DOE/EIA-M068E(98)

EIA Model Documentation

Electricity Market Module

Modeling Renewable Portfolio Standards for the Annual Energy Outlook 1998

February 1998

Energy Information Administration
Office of Integrated Analysis and Forecasting
U.S. Department of Energy
Washington, DC 20585

Released for Printing: March 2, 1998

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Introduction

The Electricity Market Module (EMM) is the electricity supply component of the National Energy Modeling System (NEMS).[1] The EMM represents the generation, tranmission, and pricing of electricity. It consists of four submodules: the Electricity Capacity Planning (ECP) Submodule, the Electricity Fuel Dispatch (EFD) Submodule, the Electricity Finance and Pricing (EFP) Submodule, and the Load and Demand-Side Management (LDSM) Submodule.

For the Annual Energy Outlook 1998 (AEO98), the EMM has been modified to represent Renewable Portfolio Standards (RPS), which are included in many of the Federal and state proposals for deregulating the electric power industry. A RPS specifies that electricity suppliers must produce a minimum level of generation using renewable technologies. Producers with insufficient renewable generating capacity can either build new plants or purchase "credits" from other suppliers with excess renewable generation.

The representation of a RPS involves revisions to the ECP, EFD, and the EFP. The ECP projects capacity additions required to meet the minimum renewable generation levels in future years. The EFD determines the sales and purchases of renewable credits for the current year. The EFP incorporates the cost of building capacity and trading credits into the price of electricity.

Methodology

Electricity Capacity Planning

The ECP is a linear programming model that projects capacity additions required to meet increases in the demand for electricity and changes in environmental regulations.[2] The objective function of the ECP minimized the total, discounted present value of the investment and operating costs over the planning horizon. The structure of the objective function is not changed by the representation of a RPS. Instead, the objective function is indirectly affected as the minimum renewable generation requirement can lead to different capacity expansion and operating decisions that result in higher costs, compared to the corresponding case without a RPS.

Representing a RPS requires additional constraints. In general, the mathematical specification of these equations is as follows:

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[1]For more information on the National Energy Modeling System, see Energy Information Administration, *The National Energy Modeling System: An Overview*, DOE/EIA-0581(96) (Washington, DC, March 1996).

[2]For more information on the ECP, see Energy Information Administration, *Model Documentation: Electricity Market Module, Electricity Capacity Planning Submodule*, DOE/EIA-M068-B (Washington, DC, March 1994).

(1) $\sum_{n} REN_{ny} \geq RPS_y * TOT_y$

where: REN_{ny} = renewable generation for technology n in year y
RPS_y = minimum renewable generation requirement in year y
TOT_y = total generation in year y

This equation states that the renewable generation must meet or exceed a pre-specified fraction of total generation and can be rearranged as follows:

(2) $\sum_{n} REN_{ny} - RPS_y * TOT_y \geq 0$

The RPS proposals differ according to their respective definitions of renewable technologies. Solar, wind, biomass, and geothermal are typically included, but some proposals exclude generation from hydroelectric and/or municipal solid waste plants. The required level of renewable generation also varies as well as the formula for computing the percentage of renewable generation. In some cases, the minimum requirement specifies the level of renewable sales relative to total sales. Alternative proposals consider renewable generation as a percent of total sales or as a percent of total nonhydroelectric sales.

In the ECP, the variable UPRNWCAS is used to identify the specification of the RPS. If UPRNWCAS equals 3, then the RPS determines the renewable generation as a percent of total sales. For all other values of UPRNWCAS, the RPS specifies renewable sales as a percent of total sales.[3] The variable $UPRNWSHR_n$ identifies the fraction of generation by plant type n that is included in renewable and total electricity production.[4]

In the ECP, the RPS is represented by adding a set of constraints that specify the minimum level of renewable generation for a given year. Since renewable generation credits can be traded, the lower bound is actually national rather than regional or utility-level. Thus, a row is required for each year of the planning region, but not each region.

Dimensions

y	=	Year In the Planning Horizon
r	=	Electricity Supply Region

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[3]This case is represented by using renewable generation and total generation, which assumes that transmission and distribution losses for renewable plants equals the average for all plant types.

[4]For nonrenewable capacity types, $UPRNWSHR_n$ equals 0, which implies that none of the generation is included in renewable generation. For renewable technologies that receive at least partial credit, then $UPRNWSHR_n$ is greater than zero and specifies the fraction of generation that is included for that technology. If $UPRNWSHR_n$ is less than zero, then generation from technology n is not counted towards either renewable or total generation.

n	=	Dispatchable Renewable Capacity Type Included in Total Renewable Generation
x	=	Renewable Capacity Type Not Included in Total Renewable Generation and Total Generation (e.g., hydroelectric)
i	=	Intermittent Renewable Capacity Type
e	=	Renewable Energy Source
l	=	Vertical Load Steps Which Define Total Electricity Load
c	=	Dispatchable Capacity Type

Decision Variables[5]

EXI_{yri}	=	Utilize Existing Intermittent Renewable Capacity Type i in Region r in Year y (Gigawatts)
INT_{yrio}	=	Build/Operate New Intermittent Renewable Capacity Type i for Owner Type o Beginning Operation in Region r in Year y (Gigawatts)
OPR_{yrn}	=	Operate Dispatchable Renewable Type n in Region r inYear y (Gigawatts)

Coefficients

$EPICFC_{yril}$	=	Utilization Rate for Intermittent Renewable Capacity Type i in Load Step l in Region r in Year y (Fraction)
$EPRCFC_{yrn}$	=	Utilization Rate for Dispatchable Renewable Capacity Type n in Region r in Year y (Fraction)
$EPHGHT_{yrl}$	=	Capacity Requirement in Load Step l in Region r in Year y (Gigawatts)
$EPWDTH_{yrl}$	=	Width of Load Step l in Region r in Year y (Hours)
$UPRNWSHR_i$	=	Amount of Generation for Intermittent Renewable Capacity Type i that is Counted Towards Minimum Requirement (Fraction)
$UPRNWSHR_n$	=	Amount of Generation for Dispatchable Renewable Capacity Type n that is Counted Towards Minimum Requirement (Fraction)
$UPRNWBND_y$	=	Amount of Total Generation or Sales Requirement that Must be Provided by Renewables (Fraction)

Based on equation (2), the following constraint for year y insures that renewable generation is greater than or equal to the level specified by the RPS.

[5]For dispatchable technologies, the model allows the flexibility to represent separate build and operate variables since these capacity types (e.g., biomass and geothermal) can involve decisions about the mode of operation as well as the amount of capacity. However, it is currently assumed that the utilization rate is the same for each load segment. For new intermittent renewable capacity types (e.g., wind and solar), separate variables are unnecessary because the utilization rates are determined by the availability of the resource, which varies by season and time of day and are an input to the ECP.

$$(3) \quad \sum_{r}\sum_{i} UPRNWSHR_i \cdot (EXI_{yri} + \sum_{o}\sum_{z=1}^{y} INT_{zrio}) \cdot \sum_{l} EPICFC_{yril} \cdot EPWDTH_{yrl} / 1000 +$$

$$\sum_{r}\sum_{n} UPRNWSHR_n \cdot OPR_{yrn} \cdot EPRCFC_{yrn} \cdot \sum_{l} EPWDTH_{yrl} / 1000 -$$

$$UPRNWBND_y \cdot \sum_{r}\sum_{l} EPHGHT_{yrl} \cdot EPWDTH_{yrl} / 1000 +$$

$$UPRNWBND_y \cdot \sum_{r}\sum_{x} OPR_{yrx} \cdot EPRCFC_{yrx} \cdot \sum_{l} EPWDTH_{yrl} / 1000 \geq 0.$$

The first term of the equation accounts for generation from existing and new intermittent technologies. For each load segment l, the product of the utilization rate ($EPICFC_{yril}$) and the hours ($EPWDTH_{yrl}$) yields the generation per unit of capacity. Summing over all load segments and then multiplying by the available capacity ($E_{yri} + \sum INT_{zrio}$) and the fraction of generation credited towards the RPS ($UPRNWSHR_i$) gives the intermittent generation that satisfies the minimum renewable requirement. Dividing this quantity by 1000 converts the total to billion kilowatthours. Similarly, the second term describes the generation from dispatchable renewable capacity. The third term includes the product of the capacity requirement ($EPHGHT_{yrl}$) and hours ($EPWDTH_{yrl}$) for each load segment, which represents the total generation produced from all sources. Multiplying this quantity by the RPS fraction ($UPRNWBND_y$) and dividing by 1000 provides the minimum renewable generation requirement. The last term is similar to the second term as it describes generation from dispatchable renewable technologies, but it accounts for capacity types (e.g., hydroelectric) that are not included in the RPS. For example, a RPS might specify the minimum level of nonhydroelectric renewable generation (the first three terms), as a fraction of total nonhydroelectric generation (the last two terms).

Subroutine *EP$INT* computes the coefficients of existing capacity (EXI_{yri}) and new capacity (INT_{yrio}) for intermittent technologies. Subroutine *EP$ORNW* determines the coefficients of dispatchable renewable capacity (OPR_{yrn}) included in the minimum renewable generation requirement. Subroutine *EP$ORNW* also calculates the coefficients of dispatchable renewables excluded from the RPS (OPR_{yrx}). The total generation requirement ($EPHGHT_{yrl} \cdot EPWDTH_{yrl}$) is determined in Subroutine *EP$RPS.*

Renewable Credit Price

The renewable credit price is based on the marginal cost of complying with the renewable generation requirement, which is represented by the dual value (shadow price) of the RPS constraint. The objective function of the ECP minimizes the present value of investment and operating costs, in nominal dollars, for the planning horizon.[6] Therefore, the dual value of the RPS constraint for a given year provides the present value of the marginal cost of compliance in

[6]For more information, see Energy Information Information, *Model Documentation: Electricity Market Module, Electricity Capacity Planning Submodule*, DOE/EIA-M068-B (Washington, DC, March 1994).

that year.

The renewable credit price is assumed to be the levelized cost of compliance over the operating period for renewable additions. The levelized cost is the annuity (i.e., constant amount of dollars in each year) that provides the same total present value as the actual stream of costs over the time horizon, as expressed in Equation (4).

$$(4) \qquad EPRPSCR_Y \cdot \sum_{z=MAXLT+1}^{ECP\$XPH} (1 + UPGNPD_z)] / (1 + AVGDCR)^z = \sum_{z=MAXLT+1}^{ECP\$XPH} EPRENEW_z$$

where: ECP\$XPH	=	Number of Years in Planning Horizon
MAXLT	=	Lead Time When All Renewable Capacity Types Can Compete to Meet RPS
$EPRPSCR_y$	=	Levelized Cost for Period Beginning in Year z=MAXLT + 1 (real dollars)
$UPGNPD_z$	=	Cumulative Inflation Factor for Year z
AVGDCR	=	Average Discount Rate (fraction)[7]
$EPRENEW_z$	=	Discounted, Annual Compliance Cost (dual value) in Year z (mills per kilowatthour in nominal dollars)

Rearranging Equation (4) to solve for the levelized compliance cost yields Equation (5).

$$(5) \qquad EPRPSCR_y = \sum_{z=MAXLT+1}^{ECP\$XPH} EPRENEW_z \;/\; \{\sum_{z=MAXLT+1}^{ECP\$XPH} (1 + UPGNPD_z)] / (1 + AVGDCR)^z\}$$

In the ECP, Subroutine *EPO$RPS* obtains the dual values of the RPS constraints and computes the levelized cost of complying with the RPS. The levelized cost is determined for the period beginning in planning year (MAXLT + 1), which is the initial operating date for new renewable capacity.

Electricity Fuel Dispatch

The EFD determines the annual allocation of available capacity to satisfy electricity demand, given current environmental regulations.[8] Capacity is dispatched on a least-cost (merit-order) basis so that the most economical capacity types are utilized to the greatest extent. For each

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[7]Since the RPS constraints include all regions, the average discount rate is used to determine the present value of the corresponding dual variables.

[8]For more information, see Energy Information Information, *Model Documentation: Electricity Market Module, Electricity Fuel Dispatch Submodule,* DOE/EIA-M068-D (Washington, DC, March 1994).

EMM region, the EFD determines the trades of renewable credits by computing the renewable generation and comparing it to the total generation (or total sales depending on the specific RPS). If the corresponding fraction exceeds the minimum RPS level, then the surplus represents the renewable credits sold. Alternatively, if the regional renewable generation is less than the required amount, then the difference represents the renewable credits bought.

The regional, total generation requirements (net imports are included since they replace domestic supplies) are computed using Equation (6).

$$(6) \quad TOTGEN_r = [\sum_c \sum_o EQPGN_{rco} + \sum_i UPRNWSHR_i \cdot \sum_o EQHGN_{rio} + \sum_i UPRNWSHR_i \cdot \sum_n EQHGN_{rno} + (ETIMPF_r + ETIMPE_r - ETEXPF_r - ETEXPE_r)] \cdot 0.001$$

where:

$TOTGEN_r$	=	Total Generation Requirement in Region r
$EQPGN_{rco}$	=	Generation by Nonrenewable Capacity Type c and Owner Type o in Region r
$UPRNWSHR_i$	=	Amount of Generation for Intermittent Renewable Capacity Type i that is Counted Towards Minimum Requirement (Fraction)
$EQHGN_{rio}$	=	Generation by Intermittent Type i and Owner Type o in Region r
$UPRNWSHR_n$	=	Amount of Generation for Dispatchable Renewable Capacity Type n that is Counted Towards Minimum Requirement (Fraction)
$EQHGN_{rno}$	=	Generation by Dispatchable Renewable Type n and Owner Type o in Region r
$ETIMPF_r$	=	Firm Power Imports in Region r
$ETIMPE_r$	=	Economy Power Imports in Region r
$ETEXPF_r$	=	Firm Power Exports in Region r
$ETEXPE_r$	=	Economy Power Exports in Region r

Next, the regional, renewable generation credited towards the RPS requirement is determined using Equation (7).

$$(7) \quad RENGEN_r = [\sum_i UPRNWSHR_i \cdot \sum_o EQHGN_{rio} + \sum_n UPRNWSHR_n \cdot \sum_o EQHGN_{rno}] \cdot 0.001$$

where:

$RENGEN_r$	=	Total Renewable Generation for RPS in Region r
$UPRNWSHR_i$	=	Amount of Generation for Intermittent Renewable Capacity Type i that is Counted Towards Minimum

		Requirement (Fraction)
$EQHGN_{rio}$	=	Generation by Intermittent Type i and Owner Type o in Region r
$UPRNWSHR_n$	=	Amount of Generation for Dispatchable Renewable Capacity Type n that is Counted Towards Minimum Requirement (Fraction)
$EQHGN_{rno}$	=	Generation by Dispatchable Renewable Type n and Owner Type o in Region r

Both the renewable and total generation amounts are then adjusted to include sales-to-the-grid ($SALGRD_r$) but not own-use ($OWNUSE_r$) from cogenerators. Total renewable cogeneration by region ($RENCOG_r$) is determined by summing over all sectors and renewable energy sources. The ratio of sales-to-the-grid to total cogeneration is then applied to renewable cogeneration to obtain sales-to-the-grid from renewables. That is,

$$(8) \quad RENCOG_{yr} = \sum_{s}\sum_{f} COGEN_{yrsf} \cdot SALGRD_{yr} / (SALGRD_{yr} + OWNUSE_{yr})$$

where: $RENCOG_{yr}$	=	Renewable Sales-to-Grid in Year y in Region r (billion kilowatthours)
$COGEN_{yrse}$	=	Cogeneration in Year y in Region r in Sector s by Renewable Energy Source e

For each region, the achieved renewable generation fraction is determined as follows:[9]

$$(9) \quad URPSPCT_r = (RENGEN_r + RENCOG_r) / (TOTGEN_r + SALGRD_r)$$

where: $URPSPCT_r$	=	Achieved Renewable Generation Level in Region r (Fraction)
$RENGEN_r$	=	Total Renewable Generation for RPS in Region r
$RENCOG_r$	=	Total Renewable Sales-to-Grid for RPS in Region r
$TOTGEN_r$	=	Total Generation for RPS in Region r
$SALGRD_r$	=	Total Sales-to-Grid for RPS in Region r

The renewable generation in each region is then compared to the required level specified by the RPS (RENPCT) to ascertain the trading of credits ($URPSCRD_r$). A surplus of renewable generation (i.e., $URPSCRD_r$ greater than 0) implies that suppliers in region r are net sellers of credits. Conversely, a deficit corresponds to a net purchase. Regional trades of renewable credits are determined as follows:

[9]If the RPS considers renewable generation as a fraction of sales instead of total generation, then the denominator is total regional electricity sales, in billion kilowatthours ($QELASN_r \cdot 0.001$).

$$(10) \quad URPSCRD_r = (RENGEN_r + RENCOG_r) - RENPCT \cdot (TOTGEN_r + SALGRD_r)$$

In a given year, the applicable credit price is assumed to be the quantity-weighted average of the levelized credit prices associated with each increment of renewable generation, as expressed in Equation (11).

$$(11) \quad RENEWCR_y = [\sum_{z=1}^{y} EPRPSCR_z \cdot (URPSRGN_z - URPSRGL_z)] / URPSRGN_y$$

where:

$RENEWCR_y$	=	average renewable credit price in year y (mills per kilowatthour)
$EPRPSCR_z$	=	levelized credit price for incremental renewable generation in year z (mills per kilowatthour)[10]
$URPSRGN_z$	=	renewable generation in year z (billion kilowatthours)
$URPSRGL_z$	=	renewable generation in year prior to year z (billion kilowatthours)

The revenues associated with renewable credit trade (ERRPS) is the product of the credits traded ($URPSCRD_r$) and the average credit price ($RENEWCR_y$). In the EFD, Subroutine *ELRPSCR* determines the renewable credit trades. It also computes the regional revenue adjustments associated with the sale or purchase of credits.

Electricity Finance and Pricing

The EFP projects the price of electricity under cost-of-service regulation (i.e., average cost pricing).[11] Average electricity prices are derived from revenue requirements, which are the costs that regulators allow a utility to recover from ratepayers. It is assumed that the revenues from renewable credit trades are included in the revenue requirements. Credit sales reduce the revenue requirements and the resulting prices of electricity, whereas purchases increase revenue requirements and prices.

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[10]For existing renewable generation (i.e., the amount of generation prior to the initial year of the RPS), the credit price is assumed to be the levelized price for the current year. In effect, this corresponds to a spot price for existing generation, whereas the levelized price for incremental generation represents a long-term contract price.

[11]For more information on electricity prices, see Energy Information Administration, Model Documentation: Electricity Market Module, Electricity Finance and Pricing Submodule, DOE/EIA-M068-C (Washington, DC, March 1994). For the AEO98, the EFP has been modified to represent prices in a competitive electricity market (i.e., based on marginal prices). For more information, see the forthcoming documentation *Modifications to Incorporate Competitive Electricity Prices in the Annual Energy Outlook 1998.*

Appendix

ELECTRICITY MARKET MODULE (EMM) SUBMODULE SUBROUTINES

This appendix contains a description of the FORTRAN subroutines of the EMM that have been modified or created to represent a Renewable Portfolio Standard (RPS). It includes a mathematical specification of the equations that derive coefficients and extract results. The Electricity Capacity Planning (ECP) Submodule incorporates changes to two existing subroutines (EP$INT and EP$ORNW) and the creation of two new subroutines (EP$RPS and EP$ORPS).[12] The Electricity Fuel Dispatch (EFD) Submodule has been revised to include one new subroutine (ELRPSCR).[13] The Electricity Finance and Pricing (EFP) Submodule requires a change to one existing subroutine (GL).[14]

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[12]For more information on the original formulation of the ECP, see Energy Information Information, *Model Documentation: Electricity Market Module, Electricity Capacity Planning Submodule*, DOE/EIA-M068-B (Washington, DC, March 1994).

[13]For more information on the original formulation of the EFD, see Energy Information Information, *Model Documentation: Electricity Market Module, Electricity Fuel Dispatch Submodule,* DOE/EIA-M068-D (Washington, DC, March 1994).

[14]For more information on the original formulation of the EFP, see Energy Information Administration, Model Documentation: Electricity Market Module, Electricity Finance and Pricing Submodule, DOE/EIA-M068-C (Washington, DC, March 1994).

SUBROUTINE: EP$INT

Description: The ECP Subroutine EP$INT revises the upper bounds and matrix coefficients for existing and new intermittent capacity vectors in each year of the planning horizon. It has been modified to compute the coefficients of existing and new capacity vectors in the renewable porfolio constraint rows. These coefficients describe the contribution of intermittent technologies towards satisfying the minimum renewable generation requirement.

Called By: ECPOML
Calls: GETIN

Equations: Revise matrix coefficients of the existing (EXI_{yri}) and build (INT_{yrio}) intermittent capacity vectors and build for each intermittent capacity type i, region r and year y.

Renewable Portfolio Standard Row Coefficient:

```
      DO IP = I , ECP$INT
        ICAP = UCPINTI(IP)
      IF(UPRNWSHR(ICAP).GT.0.00)THEN
C   FRACTION INCLUDED IN RENEWABLE GENERATION
        VALUE = UPRNWSHR(ICAP)
C    FRACTION EXCLUDED FROM TOTAL GENERATION -- SALES IF DOE
BILL
      ELSE
        VALUE = UPRNWBND(CURIYR + YEAR - 1))
         IF(UPRNWCAS.EQ.3)THEN
        CALL GETIN(1,NERC)
        IY = MIN(CURIYR + YEAR - 1,MNUMYR)
           VALUE = VALUE /(1.0 + EQTDLS * ULOSSADJ(IY))
         END IF
      END IF
C    DETERMINE GENERATION PER UNIT OF CAPACITY
        GEN = 0.0
      DO IVLS = 1 , EPNSTP(YEAR)
        VLS = EORDER(IVLS,YEAR)
        GEN = GEN + EPICFC(IP,VLS) * EPWDTH(VLS,YEAR)
      END DO
      IF(GEN.LE.0.0)GEN = 0.0001
        VALUE = VALUE * GEN / 1000.0
      END DO
```

where:

ECP$INT	=	Number if Intermittent Capacity Types (Scalar)
UCPINTI(i)	=	Index of Intermittent Capacity Type i (Scalar)
UPRNWSHR(i)	=	Amount of Generation for Intermittent Type i that is Counted Towards Minimum Renewable Requirement (Fraction)
UPRNWBND(y)	=	Fraction of Total Generation or Sales Requirement in Year y that Must be Provided by Renewables (Fraction)
UPRNWCAS	=	Index to Identify if Renewable Generation is Expressed as a Fraction of Total Generation or Total Sales (Scalar)
EQTDLS	=	Transmission/Distribution Loss Factor (Fraction)
ULOSSADJ(y)	=	Annual Improvement Factor in Transmission/Distribution Losses (Fraction)
EPNSTP(y)	=	Number of Vertical Load Steps in Year y (Scalar) y (Scalar)
EORDER(l,y)	=	Ranking (In Descending Order) of Vertical Load Step l in

		Year
EPICFC(i,l)	=	Utilization Rate for Intermittent Renewable Capacity Type I in Load Step l (Fraction)
EPWDTH(l,y)	=	Width of Load Step l in Year y (Hours)
VALUE	=	Matrix Coefficient of Build or Operate Vector for Intermittent Renewable Type i

SUBROUTINE: EP$ORNW

Description: The ECP Subroutine EP$ORNW revises the operate vectors for dispatchable renewable technologies. It has been modified to compute the coefficients in the renewable porfolio constraint rows. These coefficients describe generation per unit of dispatchable renewable capacity that counts towards the minimum renewable generation requirement and account for the corresponding contribution to total generation.

Called By: ECPOML

Calls: GETIN

Equations: Revise matrix coefficients of the dispatchable renewable operate vectors (OPR_{yrn}) for each renewable capacity type n, region r and year y.

Renewable Portfolio Constraint Row:

```
            DO IP = I , ECP$RNW
              ICAP = UCPRNWI(IP)
            IF(UPRNWSHR(ICAP).GT.0.00)THEN
      C     FRACTION INCLUDED IN RENEWABLE GENERATION
              VALUE = UPRNWSHR(ICAP)
      C     FRACTION EXCLUDED FROM TOTAL GENERATION -- SALES IF DOE
      BILL
             ELSE
              VALUE = UPRNWBND(CURIYR + YEAR - 1))
               IF(UPRNWCAS.EQ.3)THEN
                 CALL GETIN(1,NERC)
                 IY = MIN(CURIYR + YEAR - 1,MNUMYR)
                        VALUE = VALUE /(1.0 + EQTDLS * ULOSSADJ(IY))
               END IF
             END IF
      C     DETERMINE GENERATION PER UNIT OF CAPACITY
              VALUE = VALUE * EPRCFC(IP) * 8.760
            IF(GEN.LE.0.0)GEN = 0.0001
            END DO
```

where:

ECP$RNW	=	Number of Dispatchable Renewable Capacity Types (Scalar)
UCPRNWI(n)	=	Index of Dispatchable Renewable Capacity Type n (Scalar)
UPRNWSHR(n)	=	Amount of Generation for Dispatchable Renewable Type n that is Counted Towards Minimum Renewable Requirement (Fraction)
UPRNWBND(y)	=	Fraction of Total Generation or Sales Requirement in Year y that Must be Provided by Renewables (Fraction)
UPRNWCAS	=	Index to Identify if Renewable Generation is Expressed as a Fraction of Total Generation or Total Sales (Scalar)
EQTDLS	=	Transmission/Distribution Loss Factor (Fraction)
ULOSSADJ(y)	=	Annual Improvement Factor in Transmission/Distribution Losses (Fraction)
EPNSTP(y)	=	Number of Vertical Load Steps in Year y (Scalar)
EORDER(l,y)	=	Ranking (In Descending Order) of Vertical Load Step l in Year y (Scalar)
EPICFC(i,l)	=	Utilization Rate for Intermittent Renewable Capacity Type I in

Load Step l (Fraction)

EPWDTH(l,y) = Width of Load Step l in Year y (Hours)

VALUE = Matrix Coefficient of Build or Operate Vector for Intermittent Renewable Type I

SUBROUTINE: EP$RPS

Description: EP$RPSis a new ECP subroutine that creates and revises the bounds and the coefficients of decision variables that represent the total generation (or sales) component of the renewable portfolio standard row.

Called By: REVECP
Calls: GETIN

Equations: Revise bounds and coefficients of decision variable representing total generation requirement (GEN_{yri}) for each year of planning horizon i and region r.

```
C  BOUND VECTOR USING TOTAL GENERATION
       VALUE = 0.0
     DO IVLS = 1 , EPNSTP(YEAR)
       VLS = EORDER(IVLS,YEAR)
       VALUE = VALUE + EPHGHT(VLS,YEAR) * EPWDTH(VLS,YEAR) / 1000.0
     END DO
```

where:

EPNSTP(y)	=	Number of Vertical Load Steps in Year y (Scalar) y (Scalar)
EORDER(l,y)	=	Ranking (In Descending Order) of Vertical Load Step l in Year
EPHGHT(l,y)	=	Height of Load Step l in Year y (Hours)
EPWDTH(l,y)	=	Width of Load Step l in Year y (Hours)
VALUE	=	Bound of Generation or Sales Decision Variable (Billion Kilowatthours)

```
C  COEFFICIENTS OF RENEWABLE PORTFOLIO ROW (ADJUST TO SALES IN DOE
CASE)
       VALUE = DBLE(-UPRNWBND(CURIYR + YEAR - 1))
     IF(UPRNWCAS.EQ.3)THEN
       CALL GETIN(1,NERC)
       IY = MIN(CURIYR + YEAR - 1,MNUMYR)
       VALUE = VALUE / (1.0 + EQTDLS * ULOSSADJ(IY))
     END IF
```

where:

UPRNWBND(y)	=	Amount of Total Generation or Sales Requirement that Must be Provided by Renewables in Year y (Fraction)
UPRNWCAS	=	Index to Identify Type of RPS (Scalar)
VALUE	=	Coefficient of Generation or Sales Decision Variable (Scalar)

SUBROUTINE: EPO$RPS

Description: EPO$RPS is a new ECP subroutine that retrieves the dual variables of the renewable portfolio constraints and computes the levelized renewable credit prices.

Called By: ECPOML
Calls: GETBLD,EP$LBNP,WFSROW [15]

Equations: <u>Get shadow prices and determine levelized credit price.</u>

```
C   DETERMINE MAXIMUM LEADTIME FOR RENEWABLE PLANTS
       MAXLT = 0
      DO IP = 1 , ECP$RNW
       IF(UPCLYR(UCPRNWI(IP)).GT.MAXLT)MAXLT = UPCLYR(UCPRNWI(IP))
      END DO
       DO IP = 1 , ECP$INT
       IF(UPCLYR(UCPINTI(IP)).GT.MAXLT)MAXLT = UPCLYR(UCPINTI(IP))
      END DO
```

where:		
ECP$RNW	=	Number of Dispatchable Renewable Capacity Types (Scalar)
UCPRNW(n)	=	Index of Dispatchable Renewable Capacity Type n (Scalar)
UPCLYR(n)	=	Construction Lead Time for Dispatchable Renewable Capacity Type n (Years)
ECP$INT	=	Number if Intermittent Capacity Types (Scalar)
UCPINT(i)	=	Index of Intermittent Capacity Type i (Scalar)
UPCLYR(n)	=	Construction Lead Time for Intermittent ispatchable Capacity Type i (Years)
MAXLT	=	Maximum Lead Time for All Renewable Technologies (Years)

```
C   IF NO RPS CONSTRAINT THE CREDIT PRICE IS 0
       IF(UPRNWBND(CURIYR + MAXLT) .LE. 0.005)THEN
          EPRPSCR(CURIYR + MAXLT) = 0.0
       ELSE
C   COMPUTE AVERAGE DISCOUNT RATE
          AVGDCR = 0.0
        DO REG = 1 , UNRGNS
          CALL GETBLD(1,REG)
          AVGDCR = AVGDCR + EPDSCRT
        END DO
          AVGDCR = AVGDCR / FLOAT(UNRGNS)
C   GET LEVELIZED INFLATION FACTOR TO CONVERT DUALS TO REAL $
          OPYRS = ECP$FPH - (MAXLT + 1) + 1
          CALL EP$LGNP(MAXLT+1,OPYRS,AVGDCR,PVGNP)
C   USE OML TO GET DUAL FOR RENEWABLE PORTFOLIO CONSTRAINT
         DO IYR = 1 , ECP$XPH
          ROW = 'GRNWXXX' // UPYRCD(IYR)
          IRET = WFSROW(ROW,'P ',STATUS,DUAL_VALUE)
```

---

[15] WFSROW is a subroutine of the proprietary software Optimization and Modeling Library (OML) that extracts solution information from linear programs. For more details, see Ketron Management Science, *Optimization and Modeling Library* (Draft), (Arlington, VA, November 1992).

```
          EPRENEW(IYR) = -DUAL_VALUE
        END DO
C   USE CREDIT PRICE FOR YEARS WHEN ALL RENEWABLE TECHNOLOGIES ARE
C   AVAILABLE
          SUMCRD = 0.0
        DO IYR = MAXLT + 1 , ECP$XPH
          SUMCRD = SUMCRD + EPRENEW(IYR)
        END DO
          EPRPSCR(CURIYR+MAXLT) = SUMCRD / PVGNP
C   SET PRICE TO 4 CENTS (40 MILLS) IF UNABLE TO MEET CONSTRAINT AND
C    DUAL IS SET BY ESCAPE VECTOR
          IF(EPRPSCR(CURIYR+MAXLT).GT.500.0)EPRPSCR(CURIYR+MAXLT) =
      40.0
       END IF
```

where:

UPRNWBND(y)	=	Amount of Total Generation or Sales Requirement that Must be Provided by Renewables in Year y (Fraction)
CURIYR	=	Current Year Index (Scalar)
MAXLT	=	Maximum Lead Time for All Renewable Technologies (Years)
EPRPSCR(y)	=	Levelized Renewable Credit Price for Period Beginning in Year y When All New Renewable Capacity Can Begin Operation (mills per kilowatthour)
AVGDCR	=	Average Utility Discount Rate Across All Regions (Fraction)
UNRGNS	=	Number of Electricity Supply Regions (Scalar)
GETBLD	=	Subroutine to Retrieve Regional Discount Rates
EPDSCRT	=	Regional Discount Rate (Fraction)
OPYRS	=	Operating Period for New Renewable Capacity (Years)
ECP$FPH	=	Number of Years in ECP Life-Cycle Cost Period
EP$LGNP	=	Subroutine to Compute Levelized Inflation Factor
PVGNP	=	Levelized Inflation Factor (Scalar)
ECP$XPH	=	Length of Planning Horizon in ECP (Years)
WFSROW	=	OML Subroutine to Retrieve Shadow Prices
EPRENEW(y)	=	RPS Shadow Price for Year y (mills per kilowatthour in nominal dollars)
EPRPSCR(y)	=	Levelized RPS Credit Price for Operating Period Beginning in Year y (mills per kilowatthour in real dollars)

SUBROUTINE: ELRPSCR

Description: ELRPSCR is a new EFD subroutine that determines renewable credit trades for the current forecast year.

Called By: ELEFD
Calls: GETOUT, STROUT,GETIN

Equations: Get dispatching results, accumulate renewable and total generation (or sales), and determine renewable credit trades and the corresponding revenues.

```
C   STORE RENEWABLE AND TOTAL RPS GENERATION FOR LAG YEAR
        IF(UPRNWCAS.GT.0.AND.CURIYR.GT.1.AND.CURITR.EQ.1)THEN
        DO REG = 1 , MNUMNR
           URPSRGL(REG) = URPSRGN(REG)
           URPSTGL(REG) = URPSTGN(REG)
        END DO
        END IF
```

where:

UPRNWCAS	=	Index to Identify Type of RPS, If Any (Scalar)
CURIYR	=	Current Year Index(Scalar)
CURITR	=	Current Iteration Index (Scalar)
MNUMNR	=	Number of Electricity Supply Regions, Including National Total (Scalar)
URPSRLG(r)	=	Renewable Generation for Lag Year in Region r (billion kilowatthours)
URPSRGN(r)	=	Renewable Generation for Current Year in Region r (billion kilowatthours)
URPSTLG(r)	=	Total Generation for Lag Year in Region r (billion kilowatthours)
URPSTGN(r)	=	Total Generation for Current Year in Region r (billion kilowatthours)

```
C   IF RENEWABLE PORTFOLIO STANDARD IS NOT IMPOSED, SET CREDIT TRADES
C   TO 0
        IF(UPRNWCAS.LE.0)THEN
           DO REG = 1 , UNRGNS
             CALL GETOUT(CURIYR,REG)
              ERRPS = 0.0
             CALL STROUT(CURIYR,REG)
           END DO
```

where:

UPRNWCAS	=	Index to Identify Type of RPS, If Any (Scalar)
CURIYR	=	Current Year Index(Scalar)
UNRGNS	=	Number of Electricity Supply Regions (Scalar)
GETOUT	=	Subroutine to Retrieve Dispatch Solution Results
ERRPS	=	Regional Adjustment to Revenue Requirements Due to RPS Credit Trades (real dollars)
STROUT	=	Subroutine to Store Dispatch Solution Results

```
        ELSE
C   FOR EACH EFD RENEWABLE TYPE IDENTIFY CORRESPONDING ECP TYPE
C   AND GET FRACTION INCLUDED IN SATISFYING RPS
```

```
DO PLT = EFD$DSP + 1 , EFD$CAP
  IF(PLT.EQ.UIBMS)RENFAC(PLT - EFD$DSP) = UPRNWSHR(WIWD)
  IF(PLT.EQ.UIMSW)RENFAC(PLT - EFD$DSP) = UPRNWSHR(WIMS)
  IF(PLT.EQ.UIGTH)RENFAC(PLT - EFD$DSP) = UPRNWSHR(WIGT)
  IF(PLT.EQ.UIHYC)RENFAC(PLT - EFD$DSP) = UPRNWSHR(WIHY)
  IF(PLT.EQ.UIHYR)RENFAC(PLT - EFD$DSP) = UPRNWSHR(WIPS)
  IF(PLT.EQ.UIWND)RENFAC(PLT - EFD$DSP) = UPRNWSHR(WIWN)
  IF(PLT.EQ.UISTH)RENFAC(PLT - EFD$DSP) = UPRNWSHR(WISO)
  IF(PLT.EQ.UISPV)RENFAC(PLT - EFD$DSP) = UPRNWSHR(WIPV)
END DO
```

where:

EFD$DSP	=	Number of Fossil and Nuclear Capacity Types (Scalar)
EFD$CAP	=	Number of Total Capacity Types (Scalar)
UPRNWSHR(i)	=	Amount of Generation for Intermittent Type i that is Counted Towards Minimum Renewable Requirement (Fraction)
UPRNWSHR(n)	=	Amount of Generation for Dispatchable Renewable Type n that is Counted Towards Minimum Renewable Requirement (Fraction)

```
C   INITIALIZE TOTALS
        DO REG = 1 , MNUMNR
          TOTGEN(REG) = 0.0
          RENGEN(REG) = 0.0
          SALGRD(REG) = 0.0
          OWNUSE(REG) = 0.0
          TOTCOG(REG) = 0.0
          RENCOG(REG) = 0.0
        END DO
          IY = CURIYR
        DO REG = 1 , UNRGNS
          IR = REG
C     READ INPUT DATA
          CALL GETIN(1,REG)
C     READ OUTPUT DATA
          CALL GETOUT(CURIYR,REG)
C   DETERMINE RENEWABLE AND TOTAL GENERATION
C   LOOP OVER FOSSIL PLANTS
          DO PLT = 1 , EFD$DSP
C   UTILITY AND IPP ONLY
            DO OWN = 1 , 3
              TOTGEN(REG) = TOTGEN(REG) + EQPGN(PLT,OWN) * 0.001
              TOTGEN(MNUMNR) = TOTGEN(MNUMNR) + EQPGN(PLT,OWN) *
    0.001
            END DO
          END DO
C   ACCOUNT FOR IMPORTS (GEN + NET IMPORTS LESS LOSSES = SALES)
              TOTGEN(REG) = TOTGEN(REG) + (ETIMPF + ETIMPE -
                                ETEXPF - ETEXPE) * 0.001
              TOTGEN(MNUMNR) = TOTGEN(MNUMNR) + (ETIMPF + ETIMPE -
                                     ETEXPF - ETEXPE) * 0.001
```

where:

CURIYR	=	Current Year Index (Scalar)
UNRGNS	=	Number of Electricity Supply Regions (Scalar)
GETIN	=	Subroutine to Retrieve Dispatching Input Data
GETOUT	=	Subroutine to Retrieve Dispatching Output Data

EFD$DSP	=	Number of Fossil and Nuclear Capacity Types (Scalar)
TOTGEN(r)	=	Total Generation for Region r (billion kilowatthours)
EPQGN(d,o)	=	Generation by Fossil or Nuclear Plant Type d and Owner Type o (million kilowatthours)
ETIMPF	=	Firm Power Imports (million kilowattours)
ETIMPE	=	Economy Power Imports (million kilowatthours)
ETEXPF	=	Firm Power Exports (million kilowattours)
ETEXPE	=	Economy Power Exports (million kilowatthours)
MNUMNR	=	Number of Electricity Supply Regions, Including National Total (Scalar)

```
C   LOOP OVER RENEWABLE PLANTS
          DO PLT = 1 , EFD$RNW
C   IF FACTOR < 0 THEN EXCLUDE FROM RENEWABLE AND TOTAL GEN (E.G.,
C   JEFFORDS)
          IF(RENFAC(PLT).GE.0)THEN
C   UTILITY AND IPP ONLY
             DO OWN = 1 , 3
               RENGEN(REG) = RENGEN(REG) + EQHGN(PLT,OWN) *
                                 RENFAC(PLT) * 0.001
               RENGEN(MNUMNR) = RENGEN(MNUMNR) + EQHGN(PLT,OWN) *
                                 RENFAC(PLT) * 0.001
               TOTGEN(REG) = TOTGEN(REG) + EQHGN(PLT,OWN) * 0.001
               TOTGEN(MNUMNR) =TOTGEN(MNUMNR)+EQHGN(PLT,OWN) *
             0.001  END DO
          END IF
          END DO
```

where:			
	ERD$RNW	=	Number of Intermittent and Dispatchable Renewable Capacity Types (Scalar)
	RENFAC(i)	=	Amount of Generation forIntermittent Type i that is Counted Towards Minimum Renewable Requirement (Fraction)
	RENFAC(n)	=	Amount of Generation for Dispatchable Renewable Type n that is Counted Towards Minimum Renewable Requirement (Fraction)
	RENGEN(r)	=	Renewable Generation for Region r (billion kilowatthours)
	EQHGN(i,o)	=	Generation by Intermittent Capacity Type i and Owner Type o (million kilowatthours)
	EQHGN(n,o)	=	Generation by Dispatchable Renewable Capacity Type n and Owner Type o (million kilowatthours)
	MNUMNR	=	Number of Electricity Supply Regions, Including National Total (Scalar)

```
C   ACCOUNT FOR COGEN (SALES TO GRID) -- USE FTAB ARRAYS
C   RENEWABLE
C    HYDRO
             IF(RENFAC(UIHYC - EFD$DSP).GT.0)THEN
               RENCOG(IR) = RENCOG(IR) +
                        ((CGNTGEN(IR,IY,4,1) + CGNTGEN(IR,IY,4,2) +
                        (CGINDGEN(11,IY,4,1) + CGINDGEN(11,IY,4,2) +
                        CGCOMGEN(11,IY,4)) * RNWGEN(IR)) * .001) *
                        RENFAC(UIHYC - EFD$DSP)
             END IF
```

```
C   GEOTHERMAL
            IF(RENFAC(UIGTH - EFD$DSP).GT.0)THEN
              RENCOG(IR) = RENCOG(IR) +
                          ((CGNTGEN(IR,IY,5,1) + CGNTGEN(IR,IY,5,2) +
                          (CGINDGEN(11,IY,5,1) + CGINDGEN(11,IY,5,2) +
                          CGCOMGEN(11,IY,5)) * RNWGEN(IR)) * .001) *
                          RENFAC(UIGTH - EFD$DSP)
            END IF
C   MSW
            IF(RENFAC(UIMSW - EFD$DSP).GT.0)THEN
              RENCOG(IR) = RENCOG(IR) +
                          ((CGNTGEN(IR,IY,6,1) + CGNTGEN(IR,IY,6,2) +
                          (CGREGEN(11,IY,4,1) + CGREGEN(11,IY,4,2) +
                          CGINDGEN(11,IY,6,1) + CGINDGEN(11,IY,6,2) +
                          CGCOMGEN(11,IY,6)) * RNWGEN(IR)) * .001) *
                          RENFAC(UIMSW - EFD$DSP)
            END IF
C   BIOMASS
            IF(RENFAC(UIBMS - EFD$DSP).GT.0)THEN
              RENCOG(IR) = RENCOG(IR) +
                          ((CGNTGEN(IR,IY,7,1) + CGNTGEN(IR,IY,7,2) +
                          (CGINDGEN(11,IY,7,1) + CGINDGEN(11,IY,7,2) +
                          CGCOMGEN(11,IY,7)) * RNWGEN(IR)) * .001) *
                          RENFAC(UIBMS - EFD$DSP)
            END IF
C   SOLAR
            IF(RENFAC(UISTH - EFD$DSP).GT.0)THEN
              RENCOG(IR) = RENCOG(IR) +
                          ((CGNTGEN(IR,IY,9,1) + CGNTGEN(IR,IY,9,2) +
                          (CGINDGEN(11,IY,9,1) + CGINDGEN(11,IY,9,2) +
                          CGCOMGEN(11,IY,9)) * RNWGEN(IR)) * .001) *
                          RENFAC(UISTH - EFD$DSP)
            END IF
C   SALES TO GRID
            SALGRD(IR) = SALGRD(IR) +
                          CGREGEN(11,IY,1,1) + CGREGEN(11,IY,2,1) +
                          CGREGEN(11,IY,3,1) + CGREGEN(11,IY,4,1) +
                          CGREGEN(11,IY,5,1) + CGINDGEN(11,IY, 1,1) +
                          CGINDGEN(11,IY, 2,1) + CGINDGEN(11,IY, 3,1) +
                          CGINDGEN(11,IY, 4,1) + CGINDGEN(11,IY, 5,1) +
                          CGINDGEN(11,IY, 6,1) + CGINDGEN(11,IY, 7,1) +
                          CGINDGEN(11,IY, 8,1) + CGINDGEN(11,IY, 9,1) +
                          CGINDGEN(11,IY,10,1) +
                          CGOGGEN(11,IY, 1,1) + CGOGGEN(11,IY, 2,1) +
                          CGOGGEN(11,IY, 3,1) + CGOGGEN(11,IY, 4,1)
            DO LOOP1 = 1,10
            SALGRD(IR) = SALGRD(IR) +
                          CGCOMGEN(LOOP1,IY, 1) * GRIDSHR(LOOP1,IY) +
                          CGCOMGEN(LOOP1,IY, 2) * GRIDSHR(LOOP1,IY) +
                          CGCOMGEN(LOOP1,IY, 3) * GRIDSHR(LOOP1,IY) +
                          CGCOMGEN(LOOP1,IY, 4) * GRIDSHR(LOOP1,IY) +
                          CGCOMGEN(LOOP1,IY, 5) * GRIDSHR(LOOP1,IY) +
                          CGCOMGEN(LOOP1,IY, 6) * GRIDSHR(LOOP1,IY) +
                          CGCOMGEN(LOOP1,IY, 7) * GRIDSHR(LOOP1,IY) +
                          CGCOMGEN(LOOP1,IY, 8) * GRIDSHR(LOOP1,IY) +
```

```
                        CGCOMGEN(LOOP1,IY, 9) * GRIDSHR(LOOP1,IY) +
                        CGCOMGEN(LOOP1,IY,10) * GRIDSHR(LOOP1,IY)
          ENDDO
          SALGRD(IR) = (SALGRD(IR) * GRIDGEN(IR) +
                        CGNTGEN(IR,IY, 1,1) + CGNTGEN(IR,IY, 2,1) +
                        CGNTGEN(IR,IY, 3,1) + CGNTGEN(IR,IY, 4,1) +
                        CGNTGEN(IR,IY, 5,1) + CGNTGEN(IR,IY, 6,1) +
                        CGNTGEN(IR,IY, 7,1) + CGNTGEN(IR,IY, 8,1) +
                        CGNTGEN(IR,IY, 9,1) + CGNTGEN(IR,IY,10,1)) *
                        .001
C     OWN USE
          OWNUSE(IR) = OWNUSE(IR) +
                        CGREGEN(11,IY, 1,2) + CGREGEN(11,IY, 2,2) +
                        CGREGEN(11,IY, 3,2) + CGREGEN(11,IY, 4,2) +
                        CGREGEN(11,IY, 5,2) +
                        CGINDGEN(11,IY, 1,2) + CGINDGEN(11,IY, 2,2) +
                        CGINDGEN(11,IY, 3,2) + CGINDGEN(11,IY, 4,2) +
                        CGINDGEN(11,IY, 5,2) + CGINDGEN(11,IY, 6,2) +
                        CGINDGEN(11,IY, 7,2) + CGINDGEN(11,IY, 8,2) +
                        CGINDGEN(11,IY, 9,2) + CGINDGEN(11,IY,10,2) +
                        CGOGGEN(11,IY, 1,2) + CGOGGEN(11,IY, 2,2) +
                        CGOGGEN(11,IY, 3,2) + CGOGGEN(11,IY, 4,2)
          DO LOOP1 = 1,10
          OWNUSE(IR) = OWNUSE(IR) +
                        CGCOMGEN(LOOP1,IY, 1) * ( 1 - GRIDSHR(LOOP1,IY))+
                        CGCOMGEN(LOOP1,IY, 2) * ( 1 - GRIDSHR(LOOP1,IY))+
                        CGCOMGEN(LOOP1,IY, 3) * ( 1 - GRIDSHR(LOOP1,IY))+
                        CGCOMGEN(LOOP1,IY, 4) * ( 1 - GRIDSHR(LOOP1,IY))+
                        CGCOMGEN(LOOP1,IY, 5) * ( 1 - GRIDSHR(LOOP1,IY))+
                        CGCOMGEN(LOOP1,IY, 6) * ( 1 - GRIDSHR(LOOP1,IY))+
                        CGCOMGEN(LOOP1,IY, 7) * ( 1 - GRIDSHR(LOOP1,IY))+
                        CGCOMGEN(LOOP1,IY, 8) * ( 1 - GRIDSHR(LOOP1,IY))+
                        CGCOMGEN(LOOP1,IY, 9) * ( 1 - GRIDSHR(LOOP1,IY))+
                        CGCOMGEN(LOOP1,IY,10) * ( 1 - GRIDSHR(LOOP1,IY))
          ENDDO
          OWNUSE(IR) = (OWNUSE(IR) * OWNGEN(IR)) * .001
C     IF SELFGEN DOESN'T GET A CREDIT (AS IN DOE BILL) THEN INCLUDE ONLY
C     SALES TO GRID. ASSUME RENEWABLE SALES TO GRID ARE SAME PCT AS
C     TOTAL SALES TO GRID TO TOTAL COGEN
          RENCOG(IR) = RENCOG(IR) * SALGRD(IR) /
          (SALGRD(IR)+OWNUSE(IR))
C     NATIONAL TOTALS
          RENCOG(MNUMNR) = RENCOG(MNUMNR) + RENCOG(IR)
          SALGRD(MNUMNR) = SALGRD(MNUMNR) + SALGRD(IR)
          OWNUSE(MNUMNR) = OWNUSE(MNUMNR) + OWNUSE(IR)
        END DO
```

where:	RENFAC(i)	=	Amount of Generation forIntermittent Type i that is Counted Towards Minimum Renewable Requirement (Fraction)
	RENFAC(n)	=	Amount of Generation for Dispatchable Renewable Type n that is Counted Towards Minimum Renewable Requirement (Fraction)
	CGNTGEN(r,y,e,v)	=	Nontraditional Cogeneration in Region r in Year y by Energy Source e and Vintage v (million

		kilowatthours)
CGINDGEN(r,y,e,v)	=	Industrial Cogeneration in Region r in Year y by Energy Source e and Vintage v (million kilowatthours)
CGCOMGEN(r,y,e)	=	Commercial Cogeneration in Region r in Year y by Energy Source (million kilowatthours)
RNWGEN(r)	=	Share of Commercial Cogeneration Produced by Renewables (Fraction)
CGREGEN(r,y,e,v)	=	Refinery Cogeneration in Region r in Year y by Energy Source e and Vintage v (million kilowatthours)
CGOGGEN(r,y,e,v)	=	Other Cogeneration in Region r in Year y by Energy Source e and Vintage v (million kilowatthours)
GRIDSHR(r,y)	=	Commercial Sales-to-the-Grid as a Share of Total Cogeneration in Region r and Year y (Fraction)
RENCOG(r)	=	Renewable Sales-to-the-Grid in Region r (billion kilowatthours)
SALGRD(r)	=	Total Sales-to-the-Grid in Region r (billion kilowatthours)
OWNUSE(r)	=	Own Use in Region r (billion kilowatthours)

```
C      DETERMINE REGIONAL SALES/PURCHASES OF RENEWABLE CREDITS
C      IN DOE BILL, CREDITS ARE BASED ON %RENEWABLE GENERATION
C      OF TOTAL SALES.  OTHER BILLS USE %RENEWABLE SALES VERSUS
C      TOTAL SALES (SO RATIO USES RENEW GEN / TOTAL GEN)
         IF(UPRNWCAS.NE.3)THEN
              URPSRGN(MNUMNR) = RENGEN(MNUMNR) + RENCOG(MNUMNR)
              URPSTGN(MNUMNR) = TOTGEN(MNUMNR) + SALGRD(MNUMNR)
         ELSE
              URPSRGN(MNUMNR) = RENGEN(MNUMNR) + RENCOG(MNUMNR)
              URPSTGN(MNUMNR) = QELASN(MNUMNR,CURIYR) * 0.001
         END IF
              URPSPCT(MNUMNR) = URPSRGN(MNUMNR) / URPSTGN(MNUMNR)
              RENPCT = MIN(URPSPCT(MNUMNR),UPRNWBND(CURIYR))
```

where:	UPRNWCAS	=	Index to Identify Type of RPS, If Any (Scalar)
	URPSRGN(r)	=	Total Renewable Generation for Current Year in Region r (billion kilowatthours)
	RENGEN(r)	=	Renewable Generation (Excluding Cogeneration) in Region r (billion kilowatthours)
	RENCOG(r)	=	Renewable Sales-to-the-Grid in Region r (billion kilowatthours)
	URPSTGN(r)	=	Total Generation for Current Year in Region r (billion kilowatthours)
	TOTGEN(r)	=	Total Generation (Excluding Cogeneration) in Region r (billion kilowatthours)
	SALGRD(r)	=	Total Sales-to-the-Grid in Region r (billion kilowatthours)
	URPSPCT(r)	=	Renewable Generation Level Achieved in Region r (Fraction)
	UPRNWBND(y)	=	Minimum Renewable Generation Level for Year y Specified in RPS (Fraction)

```
c Rolling average type credit
       IF(UPRNWBND(CURIYR) .GT. 0.001 .AND. CURIYR .GT. 1) THEN
```

```
c cost of next increment of renewables at the credit price
c if this is the first year of the standard we treat the old renewables separately
c with a credit price of  1$
c Find first year with bound
            CREDSTART = 1
        DO IY=2,CURIYR
            CREDSTART = CREDSTART + 1
              IF(UPRNWBND(IY)  - UPRNWBND(IY - 1) .gt. 0.001)THEN
               IF(CREDSTART .eq. CURIYR) THEN
                 credcost(CREDSTART-1) = URPSRGL(MNUMNR)
               ENDIF
                 goto 2100
              ENDIF
        ENDDO
 2100   CONTINUE

             credcost(CURIYR) = (URPSRGN(MNUMNR) - URPSRGL(MNUMNR))*
                                EPRPSCR(CURIYR)

c credcost is 0 before the standard
c this catches the old grandfathered stuff multiplies it by the
c current credit price, and then catches all the other years
c this is the equivalent of long-term contracts
            TOTCRED =  credcost(CREDSTART - 1) * EPRPSCR(CURIYR)
         DO IY=CREDSTART ,CURIYR
            TOTCRED = TOTCRED + credcost(IY)
         END DO
            renewcr(CURIYR) = TOTCRED/URPSRGN(MNUMNR)
        ELSE
            renewcr(CURIYR) = 0.0
            credcost(CURIYR) = 0.0
        ENDIF
```

where:	UPRNWBND(y)	=	Minimum Renewable Generation Level for Year y Specified in RPS (Fraction)
	CURIYR	=	Current Year Index (Scalar)
	URPSRLG(r)	=	Renewable Generation for Lag Year in Region r (billion kilowatthours)
	URPSRGN(r)	=	Renewable Generation for Current Year in Region r (billion kilowatthours)
	EPRPSCR(y)	=	Levelized RPS Credit Price for Operating Period Beginning in Year y (mills per kilowatthour in real dollars)
	RENEWCR(y)	=	Rolling Average RPS Credit Price for year y (mills per kilowatthour)

```
C  DETERMINE CREDIT REVENUES, IF ANY
        IF(EPRPSCR(CURIYR).GT.0.0)THEN

C      RECONCILE REGIONAL TOTALS
        DO REG = 1 , UNRGNS
            IF(UPRNWCAS.NE.3)THEN
             URPSPCT(REG) = (RENGEN(REG) + RENCOG(REG)) /
                            (TOTGEN(REG) + SALGRD(REG))
             URPSCRD(REG) = (RENGEN(REG) + RENCOG(REG)) -
                            RENPCT * (TOTGEN(REG) + SALGRD(REG))
```

```
        ELSE
          URPSPCT(REG) = (RENGEN(REG) + RENCOG(REG)) /
                         (QELASN(REG,CURIYR) * 0.001)
          URPSCRD(REG) = (RENGEN(REG) + RENCOG(REG)) -
                         RENPCT * (QELASN(REG,CURIYR) * 0.001)
        END IF
      END DO
          RENPUR = 0.0
          RENSAL = 0.0
         DO REG = 1 , UNRGNS
         IF(URPSCRD(REG).LT.0.0)THEN
           RENPUR = RENPUR - URPSCRD(REG)
         ELSE
           RENSAL = RENSAL + URPSCRD(REG)
         END IF
         END DO
C  INSURE THAT SALES EQUALS PURCHASES, ADD PURCHASES OR SUBTRACT
SALES
C  FROM REVENUE REQUIREMENTS
         DO REG = 1 , UNRGNS
           CALL GETOUT(CURIYR,REG)
           IF(URPSCRD(REG).GT.0.0)URPSCRD(REG) = URPSCRD(REG) *
                                                 RENPUR / RENSAL
           ERRPS = -URPSCRD(REG) * RENEWCR(CURIYR)
          CALL STROUT(CURIYR,REG)
         END DO
      END IF
   END IF
```

where:	UPRNWCAS	=	Index to Identify Type of RPS, If Any (Scalar)
	URPSPCT(r)	=	Renewable Generation Level Achieved in Region r (Fraction)
	RENGEN(r)	=	Renewable Generation (Excluding Cogeneration) in Region r (billion kilowatthours)
	RENCOG(r)	=	Renewable Sales-to-the-Grid in Region r (billion kilowatthours)
	TOTGEN(r)	=	Total Generation (Excluding Cogeneration) in Region r (billion kilowatthours)
	SALGRD(r)	=	Total Sales-to-the-Grid in Region r (billion kilowatthours)
	URPSCRD(r)	=	RPS Credits Sold or Purchased (billion kilowatthours)
	RENPCT	=	National-level Renewable Generation Level (Fraction)
	QELASN(r)	=	Total Sales in Region r (billion kilowatthours)
	GETOUT	=	Subroutine to Retrieve Dispatch Results
	STROUT	=	Subroutine to Store Dispatch Results
	ERRPS	=	Revenue Requirements Adjustment Due to RPS Credit Sales or Purchases (millions of dollars)

SUBROUTINE: GL

Description: GL is a an existing EFP subroutine that accumulates financial information from dispatching. renewable credit trades for the current forecast year.

Called By: EFP

Calls: GETOUT, STROUT

Equations: Get RPS trading revenues and incorporate into variable cost component.

C ADD COST OF RENEWABLE CREDITS TO FUEL COST

EFPFL = EFPFL + ERRPS

where: EFPFL = Total Fuel Cost (millions of dollars)

ERRPS = Revenue Requirements Adjustment Due to RPS Credit Sales or Purchases (millions of dollars)