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Model Documentation

Electricity Market Module

MODIFICATIONS TO INCORPORATE COMPETITIVE ELECTRICITY PRICES IN THE ANNUAL ENERGY OUTLOOK 1998

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INTRODUCTION

The purpose of this report is to describe modifications to the Electricity Market Module (EMM) for the Annual Energy Outlook 1998. It describes revisions necessary to derive competitive electricity prices and the corresponding reserve margins.

Calculation of Competitive Market Prices for Generation Services

As proposed by W. Vickrey in 1971, spot or responsive pricing allows for economically optimal behavior by each customer and avoids system overload without having to resort to rationing because the price of electricity increases or decreases as system conditions change.[1] True spot prices are set and communicated by suppliers of electricity services (or other services) instantaneously. Different prices can be set for each customer location at each moment. Most State proposals for restructuring of the U.S. electric power industry are modeled after the spot market in the United Kingdom (UK). In the UK, spot prices for generating services are set a day in advance by an Independent System Operator (ISO), on the basis of competitive bids from generating plants.

This update documents the modifications necessary to allow the calculation of spot prices for generation using the Electricity Market Module (EMM) dispatch submodule of the National Energy Modeling System (NEMS). The prices do not indicate the locational variations that one would expect from true spot prices, which would result from localized network congestion and other phenomena.

It is well known that the optimal spot price is equal to the marginal cost of electricity. In this model, the costs of generation to be covered comprise (1) the marginal operating costs, including maintenance and marginal general and administrative (G&A) costs, (2) taxes, and (3) a reliability price adjustment equal to the marginal cost of unserved energy. Since transmission and distribution are assumed to remain regulated, the total price is the sum of the generation costs and no changes were made in the calculation of the average transmisson and distribution costs. There is no explicit representation of capital recovery in the competitive price of electricity generation, as capital and all other costs must be recovered from the difference between the market clearing price and the operating cost of each unit. The following is a description of three components of the competitive spot prices calculated in this model.

The marginal production costs are based on estimates of the marginal costs of generation. Some costs, including fuel, other consumables, and some maintenance vary directly with the hour by hour level of output of a plant. The competitive price then includes the marginal short-run

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[1] R.E. Bohn, M.C. Caramanis, and F.C. Schweppe, “Optimal Pricing in Electrical Networks Over Space and Time,” *Rand Journal of Economics* (Autumn 1984).

operating costs; that is the operating cost of the last plant dispatched (assumed to be the most expensive plant running) in each of the 108 time periods used in the Electricity Fuel Dispatch submodule (EFD) of the EMM.

The marginal production costs include more than just the operating costs listed above. Over the mid-term, these costs—primarily maintenance costs and overhead expenses—do change with the level of output and are therefore variable. Since the G&A (or overhead) costs are avoidable over the mid-term, they must be recovered over the course of the year or it would not pay to keep the plant running. The average of such costs are included the competitive pricing algorithm. All taxes other than Federal income taxes (i.e., State income taxes, sales taxes, and property taxes) are aggregated and treated as a gross receipts tax (revenue tax).

The reliability price adjustment reflects the cost of maintaining a margin of safety for generation to meet electricity demand. Such a cost can be quantified in several ways.[2] This model evaluates the reliability price adjustment on the basis of estimates of the marginal cost of expected unserved energy. It is assumed that consumers will curtail electricity usage when the spot price of electricity exceeds their cost of unserved energy. The cost of unserved energy may be revealed through energy service contracting mechanisms, where consumers are offered varying levels of reliability (greater or lower probability of a service interruption) for varying contract prices, and through behavioral responses to spot prices by spot market participants.

Marginal unserved energy is the quantity of unserved energy satisfied by the last (or marginal) unit of generating capacity. Unserved energy is the difference between supply and demand during periods when, at a given price, demand exceeds supply. Expected unserved energy is a derived quantity based on the expectation of the joint stochastic distribution of supply and demand. Expected unserved energy does not imply a system failure. Rather, it is an expected value calculated from an uncertain amount of generating capacity and an uncertain level of demand for each pricing period.[3]

In this model, the expected amount of unserved energy for each region for each dispatching period is calculated from the following inputs:

- The capacity of each generating plant in each region for each season of the year (total capacity adjusted by planned outages)

- An estimate of the probability of a forced outage for each plant

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[2] See F.C. Schweppe, M.C. Caramanis, R.D. Tabors, and R.E. Bohn, *Spot Pricing of Electricity* (Boston, MA: Kluwer Academic Publishers, 1988), p. 136. Another method to quantify this component is to use a market-clearing approach, also described in Chapter 6 of Schweppe et al.

[3] Expected unserved energy calculations are performed for the system in its current state and for the system augmented by a small amount of capacity (perhaps equal to a small turbine). These calculations yield the reduction in unserved energy for each kilowatt of additional capacity that is brought into service or, stated another way, the change in unserved energy relative to a change in capacity (marginal unserved energy).

- Stochastic hourly load data (projections of demands with an uncertainty factor that creates probability distributions from the deterministic values for demand).

The cost of unserved energy (or value of unserved energy) is an input assumption, because the value of unserved energy is difficult to estimate. The costs for consumers can vary widely. Estimates range from $2 to $25 per kilowatthour and are affected by the type of consumer, the timing of service curtailment, the length of the interruption, and the amount of warning before curtailment begins. For example, an outage without warning during the dinner hour is much more expensive for a restaurant owner than it is for most residential consumers. Hence, a restaurant owner (and commercial consumers in general) would be willing to pay more for reliable electric power than would most residential consumers. Further, a disruption is more costly if it lasts for a longer period of time and creates costs associated with food spoilage, prolonged loss of residential heating and cooling, and the like.

As mentioned above, competitors may have the means to determine the value of unserved energy through the price discovery role of competitive markets. If the revealed cost to consumers of an outage is actually lower than the assumed value that system planners have traditionally used, it means that reserve margins may fall. Lower reserve margins could have important implications for system operating costs and electricity prices.[4]

Mathematically, the reliability adjustment of price is represented as:

$$C_{ryt} = \left(\frac{\partial UE}{\partial G}\right)_{ryt} \cdot V(UE) \quad ,$$

where:

C_{ryt} = reliability adjustment of price, year y, pricing period t for region r (cents per kilowatthour),

$\left(\frac{\partial UE}{\partial G}\right)_{ryt}$ = change in unserved energy with respect to a change in generating capacity (reduction in unserved energy that results from an increase in capacity) in region r, year y, dispatch period t (kilowatthours per kilowatt per hour), and

$V(UE)$ = assumed value of a kilowatthour of unserved energy (cost to consumers of a kilowatthour of electricity during a blackout, in cents per kilowatthour).

The reliability adjustment of spot prices for each pricing period, region, and year of the projection

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4 Energy Information Administration, *Annual Energy Outlook 1996*, DOE/EIA-0383(96) (Washington, DC, January 1996), p. 30.

is calculated by multiplying the change in unserved energy per kilowatt of additional generating capacity (marginal unserved energy), calculated as described in the previous paragraphs, multiplied by the assumed value of unserved energy.

Modifications to three submodules were needed to calculate competitive prices.The capacity cumulants are calculated in subroutines ELEFD and ELRNEW of the fuel dispatch module; demand cumulants are calculated in subroutine DSMEFD of the load and DSM submodule. The reliability component is a function of the capacity and demand cumulants in each slice. All of the subsequent calculations were performed in the electricity pricing submodule. The calculation of the reliability component for each slice is performed in subroutine ELREL . The total price for each slice is summed in subroutine COMPPRC. Annual prices for each of the end-use service are calculated in subroutine RATES2. These prices were modified to reflect the transition to full competition, sectoral adjustments and converted to Census division level in the subroutine ELSET. Furthermore, subroutine REVGAP was added to summarize the relationship between revenues and total costs for each region. Finally, subroutine RATES was modified to include the effects of AB1990 in California. Figure 1 contains a diagram of the calling sequence of the subroutines used in calculation of the competitive price of generation in NEMS. Figure 2 contains a diagram of the calling sequence of subroutines used to determine the final competitive price supplied to the other NEMS modules.

In summary, the spot price of electricity under competition is represented as:

$$Pcomp_{ryt} = E_{ryt} + C_{ryt} + GA_{ry} + Tax_{ryt} + TD_{ry} \quad ,$$

where:

$Pcomp_{ryt}$= the competitive price of delivered electricity in region *r*, year *y*, period *t* (cents per kilowatthour),

E_{ryt} = the marginal short-run operating cost in region *r*, year *y*, period *t* (variable operating costs of the last plant dispatched in period *t*, in cents per kilowatthour),

C_{ryt} = the reliability adjustment of price in region *r*, year *y*, period *t* (cents per kilowatthour),

GA_{r} = general and administrative costs related to generation in period *t* for region *r*, year *y* (cents per kilowatthour),

Tax_{ryt} = recovery of Federal income taxes and all other taxes in region *r*, year *y*, period *t* (cents per kilowatthour), and

TD_{ry} = average transmission and distribution costs in region *r*, year *y* (cents per kilowattthour).

Fig. 1 Hierarchy of Subroutines: Reliability Component

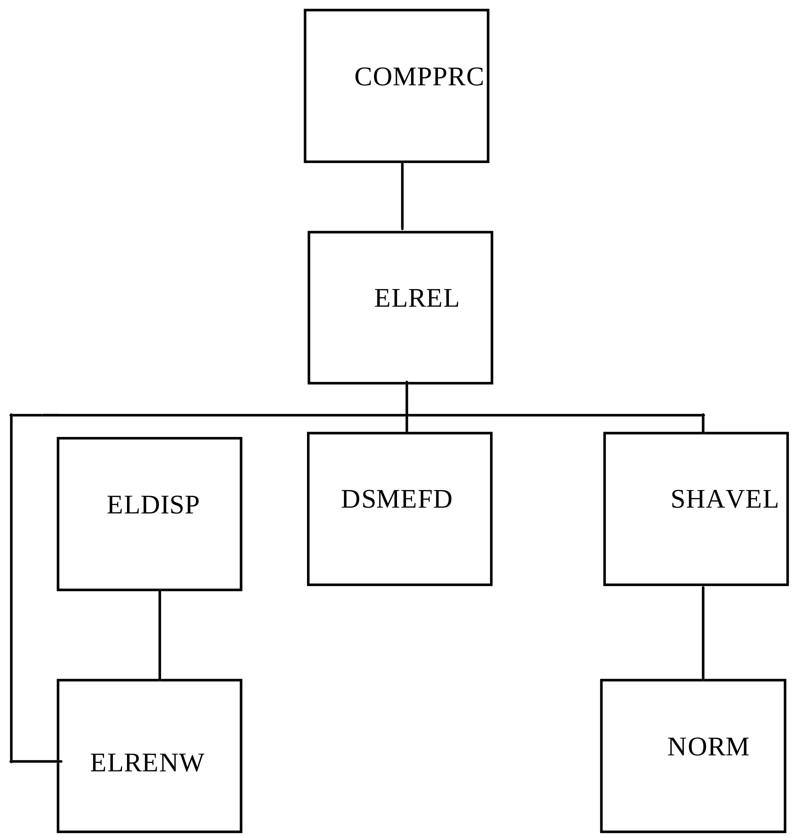
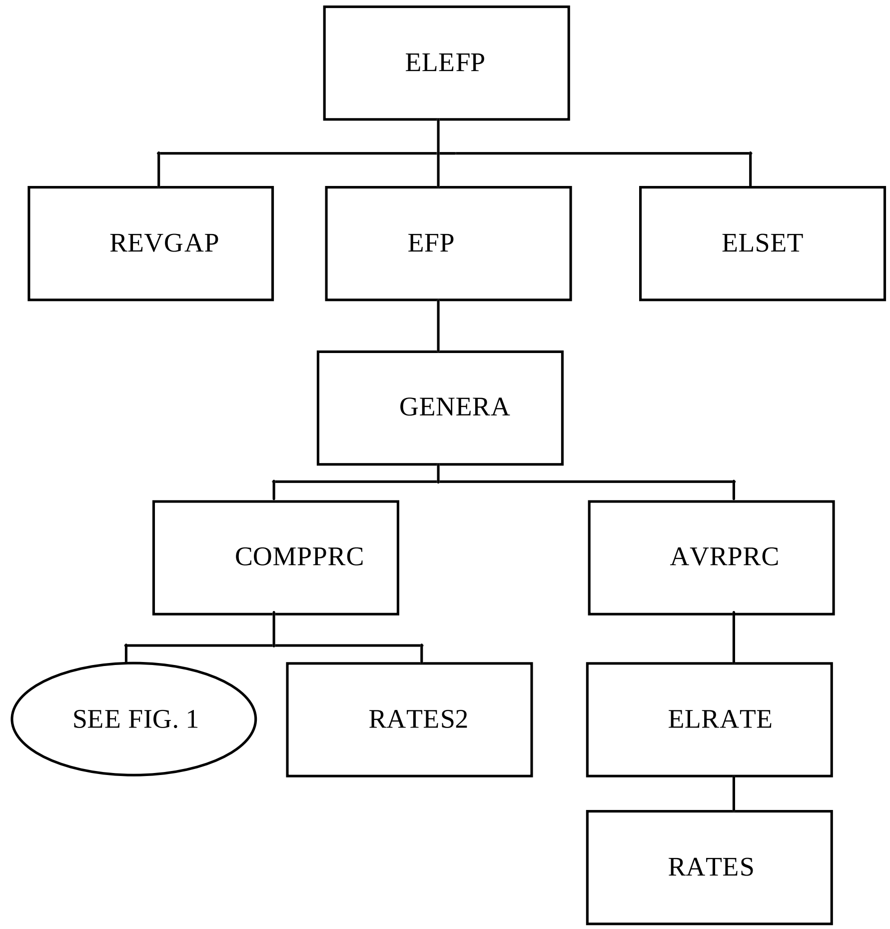


Fig. 2 Hierarchy of Subroutines: EFP



Capacity Planning under Competition

Optimal reserve margins are calculated from the relationship:

$$(\partial UE / \partial G) \cdot V(UE) = A_t \quad ,$$

where:

A_t= annual carrying cost (dollars per kilowatt per year) of the least expensive generating capacity (combustion turbine), and

$(\partial UE/\partial G) \cdot V(UE)$= Marginal cost of unserved energy (dollars per kilowatt per year).

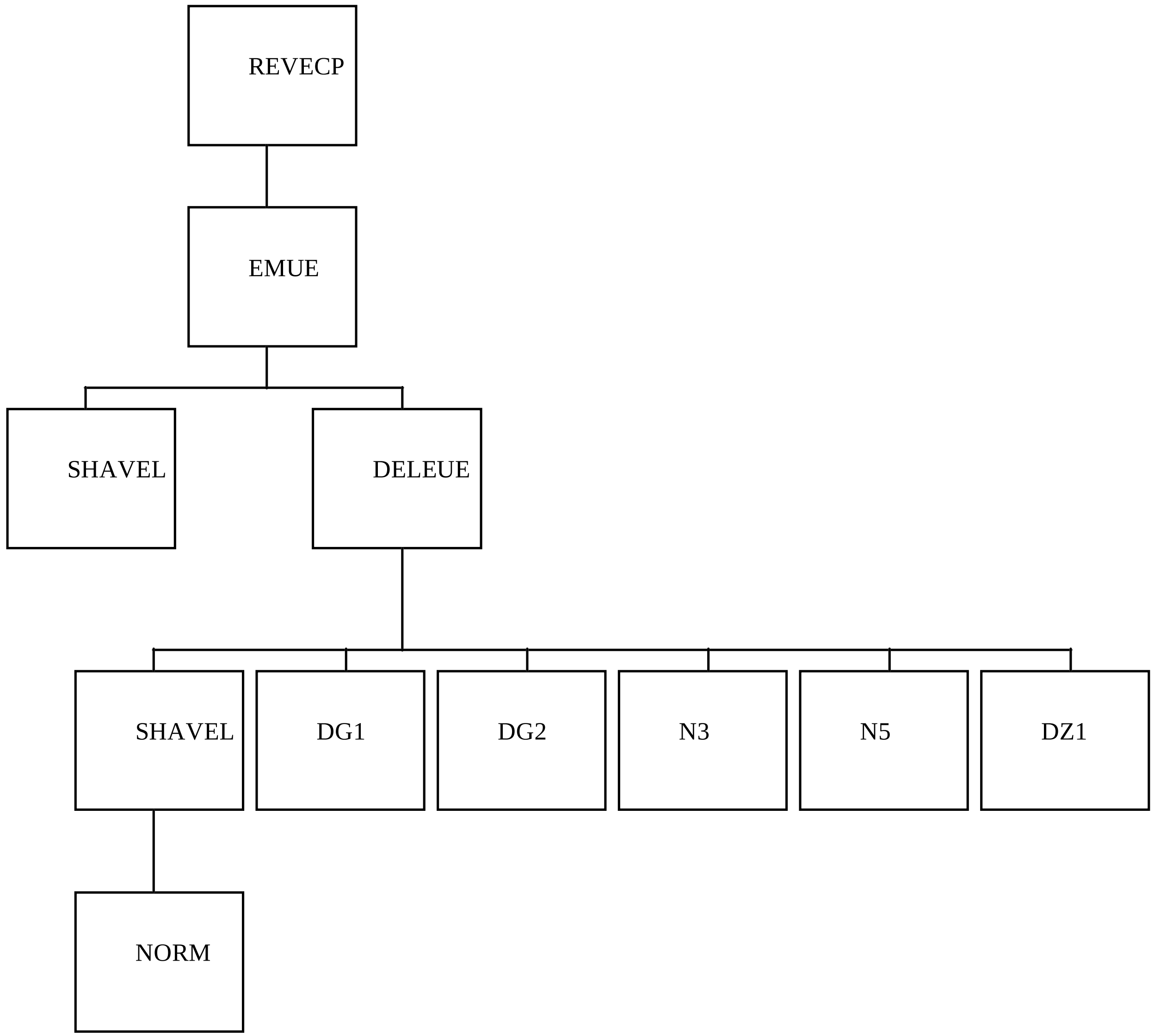
This is expressed in the Electricity Capacity Planning (ECP) submodule by a constraint row

$$\sum_{dsp}\sum_{j} delemuedsp(dsp,j)*X_{dsp}+\sum_{rnw}\sum_{j} delemuernw(rnw,j)*X_{rnw}+\sum_{int} delemueint(int)*X_{int} = delemuerhs$$

where: delemuedsp = coefficient for dispatchable capacity dsp, season j,
delemuernw = coefficient for renewable capacity rnw, season j,
delemeint = cofficient for interruptible capacity int,and
delemuerhs = right hand side.

All of the coefficients are described in subroutine EXMUE. Figure 3 contains the calling sequence of subroutines used to determine the coefficients of the capacity constraint row described above.

Fig. 3 Hierarchy of Subroutines: ECP



SUBROUTINE: ELDISP

Description: This subroutine was modified to calculate the capacity cumulants and trade used in the reliability calculations. Because of planned maintenance, capacity is different for each season.

Called by: ELEFD

Calls: None

Equations:

For each EFD capacity type in each season

$$vex1=(1-FOR)*xcap$$
$$vex2=(1-FOR)*xcap^{2}$$
$$vex3=(1-FOR)*xcap^{3}$$
$$vex4=(1-FOR)*xcap^{4}$$

where: FOR = forced outage rate of EFD capacity type J,
xcap = average size of unit of capacity type J in season I, and
vexk = moment k around 0 of capacity type J.

Then

$$vmom(1)=vex1$$
$$vmom(2)=vex2-vex1^{2}$$
$$vmom(3)=vex3-2*vex1*vex2+vex1^{3}$$
$$vmom(4)=vex4-4*vex3*vex1+6vex1^{2}*vex2-3vex1^{4}-2*vmom(2)^{2}$$

where: vmom(k) = cumulant k of a unit of type j, season i.

We can then sum the cumulants of each capacity type to get the cumulants of the capacity density function for the season.

$$capcum(I,IMOM,IRG,1)=capcum(I,IMOM,IRG,1)+vmom(IMOM)*xnumplnt$$
$$capcum(I,IMOM,IRG,2)=capcum(I,IMOM,IRG,1)+vmom(IMOM)*xnumplnt$$

where: capcum(I,IMOM,IRG,L) = total capacity cumulant IMOM season I, region IRG, type L, and xnumplnt = number of plants of type L.

In order to create the differential for calculation of marginal unserved energy, we need to add an increment of capacity.

$$capcum(I,IMOM,IRG,2) = capcum(I,IMOM,IRG,2) + vmom(IMOM)$$

where vmom(IMOM) = cumulant IMOM representation of a 50 KW turbine.

We next add firm trade. Imports are treated as if they increase capacity.

$$xnumplnt = \frac{EEITAJ(IRG,I)}{xcap}$$

where: EEITAJ(IRG,I) = firm trade (Gw) for region IRG, season I,
xcap = average capacity size of a typical coal unit,and

$$capcum(I,IMOM,IRG,1) = capcum(I,IMOM,IRG,1) + vmom(IMOM) * xnumplnt$$
$$capcum(I,IMOM,IRG,2) = capcum(I,IMOM,IRG,1) + vmom(IMOM) * xnumplnt$$

where: vmom(k) = cumulant k of a representative coal plant, and
xnumplnt = number of coal plants of size xcap giving firm trade EEITAJ.

If trade is an export we add it to the demand cumulant

$$dcum(iblk,I,RNB) = dcum(iblk,I,RNB) + EEITAJ(RNB,I)$$

where dcum (iblk, ise, RNB) = demand cumulant of block iblk season I, region RNB,and
EEITAJ(RNB, I) = firm trade in season I, region RNB.

Subroutine: ELRNEW

Description: This subroutine was modified to calculate the capacity cumulants of the renewable EFD capacity types and add them to the generating capacity cumulants.Because of seasonal factors for some renewables, capacity is different for each season.

Called by: EDISP

Calls: None

Equations:

For conventional and reversible hydropower

$$xcap = EHCAP(J,ISP) * RNWFAC / EHUNIT(J)$$

where: EHCAP = capacity of renewable type J, season ISP,
RNWFAC = capacity factor for renewable, and
xcap = average size of unit of capacity type j in season I,

while for all other renewable capacity types

$$xcap = EHCAP(J,ISP) * EHHYCF(J,ISP) / EHUNIT(J)$$

where: EHCAP = capacity of renewable type J, season ISP
EHHYCF(J,ISP) = capacity factor for renewable J, season ISP
xcap = average size of unit of capacity type J, in season ISP.

$$vex1 = (1 - RENFOR) * xcap$$
$$vex2 = (1 - RENFOR) * xcap^2$$
$$vex3 = (1 - RENFOR) * xcap^3$$
$$vex4 = (1 - RENFOR) * xcap^4$$

where: RENFOR = forced outage rate of EFD capacity type J,
vexk = moment k around 0 of capacity type J.

$$vmom(1)=vex1$$
$$vmom(2)=vex2-vex1^{2}$$
$$vmom(3)=vex3-2*vex1*vex2+vex1^{3}$$
$$vmom(4)=vex4-4*vex3*vex1+6vex1^{2}*vex2-3vex1^{4}-2*vmom(2)^{2}$$

where: vmom(k) = cumulant k of a unit of type J, season ISP.

We can then sum the cumulants of each capacity type to get the cumulants of the capacity density function for the season.

$$capcum(I,IMOM,IRG,1)=capcum(I,IMOM,IRG,1)+vmom(IMOM)*xnumplnt$$
$$capcum(I,IMOM,IRG,2)=capcum(I,IMOM,IRG,1)+vmom(IMOM)*xnumplnt$$

where: capcum(I,IMOM,IRG,L) = total capacity cumulant IMOM, season I, region IRG, type L.
xnumplnt = number of plants of type L.

Subroutine: DSMEFD

Description: This subroutine was modified to calculate the demand cumulants from the system load duration curve. Yearly system load is described by 864 load allocation factors, each representing load during a particular few hours of the year. From these load allocation factors, the load in each of 108 slices (six seasons with 18 slices per season) is determined. The corresponding demand cumulant for each slice is calculated using the load allocation factors.

Called by: ELDISP

Calls: None

Equations:

Each load allocation factor is assumed to have a normal distribution with standard deviation loadu. We approximate this through a discretization of the normal distribution, which is used as a weighting for each point.

$$dval = (1. + dincr(iprob) * loadu) * (SYLOAD2(h))$$

where: dincr = discretized value of the standard normal distribution at iprob standard deviations from the mean,
loadu = load standard deviation,
SYLOAD2(h) = system load at point h,and
dval = system load at weighting iprob.

Next we create moments around 0 at each point dval

$$dmomh(iprob,1) = dval * dprob(iprob)$$
$$dmomh(iprob,2) = dval^2 * dprob(iprob)$$
$$dmomh(iprob,3) = dval^3 * dprob(iprob)$$
$$dmomh(iprob,4) = dval^4 * dprob(iprob)$$

where dmomh(iprob,imom) = moment imom for system load dval,and
dprob(iprob) = weight of segment iprob of the discretized normal distribution.

We add the contribution of each load allocation factor to the moments for the load slice and normalize by the hours in the slice

$$dmom(blk,imom) = dmom(blk,imom) + \frac{dmomh(iprob,imom)}{efdblWidth(blk)}$$

where dmom(blk,imom) = moment imom of EFD slice blk
efdblWidth(blk) = width (hours) of slice blk.

Finally we create the cumulants for this slice

$$\begin{aligned}
&dcum(iblk,1,RNB) = dmom(i,1)\\
&dcum(iblk,2,RNB) = dmom(i,2) - dmom(i,1)^2\\
&dcum(iblk,3,RNB) = dmom(i,3) - 3*dmom(i,1)*dmom(i,2) + 2.*dmom(i,1)^3\\
&dcum(iblk,4,RNB) = dmom(i,4) - 4.*dmom(i,1)*dmom(i,3) + 6.*(dmom(i,1)^2*dmom(i,2))\\
&\qquad\qquad -3.*dmom(i,1)^4 - 3*dcum(iblk,2,RNB)^2
\end{aligned}$$

where dcum(iblk,imom,RNB) = demand cumulant imom for slice iblk and region RNB

SUBROUTINE: ELREL

Description: This subroutine calculates the reliability component of marginal cost. The basic idea is from “Incorporating Explicit Loss-of-Load Probability Constraints in Mathematical Programming Models for Power System Capacity Planning”, by Sanghvi and Shavel. We describe the capacity and load distributions by means of their first four cumulants, and form the marginal capacity function from the sum of the cumulants. See “Kendall’s Advanced Theory of Statistics”, Fifth Addition, Kendall, Stuart and Ord. Although we need the derivative of unserved energy, we instead use a differential. We do this by calculating unserved energy with and without an additional increment of capacity.

Called by: COMPPRC

Calls: Shavel

Equations:

There are 6 seasons, and 18 slices per season. We calculate marginal expected unserved energy for each slice independently. Rather than calculate the derivative of expected unserved energy, we approximate it by a differential.

We define the marginal capacity function as the stochastic function

$$M = G - L$$

where: $L(l)$ = density function for load (demand), and
$G(g)$ = density function for generating capacity.

We define unserved energy as the stochastic variable

$$UE = \begin{cases} m, m < 0 \\ 0, otherwise \end{cases}$$

and expected unserved energy

$$EUE = \int_{0}^{Z1} m M_x(m) dm$$

where

$$Z1 = \frac{[E(L) - E(G)]}{sdev}$$

the normalized mean of the marginal capacity function. Since M_x cannot be integrated analytically, it is approximated numerically from its first four cumulants using the Gram-Charlier expansion.

First, we calculate the cumulants of the marginal capacity function:

$$tdcum1(icm) = capcum(ise, icmRNB, 1) + dcum(sblkicm, RNB) * (-1)^{icm}$$

where: tdcum1 = marginal capacity cumulant icm for the slice,
capcum1 = capacity cumulant icm for season ise, region RNB,
dcum = demand cumulant icm for slice sblk and region RNB,and

$$tdcum2(icm) = capcum(ise, icmRNB, 2) + dcum(sblkicm, RNB) * (-1)^{icm}$$

where: tdcum2 = marginal capacity cumulant icm for the slice,
capcum2 = capacity cumulant (with increment) icm for season ise, region RNB,and
dcum = demand cumulant icm for slice sblk and region RNB.

Next we calculate the standard deviation of the distributions

$$sdev1 = \sqrt{tdcum1(2)}$$

$$sdev2 = \sqrt{tdcum2(2)}$$

and the normalized mean of the marginal capacity function

$$mrg1 = \frac{(0.0 - tdcum1(1))}{sdev1}$$

$$mrg2 = \frac{(0.0 - tdcum2(1))}{sdev2}$$

Then we partition the integral and sum the contribution of each partition to the total and calculate the area of each trapezoid from:

$$EUE_1 = \sum_{i=1}^{N} vfreq * i * M_{x1}(vfreq * i) - M_{x1}(vfreq * (i-1))$$

where vfreq = step size and

$$M_{x1}(Z) = \int_0^Z M_{x1}(m) dm$$

$$M_{x2}(Z) = \int_0^Z M_{x2}(m) dm$$

Note that the difference

$$M_{x1}(vfreq * i) - M_{x1}(vfreq * (i-1))$$

represents the area of the trapezoid, which, multiplied by the product *vfreq* * *i* gives the contribution of each trapezoid to the total integral.

This is repeated using M_{x2} giving

$$EUE_2 = \sum_{i=1}^{N} vfreq * i * M_{x2}(vfreq * i) - M_{x2}(vfreq * (i-1))$$

and the marginal unserved energy is then

$$\frac{(EUE_1 - EUE_2)}{newcap}$$

where newcap = capacity increment added to capcum2.

SUBROUTINE: SHAVEL

Description: Computes the Shavel/Sanghvi approximation to the cumulative distribution at a point z given its first four cumulants. This is based on first few terms of the Gram-Charlier expression of a distribution as an infinite series of its cumulants.

Parameters: z = z-value (input)
cum1 = first cumulant of marginal capacity function
cum2 = second cumulant of marginal capacity function
cum3 = third cumulant of marginal capacity function
cum4 = fourth cumulant of marginal capacity function
cum = cumulative distribution (output)

Called by: ELREL,EMUE

Calls: NORM

Equations:

$$g1 = \frac{cum3}{cum2^{1.5}}$$

$$g2 = \frac{cum4}{cum2^{2}}$$

$$norm0 = pinorm * \exp^{-\frac{z^2}{2}}$$

call norm(z1,norm0,normx1)

$$cum = normx1 - \frac{g1 * norm0 * (z^2 - 1)}{6!} + \frac{g2 * norm0 * (3z - z^3))}{4!} + \frac{g1^2 * 10 * norm0 * (10z^3 - 5z - z^5)}{6!}$$

where: for = forced outage rate,

cap = size of the unit (Gigawatts),

cum1 = first cumulant of marginal capacity function,

cum2 = second cumulant of marginal capacity function,

cum3 = third cumulant of marginal capacity function,and

cum4 = fourth cumulant of marginal capacity function.

FUNCTION: DELEUE

Description: Develops the contribution of a unit of capacity of a particular ECP type to the reduction in marginal expected unserved energy.

Called by: DELEUE

Calls: Shavel.

Equations:

Determine loss of load probability (LOLP)

CALL Shavel(cum1,cum2,cum3,cum4,LOLP)

$$G1 = (\frac{cum3}{cum2})^{3/2}$$

$$DELEUE = 0 + DZ1(for,cap,cum1,cum2) * LOLP - DG1(for,cap,cum2,cum3) + \frac{N2(z14)}{3!} + \frac{DG2(for,cap,cum2,cum4) * N3(z14)}{4!} + \frac{2 * G1 * DG1(for,cap,cum2,cum3) * 10 * N5(z14)}{6!}$$

where: for = forced outage rate,
cap = size of the unit (Gigawatts),
cum1 = first cumulant of marginal capacity function,
cum2 = second cumulant of marginal capacity function,
cum3 = third cumulant of marginal capacity function,and
cum4 = fourth cumulant of marginal capacity function.

FUNCTION:DZ1

Description: DZ1 creates the coefficent for the third order term of the approximation of marginal unserved energy function for the ECP.

Called by: DELEUE

Calls: None.

$$DZ1 = -for * \sqrt{cum2} - .5 * (-1 * cum1) * for * (1 - for) * cap * cum2^{-3/2}$$

Equation:

where: for = forced outage rate,
cap = size of the unit (Gigawatts),
cum1 = first order cumulant of marginal capacity function,and
cum2 = second cumulant of marginal capacity function.

FUNCTION: NORM

Description: NORM finds the cumulative normal probability distribution for any value z1.

Called by: DELEUE

Calls: None.

Parameters: dens = normal density evaluated at z1

Equations:

data a/0.2316419/

data b/0.31938153,-0.356563782,1.781477937,-1.821255978,1.330274429/

$$val3=\sum_{i=1}^{5} b_i*\left(\frac{1.0}{1.0+a*z1}\right)^{i}$$

where: val3 = intermediate value,

b = constant,and

a = constant.

$$cum=1.0-dens*val3$$

where: cum = cumulative distribution evaluated at z1,and

dens = normal density evaluated at z1.

FUNCTION:DG2

Description: DG2 creates the coefficent for the fourth order term of the approximation of marginal unserved energy function for the ECP.

Called by: DELEUE

Calls: None.

Equation:

$$
\begin{aligned}
DG2 &= for * cap^{3} * (1 - 7 * for + 12 * for^{2} - 6 * for^{3}) \\
&* cum2^{-2} - 2 * cum4 * for * cap * (1 - for) * cum2^{-3}
\end{aligned}
$$

where: for = forced outage rate,

cap = size of the unit (Gigawatts),

cum2 = second cumulant of the marginal capacity function,and

cum4 = fourth order cumulant of the marginal capacity function.

FUNCTION: DG1

Description: DG1 creates the coefficent for the second order term of the approximation of marginal unserved energy function for the ECP.

Called by: DELEUE

Calls: None.

Equation:

$$\mathit{DG1} = \mathit{for} * \mathit{cap}^{2} * (1 - 3 * \mathit{for} + 2 * \mathit{for}^{2})$$
$$* \mathit{cum2}^{3/2} - 1.5 * \mathit{cum3} * \mathit{for} * \mathit{cap} * (1 - \mathit{for}) * \mathit{cum2}^{-5/2}$$

where: for = forced outage rate,

z3= mean of the marginal capacity function,

cap = size of the unit (Gigawatts),

cum2 = second cumulant of marginal capacity function,and

cum3 = third cumulant of marginal capacity function.

FUNCTION: N2

Description: N2 creates the coefficent for the second order term for the approximation of marginal unserved energy function for the ECP.

Called by: DELEUE

Calls: None.

Equation:

$$N2 = -1 * (z2^2 - 1.0) * pinorm * Exp \frac{-z2^2}{2}$$

where: pinorm=0.39894228040,and
z2 = mean of the marginal capacity function.

FUNCTION: N3

Description: N3 creates the coefficent for the third order term for the approximation of marginal unserved energy function for the ECP.

Called by: DELEUE

Calls: None.

Equation:

$$N3 = -1 * (z3^{3} - 3 * z3) * pinorm * Exp(\frac{-z3^{2}}{2})$$

where: pinorm=0.39894228040,and

z3= mean of the marginal capacity function.

FUNCTION: N5

Description: N5 creates the coefficent for the fifth order term for the approximation of marginal unserved energy function for the ECP.

Called by: DELEUE

Calls: None.

Equation:

$$N5 = -1 * (z5^5 - 10 * z5^3 + 15 * z5) * pinorm * Exp(\frac{-z5^2}{2})$$

where: pinorm=0.39894228040,and
z5= mean of the marginal capacity function.

SUBROUTINE: EMUE

Description: This subroutine calculates the coefficients for the reserve margin row. Reserve margins are calculated from the relationship

$$(\partial UE / \partial G) \cdot V(UE) = A_t \quad ,$$

where:

A_t= annual carrying cost (dollars per kilowatt per year) of the least expensive generating capacity (combustion turbine), and

$(\partial UE/\partial G) \cdot V(UE)$= Marginal cost of unserved energy (dollars per kilowatt per year).

Substituting the Taylor series expansion of the Gram-Charlier approximation to the expression for expected unserved energy, we get

$$EUE^{J} = EUE^{1} + \sum_{i} (\partial UE / \partial X_i) * (X_i^j - X_i^1) + (\partial UE / \partial L^j) * (L^j - L^1)$$

where: EUE^J = expected unserved energy in forecast year J,

L^J = load in forecast year I,and

χ_i = capacity of type I.

If we approximate $(\partial UE/\partial G)$ by $\Delta UE/\Delta G$ and note

$$\Delta G = \sum_{i} (X_i^j - X_i^1) + (L^j - L^1)$$

after some algebraic manipulation, we get

$$\sum_{i} (\partial UE / \partial X_i - A_t / V(UE)) * (X_i^j - X_i^1) + (\partial UE / \partial L_i - A_t / V(UE)) * (L_i - L_1) = 0$$

where: $(\partial EUE/\partial X_i)$ = partial derivative of unserved energy for each capacity type, and

$(\partial UE/\partial L_i)$ = partial derivative of unserved energy for changes in load.

Called by: REVECP

Calls: Shavel, Deleue

Parameters: NERC = NERC region
YEAR = Forecast year

Equations:

We calculate capacity cumulants by ECP season and demand cumulants by ECP slice. These are used to calculate loss of load probability (LOLP) in each slice, and also the contribution of each capacity to the reduction of marginal unserved energy in each slice.

$$xcap = \frac{(ECUMDSP(ISP,IP,NERC) - PMDSP(ISP,IP,NERC))}{ECUNIT(IP,1)}$$

where: xcap = average size of unit capacity type IP,
ECUMDSP = dispatchable capacity (Gw) of type IP in season ISP, region NERC,
PMDSP = planned maintenance of capacity IP in season ISP, region NERC.

For each ECP capacity type in each season

$$\begin{aligned} vex1 &= (1 - UPFORT) * xcap \\ vex2 &= (1 - UPFORT) * xcap^2 \\ vex3 &= (1 - UPFORT) * xcap^3 \\ vex4 &= (1 - UPFORT) * xcap^4 \end{aligned}$$

where: UPFORT = forced outage rate of ECP capacity type j,
xcap = average size of unit of capacity type j in season i
vexk = moment k around 0 of capacity type j,and

$$\begin{aligned} vmom(1) &= vex1 \\ vmom(2) &= vex2 - vex1^2 \\ vmom(3) &= vex3 - 2 * vex1 * vex2 + vex1^3 \\ vmom(4) &= vex4 - 4 * vex3 * vex1 + 6 vex1^2 * vex2 - 3 vex1^4 - 2 * vmom(2)^2 \end{aligned}$$

where: vmom(k) = cumulant k of a unit of type J, season I.

We can then sum the cumulants of each capacity type to get the cumulants of the capacity density function for the season.

$$ecapcum(ISP,IMOM)=ecapcum(ISP,IMOM)+vmom(IMOM)*ECUNIT(IP,YEAR)$$

where: ecapcum(ISP,IMOM) = total capacity cumulant IMOM, season ISP,and
Ecunit = number of plants of type L.

The cumulants of the rest of the ECP capacity types are calculated similarly. For conventional and reversible hydropower

$$xcap=\frac{EPECAP(J,YEAR)*RNWFAC}{ECUNIT(J,YEAR)}$$

where: EPECAP = capacity of renewable type J, season ISP
ECUNIT(J) = number of units of type J,
RNWFAC = capacity factor for renewable,
xcap = average size of unit of capacity type j in season I,

while for all other renewable capacity types

$$xcap=EPECAP(J,ISP)*EHHYCF(J,ISP)/ECUNIT(J)$$

where: EPECAP = capacity of renewable type J, season ISP, year YEAR,
EHHYCF(J,ISP) = capacity factor for renewable J season ISP,and
xcap = average size of unit of capacity type J in season ISP.

$$\begin{aligned}vex1&=(1-RENFOR)*xcap\\vex2&=(1-RENFOR)*xcap^2\\vex3&=(1-RENFOR)*xcap^3\\vex4&=(1-RENFOR)*xcap^4\end{aligned}$$

where: RENFOR = forced outage rate of EFD capacity type J,
vexk = moment k around 0 of capacity type J.

$$\begin{aligned}&vmom(1)=vex1\\&vmom(2)=vex2-vex1^2\\&vmom(3)=vex3-2*vex1*vex2+vex1^3\\&vmom(4)=vex4-4*vex3*vex1+6vex1^2*vex2-3vex1^4-2*vmom(2)^2\end{aligned}$$

where vmom(k) = cumulant k of a unit of type J, season ISP.

We can then sum the cumulants of each capacity type to get the cumulants of the capacity density function for the season.

$$ecapcum(ISP,IMOM)=ecapcum(ISP,IMOM)+vmom(IMOM)*ECUNIT(IP,YEAR)$$

where ecapcum(ISP,IMOM) = total capacity cumulant IMOM season ISP.
Ecunit = number of plants of type L

For each slice we calculate

$$dem=EPHGHT(VLS,YEAR)+UEITAJ(IGRP,NERC)$$

$$\begin{aligned}
cum(1)&=ecapcum(ISP,1)-dem\\
cum(2)&=ecapcum(ISP,2)+(dem*loadecpu)^2\\
cum(3)&=ecapcum(ISP,3)\\
cum(4)&=ecapcum(ISP,4)
\end{aligned}$$

where: cum(I) = cumulant of order I,
Ecapcum (ISP,IMOM) = capacity cumulant in season ISP of order IMOM,and
Loadecpu = fraction used to calculate load standard deviation.

We get the LOLP for this slice from calling the subroutine

$$Shavel(z1,cum(1),cum(2),cum(3),cum(4),LOLP)$$

where: LOLP = loss of load probability in slice VLS.

The contribution to reduction of marginal energy is calculated for each capacity type. For dispatchable capacity

$$\begin{aligned}
FOR&=1-UPFORT(IP)\\
PMR&=1.0-UPPMRT(IP)*FOR
\end{aligned}$$

where: PMR = effective planned maintenance rate,
UPFORT = forced outage rate of capacity type IP,

FOR = availability rate,
UPPMRT(IP) = planned maintenance rate,and

$$DELEMUEDSP(ISP,IP,NERC)=\sum_{VLS}\Big(DELEUE(z1,cum(1),cum(2),cum(3),cum(4),xcap,FOR,LOLP$$
$$-\frac{CCOSTTURB}{(8760*ECPVOLL)}\Big)*EPWIDTH(VLS)*PMR$$

where: DELEUE = ontribution to reduction in marginal unserved energy from capacity IP in slice VLS,
COSTTURB = cost of a turbine ($/Kwh),
ECPVOLL = value of unserved energy ($),
EPWIDTH =width in hours of slice VLS,

while for conventional hydroelectric sources

$$DELEMUERNW(ISP,IP,NERC)=\sum_{VLS}\Big(DELEUE(z1,cum(1),cum(2),cum(3),cum(4),xcap,FOR,LOLP$$
$$-\frac{CCOSTTURB}{(8760*ECPVOLL)}\Big)*EPWIDTH(VLS)*RNWFAC$$

where: RNWFAC = capacity factor for hydro renewables and EPIRCCR for non-hydro renewables.

The contribution from all existing capacity is then

$$EXMUE(NERC)=\sum_{ip} delemue(ip)*epecap(ip,YEAR)$$

where delemue = contribution to reduction in marginal unserved energy of capacity type ip.

The contribution for demand is

$$LMUE(YEAR)=\sum_{VLS}(LOLP*(LCUM(VLSA,NERC,YEAR)-LCUM(VLS,NERC,1))*(1.0+ADJ)$$
$$-\frac{CCOSTTURB}{8760.0*ECPVOLL(NERC)})*EPWDTH(VLS,YEAR)$$

where: LMUE = contribution to marginal unserved energy by load increase,
LCUM = load in slice VLS region NERC forecast year YEAR,
ADJ = adjustment factor for revenue reconciliation,

and

$$ADJ = (DGAPOLD(NERC) - 1.0) * MEFAC(NERC)$$

where: DGAPOLD = revenue gap in region NERC,
MEFAC = scaling factor for region NERC.

The right hand side is then

$$DELEMUERHS(YEAR,NERC) = EXMUE(YEAR) + LCUM(NERC).$$

SUBROUTINE COMPPRC

Description: Calculates the competitive price of generation services, by load slice.

Called by: GENERA

Calls: Subroutine ELREL - to calculate reliability component, Subroutine RATES2 - to calculate average end-use service prices

Equations:

$$ERSLCPRC_{ijklm} = ERMEC_{ijkl} + ERREL_{ijkl} + ERFXGNA_{ijm} + EROTAX_{ijm} + ERITAX_{ijm}$$

i = year; j = region; k = season; l = load slice; m = ownership (public/private)

where: ERMEC =marginal energy component = fuel and variable operation and maintenance costs for the marginal unit for the load slice, from the EFD model - after trade,
ERREL = reliability component for the load slice, calculated in subroutine ELREL,
ERFXGNA = fixed operation and maintenance costs, and general and administrative, costs, calculate average by ownership (as done under regulation),
EROTAX = other taxes (gross receipts tax) = revenues*(1 + EGTXRT),and
ERITAX = income taxes, use average costs and tax calculation from regulated pricing.

SUBROUTINE RATES2

Description: Calculate the annual average competitive price, by end-use service. Slice prices are weighted by share of demand in that slice for a given end-use service.

Called by: COMPPRC

Calls: None

Equation:

$$EPRIC2_{jn} = \sum_{k=1}^{6} \sum_{l=1}^{18} ERSLCPRC_{ijkl3} * sortefdblk_{kln}$$

i = year; j = region; k = season; l = load slice; m = ownership; n = end-use sector

where: ERSLCPRC = competitive generation price for the slice (m = 3 = average of public and private),and
sortefdblk = percent of total load in each slice, by end-use service.

The subroutine calculates annual averages of the components of the competitive price, using the same weighting scheme as above.
The subroutine also calculates final averages by sector (residential, commercial, industrial and transportation) by calculating a demand weighted average of the end-use services in the sector.

SUBROUTINE: ELSET

Description: Changes were made to subroutine ELSET to calculate 23 end-use prices, as well as the four sector averages, by EMM region. Depending on the input assumptions, the price can be based on marginal cost pricing, average cost pricing, or a combination of both. Currently, sectoral subsidies are calculated based on the differences in sectoral prices under regulation. Finally, census level prices are calculated based on the EMM region prices, given a mapping.

Called by: ELEFP

Calls: None

Equations:

$$tempreg_{jn} = EPRIC2_{jn} + EPRICE_{jn2} + EPRICE_{jn3}$$

j = region; n = end-use service, o=stage of production

where: EPRIC2 = competitive price for generation, calculated in RATES2,and
EPRICE = regulated price for transmission (o=2) and distribution (o=3).

$$tempreg_{jn} = tempreg_{jn} * CLPRNEW$$

j = region; n=end-use sector

where: CLPRNEW = sectoral subsidy, calculated to keep the same ratio between sector prices as under regulation, while maintaining same average price (total revenues) as calculated under competition.

$$tempreg_{jn} = FRMARG_j * tempreg_{jn} + (1 - FRMARG_j) * EPRICE_{jn4}$$

j=region; n=end-use sector; o=stage of production

where: FRMARG = input value representing the fraction of the price based on marginal costs,and
EPRICE = regulated sectoral price for generation, transmission and distribution combined (o = 4).

Census region price variables are filled in using a mapping from CENSUS to EMM regions. The units are also converted from mills/kwh to $/MMBTU.

SUBROUTINE: RATES

Description: The subroutine was modified to adjust prices for California based on announced rate freezes due to competition.

Called by: ELRATE

Calls: None

Equations:

For years 1997-2001:

$$EPRICE_{jno} = \frac{REVH2_{jn}}{SALH2_{jn}} * 1000; \quad EPRICE_{j1o} = EPRICE_{j1o} * 0.9$$

For years 2002-2008:

$$EPRICE_{jno} = \frac{REVH2_{jn}}{SALH2_{jn}} * 1000 * \frac{DEF_i}{DEF_{12}}; \quad EPRICE_{j1o} = EPRICE_{j1o} * 0.9$$

i=year; j=region; n=class; o=stage of production

where: REVH2 = total revenues for region 13 for 1996 (in 1996$),
SALH2 = total sales for region 13 for 1996 (billion kWh),and
DEF = price deflator for year i

The above code assumes that between 1997 and 2001, sector prices are fixed at the nominal 1996 rate. Between 2002 and 2008, prices are fixed at the real rate reached in 2001. In both cases residential rates are further reduced 10 percent. This approximates the legislative decisions announced at the time of the AEO98. (Between 1997 and 2001 the final price is based on the above calculation, after 2001, marginal prices are averaged with the above calculation, which is used for the regulated price.)

SUBROUTINE: REVGAP

Description: This subroutine calculates the annual gap between competitive revenues and costs (less depreciation). This fraction is saved and used in EMUE to determine the need for new capacity.

Called by: ELEFP

Calls: None

Equations:

$$tgap = \frac{trevs}{tcost}, \ for \ each \ region \ j$$

where: trevs = revenues for generation, based on a purely competitive price, in nominal dollars, for the current year and region,and
tcost = annual expenses - made up of direct capital expenditures, and all other expenses except depreciation.

$$tgap = (1.0 - FRMARG_{ij}) * 1.05 + FRMARG_{ij} * tgap$$

where: FRMARG = fraction of the total price based on marginal costs.

This equation creates a weighted gap variable for years when the price is not fully competitive (based only on marginal costs).

$$DGAPOLD_j = 0.5 * DGAPOLD_j + 0.5 * tgap$$

After the first year a rolling average is used based on the two most recent calculations.

SUBROUTINE: EPO$PM

Description: This subroutine captures planned maintenance schedules for forecast year 2.

Called by: ECPOML

Calls: None

Equations:

$$PMDISP(ISP,IP,NERC)=level$$

where: PMDISP = planned maintenance of capacity type IP in season ISP, region NERC.

SUBROUTINE: EPO$CRM

Description: This subroutine captures actual reserve margins.

Called by: ECPOML

Calls: None

Equations:

$$ERMRGN(NERC,YEAR)=\left(\frac{LEVEL-ETRMRGN(NERC,YEAR)}{EPKMRGN(NERC,YEAR)}-1.0\right)*100$$

where: ERMRGN = reserve margin in forecast year YEAR region NERC,
LEVEL = total capacity in region NERC,
ETRMRGN = firm trade in region NERC,and
EPKMRGN = peak demand in region NERC forecast year YEAR.

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