:

TAXES
INCOME
DIVIDENDS
FUNDS
LIMITS
FINANCE
CAPITAL

The actual error is found by dividing the initial value by the sum of the same quantities, which were recomputed in the loop. The quotient should be close to 1. The absolute value of the amount by which it differs from 1 is the error.

FINERR=ABS(FINERR/(CSDV+INCBC)-1)

where:

CSDV: Common Stock Dividends (M$/YR)
FINERR: Error check for Financial Loop
INCBC: Income before CS Dividend Payments (M$/YR)

The loop counter is set at the next increment and the next iteration of the loop is performed. After 100 iterations, it is assumed that the results are not converging and this warning message appears.

" Financial Loop is not converging; abort all processing
and call Systematic Solutions at (513) 878-8603. "

PROCEDURE EXOPRICE: EXOGENOUS PRICES

When the price of electricity is to be determined exogenously, it is based on the historical price adjusted for inflation. The price of solar power to residential and commercial customers is based on the exogenous price. Fuel demands of electric utilities and IPPs are set at their historical levels.

The price of electricity is set to the historical price adjusted for inflation.

PE=XPE*INFLA

where:

INFLA(YEAR): Inflation Index (DLESS)
PE(CLASS,YEAR): Price of Electricity (MILLS/KWH)
XPE(CLASS,YEAR): Historical Electricity Price (MILLS/KWH)

The fuel price of electricity for the residential, commercial, and industrial classes is the historical electricity price, converted from mills/kwh to dollars/GJ and adjusted for inflation.

FP(RES_ELECTRIC)=XPE(RES)/EECONV*1000*INFLA(NEXT)
FP(COM_ELECTRIC)=XPE(COM)/EECONV*1000*INFLA(NEXT)

FP(IND_ELECTRIC)=XPE(IND)/EECONV*1000*INFLA(NEXT)

where:

EECONV: Electric Energy Conversion (KJ/KWH)
FP(PRICES): Delivered Fuel Price ($/GJ)
INFLA(YEAR): Inflation Index (DLESS)
XPE(CLASS,YEAR): Historical Electricity Price (MILLS/KWH)

The price of solar power to residential and commercial customers is set at 1/5 of the exogenously determined price of electricity.

FP(RES_SOLAR)=FP(RES_ELECTRIC)*0.20
FP(COM_SOLAR)=FP(COM_ELECTRIC)*0.20

where:

FP(PRICES): Delivered Fuel Price ($/GJ)

The fuel demands for electric utilities and qualified facilities is set to their historical levels.

EUDMD=XEUDMD
QFDMD=XQFDMD

where:

EUDMD(PLANT): Utility Fuel Demand (TBTU/YR)
QFDMD(TECH): Fuel Demand from QF (TBTU/YR)
XEUDMD(PLANT): Historical Utility Fuel Demand (TBTU/YR)
XQFDMD(TECH): Qualified Facilities Fuel Demand (TBTU/YR)

The energy supply constraint multiplier is set to 1.00.

ENMSM(ELECTRIC,Y)=1.00
ENMSM(SOLAR,Y)=1.00

where:

ENMSM(FUEL,YEAR): Energy Supply Constraint Multiplier (BTU/BTU)

PROCEDURE TESTYEAR: REGULATION TEST YEAR ANALYSIS

The regulatory process centers around a test year, either historical or one year forward, when the proposed rates will go into effect. The future or historical test year can change from year to year as a policy (REGSW). If a future test year is use, the utility forecasts test year sales and peak demand by season and class. The test year sales are used to determine average revenue while the test year peaks are used to determine the class-specific responsibility for the system peak and thereby allocate generation capacity responsibility. The regulatory procedures (TESTYEAR and PRICE) use allowed rates-of-return and test year costs/demands to determine allowed revenues.

Sales Growth Rate and Forecast by Class and Season

The extrapolation process described in the forecasting section is used to estimate future class sales by season (TYCLDC) and future sales by class (TYSALES). TYCLDC is summed over

class to obtain the system load by season (TYSLDC). This term will later be used to allocate operating costs.

```
SALEGR(C)=(SALESM(C,1)/SALESM(C,2)-1)/(UST-USMT(2))
TYSALES(C)=SALESM(C,1)*EXP((SALEGR(C)*(1-EXTSW)+LN(1+SALEGR(C))*EXTSW)*
    (1+USMT(2)))
```

where:

EXTSW: Extrapolation Switch; 4 Methods
SALEGR(CLASS): Annual Sales of Elect. Growth Rate (GWH/YR)
SALESM(CLASS,LV2): Level for Electricity Sales Extrapolation
TYSALES(CLASS): Test Year Electricity Sales (GWH/YR)
USMT(HORIZON): Smoothing Time (Year)
UST: Short-term Smoothing Time (Year)

Update Smoothed Values

The smoothed value of electricity sales is the integral of sales over time. Update this value by replacing a fraction of the old value determined by the smoothing time. For example, if the smoothing time is 5 years, 1/5 of the old value is replaced each year.

```
SALESM(C,1)=SALESM(C,1)+DT*(SALES(C,ELECTRIC)-SALESM(C,1))/USMT(2)
SALESM(C,2)=SALESM(C,2)+DT*(SALES(C,ELECTRIC)-SALESM(C,2))/UST
```

where:

SALES(CLASS,FUEL) 'Annual Sales of Electricity (GWH/YR)',
SALESM(CLASS,LV2): Level for Electricity Sales Extrapolation
USMT(HORIZON): Smoothing Time (Year)
UST: Short-term Smoothing Time (Year)

Historical Test Year

Sales

Test year sales are initialized with the value of current electricity sales by class.

```
TYSALES(C)=SALES(C,ELECTRIC)
```

where:

SALES(CLASS,FUEL): Annual Sales of Electricity (GWH/YR)
TYSALES(CLASS): Test Year Electricity Sales (GWH/YR)

The smoothed value of the contribution to peak is the sum of each month's contributions to peak, integrated over time. This value is updated by replacing a fraction of the old value determined by the smoothing time. For example, if the smoothing time is 5 years, 1/5 of the old value is replaced each year.

```
CTPSM(C)=CTPSM(C)+DT*(SUM(M)(CTP(C,M))-CTPSM(C))/USMT(1)
```

where:

CTP(CLASS,MONTH): Contribution to Electric Peak Load (MW)

CTPSM(CLASS): Smoothed Value of Contribution to Peak
USMT(HORIZON): Smoothing Time (Year)

The sales growth adjustment for exogenously specified classes is the percent of increase in sales from the current year to next year.

SELECT CLASS(RESALE,ORESALE),FUEL(ELECTRIC)
TYADJ(C)=(XSALES(C,NEXT)-XSALES(C,CURRENT))/XSALES(C,CURRENT)

where:

TYADJ(CLASS): Adjustment for Exogenous Classes
XSALES(CLASS,YEAR): Historical Electricity Sales (GWH/YR)

The classes for which sales (XSALES) are exogenous, are adjusted to reflect the change in sales from one period to the next.

TYSALES=TYSALES*(1+TYADJ)
CTPSM=CTPSM*(1+TYADJ)

where:

CTPSM(CLASS): Smoothed Value of Contribution to Peak
TYADJ(CLASS): Adjustment for Exogenous Classes
TYSALES(CLASS): Test Year Electricity Sales (GWH/YR)

Test year electricity sales is the sum of test year sales over all classes.

TYTSALE=SUM(C)(TYSALES(C))

where:

TYSALES(CLASS): Test Year Electricity Sales (GWH/YR)
TYTSALE: Test Year Electricity Sales (GWH/YR)

Capacity Construction

Capacity construction is initiated when forecasted demand exceeds existing construction and capacity under construction. Next year's ratebase is forecasted from the construction work in progress (CWIP) and the AFUDC coming on-line next year. The rate base additions are added to conventional generation assets. For each non-nuclear plant type construction work in progress (CWIP) and AFUDC coming on-line next year are included, plus plant capital additions. The generating capacity for the test year is then the current generating capacity plus next year's additions less next year's retirements.

The value of the rate-base is a major contributor to the price of electricity. As part of the test year estimates, net additions to the rate-base (TYRBADD) affecting the test year price of electricity must be calculated. The additions to the rate-base are the amounts of construction work in progress and AFAC for all plants to be completed before or during the test year. Also all capital additions to existing capacity (GCAD) and pollution control to be financed (PCTBF) must be added.

TYRBADD(GENER)=TYRBADD(GENER)+CWAC(P,LOC1)+AFAC(P,LOC1)+GCAD(P)

Pollution control to be financed is added to rate base additions.

TYRBADD(GENER)=TYRBADD(GENER)+PCTBF

where:

AFAC(PLANT,LV12): Accumulated AFUDC (M$)
CWAC(PLANT,LV12): Const. Work in Progress Accum. (M$)
GCAD(PLANT): Plant Capital Additions (M$)
TYRBADD(AA): Test Year Rate Base Additions (M$)
PCTBF: Pollution Control To Be Financed (M$/YR)

For nuclear plants, additions to the rate base from construction work and AFUDC coming on-line next year, the AFUDC and CW portions of the deferred rate base, plus plant capital additions are recomputed.

TYRBADD(NUCLEAR)=CWAC(NUCLEAR,LOC1)+AFAC(NUCLEAR,LOC1)+AFDFRB+
CWDFRB+GCAD(NUCLEAR)

The procedure is designed so that nuclear rate base additions may not exceed a predetermined fraction.

TYRBADD(NUCLEAR)=XMIN(TYRBADD(NUCLEAR),NUCRB(NEXT))

where:

AFAC(PLANT,LV12): Accumulated AFUDC (M$)
AFDFRB: AFUDC portion of Deferred Rate Base (M$/YR)
CWAC(PLANT,LV12): Const. Work in Progress Accum. (M$)
CWDFRB: CW portion of Deferred Rate Base (M$/YR)
GCAD(PLANT): Plant Capital Additions (M$)
TYRBADD(AA): Test Year Rate Base Additions (M$)

In the transportation, distribution, conservation, and “other” categories, rate base additions are equivalent to any construction-related additions to gross assets.

TYRBADD=CWGAA

where:

CWGAA(AA): Direct Const. Costs to Gross Assets (M$)
TYRBADD(AA): Test Year Rate Base Additions (M$)

Inflation

Inflation is forecasted for price calculations.

INFLA(NEXT)=INFLA(CURRENT)+(INFLA(CURRENT)*INFLR(NEXT))

where:

INFLA(YEAR): Inflation Index (DLESS)
INFLR(YEAR): Inflation Rate (1/YR)

Test Year Capacity

For each plant type, determine the capacity due to come on line next year based on what was under construction during the previous period and the length of time required to bring new capacity of that type online.

```
GCCR(P)=SUM(L)(CUC(P,L))
```

where:

CUC(PLANT,LV12): Capacity Under Construction in Previous Period (MW)
GCCR(PLANT): Generation Capacity Completion Rate (MW/YR)

Before projecting fuel costs and electricity generation, the model pointers for the current and prior years are set forward one year. A test year switch is set to indicate that this is a projection and not the actual simulation of the next year, since much of the same logic is employed.

Test Year Fuel Costs

Fuel Prices

For each plant type, the prices charged to electric utilities for fuel are determined. These prices are specified in the map between plants and electric utility prices (PRPLMAP). For example, for coal plants, look at the electric utility price for coal; for oil/gas plants, look at the natural gas, distillate, and residual prices.

These prices are computed as if they are endogenous. (Endogenous prices are identified by the value of the price switch, PRSW.) Fuel price is computed from the normal exogenous price for the contributing fuel, identified by the map between prices and fuels (PFMAP). For example, when computing the electric utility distillate and residual prices, the normal exogenous price for oil is used. To this price are added the delivery charge and fuel tax, all adjusted for inflation, and the energy sales tax.

```
FP=(XENPN+FPDCHG+FPTAX)*INFLA*(1+FPSM)
```

where:

FP(PRICES): Delivered Fuel Price ($/GJ)
FPDCHG(PRICES): Fuel Delivery Charge ($/GJ)
FPSM(PRICES): Energy Sales Tax ($/GJ)
FPTAX(PRICES,YEAR): Fuel Tax ($/GJ)
INFLA(YEAR): Inflation Index (DLESS)
XENPN(FUEL,YEAR): Exogenous Price Normal ($/BTU)

If the price is exogenous, it is simply adjusted for inflation.

```
ELSE PRSW(P) EQ EXOGENOUS
   FP=XFP*INFLA
```

where:

FP(PRICES): Delivered Fuel Price ($/GJ)
INFLA(YEAR): Inflation Index (DLESS)
XFP(PRICES,YEAR): Delivered Fuel Prices ($/MBTU)

Fuel prices for each plant type are determined based on the map between prices and plant type (PRPLMAP), except for the oil and gas plants (OILG) which use both gas and oil.

```
EUFP(PLANT)=SUM(PRICES)(FP(PRICES)*PRPLMAP(PLANT,PRICES))
```

where:

EUFP(PLANT): Fuel Price for Electric Utility ($/MBTU)
FP(PRICES): Delivered Fuel Price ($/GJ)
PRPLMAP(PLANT,PRICES): Map between PLANT and PRICES

For oil/gas plants, compute the fraction of fuel which is oil. This depends on the relative prices of gas and oil, the calibrated oil fraction multiplier that captures non-price factors and the fungible market share variance factor that picks up imperfect price information.

```
OILFR=1/(1+(FP(EU_GAS)/(EUOFM*FP(EU_DIST)))**EUFVF)
```

where:

EUFVF: Fungible Market Share Variance Factor (DLESS)
EUOFM: OIL Fraction Mult. (Fraction)
FP(PRICES): Delivered Fuel Price ($/GJ)
OILFR: Fraction of Oil/Gas which is Oil (FRAC.)

The fuel price for oil/gas plants is the weighted average of fuel prices for oil and gas, with the oil fraction and 1 minus the oil fraction as the weights.

```
EUFP(OILG)=(FP(EU_DIST)*OILFR+FP(EU_GAS)*(1-OILFR))
```

where:

EUFP(PLANT): Fuel Price for Electric Utility ($/MBTU)
FP(PRICES): Delivered Fuel Price ($/GJ)
OILFR: Fraction of Oil/Gas which is Oil (FRAC.)

Unit Fuel Cost

Fuel costs for the test year are calculated by dispatching the supplies which will be available in the test year through use of the test year system load curve. The unit fuel cost for conventional plants depends on fuel price, average heat rate, and an operational factor specific to the plant type. Nuclear unit fuel costs are exogenous.

```
UFC=EUFP*HRTA*EUOPM/1000
UFC(NUCLEAR)=XUFC(NUCLEAR)
```

where:

EUFP(PLANT): Fuel Price for Electric Utility ($/MBTU)
EUOPM(PLANT): Operational Mult.
HRTA(PLANT): Average Heat Rate (BTU/KWH)
UFC(PLANT): Unit Fuel Cost (MILLS/KWH)
XUFC(PLANT): Historical Unit Fuel Cost (MILLS/KWH)

Test Year Generation Capacity

Generating capacity is the capacity completion rate minus the retirement rate plus fuel conversion, integrated over time. (The completion rate for hydroelectric plants is exogenous).

```
GCCR(HYDRO)=XGCCR(HYDRO)
GC=GC+DT*(GCCR-GCR+GCFCV)
```

where:

GC(PLANT): Generation Capacity (MW)

GCFCV(PLANT): Fuel Conversion (MW)
GCCR(PLANT): Generation Capacity Completion Rate (MW/YR)
GCR(PLANT,YEAR): Generation Capacity Retirements (MW/YR)
XGCCR(PLANT): Generation Capacity Construction Completion Rate (MW/YR)

Procedures to simulate test year production, the determination of O&M costs, and decommissioning are the same as the original simulation procedures.

Call:

PRODUCTION
OMCOSTS
DECOMMISSION

The values for test year unit fuel cost and electricity generated come directly from this simulation.

TYUFC=UFC
TYEG=EG

Test year fuel cost is the product of unit fuel cost times generation, summed over plant type.

TYFC=SUM(P)(UFC(P)*EG(P))/1000

where:

EG(PLANT): Electricity Generated (GWH/YR)
TYEG(PLANT): Test Year Electricity Generated (GWH/YR
TYFC: Test Year Fuel Costs (M$)
TYUFC(PLANT): Test Year Unit Fuel Cost (MILLS/KWH)
UFC(PLANT): Unit Fuel Cost (MILLS/KWH)

The value for test year purchase power cost comes directly from the test year simulation.

TYPUCT=PUCT

where:

PUCT: Cost of Purchase Power (M$/YR)
TYPUCT: Test Year Purchased Power Costs (M$)

Test year O&M costs is the sum of O&M and decommissioning costs from the test year simulation.

TYOMC=TOMC+DCA

where:

DCA: Decommission Annual Cost (M$/yr)
TOMC: Total Operation and Maintenance Costs (M$/YR)
TYOMC: Test Year O&M Costs (M$)

Once fuel costs and generation have been projected, the test year switch is reset and the current and prior year pointers are reset to the original time.

Test Year Property Taxes

Test year information is generated for most income related variables with forecasted or estimated test year values from the same equations used for the "normal year" calculations. For example, property taxes for the test year are calculated "normally" except that rate-base additions are included. The rate base additions for the test year are included in the net assets before multiplying by the appropriate tax rate. The result is multiplied by the municipal asset fraction (MAF) for municipal taxes and 1 minus the MAF for property taxes.

TYPTAX=SUM(AA)(PTAXR(AA)*(NA(AA)+TYRBADD(AA)))*(1-MAF)
TYMTAX=SUM(AA)(MTAXR(AA)*(NA(AA)+TYRBADD(AA)))*MAF

where:

MAF: Municipal Asset Fraction (Dless)
NA(AA): Net Assets (M$)
MTAXR(AA): Municipal Property Tax Rate (1/YR)
PTAXR(AA): Property Tax Rate (1/YR)
TYMTAX: Test Year Property Tax (M$
TYPTAX: Test Year Property Tax (M$)
TYRBADD(AA): Test Year Rate Base Additions (M$)

Test Year Depreciation

Depreciation for the next year is projected in the same fashion by including the rate base additions for the test year in the gross assets and multiplying the result by the depreciation rate.

TYSLDP=SUM(AA)((GA(AA)+TYRBADD(AA))*DPRSL(AA))

where:

DPRSL(AA): Straight Line Depreciation Rate (1/YR)
GA(AA): Gross Assets (M$)
TYRBADD(AA): Test Year Rate Base Additions (M$)
TYSLDP: Test Year Straight Line Depr. (M$

Test Year Revenues

Revenues are projected by multiplying projected electricity sales by the price of electricity and summing over all classes; then gas revenues, adjusted for next year's inflation, are added.

TYREV=SUM(CLASS)(PE(CLASS,Y)*TYSALES(CLASS))/1000+GSREV*INFLA(NEXT)

where:

GSREV: Gas Revenues (M$/YR)
INFLA(YEAR): Inflation Index (DLESS)
PE(CLASS,YEAR): Price of Electricity (MILLS/KWH)
TYREV: Test Year Revenue (M$/YR)
TYSALES(CLASS): Test Year Electricity Sales (GWH/YR)

Test Year Income Tax

Test year income taxes reported are calculated differently than in the "normal" year because the regulatory process does not use accelerated depreciation methods. The "normal" year reported tax (ITXRP) calculation can be used, however, as a basis for understanding the regulatory counterpart. Amortized tax credits (AMTC) are treated as usual. Deferred tax credits (DFITC) are replaced by claimed tax credits (CLTC) when there is flow-through accounting (NMTC equals 0.0). The deferred taxes from the AFC (AFDTX) term is replaced by a calculation using the test year values as TAXR*TYAFDB. The test year AFC from debt (TYAFDB) uses the normal calculation of "AFDB" with updated values. The normal indicated income tax term (ITX) is replaced by TAXR*TYNTINC.Income taxes are computed on the net income and AFUDC from debt funds. Projected net income is made up of projected revenue minus the projections for fuel and purchased power costs, O&M costs, miscellaneous deductions, the cost of gas purchased for resale, property taxes, depreciation, debt interest, and construction losses.

The first step is the calculation of test year net income:

```
TYNTINC=(TYREV-TYFC-TYPUCT-TYOMC-MISCDED(NEXT)-GSEXP*INFLA(NEXT))-
    TYPTAX-TYSLDP*(1-MAF)-(DBIN+IDIN+SDIN)*(1-MDF)-CNLEX
```

where:

CNLEX: Construction Loss Expensed to Ratepayers (M$/YR)
DBIN: Debt Interest on Long Term Debt (M$/YR)
GSEXP: Gas Purchased for Resale (M$)
IDIN: Interest on Intermediate Debt (M$/YR)
INFLA(YEAR): Inflation Index (DLESS)
MAF: Municipal Asset Fraction (Dless)
MDF: Municipal Debt Fraction (DLESS)
MISCDED(YEAR): Miscellaneous Deductions (M$)
SDIN: Interest on Short Term Debt (M$/YR)
TYFC: Test Year Fuel Costs (M$)
TYNTINC: Test Year Net Income (M$)
TYOMC: Test Year O&M Costs (M$)
TYPUCT: Test Year Purchased Power Costs (M$)
TYPTAX: Test Year Property Tax (M$
TYREV: Test Year Revenue (M$/YR)
TYSLDP: Test Year Straight Line Depr. (M$)

To project the AFUDC coming from debt funds, sum construction costs and accumulated AFUDC over all plants and construction levels and multiply this by the fraction of in-progress construction work not already in the rate base. Multiply the result by the gross rate for AFUDC times the fraction of AFUDC coming from debt funds.

```
TYAFDB=AFDBF*AFGSR*(1-FCWRB)*
    SUM(PLANT)(SUM(L)(CWAC(PLANT,L)+AFAC(PLANT,L)))
```

where:

AFAC(PLANT,LV12): Accumulated AFUDC (M$)
AFDBF: Fraction of AFUDC from Debt Funds (DLESS)
AFGSR: Gross Rate for AFUDC (1/YR)
CWAC(PLANT,LV12): Const. Work in Progress Accum. (M$)
FCWRB: Fraction of CWIP in Rate Base (DLESS)

TYAFDB: Test Year AFUDC from Debt Funds (M$/YR)

To project income tax, multiply the projected net income and AFUDC by the tax rate and subtract any amortized tax credit. Subtract claimed tax credits if there is flow-through accounting (NMTC=0.0).

TYITXRP=TAXR*(TYNTINC+TYAFDB)-AMTC-CLTC*(1-NMTC)

where:

AMTC: Amortized Investment Tax Credit (M$/YR)
CLTC: Claimed Investment Tax Credit (M$/YR)
NMTC: Normalization Switch for Tax Credits (DLESS)
TAXR: Income Tax Rate (DLESS)
TYAFDB: Test Year AFUDC from Debt Funds (M$/YR)
TYITXRP: Test Year Income Tax Reported (M$)
TYNTINC: Test Year Net Income (M$)

Test Year Operating Income

Projected operating income is made up of projected revenue minus the projections for fuel and purchased power costs, O&M costs, miscellaneous expenses, the cost of gas purchased for resale, property taxes, depreciation, income tax, and construction losses.

TYOPINC=(TYREV-TYFC-TYPUCT-TYOMC-MISCEXP-GSEXP*INFLA(NEXT))-
TYPTAX-TYSLDP*(1-MAF)-TYITXRP-CNLEX

where:

CNLEX: Construction Loss Expensed to Ratepayers (M$/YR)
GSEXP: Gas Purchased for Resale (M$)
INFLA(YEAR): Inflation Index (DLESS)
MAF: Municipal Asset Fraction (Dless)
MISCEXP: Miscellaneous Expenses (M$)
TYFC: Test Year Fuel Costs (M$)
TYITXRP: Test Year Income Tax Reported (M$)
TYOMC: Test Year O&M Costs (M$)
TYOPINC: Test Year Operating Income (M$)
TYPTAX: Test Year Property Tax (M$
TYREV: Test Year Revenue (M$/YR),
TYPUCT: Test Year Purchased Power Costs (M$)
TYSLDP: Test Year Straight Line Depr. (M$)

Test Year Rate Base

Rate-base equals net plant-in-service, plus any plants coming on-line during the test year, plus working capital, plus any CWIP and AFC allowed in the rate-base (less adjustments for plants coming on-line during the test year). Deferred taxes (ADTX) and tax credits (ADTC) are also netted out of the rate base. To project the rate base, working capital, net plant in service, and construction work in progress and coming on line during the test year need to be projected first. The projected rate base implies a level of operating income which will later be compared with the operating income projected above.

Working Capital

Working capital is the cash needed to cover the portion of projected O&M costs in the rate base plus the portion of projected fuel costs in the rate base. Working capital associated with conventional fuels reflects the carrying cost of inventory. For example, if the inventory were, on average, equivalent to six weeks of fuel use, the fraction (FFCRB) of total fuel costs considered as working capital would be 6/52nds of a year or approximately 0.12. There is a similar fraction (FOMRB) for operation/maintenance costs. Projected fuel costs are computed by multiplying the projected unit fuel cost by the projected electricity generation, summing over all plant types (except nuclear and hydroelectric), and adding purchased power costs. This number is then multiplied by the fraction of fuel costs in the rate base. No nuclear or hydro is considered in the need for working capital because no fuel inventory is required. The O&M portion of working capital is simply the projected O&M cost times the O&M ratebase fraction.

WORKCAP=TYOMC*FOMRB+(SUM(P)(UFC(P)*EG(P))/1000+PUCT)*FFCRB

where:

EG(PLANT): Electricity Generated (GWH/YR)
FFCRB: Fraction of Fuel Costs in Rate Base
FOMRB: Fraction of O&M Costs in Rate Base
PUCT: Cost of Purchase Power (M$/YR)
TYOMC: Test Year O&M Costs (M$)
UFC(PLANT): Unit Fuel Cost (MILLS/KWH)
WORKCAP: Working Capital (M$)

Net Plant

Net plant is the sum of net assets over all asset types (transmission, generation, distribution, nuclear, conservation, and other).

NETPLANT=SUM(AA)(NA(AA))

where:

NA(AA): Net Assets (M$)',DISK(EOUTPUT,NA(AA,YEAR))
NETPLANT: Total Net Assets (M$)

Construction

Total construction is the construction work in progress plus the AFDUC, summed over all construction levels.

TCWAC(PLANT)=SUM(LV)(CWAC(PLANT,LV)+AFAC(PLANT,LV))

where:

AFAC(PLANT,LV12): Accumulated AFUDC (M$)
CWAC(PLANT,LV12): Const. Work in Progress Accum. (M$)
TCWAC(PLANT): CWIP plus AFUDC Accumulated (M$)

For the construction work in progress to be included in the ratebase, CWIP for all plant types (TCWAC) is summed and CWIP coming online next year (TYRBADD) is subtracted from it. Multiply by the fraction of CWIP allowed in the ratebase. CWIP included in the ratebase must be non-negative.

```
TYCWAC=(SUM(P)(TCWAC(P))-SUM(AA)(TYRBADD(AA)))*FCWRB
TYCWAC=XMAX(TYCWAC,0)
```

where:

FCWRB: Fraction of CWIP in Rate Base (DLESS)
TCWAC(PLANT): CWIP plus AFUDC Accumulated (M$)
TYCWAC: Const. Work in Progress into Ratebase (M$)
TYRBADD(AA): Test Year Rate Base Additions (M$)

Ratebase equals net plant in service, working capital, and the CWIP allowed in the ratebase, minus the AFUDC and construction work portions of the deferred rate base and deferred taxes and tax credits.

```
RB=NETPLANT+WORKCAP-AFDFRB-CWDFRB-ADTX-
        ADTC+TYCWAC+SUM(AA)(TYRBADD(AA))
```

where:

ADTC: Accum. Deferred Investment Tax Credits (M$)
ADTX: Accum. Deferred Taxes from Depreciation (M$)
AFDFRB: AFUDC portion of Deferred Rate Base (M$/YR)
CWDFRB: CW portion of Deferred Rate Base (M$/YR)
NETPLANT: Total Net Assets (M$)
RB: Forecast Rate Base (M$)
TYCWAC: Const. Work in Progress into Ratebase (M$)
TYRBADD(AA): Test Year Rate Base Additions (M$)
WORKCAP: Working Capital (M$)

Operating Income

Operating income implied by the forecast ratebase is the ratebase times the weighted cost of capital, times the fraction not included in municipal assets (1-MAF).

```
RBOPINC=RB*WCC*(1-MAF)
```

where:

MAF: Municipal Asset Fraction (Dless)
RB: Forecast Rate Base (M$)
RBOPINC: Operating Income from Forecast Rate Base (M$)
WCC: Weighted Cost of Capital (1/YR)

Operating income from municipal debt is debt interest times a regulation factor (MTIER) times the municipal debt fraction (MDF).

```
RMOPINC=(DBIN+IDIN)*MTIER*MDF
```

where:

DBIN: Debt Interest on Long Term Debt (M$/YR)
IDIN: Interest on Intermediate Debt (M$/YR)
MDF: Municipal Debt Fraction (DLESS)
MTIER: Municipal Times-Interest-Earned Regulation
RMOPINC: Operating Income from Municipal Debt (M$)

Revenue Deficiency and True-Up Revenue Variable

To determine the revenue deficiency, first take the difference between the forecasted operating income and the operating income implied by the forecast rate base. The revenue deficiency is the portion of the difference which is not municipal revenue, plus the portion of the difference which is municipal revenue. Since expenses have been accounted for, the portion which is not municipal revenue is divided by 1 minus the tax rate (1-TAXR) since it is taxable income.

```
DREV=(RBOPINC-TYOPINC)*(1-MRF)/(1-TAXR)+
   (RBOPINC-TYOPINC)*MRF
```

where:

DREV: Revenue Deficiency (M$)
MRF: Municipal Revenue Fraction (Dless)
RBOPINC: Operating Income from Forecast Rate Base (M$)
TAXR: Income Tax Rate (DLESS)
TYOPINC: Test Year Operating Income (M$)

True-up revenue is the difference between the allowed and actual revenues.

```
TUREV=AREV-REV
```

where:

AREV(YEAR): Allowed Revenue (M$/YR)
REV: Revenues (M$/YR)
TUREV: True Up Revenue (M$/YR)

PROCEDURE PRICE: ELECTRIC UTILITY PRICE CALCULATIONS

The price of electricity is the sum of three separately calculated components. First, generation fuel costs (PEFC) are allocated by customer class according to sales. Second, differential charges (PEDC) are allocated by class according to peak contribution. Differential charges attempt to capture energy-related cost-to-serve differences between classes and, to some extent, policy-related "external" adjustments of electricity prices across customer classes. Third, operating costs (PEOC) are allocated by customer class on a contribution to peak basis. The allocation according to peak contribution recognizes that new capacity is built to meet peak demand. The cost responsibility and benefits by customer class from that plant are in proportion to the peak demand contribution.

The allocation of the allowed revenues to generate new electricity prices requires three steps. In the first step the revenues associated with the differential charges are estimated. Next, these revenues plus the fuel cost and purchased power cost are subtracted from allowed revenues to obtain the "fixed" revenue that is allocated by contribution to peak. The fixed revenues represent the costs associated with having the power plants in place (fixed) and available. In the last step, fuel costs (the cost per GWH of fuel plus purchased power) are calculated. All the component costs are added to generate the electricity price by class. This price will be the actual price used in the following year.

Preliminary Calculations

Lost Revenue

Savings in demand, often from the initiation of utility DSM programs, result in the loss of anticipated revenue which would have helped cover fixed costs. (Variable costs won't need to be covered because fuel for generation will not need to be purchased.) To compute lost revenue, the increase in demand savings is multiplied by the price of electricity capital costs. Lost revenue, by definition, must be non-negative.

```
LREV(C)=(XDSAV(C,Y+1)-XDSAV(C,Y))*(PEOC(C,Y)*0.4/2)/1000
LREV=XMAX(0,LREV)
```

where:

LREV(CLASS): DSM Lost Revenue (M$)
PEOC(CLASS,YEAR): Price of Electricity Capital Costs (MILLS/KWH)
XDSAV(CLASS,YEAR): Total Exogenous Demand Savings (GWH)

Allowed Revenue

The allowed revenue is the test year revenue plus the discrepancy between the allowed and projected ratebase income (DREV) and any unique or negotiated adjustments to the allowed revenues (RVADJ), minus any gas revenues (adjusted for inflation). A true-up revenue variable (TUREV) is added if the true-up switch (TUSW) is turned on. TUREV is any revenue shortfalls that are being "recovered" during this year.

```
AREV(NEXT)=TYREV+DREV+TUREV*TUSW+RVADJ(NEXT)-GSREV*INFLA(NEXT)
```

where:

AREV(YEAR): Allowed Revenue (M$/YR)
DREV: Revenue Deficiency (M$)
GSREV: Gas Revenues (M$/YR)
INFLA(YEAR): Inflation Index (DLESS)
RVADJ(YEAR): Revenue Adjustment (M$/YR)
TUREV: True Up Revenue (M$/YR)
TUSW: True Up Revenue Switch
TYREV: Test Year Revenue (M$/YR)

Differential Charge Component

The differential charge revenue is calculated by multiplying projected sales (TYSALES) by the calibrated delivery charge per GWH (PEDC), adjust for inflation, and summing over all customer classes.

```
DCRV=SUM(CLASS)(TYSALES(CLASS)*PEDC(CLASS,NEXT)*INFLA(NEXT))/1000
```

where:

DCRV: Differential Charge Revenue (M$/YR)
INFLA(YEAR): Inflation Index (DLESS)
PEDC(CLASS,YEAR): Real Electricity Delivery Chg. (MILLS/KWH)
TYSALES(CLASS): Test Year Electricity Sales (GWH/YR)

Operating Cost Component

Fixed Revenue

Fixed revenue, which will be allocated by contribution to peak, is the residual when fuel (TYFC) and purchase power costs (TYPUCT) and the differential charges (DCRV) are subtracted from allowed revenue (AREV).

FXRV=AREV(NEXT)-TYFC-TYPUCT-DCRV

where:

AREV(YEAR): Allowed Revenue (M$/YR)
DCRV: Differential Charge Revenue (M$/YR)
FXRV: Fixed Revenues (M$/YR)
TYFC: Test Year Fuel Costs (M$)
TYPUCT: Test Year Purchased Power Costs (M$)

Peak Fraction Contribution

The peak contribution of the customer class is calculated as a fraction of the sum of the smothes value of contribution to peak by class (CTPSM). This fraction is used to allocate fixed revenue and other charges according to peak contribution.

LOC1=SUM(CLASS)(CTPSM(CLASS))
PFR(CLASS)=CTPSM(CLASS)/LOC1

where:

CTPSM(CLASS): Smoothed Value of Contribution to Peak
PFR(CLASS): Peak Fraction Contribution (DLESS)

Demand Charge

For policy testing purposes, a monthly demand charge (PEDM) can be calculated for each customer class by multiplying the class share of the fixed costs by the fraction of revenue allocated to the demand charge, and dividing by the class contribution to peak. The proportion of fixed costs allocated to the demand charge can be varied as a policy.

PEDM(CLASS,NEXT)=FXRV*PFR(CLASS)*DMCFR(CLASS)/(CTPSM(CLASS)/12)*1000

where:

CTPSM(CLASS): Smoothed Value of Contribution to Peak
DMCFR(CLASS): Fraction of Revenue allocated to Demand Charge
FXRV: Fixed Revenues (M$/YR)
PEDM(CLASS,YEAR): Electricity Demand Charge ($/KW)
PFR(CLASS): Peak Fraction Contribution (DLESS)

Price of Electricity from Operating Costs

The price of electricity from operating costs allocated to each customer class is the fixed revenues per kWh, scaled by the class peak fraction contribution.

PEOC(CLASS,NEXT)=FXRV/TYSALES(CLASS)*PFR(CLASS)*1000

where:

FXRV: Fixed Revenues (M$/YR)
PEOC(CLASS,YEAR): Price of Electricity Capital Costs (MILLS/KWH)
PFR(CLASS): Peak Fraction Contribution (DLESS)
TYSALES(CLASS): Test Year Electricity Sales (GWH/YR)

Fuel Cost Component

The fuel cost price component (PEFC) is the sum of the generation fuel (TYFC) and purchased power costs (TYPUCT) divided by test year sales (TYTSALE).

```
PEFC(NEXT)=(TYFC+TYPUCT)/TYTSALE*1000
```

where:

PEFC(YEAR): Price of Electricity Fuel Component (MILLS/KWH)
TYFC: Test Year Fuel Costs (M$)
TYPUCT: Test Year Purchased Power Costs (M$)
TYTSALE: Test Year Electricity Sales (GWH/YR)

Electricity and Fuel Prices for Next Year

Electricity prices

The three projected price components - operating cost (PEOC), fuel cost (PEFC), and differential charges (PEDC) are added to generate the electricity price by class PE in mills/kwh. This price will be the actual price used in the following year.

```
PE(CLASS,NEXT)=PEOC(CLASS,NEXT)+PEFC(NEXT)+
    PEDC(CLASS,NEXT)*INFLA(NEXT)
```

where:

INFLA(YEAR): Inflation Index (DLESS)
PE(CLASS,YEAR): Price of Electricity (MILLS/KWH)
PEDC(CLASS,YEAR): Real Electricity Delivery Charge (MILLS/KWH)
PEFC(YEAR): Price of Electricity Fuel Component (MILLS/KWH)
PEOC(CLASS,YEAR): Price of Electricity Capital Costs (MILLS/KWH)

For each class with non-zero projected sales, lost revenue per kWh is added to the electricity price if the lost revenue switch is turned on.

```
PE(C,NEXT)=PE(C,NEXT)+LREV(C)/TYSALES(C)*1000*LRSW
```

where:

LREV(CLASS): DSM Lost Revenue (M$)
LRSW: Lost Revenue Switch (1 = on)
PE(CLASS,YEAR): Price of Electricity (MILLS/KWH)
TYSALES(CLASS): Test Year Electricity Sales (GWH/YR)

For classes with no projected sales, the historical price of electricity adjusted for inflation is used.

```
PE(C,NEXT)=XPE(C,NEXT)*INFLA(NEXT)
```

where:

INFLA(YEAR): Inflation Index (DLESS)
PE(CLASS,YEAR): Price of Electricity (MILLS/KWH)
XPE(CLASS,YEAR): Historical Electricity Price (MILLS/KWH)

If there are restrictions on prices changes, the electricity prices are adjusted now to limit price change to the maximum allowed. (Declining prices have a maximum downward price change; rising prices have a maximum upward price change;).

```
PE(C,NEXT)=XMAX(PE(C,NEXT),PE(C,CURRENT)*(1-PEMDC))
PE(C,NEXT)=XMIN(PE(C,NEXT),PE(C,CURRENT)*(1+PEMRC))
```

where:

PE(CLASS,YEAR): Price of Electricity (MILLS/KWH)
PEMDC: Electricity Price Maximum Declining Change (($/YR)/$)
PEMRC: Electricity Price Maximum Rising Change (($/YR)/$)

Fuel Price of Electricity

The fuel price for electricity in a sector is the price of electricity in the sector converted to dollars per GJ, plus the fuel tax and energy sales tax adjusted for inflation.

```
FP(RES_ELECTRIC)=(PE(RES,NEXT)/EECONV*1000+
    FPTAX(RES_ELECTRIC,NEXT)*INFLA(NEXT))*(1+FPSM(RES_ELECTRIC))
FP(COM_ELECTRIC)=(PE(COM,NEXT)/EECONV*1000+
    FPTAX(COM_ELECTRIC,NEXT)*INFLA(NEXT))*(1+FPSM(COM_ELECTRIC))
FP(IND_ELECTRIC)=(PE(IND,NEXT)/EECONV*1000+
    FPTAX(IND_ELECTRIC,NEXT)*INFLA(NEXT))*(1+FPSM(IND_ELECTRIC))
```

where:

EECONV: Electric Energy Conversion (KJ/KWH)
FP(PRICES): Delivered Fuel Price ($/GJ)
FPSM(PRICES): Energy Sales Tax ($/$)
FPTAX(PRICES,YEAR): Fuel Tax ($/GJ)
INFLA(YEAR): Inflation Index (DLESS)
PE(CLASS,YEAR): Price of Electricity (MILLS/KWH)

Residential and commercial prices for solar energy are set at 1/5 of the fuel price for electricity in the sector.

```
FP(RES_SOLAR)=FP(RES_ELECTRIC)*0.20
FP(COM_SOLAR)=FP(COM_ELECTRIC)*0.20
```

where:

FP(PRICES): Delivered Fuel Price ($/GJ)

PROCEDURE DSMPOST: CALCULATIONS FOR DSM EVALUATION

This procedure calculates market revenue and expenses for DSM evaluation. Market revenue is the revenue the utility would earn in a competitive market if it received the allowed rate of return (AROE). Rate-based conservation costs are calculated and used in computing the total conservation cost to the utility.

Market revenue

Market revenue (MREV) is equal to the allowed return on common stock and retained earnings minus total costs for O&M, purchased power, and fuel; depreciation; taxes; miscellaneous expenses; debt interest; and dividends on preferred stock.

```
SELECT FUEL(ELECTRIC)
MREV=TOMC+PUCT+TFC+SLDPR+PTAX+MTAX+ITXRP+MISCEXP+
   DBIN+IDIN+SDIN+PSDV+AROE*(CS+RE)
```

where:

AROE: Allowed Return on Equity (1/YR)
CS: Common Stock (M$)
DBIN: Debt Interest on Long Term Debt (M$/YR)
IDIN: Interest on Intermediate Debt (M$/YR)
ITXRP: Income Tax Reported (M$/YR)
MISCEXP: Miscellaneous Expenses (M$)
MREV: Market Revenue
MTAX: Municipal Property Tax (M$/YR)
PSDV: Preferred Stock Dividends (M$/YR)
PTAX: Property and Revenue Tax (M$/YR)
PUCT: Cost of Purchase Power (M$/YR)
RE: Retained Earnings (M$)
SDIN: Interest on Short Term Debt (M$/YR)
SLDPR: Total Straight Line Depreciation (M$/YR)
TFC: Total Fuel Cost (M$/YR)
TOMC: Total Operation and Maintenance Costs (M$/YR)

Conservation Costs

The rate-based conservation cost (CONRB) is the weighted cost of conservation net assets and rate base additions, plus depreciation.

```
CONRB=(NA(CON)+TYRBADD(CON))*WCCTX+SLDP(CON)
```

where:

CONRB: Rate-based Conservation Costs (M$/YR)
NA(AA): Net Assets (M$)
TYRBADD(AA): Test Year Rate Base Additions (M$)
SLDP(AA): Straight Line Depreciation (M$/YR)
WCCTX: Weighted Cost of Capital including Taxes (1/YR)

Utility conservation costs (CONCST) are equal to the rate-based conservation costs just computed plus conservation administration costs and conservation expenses.

```
CONCST=CONRB+SUM(S)(CONADM(S)+CONEXP(S)+XCONEXP(S))
```

where:

CONADM(SECTOR): Conservation Administration Costs (M$/YR)
CONCST: Conservation Costs (M$/YR)
CONEXP(SECTOR): Conservation Expense ($M/YR)
CONRB: Rate-based Conservation Costs (M$/YR)
XCONEXP(SECTOR): Exogenous Conservation Expense (M$/YR)

PROCEDURE POSTPROCESS: POST PROCESS OUTPUT VARIABLES

In this procedure, additional output variables, primary generating capacity by fuel and primary energy consumption are derived from other model calculated variables. Generally these variables are aggregates of variables calculated and used separately in the model.

Primary generating capacity

Generating capacity by primary fuel (PEGC) is equal to the utility generating capacity (GC) plus independent power producer capacity (XQFGC) plus power purchases (PPGC) for the matching fuel types.

PEGC(GAS)=GC(GCC)+GC(OGCT)+XQFGC(GAS)

Capacity which burns either oil or gas (OILG) is placed in the oil category (OIL).

PEGC(OIL)=GC(OGST)+GC(OGCC)+GC(OILG)+XQFGC(OIL)
PEGC(COAL)=GC(COAL)+GC(GCOAL)+XQFGC(COAL)
PEGC(NUCLEAR)=GC(NUCLEAR)

Pumped storage capacity (PSGC) is included in the hydroelectric category (HYDRO).

PEGC(HYDRO)=GC(HYDRO)+XQFGC(HYDRO)+PSGC
PEGC(BIOMASS)=GC(WOODS)+GC(WOODG)+XQFGC(BIOMASS)+XQFGC(REFUSE)
PEGC(SOLAR)=XQFGC(SOLAR)+GC(SOLAR)
PEGC(WIND)=XQFGC(WIND)+GC(WIND)

Purchase power capacity is assigned to the OTHER category.

PEGC(OTHER)=SUM(PP)(PPGC(PP))

where:

GC(PLANT): Generation Capacity (MW)
PEGC(PFUEL): Primary Energy Generating Capacity
PPGC(PP,YEAR): Purchase Power Capacity (MW)
PSGC: Pumped Storage Capacity (MW)
XQFGC(TECH,YEAR): Historical QF Generating Capacity (MW)

Out-of-region generating capacity is the purchase power capacity available in neighboring regions.

PEGCREG=PPGC(OUTNE)+PPGC(NEWB)+PPGC(HQ)

where:

PEGCREG: Out of Region Generating Capacity (MW)
PPGC(PP,YEAR): Purchase Power Capacity (MW)

Capacity Additions and Retirements

IPP Capacity

If the current capacity is less than the capacity in the previous year, the additions are 0; if greater, the retirements are 0. The additions to IPP capacity (QFGCA) are equal to the current IPP capacity (XQFGC(T,Y)) minus the IPP capacity in the previous period (XQFGC(T,Y-1)).

QFGCA(T)=XMAX(XQFGC(T,Y)-XQFGC(T,Y-1),0)

where:

QFGCA(TECH): QF Generation Capacity Additions (MW)
XQFGC(TECH,YEAR): Historical QF Generating Capacity (MW)

The retirements to IPP capacity (QFGCR) are equal to the IPP capacity in the previous period (XQFGC(T,Y-1)) minus the current IPP capacity (XQFGC(T,Y)).

QFGCR(T)=XMAX(XQFGC(T,Y-1)-XQFGC(T,Y),0)

where:

QFGCR(TECH): QF Generation Capacity Retirements (MW)
XQFGC(TECH,YEAR): Historical QF Generating Capacity (MW)

Power Purchases

If the current capacity is less than the capacity in the previous year, the additions are 0; if greater, the retirements are 0. The additions to power purchases (PPGCA) are equal to the current power purchases (PPGC(PP,Y)) minus the power purchases in the previous period (PPGC(PP,Y-1)).

PPGCA(PP)=XMAX(PPGC(PP,Y)-PPGC(PP,Y-1),0)

where:

PPGC(PP,YEAR): Purchase Power Capacity (MW)
PPGCA(PP): Purchase Power Capacity Additions(MW)

The retirements to power purchases (PPGCR) are equal to the power purchases in the previous period (PPGC(PP,Y-1)) minus the current power purchases (PPGC(PP,Y)).

PPGCR(PP)=XMAX(PPGC(PP,Y-1)-PPGC(PP,Y),0)

where:

PPGC(PP,YEAR) 'Purchase Power Capacity (MW)',
PPGCR(PP) 'Purchase Power Capacity Retirements (MW)',

Primary Generating Capacity Additions

Generating capacity additions by primary fuel (PEGCA) equal the additions to utility generating capacity (GCCR) plus the additions to independent power producer (IPP) capacity (QFGCA) for the matching fuel types.

PEGCA(GAS)=GCCR(GCC)+GCCR(OGCT)+QFGCA(GAS)

Capacity additions which burn either oil or gas (OILG) are placed in the oil category (OIL).

PEGCA(OIL)=GCCR(OGST)+GCCR(OGCC)+GCCR(OILG)+QFGCA(OIL)
PEGCA(COAL)=GCCR(COAL)+GCCR(GCOAL)+QFGCA(COAL)
PEGCA(NUCLEAR)=GCCR(NUCLEAR)

Pumped storage capacity (PSGC) is included in the hydroelectric category (HYDRO).

PEGCA(HYDRO)=GCCR(HYDRO)+QFGCA(HYDRO)+PSGCA
PEGCA(BIOMASS)=GCCR(WOODS)+GCCR(WOODG)+QFGCA(BIOMASS)+QFGCA(REFUSE)
PEGCA(SOLAR)=QFGCA(SOLAR)+GCCR(SOLAR)
PEGCA(WIND)=QFGCA(WIND)+GCCR(WIND)

Additions to purchase power capacity (PPGCA) are assigned to the OTHER category.

PEGCA(OTHER)=SUM(PP)(PPGCA(PP))

where:

GCCR(PLANT): Gen. Capac. Completion Rate (MW/YR)
PEGCA(PFUEL): Primary Energy Generating Capacity Additions
PPGCA(PP): Purchase Power Capacity Additions(MW)
PSGCA: Pumped Storage Capacity Additions (MW)
QFGCA(TECH): QF Generation Capacity Additions (MW)

Additions to generating capacity outside the region consist of purchase power capacity additions in neighboring regions.

PEGCAREG=PPGCA(OUTNE)+PPGCA(NEWB)+PPGCA(HQ)

where:

PEGCAREG: Out of Region Generating Capacity Additions (MW)
PPGCA(PP): Purchase Power Capacity Additions(MW)

The generating capacity retirements by primary fuel (PEGCR) are equal to retirements of utility generating capacity (GCR) plus retirements of independent power producer (IPP) capacity (QFGCR) plus retirements of power purchases (PPGCR).

PEGCR(GAS)=GCR(GCC)+GCR(OGCT)+QFGCR(GAS)

Retired capacity which burned either oil or gas (OILG) is placed in the oil category (OIL).

PEGCR(OIL)=GCR(OGST)+GCR(OGCC)+GCR(OILG)+QFGCR(OIL)
PEGCR(COAL)=GCR(COAL)+GCR(GCOAL)+QFGCR(COAL)
PEGCR(NUCLEAR)=GCR(NUCLEAR)

Pumped storage capacity (PSGC) is included in the hydroelectric category (HYDRO).

PEGCR(HYDRO)=GCR(HYDRO)+QFGCR(HYDRO)+PSGCR
PEGCR(BIOMASS)=GCR(WOODS)+GCR(WOODG)+QFGCR(BIOMASS)+QFGCR(REFUSE)
PEGCR(SOLAR)=QFGCR(SOLAR)+GCR(SOLAR)
PEGCR(WIND)=QFGCR(WIND)+GCR(WIND)

Retirements of purchase power capacity (PPGCA) are assigned to the OTHER category.

PEGCR(OTHER)=SUM(PP)(PPGCR(PP))

where:

GCR(PLANT,YEAR): Generation Cap. Retirements (MW/YR)
PEGCR(PFUEL): Primary Energy Generating Capacity Retirements
PPGCR(PP): Purchase Power Capacity Retirements (MW)
PSGCR: Pumped Storage Capacity Retirements (MW)

QFGCR(TECH): QF Generation Capacity Retirements (MW)

Retirements of generating capacity outside the region consist of retirements of purchase power capacity in neighboring regions.

PEGCRREG=PPGCR(OUTNE)+PPGCR(NEWB)+PPGCR(HQ)

where:

PEGCRREG: Out of Region Generating Capacity Retirements (MW)
PPGCR(PP): Purchase Power Capacity Retirements (MW)

Primary Energy Consumption

Primary energy consumption (PECES) is the sum of utility fuel demand (EUDMD), fuel demand from IPPs (QFDMD), and the purchase power fuel demand (PPDMD) for the matching fuel types. Gas consumption and oil consumption include demand by facilities which burn either oil or gas (EUDMD(OILG)). This demand is separated into oil and gas by multiplying by the fraction which is oil (OILFR) and the fraction which is gas (1-OILFR).

PECES(GAS)=EUDMD(OGCT)+EUDMD(GCC)+
(EUDMD(OGST)+EUDMD(OGCC)+EUDMD(OILG))*(1-OILFR)+QFDMD(GAS)
PECES(OIL)=(EUDMD(OGST)+EUDMD(OGCC)+EUDMD(OILG))*OILFR+QFDMD(OIL)
PECES(COAL)=EUDMD(COAL)+EUDMD(GCOAL)+QFDMD(COAL)
PECES(BIOMASS)=EUDMD(WOODS)+EUDMD(WOODG)+QFDMD(BIOMASS)+QFDMD(REFUSE
)
PECES(SOLAR)=EUDMD(SOLAR) +QFDMD(SOLAR)
PECES(NUCLEAR)=EUDMD(NUCLEAR)
PECES(HYDRO)=EUDMD(HYDRO)+QFDMD(HYDRO)
PECES(WIND)=EUDMD(WIND)+QFDMD(WIND)

Purchase power demand (PPDMD) is assigned to the OTHER category.

PECES(OTHER)=SUM(PP)(PPDMD(PP))

where:

EUDMD(PLANT): Utility Fuel Demand (TBTU/YR)
OILFR: Fraction of Oil/Gas which is Oil (FRAC.)
PECES(PFUEL): Primary Energy Consumption (TBTU/YR)
PPDMD(PP): Purchase Power Fuel Demand (TBTU/YR)
QFDMD(TECH): Fuel Demand from QF (TBTU/YR)

Consumption outside the region consists of purchase power demand in neighboring regions.

PECESREG(ES)=PPDMD(OUTNE)+PPDMD(NEWB)+PPDMD(HQ)

where:

PECESREG(ES): Out of Region Consumption (TBTU/YR,
PPDMD(PP): Purchase Power Fuel Demand (TBTU/YR)

Primary Electricity Generation

Electricity generated by primary fuels (PEG) is the sum of generation by the utilities (EG) and by IPPs (QFEG) for the matching fuel types, plus purchased power (PPEG). Gas generation and oil generation include generation by facilities which burn either oil or gas (EG(OILG)). This

generation is separated into the oil and gas categories by multiplying by the fraction which is oil (OILFR) and the fraction which is gas (1-OILFR).

```
PEG(GAS)=EG(OGCT)+EG(GCC)+
        (EG(OGST)+EG(OGCC)+EG(OILG))*(1-OILFR)+QFEG(GAS)
PEG(OIL)=(EG(OGST)+EG(OGCC)+EG(OILG))*OILFR+QFEG(OIL)
PEG(COAL)=EG(COAL)+EG(GCOAL)+QFEG(COAL)
PEG(BIOMASS)=EG(WOODS)+EG(WOODG)+QFEG(BIOMASS)+QFEG(REFUSE)
PEG(SOLAR)=EG(SOLAR)+QFEG(SOLAR)
PEG(NUCLEAR)=EG(NUCLEAR)
PEG(HYDRO)=EG(HYDRO)+QFEG(HYDRO)
PEG(WIND)=EG(WIND)+QFEG(WIND)
```

Purchased power (PPEG) is assigned to the OTHER category.

```
PEG(OTHER)=SUM(PP)(PPEG(PP))
```

where:

EG(PLANT): Electricity Generated (GWH/YR)
OILFR: Fraction of Oil/Gas which is Oil (FRAC.)
PEG(PFUEL): Electricity Generated by Primary Fuel (GWh)
PPEG(PP): Purchase Power Purchases (GWH)
QFEG(TECH): QF Electricity Generated (GWH/YR)

Power purchased outside the region is the sum of power purchases from neighboring regions.

```
PEGREG= PPEG(OUTNE)+PPEG(NEWB)+PPEG(HQ)
```

where:

PEGREG: Out of Region Purchases (GWh)
PPEG(PP): Purchase Power Purchases (GWH)