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Part 2

PETROLEUM MARKET MODEL
OF THE
NATIONAL ENERGY MODELING SYSTEM

Part 2 - Appendices B thru J

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APPENDIX B

Mathematical Description of Model

APPENDIX B. Mathematical Description of Model

In the refining industry, each refiner is trying to minimize the cost of meeting demands. Therefore, the market moves toward lower-cost refiners who have access to crude oil and markets. A key premise is that the selection of crude oils, refinery process utilization, and logistics will adjust to minimize the overall cost of supplying the market with petroleum products. In order to generate refined product prices, the PMM contains a linear programming (LP) model of the U.S. petroleum refining, liquid fuels production, and marketing system that meets demand for refined products while minimizing costs. This Appendix describes the mathematical model represented by the LP.

The PMM, like the other NEMS models, is written in FORTRAN. The software includes the Optimization Modeling Library (OML), a set of FORTRAN callable subroutines. The LP portion of the PMM is a complete problem matrix, most of which is prepared prior to NEMS processing. The coal supply curves (linked to the Coal-to-Liquids processing) and the E85 demand curves are the exception. These components are created within the PMM code, using information provided each year by other models. Thus, at the beginning of a NEMS run, the LP is loaded into an OML database; and, every iteration, every year, the matrix is updated with the values to be used for that year, copied into memory, and solved.

It is necessary to view the PMM in the context of the NEMS program to understand its function. For each cycle, the main NEMS model calls the demand models to calculate energy demands. Each supply model is then called to calculate energy prices. When the prices and demands converge to within the specified tolerance, the NEMS iteration is complete and the next yearly NEMS cycle begins. If the computed prices have not converged, new demand quantities are computed, passed to the supply models, and the cycle is repeated. In the case of the PMM, a supply model, the refined product prices are obtained from the marginal prices of an optimal solution to the PMM LP, with transportation costs and taxes added. These product prices are sent to the NEMS demand models. The LP matrix is updated with the new demands for refined products and the cycle continues until convergence is reached. The demand level modifications to the PMM LP and the re-optimization of the LP matrix are accomplished by executing FORTRAN callable subroutines.

For *AEO2009* the original generation of the PMM matrix is performed using OML[1] and FORTRAN. OML (Optimization Modeling Library) is a library of FORTRAN callable subroutines for data table manipulation, matrix generation, and solution retrieval programs for report writing. These same library functions are also called to update the matrix during a NEMS run. The matrix is solved with the optimizer,

[1]Ketron Management Science, Inc., *Optimization Modeling Library, OML User Manual*, (November 1994).

C-WHIZ.[2]

B.1 Model Structure

The general structure of the matrix is shown in Table B1.

[2]Ketron Management Science, Inc., *C-WHIZ Linear Programming Optimizer, User Manual*, (July 1994).

Table B1. PMM Linear Program Structure

PMM Linear Program Overview

	Crude Trans.	Purchases Crude Oil, Other Inputs	Crude Distillation	Other Process Unit Operations	Capacity Expansion	Ethanol	Blending	Product Sales	Product Trans.	Row Type	RHS
Objective	-ct	-c	-o	-o	-i	-i -fd/+co		+p	-pt	NC	Max
Crude Oil Balance	+1 +1 -1	+1 +1 +1	-1 -1							GE	0
Intermediate Stream Balance			+y +y	-1 -1 +y +y		-1 +1 -1 +1	-1 -1			GE	0
Utilities		+1	-u	-u +1		-u				GE	0
Policy Constraints				+z -z				+z -z		GE LE	0
Environmental Constraints			+q	+q						GE LE	E
Unit Capacities			+1	+1	-1	+1				LE	K
Quality Specifications							+q +q -Q			GE LE	0
Product Sales							-1	-1	-1 +1 +1 -1	GE	0
Pipeline/Marine Capacities	+1 +1					-1			+1 +1	LE	C
Bounds	Up/Lo/Fix	Up/Lo/Fix				Up		Up/Lo/Fix			

Legend:
c = crude cost
p = price
Q = product specifications
y = yield
z = policy ratio
C = pipeline/marine capacity
u = utility consumption
q = stream quality
E = environmental quality limit
K = unit capacity
ct = crude transportation cost
i = investment cost
o = operating cost
pt = product transportation cost
fd/co=Feedstock /Co-product credit

B.2 Notation

The PMM LP matrix is composed of an objective function and mathematical equations, whose variable names and constraint names are defined with specific notation. These variable names, constraint names, and indexes are defined in Appendix G. The current appendix uses the following conventions:

- The index (r) refers to the five refinery regions (PAD Districts) and the index (d) refers to the nine demand regions (Census Divisions).
- In the objective function, *C* and *P* are generic representations of a cost coefficient and a revenue coefficient, respectively.
- In the constraints, *A* is a generic representation of a parameter.
- In the constraints, letters with subscripts represent parameters.

B.3 Objective Function

The objective function represents an accounting of the revenues and costs associated with importing and producing petroleum products and other liquid fuels, in order to meet domestic and foreign petroleum product demands. The goal is to maximize revenues minus costs:

MAX: Revenues - Costs

This is represented by the objective function below. Note that the objective function presented below has been subdivided into revenue and cost categories in order to clearly identify what the terms represent.

Alaska exports:

$$+P \cdot ZZAMHTOT + \sum_{i=4}^{6} P \cdot NZAMHP(i) - \sum_{i=1}^{3} C \cdot NZAMHN(i) - C \cdot PANGLQ1 - C \cdot TAAMHXZ$$

Cogeneration:

$$+\sum_{r}\left[P \cdot R(r)CGNCGN - C \cdot E(r)CGNINV - C \cdot L(r)CGNBLD\right]$$
$$+\sum_{r}\left[P \cdot R(r)CGXCGN - C \cdot E(r)CGXINV - C \cdot L(r)CGXBLD\right]$$
$$+\sum_{r}[\sum_{mod} P \cdot R(r)CHP(mod) - C \cdot E(r)CHPINV - C \cdot L(r)CHPBLD]$$

Crude imports:

$$-\sum_{r}\sum_{crt}\sum_{Qs} C \cdot P(r)(crt)(Qs) - \sum_{r}\sum_{crt}\sum_{m}\sum_{r'} Y(r)(crt)(m)(r')$$

Domestic product demands and transport (E85 created in PMM):

$$+\sum_{d}[\sum_{prd} P \cdot D(d)(prd)S1 - C \cdot CUSCREDT - C \cdot ESCAPEVAL + \sum_{S=01}^{56} C \cdot D(d)E85(s)]$$
$$-\sum_{d}\sum_{prx}\sum_{m}\sum_{d'} C \cdot W(d)(prd)(m)(d') - \sum_{r}\sum_{prx}\sum_{m}\sum_{d} C \cdot W(r)(prd)(m)(d)$$

Product exports

$$+\sum_{d'}\sum_{prx} P \cdot D(d')(prx)SX + P \cdot D9ASTSX \quad \text{(for d' = 2, 3, 7, 8, 9)}$$

Product and blend component imports, unfinished oil imports, methanol imports:

$$-\sum_{r}\sum_{pri}\sum_{s=1}^{3}\sum_{wr=n,r,u,a} C\cdot I(r)(pri)(wr)(s)+\sum_{r}\sum_{ufo}\sum_{s=1}^{3}\sum_{wr} C\cdot I(r)(ufo)(wr)(s)$$

$$-\sum_{r}\sum_{s=1}^{9} C\cdot I(r)METR(s)$$

Product distresses:

Export cost and import cost:

$$-\sum_{d'}\sum_{px9} C\cdot D(d')(px9)Z9-\sum_{d}\sum_{pi9} C\cdot I(d)(pi9)Z9-C\cdot I\ @\ METZ9$$

(where d’ = demand regions which can export: 2, 3, 7, 8, 9)

Domestic crudes and transport costs:

$$-\sum_{o+A}[C\cdot P(o)DCRQ1-\sum_{crd}\sum_{m}\sum_{r} C\cdot Y(o)(crd)(m)(r)]-C\cdot TAGTLTOT-C\cdot TANSOTOT$$

$$-\sum_{r}\sum_{crd}\sum_{m}\sum_{r'} C\cdot Y(r)(crd)(m)(r')$$

Renewable ethanol and biodiesel :

Ethanol co-products (ist=distillers grain (DDG,EDG), glycerin (GLY), wet mill co-product (WMC)):

$$+\sum_{d=3,4}\sum_{mod} P\cdot H(d)(ist)TOT$$

Ethanol and biodiesel carbon tax credit (default, P=0):

$$+\sum_{d} P\cdot H(d)CETCCT+P\cdot H(d)CLECCT+P\cdot H(d)BDVCCT+P\cdot H(d)BDNCCT$$

$$+\sum_{r} P\cdot J(r)GRDCCT+P\cdot J(r)GRNCCT$$

Corn/advanced starch and biomass supply and transport:

$$-\sum_{d}\sum_{s=1}^{5}[C\cdot C(d)CRNR(s)-C\cdot C(d)BIOR(s)]-\sum_{d} C\cdot H(d)CETADV$$

$$-\sum_{d}\sum_{m}\sum_{d'} W(d)CRN(m)(d')$$

Fuel use:

$$-\sum_{d} C\cdot N(d)ETHCOA$$

Transport of denaturant for ethanol:

$$-\sum_{r}\sum_{d\in r} C\cdot H(r)NATE(d)-\sum_{r}\sum_{d\in r} C\cdot H(r)SSEE(d)$$

Capital costs for new and existing corn ethanol unit (DM1, DM2) capacity:

$$-\sum_d C \cdot E(d)CETDM1 - \sum_d C \cdot L(d)CETDM1$$

$$-\sum_d C \cdot E(d)CETDM2 - \sum_d C \cdot L(d)CETDM2$$

Fixed costs for new and existing cellulosic ethanol unit (CLE, CLZ) capacity:

$$-\sum_d C \cdot E(d)CLEINV - \sum_d C \cdot L(d)CLEBLD - \sum_d C \cdot E(d)CLZINV$$

Capital costs for new and existing biodiesel unit (virgin (BDV), non-virgin (BDN), white grease (BDW)) capacity:

$$-\sum_d C \cdot E(d)BDVINV - \sum_d C \cdot L(d)BDVBLD$$

$$-\sum_d C \cdot E(d)BDWINV - \sum_d C \cdot L(d)BDWBLD$$

$$-\sum_d C \cdot E(d)BDNINV - \sum_d C \cdot L(d)BDNBLD$$

Biodiesel feedstock supply (seed oil (SBO, palm oil (PLM, for d=4,9 only), white grease (WGR), yellow grease (YGR)):

$$-\sum_d \sum_{s=01}^{99} C \cdot C(d)SBOR(s) - \sum_{d=4,9} [C \cdot I @ PLMM(d) + / - \sum_{s=1}^{5} C \cdot I(d)PLMR(s)]$$

$$-\sum_{s=1}^{5} C \cdot I @ PLMR(s) - \sum_d \sum_s C \cdot C(d)WGRR(s) - \sum_d \sum_s C \cdot C(d)YGRR(s)$$

Cogenerated electricity to grid, from cellulosic ethanol:

$$+\sum_d P \cdot H(d)CLEKWH$$

Interregional transport of ethanol and biodiesel:

$$-\sum_d \sum_{d'} \sum_m C \cdot W(d)BIM(m)(d') - \sum_d \sum_{d'} \sum_m C \cdot W(d)BIN(m)(d')$$

$$-\sum_d \sum_{d'} \sum_m C \cdot W(d)ETH(m)(d')$$

Ethanol and biodiesel imports/exports (linked to world regions, wr= n, r only):

$$+\sum_s P \cdot D3ETHSX(s) + \sum_s P \cdot D4ETHSX(s)$$

$$+ / - \sum_{d=7,9} \sum_{s=1}^{5} P \cdot I(d)BIMR(s) \quad - \sum_{s=1}^{5} C \cdot I @ BIMR(s)$$

$$+ / - \sum_{wr} \sum_{s=1}^{5} \sum_{d=2,5,7,9} P \cdot I(d)ETC(wr)(s) \quad - \sum_{s=1}^{5} C \cdot I @ ETCR(s) - \sum_{d=2,5,7,9} C \cdot I @ ETCM(d)$$

$$+ / - \sum_{wr} \sum_{s=1}^{5} \sum_{d=2,5,7,8,9} P \cdot I(d)ETA(wr)(s) \quad - \sum_{s=1}^{5} C \cdot I @ ETAR(s) - \sum_{d=2,5,7,9} C \cdot I @ ETAM(d)$$

$$-\sum_{d=8} C \cdot I @ ETAC(d)$$

$$-C \cdot I @ ETAUSB - C \cdot I @ ETCUSB - C \cdot I @ TOTCBB$$

Carbon tax for refinery fuel use:

$$-\sum_{r} C \cdot T(r)CBNTAX$$

Gasoline and diesel blending:

$$-\sum_{r}\sum_{mgb} C \cdot Q(r)(mgb) - \sum_{r}\sum_{dfo} C \cdot Q(r)(dfo)$$

Capital costs for new and existing unit capacity (refinery and merchant plant):

$$-\sum_{r}\sum_{uns} C \cdot E(r)(uns)INV - \sum_{r}\sum_{uns} C \cdot L(r)(uns)BLD$$

Merchant plant:

Generated and purchased electricity:

$$+\sum_{r} P \cdot H(r)CTXKWH + \sum_{r} P \cdot H(r)BTLKWH - \sum_{r} H(r)KWHMCH$$

Operating variable costs:

$$-\sum_{r} C \cdot T(r)MCHOVC$$

Transfers to and from merchant plant:

$$-\sum_{r}\sum_{ist'} \left[C \cdot H(r)MPGP(ist')\right] - \sum_{r}\sum_{ist'} C \cdot H(r)MPRF(ist')$$

$$-\sum_{r}\sum_{ist'} C \cdot H(r)GPMP(ist') - \sum_{r}\sum_{ist'} C \cdot H(r)RFMP(ist')$$

where ist' = characters 1 and 3 of ist

Alaska natural gas supply curve for GTL processing and product transfer:

$$-\sum_{r}\sum_{s} C \cdot N(r)NGKN(s) - \sum_{m}\sum_{r} WAGTL(m)(r)$$

Coal supply and transportation for coal-to-liquids (CTL): (created in PMM, not MRM)

$$-\sum_{n}\sum_{j}\sum_{k} C \cdot CT(n)(j)(k)$$

$$-\sum_{n}\sum_{k}\sum_{q} C \cdot CP(n)(k)(q)$$

CO2 from CTL emissions:

$$-\sum_r \sum_s C \cdot N(r)SCSN(s)$$

Natural gas supply steps to refinery:

$$+\sum_r \left[\sum_{i=1}^{4} P \cdot N(r)NGRFN(i) - \sum_{i=5}^{8} C \cdot N(r)NGRFP(i) \right]$$

Non-refinery natural gas and methanol plant:

Revenue from shift of ethane/propane to natural gas:

$$+\sum_r [P \cdot G(r)SC2CC1 + P \cdot G(r)SC3CC1]$$

Operating variable costs:

$$-\sum_r C \cdot T(r)GPLOVC$$

Cost to transform natural gas liquids (NGL) to product:

$$-\sum_r C \cdot G(r)(ngl)OTH - \sum_r C \cdot G(r)(ngl)LPG - \sum_r C \cdot G(r)(ngl)FLG - \sum_r C \cdot G(r)(ngl)PCF$$

Cost to transport NGL (ist=C4, C5+) to refinery (RFN):

$$-\sum_r \sum_{ist} [C \cdot G(r)(ist)RFN]$$

Cost to transfer methanol to refinery, chemical industry:

$$-\sum_r C \cdot G(r)METRFN - \sum_r C \cdot G(r)METDEM$$

Cost to add methanol plant capacity:

$$-\sum_r C \cdot E(r)MOHINV - \sum_r C \cdot L(r)MOHBLD$$

Recipe blending:

$$+\sum_r [P \cdot X(r)CKHCOK + P \cdot X(r)CKLCOK + P \cdot X(r)SULSAL]$$

$$-\sum_r C \cdot X(r)AVG0$$

Refinery processes:

Capital cost of new and existing capacity:

$$-\sum_r \sum_{uns} [C \cdot E(r)(uns)INV + C \cdot L(r)(uns)BLD + C \cdot K(r)(uns)CAP] + \sum_r K(r)ACUMOTH$$

Operating variable costs:

$$-\sum_r C \cdot T(r)OVCOBJ$$

Utilities:

$$-\sum_{r}\sum_{uuu} C \cdot U(r)(uuu) - \sum C \cdot R(r)FUMNGS$$

Hydrogen production:

$$+/-\sum_{r}\sum_{\text{mod}} C \cdot R(r)H2P(\text{mod})$$

Domestic marginal refinery representation:

Basic annualized capital and variable operating cost to produce petroleum product pools:

$$-\sum_{r} C \cdot R(r)MARFLL$$

Added cost differential to produce specific distillates, motor gasoline, and propane types:

$$-\sum_{r}[C \cdot R(r)DISDSU + C \cdot R(r)DISDSL + C \cdot R(r)GASTRG + C \cdot R(r)GASSSR + C \cdot R(r)LRGLPG + C \cdot R(r)$$

Domestic crude supplied to marginal refinery:

$$-\sum_{r} C \cdot T(r)DLLTLL$$

World refinery:

World crude supply curve, total and regional:

$$-\sum_{s=1}^{9} C \cdot PWRLDQ(s) + \sum_{wcrd}\sum_{s=1}^{5} P \cdot P@(wcrd)Q(s)$$

Product Demand curve, world regional transfers, distress supply:

$$+\sum_{wr}\sum_{wprd}\sum_{s=1}^{9} P \cdot D(wr)(wprd)S(s) - \sum_{wr}\sum_{wprd} C \cdot P(wr)(wprd)DEX - \sum_{wr}\sum_{wprd} C \cdot P(wr)(wprd)TMP$$

Basic annualized capital and variable operating cost to produce petroleum product pools:

$$-\sum_{wr} C \cdot R(wr)MARFLL - \sum_{wr} C \cdot R(wr)MARIMC$$

Added cost differential to produce specific distillates, motor gasoline, and propane types:

$$-\sum_{r}[C \cdot R(wr)DISDSU + C \cdot R(wr)DISDSL + C \cdot R(wr)DISJTA + C \cdot R(wr)DISN2H]$$

$$-\sum_{r}[C \cdot R(wr)NAPTRG + C \cdot R(wr)NAPSSR + C \cdot R(wr)NAPPCF + C \cdot R(wr)ILGL2D]$$

$$-\sum_{r}[C \cdot R(wr)N6IRES + C \cdot R(wr)N6BRES + C \cdot R(wr)IUPR2D1 + C \cdot R(wr)IUPR2D2 + C \cdot R(wr)IUPN2D]$$

Regional product transport:

$$-\sum_{wr}\sum_{wprd}\sum_{m}\sum_{wr'} C \cdot W(wr)(wprd)(m)(wr')$$

World NGL supply:

$$-\sum_{s=1}^{9} PGLBNGL(s)$$

Other variables-- (compressed NG (CNG), electric vehicle (EV) demand, LNG demand, escape variables, ethanol from CD to PADD):

$$-C \cdot CNGDMD - C \cdot EVDMD - C \cdot ESCAPE - C \cdot ESCAPEVL$$
$$-C \cdot PRIOCRT - C \cdot LPGDMD - \sum_{d}\sum_{m}\sum_{r} W(d)ETH(m)(r)$$

B.4 Constraints

Accounting Constraints

The following "accounting constraints" are "free" (i.e., unconstrained) and therefore do not affect the PMM optimization:

A(d)(prd), A(r)(prd), A@AKAEXP, A(d)BDN(uuu), A(d)BDV(uuu), A(d)BDW(uuu), A(d)BIMPRD, A(d)BINPRD, A@BIMPRD, A@BINPRD, A@BTL, A(r)BTLWH, A(d)CET(fuel), A(d)(xxx)CNS, A@(xxx)CNS, A(r)CHPCGN, A@COKEXP, A@CRDAKA, A@CRDDCR, A@CRDEXP, A(r)CRDFCR, A@CRDFCR, A@CRDL48, A@CRDSPR, A@CRDTOT, A(r)CRX(crt),, A(r)CTLWH, A(r)DSLCTI, A(r)DSUCTI, E(r)(emis), A(d)ETH, A@ETAPRD, A@ETHE85, A@ETHEXP, A@ETHRFG, A@ETHRFH, A@ETHTRG, A@ETHTRH, A(r)ETHRFN, A(r)FUEL, A@FUEL, A(r)FUM(xxx), A@FUM(xxx), A(r)FXOC, A@FXOC, A(d)G08(yyy), A(r)G(gbt)(xxx), A@G(yy)(xxx), A(r)GAIN, A@GAIN, A(r)GPLLPG, A(r)GPLOTH, A(r)GPLPCF, A(r)GPFDLG, A(r)GRD2DS, A(r)GRN2MG, A@KWHRFN, A@MARPRD, A@METDEM, A(r)METIMP, A@METIMP, A@METM85, A@METPRD, A(r)METRFN, A(r)NATDEN, A(r)NGFTOT, A@NGFTOT, A(r)NGLPRD, A@NGLPRD, A(r)NGLRFN, A@NGLRFN, A(r)NGSH2P, A@NGSH2P, A(r)NGSMER, A@NGSMER, A(r)NGSMET, A@NGSMET, A(r)NGSRFN, A(r)PETCOK, A@PETCOK, A(x)PRDEXP, A@PRDEXP, A@PRDDEM, A@PRDRFN, A(r)SG2H2P, A@SG2H2P, A(d)RFG(yyy), A(d)TRG(yyy), A(r)RFGM00, A(r)RFGR00, A(r)TRGM00, A(r)TRGR00, A(r)SULSAL, A@SULSAL, A(r)UNFIMP, A@ZZEXP, A@ZZIMP, C(r)BTL(liq), C(r)BTLTOT, C(r)CTL(liq), C(r)CTLTOT, C(r)GTL(liq), C@ETHCRD, C@ETHVOL, P(r)(pol), P(r)COK, P(r)LOS, H(r)LOS, G(r)LOS, L(d)CETCAP, OPAFLTC, OPAFLTD, OPAFLTL, OPAFLTO, O(o)(crd), Z@FLLIMP, Z@IRACN, Z@IRACX

(emis) = vocn,vocc,soxn,soxc,carn,carc,co1n,colc.co2c,noxn,noxc
(fuel) = KWH, NGS, COA
(liq) = liquid streams produced from BTL, CTL, GTL processing
(pol) = policy concerns
(prd) = product codes
(uuu) = utilities KWH, STM, NGS
(x)= export CD 2,3,7,8,9
(xxx) = fuel streams
(yyy) = TRG,RFG,TRH,RFG

A@1YRBLD

The total ACU (atmospheric crude unit) capacity addition in a single year is constrained by a maximum.

$$\sum_{r} E(r)1YRBLD \leq \max$$

E(r)1YRBLD	ACU capacity added in region (r) in the current year.
max	Maximum allowable ACU capacity addition in a single year

A@CBBIMP

The total quantity of ethanol from Brazil that is imported to the U.S. through the Caribbean Basin is composed of biomass ethanol and advanced ethanol.

$$I\ @\ TOTCBB = I\ @\ ETACBB + I\ @\ ETCCBB$$

I/@TOTCBB	Total ethanol imported to the U.S. from Brazil through the Caribbean Basin.
I/@ETACBB	Total advanced ethanol imported to the U.S. from Brazil through the Caribbean Basin.
I/@ETCCBB	Total biomass ethanol imported to the U.S. from Brazil through the Caribbean Basin.

A@COKEXP

Previously, the total quantity of coke exported from all regions (d) was constrained to be greater than some minimum. Now this constraint is FREE.

$$\sum_{d'} D(d')COKSX \quad \text{FREE} \qquad \text{for } d' = 2, 3, 7, 8, 9$$

D(d')COKSX	Quantity of coke exported from region (d' = 2, 3, 7, 8, 9).
min	Minimum total coke exports.

A@CLZPRD

Maximum CTL capacity allowed to receive a credit for its gasifier component according to the Energy Bill 2005.

$$\sum_{d} \left[E(r)CLZINV + K(r)CLZCAP \right] \leq \max$$

E(r)CLZINV	Unplanned CTL capacity allowed to receive gasifier credit.

K(r)CLZCAP Planned or existing CTL capacity allowed to receive gasifier credit.
max Maximum total CTL capacity allowed to receive gasifier credit.

A@ETCPRD

Total production of cellulosic ethanol must not exceed the market penetration as defined by the Mansfield-Blackman (M-B) algorithm.

$$\sum_d H(d)ETCTOT \le \max_{ETC}$$

H(d)ETCTOT Total production of cellulosic ethanol in region (d).

$\max_{ETC}$ Upper limit on total cellulosic ethanol production in the US, based on the Mansfield-Blackman penetration algorithm (Appendix F).

A@ETHPRD

An accounting of total ethanol produce by and imported to the U.S., with the potential to put a limit on the maximum total (no limit set for *AEO2009*).

$$\sum_d \left[H(d)ETCTOT + H(d)ETHTOT + H(d)CETADV + H(d)CETEXP\right]$$
$$+ \sum_{d=2,5,7,9} I@ETCM(d) + \sum_{d=2,5,7,9} I@ETAM(d)$$
$$+ \sum_{d=8} I@ETCC(d) + \sum_{d=2} I@ETAC(d) \le \max_{\mathrm{ETH}}$$

H(d)ETCTOT Total production of cellulosic ethanol in region (d).
H(d)ETHTOT Total production of corn ethanol in region (d).
H(d)CETADV Total production of advanced ethanol in region (d).
H(d)CETEXP Total production of corn ethanol exported in region (d).
I@ETCM(d) Total imports of cellulosic ethanol from Brazil into region (d=2,5,7,9).
I@ETAM(d) Total imports of advanced ethanol from Brazil into region (d=2,5,7,9).
I@ETCC(d) Total imports of cellulosic ethanol from Canada into region (d=2).
I@ETAC(d) Total imports of advanced ethanol from Canada into region (d=8).
$\max_{\mathrm{ETH}}$ Maximum allowable supply of ethanol to the U.S. (set large for *AEO2009*, thus non-binding).

A@(xxx)FU

Total use of refinery fuels related to (xxx = LPG,OTH,RES,STG) is constrained in all US regions.

A@LPGFU: $\sum_{r}\sum_{m} R(r)FUM(m) \le \max$ m = refinery fuels related to LPG

A@OTHFU: $\sum_{r}\sum_{m} R(r)FUM(m) \ge \min$ m = refinery fuel related to OTH

A@RESFU: $\sum_{r}\sum_{m} R(r)FUM(m) \le \max$ m = refinery fuel related to RES

A@STGFU: $\sum_{r}\sum_{m} R(r)FUM(m) + \sum_{r} R(r)MARFLL \cdot A_r \ge \min$ m = refinery fuel related to STG

R(r)FUM(m)	Manufacturing activity level in mode (m) operation in the Fuel Use Module (FUM) at the refinery in region (r).
max, min	Limit on the use of a particular type of fuel. For each year, the value of max or min is constrained by historical usage levels and growth rates.

A(r)BTLGRD

Total cogenerated electricity produced by the biomass to liquids (BTL) process and sent to the grid, by refinery region.

$$H(r)BTLKWH = A \cdot H(d)BTLRED + A \cdot H(d)BTLREJ$$ for all r

A(d)(ren)CCT (for ren = BDV, BDN, CET, CLE)

Equality rows to account for total renewable fuels produced that is allowed to receive a carbon credit, by Census Division.

A(d)CETCCT: $H(d)CETCCT = A \cdot \sum_{mg} X(d)ETH(mg)$

for all d, mg = TRG,TRH,RFG,RFH,E85

A(d)CLECCT: $H(d)CLECCT = \sum_{mod} [H(d)CLE(mod) + H(d)CLZ(\text{mod})]$ for all d, mod = LIG

A(d)BDVCCT: $H(d)BDVCCT = \sum_{mod} H(d)BDV(mod)$ for all d, mod = SBO

A(d)BDNCCT: $H(d)BDNCCT = \sum_{mod} H(d)BDN(mod)$ for all d, mod = YGR

H(d)CETCCT	Used to determine the carbon credit for corn ethanol production in region (d).
X(d)ETH(mg)	Total corn ethanol-blended motor gasoline (mg) in region (d). Used (with A) to determine quantity of corn ethanol production in region (d) blended into motor gasoline (mg).
A	Fraction of corn ethanol in blended motor gasoline (mg).
H(d)CLECCT	Used to determine the carbon credit for cellulosic ethanol production in region (d).
H(d)CLELIG	Production of cellulosic ethanol from unplanned capacity in region (d).
H(d)CLZLIG	Production of cellulosic ethanol from planned capacity in region (d).

A(d)(ren)DMD (for ren = BIM, BIN)

Equality row to account for total biodiesel produced and blended with petroleum diesel, by Census Division.

A(d)BIMDMD: $$H(d)BIMDMD = A \cdot \sum_{d} [X(d)BIMDSL + X(d)BIMDSU]$$

A(d)BINDMD: $$H(d)BINDMD = A \cdot \sum_{d} [X(d)BINDSL + X(d)BINDSU]$$

H(d)BIMDMD	Total biodiesel blended with petroleum diesel, in region (d).
X(d)ETH(mg)	Total biodiesel-blended diesel fuel, in region (d). Used (with A) to determine quantity of biodiesel blended into diesel fuel.
A	Fraction of biodiesel in blended diesel fuel.

A(d)CET(ful) (ful=COA, KWH, NGS)

Accounting row for coal, electricity, and natural gas use to produce corn ethanol (unconstrained).

A(d)CETCOA:	$A \cdot H(d)CETWME$	FREE	for all *d*
A(d)CETKWH:	$\sum_{mod} H(d)CET(mod) \cdot A$	FREE	for all *d*, *mod* = DM1, DM2, DME, WME
A(d)CETNGS:	$\sum_{mod} H(d)CET(mod) \cdot A$	FREE	for all *d*, *mod* = DM1, DM2, DME, WME

H(d)CET(mod) Corn ethanol production in region (d) via mode (mod).

A(d)CLEGRD

Equality row to account for total cogenerated electricity produced by the biomass to ethanol process and sent to the grid, by Census Division.

$$H(d)CLEKWH = A \cdot \left[H(d)CLELIG + H(d)CLZLIG\right] \qquad \text{for all } d$$

H(d)CLELIG Production of cellulosic ethanol from unplanned capacity in region (d).

A	Ratio of electricity production for grid per volume of ethanol produced.

A(*)CRDIMP

For each applicable combination of imported crude oil and region, the total imports received directly to the U.S. must be greater than a specified minimum.

A@CRDIMP: $$\sum_r \sum_c \sum_q P(r)F(c)Q(q) \geq \min \text{ for } F(c) = \text{FLL, FMH, FHL, FHH, FHV}$$

The volume of crude oil imported from Canada into regions C and M must be less than a specified maximum.

A(r)CRDIMP: $$\sum_c \sum_q P(r)F(c)Q(q) \leq \max_r \text{ for } r = \text{C, M; for } F(c) = \text{FLL, FMH, FHL, FHH, FHV}$$

P(r)F(c)Q(q)	Volume of imported oil at cost (q) received directly to region (r = C, M). F(c) = FLL, FHL, FHH, FHV
$\max_r$	Maximum import level for region (r = C, M), based on historical levels and growth rates.
min	Minimum total import level (zero for *AEO2009*).

A(r)CTXGRD

Equality row to account for total cogenerated electricity produced by the coal to liquids (CTL) process and sent to the grid, by refinery region.

$$H(r)CTXKWH = A \cdot \sum_r \left[H(r)CTXBIT + H(r)CTZBIT\right] \text{ for all } r$$

H(r)CTXKWH	Used in the objective function to determine the credit for electricity (from CTL production) sold to the grid.
H(r)CTXBIT	Operating level of the unplanned coal to liquids unit in region (r).
H(r)CTZBIT	Operating level of the planned coal to liquids unit in region (r).
A	Ratio of electricity production for grid per volume of liquids produced from coal.

A(r)(ist)CCT

Equality rows to account for total renewable diesel (GRD) and total renewable naphtha (GRN) produced by the renewable diesel hydrotreater (GDT) process, by refinery region, to which a carbon tax credit can be applied.

$$J(r)(ist)CCT = \sum_r \sum_{\text{mod}=GDG,GDV} A_{ist}^{\text{mod}} \cdot R(r)GDT(\text{mod}) \qquad \text{for all } r,\ ist = \text{GRD, GRN}$$

J(r)(ist)CCT	Total renewable fuel stream (ist=GRD, GRN) generated from seed oil and yellow grease by a renewable diesel hydrotreater, in region (r). Carbon credit is applied to this vector.

R(r)GDT(mod) Operating level the renewable diesel hydrotreater for operating modes that convert seed oils and yellow grease to renewable diesel and naphtha, in region (r).

A_{ist}^{mod} Ratio of ist (GRD, GRN) produced per volume of renewable feedstock processed, unique for each operating mode (mod).

A(*)INVST

For each region (r) and nearby regions (d_r), the capital investment for expansion of processing unit (u) in (r) and processing unit (u' for biodiesel and ethanol) in (d_r) is constrained by a maximum value.

$$\textbf{A(r)INVST}: \sum_u E(r)(u)INV \cdot A_{ru} + \sum_{d_r}\sum_{u'} E(d_r)(u')INV \cdot A_{d_r u'} \leq \max{}_r$$

u'=BDN, BDV, BDW, CET, CLE, CLZ , for all *r*

The total capital investment in U.S. refineries and renewables plants is constrained by a maximum value.

$$\textbf{A@INVST:} \sum_r\sum_u E(r)(u)INV \cdot A_{ru} + \sum_d\sum_{u'} E(d)(u')INV \cdot A_{du'} \leq \max$$

u'=BDN, BDV, BDW, CET, CLE, CLZ

$A_{du'}$	Capital investment required per unit of capacity ($million per Mbbl/d). (u'=BDN, BDV, BDW, CET, CLE, CLZ)
A_{ru}	Capital investment required per unit of capacity ($million per Mbbl/d).
d_r	Regions (d) near region (r): d_C=3, 4; d_E=1,2,5; d_G=6, 7; d_M=8; d_W=9
E(r)(u)INV	Capacity addition for this operating year for processing unit type (u) in region (r).
E(d)(u')INV	New capacity for renewables processing unit (u'=BDN,BDV,BDW,CET,CLE,CLZ) in region (d).
max	Maximum capital investment ($million) allowed over all refinery and regions. Set in subroutine CHGCESW.
$\max_r$	Maximum capital investment ($million) allowed in region (r). Set in rfinvest.txt.

A(r)MGTOT(s)

For each region (r) and each price step (s) on the import supply curves for conventional motor gasoline (both standard and blend component imports), account for the total and limit the total to an upper bound.

$$I(r)TRGT(s) = \sum_w I(r)SSE(w)(s) + \sum_w I(r)TRG(w)(s) \qquad \text{for all r; s=1,2,3}$$

I(r)TRGT(s) Total conventional motor gasoline imports, for each region (r) and each price step (s). An upper bound is set for each (r), (s) combination.

I(r)TRG(w)(s)	Conventional motor gasoline imports from world region (w), to each region (r), for each price step (s).
I(r)SSE(w)(s)	Conventional motor gasoline blend component import from world region (w), to each region (r), for each price step (s).

A@MTBPRD

The total MTBE and ETBE produced for gasoline blending must be less than a maximum.

$$\sum_r \left[H(r)ETXETB + H(r)ETXMTB\right] + \sum_r R(r)ETHMTB \leq \max$$

H(r)ETXMTB	MTBE produced from methanol at a merchant plant, for each region (r).
H(r)ETXETB	ETBE produced from ethanol at a merchant plant, for each region (r).
H(r)ETHMTB	MTBE produced from methanol at the refinery, for each region (r).
max	Upper limit on total MTBM and ETBE produced for gasoline blending in the U.S. (set to zero for *AEO2009*)

A@(ful)FU

The use of liquefied petroleum gas (LPG), "other" (OTH), resid (RES), and still gas (STG) as fuel in region (r) is bounded by either a maximum or minimum.

A@LPGFU: $$\sum_r \sum_{mod} R(r)FUM(mod) \leq \max$$ for *mod* related to LPG

A@OTHFU: $$\sum_r \sum_{mod} R(r)FUM(mod) \geq \min$$ for *mod* related to OTH

A@RESFU: $$\sum_r \sum_{mod} R(r)FUM(mod) \leq \max$$ for *mod* related to RES

A@STGFU: $$\sum_r \sum_{mod} R(r)FUM(mod) + \sum_r R(r)MARFLL \cdot A \geq \min$$ for *mod* related to STG

A	Ratio of still gas to crude processed at the marginal refinery in region (r).
R(r)FUM(mod)	Amount of fuel used in the fuel use module (FUM) in region (r) in operating mode (mod).
R(r)MARFLL)	Amount of fuel used in the marginal refinery in region (r).

A(r)NATDEN

Accounting row for total natural gasoline (NAT) transported from refinery regions (r) to various ethanol production regions.

$$\sum_{d_r} H(r)NATE(d_r) \qquad \text{FREE} \qquad \text{for all } r$$

H(r)NATE(d_r) Natural gasoline produced in region (r) used for denaturant in ethanol production.
d_r regions (d) associated with (r) for NAT: d_C=2,3,4,5,6,7,8; d_E=1,2,5; d_G=1,2,3,4,5,6,7,8; d_M=4,8,9; d_W=9

A(r)PRDIMP

The total product imports received directly by refining region (r = C, M) must be less than a maximum.

$$\sum_{pri}\sum_{w}\sum_{q} I(r)(pri)(w)(q) \le \max{}_r \qquad r = \text{C, M}$$

I(r)(p)(w)(q) Volume of imported product (pri) imported from world region (w) to refinery region (r) at cost (q).
$\max_r$ Maximum import level for region (r = C, M only), based on historical levels and growth rates

A@PRDIMP

The total product import volume is constrained by a maximum value.

$$\sum_{r}\sum_{pri}\sum_{w}\sum_{q} I(r)(pri)(w)(q) \le \max$$

I(r)(pri)(w)(q) Volume of product (pri) imported from world region (w) to refinery region (r) at cost (q=1,2,3).
max Maximum total level of all product imports (unconstrained for *AEO2009*).

A@UNFIMP

The total U.S. unfinished oil import volume is set equal to the sum of the individual unfinished oils imported into each refinery region.

$$T@UNFTOT = \sum_{r}\sum_{unf} I(r)(unf)TOT$$

T@UNFTOT Total volume of unfinished oil imports to the U.S.
I(r)(unf)TOT Volume of unfinished oil import by type, to refinery region (r).
B(r)(ist), H(r)(ist), G(r)(ist)
Balance each intermediate stream (ist) (at the refinery, merchant plant, gas plant) in each refinery region (r).

$$\sum_{unt}\sum_{\mathrm{mod}} A\cdot R(r)(unt)(\mathrm{mod}) + \sum_{ist'} T(r)(ist')(ist) + G(r)(ist)RFN + H(r)MPRF(ist) =$$
$$\sum_{unt}\sum_{\mathrm{mod}} A'\cdot R(r)(unt)(\mathrm{mod}) + \sum_{ist'} T(r)(ist)(ist') + H(r)RFMP(ist) + \sum_{prd} B(r)(prd)(ist)$$

R(r)(unt)(mod)	Manufacturing processing level in operating mode (mod) for process unit (unt) in refinery region (r).
T(r)(ist')(ist)	Volume of stream (ist') transferred into intermediate stream (ist) in refinery region (r).
H(r)RFMP(ist)	Volume of intermediate stream (ist) transferred from refinery to merchant plant in refinery region (r).
G(r)(ist)RFN	Volume of intermediate stream (ist) produced at and transferred from the gas plant to the refinery in refinery region (r).
B(r)(prd)(ist)	Volume of intermediate stream (ist) blended into product in refinery region (r).
A, A'	Volume fraction of intermediate stream (ist) created (or consumed) per manufacturing level and operating mode, in refinery region (r).

B(w)ARB

Equality row to balance the production of unfinished residual oil (ARB) with its destination (either for U.S. import or transfer to distillate), in world refinery region (w).

$$A\cdot R(w)MARIMC = R(w)ARBRES + R(w)IUPR2D1 \qquad \text{for all } w$$

R(w)MARIMC	Manufacturing processing level for the downstream processing in a non-U.S. refinery, in world region (w).
R(w)ARBRES	The quantity of unfinished oil (ARB) transferred to the foreign residual pool for U.S. import, from world region (w).
R(w)IUPR2D1	The quantity of unfinished oil (ARB) transferred to the foreign distillate pool for U.S. import, from world region (w).
A	Volume ratio of unfinished oil (ARB) created per manufacturing level of the world refinery, in world region (w).

B(w)ARC

Equality row to balance the production of unfinished residual oil (ARC) with its destination (U.S. import), in world refinery region (w).

$$A\cdot R(w)MARFLL = R(w)ARCRES \qquad \text{for all } w$$

R(w)MARFLL	Manufacturing processing level for the non-U.S. refinery unit, in world region (w).

R(w)ARCRES The quantity of unfinished oil (ARC) transferred to the foreign residual pool for U.S. import, from world region (w).

A Volume ratio of unfinished oil (ARC) created per manufacturing level of the world refinery, in world region (w).

C(o)(xxx)TOT (o=A; xxx = ALL, AMH, NSO)

Production of Alaska (o=A) crude oil (ALL, AMH, NSO) must equal exports through Valdez. See also: c(o)(crt) for o=A.

CAALLTOT: $TAALLTOT = A \cdot PADCRQ1$

CAAMHTOT: $TAAMHTOT = (1 - A) \cdot PADCRQ1$

CANSOTOT: $TAAMHXZ + YAAMH5W = TANSOTOT + 0.01 \cdot TAGTLTOT$

A Fraction of crude produced in Alaska that is type ALL.

(1- A) Fraction of crude produced in Alaska that is type AMH.

PADCRQ1 Total volume of crude produced in Alaska.

TAAMHXZ Volume of type AMH crude exported from Alaska to Valdez.

TAALLTOT Total volume of type ALL crude produced in Alaska.

TAGTLTOT Total GTL transported from Alaska North Slope to Valdez on Trans-Alaska pipeline.

TANSOTOT Total crude of type NSO transported from Alaska North Slope to Valdez on Trans-Alaska pipeline.

YAAMH5W Volume of medium sulfur heavy crude oil transferred from Alaska (o=A) to refinery region W (r=W) via transport mode 5.

C(o)(crt)

Balance the domestic production of each crude type (crt) at each producing region (o) against shipments to domestic refineries and exports. For non-Alaska U.S. crude oil production regions (o = 1 - 6), and Alaska crude production region (o=A).

$$\sum_{r}\sum_{m} Y(o)(crt)(m)(r) = A_{o,crt} \cdot P(o)DCRQ1 \quad \text{for all } o \neq A,\ crt = \text{DHH, DHL, DHV, DLL, DMH}$$

Y(r')(crt)(m)(r) Volume of crude type (crt) received into region (r) from region (r') via mode (m).

Y(r)(crt)(m)(r') Volume of crude type (crt) sent from region (r) to region (r') via mode (m).

P(o)DCRQ1 Volume of domestic crude produced in region (o).

$A_{o,crt}$ Fraction of domestic crude in region (o) classified as crude type (crt).

For Alaska crude oil production **(o = A)**

CAALL: $TAALTOT = YAALL5W$ (i.e., *o* = A, *crt* = ALL)

CAAMH: $TAAMHTOT + 0.01 \cdot TAGLTOT = TAAMHXZ + YAAMH5W$ (i.e., o = A, crt = AMH)

CZAMH: $TAAMHTOT = ZZAMHTOT$ (i.e., o = A, crt = AMH)

TAALLTOT	Volume of low sulfur light crude oil produced in Alaska (o=A).
YAALL5W	Volume of low sulfur light crude oil transferred from Alaska (o=A) to refinery region W (r=W) via transport mode 5.
TAAMHTOT	Volume of medium sulfur heavy crude oil produced in Alaska (o=A).
ZZAMHTOT	Volume of medium sulfur heavy crude oil produced in Alaska (o=A).
YAAMH5W	Volume of medium sulfur heavy crude oil transferred from Alaska (o=A) to refinery region W (r=W) via transport mode 5.
TAAMHXZ	Volume of medium sulfur heavy crude oil transferred from Alaska to Valdez.
TAGTLTOT	Volume of liquids produced from natural gas in Alaska; with the assumption that 1 percent of the volume is lost to the crude during transport.

C(r)(crt)

For each applicable combination of crude oil (crt) and region (r), the volume received directly from producing regions plus transshipments received from other regions must equal the volume consumed at the refinery plus transshipments sent to other regions plus crude processed at the marginal refinery. (Note: the marginal refinery processes only DLL and FLL crudes).

$$\sum_{Qs} P(r)(crt)(Qs) = R(r)ACU(crt) \qquad \text{for all } r; \qquad crt = \text{FHH, FHL, FHV, FMH}$$

$$\sum_{Qs} P(r)(crt)(Qs) = R(r)ACU(crt) + T(r)(crt)TLL \qquad \text{for all } r, \qquad crt = \text{FLL}$$

crt = DHH, DHV, DMH

$$\sum_{o} Y(o)(crt)(m)(r) + \sum_{r'} Y(r')(crt)(m)(r) = R(r)ACU(crt) + \sum_{r'} Y(r)(crt)(m)(r')$$

crt = DLL

$$\sum_{o} Y(o)(crt)(m)(r) + \sum_{r'} Y(r')(crt)(m)(r) = R(r)ACU(crt) + \sum_{r'} Y(r)(crt)(m)(r') + T(r)(crt)TLL$$

$$R(r)MARFLL = T(r)DLLTLL + T(r)FLLTLL \qquad crt = \text{TLL}$$

P(r)(crt)Q(q)	Volume of foreign crude type (crt) purchased in region (r) at price level (q).
R(r)ACU(crt)	Volume of crude type (crt) that enters the ACU (atmospheric crude unit) in region (r).
R(r)MARFLL	Volume of low sulfur light crude (foreign and domestic) that enters the marginal refinery (MAR) in region (r).
T(r)(crt)TLL	Low sulfur light crude (crt = DLL, FLL) sent to the marginal refinery for processing in region r.

Y(o)(crt)(m)(r)	Volume of crude type (crt) sent from crude region (o) to refinery region (r) via mode (m).

C(*)BIMIMP

The total volume of biodiesel from virgin oil (BIM) imported into region (d =7, 9) is equal to the volume imported at all price steps.

C(d)BIMIMP: $I\ @\ BIMM(d) = \sum_{Rs} I(d)BIM(Rs)$ for d=7,9

The total volume of BIM imported into regions 7 and 9 is equal to the total volume imported at all price steps.

C@BIMIMP: $I\ @\ BIMM7 + I\ @\ BIMM9 = \sum_{Rs} I\ @\ BIM(Rs)$

I@BIMM(d)	Total volume of biodiesel from virgin oil imported into region (d).
I(d)BIMMR(s)	Total volume of biodiesel from virgin oil available for import into region (d) at all price steps (s=1,5).
I@BIMMR(s)	Total volume of biodiesel from virgin oil available for import at all price steps (s=1,5).

C@BIOTOT

The total production of biodiesel from virgin oil (BIM) and non-virgin oil (BIN) plus production of green naphtha (a co-product of biodiesel) plus imports of biodiesel made from virgin oil must be greater than the minimum biodiesel schedule for the Renewable Fuels Standard (RFS) defined by the Energy Independence and Security Act 2007 (EISA2007).

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$$\sum_{d}\left[H(d)BIMTOT + H(d)BINTOT\right] + \sum_{r}\sum_{mgb}\sum_{nap} B(r)(mgb)(nap) + \sum_{r}\sum_{dis}\sum_{nap} F(r)(dis)(nap) + \sum_{d=7,9} I\ @\ BIMM(d) \geq \min$$

B(r)(mgb)(nap)	Total green naphtha (nap=GNN,GNV,GNW) blended into mgb (RFG, TRG) in region (r).
F(r)(dis)(nap)	Total green naphtha (nap=GDN,GDV,GDW) blended into distillate (dis=DSL,DSU, N2H) in region (r).
H(d)BIMTOT	Total biodiesel production from virgin oil in region (d).
H(d)BINTOT	Total biodiesel production from non-virgin oil in region (d).
I@BIMM(d)	Total imports of biodiesel made from virgin oil into region (d=7,9).
min	Minimum allowable volume of biodiesel and green naphtha co-product.

C(r)BTL(lqb)

Row to account for the individual liquid streams (lqb = BDX, BKE, BNL, BNP) produced by the BTL (biomass-to-liquid) process in each region (r). Note, each liquid stream is denoted by its first and last letter (BX, BE, BL, BP).

$$H(r)MPRF(xx) + H(r)MPWH(xx) \quad \text{FREE} \quad \text{for all } r;\ (xx) = \text{BX,BE,BL,BP}$$

H(r)MPRF(xx) Amount of liquid stream (xx) produced by the BTL process that is transferred to the refinery for further processing, in region (r).

H(r)MPWH(xx) Amount of liquid stream (xx) produced by the BTL process that is sent directly to market, in region (r).

C(r)BTLTOT

Row to account for the total liquid stream (lqb = BDX, BKE, BNL, BNP) produced by the BTL (biomass-to-liquid) process in each region (r). Note: each liquid stream is denoted by its first and last letter (BX, BE, BL, BP).

$$\sum_{xx}\left(H(r)MPRF(xx) + H(r)MPWH(xx)\right) \quad \text{FREE} \qquad \text{for all } r;\ (xx) = \text{BX,BE,BL,BP}$$

H(r)MPRF(xx) Amount of liquid stream (xx) produced by the BTL process that is transferred to the refinery for further processing, in region (r).

H(r)MPWH(xx) Amount of liquid stream (xx) produced by the BTL process that is sent directly to market, in region (r).

C@CLLBIO

The total advanced cellulosic biofuels must be greater than the minimum biodiesel schedule for the Renewable Fuels Standard (RFS) defined by the Energy Independence and Security Act 2007 (EISA2007). The constant coefficients are the credit ratings defined by the Act.

$$CUSCREDT$$

$$+\sum_{d}\left[H(d)CETADV + H(d)ETCTOT\right] + I@ETAC8 + I@ETCC2$$

$$+\sum_{d=2,5,7,9}\left[I@ETAM(d) + I@ETCM(d)\right]$$

$$+1.54\cdot\sum_{r}\sum_{mgb}\sum_{ist'} B(r)(mgb)(ist') \qquad ist' = \text{GNN, GNV, GNW}$$

$$+1.7\cdot\sum_{r}\sum_{dfo'}\sum_{ist'} F(r)(dfo')(ist') \qquad dfo' = \text{DSL, DSU, N2H};\ ist' = \text{GDN, GDV, GDW}$$

$$+1.5 \cdot \left[I@BIMM7 + I@BIMM9 + \sum_{d} \left[H(d)BIMTOT + H(d)BINTOT \right] \right]$$
$$+1.5 \cdot \sum_{r} \left[H(r)MPRFBE + H(r)MPRFBL + H(r)MPRFBP + H(r)MPRFBX \right]$$
$$+1.5 \cdot \sum_{r} \left[H(r)MPWHBE + H(r)MPWHPX \right]$$
$$\geq \min$$

CUSCREDT	Credit purchased to meet the minimum RFS requirement.
B(r)(mgb)(ist')	Volume of intermediate stream (ist'=GNN,GNV,GNW) blended into gasoline (mgb) in refinery region (r).
F(r)(dfo')(ist')	Volume of intermediate stream (ist'=GNN,GNV,GNW) blended into distillate (dfo'=DSL,DSU,N2H)) in refinery region (r).
H(d)BIMTOT	Total production of biodiesel from virgin oil in (d).
H(d)BINTOT	Total production of biodiesel from non-virgin oil in (d).
H(r)MPRF(xx)	Amount of liquid stream (xx) produced by the BTL process that is transferred to the refinery for further processing, in region (r).
H(r)MPWH(xx)	Amount of liquid stream (xx) produced by the BTL process that is sent directly to market, in region (r).
H(d)ETCTOT	Total cellulosic ethanol production in (d).
H(d)CETADV	Total advanced cellulosic ethanol production in (d).
I@BIMM(d)	Total imports of biodiesel made from virgin oil into (d=7,9).
I@ETCM(d)	Total imports of cellulosic ethanol from Brazil into region (d=2,5,7,9).
I@ETAM(d)	Total imports of advanced ethanol from Brazil into region (d=2,5,7,9).
I@ETCC(d)	Total imports of cellulosic ethanol from Canada into region (d=2).
I@ETAC(d)	Total imports of advanced ethanol from Canada into region (d=8).
min	RFS schedule for advanced biofuels as defined in EISA2007.

C@CLLTOT

The total cellulosic biomass must be greater than the minimum biomass schedule for the Renewable Fuels Standard (RFS) defined by the Energy Independence and Security Act 2007 (EISA2007). The constant coefficients are the credit ratings defined by the Act.

$$
\begin{aligned}
& CUSCREDT \\
& + \sum_{d} H(d)ETCTOT \\
& + \left[I@ETCC2 + I@ETCM2 + I@ETCM5 + I@ETCM7 + I@ETCM9 \right] \\
& + 1.5 \cdot \sum_{r} \left[H(r)MPRFBE + H(r)MPRFBL + H(r)MPRFBP + H(r)MPRFBX \right] \\
& + 1.5 \cdot \sum_{r} \left[H(r)MPWHBE + H(r)MPWHBX \right] \\
& \geq \min
\end{aligned}
$$

CUSCREDT	Credit purchased to meet the minimum RFS requirement.
H(r)MPRF(xx)	Amount of liquid stream (xx) produced by the BTL process that is transferred to the refinery for further processing, in region (r).
H(r)MPWH(xx)	Amount of liquid stream (xx) produced by the BTL process that is sent directly to market, in region (r).
H(d)ETCTOT	Total cellulosic ethanol production in (d).
I@ETCM(d)	Total imports of cellulosic ethanol from Brazil into region (d=2,5,7,9).
I@ETCC(d)	Total imports of cellulosic ethanol from Canada into region (d=2).
min	RFS schedule for advanced biofuels as defined in EISA2007.

C(r)CTL(lqc)

Row to account for the individual liquid streams (lqc = CDX, CKE, CNL, CNP) produced by the CTL (coal-to-liquid) process in each region (r). Note, each liquid stream is denoted by its first and last letter (CX, CE, CL, CP).

$$H(r)MPRF(xx) + H(r)MPWH(xx) \quad \text{FREE for all } r;\ (xx) = \text{CX,CE,CL,CP}$$

H(r)MPRF(xx)	Amount of liquid stream (xx) produced by the CTL process that is transferred to the refinery for further processing, in region (r).
H(r)MPWH(xx)	Amount of liquid stream (xx) produced by the CTL process that is sent directly to market, in region (r).

C(r)CTLTOT7

Row to account for the total liquid stream (lqc = CDX, CKE, CNL, CNP) produced by the CTL (coal-to-liquid) process in each region (r). Note: each liquid stream is denoted by its first and last letter (CX, CE, CL, CP).

$$\sum_{xx}\left(H(r)MPRF(xx)+H(r)MPWH(xx)\right) \quad \text{FREE} \qquad \text{for all } r;\ (xx) = \text{CX,CE,CL,CP}$$

H(r)MPRF(xx) Amount of liquid stream (xx) produced by the CTL process that is transferred to the refinery for further processing, in region (r).

H(r)MPWH(xx) Amount of liquid stream (xx) produced by the CTL process that is sent directly to market, in region (r).

C8ETACNI

The total volume of advanced ethanol imported from Canada into region (d =8) is equal to the total volume imported at all price steps.

$$I\ @\ ETAC8 = \sum_{Ns=N1}^{N5} I8ETA(Ns)$$

C@ETABRZ

The total volume of advanced ethanol imported from Brazil either directly to the U.S. or via the Caribbean Basin is equal to the total volume of imports at all price steps.

$$I\ @\ ETACBB + I\ @\ ETAUSB = \sum_{Rs} I\ @\ ETA(Rs)$$

C@ETACBI

The total volume of advanced ethanol imported from the Caribbean Basin is equal to the quantity from Brazil plus the quantity produced in the Caribbean.

$$I\ @\ ETACBB + I\ @\ ETACBD = I\ @\ ETACBI$$

C(*)ETAIMP

The total volume of advanced ethanol imported into region (d =2,5,7,9) is equal to the volume imported at all price steps.

C(d)ETAIMP: $I\ @\ ETAM(d) = \sum_{Rs} I(d)ETA(Rs)$ for d=2,5,7,9

I@ETAM(d) Total imports of advanced ethanol from Brazil into region (d=2,5,7,9).

I(d)ETA(Rs) Total volume of advanced ethanol available for import into region (d=2,5,7,9) at all price steps (s=1,5).

The total volume of advanced ethanol imported into all regions (d =2,5,7,9) is equal to the total volume imported at all price steps.

C@ETAIMP: $I\ @\ ETAUSB + I\ @\ ETACBI = \sum_{d=2,5,7,9} I\ @\ ETAM(d)$

I@ETAM(d)	Total imports of advanced ethanol from Brazil into region (d=2,5,7,9).
I@ETAUSB	Total imports of advanced ethanol directly from Brazil to the U.S.
I@ETACBI	Total imports of advanced ethanol directly from Brazil to the U.S. through the Caribbean Basin.

C(*)ETCIMP

The total volume of cellulosic ethanol imported into region (d =2,5,7,9) is equal to the volume imported at all price steps.

C(d)ETCIMP: $I\ @\ ETCM(d) = \sum_{Rs} I(d)ETC(Rs)$ for d=2,5,7,9

I@ETCM(d)	Total imports of cellulosic ethanol from Brazil into region (d=2,5,7,9)
I(d)ETC(Rs)	Total volume of cellulosic ethanol available for import into region (d=2,5,7,9) at all price steps (s=1,5).

The total volume of cellulosic ethanol imported into all regions (d =2,5,7,9) is equal to the total volume imported at all price steps.

C@ETCIMP: $I\ @\ ETCUSB + I\ @\ ETCCBI = \sum_{d=2,5,7,9} I\ @\ ETCM(d)$

I@ETCM(d)	Total imports of cellulosic ethanol from Brazil into region (d=2,5,7,9).
I@ETCUSB	Total imports of cellulosic ethanol directly from Brazil to the U.S.
I@ETCCBI	Total imports of cellulosic ethanol directly from Brazil to the U.S. through the Caribbean Basin.

C2ETCCNI

The total volume of cellulosic ethanol imported from Canada into region (d =2) is equal to the total volume imported at all price steps.

$$I\ @\ ETCC2 = \sum_{Ns=N1}^{N5} I2ETC(Ns)$$

C@ETCBRZ

The total volume of cellulosic ethanol imported from Brazil either directly to the U.S. or via the Caribbean Basin is equal to the total volume of imports at all price steps.

$$I\ @\ ETCCBB + I\ @\ ETCUSB = \sum_{Rs} I\ @\ ETC(Rs)$$

C@ETCCBI

The total volume of cellulosic ethanol imported from the Caribbean Basin is equal to the quantity from Brazil plus the quantity produced in the Caribbean.

$$I\ @\ ETCCBB + I\ @\ ETCCBD = I\ @\ ETCCBI$$

C@ETHBIO

The total volume of renewables (ETC, ETH, BIM, BIN) used in U.S. gasoline and diesel products, plus credit trading, must meet the minimum RFS (renewable fuel standard) requirement defined by the EISA2007.

$$
\begin{aligned}
&CUSCREDT \\
&-\sum_{s=1}^{5} D3ETHSX(s) - \sum_{s=1}^{5} D4ETHSX(s) \\
&+\sum_{d}\left[H(d)CETADV + H(d)ETCTOT + H(d)ETHTOT\right] \\
&+I\ @\ ETAC8 + \sum_{d=2,5,7,9}\left[I\ @\ ETAM(d) + I\ @\ ETCM(d)\right] \\
&+1.54\cdot\sum_{r}\left[B(r)RFGGNN + B(r)RFGGNV + B(r)RFGGNW\right] \\
&+1.54\cdot\sum_{r}\left[B(r)TRGGNN + B(r)TRGGNV + B(r)TRGGNW\right] \\
&+1.7\cdot\sum_{r}\left[F(r)DSLGDN + F(r)DSLGDV + F(r)DSLGDW\right] \\
&+1.7\cdot\sum_{r}\left[F(r)DSUGDN + F(r)DSUGDV + F(r)DSUGDW\right] \\
&+1.7\cdot\sum_{r}\left[F(r)N2HGDN + F(r)N2HGDV + F(r)N2HGDW\right] \\
&+1.5\cdot\sum_{d}\left[H(d)BIMTOT + H(d)BINTOT\right] \\
&+1.5\cdot\sum_{r}\left[H(r)MPRFBE + H(r)MPRFBL + H(r)MPRFBP + H(r)MPRFBX\right] \\
&+1.5\cdot\sum_{r}\left[H(r)MPWHBE + H(r)MPWHPX\right] \\
&+1.5\cdot\left[I\ @\ BIMM7 + I\ @\ BIMM9\right] \\
&\geq \min
\end{aligned}
$$

CUSCREDT	Credit purchased to meet the minimum RFS requirement.
B(r)(mgb)(ist')	Volume of intermediate stream (ist'=GNN,GNV,GNW) blended into gasoline (mgb) in refinery region (r).
F(r)(dfo')(ist')	Volume of intermediate stream (ist'=GNN,GNV,GNW) blended into distillate (dfo'=DSL,DSU,N2H)) in refinery region (r).
D(d)ETHSX(s)	Volume of corn ethanol exported from demand region (d).
H(d)BIMTOT	Total production of biodiesel from virgin oil in (d).
H(d)BINTOT	Total production of biodiesel from non-virgin oil in (d).
H(r)MPRF(xx)	Amount of liquid stream (xx) produced by the BTL process that is transferred to the refinery for further processing, in region (r).
H(r)MPWH(xx)	Amount of liquid stream (xx) produced by the BTL process that is sent directly to market, in region (r).
H(d)ETCTOT	Total cellulosic ethanol production in (d).
H(d)ETHTOT	Total corn ethanol production in (d).

H(d)CETADV	Total advanced cellulosic ethanol production in (d).
I@BIMM(d)	Total imports of biodiesel made from virgin oil into (d=7,9).
I@ETCM(d)	Total imports of cellulosic ethanol from Brazil into region (d=2,5,7,9).
I@ETAM(d)	Total imports of advanced ethanol from Brazil into region (d=2,5,7,9).
I@ETCC(d)	Total imports of cellulosic ethanol from Canada into region (d=2).
I@ETAC(d)	Total imports of advanced ethanol from Canada into region (d=8).
min	RFS schedule for advanced biofuels as defined in EISA2007.

C(r)GTL

The total volume of GTL transported from Alaska to region (r) via mode J (tanker) is equal to 0.99 fraction of the total production from process MPR at the GTL merchant plant in region (r). The production can be any of four liquid streams (lqg=SDX,SKE,SNL,SNP). In the constraint, each liquid stream is denoted by its first and last letter (xx=SX,SE,SL,SP).

$$WAGTLJ(r) = 0.99 \cdot \sum_{xx} H(r)MPRF(xx) \qquad \text{for all } r\text{, and } xx\text{=SE,SL,SF,SX}$$

H(r)MPRF(xx)	Production from process MPR in operating mode F(xx) (xx=SE, FSL, FSF, FSX) at the GTL merchant plant in region (r).
WAGTLJ(r)	Total volume of GTL transported from Alaska to region (r) via mode J (tanker).

C(r)GTL(lqg)

Row to account for the individual liquid streams (lqg = SDX, SKE, SNL, SNP) produced by the GTL (gas-to-liquid) process in Alaska for region (r). Note, each liquid stream is denoted by its first and last letter (SX, SE, SL, SP).

$$H(r)MPR(lqg) \qquad \text{FREE for all } r \text{ and } lqg$$

H(r)MPRF(lqg)	Volume of GTL liquid stream (lqg=SX,SE,SL,SP) produced for (r) and transferred from merchant plant to refinery.

CAGTLTOT

Row to account for the total liquid stream produced by the GTL (gas-to-liquids) process in Alaska. Note, each liquid stream (lqg) is denoted by its first and last letter (SX,SE,SL,SP).

$$TAGTLTOT = \sum_{i} H(r)MPRF(xx) \qquad \text{for } xx\text{=\{SE,SL,SF,SX\}}$$

TAGTLTOT	Total GTL transported from Alaska North Slope to Valdez via the trans-Alaska pipeline.
H(r)MPRF(xx)	Volume of GTL liquid stream (xx=SX,SE,SL,SP) produced for (r).

C(*)PLMIMP

Total palm oil (PLM) imports into region (d = 4, 9), and total palm imports into U.S..

C(d)PLMIMP: $I@PLMM(d) = \sum_{s} I(d)PLMR(s)$ for d = 4, 9

C@PLMIMP: $I@PLMM(4) + I@PLMM(9) = \sum_{s} I@PLMR(s)$

I@PLMM(d)	Total volume of palm oil (PLM) imported into region (d = 4, 9).
I(r)PLM(Rs)	Volume of palm oil (PLM) imported into region (d = 4, 9) at price step (Rs).
I@PLM(Rs)	Volume of palm oil (PLM) imported into the U.S. at price step (Rs).

CL(j)CTL

The total quantity of coal (col = BIT) transferred to region (r) from its associated coal-producing regions (j) for CTL production cannot exceed the sum of the coal quantity shipped to the coal supply distribution point.

$N(r)(col)N1 \leq \sum_{n} \sum_{k} CT(n)(j)(k)$ for *col* = BIT, and all *j*, and *r* where *j* is "associated" with *r*

N(r)(col)N1	Total quantity of coal type (col=BIT) transferred to region (r) from its associated coal demand regions (j).
CT(n)(j)(k)	Quantity of coal with characteristics (k) transferred from coal supply region (n) to coal demand region (j).

D(d)BIM

The quantity of virgin biodiesel produced, transferred, and imported into region (d) must equal the quantity of virgin biodiesel blended into recipes (i.e., biodiesel blend) and transferred from region (d). Currently, imports only occur for d=7,9, and transfers only originate in d'=3,4.

$$H(d)BIMTOT + \sum_{d'=3,4} W(d')BIMV(d) + I@BIMM(d) =$$

$$\sum_{p} X(d)BIM(p) \cdot A_p + \sum_{d=3,4} W(d)BIMV(d')$$

A_p	Volume fraction of virgin biodiesel in the biodiesel blend (p=DSL,DSU).

H(d)BIMTOT	Total volume of virgin biodiesel produced in region (d).
I@BIMM(d)	Total volume of virgin biodiesel imported into region (d=7,9 only) via mode M.
W(d')BIMV(d)	Total volume of virgin biodiesel transshipped from region (d'=3,4) to region (d) via mode V.
X(d)BIM(p)	Total volume of virgin biodiesel splash blended into product (p=DSL,DSU) at region (d).

D(d)BIN

The quantity of non-virgin biodiesel produced and transferred into region (d) must equal the quantity of non-virgin biodiesel blended into recipes (i.e., biodiesel blend) and transferred from region (d).

$$H(d)BINTOT + \sum_{d'=3,4} W(d')BINV(d) = \sum_{p} X(d)BIN(p) \cdot A_p$$

A_p	Volume fraction of non-virgin biodiesel in the biodiesel blend (p=DSL,DSU).
H(d)BINTOT	Total volume of non-virgin biodiesel produced in region (d).
W(d')BINV(d)	Total volume of non-virgin biodiesel transshipped from region (d'=3,4) to region (d) via mode V.
X(d)BIN(p)	Total volume of non-virgin biodiesel splash blended into product (p=DSL,DSU) in region (d).

D(d)ETA

The quantity of advanced ethanol produced and imported into region (d) must equal the quantity of advanced ethanol blended into recipes (i.e., TRG, TRH, RFG, RFH, and E85) in region (d). Currently, imports only occur from Brazil for d=2,5,7,9, and from Canada for d=8.

$$H(d)CETADV = \sum_{mgb} X(d)ETA(mgb) \cdot A_{mgb} \qquad \text{for } d = 1,3,4,6$$

$$H(d)CETADV + I@ETAM(d) = \sum_{mgb} X(d)ETA(mgb) \cdot A_{mgb} \qquad \text{for } d = 2,5,7,9$$

$$H(d)CETADV + I@ETAC(d) = \sum_{mgb} X(d)ETA(mgb) \cdot A_{mgb} \qquad \text{for } d = 8$$

A_{mgb}	Volume fraction of advanced ethanol in the gasoline blend (mgb=TRG,TRH,RFG,RFH).
H(d)CETADV	Total volume of advanced ethanol produced in region (d).
I@ETAM(d)	Total volume of advanced ethanol imported from Brazil into region (d=2,5,7,9 only) via mode M.
I@ETAC(d)	Total volume of advanced ethanol imported from Canada into region (d=8 only) via mode C.

X(d)ETA(mgb) Total volume of advanced ethanol splash blended into product (mgb=TRG,TRH,RFG,RFH,E85) in region (d).

D(d)ETC

The quantity of cellulosic ethanol produced and imported into region (d) must equal the quantity of cellulosic ethanol blended into recipes (i.e., TRG, TRH, RFG, RFH, and E85) in region (d). Currently, imports only occur from Brazil for d=2,5,7,9, and from Canada for d=2.

$$H(d)ETCTOT = \sum_{mgb} X(d)ETC(mgb) \cdot A_{mgb} \qquad \text{for } d = 1,3,4,6,8$$

$$H(d)ETCTOT + I@ETCM(d) = \sum_{mgb} X(d)ETC(mgb) \cdot A_{mgb} \qquad \text{for } d = 5,7,9$$

$$H(d)ETCTOT + I@ETCM(d) + I@ETCC(d) = \sum_{mgb} X(d)ETC(mgb) \cdot A_{mgb} \quad \text{for } d = 2$$

A_{mgb} Volume fraction of cellulosic ethanol in the gasoline blend (mgb=TRG,TRH,RFG,RFH).
H(d)ETCTOT Total volume of cellulosic ethanol produced in region (d).
I@ETCM(d) Total volume of cellulosic ethanol imported from Brazil into region (d=2,5,7,9 only) via mode M.
I@ETCC(d) Total volume of cellulosic ethanol imported from Canada into region (d=2 only) via mode C.
X(d)ETC(mgb) Total volume of cellulosic ethanol splash blended into product (mgb=TRG,TRH,RFG,RFH,E85) in region (d).

D(d)ETH

The quantity of corn ethanol produced and transferred into region (d) must equal the quantity of corn ethanol blended into recipes (i.e., biodiesel blend), exported, and transferred from region (d). Currently, corn ethanol is only exported from d=3,4.

$$H(d)ETHTOT + H(d)CETEXP + \sum_{d'=3,4} W(d')ETHM(d) = \sum_{mgb} X(d)ETH(mgb) \cdot A_{mgb} \quad \text{for } d \neq 3,4,$$

$$H(d)ETHTOT + H(d)CETEXP + \sum_{d'=3,4} W(d')ETHM(d) =$$

$$\sum_{d'=3,4} W(d)ETHM(d') + \sum_{mgb} X(d)ETH(mgb) \cdot A_{mgb} + \sum_{s} D(d)ETHSX(s) \qquad \text{for } d = 3,4$$

A_{mgb} Volume fraction of corn ethanol in the gasoline blend (mgb=TRG,TRH,RFG,RFH).

H(d)ETCTOT Total volume of corn ethanol produced that is included in the total RFS (EISA2007) in region (d).

H(d)CETEXP Total volume of corn ethanol produced in region (d) that is not included in the total RFS (EISA2007). This includes volumes produced for export from region (d).

W(d')ETHM(d) Total volume of corn ethanol transshipped from region (d'=3,4) to region (d) via mode M.

D(d)ETHSX(s) Total volume of corn ethanol exported from region (d=3,4 only) at price levels (s).

X(d)ETC(mgb) Total volume of corn ethanol splash blended into product (mgb=TRG,TRH,RFG,RFH,E85) in region (d).

D(d)MET

The quantity of methanol transferred into region (d) must equal the quantity of methanol blended into recipes (i.e., M85) and consumed during the production of biodiesel in region (d).

$$I(d)METZ9 + W(r_d)METX(d) = 0.85 \cdot X(d)METM85 + \sum_{p'}\sum_{\text{mod}} H(d)(p')(\text{mod}) \cdot A_{p\,\text{mod}}$$

For $r_1 = E$, $r_2 = E$, $r_3 = C$, $r_4 = C$, $r_5 = G$, $r_6 = G$, $r_7 = G$, $r_8 = E$, $r_9 = W$
and (p')(mod) = {BDNYGR, BDVSBO, BDWWGR}

$A_{p'mod}$ Volume ratio of methanol used per unit volume of biodiesel (p') produced from for operating mode (mod). Note: (p'mod = BDNYGR, BDVSBO, BDWWGR).

H(d)METM85 Total M85 produced from splash blended methanol and motor gasoline in region (d).

H(d)(p')(mod) Volume of biodiesel (p') produced from operating mode (mod) -- used with $A_{p'mod}$ to define methanol consumed to produce biodiesel in region (d).

I(d)METZ9 Distress imports of methanol into region (d).

W(r_d)METX(d) Methanol transported from nearby region (r_d) to region (d).
($r_1 = E$, $r_2 = E$, $r_3 = C$, $r_4 = C$, $r_5 = G$, $r_6 = G$, $r_7 = G$, $r_8 = E$, $r_9 = W$)

D@MET

The total methanol consumed by the U.S. chemical industry must equal the sum of the amount consumed in each region (d) plus the amount of distress methanol imported into region (d).

$$D@METS1 = \sum_{r} G(r)METDEM + \sum_{d} I(d)METZ9$$

D@METS1 Total methanol demanded by the U.S. chemical industry (an input).

G(r)METDEM Methanol production in region (r) that is used by the U.S. chemical industry.

I(d)METZ9 Distress methanol imports to region (d).

D(d)(prd)

(for prd = E85, M85)

The volume of E85 and M85 sold in each region (d) is equal to the volume distress imported plus the volume splash blended at the demand terminals.

D(d)E85: $$D(d)E85TBL = I(d)E85Z9 + \sum_{h=ETH,ETC,ETA} X(d)(h)E85 \quad \text{for all } d$$

D(d)M85: $$D(d)M85S1 = I(d)M85Z9 + X(d)METM85 \quad \text{for all } d$$

D(d)E85TBL	Volume of recipe product E85 sold in region (d).
D(d)M85S1	Volume of recipe product M85 sold in region (d).
I(d)(prd)Z9	Volume of recipe product (prd=E85, M85) distress imports into region (d).
X(d)(h)(prd)	Volume of recipe product (prd=E85,M85) made in region (d) by splash blending component *(h)* into gasoline. For prd=E85, h=ETH,ETC,ETA (corn, cellulosic, advanced ethanol). For prd=M85, (h=MET= (methanol).

(for prd = TRG, RFG, TRH, RFH)

For each (d) and product (prd = TRG,RFG,TRH,RFH), domestic transshipment receipts plus the splash blended amount manufactured plus distress imports must equal the volume blended into recipes (prd=TRG only) plus domestic and export (prd=TRG only) sales volume plus distress exports.

D(d)(prd): for all *d, prd=RFG,TRH,RFH*

$$I(d)(prd)Z9 + \sum_r \sum_m W(r)(prd)(m)(d) + \sum_h X(d)(h)(prd) =$$
$$D(d)(prd)S1 + D(d)(prd)Z9$$

D(d)TRG:

$$I(d)(prd)Z9 + \sum_r \sum_m W(r)(prd)(m)(d) + \sum_h X(d)(h)(prd) =$$
$$\sum_{p'} \sum_h X(d)METM85 \cdot A_p + D(d)(prd)SX + D(d)(prd)S1 + D(d)(prd)Z9$$

A_p	Volume fraction of product (p) used to make one unit of recipe product (METM85).
I(d)(prd)Z9	Distress imports of product (prd) into region (d).
D(d)(prd)Z9	Distress exports of product (prd) from region (d).
D(d)(prd)SX	Export volume of product (prd=TRG) from region (d).
D(d)(prd)S1	Volume of product (prd) sold in region (d).
W(r)(prd)(m)(d)	Domestic transshipments of product (prd) from region (r) to region (d) via mode (m)
X(d)(h)(prd)	Volume of recipe product (prd) made at region (d) by splash blending component (h).

X(d)METM85	Volume of recipe product M85 produced in region (d) -- used with A_p to define (prd=TRG) consumed to produce M85.

(for prd = DSU,DSL)

For each (d) and product (prd = DSU,DSL, prd_s=SSU,SSL), domestic transshipment receipts from refinery production must equal the volume blended into recipes (biodiesel blends) plus domestic unblended volumes intended for sale.

D(r)(prd$_s$): for all d, prd_s=SSU,SSL (linked to DSU,DSL)

$$\sum_r \sum_m W(r)(prd)(m)(d) = \sum_{prd} \sum_{h=BIM,BINh} X(d)(h)(prd) \cdot A_p + J(d)(prd)(prd)$$

For each (d) and product (prd = DSU,DSL), domestically produced unblended diesel plus recipe biodiesel blends plus distress imports of diesel must equal domestic and export sales volume plus distress exports.

D(r)(prd): for all d, prd=DSU,DSL, linked to SSU,SSL

$$I(d)(prd)Z9 + J(d)(prd)(prd) + \sum_h X(d)(h)(prd) =$$
$$D(d)(prd)S1 + D(d)(prd)SX + D(d)(prd)Z9$$

A_p	Volume fraction of product (p=DSU,DSL) used to make one unit of recipe product (biodiesel blend).
I(d)(prd)Z9	Distress imports of product (prd) into region (d).
D(d)(prd)Z9	Distress exports of product (prd) from region (d).
D(d)(prd)SX	Export volume of product (prd) from region (d).
D(d)(prd)S1	Volume of product (prd) sold in region (d).
W(r)(prd)(m)(d)	Domestic transshipments of product (prd) from region (r) to region (d) via mode (m)
X(d)(h)(prd)	Volume of recipe product (prd) made at region (d) by splash blending component (h=BIM,BIN).
J(d)(prd)(prd)	Volume of domestically produced diesel not splash-blended with biodiesel in region (d).

(for all other prd =AST,COK,FLG,JTA,LPG,N2H,N67,N68,N6I,N6B,OTH,PCF)

For each (d) and product (prd), domestic transshipment receipts plus distress imports must equal domestic and export sales volume plus distress exports.

D(d)(prd): for all *d, prd=all other products*

$$I(d)(prd)Z9 + \sum_r \sum_m W(r)(prd)(m)(d) =$$
$$D(d)(prd)SX + D(d)(prd)S1 + D(d)(prd)Z9$$

I(d)(prd)Z9 Distress imports of product (prd) into region (d).
D(d)(prd)Z9 Distress exports of product (prd) from region (d).
D(d)(prd)SX Export volume of product (prd) from region (d).
D(d)(prd)S1 Volume of product (prd) sold in region (d).
W(r)(prd)(m)(d) Domestic transshipments of product (prd) from region (r) to region (d) via mode (m)

D(d)(Ss)

Calculate the volume of sub-spec products (SSR, SST, SSE) used in region (d). These sub-spec products are blended with ethanol (eth = ETA, ETC, ETH) at varying proportions to produce the following finished gasoline products: E85, RFG, RFH, TRG, TRH.

$$\textbf{D(d)SSE}: \sum_{r_d}\sum_{m} W(r_d)SSE(m)(d) = 0.26 \cdot \sum_{eth} X(d)(eth)E85 + 0.90 \cdot \sum_{eth} X(d)(eth)TRG \quad \text{for all } d$$

$$\textbf{D(d)SSR}: \sum_{r_d}\sum_{m} W(r_d)SSR(m)(d) = 0.942 \cdot \sum_{eth} X(d)(eth)RFH + 0.90 \cdot \sum_{eth} X(d)(eth)RFG \quad \text{for all } d$$

$$\textbf{D(d)SST}: \sum_{r_d}\sum_{m} W(r_d)SST(m)(d) = 0.90 \cdot \sum_{eth} X(d)(eth)TRH \quad \text{for all } d$$

W(r_d)*(prd)(m)(d)* Domestic transshipments of blend component (prd=SSE,SSR,SST) from region (r_d) to region (d) via mode (m).
X(d)(h)(prd) Volume of recipe product (prd) made at region (d) by splash blending component (h=ETH,ETC,ETA) to produce products (E85,RFG,RFH,TRG,TRH).

D(d)PRDEQU

Balance row to ensure total E85 plus motor gasoline (mgb=RFG,RFH,TRG,TRH) demand (D_d) is met via any quantity distribution of each in (d)

$$1.43813 \cdot \sum_{Sqq} D(d)E85(Sqq) + 1.85479 \cdot \sum_{mgb} D(d)(mgb)TBL = \mathrm{D}_d \quad \text{for all } d$$

D_d Total demand for E85 and motor gasoline (RFG,RFH,TRG,TRH) in region(d).
D(d)(mgb)TBL Demand for motor gasoline (mgb=RFG,RFH,TRG,TRH) into region (d).
D(d)E85(Sqq) Demand curve for E85 represented with price steps Sqq (qq=01-56) into region (d).

D(d)(prd)CRV (prd = mgb + E85)

Balance row to set motor gasoline demand (prd=mgb + E85) volumes to an accounting variable in each (d).

D(d)E85CRV: $D(d)E85TBL = \sum_{Sqq=S01}^{S55} D(d)E85(Sqq)$ for all *d*

D(d)(mgb)CRV: $D(d)(mgb)TBL = D(d)(mgb)S1$ for all *d, mgb*

D(d)(mgb)TBL Demand for motor gasoline (mgb=RFG,RFH,TRG,TRH,E85) into region (d).

D(d)E85(Sqq) Demand curve for E85 represented with price steps Sqq (qq=01-56) into region (d).

D(d)(mgb)FRC (mgb ≠ TRG)

Balance row to maintain the original motor gasoline (mgb only) market share in each region (d) as motor gasoline and E85 trade market shares (as allowed by row D(d)PRDEQU above).

D(d)(mgb)FRC: $A \cdot D(d)(mgb)TBL = \sum_{mgb' \neq mgb} A' \cdot D(d)(mgb')TBL$ for all *d, mgb=TRH,RFH,RFGy*

A and A' Define the ratio of the relative shares between *mgb* and *mgb'* in region (d).

D(d)(mgb)TBL Demand for motor gasoline (mgb=RFG,RFH,TRG,TRH,E85) into region (d).

D(w)(xxx)

For each world region (w) and product (xxx), international transshipment receipts plus distress supply must equal local world demand (represented by a demand curve) plus world distress exports.

$$P(w)(x)TMP + \sum_{w'} W(w')(x)X(w) = \sum_{s=S01}^{S09} D(w)(x)(s) + P(w)(x)DEX$$ for all *w, x≠LPG*

$$P(w)(x)TMP + \sum_{w'} W(w')(x)X(w) + W(w)NGL(x) = \sum_{s=S01}^{S09} D(w)(x)(s) + P(w)(x)DEX$$

for all *w, x=LPG*

P(w)(x)TMP World distress imports of product (x) into region (w).

P(w)(x)DEX World distress exports of product (x) from region (w).

D(w)(x)(s) Volume of product (x) sold in region (w) on price step (s=S01-S09).

W(w')(x)X(w) World transshipments of product (x) from region (w') to region (w) via mode (X).

DOMDDGMK

The total distiller dry grain (DDG) by-product produced from corn ethanol production in the U.S. must be less than a maximum value.

$$\sum_{d} H(d)DDGTOT \leq \max$$

H(d)DDGTOT	Total DDG by-product produced from corn ethanol production in (d).
max	Maximum allowable DDG by-product.

E@BTLMBX

Calculate total BTL investment.

$$E@BTLINV = \sum_{r} \left[E(r)BTLINV + L(r)BTLBLD + A \cdot K(r)BTLCAP \right]$$

A	Coefficient
E@BTLINV	Total U.S. BTL operating capacity allowed to be built in a single year (subject to an upper bound based on the Mansfield-Blackman penetration algorithm, see Appendix F).
E(r)BTLINV	Stream day capacity added during this simulated period in region (r).
K(r)BTLCAP	Base processing capacity at region (r). Subject to an upper bound.
L(r)BTLBLD	Cumulative stream day capacity added for processing unit at region (r) during the previous simulated periods. This variable is fixed.

E@CTXMBX

Tally the number of coal-to-liquids (CTL) facilities that have penetrated the market in a single year.

$$E@CTXINV = \sum_{r} \sum_{i=CTX,CTZ} \left[E(r)(i)INV + K(r)(i)CAP + L(r)(i)BLD \right]$$

E@CTXINV	Total U.S. CTL operating capacity allowed to be built in a single year (subject to an upper bound based on the Mansfield-Blackman penetration algorithm, see Appendix F).
E(r)(u)INV	Stream day capacity added during this simulated period for processing unit type (u = CTX, CTZ) in region (r).
K(r)(u)CAP	Base processing capacity in processing unit (u = CTX, CTZ) at region (r). Subject to an upper bound.
L(r)(u)BLD	Cumulative stream day capacity added for processing unit (u = CTX, CTZ) at region (r) during the previous simulated periods. This variable is fixed.

E@CTZEPC

The number of CTL units (converted to volumetric flow) that can be built under the EPACT2005 gasifier credit ruling is subject to an upper bound.

$$\sum_r \left[K(r)CTZCAP + L(r)CTZBLD + E(r)CTZINV \right] \leq \max$$

E(r)CTZINV	Stream day capacity added during the current year for processing unit CTZ in region (r).
K(r)CTZCAP	Base operating capacity of processing unit CTZ in region. Subject to an upper bound.
L(r)CTZBLD	Cumulative stream day capacity added during previous years for processing unit CTZ in region (r). This variable is fixed.
max	Maximum CTL capacity eligible for EPACT2005 credit (CTLMAXEPACT).

E(r)(emu)(e)

Tally the emissions source (e = carbon (CAR), carbon monoxide (CO1), carbon dioxide (CO2), nitrogen oxides (NOX) sulfur oxides (SOX), and volatile organic compounds (VOC) in region (r). These accounting rows are unconstrained.

E(r)CARC

65.4 R(r)FUMC2E + 65.4 R(r)FUMCC3 + 65.4 R(r)FUMIC4
\+ 75.5 R(r)FUMN2H + 81.9 R(r)FUMN6B + 81.9 R(r)FUMN6I
\+ 65.4 R(r)FUMNC4 + 55.1 R(r)FUMNGS + 55.1 R(r)FUMPGS
\+ 65.4 R(r)FUMRC3 + 65.4 R(r)FUMRI4 + 65.4 R(r)FUMRN4
\+ 65.4 R(r)FUMUC3 + 65.4 R(r)FUMUC4

E(r)CARN

5.9 K(r)FCCCAP + 1.6 K(r)VBRCAP

E(r)CO1N

13.7 K(r)FCCCAP + 3.8 K(r)VBRCAP

E(r)CO2C

239.4 R(r)FUMC2E + 239.4 R(r)FUMCC3 + 239.4 R(r)FUMIC4
\+ 277 R(r)FUMN2H + 300 R(r)FUMN6B + 300 R(r)FUMN6I
\+ 239.4 R(r)FUMNC4 + 201.7 R(r)FUMNGS + 201.7 R(r)FUMPGS
\+ 239.4 R(r)FUMRC3 + 239.4 R(r)FUMRI4 + 239.4 R(r)FUMRN4

+ 239.4 R(r)FUMUC3 + 239.4 R(r)FUMUC4

E(r)NOXC
0.8978 R(r)FUMC2E + 0.8924 R(r)FUMCC3 + 0.8225 R(r)FUMIC4
+ 2.31 R(r)FUMN2H + 2.31 R(r)FUMN6B + 2.31 R(r)FUMN6I
+ 0.7903 R(r)FUMNC4 + 0.8642 R(r)FUMNGS + 0.8642 R(r)FUMPGS
+ 0.8924 R(r)FUMRC3 + 0.8225 R(r)FUMRI4 + 0.7903 R(r)FUMRN4
+ 0.8978 R(r)FUMUC3 + 0.8064 R(r)FUMUC4

E(r)NOXN
0.071 K(r)FCCCAP + 0.005 K(r)VBRCAP

E(r)SOXC
6.06 R(r)FUMC2E + 6.03 R(r)FUMCC3 + 5.56 R(r)FUMIC4
+ 1.67 R(r)FUMN2H + 6.678 R(r)FUMN6B + 6.678 R(r)FUMN6I
+ 5.34 R(r)FUMNC4 + 0.0037 R(r)FUMNGS + 5.864 R(r)FUMPGS
+ 6.03 R(r)FUMRC3 + 5.56 R(r)FUMRI4 + 5.34 R(r)FUMRN4
+ 6.06 R(r)FUMUC3 + 5.45 R(r)FUMUC4

E(r)SOXN
0.493 K(r)FCCCAP + 0.06 K(r)VBRCAP

E(r)VOCC
0.0182 R(r)FUMC2E + 0.0181 R(r)FUMCC3 + 0.0167 R(r)FUMIC4
+ 0.0126 R(r)FUMN2H + 0.0126 R(r)FUMN6B + 0.0126 R(r)FUMN6I
+ 0.0161 R(r)FUMNC4 + 0.0173 R(r)FUMNGS + 0.0173 R(r)FUMPGS
+ 0.0181 R(r)FUMRC3 + 0.0167 R(r)FUMRI4 + 0.0161 R(r)FUMRN4
+ 0.0182 R(r)FUMUC3 + 0.0164 R(r)FUMUC4

E(r)VOCN
0.1408 K(r)FCCCAP + 0.016 K(r)KRFCAP + 0.0557 K(r)VBRCAP + 0.05 K(r)VCUCAP

F@TOTCRD

The total volume of unfinished oil processed in U.S. refineries must be less than some linear function of the total amount of crude oil processed.

$$B1 \cdot T\ @\ UNFTOT \leq B2 + \sum_{r}\sum_{v}\sum_{c} R(r)ACU(v)(c) + \sum_{r} R(r)MARFLL$$

B1	Regression coefficient.
B2	Regression coefficient.
T@UNFTOT	Total volume of unfinished oil processed at U.S. refineries.
R(r)ACU(v)(c)	Total volume of crude oil processed in region (r).
R(r)MARFLL	Total volume of crude oil processed at the marginal refinery in region (r).

G(r)CC1

Calculate the volume of dry gas residue (DGR) exiting the natural gas plant in region (r).

$$G(r)DGR = \mathrm{FAC}_{\mathrm{r}} \cdot N(r)DGP + \mathrm{S}_{\mathrm{C2}}^{\mathrm{C1}} \cdot G(r)SC2CC1 + \mathrm{S}_{\mathrm{C3}}^{\mathrm{C1}} \cdot G(r)SC3CC1$$

$\mathrm{FAC}_{\mathrm{r}}$	This parameter specifies the ratio of methane extracted at the Gas Plant in region (r) to the total volume of dry natural gas marketed in region (r). The ratio can be greater than 1.0 if a large percentage of the natural gas produced is re-injected into the ground rather than being marketed. $\mathrm{FAC}_{\mathrm{r}}$ is specified in table GASCAP in file nrfplant.dat.
G(r)DGR	Volume of methane (bcf/day) exiting the Gas Plant.
G(r)SC2CC1	Volume of rejected ethane (Mbfoe/day) remaining in the outgoing methane stream.
G(r)SC3CC1	Volume of rejected propane (Mbfoe/day) remaining in the outgoing methane stream.
N(r)DGP	Volume of dry natural gas (bcf/day) marketed in region (r). Approximately equal to PRNG_PADD(r), passed to PMM from NGTDM.
$\mathrm{S}_{\mathrm{C2}}^{\mathrm{C1}}$	(bcf/bfoe for C2) = 0.0017. This parameter is specified in table GASSHFT in file nrfplant.dat
$\mathrm{S}_{\mathrm{C3}}^{\mathrm{C1}}$	(bcf/bbl for C3) = 0.0015. This parameter is specified in table GASSHFT in file nrfplant.dat

G(r)CC3

Propane extracted at the Gas Plant (or received from the merchant plant, MPGPC3) is blended into LPG (CC3LPG). SC3CC1 accounts for any propane that was not extracted from the incoming gas stream due to propane rejection.

$$\mathrm{T}_{\mathrm{r}}^{\mathrm{CC3}} \cdot G(r)GPL01 + H(r)MPGPC3 = G(r)CC3LPG + G(r)SC3CC1 \quad \text{for all } r$$

G(r)CC2CC3TOT

See “G(r) ethane/propane rejection”.

G(r)DGP

$$G(r)GPL01 = \mathrm{DGP}_{\mathrm{r}} \cdot G(r)DGR$$

$\mathrm{DGP}_{\mathrm{r}}$	A parameter > 1.00. For every unit volume of methane that is extracted at the Gas Plant, $\mathrm{DGP}_{\mathrm{r}}$ volume of (methane + NGLs) enters the Gas Plant. $\mathrm{DGP}_{\mathrm{r}}$ is specified in table GSPLT in file nrfplant.dat.
G(r)DGR	Volume of methane (bcf/day) exiting the Gas Plant.
G(r)GPL01	Volume of natural gas (bcf/day) that enters the Gas Plant in region (r).

G(r)IC4

Iso-butane extracted at the Gas Plant is either blended into LPG (IC4LPG), used in the refinery (IC4RFN), or sent to the merchant plant (GPMI4).

$$\mathrm{T}_{\mathrm{r}}^{\mathrm{IC4}} \cdot G(r)GPL01 = G(r)IC4LPG + G(r)IC4RFN + H(r)GPMPI4 \quad \text{for all } r$$

G(r)NAT

Natural gasoline (pentanes plus) extracted at the Gas Plant is either used as petrochemical feedstock (NATPCF), used in the refinery (NATRFN), used as a denaturant (NATE) in an ethanol plant, or put to some other use (NATOTH).

$$\mathrm{T}_{\mathrm{r}}^{\mathrm{NAT}} \cdot G(r)GPL01 = G(r)NATPCF + G(r)NATRFN + \sum_{d} H(r)NATE(d) + G(r)NATOTH \quad \text{for all } r$$

G(r)NC4

Normal butane extracted at the Gas Plant is either blended into LPG (NC4LPG), used in the refinery (NC4RFN), or sent to the merchant plant (GPMN4).

$$\mathrm{T}_r^{NC4} \cdot G(r)GPL01 = G(r)NC4LPG + G(r)NC4RFN + H(r)GPMPN4 \qquad \text{for all } r$$

G(r)OVC

Calculate combined variable costs at the gas plant *and* at the methanol plant in (r).

$$T(r)GPLOVC = A \cdot G(r)DGR + B \cdot G(r)MOH01 \qquad \text{for all } r$$

A	Variable cost per unit of dry gas exiting the Gas Plant.
B	Variable cost per unit of methanol produced at the methanol plant.
G(r)DGR	Volume of dry gas exiting the Gas Plant.
G(r)MOH01	Volume of methanol produced at the methanol plant.
T(r)GPLOVC	Gas plant operating costs in region (r).

G(r)PGS

$$\mathrm{T}_r^{PGS} \cdot G(r)GPL01 + H(r)MPGPPS = G(r)PGSFLG + G(r)PGSLPG + G(r)SC2CC1 \qquad \text{for all } r$$

G(r)PGSLGX

At most 25% of the ethane in the incoming gas stream can be used as LPG.

$$G(r)PGSLPG \leq 0.25 \cdot \mathrm{T}_r^{PGS} \cdot G(r)GPL01 \qquad \text{for all } r$$

G(r)SC2C1X

See “G(r) ethane/propane rejection”

G(r)SC2SC3TOT

See “G(r) ethane/propane rejection”.

G(r)SCCCC1X

See “G(r) ethane/propane rejection”.

G(r) ethane/propane rejection

G(r)SC2C1X: $G(r)SC2CC1 \leq 0.15 \cdot \mathrm{T}_{\mathrm{r}}^{\mathrm{PGS}} \cdot G(r)GPL01$ for all r

G(r)CC2CC3TOT: $G(r)CC2CC3 = \left[\mathrm{T}_{\mathrm{r}}^{\mathrm{PGS}} + \mathrm{T}_{\mathrm{r}}^{\mathrm{CC3}} \cdot \left(\mathrm{S}_{\mathrm{C3}}^{\mathrm{C1}} / \mathrm{S}_{\mathrm{C2}}^{\mathrm{C1}} \right) \right] \cdot G(r)GPL01$ for all r

G(r)SC2SC3TOT: $G(r)SC2SC3 = G(r)SC2CC1 + \left(\mathrm{S}_{\mathrm{C3}}^{\mathrm{C1}} / \mathrm{S}_{\mathrm{C2}}^{\mathrm{C1}} \right) \cdot G(r)SC3CC1$ for all r

G(r)SCCC1X: $G(r)SC2SC3 \leq \mathrm{T}_{\mathrm{r}}^{\mathrm{LIM}} \cdot G(r)CC2CC3$ for all r

G(r)CC2CC3 Total amount of (ethane + propane) in the stream entering the Gas Plant, in Mbfoe/day.

G(r)SC2SC3 Total amount of (ethane + propane) rejected, in Mbfoe/day.

$\mathrm{S}_{\mathrm{C3}}^{\mathrm{C1}} / \mathrm{S}_{\mathrm{C2}}^{\mathrm{C1}}$ Converts C3 units from (Mbbl/day) to (Mbfoe/day).

$\mathrm{T}_{\mathrm{r}}^{\mathrm{LIM}}$ Maximum fraction of (ethane + propane) that can be rejected. This parameter (0.04) is specified in table GASCAP in file nrfplant.dat

H(d)DEN

The total volume of denaturant required in region (d), whether NAT (natural gasoline) from the Gas Plant or SSE, must equal 4.5% of the volume of ethanol produced in region (d).

$$\sum_{r_d} \left[H(r_d)NATE1 + H(r_d)SSE1 \right] = \qquad \text{for all } d$$

$$0.045 \cdot \left[H(d)CLELIG + H(d)CLZLIG + \sum_{mod} H(d)CET(mod) \right]$$

H(d)(cp)

For each region (d), the total volume of co-product (GLY, DDG, EDG, WMC) associated with corn ethanol (DDG, EDG, WMC) or biodiesel (GLY) production equals the sum of co-product production from each operating mode (processing unit and feedstock).

for all d

H(d)GLY: $H(d)GLYTOT = 0.96 \cdot \left(H(d)BDNYGR + H(d)BDVSBO + H(d)BDWWGR\right)$

for all d

H(d)DDG:
$$H(d)DDGTOT + H(d)EDGTOT = 0.1352 \cdot H(d)CETDM1 + 0.1275 \cdot H(d)CETDM2 + 0.1428 \cdot H(d)CETDME$$

H(d)WMC: $H(d)WMCTOT = 0.1085 \cdot H(d)CETWME$ for all d

H(d)(cp)TOT Total volume of co-product (cp = GLY, DDG, EDG, WMC) produced per unit volume of corn ethanol or biodiesel made in region (d).

H(d)(uns)(fff) Total volume of corn ethanol or biodiesel produced in region (d) using process (uns) and feedstock (fff), where (u)(fff) = BDNYGR, BDVSBO, BDWWGR, CETDM1, CETDM2, CETDME, CETWME.

H(d)(fff) (fff = BIO,CRN,SBO,WGY,YGR)

Calculate requirement for feedstock (fff).

H(d)BIO: $X(d)BIOTE + A \cdot \left(H(d)CLELIG + H(d)CLZLIG\right) = \sum_{Rs} C(d)BIO(Rs)$ for all d

H(d)CRN: $\sum_{mod} A_{mod} \cdot H(d)CET(mod) = \sum_{Rs} C(d)CRN(Rs)$ for all d

H(d)SBO: $X(d)SBO + A \cdot H(d)BDVSBO = \sum_{Rqq=R01}^{R99} C(d)SBO(Rqq)$ for all d

H(d)WGR: $X(d)WGRTE + A \cdot H(d)BDWWGR = \sum_{Rs} C(d)WGR(Rs)$ for all d

H(d)YGR: $X(d)YGRTE + A \cdot H(d)BDNYGR = \sum_{Rs} C(d)YGR(Rs)$ for all d

H(d)(mod)

Calculate usage of each processing mode.

H(d)BDN: $H(d)BDNTOT = H(d)BDNYGR$ for all d

H(d)BDV: $H(d)BDVTOT = H(d)BDVSBO$ for all d

H(d)BDW: $H(d)BDWTOT = H(d)BDWWGR$ for all d

H(d)WMC: $H(d)WMCTOT = 0.1085 \cdot H(d)CETWME$ for all d

H(d)(ren) (for ren = BIM, BIN, ETC, ETH)

For each region (d), the total production of virgin (BIM) and non-virgin (BIM) biodiesel equals the sum of the production from each operating mode (processing unit and feedstock).

H(d)BIM: $H(d)BIMTOT = H(d)BDVSBO + H(d)BDWWGR$ for all d

H(d)BIN: $H(d)BINTOT = H(d)BDNYGR$ for all d

H(d)BIMTOT	Total production of biodiesel from virgin oil in region (d).
H(d)BIMTOT	Total production of biodiesel from non-virgin oil in region (d).
H(d)(u)(f)	Total volume of corn ethanol produced in region (d) using process (u) and feedstock (f), where (u)(f) = BDVSBO, BDWWGR, BDNYGR.

For each region (d), the total production of ethanol equals the sum of ethanol production from each operating mode (processing unit and feedstock).

H(d)ETC: $H(d)ETCTOT = H(d)CLELIG + H(d)CLZLIG$ for all d

H(d)ETH: for all d

$$H(d)ETHTOT = H(d)CETDM1 + H(d)CETDM2 + H(d)CETDME + H(d)CETWME$$

H(d)ETCTOT	Total production of cellulosic ethanol in region (d).
H(d)ETHTOT	Total production of non-cellulosic corn ethanol in region (d).
H(d)(u)(f)	Total volume of corn ethanol produced in region (d) using process (u) and feedstock (f), where (u)(f) = CETDM1, CETDM2, CETDME, CETWME, CLELIG, CLZLIG.

H(r)BIT

$$N(r)BITN1 = N(r)BITXX + A \cdot H(r)CTXBIT + A \cdot H(r)CTZBIT \quad \text{for all } r$$

N(r)BITN1	Quantity of coal transferred to refinery region (r) for CTL production.
N(r)BITXX	Very small quantity of coal in region(r) used to keep the row from being basic (in an LP sense).
H(r)CTXBIT	Manufacturing activity level for coal-to-liquids (CTL) operating mode (m) in refinery region (r).
H(r)CTZBIT	Manufacturing activity level for coal-to-liquids (CTL) operating mode (m) in refinery region (r).

H(r)CC3

$$H(r)MPGPC3 = \mathrm{I}_{CC3} \cdot H(r)C4XNC4 + \mathrm{D}_{CC3} \cdot H(r)OLXIC4 - 1.66 \cdot H(r)FUXCC3$$

D_{CC3}	This parameter (0.03) specifies the volume of C3 created per unit of iso-butane produced in process OLX. See Table OLXREP in mchproc.dat.
H(r)C4XNC4	Volume of NC4 sent to isomerization process.
H(r)FUXCC3	Volume of C3 used as fuel at the merchant plant.
H(r)MPGPC3	Volume of C3 transferred from the merchant plant to the Gas Plant.
H(r)OLXIC4	Volume of IC4 sent to de-hydrogenation process.
I_{CC3}	This parameter (0.022) specifies the volume of C3 created per unit of iso-butane produced in process C4X. See Table C4XREP in mchproc.dat.

H(r)FUMCAP

Calculate total throughput through processing unit FUX (fuel use module) for the merchant plant in region (r).

$$K(r)FUXCAP = \sum_{ist} H(r)FUX(ist) \qquad \text{for all} \quad r, \quad ist = CC3, HYL, NGS, PGS$$

H(r)FUX(ist)	Operating level for merchant fuel use plant. ist=CC3, HYL, NGS, PGS.
K(r)FUXCAP	Capacity for merchant fuel use plant.

H(r)PGS

$$H(r)MPGPPS = \mathrm{I}_{PGS} \cdot H(r)C4XNC4 + \mathrm{D}_{PGS} \cdot H(r)OLXIC4 - H(r)FUXPGS$$

D_{PGS}	Volume of PGS created per unit of iso-butane produced in process OLX.
H(r)C4XNC4	Volume of NC4 sent to isomerization process.
H(r)FUXPGS	Volume of PGS used as fuel at the merchant plant.
H(r)MPGPPS	Volume of PGS transferred from the merchant plant to the Gas Plant.
H(r)OLXIC4	Volume of IC4 sent to de-hydrogenation process.
I_{PGS}	Volume of PGS created per unit of iso-butane produced in process C4X.

H(r)(uuu)

The amount of utility (uuu = COA, KWH, STM, but not NGF) supplied to the corn ethanol plants in the regions (d_r: d_C=3,4; d_E =1,2, 5; d_G =6,7; d_M =8, d_W =9) near region (r) is proportional to the amount of corn ethanol produced in those regions.

The amount of coal (COA) supplied to the corn ethanol plants in the regions (d_r) near region (r) is proportional to the amount of corn ethanol produced in those regions.

H(r)COA: $$\sum_{d_r} N(d)ETHCOA = 1.7136 \cdot \sum_{d_r}\sum_{mod} H(d_r)CET(mod) \quad \text{for all } r$$

N(d)ETHCOA Quantity of coal consumed for corn ethanol production in region (d).
H(d)CETWME) Manufacturing level for the CET process unit in operating mode WME in region (d).

H(r)KWH: $$H(r)KWHMCH = \sum_{uns}\sum_{m} H(r)(uns)(m)\cdot A + \sum_{d_r}\sum_{mod} H(d_r)(uns)(mod)\cdot A \quad \text{for all } r$$

A Electricity usage per unit of manufacturing in operating mode (m) for unit (uns).
H(r)(uns)(m) Manufacturing level in operating mode (m) for process unit (uns) in region (r).
H(r)KWHMCH Amount of electricity purchased by merchant (non-refinery) units in region (r).

H(r)STM: $$H(r)STM = \sum_{uns}\sum_{m} H(r)(uns)(m)\cdot A + \sum_{d_r}\sum_{mod} H(d_r)(uns)(mod)\cdot A \quad \text{for all } r$$

A Electricity usage per unit of manufacturing in operating mode (m) for unit (uns).
H(r)(uns)(m) Manufacturing level in operating mode (m) for unit (uns) in region (r).
H(r)KWHMCH Amount of electricity purchased by merchant (non-refinery) units in region (r).

H(r)LOS

FREE

H(r)OVC

Calculate the total variable cost at the merchant oxygenate plant in region (r).

$$A_{87} \cdot T(r)MCHOVC = \sum_{uns}\sum_{mod} A\cdot H(r)(uns)(mod) + \sum_{d_r}\sum_{uns}\sum_{mod} A\cdot H(d_r)(uns)(mod)$$

A	Various coefficients.
A_{87}	Coefficient to convert from 1987$ to 2000$.
H(d$_r$)(uns)(mod)	Production at biodiesel, corn ethanol, and cellulosic ethanol plants in region (d_r). d_C=3,4; d_E=1,2,5; d_G=6,7; d_M=8; d_W=9
H(r)(uns)(mod)	Production from process (uns) in operating mode (mod) in region (r).
T(r)MCHOVC	Merchant plant operating costs in region (r).

HG_CTL_U

See (z)CTL(i).

I@(crt)

Crude oil imports.

For *crt*=FHM,FHL,FHV,FLL,FMH:

$$\sum_{Qs} P@(crt)(Qs) = \sum_{r}\sum_{Qs} P(r)(crt)(Qs) + \sum_{w} T(w)FLL \cdot A_w^{crt} +$$
$$\sum_{w} T(w)IMC \cdot B_w^{crt} + \sum_{d} P(d)DCRQ1 \cdot A_o^{crt}$$

P@(crt)(Qs)	World crude supply of crude type (crt) by price level (Qs).
P(r)(crt)(Qs)	Crude (crt) imports by price level (Qs), to region (r).
P(d)DCRQ1	Total U.S. domestic crude supply. Used with A_o^{crt} will define quantity of crude by crude type (crt).
T(w)FLL	Crude (crt=FLL) demand at world marginal refinery in region (w).
T(w)IMC	Crude (crt=IMC= FHM,FHL,FHV,FLL,FMH) demand at world infra-marginal refinery in region (w).
A_o^{crt}	Factor defining fraction of total U.S. domestic crude supply by crude type (crt) in crude supply region (o).
A_w^{crt}	Factor defining fraction of total crude processed in world region (w) that is crude type (crt).

Note: $\sum_{d} A_d^{crt} = 1.0$ for *crt* = FHM, FHL, FHV, FLL, FMH

$\sum_{crt} A_w^{crt} = 1.0$ for *w* = A, N, R, U

$$\sum_{crt} B_w^{crt} = 1.0 \qquad \text{for } w = \text{A, N, R, U}$$

I@GENCRD

$$\sum_{crt}\sum_{Qs} P\,@(crt)(Qs) = \sum_{s} PWRLDQQ(s) \qquad \text{where } crt = \text{FHH,FHL,FHV,FMH,FLL}$$

I@GLBNGL

$$\sum_{s} PGLBLNGL(s) = \sum_{w} W(w)GLBLPG$$

PGLBLNL(s)	World NGL supply curve for price steps (s=1,9).
W(w)GLBLPG	World transshipments of LPG to region (w).

I(r)DIS

The distillate produced at the marginal refinery in each region (r) comprises #2 heating oil (N2H), DSL (low-sulfur diesel), and DSU (ultra-low-sulfur diesel).

$$A \cdot R(r)MARFLL = R(r)DISDSL + R(r)DISDSU + R(r)DISN2H \qquad \text{for all } r$$

A	Ratio of distillate produced at the marginal refinery per volume of crude processed in region (r).
R(r)MARFLL	Total volume of crude oil processed at the marginal refinery in region (r).
R(r)DIS(xxx)	Volume of distillate type (xxx=DSL,DSU,N2H) produced at the marginal refinery in region (r).

I(r)GAS

The motor gasoline-type product produced at the marginal refinery in each region comprises SSE, SSR, and TRG.

$$A \cdot R(r)MARFLL = R(r)GASSSE + R(r)GASSSR + R(r)GASTRG \qquad \text{for all } r$$

A	Ratio of motor gasoline produced at the marginal refinery per volume of crude processed in region (r).
R(r)MARFLL	Total volume of crude oil processed at the marginal refinery in region (r).
R(r)GAS(xxx)	Volume of motor gasoline-type product (xxx=SSE,SSR,TRG) produced at the marginal refinery in region (r).

I(r)(pri)IMP

For each region (r), calculate total imports of import product (pri) from all world refineries (w=A,N,R,U).

$$I(r)(pri)TOT = \sum_{w} \sum_{s-1}^{3} I(r)(pri)(w)(s) \qquad \text{for all } r, pri$$

I(r)(pri)TOT	Total imports of product (pri).
I(r)(pri)(w)(s)	Imports of product (pri) into region (r) from world refinery (w) at price point (s).

pri Let prd'= DSL,DSU,JTA,LPG,N2H,N6B,N6I,OTH,PCF,TRG
(i.e., prd' is a subset of prd). Then:

pri(C) = prd' + {SSE,SSR} + {HGM,NPP}
pri(E) = prd' + {SSE,SSR} + {ARB,HGM,NPP}
pri(G) = prd' + {SSE,SSR} + {ARB,HGM,NPP}
pri(M) = prd' + {SSE,SSR}
pri(W) = prd' + {SSE,SSR} + {ARB,HGM,NPP}

L(d)CET(xxx) **(for xxx = CD1, CD2)**

Total production of ethanol from corn for unit type (xxx) must not exceed the available capacity as defined by the upper limit on the existing and new capacity vectors.

For new technology:

L(d)CETCD1: $H(d)CETDM1 = K(d)CETDM1 + L(d)CETDM1 + E(d)CETDM1$ for all d

L(d)CETCD2: $H(d)CETDM2 = K(d)CETDM2 + L(d)CETDM2 + E(d)CETDM2$ for all d

E(d)CET(mod)	New corn ethanol capacity in region (d) for dry mill process (mod=DM1, DM2).
H(d)CET(mod)	Corn ethanol production in region (d) in operating mode (mod=DM1, DM2).
K(d)CET(mod)	Cumulative corn ethanol capacity added in region (d) for dry mill process (mod=DM1, DM2) determined to be uneconomical to run in any year after the year it was built.

L(d)CET(mod) Cumulative corn ethanol capacity added in region (d) for dry mill process (mod=DM1, DM2).

L(d)CETOLD

For existing (OLD) corn ethanol unit (CET) capacity. Total existing capacity is put into an accounting variable.

$$H(d)CETDME + H(d)CETWME = K(d)CETOLD \qquad \text{for all } d$$

H(d)CETDME Total existing corn ethanol unit capacity for dry mill processing in region (d).
H(d)CETWME Total existing corn ethanol unit capacity for wet mill processing in region (d).
K(d)CETOLD Total existing corn ethanol (CET) unit capacity in region (d).

L(d)(uns)CAP

Define builds and investments for biodiesel plants and ethanol plants.

L(d)BDNCAP: $H(d)BDNYGR = K(d)BDNCAP + L(d)BDNBLD + E(d)BDNINV \qquad \text{for all } d$

L(d)BDVCAP: $H(d)BDVSBO = K(d)BDVCAP + L(d)BDVBLD + E(d)BDVINV \qquad \text{for all } d$

L(d)BDWCAP: $H(d)BDWWGR = K(d)BDWCAP + L(d)BDWBLD + E(d)BDWINV \qquad \text{for all } d$

L(d)CETCAP: FREE

$$L(d)CETBLD + \sum_{m} \left[K(d)CET(m) + L(d)CET(m) + E(d)CET(m) \right] \qquad \text{for all } d,\ m=DM1,\ DM2$$

L(d)CLECAP: $H(d)CLELIG = K(d)(u)CAP + L(d)CLEBLD + E(d)CLEINV \qquad \text{for all } d$

L(d)CLZCAP: $H(d)CLXLIG = K(d)CLZCAP + E(d)CLZINV \qquad \text{for all } d$

L(r)(uns)CAP

$$K(r)(uns)CAP + E(r)(uns)INV + L(r)(uns)BLD = \sum_{mod} R(r)(uns)(mod) \qquad \text{for } uns \neq \text{ACU}$$

$$K(r)(uns)CAP + E(r)(uns)INV + L(r)(uns)BLD = \sum_{crt} R(r)(uns)(crt) \qquad \text{for } uns = \text{ACU}$$

E(r)(uns)INV Stream day capacity added during this simulated period for processing unit type (uns) in region (r).
K(r)(uns)CAP Base processing capacity in processing unit (uns) in region (r).

L(r)(uns)BLD Cumulative stream day capacity added for processing unit (uns) in region (r) during the previous simulated periods. This variable is fixed.
R(r)(uns)(crt) Volume of crude type (crt) processed in region (r), for uns = ACU only.
R(r)(uns)(mod) Refinery process operation in mode (mod) in region (r).

L(r)BTLCAP

(some variables subject to upper bound...)

$$A \cdot E(r)BTLINV + K(r)BTLCAP + A \cdot L(r)BTLBLD = H(r)BTLRED + H(r)BTLREJ \quad \text{for all } r$$

L(r)GDTCAP

$$A \cdot E(r)GGDTINV + K(r)GDTCAP + A \cdot L(r)GDTBLD = R(r)GDTGDG + R(r)GDTGDV + R(r)GDTGDW \quad \textbf{for all } \boldsymbol{r}$$

L(w)ILGCAP

$$K(w)ILGCAP = R(w)ILGL2D \quad \text{for } w = \text{A,N,U}$$
$$K(w)ILGCAP = 0 \quad \text{for } w = \text{R}$$

L(w)IUPCAP

$$K(w)IUPCAP = R(w)IUPN2D + R(w)IUPR2D1 + R(w)IUPR2D2$$

MAXCORN4RFS

The total volume of corn ethanol production must be less than some maximum value.
(Also, note that the constraint name is longer than eight characters.)

$$\sum_d H(d)ETHTOT \leq \max$$

H(d)ETHTOT Total volume of corn ethanol produced in region (d).
max Maximum allowable total ethanol production.

M(d)(ppd) **(ppd is a subset of prd+Ss)**

For regions 5 (South Atlantic) and 6 (South Central), the volume of each product shipped into the region equals the pipeline sales within the region plus the volume shipped out of the region.

M5(ppd): $W6(ppd)T5 = W5(ppd)X5 + W5(ppd)T2$ for all *ppd*

M6(ppd): $WG(ppd)T6 = W6(ppd)X6 + W6(ppd)T5$ for all *ppd*

W(i)(p)T(m)	Volume of product (p) shipped from region (i=G, 5, 6) to region (m=2,5,6).
W(m)(p)X(m)	Volume of pipeline sales of product (p) in region (m).
ppd	Subset of (prd)+(Ss): DSL, DSU, JTA, LPG, N2H, RFG, RFH, SSE, SSR, SST, TRG, TRH. Note: W6LPGT5 and W5LPGT2 do not exist, which forces W5LPGX5=0

M(r)(p) **(where p is a subset of: (prd)+(Ss)+JP5+NPI)**

For each product at each refinery, the volume manufactured plus volume imported plus volume transferred from another higher quality product must equal to the volume transferred to other lower quality products plus the amount consumed by recipe plus the volume shipped to market.

$$R(r)MARFLL \cdot A_{rp} + Q(r)(p) + \sum_{i} G(r)(i)(p) + \sum_{Rq} I(r)(p)(Rq) + \sum_{p} T(r)(s)(p) +$$

$$\sum_{m} R(r)RES(p) = \sum_{m}\sum_{d} W(r)(p)(m)(d) + \sum_{p} R(r)FUM(p) \qquad \text{for all } r, p$$

A_{rp}	Volume of product (p=JTA,OTH,PCF) manufactured at the marginal refinery in region (r) per unit volume of crude entering the refinery.
G(r)(i)(p)	Gas plant output transfer of stream (i) to product (p=LPG,PCF,OTH) in region (r).
I(r)(p)(Rq)	Volume of product (p) imported into region (r) at price step (Rq).
Q(r)(p)	Volume of spec product (p) manufactured in region (r).
R(r)FUM(p)	Manufacturing activity level in mode (p) operation in processing unit FUM at region (r). For p=N6B and N6I only. (Note: the mode name is identical to the product name in this case).
R(r)MARFLL	Volume of crude entering the marginal refinery in region (r).
R(r)RES(p)	Manufacturing activity level in mode (p) operation in processing unit FUM at region (r). For p=N6I only. (Note: the mode name is identical to the product name in this case).
T(r)(s)(p)	Volume of stream (s) transferred into product (p) in region (r).

W(r)(p)(m)(d)	Volume of product (p) shipped from region (r) to region (d) via mode (m).

M(r)MTB(mgb)

This constraint is no longer active. Formerly, it restricted the volume percentage of undesirable MTBE oxygenate in RFG-related and TRG-related motor gasoline produced at refinery (r) for sale or splash blending.

M(w)(ppw) (ppw is a subset of: (prd)+(Ss)+DIS+NAP+RES)

The volume of product manufactured in or transferred in each world refinery region (w) must equal the volume of product sent to the U.S. or to other world refinery regions.

$$A_{p1} \cdot R(w)MARFLL + A_{p2} \cdot R(w)MARIMC + \sum_{p'} R(w)(p')(p) =$$

$$\sum_{r_w} \sum_{s=1}^{3} I(r_w)(p)(w)(s) + \sum_{w'} W(w)(p)X(w') \qquad \text{for all } w, p$$

A_{p1}	Volume of product (p) manufactured at the marginal refinery in region (w) per unit volume of crude type FLL entering the refinery.
A_{p2}	Volume of product (p) manufactured at the marginal refinery in region (w) per unit volume of crude type IMC entering the refinery.
$I(r_w)(p)(w)(s)$	Volume of product (p) imported to U.S. region (r) from region (w) at price step (s).
R(w)MARFLL	Volume of crude type FLL entering the marginal refinery in region (w).
R(w)MARIMC	Volume of crude type IMC entering the marginal refinery in region (w).
R(w)(p')(p)	Volume of product (p) transferred to product (p') in region (w).
W(w)(p)X(w')	Volume of product (p) transported from region (w) to region (w').

O(o)(crt)

Allocate total domestic crude oil production in supply region (o) into different types of crude oil (crt).

$$A_o^{crt} \cdot P(o)DCRQ1 \qquad \text{FREE} \qquad \text{for all relevant combinations of (o) and (crt)}$$

P(o)DCRQ1	Total volume of crude oil produced in domestic supply region (o).
A_o^{crt}	Proportion of crude produced in (o) that is type (crt). Note: $\sum_{crt} A_o^{crt} = 1.0$ for all (o).

OPAFLT(x) (x=C,D,L,O)

Accounting of all product imports to the U.S. by product group (C=DSL,DSU,JTA,NPP,PCF,SSE,SSR,TRG; D=ARB,HGM,N2H,N6I,N6B; L=LPG; O=OTH).

for all relevant combinations such that (prd’) is a subset of (x), as defined above.

$$\sum_{r}\sum_{prd}\sum_{w}\sum_{s} I(r)(prd')(w)(s) \qquad \text{FREE}$$

I(r)(prd’)(w)(s)	Total volume of product (prd’) imported from region (w) to region (r) at price level (s=1,3).

P(r)(pol), H(r)(pol)

Refineries and merchant plants adhere to 'policy' table entries (Note: “≤=≥” indicates =, ≤, or ≥, depending on the specific policy requirement).

P(r)(pol): $\sum_{u}\sum_{m} R(r)(u)(m)\cdot A_{pol,rum} \leq=\geq A_{pol,r}\cdot Z(r)FLO(u)$ for all *r, pol*

H(r)(pol): $\sum_{u}\sum_{m} H(r)(u)(m)\cdot A_{pol,rum} \leq=\geq A_{pol,r}\cdot Z(r)FLO(u)$ for all *r, pol*

$A_{pol,rum}$	Coefficient representing policy emission level as a function of processing unit operating level.
R(r)(u)(m)	Manufacturing activity level in operating mode (m) in processing unit (u) in region (r).
H(r)(u)(m)	Manufacturing activity level in operating mode (m) in processing unit (u) at the merchant plant in region (r).
Z(r)FLO(u)	Sum of the existing, built, and expanded capacity in processing unit (u) in region (r) – as defined by row constraint Z(r)CAP(u), directly below.

Note: The type of row (≤, ≥,=) is determined by the entry in column heading TYPE of the policy table (r)POL (located in *setrows.dat* input file) where $A_{e,r}$, appears. It may also be a non-constraining row, in which case the row is free. The total processing unit throughput is the base for the policy limits in each region:

Z(r)CAP(u): $Z(r)FLO(u) = K(r)(u)CAP + A\cdot(L(r)(u)BLD + E(r)(u)INV)$ for all *r, u*

L(r)(u)BLD	Cumulative new capacity built prior to current year, for processing unit (u) in region (r).
E(r)(u)INV	New capacity allowed to build in current year, for processing unit (u) in region (r).
K(r)(u)CAP	Planned or existing capacity, for processing unit (u) in region (r).
A	Annual utilization defined for processing unit (u) in region (r).

P(r)CBNTAX

Calculate taxable carbon emissions.

$$T(r)CBNTAX = 0.001 \cdot \sum_{m} R(r)FUM(m) \qquad \text{for all } r$$

T(r)CBNTAX	Total taxable carbon emissions resulting from refinery operations in region (r).
R(r)FUM(m)	Manufacturing activity level in mode (m) operation of the fuel use module (FUM) in region (r).

P(r)LOS

Free.

P(r)OVC

Calculate total variable cost for refinery in region (r).

$$A_{87} \cdot T(r)OVCOBJ = \sum_{uns} \sum_{mod} A \cdot R(r)(uns)(mod)$$

A	Various coefficients.
A_{87}	Coefficient to convert from 1987\$ to 2000\$.
R(r)(uns)(mod)	Production from process (uns) in operating mode (mod) in region (r).
T(r)OVCOBJ	Merchant plant operating costs in region (r).

Q(r)(p)(y)

The sum of specs of blend streams must meet overall product quality spec (e.g., RVP, sulfur content, etc.). The sense of a particular constraint sense might be “=”, “≤” or “≥”.

Q(r)(mgb)(y): $\sum_{ist} B(r)(mgb)(ist) \cdot A_{y,ist}^{mgb} \geq = \leq Q(r)(mgb) \cdot B_{y}^{mgb}$ for all y, *r, mgb* = RFG,TRG

Q(r)(dfo)(y): $\sum_{ist} F(r)(dfo)(ist) \cdot A \geq = \leq Q(r)(dfo) \cdot B$ for all *y,r, dfo*

$A_{y,ist}^{p}$	Blend value of stream (ist) for property (y) of product (p).
B_{y}^{p}	Constraining value of property (y) that product (p) must adhere to (e.g., octane number, RVP) at region (r).
B(r)(mgb)(ist)	Volume of intermediate stream (ist) blended into gasoline product (mgb) at region (r).

F(r)(dfo)(ist)	Volume of intermediate stream (ist) blended into distillate product (mgb) at region (r).
Q(r)(p)	Volume of final product (p = mgb, dfo) made at region (r).

Q(r)RFGREN

Sum oxygen percentage contribution by renewable oxygenates blended to reformulated gasoline (RFG). The oxygenates from ethanol include ETB, TAE, and THE. Ethanol from splash blending is also included. (Unconstrained in *AEO2009*.)

$$\sum_{ist} A_{ist} \cdot B(r)RFG(ist) + \sum_{d_r} \sum_{prd=RFG,RFH} A_{prd} \cdot X(d_r)ETH(prd) \geq 0 \quad \text{for all } r$$

A_{ist}	Percentage of OXY in stream (ist).
A_{prd}	Percentage of OXY in product (prd).
B(r)RFG(ist)	Volume of stream (ist=ETB, TAE, THE) blended into RFG in region (r).
d_r	Regions (d) close to region (r): d_C=3, 4; d_E=2, 5; d_G=6, 7; d_M=8; d_W=9
$X(d_r)ETH(prd)$	Volume of ethanol splash blended into product (prd = RFG, RFH) in region (r).

R(r)(ist)

Balance each refinery gas stream (ist) that does *not* go through the Saturated Gas Plant (SGP) in each region:

$$\sum_{uns} \sum_{m} R(r)(uns)(m) \cdot A_{ist,urm} = \sum_{ist'} R(r)FUM(ist')$$

for all *r*, and ist'=CC1,CC2,CC3,IC4,NC4,HYL where *u,m* produce gas streams (*ist*) *not* sent to SGP.

$A_{ist,urm}$	Volume fraction of intermediate stream (ist) created per unit of manufacturing activity level of operating mode (m) for processing unit (u) at region (r). (ist=CC1, CC2, CC3, HYL, IC4, NC4)
R(r)(u)(m)	Manufacturing activity level of operating mode (m) for processing unit (u) in region (r), where (u)(m) produce refinery gas streams (ist) *not* sent to the SGP.
R(r)FUM(ist')	Manufacturing activity level of the fuel usage module (FUM) processing refinery gas stream (ist') in region (r). Note: (ist'=RC1,RC2,RC3,RI4,RN4, RHL) to distinguish (ist') from refinery gas that is processed by the SGP and sent to FUM.

S_CL(n)(k)

For each coal supply curve and coal type, the total quantity of coal purchased must be greater than the quantity of coal shipped to the coal supply distribution points (coal supply regions) plus the total non-refinery demand from the same supply curve and coal type.

$$\sum_j CT(n)(j)(k) + CP(n)OTXX \le \sum_q CP(n)(k)(q) \qquad \text{for all } n$$

CP(n)(k)(q)	Quantity of coal with characteristics (k) produced from coal supply source (n) at price (q).
CT(n)(j)(k)	Quantity of coal with characteristics (k) produced from coal supply source (n) to coal demand region (j).
CP(n)OTXX	Quantity of coal from supply source (n) demanded by non-refining sources.

S(r)(dfo)E

The total volume of each distillate fuel oil blend (dfo = DSL, DSU, JTA, N2H, N6B, N6I) is equal to the sum of the volume of its component streams (ist).

$$Q(r)(dfo) = \sum_{ist} B(r)(dfo)(ist) \qquad \text{for all } r$$

B(r)(dfo)(ist)	Volume of intermediate stream (ist) blended into spec product (dfo) in region (r).
dfo	DSL, DSU, JTA, N2H, N6B, N6I
ist	ist = dfo (i.e., for JTA, ist=JTA only)
Q(r)(dfo)	Total volume of spec-blended product (dfo) made in region (r).

S(r)(mgb)E

The total volume of each motor gasoline blend (mgb=TRG, RFG) is equal to the sum of the volume of its component streams (ist).

$$Q(r)(mgb) = \sum_{ist} B(r)(mgb)(ist) \qquad \text{for all } r \text{ and } mgb = RFG, TRG$$

B(r)(mgb)(ist)	Volume of intermediate stream (ist) blended into product (mgb) in region (r).
ist	For TRG, ist=TRG, TRH, SST, SSE; for RFG, ist=RFG, RFH, SSR.
Q(r)(mgb)	Total volume of motor gasoline blend (mgb) produced in region (r).

S(r)(ist)

Balance row for intermediate refinery gas plant stream (ist = CC1, CC2, CC3, HYL, IC4, NC4).

$$R(r)SGP(ist) = \sum_{u}\sum_{m} A_{um}^{ist} \cdot R(r)(u)(m) \qquad \text{for all } r \text{ and } ist = CC1,CC2,HYL,IC4,NC4$$

S(r)RFGOXY

Sum oxygen percentage contribution by oxygenates blended to reformulated gasoline. The oxygenates from methanol include MTB, TAM, and THM; the oxygenates from ethanol include ETB, TAE, and THE. Ethanol from splash blending is also included.

$$Z(r)RFGOXY = \sum_{ist} A_{ist} \cdot B(r)RFG(ist) + \sum_{d_r}\sum_{prd=RFG,RFH} A_{prd} \cdot X(d_r)ETH(prd) \qquad \text{for all } r$$

A_{ist}	Percentage of OXY in stream (ist).
A_{prd}	Percentage of OXY in product (prd).
B(r)RFG(ist)	Volume of stream (ist=ETB, MTB, TAE, TAM, THE, THM) blended into RFG in (r).
d_r	Regions (d) close to region (r): d_C=3, 4; d_E=2, 5; d_G=6, 7; d_M=8; d_W=9
$X(d_r)ETH(prd)$	Volume of ethanol splash blended into product (prd = RFG, RFH) in (r).
Z(r)RFGOXY	Total OXY in RFG in (r).

Note: This row is unconstrained for *AEO2009*. Variable *Z(r)RFGOXY* appears only in this constraint...

S02_CTL1

See (z)CTL(i) listed below.

S02_CTL2

See (z)CTL(i) listed below.

TANGKGTX

Maximum natural gas available for processing to GTL in Alaska:

$$\sum_{r}\sum_{q} N(r)NGKN(q) \le \max$$

Max	Maximum natural gas available for processing to GTL in Alaska.
N(r)NGKN(q)	Natural gas supply available in Alaska (r) by price step (q).

TAOILGTN, TAOILGTX

Minimum (and maximum) flow allowed on Trans-Alaska Pipeline System (TAPS) in Alaska:

$$TAGTLTOT + TANSOTOT \geq \min$$
$$TAGTLTOT + TANSOTOT \leq \max$$

min	Minimum flow on Trans-Alaska pipeline.
max	Maximum flow on Trans-Alaska pipeline.
TAGTLTOT	Total GTL transported from Alaska North Slope to Valdez on Trans-Alaska pipeline.
TANSOTOT	Total crude of type NSO transported from Alaska North Slope to Valdez on Trans-Alaska pipeline.

TPC(b)(m)(r)

Calculate the total pipeline shipments to every region (r) via mode (m) from crude oil production regions or other region (b = o + r).

$$VTPC(b)(m)(r) = \sum_{v}\sum_{c} Y(b)(v)(c)(m)(r) \qquad \text{for all} \quad b{=}o{+}r,\ r,\ m{=}\text{pipeline}$$

VTPC(b)(m)(r)	Total volume of crude oil shipped to region (r) via pipeline mode (m) from domestic production region (o) or other region (r). This variable is constrained by an upper bound.
Y(b)(v)(c)(m)(r)	Volume of crude oil type (c) shipped to region (r) via pipeline mode (m) from domestic production region (o) or other region (r) (i.e., b = o + r).

TPL(r)(m)(d)

For each relevant region (r) / region (d) combination, calculate total pipeline shipments of LPG, FLG, and PCF.

$$VTPL(r)(m)(d_r) = \sum_{r}\sum_{p'}\sum_{m} W(r)(p')(m)(d_r) \qquad \text{for all } r,\ m{=}\text{U},\ d_r$$

d_r	d_C=2,5,7,8; d_E=6; d_G=3,4,6; d_M=4; d_W= nil
p'	FLG, LPG, and PCF products which can be shipped from region (r) to region (d) via pipeline mode (m=U).

W(r)(p')(m)(d) Volume of product (p'=FLG,LPG,PCF) shipped from region (r) to region (d) via pipeline mode (m=U).

VTPL(r)(m)(d) Total volume of LPG and PCF products (p') shipped via pipeline mode (m=U) from region (r) to region (d). Constrained by an upper bound.

TPP(r)(m)(d)

For each relevant region (r) / region (d) combination, calculate total pipeline shipments of light products.

$$VTPP(r)(m)(d) = \sum_{r} \sum_{p'} \sum_{d} W(r)(p')(m)(d)$$

for all *r (*and including regions 5 and 6*), d, m=T,X,Y,Z (*pipeline), *p'*=light products shipped by pipeline

p' Light products which can be shipped from region (r) to region (d) via pipeline mode (m).

r For this constraint, (r) includes regions 5 and 6.

VTPP(r)(m)(d) Total volume of light products shipped from region (r) to region (d) via pipeline mode (m). Constrained by an upper bound.

W(r)(p')(m)(d) Volume of light product (p') shipped from region (r) to region (d) via pipeline mode (m).

TVC(m)CP (for m=5)

The total weight of crude oil transported on Jones Act (U.S. flag) marine tankers is equal to the sum of the individual weights transported to each region.

$$\textbf{TVC5CP}: \quad VTVC5CP = \sum_{b} \sum_{v} \sum_{c} \sum_{m} \sum_{r} Y(b)(v)(c)(m)(r) \cdot A_c$$

A_c Deadweight tons per Mbbl of crude oil of type (c).

Y(b)(v)(c)(m)(r) Volume of crude oil type (c) with source code (v) produced in domestic region (b) that is shipped to region (r) via mode (m).

VTVC5CP Total deadweight tons of Jones Act crude oil. Constrained by the total capacity of Jones Act marine tankers.

TVP(m)CP

The total weight of shipments of refined product (prd) and GTL on Jones Act (U.S. flag) tankers is equal to the sum of the weights of individual products.

TVP(m')CP: $VTVP(m')CP = \sum_{r}\sum_{prd}\sum_{m'}\sum_{d} W(r)(prd)(m')(d) \cdot A_{p'} + \sum_{m'}\sum_{d} WAGTL(m')(d) \cdot A_{GTL}$

$A_{p'}$	Deadweight tons per Mbbl of product *p'*.
m'	Jones Act tankers.
VTVP(m')CP	Total weight of shipments of refined product and GTL on Jones Act tankers. Constrained by an upper bound.
W(r)(p)(m)(d)	Volume of product (p) shipped from region(r) to region (d) via mode (m).

U(r)(uuu)

Calculate usage of each utility (uuu=KWH,NGF,STM) at each region (r).

For all r,

U(r)KWH: $U(r)KWH = \sum_{u}\sum_{m} R(r)(u)(m) \cdot A_{urm}^{KWH} + \sum_{p} Q(r)(p) \cdot A_{pr}^{KWH} + G(r)MOH01 \cdot A_{r}^{KWH}$

U(r)NGF: $U(r)NGF = T(r)NGFNGS + G(r)MOH01 \cdot A_{r}^{NGF}$

U(r)STM: $U(r)STM = \sum_{u}\sum_{m} R(r)(u)(m) \cdot A_{urm}^{STM} + \sum_{p} Q(r)(p) \cdot A_{pr}^{STM} + \sum_{p}\sum_{h} X(r)(h)(p) \cdot A_{hr}^{STM}$

A_{urm}^{uuu}	Quantity of utility (uuu) consumed (-) or manufactured (+) per unit of operation of processing unit (u) in mode (m) in region (r). The (u) index includes the utility manufacturing units.
A_{pr}^{uuu}	Quantity of utility (uuu) consumed per unit of spec product (p) made in region (r).
A_{hr}^{uuu}	Quantity of utility (uuu) consumed per unit of recipe product (h) made in region (r).
A_{r}^{uuu}	Quantity of utility (uuu) consumed per unit of methanol made at the merchant plant in region (r).
G(r)MOH01	Volume of methanol made at the merchant plant in region (r).
Q(r)(p)	Volume of spec product (p) made in region (r).
R(r)(u)(m)	Manufacturing activity level in mode (m) operation in processing unit (u) in region (r).
U(r)(uuu)	Quantity of utility (uuu = KWH, NGF, STM) purchased in region (r).
X(r)(h)(p)	Volume of product (p) made by recipe blend (h) at region (r).

X(d)MAXSPL

Calculate the total volume of ethanol splash-blended into motor gasoline.

$$X(d)MAXSPL = \sum_{mgb} \left[X(d)ETA(mgb) + X(d)ETC(mgb) + X(d)ETH(mgb) \right] \qquad \text{for all } d$$

X(d)MAXSPL Volume of ethanol splash-blended into motor gasoline. This variable is constrained by an upper bound.

X(d)(xxx)(mgb) Volume of ethanol type (eth = ETA, ETC, ETH) splash-blended into motor gas blend (mgb = RFG,RFH,TRG,TRH).

Z(r)CAP(uns)

Calculate the total flow through the processing unit (uns=DDS,ETH,ETM,FCC,FUM,KRF,RFL). This value might be subject to an upper bound.

$$Z(r)FLO(uns) = A \cdot E(r)(uns)INV + K(r)(uns)CAP + A \cdot E(r)(uns)BLD \qquad \text{for all } r$$

E(r)(uns)INV Stream day capacity added during this simulated period for processing unit type (uns) in region (r).

K(r)(uns)CAP Base processing capacity in processing unit (uns) in region (r).

L(r)(uns)BLD Cumulative stream day capacity added for processing unit (uns) in region (r) during the previous simulated periods. This variable is fixed.

Z(r)FLO(uns) Total flow through processing unit (uns) in region (r). Might be subject to an upper bound.

Z@CRDTOT

The total volume of foreign crude oil used is equal to the sum of crude oil volumes processed in all regions.

$$Z@TOTCRD = \sum_{r} \sum_{c} R(r)ACUF(c) + \sum_{r} R(r)MARFLL$$

R(r)ACUF(c) Volume of foreign (F) crude oil of type (c) processed through the atmospheric crude unit (ACU) in region (r). Note: F(c) =FHH, FHL, FHV, FLL, FMH.

R(r)MARFLL Crude oil volume distilled in the marginal refinery in region (r).

Z@TOTCRD Total volume of foreign crude processed in all regions (r).

ZD(mm)(dd)(yy)

The name of this free constraint records the date of the run.

Z@FLLIMP

Imports of FLL crude oil must exceed a lower limit which is based on historical levels. The lower limit decreases by a specified percentage each year.

$$\sum_{r}\sum_{q} P(r)FLLQ(q) \geq \min$$

min	Minimum level of FLL crude imports.
P(r)FLLQ(q)	Volume of FLL crude imported to region (r) at price level (q).

Z@IRAC(c) **(c=X, N)**

The implicit world oil price, WOP (the refiner's acquisition cost of imported crude oil), must be at least some fraction of the premised WOP.

Z@IRACN: $$\sum_{c}\sum_{r}\sum_{q} P(r)F(c)Q(q)\cdot C(r)(c)(q) \geq WOP \cdot N_{wop} \cdot Z@TOTCRD$$

Z@IRACX: $$\sum_{c}\sum_{r}\sum_{q} P(r)F(c)Q(q)\cdot C(c)(r)(q) \leq WOP \cdot X_{wop} \cdot Z@TOTCRD$$

C(r)F(c)Q(q)	Purchase price of one unit of foreign (F) crude oil type (c) purchased at price level (q) in region (r).
N_{wop}	Minimum fraction (≤1.0) of WOP at which refiners can acquire crude oil.
P(r)F(c)Q(q)	Volume of foreign (F) crude oil type (c) purchased at price level (q) in region (r).
WOP	World oil price.
X_{wop}	Maximum fraction (≥1.0) of WOP at which refiners can acquire crude oil.
Z@TOTCRD	Total volume of foreign crude processed in all regions.

These two constraints are set as non-binding in *AEO2009*.

Z(r)NGFSUM

The total volume of natural gas consumed in each region (r) is equal to the total amount purchased at various price discounts and price increments.

$$U(r)NGF = \sum_{q=1}^{4} N(r)NGRFN(q) + \sum_{q=5}^{8} N(r)NGRFP(q) \qquad \text{for all } r$$

N(r)NGRFN(q)	Volume of natural gas purchased at price discount (q) in region (r).
N(r)NGRFP(q)	Volume of natural gas purchased at price increment (q) in region (r).
U(r)NGF	Total volume of natural gas consumed in region (r).

Z@YRITER

This free accounting constraint keeps track of the current iteration within the model year.

Z@WOP

This free accounting constraint keeps track of the world oil price.

ZZAMHSUM

The total volume of AMH type crude exports from Alaska is equal to the total amount sold at various price discounts and price increments.

$$ZZAMHTOT = \sum_{q=1}^{3} NZAMHN(q) + \sum_{q=4}^{6} NZAMHP(q)$$

NZAMHN(q)	Volume of AMH exports from Alaska at price discount (q).
NZAMHP(q)	Volume of AMH exports from Alaska at price increment (q).
ZZAMHTOT	Total volume of AMH crude exports from Alaska.

(z)CTL(i) (z,i = S02_,1; SO2,2; HG,_U)

Calculate the total emissions from coal purchased for CTL and non-refinery consumption.

SO2_CTL1: $P\_SO2\_1 \geq \sum_{n}\sum_{j}\sum_{k} A_{njk}^{SO2\_1} \cdot CT(n)(j)(k)$

SO2_CTL2: $P\_SO2\_2 \geq \sum_{n}\sum_{j}\sum_{k} A_{njk}^{SO2\_2} \cdot CT(n)(j)(k)$

HG_CTL_U: $P\_HG\_US \geq \sum_{n}\sum_{j}\sum_{k} A_{njk}^{HG\_US} \cdot CT(n)(j)(k)$

A_{njk}^{emu}	Emissions of type (emu) per unit of coal with characteristics (k) transferred from coal supply source (n) to coal demand region (j).
CT(n)(j)(k)	Quantity of coal with characteristics (k) transferred from coal supply source (n) to coal demand region (j).
P_(zi)	Total emissions of type (zi=S02_1, SO2_2, HG_US) from coal purchased for CTL and non-refinery consumption.

APPENDIX C

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APPENDIX C Bibliography

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Also see citations in Appendix A.

APPENDIX D

Model Abstract

Appendix D. Model Abstract

D.1 Model Name:

Petroleum Market Model

D.2 Model Acronym:

PMM

D.3 Description:

The Petroleum Market Model is a simulation of the U.S. petroleum industry. It includes 12 domestic crude oil production regions, five refining centers with full processing representations and capacity expansion capability and gas plant liquid production, and nine marketing regions. The heart of the model is a linear programming optimization which ensures a rational economic simulation of decisions of petroleum sourcing, resource allocation, and the calculation of a marginal price basis for the products. Twenty-three refined products are manufactured, imported, and marketed. Ten of these products are specification blended, nine are recipe blended, and four are either unfinished products or by-product.

Capacity limited transportation systems are included to represent existing intra-U.S. crude oil and product shipments (LPG, clean, dirty) via pipeline, marine tanker, barge, and truck/rail tankers. The export and import of crude oil and refined products is also simulated. All imports are purchased in accordance with import supply curves. Domestic manufacture of methanol is represented as though the processing plants are part of a refinery complex. Ethanol sources are treated as merchant plants. Transportation is allowed for ethanol shipments to the demand region terminals for splash blending.

The program is written in FORTRAN which includes callable subroutines allowing full communication with the LP portion of the model which is in the form of an MPS resident file.

D.4 Purpose of the Model:

The PMM models domestic petroleum refining activities, the marketing of petroleum products to consumption regions, the production of natural gas liquids in gas processing plants, and domestic methanol and MTBE production. The purpose of the PMM is to project petroleum product prices, refining activities, and movements of petroleum across United States' borders and among domestic regions. In addition, the model contains adequate structure and is sufficiently flexible to examine the impact of a wide variety of petroleum-related issues and policy options. These capabilities allow for understanding of the petroleum refining and marketing industry as well as determine the effects of certain policies and regulations.

The PMM projects sources of supply for meeting petroleum product demand. The sources of supply include crude oil, both domestic and imported; other inputs including alcohols and ethers; natural gas plant liquids production; petroleum product imports; and refinery processing gain. In addition, the PMM estimates domestic refinery capacity expansion and fuel consumption. Product prices are estimated at the Census Division (CD) level and much of the refining activity information is at the Petroleum Administration for Defense District (PADD) level.

D.5 Most Recent Model Update:

April 2009

D.6 Part of Another Model?

The PMM is a component of the National Energy Modeling System (NEMS)

D.7 Model Interfaces:

The PMM receives information from the International, Natural Gas Transmission and Distribution, Oil and Gas Supply, Renewable Fuels, Electricity Market, Residential, Commercial, Industrial, and Transportation Models and delivers information to each of the models listed above plus the Macroeconomic Model.

D.8 Official Model Representative:

William Brown
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(202) 586-8181

D.9 Documentation:

EIA Model Documentation: Petroleum Market Model of the National Energy Modeling System (NEMS), December 2008. (DOE/EIA-M059(2008)).

D.10 Archive Media and Installation Manual

Archived as part of the NEMS *AEO2009* production runs.

D.11 Energy System Described:

Petroleum refining industry and refined products market.

D.12 Coverage:

Geographic: Twelve domestic crude oil production regions (East Coast, Gulf Coast, Mid-Continent, Permian Basin, Rocky Mountain, West Coast, Atlantic Offshore, Gulf Offshore, Pacific Offshore, Alaska South, Alaska North, Alaska Offshore); five refining regions (PADDs I-V); nine market regions, the Census divisions (New England, Mid Atlantic, East North Central, West North Central, South Atlantic, East South Central, West South Central, Mountain, Pacific).

Time Unit/Frequency: Annual, 2008 through 2030.

Products: LPG, conventional motor gasoline, conventional high oxygen motor gasoline, reformulated motor gasoline, reformulated high oxygen motor gasoline, M85, E85, jet fuel, distillate fuel oil, low-sulfur diesel, ultra-low sulfur diesel, low-sulfur residual fuel oil, high-sulfur residual fuel oil, petrochemical feedstocks, asphalt/road oil, marketable coke, still gas, "other" petroleum products, ethanol and biodiesel.

Refinery Processes: crude distillation, vacuum distillation, delayed coker, fluid coker, visbreaker, fluid catalytic cracker, thermal cracker, hydrocracker-distillate, hydrocracker-residual fuel, solvent deasphalter, residual fuel desulfurizer, FCC feed hydrofiner, distillate HDS, naphtha hydrotreater, catalytic reformer-450 psi, catalytic reformer-200 psi, alkylation plant, catalytic polymerization, pen/hex isomerization, butane isomerization, etherification, butanes splitter, dimersol, butylene isomerization, total recycle isomerization, naphtha splitter, C2-C5 dehydrogenator, cyclar unit, hydrogen plant, sulfur plant, aromatics recovery plant, lube + wax plants, FCC gasoline splitter, gas/H2 splitter, stream transfers, fuel system, steam production, power generation, and petroleum coke gasification.

Crude Oil: Alaska low-sulfur light, Alaska mid-sulfur heavy, domestic low-sulfur light, domestic mid-sulfur heavy, domestic high-sulfur light, domestic high-sulfur heavy, domestic high-sulfur very heavy, imported low-sulfur light, imported mid-sulfur heavy, imported high-sulfur light, imported high-sulfur heavy, imported high-sulfur very heavy.

Transportation Modes: Jones Act dirty marine tanker, Jones Act clean marine tanker, LPG marine tanker, import tankers, clean barge, dirty barge, LPG pipeline, clean pipelines, dirty pipelines, rail/truck tankers. These cover all significant U.S. links.

D.13 Modeling Features:

Model Structure: FORTRAN callable subroutines which update the linear programming matrix, re-optimize, extract and post-process the solution results, update system variables, and produce reports.

Model Technique: Optimization of linear programming representation of refinery processing and transportation which relates the various economic parameters and structural capabilities with resource constraints to produce the required product at minimum cost, thereby producing the marginal product prices in a manner that accounts for the major factors applicable in a market economy.

Special Features: Choice of imports or domestic production of products is modeled, capacity expansion is determined endogenously, product prices include fixed and environmental costs, oxygenated and reformulated gasolines, and low-sulfur and ultra-low sulfur diesel fuels are explicitly modeled.

D.14 Non-DOE Input Sources:

Information Resources Inc. (IRI), WORLD model data, National Petroleum Council, ICF Resources, Oil and Gas Journal, U.S. EPA gasoline properties survey, Jacobs Consulting Refinery Technology database.

D.15 DOE Input Sources:

Forms:

EIA-14	Refiners' Monthly Cost Report
EIA-182	Domestic Crude Oil First Purchase
EIA-782A	Monthly Petroleum Product Sales

EIA-782B	Reseller/Retailer's Monthly Petroleum Product Sales
EIA-782C	Monthly Petroleum Products Sold into States for Consumption
EIA-759	Monthly Power Plant Report
EIA-810	Monthly Refinery Report
EIA-811	Monthly Bulk Terminal Report
EIA-812	Monthly Product Pipeline Report
EIA-813	Monthly Crude Oil Report
EIA-814	Monthly Imports
EIA-817	Monthly Tanker and Barge Movement
EIA-820	Annual Refinery Report
EIA-826	Monthly Electric Utility Sales
EIA-856	Monthly Foreign Crude Oil Acquisition
EIA-920	Combined Heat and Power Plant Report (and predecessor forms)
FERC-423	Monthly Report of Cost and Quality of Fuels for Electric Plants

In addition to the above, information is obtained from several Energy Information Administration formal publications: *Petroleum Supply Annual*, *Petroleum Supply Monthly*, *Petroleum Marketing Annual*, *Petroleum Marketing Monthly*, *Fuel Oil and Kerosene Sales*, *Natural Gas Annual*, *Natural Gas Monthly*, *Annual Energy Review*, *Monthly Energy Review*, *State Energy Data Report*, *and State Energy Price and Expenditure Report*.

D.16 Independent Expert Reviews Conducted:

Independent reviews of the PMM were conducted by:

A.S. Manne, ASM Consulting Services, July 1992
A.S. Manne, ASM Consulting Services, September 1992
N. Yamaguchi, Trans-Energy Research Associates, Inc., November 1997.
J. Urbanchuk, AUS Consultants, May 1998.
Ray Ory, independent consultant, June 2003
Terry Higgins, International Fuel Quality Center, June 2003
Fred Joutz and Inderjit Kundra, George Washington University and Statistics and Methods Group of EIA, December 2003
Julian Silk, Robert P. Trost, Michael Ye, and Inderjit Kundra, Statistics and Methods Group of EIA, November 2005
Michael Ye, Robert P. Trost, Michael Ye, Ramesh Dandekar, and Inderjit Kundra, Statistics and Methods Group of EIA, April 2009

D.17 Status of Evaluation Efforts by Sponsor:

None.

APPENDIX E

Data Quality

Appendix E. Data Quality

E.1 Quality of Distribution Cost Data

Costs relating to distributing petroleum products to end-users are incorporated by adding fixed transportation markups to the wholesale prices which include the variable and fixed refinery costs. Transportation markups for petroleum products are estimated as the average annual difference between retail and wholesale prices over the years 1990 through 2007.[1] The differences are based on wholesale prices in the producing Census Division and end-use prices (which do not include taxes) in the consuming Census Division. See Appendix F for a discussion of programs and input files used in estimating these markups.

Annual **wholesale prices** for all petroleum products are aggregated from state-level prices from the EIA-782A. The estimation and reliability of the EIA-782A data is discussed in the *Petroleum Marketing Annual 72007 (http://www.eia.doe.gov/oil_gas/petroleum/data_publications/petroleum_marketing_annual/pma.html*. See Explanatory Notes for inputs and sources.

With the exception of gasoline, non-utility distillate fuel, and jet fuel, **sectoral end-user prices** through 2005 are aggregated from prices from *State Energy Data 20052005: Prices (SEDP) (http://www.eia.doe.gov/emeu/states/_seds.html)* . The methodology behind these state-level sectoral prices is discussed in the Technical notes section (*http://www.eia.doe.gov/emeu/states/sep_prices/notes/pr_petrol.pdf*).

Gasoline, jet fuel, and non-utility distillate prices are estimated as weighted averages using end-user prices from EIA-782A and sectoral consumption from the *State Energy Data 20052005: Consumption (SEDC) (http://www.eia.doe.gov/emeu/states/_seds.html)*.

Due to a lag in the publication of the *SEDP* data, end-use price estimates for 2006 & 2007 are calculated using the same data series and methodology described in *SEDP*. The *SEDP* methodology uses prices from EIA-782A, FERC-423, EIA-759, and weights them with most recent consumption volumes from *SEDC*. Refer to *SEDC* for a discussion of the reliability of consumption data (*http://eia.doe.gov/pub/state.data/pdf/petrol.pdf*, May 2001). Year 2007 is estimated by applying the percent change of national product prices as reported in the September 2007 Short Term Energy Outlook (STEO) to each 2005 sector price.

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[1]Transportation markups for kerosene are based on the difference between end-user kerosene prices and wholesale distillate prices.

Table E1. Sources of Markup Inputs

Products	Sectors	Data Series Inputs
Distillate	CM, IN, RS	EIA-782A, SEDC
Jet Fuel	TR	EIA-782A, SEDC
Low Sulfur Diesel Fuel	TR	EIA-782A, SEDC
Motor Gasoline	CM, IN, TR	EIA-782A, SEDC
Asphalt and Road Oil	IN	SEDP, EIA-782A, SEDC
Kerosene	CM, IN, RS	SEDP, EIA-782A, SEDC
Liquefied Petroleum Gases	CM, IN, RS, TR	SEDP, EIA-782A, SEDC
Low Sulfur Residual Fuel	CM, IN	SEDP, EIA-782A, SEDC
High Sulfur Residual Fuel	TR	SEDP, EIA-782A, SEDC
Distillate	EU	SEDP, EIA-759, FERC-423
Low Sulfur Residual Fuel	EU	SEDP, EIA-759, FERC-423
High Sulfur Residual Fuel	EU	SEDP, EIA-759, FERC-423

E.2 Quality of Tax Data

In the PMM, State and Federal taxes are added to the prices of gasoline, distillate fuel, liquefied petroleum gas (LPG), jet fuel, ethanol, and methanol in the transportation sector. State taxes are assumed to keep pace with inflation (held constant in real terms) while Federal taxes are held at current nominal levels (deflated in each forecast year).[2] The Federal tax assumption reflects the overall forecast assumption of current laws and legislation. The assumption that State taxes will increase at the rate of inflation reflects an implied need for additional highway revenues as driving increases. An additional 1 percent per gallon of gasoline price is added to the State gasoline taxes to approximate local taxes.

The State taxes are added as Census Division weighted averages which are based on the most recently-available State taxes. State taxes for jet fuel are derived from unpublished data collected by the Petroleum Marketing Division of EIA, while state taxes for ethanol are taken from average prices reported in *Oxy Fuel News* (published by Hart Energy Publishing, LP). State and Federal taxes for gasoline, transportation distillate, and LPGs are based on data from the Federal Highway Administration, but are modified to include other known changes to State taxes. The quality of the State level tax data is unknown but deemed reliable. The local tax estimate of 1 percent per gallon of gasoline price is reasonable given that a comparison of two EIA data series, one including local taxes and one not, revealed a gasoline price difference of 1.6 cents-per-gallon.[3] Federal taxes, which were adjusted in January of 2001, are widely published and deemed highly reliable.

See Appendix F for a description of programs and input files used in the calculation of historical taxes and the estimation of taxes used in the price projections.

2[2]Refer to Stacy MacIntyre, *Motor Fuels Tax Trends and Assumptions*, Issues in Midterm Analysis and Forecasting 1998, DOE/EIA-0607(98), (Washington, D.C., July 1998).

[3]Macro International, Inc., *EIA-888 and EIA-878 Data Comparisons and Performance Measures*, Third Quarter 1997 (Washington, D.C., December 15, 1997).

E.3 PMM Critical Variables

The PMM contains numerous variables and parameters. Some variables have greater impact on model results than others. The following is a list of variables that we believe has a high degree of influence on PMM results. It is provided to help users understand the critical factors affecting the PMM.

- World oil price
- Product demands
- Imported crude supply curves
- Imported product supply curves
- Domestic crude production
- Prices and available supplies of methanol, ethanol, MTBE, and other ethers
- Investment cost for capacity expansion
- Market shares for gasoline and distillate types
- NGL supply volumes

Most of these variables are provided by other models in the NEMS system. Ethanol supply and prices are provided by the Ethanol Supply Model, a sub-module of the PMM, documented in Appendix I. The investment cost and market share data are developed offline and read in to the PMM.

Appendix F. Estimation Methodologies

F.1 Refinery Investment Recovery Thresholds

The threshold for expansion investment decisions is represented by the process plant cost function (PCF). The PCF considers actual cash flows associated with the operation of the individual process plants within the refinery, as well as cash flows associated with capital for the construction of new plants. It includes terms for capital-related financial charges (CFC), fixed operating costs (FOC), and other variable operating costs (OVC):

$$PCF = \Sigma_i (CFC_i + FOC_i + OVC_i) \qquad (1)$$

where

i = individual process plants that make up the petroleum refinery, such as the atmospheric crude distillation unit, fluid catalytic cracking unit, etc.

However, since the OVC_i for each processing unit are represented as a separate term in the PMM LP objective function, only the sum of the FOC_i and CFC_i is included as the coefficient in the objective function row corresponding to the unit expansion vectors (E(r)(uns)INV and L(r)(uns)BLD, respectively) in the PMM. The methodologies used to calculate the capital-related financial charges and the fixed operating costs are presented below.

Capital-Related Financial Charges (CFC)

The CFC equation includes an annual capital recovery charge (ACR) minus a depreciation tax credit (DTC):

$$CFC_i = ACR_i - DTC_i \qquad (2)$$

A discounted cash flow calculation is generally used to determine the annual capital charge for any given plant investment. The annual capital recovery charge assumes a discount rate equal to the cost of capital (COC), which includes equity (cost of equity, COE) and interest payments on any loans or other debt instruments used as part of capital project financing (cost of debt, COD). The depreciation of capital equipment is used for the purpose of determining the depreciation tax credit (DTC). Both the ACR and DTC are estimated on an after-tax basis.

Since the PMM and other energy forecasting models employ "notional" representations of U.S. petroleum refineries involving aggregation of data for many individual refineries, the cost estimating algorithm has been simplified while still capturing all the factors and costs refiners must consider when adding a new processing unit. The methodology draws upon the National Petroleum Council (NPC) study[1] and other sources.[2] Some of the steps for the cost estimate are conducted exogenous to the NEMS (Step 0 below), either by the analyst in preparing the input data or during input data preprocessing, such as the estimate for the inside battery-limit (ISBL) field cost of the process unit. The individual steps in the plant capital cost estimation algorithm are:

1) Estimation of the ISBL field cost
2) Estimation of the ISBL field cost for different refinery locations
3) Estimation of the outside battery-limit (OSBL) field cost and the total field cost
4) Estimation of total project cost
5) Estimation of capital-related financial charges
6) Convert capital-related charges to a "per-day," "per-capacity" basis

Step 1 may involve several adjustments which must be made prior to input into the PMM. The remaining steps are performed within the PMM.

Step 1 - Estimation of ISBL Field Cost

The inside battery limits (ISBL) field costs include the direct cost such as major equipment, bulk materials, direct labor costs for installation, construction subcontracts, and indirect costs . The ISBL investment cost and labor costs for most of the processing unit types modeled were initially obtained from a study by Bonner and Moore Associates (BMA),[3] and updated annually with revised estimates from EnSys Energy and Systems, Inc. (EnSys). The data for typical unit sizes and stream factors, as well as supplementary investment and labor, were obtained from the World Oil Refining, Logistics, and Distribution (WORLD) model.[4] The data used by the PMM currently represent process plants sited at a generic U.S. Gulf Coast

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[1]National Petroleum Council, *U.S. Petroleum refining – Meeting Requirements for Cleaner Fuels and Refineries*, Washington, D.C., August 1993.
[2]J.H. Gary and G.E. Handwerk, *Petroleum Refining: Technology and Economics,* 4th edition (New York: Marcel Dekker, 2001), Chapters 17 and 18.
[3]Bonner & Moore Associates, Inc., *A Capital Expansion Methodology Review of the Department of Energy's Petroleum Market Model*, prepared for the United States Department of Energy, Contract No. EI-94-25066 (Houston, TX, July 1994).
[4]EnSys Energy & Systems, Inc., *WORLD Reference Manual*, a reference for use by the analyst and management prepared for the United States Department of Energy, Contract No. DE-AC-01-87FE-61299 (Washington, D.C., September 1992).

(PADD III) location, and are in year 1993 dollars.

Step 2 - Year-Dollar and Location Adjustment to ISBL Field Costs

Before the PMM can utilize the ISBL investment cost data, it must convert the raw information via the following steps:

a) Adjust the ISBL field costs and labor costs for each processing unit (j) from 1993 dollars, first to the year-dollar (rptyr) reported by NEMS for *AEO2008*, which is in 2006 dollars, using the Nelson-Farrar refining-industry cost-inflation indices. Then the GDP chain-type price indices provided by the NEMS Macroeconomic Activity Model are used to convert from report-year dollars to 1987 year dollars used internally by the NEMS.

b) Convert the ISBL field costs in 1987 dollars for each processing unit (j) from a PADD III (Gulf Coast) basis (BM_ISBL_j) to costs of the same processing unit for other PADD regions ($RISBL_j$) via location multipliers ($INVLOC_l$). The location multipliers represent differences in material costs between the various PADD regions.

$$RISBL_j = BM\_ISBL_j * INVLOC_l / 1000 \quad (3)$$

where

$RISBL_j$ = ISBL costs for processing unit j in refining region (PADD) l, in million 1987 dollars (MM 87$)

BM_ISBL_j = ISBL costs for processing unit j in PADD III, in thousand 1987 dollars (M 87$)

$INVLOC_l$ = Location multiplier for refining region l

Location multipliers for refinery construction were developed on a PADD basis using the most recent data available from the U.S. Bureau of Labor Statistics (BLS)[5] and the EIA.[6] The development of these multipliers and assumed values for other factors is described elsewhere.[7] The recommended location multipliers for refinery construction are given below:

[5] Wages Data, U.S. Department of Labor, Bureau of Labor Statistics, available on the web at www.bls.gov/bls/blswage.htm.

[6] Refinery Capacity Data, U.S. Department of Energy, Energy Information Administration, available on the web at www.eia.doe.gov/oil_gas/petroleum/data_ publications/refinery_capacity_data/refcapacity.html.

[7] *A General Cost Estimating Methodology for New Petroleum Refinery Process Capacity,* Appendix D, prepared for the U.S.
[8] Department of Energy, National Energy Technology Laboratory, and Energy Information Administration by John Marano, Ph.D., September 2004.

Table F1. Location Multipliers for Refinery Construction

Location	Construction Location Multiplier
PADD I – U.S. East coast	1.50
PADD II – U.S. Midwest	1.29
PADD III – U.S. Gulf Coast	1.00
PADD IV – U.S. Rocky Mountain	1.40
PADD V – U.S. West Coast	1.48

Step 3 - Estimation of OSBL Cost and Total Field Cost

The outside battery-limit (OSBL) costs include the cost of cooling water, steam and electric power generation and distribution, fuel oil and fuel gas facilities, water supply, etc. The total field cost (FDC) is the sum of the ISBL and OSBL field costs. The OSBL field cost is estimated as a fraction (OSBLFAC) of the ISBL costs. Thus, the resulting FDC equation is:

$$RFDC_j = (1. + OSBLFAC) * RISBL_j \qquad \text{(MM 87\$)} \qquad (4)$$

A default value of 0.45 is assumed by the PMM for the OSBL cost factor.[8]

Step 4 – Estimation of Total Project Cost

The total project investment (TPI) is the sum of the total field cost (Eq. 4) and other one-time costs (OTC):

$$RTPI_j = RFDC_j + ROTC_j \qquad \text{(MM87\$)} \qquad (5)$$

Other one-time costs include the contractor's cost (such as home office costs), the contractor's fee and a contractor's contingency, the owner's cost (such as pre-startup and startup costs), and the owner's contingency and working capital (WC). The OTC's are estimated as a function of total field costs (FDC), using cost factors (OTCFAC). The corresponding equations are presented below.

$$OTCFAC = PCTENV + PCTCNTG + PCTLND + PCTSPECL + PCTWC \qquad (6)$$

where

PCTENV	= 0.10	Home, office, contractor fee
PCTCNTG	= 0.05	Contractor & owner contingency
PCTLND	= 0.00	Land (assuming expansion only at existing refinery)
PCTSPECL	= 0.05	Prepaid royalties, license, start-up costs
PCTWC	= 0.10	Working capital
thus, OTCFAC	= 0.30	

and

$$ROTC_j = OTCFAC * RFDC_j \quad \text{(MM 87\$)} \quad (7)$$

The TPI given above represents the total project cost for "overnight construction." The TPI at project completion and startup will be discussed in Step 4 below.

Closely related to the total project investment are the fixed capital investment (FCI) and total depreciable investment (TDI). The fixed capital investment is equal to the total project investment less working capital. It is used to estimate capital-related fixed operating costs (discussed later). A default value of 0.10 is assumed for the WC factor:

$$WRKCAP = PCTWC * RFDC_j \quad \text{(MM 87\$)} \quad (8)$$

thus,

$$RFCI_j = RTPI_j - WRKCAP \quad \text{(MM 87\$)} \quad (9)$$

The total depreciable investment is equal to the total project investment less the cost of land, interest during construction and working capital (as discussed in Step 4 below). For construction at an existing refinery site through expansion, as most likely the case in the United States, the cost of land can be assumed to be zero, and interests during construction are considered implicitly in the calculation of the capital charge factor (Step 4); thus, total depreciable investment is assumed to be approximately equal to fixed capital investment:

$$RTDI_j = RFCI_j \quad \text{(MM 87\$)} \quad (10)$$

Step 5 - Estimation of Capital-Related Financial Charges

For the purpose of determining the economic viability of expanding refinery processing capacity, capital-related financial charges (CFC), which consist of an annual capital recovery charge (ACR) and a depreciation tax credit (DTC), must be estimated from the total project investment (TPI). The ACR is based on the cost of capital (COC) for the corporation that owns the refinery where the project is located. It is assumed that projects will be financed by both debt and equity and will return the expected interest payments to creditors and the expected dividends to shareholders. Therefore, the after-tax weighted average cost of capital is an appropriate discount rate for evaluating investment opportunities.

a) Cost of Capital

The cost of capital (COC) is the weighted average of the cost of equity (COE) and cost of debt (COD). The COE represents an implied opportunity of financial return to the corporation's stockholders in the form of dividend payments and stock price appreciation. The COD is the after-tax interest rate, which a company would pay for new, long-term borrowing. In general, the required rate of return for equity investors is much higher than the required rate of return for debt investors (creditors) since the holder of common stock (equity investors) accepts all the risks involved in business ownership. The COC is related to COE and COD as follows:

$$COC = x_{eq} \times COE + x_{debt} \times COD(at) \qquad (11)$$

and,

$$COD(at) = (1 - T_{eff,l}) \times COD(bt) \qquad (12)$$

where

x_{eq}, x_{debt}	=	Fractions of equity and debt financing, respectively ($x_{debt} = 1 - x_{eq}$)
$T_{eff,l}$	=	Effective corporate income tax rate; "l" is for refining region index where all state taxes in that region are averaged to represent a single value.
at, bt	=	Indices for after- and before-taxes, respectively

Based on a review of annual financial reports of refining companies or their parent companies, the relative fraction of equity and debt used in the model is set to the capacity-weighted average determined for 2002 ($x_{eq} = 0.60$ and $x_{debt} = 0.40$).

Also, T_{eff} is related to the federal tax rate T_{fed} (FTAXRAT in the PMM) and state tax rate T_{state} (STAXRAT in the PMM, which is location dependent) as follows:

$$T_{eff,l} = T_{state,l} + T_{fed} \times (1 - T_{state,l})$$
$$= T_{fed} + T_{state,l} - T_{fed} \times T_{state,l}, \quad (13)$$

Average state and federal income tax rates were developed on a PADD basis using the most recent tax information available as of Jan. 1, 2004.[9] PADD averages were weighted based on the crude oil processing capacity within the states making up each PADD. The resulting state and federal tax rates used in the model are:

Table F2. State and Federal Corporate Income Tax Rates

Location	State	Federal
PADD I – U.S. East coast	9.32%	35%
PADD II – U.S. Midwest	7.38%	35%
PADD III – U.S. Gulf Coast	3.32%	35%
PADD IV – U.S. Rocky Mountain	4.21%	35%
PADD V – U.S. West Coast	6.76%	35%

The pre-tax cost of debt (COD(bt)) will vary based on the proportions of short-term loans and bonds. A Baa average corporate bond rate (MC_RMCORPBAA from the NEMS Macroeconomic Activity Model) is used for COD(bt).

The expected opportunity cost, or cost of equity (COE), for stockholders should be comparable to what could be realized from alternative investments of similar risk. The Capital Asset Pricing Model (CAPM) is used to compute a cost of equity,[10] which is an implied investor's opportunity cost or the required rate of return of any risky investment. The model is:

$$COE = RFR + \beta \times EMRP \quad (14)$$

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[9] State Corporate Income Tax Rates, available on the web at: *www.taxfoundation.org/corporateincometaxrates.html*, and at www.taxadmin.org/fta/rate/corp_inc.html.

[10] The **capital asset pricing model** (CAPM) was introduced by Treynor (1961), Sharpe (1964) and Lintner (1965). It extended portfolio theory to introduce the notions of systematic and specific risk. More description of the model can be found at: http://www.riskglossary.com/articles/capital_asset_pricing_model.htm

The model requires three variables be specified: RFR, a "risk-free" rate; EMRP, an expected market risk premium; and β, a systematic risk coefficient relative to the stock market (referred to as the "equity beta"). In the model, the risk-free rate is based on 10-year Treasury note rates (MC_RMTCM10Y, provided by the NEMS Macroeconomic Activity Model). The EMRP and β (BEQ, in model) are assumed to be constant. Thus, the EMRP is assumed at 6.75 percent (7% for high risk) based on the expected return on market over the rate of a 10-year Treasury note (risk-free rate); and, the β is set based on the risk level of the processing unit investment (for average risk, β = 0.8; for high risk, β = 1.25).

b) Annual Capital Recovery

The annual capital recovery (ACR) is the difference between the total project investment (TPI) and the recoverable investment (RCI), all in terms of present value (e.g., at startup). The TPI estimated in Step 3 is for overnight construction (ONC). In reality, the TPI is spread out through the construction period. Land costs (LC) will occur as a lump-sum payment at the beginning of the project, construction expenses (TPI – WC – LC = FCI - LC) will be distributed during construction, and working capital (WC) expenses will occur as a lump-sum payment at startup. Thus, the TPI at startup (present value) is determined by discounting the construction expenses (assumed as discrete annual disbursements) and adding working capital (WC):

$$TPI(startup) = F_v(COC,N_{con}) \times LC + F_{v,n}(COC,N_{con}) \times (\ TPI(ONC) - LC - WC\ ) + WC \tag{15}$$

where

- F_v = Future-value compounding factor for an instantaneous payment made n years before the startup year
- $F_{v,n}$ = Future-value compounding factor for discrete uniform payments made at the beginning of each year starting n years before the startup year.

The future-value factors are a function of the number of compounding periods (n), and the interest rate (r) assumed for compounding. In this case, (n) equals the construction time in years before startup (N_{con} years), and the compounding rate used is the cost of capital (COC). The formulae for computing each of the discrete compounding factors are:

$$F_v(COC,N_{con}) = (1. + COC)^{**} N_{con} \tag{16}$$

$$F_{v,n}(COC,N_{con}) = (\ \sum_{k=1,\ N_{con}} (\ (1.+ COC)^{**}k)\ )\ /\ N_{con} \tag{17}$$

The recoverable investment (RCI) includes the value of the land and the working capital (assumed not to depreciate over the life of the project), as well as the salvage value (SV) of the used equipment:

$$RCI = LC + WC + SV \qquad \text{(MM87\$)} \qquad (18)$$

The present value of RCI is subtracted from the TPI at startup to determine the present value of the project investment (PVI):

$$PVI(startup) = TPI(startup) - P_v(COC,N_{asset}) \times RCI \qquad \text{(MM87\$\})} \qquad (19)$$

Where

P_v = Present-value discounting factor for an instantaneous payment made n years (project life) in the future. The present-value factor is a function of the number of discounting periods (n), and the interest rate (r) used for discounting. In this case, (n) equals the asset's economic life in years N_{asset}, and the discounting rate is the cost of capital COC:

$$P_v(COC,N_{asset}) = 1./((1.+COC)^{**} N_{asset}) \qquad \text{(MM87\$)} \qquad (20)$$

If the cost of land is assumed to be zero, and the salvage value is equal to dismantling costs, then the PVI(startup) can be reduced to:

$$PVI(startup) = F_{v,n}(COC,N_{con}) \times FCI + (1 - P_v(COC,N_{asset}) \times WC) \qquad (21)$$

Thus, the annual capital recovery (ACR) is given by:

$$ACR(at) = A_v\,(COC,N_{asset}) \times PVI(startup) \qquad \text{(MM87\$/yr)} \qquad (22)$$

where

A_v = uniform-value leveling factor for a periodic payment (annuity) made at the end of each year for (n) years in the future, and (at) signifies that the required annual capital recovery is on an after-tax basis. The uniform-value factor is a function of the number of periods (n), and the interest rate (r), where (n) equals the asset's economic life in years N_{asset}, and the discounting rate is the cost of capital COC, as defined by:

$$A_v\ (COC,N_{asset})\ = (COC\ *((1.+COC)**\ N_{asset}))\ \ /\ (((1.+\ COC)**\ N_{asset})\ -1.) \qquad (23)$$

A construction period of 2 years and asset life of 20 years are assumed for construction of a new plant within an existing refinery.

c) Depreciation Tax Credit & Capital-Related Financial Charges

The depreciation tax credit (DTC) is based on the depreciation schedule for the investment and the total depreciable investment (TDI). The simplest method used for depreciation calculations (and used in the PMM) is the straight-line method, where the total depreciable investment is depreciated by a uniform annual amount over the tax life of the investment. Generic equations representing the present value and the levelized value of the annual depreciation charge are:

$$PVD_{DPM}(startup)\ =\ P_{v,DPM}(COC,N_{tax}) \times TDI \qquad \text{(MM87\$)} \qquad (24)$$

$$DTC(at)\ =\ A_v\ (COC,N_{asset}) \times T_{eff}\ \times PVD_{DPM}(startup) \qquad \text{(MM87\$/yr)} \qquad (25)$$

where

$P_{v,DPM}$ =Present-value discounting factor for depreciation, which is a function of the number of discounting periods (n), and the interest rate (r)

A_v = is the uniform-value leveling factor

T_{eff} = Effective combined income tax rate

at = Signifies the depreciation tax credit on an after-tax basis.

In this case, (n) equals the tax life in years N_{tax}, and (r) equals the cost of capital COC. The subscript DPM signifies the depreciation method used (i.e., straight-line method). If the tax life N_{tax} is assumed to be equal to the asset life N_{asset}, then the leveled depreciation tax credit (DTC) can be represented as follows:

$$DTC(at)\ =\ T_{eff}\ \times TDI\ \ / N_{asset} \qquad \text{(MM87\$/yr, DPM = SRL, } N_{tax} = N_{asset}\text{)} \qquad (26)$$

Finally, the capital-related financial charges (CFC) are set equal to the ACR less the DTC, after taxes (at) and before taxes (bt):

$$CFC(at)\ =\ ACR(at)\ -\ DTC(at) \qquad \text{(MM87\$/yr)} \qquad (27)$$

and,

$$CFC(bt) = CFC(at) / (1 - T_{eff}) \qquad \text{(MM87\$/yr)} \qquad (28)$$

Step 6 - Convert Fixed Operating Costs to a "per-day," "per-capacity" Basis

The annualized capital-related financial charge is converted to a daily charge, and then converted to a "per-capacity" basis by dividing the result by the operating capacity of the unit being evaluated. The result is a fixed operation cost on a per-barrel basis. It is the after-tax CFC that is included in the process plant cost function (PCF) presented in equation (1) above.

Refinery Unit Fixed Operating Costs

Fixed operating costs (FOC), a component of total product cost, are costs incurred at the plant that do not vary with plant throughput, and any other costs which cannot be controlled at the plant level. These include such items as wages, salaries and benefits; the cost of maintenance, supplies and repairs; laboratory charges; insurance, property taxes and rent; and other refinery overhead. These components can be factored from either the operating labor requirement or the capital cost. The accuracy of this type of estimate should be within ±50 percent.

Like capital cost estimations, operating cost estimations, involve a number of distinct steps. Some of the steps associated with the FOC estimate are conducted exogenous to NEMS (Step 0 below), either by the analyst in preparing the input data or during input data preprocessing. The individual steps in the plant fixed operating cost estimation algorithm are:

0) Estimation of the annual cost of direct operating labor
1) Year-dollar and location adjustment for operating labor costs (OLC)
2) Estimation of total labor-related operating costs (LRC)
3) Estimation of capital-related operating costs (CRC)
4) Convert fixed operating costs to a "per-barrel" basis

Step 0 involves several adjustments which must be made prior to input into the PMM; steps 1-4 are performed within the PMM.

Step 1 – Estimation of Direct Labor Costs

Direct labor costs are reported based on a given processing unit size. The operating labor cost data for most of the processing unit types modeled in the PMM were initially obtained from a study by Bonner and Moore Associates (BMA), and updated annually with revised estimates from EnSys. The actual data were obtained from the World Oil Refining, Logistics, and Distribution (WORLD) model.[11] The data used by the PMM currently represent process plants sited at a generic U.S. Gulf Coast (PADD III) location, and are in year 1993 dollars.

Step 2 – Year-Dollar and Location Adjustment for Operating Labor Costs

Before the PMM can utilize the labor cost data, it must convert the raw information via the following steps:

a) Adjust the labor costs for each processing unit (j) from 1993 dollars, first to the year-dollar (rptyr) reported by NEMS for AEO2008, which is in 2006 dollars, using the Nelson-Farrar refining-industry cost-inflation indices. Then the GDP chain-type price indices provided by the NEMS Macroeconomic Activity Model are used to convert from report-year dollars to 1987 dollars used internally by the NEMS.

b) Convert the 1987 operating labor costs for each processing unit (j) from a PADD III (Gulf Coast) basis into regional (other U.S. PADDs) costs using regional (l) location factors. The location multiplier (LABORLOC) represents differences in labor costs between the various locations and includes adjustments for construction labor productivity.

$$RLABOR_{j,i} = BM\_LABOR_j * LABORLOC_i \quad \text{(87\$/calendar day)} \qquad (29)$$

Location multipliers for refinery operating labor were developed on a PADD basis using the most recent data available from the U.S. Bureau of Labor Statistics (BLS)[12] and the EIA.[13] The recommended location multipliers for refinery construction are given below:

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[11]EnSys Energy & Systems, Inc., *WORLD Reference Manual*, a reference for use by the analyst and management prepared for the United States Department of Energy, Contract No. DE-AC-01-87FE-61299 (Washington, D.C., September 1992).

[12]Wages Data, U.S. Department of Labor, Bureau of Labor Statistics, available on the web at *www.bls.gov/bls/blswage.htm*.

[13]Refinery Capacity Data, U.S. Department of Energy, Energy Information Administration, available on the web at *www.eia.doe.gov/oil_gas/petroleum/data_ publications/refinery_capacity_data/refcapacity.html*.

Table F3. Location Multipliers for Refinery Operating Labor

Location	Operating Labor Multiplier
PADD I – U.S. East coast	1.11
PADD II – U.S. Midwest	0.98
PADD III – U.S. Gulf Coast	1.00
PADD IV – U.S. Rocky Mountain	1.07
PADD V – U.S. West Coast	1.06

Step 3 - Estimation of Labor-Related Fixed Operating Costs

Fixed operating costs related to the cost of labor include the salaries and wages of supervisory and other staffing at the refinery, charges for laboratory services, and payroll benefits and other plant overhead. These labor-related fixed operating costs (LRC) can be factored from the direct operating labor cost (OLC). This relationship is expressed by:

$$LRC = M_{LRC} * OLC \qquad \text{(M87\$/yr)} \qquad (30)$$

where

M_{LRC} = Aggregate of LRC cost multipliers relating the LRC to the cost of direct operating labor cost (OLC). Default values of 0.55 for supervisory/staff and 0.39 for benefits/overhead are combined in the following set of component equations to produce the aggregate multiplier of 2.15.

FXOC_STAFF = 0.55*OLC <supervisory/staff>
FXOC_OH = 0.39*FXOC_STAFF <benefits/OH>
RLABOR = OLC <labor>

$$\begin{aligned} LRC &= FXOC\_STAFF + FXOC\_OH + RLABOR \\ &= (0.55*OLC) + 0.39*(0.55*OLC) + OLC \\ &= 2.15 * OLC \qquad \text{(M87\$/yr)} \qquad (31) \end{aligned}$$

Step 4 - Estimation of Capital-Related Fixed Operating Costs
Capital–related fixed operating costs (CRC) include insurance, local taxes, maintenance, supplies, non-labor related plant overhead, and environmental operating costs. These costs can be factored from the fixed capital investment (FCI). This relationship is expressed by:

$$CRC = M_{CRC} * FCI \qquad (MM87\$/yr) \qquad (32)$$

where

M_{CRC} = Sum of CRC cost multipliers.

The multipliers used in the PMM are defined in the table below:

Table F4. Capital-Related Fixed Operating Cost Multipliers

Yearly Insurance	0.005
Local Tax Rate	0.01
Yearly Maintenance	0.03
Yearly Supplies, Overhead, Etc.	0.005

Step 5 - Convert Fixed Operating Costs to a "per-capacity" Basis
On a "per-capacity" basis, the FOC is the sum of capital-related operating costs and labor-related operating costs, divided by the operating capacity of the unit being evaluated.

Deviations from the PCF Calculations

There are a few instances where part or all of the PCF procedures were altered. These are listed below.

- The coker units (KRD and KRF) in the PMM are allowed to be financed at 100% debt because they serve to monetize crude assets that would otherwise be stranded. Thus, cost of capital is calculated:

    - $COC = COD(at)$ (from equation 11 above)

- Because of the unproven new technology, the S-Zorb distillate unit (PSZ) in the PMM is modeled with a higher set of risk factors associated with the cost of equity, and is required to be financed at

100% equity. The COE factors impacted are the expected market risk premium (EMRP=0.07 vs. 0.0675) and the equity beta coefficient (β=1.25 vs. 0.8).

- $COE = RFR + \beta \times EMRP$
  (from equation 14 above)

- Because of the unique processing characteristics for coal-to-liquids (CTL), numerous cost factors were set differently for the CTL, as defined below (from the input file *rfinvest.txt*):
  - ! except OSBL, all as percent of Total Field Cost (FDC)
  - CTL_BLDYRS = 4 ! Construction years
  - CTL_PRJLIFE = 20 ! Project life (updated 9-05-07)
  - CTL_OSBLFAC = 0.00 ! ratio OSBL/ISBL
  - CTL_PCTENV = 10.0 % !@! Home Office +Contractor's fee
  - CTL_PCTCNTG= 10.0 % ! Contractor's +Owners Contingency
    CTL_PCTLND = 4.0 % ! Land
  - CTL_PCTSPECL= 5.0 % ! Prepaid Royalties &License +Start-up costs
  - CTL_PCTWC = 10.0 % ! Working Capital
  - CTL_STAFF_LCFAC = 55.0 % ! Supervisory & other Staffing (% of Op Labor)
  - CTL_OH_LCFAC = 39.0 % ! Benefits and other OH (% of Op Labor + Staffing)
  - CTL_INVLOC = 1.16, 1.00, 1.00, 1.08, 1.15 ! Location factor by PADD

- To represent cost improvements over time (due to learning), a decline rate of 0.5% (CTL_DCLCAPCST) is applied to the original CTL capital costs after builds begin. However, once the capacity builds exceed 330,000 bbl/cd, a supplemental algorithm is applied to increase costs in response to impending resource depletions. A separate term representing co-generated electricity transmission costs is also included. More details on CTL cost assumptions are presented in section F.18.

- A cost factor has been established for the ultra low sulfur diesel production units (HD1, HD2, HS2) to represent the cost difference between new and revamped units. The assumption is that unit additions will be 2/3 revamp (50% cost) and 1/3 new (100% cost) units. This results in a cost factor of 2/3, at 100% cost. This cost factor (DSU_CSTFAC, defined in the input file *rfinvest.txt*) is applied to the total PCF defined in equation 1 above (with OVC accounted for separately).

  - $PCF = \Sigma_i (CFC_i + FOC_i)$ (from equation 1 above)

F.2 Gas Plant Models

The gas plant models for each PADD are recorded on a spreadsheet maintained within EIA by the Oil and Gas Division. These models require gas plant wet gas volumes as input. In order to accommodate the information available and permit gas plant activity to be driven by dry natural gas demand, factors are applied to dry gas production volumes to calculate imputed volumes of processed wet gas. The PMM uses California gas processing plants as a proxy for PADD V. Although Alaska produces and processes a considerable volume of natural gas, it is nearly all re-injected with some NGL dumped into the crude pipeline with the exception of modest volumes of southern Alaska production (provided by OGSM using the NEMS variable OGNGLAK). The southern Alaska production has a local NGL market with much of the dry gas shipped to Japan as LNG. In any case, the PADD V refinery industry is virtually unaffected by Alaska NGL production, and California serves as a proxy for the district. Thus, the PMM aggregate gas plant for PADD V includes California only.

The basic model structure for the gas plant was originally devised from the Pace Consultants annual petrochemical report[14] and has been modified over the years as gas markets have evolved. Natural Gas Liquids (NGL) extraction data have been calculated by averaging actual liquid extraction volumes from the 5-year period 2000 – 2004.[15] A ratio of these liquid volumes to wet gas input was developed at the PADD level. These data are contained in the MRM Table GASPLT in file nrfplant.dat (see Appendix G), and are shown in Table F5 for illustrative purposes.

Table F5. Gas Plant Model Liquid Component Yields
(M bbls per Mmcf of wet gas)

	PADD I	PADD II	PADD III	PADD IV	PADD V
Ethane	2.69	29.04	20.94	14.54	0.02
Propane	25.03	24.20	14.78	9.98	1.62
Iso Butane	4.19	4.65	5.65	1.68	1.97
Normal Butane	8.55	7.47	3.09	4.22	1.11
Natural Gasoline	8.11	8.16	7.53	5.23	4.31

[14] Pace Petrochemical Service, *Annual Issue*, (Houston, TX, September 1989).

[15] Energy Information Administration, *Petroleum Supply Annual 1992-2004*, DOE/EIA, and similarly, the *Natural Gas Annual* for years 1992-2004.

Since wet gas volumes sent to the gas plant are not available to the PMM, but marketed dry gas volumes are, a relationship was developed to calculate wet gas entering the gas plant as a function of regional dry gas to market. Dry gas to market includes both processed (through gas plant) and unprocessed (bypass) gas, net of Coal Bed Methane (CBM) and lease/plant (L&P) consumption. CBM volumes are excluded from both the wet gas input and marketed dry gas volumes because they contain little or no liquids to provide an economic incentive to process them. The marketed dry gas data is passed from the NGTDM to the PMM via a NEMS common block, as described below:

Common block:	NGTDMOUT
Variable matrix:	PRNG_PADD(PADD,YEAR), BCF
Description:	Total dry gas produced excluding lease and plant fuel (L&P) for PADD 'PADD' in year 'YEAR' excluding Alaska.

The dry gas volume in each PADD is multiplied by a factor to obtain regional estimates of the corresponding wet gas that is processed by the gas plants; i.e. in each region, the total dry gas volumes are multiplied by the ratio of processed wet gas to total dry gas production. The conversion ratios (Factor) are derived from the average of the most recent five years of data[16] with the analysis maintained offline. These data are further broken down into two additional sets of ratios used as input in Tables GASPLT and GASCAP (respectively) in the MRM file nrfplant.dat (see Appendix G): 1) a ratio of the wet gas in, to dry gas residue out of the gas plant (DGP), and 2) a ratio of the marketed dry gas volumes, to the dry gas residue out of the gas plant (FAC). These three sets of ratios are shown in Table F6 below.

Table F6. Total Dry Gas Multiplier

PADD	Factor	FAC	DGP
I	0.3343	0.3094	1.0834
II	0.6807	0.6116	1.0875
III	0.7397	0.7008	1.0723
IV	0.7708	1.0234	1.0643
V (CA)	0.7209	0.6936	1.0514

Note that the FAC and Factor data for PADD I are relatively low because little of the modest PADD I gas production is processed for liquids extraction beyond field decontamination (i.e., most marketed gas bypasses the gas plant in PADD I). The FAC multiplier is high for PADD IV because a great deal of Utah

[16]Energy Information Administration, *Natural Gas Annual* for years 1992-2002, DOE/EIA,

gas production is re-injected for field pressure maintenance. This re-injected gas is not counted in total dry gas production.

Both ethane and propane rejection can occur at the gas plant. This represents the quantity of these liquids that remain in the dry gas. A processing credit for each barrel rejected is linked in the objective function row. For *AEO2009*, ethane rejection in each PADD [G(r)SC2CC1] is limited to 15 percent (based on historical averages) of the total ethane available for extraction. Likewise, total ethane and propane rejection in each PADD [G(r)SC2SC3, Mbfoe/cd] is limited to 4 percent of corresponding total ethane and propane available for extraction [G(r)CC2CC3, Mbfoe/cd]. An additional restriction is put on the amount of ethane (NGL) allowed to transfer into the LPG stream. This is limited to 25 percent of the total ethane available for extraction from the wet gas.

F.3 Chemical Industry Demand for Methanol

The PMM incorporates methanol plant models in each PADD representing all operating methanol capacity in the U.S. Given the diverse and competing uses for methanol in both the refining and petrochemical industries, U.S. chemical industry demand (demand other than for MTBE/TAME feedstock and neat fuel) is a required input to gauge market supply pressures. The chemical industry demand requirement (Tables DEMMET and PRDDMDME) is entered in files demand.dat and rfctrl.txt, respectively. Chemical Market Associates, Inc. (CMAI) makes long range forecasts of demand for methanol [17] by the chemical industry. This forecast is outlined in Table F7.

Table F7. Chemical Industry Demand for Methanol

Year	Demand (Mbbl/d)	Year	Demand (Mbbl/d)
1990	77.7	2011	140.7
1991	73.1	2012	143.7
1992	80.0	2013	146.3
1993	83.9	2014	149.1
1994	87.7	2015	151.9
1995	90.2	2016	155.7
1996	94.6	2017	158.9
1997	100.2	2018	162.4
1998	108.8	2019	165.7

[17] CMAI, (Houston, TX), United States Methanol Chemicals Demand, (January 2004), updated July 2005.

1999	111.0	2020	169.4
2000	118.3	2021	173.0
2001	110.6	2022	176.9
2002	112.7	2023	180.7
2003	114.1	2024	184.9
2004	117.3	2025	189.0
2005	120.8	2026	193.3
2006	124.1	2027	197.8
2007	127.7	2028	202.3
2008	131.2	2029	207.0
2009	134.4	2030	211.8
2010	137.3		

The methanol plant model in each PADD is represented by a single column activity that consumes natural gas and produces methanol. Two additional transportation activities allow the methanol produced to be sent to meet the national demand for methanol by chemical plants, and transported to the refining region. At the refining region, methanol can be used to produce MTBE/TAME, splash blended into M85, or used to produce biodiesel. Also, methanol can be imported into the refining regions. Given the phase-out of MTBE as a gasoline blending component, methanol has become a less-sensitive refinery driver component within the PMM modeling structure.

Methanol plant capacity (Table MOHCAP) is updated periodically for the five PADDs in file nrfplant.dat using *Chemical Market Reporter* and other industry trade references for establishing current operating capacity. The model allows capacity expansion of methanol plants, if ever needed. However, from a practical standpoint, an abundance of mothballed plants would likely be reopened rather than implementing new construction since nearly half U.S. methanol production capacity has been closed down since the late 1990s. In mid-2005, 75 percent of methanol production capacity was shut down, and that figure was estimated to increase to 80 percent by the end of the year.

F.4 Estimation of Distribution Costs

Costs related to distributing petroleum products to end-users are incorporated by adding fixed transportation markups to the wholesale prices which include the variable and fixed refinery costs. Transportation markups for petroleum products except gasoline are estimated as the average annual difference between retail and wholesale prices.

Historically, these values were obtained by transforming a variety of different data sources into files that could be read and manipulated by mainframe SAS. EIA is transitioning away from mainframe data storage to storing and manipulating data within Oracle and MS SQL Server repositories via the Refinery Markups Database (RMD). When direct connections are available, the RMD uses connections to these servers to automatically retrieve data that are necessary to compute sector markups and generate input flat files. When direct connections are not available (as is the case with State price and consumption data), routines have been coded so that data for a specifically designed input format can be efficiently shared in NEMS.

Sector level prices provided by EIA's Office of Energy Markets and End-Use (EMEU) typically lag behind current average prices to all sectors by more than two years. The RMD uses various calculations to compute suitable proxies for Sector level prices during this time. Computer programs and data files used to estimate transportation markups are discussed below.

Data-Reading Programs

Database: RefineryMarkups.mdb

Input Files:

1) pr_pet_all_price.csv:	This is imported from a file generated by CSEDS, at the direction of EMEU staff. It contains retail prices in comma-delimited format.
2) use_pet_all_btu.csv:	This is imported from a file generated by CSEDS, at the direction of EMEU staff. It contains petroleum volumes in comma-delimited format.
3) taxfile.csv:	This file is manually developed. It contains petroleum tax information, listed by State, in comma-delimited format. It includes dollar amounts and percentages, where applicable.
4) OGIRS_data:	This includes the wholesale price data that are imported from OGIRS; data are imported via a direct ***read-only*** connection to OGIRS.

From the Data Import dialog box, you may select the desired file to import from a drop-down list. Each file to be imported must be copied to the same directory in which the **RefineryMarkup.MDB** file resides. Select the desired option and click the **Import Data** button. Data import is then performed and the various forms and tables within the Access database are automatically updated and populated.

Updating to the current year

The markups database last year is based on the HeatContent_Year table when the data is imported and created. Also, for missing values to be populated, the IRAC Table needs to have the most current value.

In addition, update the "qRetailPrice_KSRAFN_2002" query to include the year of the most recent CSEDS retail prices. This will allow the IRAC proxy variable calculations to only calculate for those years after which we already have retail prices for these fuels. This same year needs to be applied to the "qRetailPriceList_CDBasedPrice_KSARFN" query for the IRAC calculation (the > [year] criteria) to only occur after the last CSEDS year.

Also, the Federal Tax Table (CSeds_Fedtax) needs to be manually updated for the most recent year of markup calculations for the markups to be properly calculated. Otherwise the markups will be too high with the absence of the federal tax being subtracted from the retail price.

These files include the following data series from 1960-2003:

ARICB	ARICD	ARICV	AVACB	AVACD
AVACV	DFACB	DFACD	DFACV	DFCCB
DFCCD	DFCCV	DFEUB	DFEUD	DFEUV
DFICD	DFICV	DFISB	DFRCB	DFRCD
DFRCV	FNICB	FNICD	FNICV	FOICB
FOICD	FOICV	FSICB	FSICD	FSICV
JFACB	JFACD	JFACV	JFEUB	JFEUD
JFEUV	KSCCB	KSCCD	KSCCD	KSICB
KSICD	KSICV	KSRCB	KSRCD	KSRCV
LGACB	LGACD	LGACV	LGCCB	LGCCD
LGCCV	LGICD	LGICV	LGISB	LGRCB
LGRCD	LGRCV	LUACB	LUACD	LUACV
LUICB	LUICD	LUICV	MGACB	MGACD
MGACV	MGCCB	MGCCD	MGCCV	MGICB
MGICD	MGICV	MSICB	MSICD	MSICV
PCEUB	PCEUD	PCEUV	PCICD	PCICV
PCISB	RFACB	RFACD	RFACV	RFCCB
RFCCD	RFCCV	RFEUB	RFEUD	RFEUV
RFICD	RFICV	RFISB	SNICB	SNICD
SNICV	WXICB	WXICD	WXICV	

The Five letter code corresponds to the following information.

Data Identification Codes

Characters	Identity
1 and 2	represent an Energy Source (Fuel)
3 and 4	represent an Energy Consumption End-Use Sector (Sector)
5	represents a Type of Data (Type)

Energy Source (Characters 1 and 2)	
Code	**Name**
AR	asphalt and road oil
AV	aviation gasoline
DF	distillate fuel
FN	petrochemical feedstocks naphtha less than 401 degrees F.
FO	petrochemical feedstocks other oils equal to or greater than 401 degrees F.
JF	jet fuel
KS	Kerosene
LG	liquefied petroleum gases
LU	Lubricants
MG	motor gasoline
MS	miscellaneous petroleum products
PC	petroleum coke
RF	residual fuel
WX	Waxes

Energy End-Use Sectors (Characters 3 and 4)	
Code	**Name**
AC	transportation sector estimates
CC	commercial sector estimates
EI	Electric power sector estimates
EU	Electric utility sector estimates
IC	industrial sector estimates
RC	residential sector estimates
TC	total energy sector estimates

Type of Data (Character 5)	
Code	**Name**
B	Consumption in Btu. Data are in billion Btu

D	Current price per Btu. Data are in dollars per million Btu
P	Consumption in various physical units.
V	Expenditures in current dollars. Data are in millions of dollars

The other tables should be updated as well: BTU to Barrels (conversion factors), GDP87 (Macroeconomic inflators)

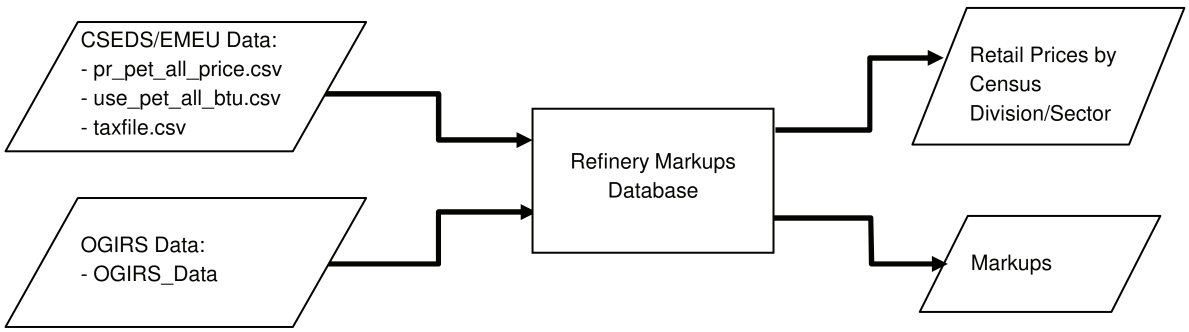
This database compiles state and sector level Retail prices to provide Census District retail prices by sector

Markup Estimating Program

The database RefineryMarkups.mdb is used to compute the differences in wholesale product prices and retail product prices. The Refinery Markups Database (RMD) is built into a single Microsoft Access database (.MDB) file, called RefineryMarkups.mdb. It includes 1 Form, 2 Macros, 53 Tables, 2 Reports, and over 100 Queries. In order to be able to import data from the Oil and Gas Information Resource System (OGIRS), the user must have "read data" permission, provided by Office of Oil and Gas, Collection and Dissemination Division personnel, on the OGIRS database.

System Flow

A basic flow chart, showing the flow of data into and out of the RMD, is shown below:



Data files are generated by the Combined State Energy Data System (CSEDS), at the direction of EMEU staff, and imported from OGIRS into the RMD, and the desired Retail, Wholesale and Markup Prices are calculated and presented in various pre-defined reports and text files created by Access.

NOTE: Users of the RMD are granted read-only access to OGIRS, for importing purposes only. Therefore, the RMD can never be used to make any changes within OGIRS, e.g., alter any Sourcekeys. More detailed instructions can be found through the Refinery Markups Documentation provided by ABACUS Technology Corporation.

F.5 Estimation of Taxes

In the PMM, taxes are added to the prices of gasoline, transportation distillate fuel (diesel), transportation liquefied petroleum gases (LPG), and jet fuel. Taxes are also estimated for E85 (transportation ethanol) and a placeholder is used for M85 (transportation methanol) because M85 prices are no longer projected by PMM. Weighted averages of the most recently available State and Federal taxes are developed for each Census Division (CD) using periodic State survey data collected by the Defense Energy Support Center (DESC).[18] The DESC data is then aggregated to the CD level in an analyst's spreadsheet using State annual product volumes obtained from the Petroleum Marketing Annual to calculate a volume-weighted CD average. The spreadsheets utilized for each product are as follows:

Gasoline- gasoline tax CD volumes.xls

[18] Defense Energy Support Center, "Compilation of United States Fuel Taxes, Inspection Fees and Environmental Taxes and Fees," June 29, 2007.

Diesel-	diesel tax CD volumes.xls
Jet-	jet tax CD volumes.xls
E85-	E85 tax CD volumes.xls

The State taxes are fixed in real terms; the Federal taxes decline at the rate of inflation (i.e., Federal taxes are fixed in nominal terms). An additional 1 percent of the retail product CD value is added to the gasoline and diesel taxes to approximate local taxes. Historical values are also calculated for gasoline, transportation distillate, jet fuel and LPG, which are then added to historical end-use prices excluding taxes in order to develop a series with taxes included. The CD taxes, including both historical and projected series by sector, product, and year, are contained in the following file, which resides in the default input directory:

MU2PRDS.txt

The Federal taxes are read into the PMM from file:

RFCTRL.txt

and are updated each forecast year by deflating the current value by the rate of inflation for that forecast year.

F.6 Gasoline Specifications

The PMM models the production and distribution of four different types of gasoline: conventional, oxygenated, reformulated, and CARB gasoline. The following specifications are included in PMM to differentiate between conventional and reformulated gasoline blends: octane, oxygen content, Reid vapor pressure (RVP), benzene content, aromatic content, sulfur content, olefin content, and the percent evaporated at 200 and 300 degrees Fahrenheit (E200 and E300).

The sulfur specification for gasoline is reduced to reflect recent regulations requiring the average annual sulfur content of all gasoline used in the United States to be phased-down to 30 ppm between the years 2004 and 2007. PMM assumes that RFG has an average annual sulfur content of 135 ppm in 2000 and will meet the 30 ppm requirement in 2004. The reduction in sulfur content between now and 2004 is assumed to reflect incentives for "early reduction." The regional assumptions for phasing-down the sulfur in conventional gasoline account for less stringent sulfur requirements for small refineries and refineries in the Rocky Mountain region. The 30 ppm annual average standard is not fully realized in conventional gasoline until 2008 due to allowances for small refineries.

Starting in 1998 the specifications for conventional gasoline reflect the Environmental Protection Agency's (EPA) "1990 baseline." These specifications prevent the quality of conventional gasoline from eroding over time, which is the intent of the EPA's "antidumping" requirements.

Oxygenated gasoline, which has been required during winter in many U.S. cities since October of 1992, requires an oxygen content of 2.7 percent by weight. Oxygenated gasoline is assumed to have specifications identical to conventional gasoline with the exception of a higher oxygen requirement. Some areas that require oxygenated gasoline will also require reformulated gasoline. For the sake of simplicity, the areas of overlap are assumed to require gasoline meeting the reformulated specifications.

Reformulated gasoline has been required in many areas of the United States since January 1995. Beginning in 1998, the EPA has certified reformulated gasoline using the "Complex Model," which allows refiners to specify reformulated gasoline based on emissions reductions either from their companies' 1990 baseline or from the EPA's 1990 baseline. In 2000 the Complex Model was tightened to require further emissions reductions. The PMM has used a set of specifications that meet these "Phase 2" Complex Model requirements, but it does not attempt to determine the optimal specifications that meet the Complex Model. Actually, gasoline currently sold in the United States slightly exceeds the quality implied in the Complex Model 2 specifications (i.e., over-compliance). Thus, in addition to assuming Complex Model 2 compliance for the RFG, *AEO2009* also reflects the "over-compliance" nature of gasoline in general (including conventional gasoline) by adopting the EPA survey of RFG properties in 2004.[19]

The State of California currently uses its own set of performance based gasoline standards instead of the Federal Complex Model standards. The PMM assumes that all West Coast refiners must meet the current California Air Resources Board "CARB 2" requirements until 2003 when a new set of "CARB 3" requirements will take their place. The CARB 3 standards reflect the removal of the oxygen requirement designed to compliment the State's plans to ban the oxygenate, methyl tertiary butyl ether (MTBE) by the end of 2003.

Other areas of California do not have an oxygen requirement but use oxygenates because of their octane boosting, and volume extending properties. RFG in the areas with the Federal oxygen requirement is classified in the PMM as "RFG" while CARB gasoline in other areas is classified as "RFH."

AEO2009 capped the ethanol volume percentage in RFG at 5.7% for California. However, the Phase 3

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[19]. Information on Reformulated Gasoline (RFG) Properties and Emissions Performance by Area and Season, U.S. EPA Office of Transportation and Air Quality, http://www.epa.gov/otaq/regs/fuels/rfg/properf/rfgperf.htm

California Reformulated Gasoline Regulations were amended effective August 29, 2008 to allow up to 10% ethanol in gasoline. See http://www.arb.ca.gov/regact/2007/carfg07/finalreg07.pdf and http://www.arb.ca.gov/fuels/gasoline/faq/faq.htm ("…ethanol is not required under either the current or the amended regulation. However, increasing ethanol from 5.7 percent to 10 percent helps to mitigate permeation emissions under the amended Predictive Model.") Effective Jan. 1, 2010 the Phase 3 regulations will be amended allow for E10 in California using very low sulfur petroleum gasoline blendstocks.

AEO2008 reflects legislation which bans or limits the use of MTBE in 25 States: Arizona, California, Colorado, Connecticut, Illinois, Indiana, Iowa, Kansas, Kentucky, Maine, Michigan, Minnesota, Missouri, Montana, Nebraska, New Hampshire, New Jersey, New York, North Carolina, Ohio, Rhode Island, South Dakota, Vermont, Washington, and Wisconsin.[20] MTBE is assumed to phase out by the end of 2008 as a result of Energy Policy Act of 2005 (EPACT05) which allows refiners to discontinue use of oxygenates in reformulated gasoline, and on the concern over MTBE's impact to surface water and groundwater resources

Arizona also has a reformulated gasoline program for the Phoenix area which is mandated by State law. Phoenix had previously been part of the Federal RFG program but opted out when State requirements were adopted. Phoenix is required to use CARB in the winter but may use either CARB or Federal RFG in the summer. Arizona is in a different model region than California and, for the sake of simplicity, is assumed to use RFG meeting Federal specifications.

Annual Average RVP Methodology

The annual average RVP limits are derived based on the latest EPA survey of summertime gasoline and estimated wintertime levels.[21] The assumed summer and winter RVP specifications had been annualized by simple averaging using summer and winter weights provided by the EPA.[22] The RVP specifications used in the PMM are shown in Table F8. The lower RVP specifications in PADD V reflect more stringent California limits that are imposed statewide.

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[20]Maine has passed legislation that provides a "goal" of phasing-out MTBE. Since the legislation is not binding, Maine is not included in *AEO2004* assumptions.

[21] *Information on Reformulated Gasoline (RFG) Properties and Emissions Performance by Area and Season*, U.S. EPA Office of Transportation and Air Quality, *http://www.epa.gov/otag/regs/fuels/rfg/properf/rfgperf.htm*

[22]The summer weight of 0.396 and winter weight of 0.604 were provided by Dave Korrotney of EPA (313-668-5507).

Table F8. Estimated Annual Reid Vapor Pressure

Gasoline Market/Type	Annual RVP in PMM				
	PADD I	PADD II	PADD III	PADD IV	PADD V
Conventional	9.6	10.2	9.9	10.8	9.2
Reformulated	8.5	9.5	8.6	8.6	7.9

Complex Model Standards for Motor Gasoline

The U.S. EPA has promulgated regulations for reformulated motor gasoline that are designed to lower vehicle emission pollutants as required by the amended Clean Air Act of 1990.[23] The reformulated gasolines are designed to reduce vehicle emissions of toxic and ozone-forming compounds. Reformulated gasoline must be sold in certain regions where there are severe ozone problems as well as in areas with less severe ozone problems which opt into the program. Conventional gasoline may be sold elsewhere but it must not be more polluting than it was in 1990. These areas are discussed elsewhere in the documentation. Although the EPA has established some conventionally treated specifications, namely minimum oxygen content and maximum benzene content, the conceptual aspect of the emission standards is that the reformulated gasoline must be blended in such a way that it meets maximum allowable emissions of volatile organic compounds (VOCs), nitrous oxides (NO_x), and toxics. These motor gasoline standards are calculated by complex formulae based upon key properties of the gasoline blend. The regulations cover Phase I (1 January 1995 through 31 December 1999) and Phase II (1 January 2000 and afterwards). The model uses a set of specifications that meet or exceed emissions requirements for Phase II of the Complex Model. Also, the refiner may meet the requirements for VOCs and NO_x on either a per gallon basis or on an average basis although some per gallon constraints still apply. The average basis has been incorporated into the model.

The NO_x and toxics emission standards for reformulated gasoline apply year-round whereas the VOC standards apply only in the summer. The NO_x standard varies depending upon whether the VOC standards apply, i.e. depending upon whether it is summer or winter. The VOC standard for the north[24] is different

[23]Federal Register, Environmental Protection Agency, Regulation of Fuels and Fuel Additives;Standards for Reformulated and Conventional Gasoline; Final Rule, Part II, 40 CFR Part 80, (Washington, DC, 16 February 1994)

[24]For the sake of simplicity, we use the terms south and north to refer to EPA regions 1 and 2 respectively. Region 1 is covered

from the VOC standard applying to the south, greater volatility is allowed in the north. The Complex Model Averaged Standards are shown below in Table F9.

Table F9. Complex Model Standards

	Phase I 1995 - 1999	**Phase II 2000+**
VOC Reduction, %		
South	≥ 36.6	≥ 29.0
North	≥ 17.1	≥ 27.4
NO_x Reduction, %		
Summer	≥ 1.5	≥ 6.8
Winter	≥ 1.5	≥ 1.5
Toxics Reduction, %	≥ 16.5	≥ 21.5
Oxygen, wt%	≥ 2.1	≥ 2.1
Benzene, %	≤ 0.95	≤ 0.95

Source: U. S. Environmental Protection Agency 40 CFR Part 80, *Regulation of Fuels and Fuel Additives: Modifications to Standards and Requirements for Reformulated and Conventional Gasoline*.

These standards were translated into conventionally configured specifications for blending motor gasoline. First, two winter specifications were developed, one for Phase I and one for Phase II. Of course, the VOC standard was excluded from consideration. Then four summer specifications were created, a south set and a north set for Phase I and similarly for Phase II. Specifications for Phase I were used in prior forecasts for years up to 1999. PMM currently uses only the Phase II specifications as 2008 is the initial forecast year. The sulfur specification is adjusted to reflect the regulations requiring the reduction of sulfur in gasoline. RFG is assumed to reach the target of 30 ppm sulfur by 2004.

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by ASTM Class B while Region 2 is covered by Class C.

These sets were developed by use of a spreadsheet, developed by EPA, which calculates the VOCs, NO_x, and Toxics of a reformulated gasoline as a function of the 'conventional' properties of the gasoline, i.e. as a function of RVP, sulfur content, oxygen content, aromatics content, olefins content, benzene content, percent evaporation at 200 degrees Fahrenheit (E200), and percent evaporated at 300 degrees Fahrenheit (E300). The approach was to start with 'best informed guess' properties and use trial and error to gradually expand the allowable property limits. The blend properties cited as typical fuels in an EPA presentation[25] served as the starting values for both Phases I and II. The same starting point was used for both winter and summer. Table F11, following a chart developed by the EPA,[26] indicates the directional sensitivities of the properties on the standards. Of course, a more rigorous approach is possible in establishing the specification sets. For instance, one might perform incremental changes over the reformulated gasoline properties followed by computer runs to establish minimum cost specifications. However, this approach was not implemented due to resource constraints.

Table F10. Directional Emission Effects of Gasoline Property Changes

Property	VOC	NO_x	Air Toxics
RVP ↓	↓ ↓ ↓	–	↓
Sulfur ↓	↓	↓ ↓ ↓	↓ ↓
Aromatics ↓	↓	↓	↓ ↓
Olefins ↓	–	↓	–
E200 ↑	↓	↑	↓
E300 ↑	↓	–	–
Oxygen ↑	–	–	↓ ↓
Benzene ↓	–	–	↓ ↓ ↓

The PMM is an annual model, i.e. it does not have seasonality. A decision was made to develop, for PADDs I-IV, a single reformulated gasoline specification for Phase I simulation and a single specification

[25]C.L. Gray, "Reformulated Gasoline Final Rulemaking and Renewable Oxygenate Proposal," Proceedings of The World Conference on Refinery Processing and Reformulated Gasoline, March 22-24, 1994, Information Resources, Inc.

[26]Ibid.

for Phase II. This required several actions. The two summer sets for Phase I were linearly blended by combining the projected gasoline sales-weighted south specifications to the appropriately weighted specifications of the north. The resulting two sets of specifications for Phase I, one for summer and one for winter, were then combined after weighting them according to summer sales and winter sales respectively. The Phase II specifications were collapsed to a single set in the same manner. The composites were calculated in a spreadsheet maintained by the Oil and Gas Division. This specification was adapted from the presentation made by Charles L. Gray at the conference cited above. The resulting reformulated gasoline specifications are shown in Table F12. It is, of course, a simple matter to convert the PMM blending stock distillation temperature values as needed.

Table F11. PMM Reformulated Gasoline Specifications

	Phase I PADDs I-IV	Phase II PADDs I-IV	Phase II with Reduced Sulfur PADDs I-IV
Max RVP, psi	8.7	8.6	8.6
Max S, ppm	305	108.75	30
Max Aro, %	25.0	25.0	25.0
Max Ole, %	12.0	12.0	12.0
Min E200, %	49.0	49.0	49.0
Min E300, %	87.0	87.0	87.0
Min Oxy, wt%	2.1	2.0	2.0
Max Ben, %	0.95	0.66	0.66

Data represent 2001 specifications to meet Complex Model standards. PMM adopted specifications in each forecast year based on the regulations in effect at the time. Therefore, in 2004 when the Tier 2 regulation kicks in, the maximum sulfur content is reduced to 30 ppm. The sulfur specification on the Complex Model is adjusted to meet Tier 2 gasoline requirements.

F.7 Estimation of Gasoline Market Shares

Within the PMM, total gasoline demand is disaggregated into demand for conventional, oxygenated, reformulated and CARB gasolines by applying assumptions about the annual market shares for each type. Annual assumptions for each region account for the seasonal and city-by-city nature of the regulations. The market shares are assumed to remain constant at the actual 2007 level.

In 2004 and onward, the Census Division 9 market share for RFG is separated into two different categories which represent CARB3 gasoline without an oxygen requirement (RFH) and CARB3 gasoline with the Federal oxygen requirement (RFG). This breakout into another product is needed to represent the planned MTBE ban in California in the absence of a waiver to the Federal RFG oxygen requirement. PMM assumes the Federal oxygen requirement remained intact in the four areas of California bound by the Federal requirement; Los Angeles, Sacramento, San Diego, and the recently added San Joaquin Valley. In effect, these areas must use ethanol to meet the oxygen requirement. The market shares assume that 60 percent of the gasoline in Census Division 9 will continue to meet the Federal RFG requirement, and 15 percent will meet California specifications.

Although the shares are assumed to remain constant after 2007, the PMM structure allows for them to change over time based on alternative assumptions about the market penetration of new fuels. This allows for flexibility to analyze the impact of differing market share assumptions and to adjust the assumptions over time based on updated information about announced participation in the oxygenated and reformulated gasoline programs.

Limitation on MTBE Blended into Gasoline

MTBE is a gasoline blending component used primarily to meet the oxygen requirement of reformulated gasoline specified by the Clean Air Act Amendments of 1990. In the past few years, the use of MTBE has become a source of debate, because it has made its way from leaking pipelines and storage tanks into water supplies. Legislation to ban/limit the use of MTBE in California and 24 other States is modeled as a requirement to produce ethanol blended gasoline in the CHGDMDS subroutine. Ethanol blends are assumed to account for the following minimum market percentages:

29.0 percent of RFG in Census Division 1
36.5 percent of RFG in Census Division 2
99.0 percent of RFG in Census Division 8
100.0 percent of RFG (with 2.0 percent oxygen requirement) in Census Division 9
100.0 percent of oxygenated gasoline in Census Division 4
100.0 percent of oxygenated gasoline in Census Division 8
100.0 percent of oxygenated gasoline in Census Division 9

Although MTBE is not explicitly banned in the Energy Policy Act of 2005, concerns for water quality and the removal of oxygenate requirement in RFG by the Energy Policy Act of 2005, the PMM assumes that MTBE would be phased out by 2008. In therfctrl.txt input file, the user can define the allowed volume percent of MTBE (combined with other undesirable ethers) for either or both conventional and reformulated gasolines, and the year the restrictions will go into effect. The constraints are defined mathematically below.

For reformulated gasoline (RFG):

$$\Sigma_{\text{ethers}}\ B(r)RFG(ethers) \leq pct * Q(r)RFG + pct * Q(r)RFH + pct * Q(r)SSR$$

and for conventional gasoline (TRG):

$$\Sigma_{\text{ethers}}\ B(r)TRG(ethers) \leq pct * Q(r)TRG + pct * Q(r)TRH + pct * Q(r)SST + pct * Q(r)SSE$$

where ethers include all or some of the following:

MTBE, ETBE, TAME, TAEE, THME, THEE (all oxygen-containing hydrocarbon compounds)

F.8 Diesel Specifications

PMM models three types of distillate fuel oil: heating oil (N2H), low-sulfur diesel (DSL), and ultra-low-sulfur-diesel (DSU). Both types of diesel fuel differ in their specifications for sulfur, aromatics content, and API gravity. DSL reflects current highway diesel fuel requirements while DSU reflects the tighter "ultra-low-sulfur-diesel" (ULSD) requirement which began phasing-in in 2006. ULSD also covers growing volumes of nonroad, locomotive and marine (NRLM) applications beginning after 2010. DSL in Census Divisions 1 through 8 is assumed to meet Federal specifications including a maximum sulfur content of 500 parts per million (ppm) and a maximum aromatic content of 35 percent by volume.[1] DSL in Census Division 9 is assumed to meet California Air Resources Board (CARB) standards that limit sulfur content to 500 ppm and aromatics to 10 percent by volume.[2]

According to the "ultra-low-sulfur diesel" (ULSD) regulation finalized in December 2000, ULSD is

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[1] Federal regulations require either a maximum 35 percent (volume) aromatics or a cetane index of 40.

[2] http://arbis.arb.ca.gov/diesel/diesregs.pdf

highway diesel that contains no more than 15 ppm sulfur at the pump. In the PMM, this new product is assumed to contain 7 ppm sulfur at the refinery gate, reflecting the general consensus that refiners will need to produce diesel with a sulfur content below 10 ppm to allow for contamination during the distribution process.

During mid-2004, the U. S. Environmental Protection Agency (EPA) finalized its new nonroad diesel rules

Final U.S. EPA Diesel Fuel Sulfur Limits

Refiner Class	6/1/2006	6/1/2007	6/1/2010	6/1/2012	6/1/2014 +
HIGHWAY DIESEL					
Non-"small" refineries	> 80% 15 ppm		15 ppm		
"Small" refineries (< 155,000 bbl/day; < 1,500 employees)	-		15 ppm		
NONROAD AND LOCOMOTIVE/MARINE (NRLM) DIESEL					
Non-"small" refineries nonroad (NR) diesel	-	500 ppm	15 ppm		
Non-"small" refineries locomotive/marine (LM) diesel	-	500 ppm		15 ppm	
"Small" refineries (< 155,000 bbl/day; < 1,500 employees)	-	-[a]	500 ppm		15 ppm[b]

a. Northeast/Mid-Atlantic requires 500 ppm for all NRLM diesel starting mid-2007.
b. LM diesel downgrade to 500 ppm is allowed indefinitely. Fifteen ppm sulfur is required at refinery gate only.

which effectively parallel the highway standards but lag by several years in implementation. The specifications and timing of each quality type by refiner class are summarized below.

In late November 2004, after *AEO2005* model runs had been frozen, CARB announced that 15-ppm diesel would be required in harbor-craft in the South Coast Air Quality Management District (SCAQMD, metro Los Angeles) by January 1, 2006.[3] The state ULSD mandate would spread statewide for harbor-craft and intrastate locomotives by January 1, 2007. Given the relatively short lead time (13 months) of the CARB rule, it is uncertain whether this accelerated timetable (versus the Federal nonroad rule) is achievable, and whether legal challenges will be mounted in the meantime by affected parties. An abundance of available ULSD arising from the highway program is the rationale for CARB's decision. Since locomotive and marine fuels represent only a very small percentage of California diesel markets, modeling impacts would have been inconsequential in *AEO2005.*

[3]"CARB to Mandate ULSD in Locomotives, Harborcraft Between 2006-2007," *World Fuels Today* (November 22, 2004), page 3.

F.9 Estimation of Diesel Market Shares

When the 2000 ULSD Federal regulations and the 2004 nonroad diesel rules are fully implemented after 2014, there will be three (3) distillate fuels in the marketplace: (a) 15 ppm highway, (b) Nonroad Locomotive & Marine (NRLM) diesel; (c) high-sulfur heating oil. The PMM has been revised to reflect this new rule and at the same time has been re-calibrated regarding market shares of highway and NRLM diesels, as well as other distillate (mostly heating oil, but excluding jet fuel and kerosene).

Historically, highway-grade diesel supplied has nearly matched total transportation distillate sales, although some highway-grade diesel has gone to non-transportation uses such as agriculture and construction. An analysis was performed to re-aggregate diesel fuel by sector and by quality to reflect individual uses for the PMM. Year 2006 historical percentages were computed from sector level data available in the Fuel Oil and Kerosene report. The following table provides an overview of how the categories were regrouped between the former listings and the new labeled applications.

Distillate Consumption

Fuel Oil & Kerosene Sales Total Distillate Consumption by Sector (Thousands of gallons per year; adjusted sales)

NEMS (SEDS) Sectors	FO & Kero Sectors				In MMBCD 1998	1999	2000	2001	2002	2005	
U.S. Total					**3.461**	**3.572**	**3.732**	**3.847**	**3.776**	**4.118**	
Residential					**0.367**	**0.381**	**0.399**	**0.409**	**0.384**	**0.362**	
Commercial					**0.199**	**0.196**	**0.217**	**0.229**	**0.199**	**0.198**	
Industrial					0.147	0.142	0.138	0.152	0.145	0.163	
	Oil Company				0.037	0.038	0.044	0.054	0.054	0.033	
	Farm				0.198	0.189	0.204	0.224	0.206	0.230	
	0.35				0.069	0.066	0.071	0.078	0.072	0.081	<- "Road" diesel
	0.65				0.129	0.123	0.132	0.146	0.134	0.150	<- "Off-highway" diesel
	Off-Highway Diesel				0.142	0.140	0.150	0.164	0.144	0.198	
	Total Industrial				**0.524**	**0.508**	**0.535**	**0.594**	**0.549**	**0.624**	
Transportation											
	On-Highway Diesel				1.967	2.091	2.161	2.167	2.238	2.482	
	Railroad				0.185	0.182	0.197	0.193	0.200	0.239	
	Vessel Bunkering				0.139	0.135	0.133	0.137	0.134	0.138	
	Military				0.018	0.019	0.015	0.023	0.021	0.018	
	Total Transportation				**2.308**	**2.427**	**2.507**	**2.519**	**2.593**	**2.877**	
Electric Power					**0.063**	**0.060**	**0.074**	**0.095**	**0.052**	**0.057**	
Diesel used for highway diesel engines & Military					1.985	2.110	2.176	2.189	2.259	2.500	<- tracked separately from the Transportation Demand Module
Rail (locomotive) & Vessel (marine)					0.323	0.317	0.331	0.330	0.334	0.377	<- tracked separately from the Transportation Demand Module
Industrial	**(2005 data)**	67%	**(1998-2002 avg)** 64%	off-highway	0.335	0.320	0.340	0.378	0.348	0.420	<- Nonroad Farm + Off-Highway + Industrial High-Sulfur (= Indust - sum of other constants)
		22%	22%	highway	0.106	0.108	0.124	0.134	0.123	0.138	<- Industrial Low-Sulfur + Farm "Road" Diesel.
		11%	14%	heating oil	0.083	0.080	0.073	0.082	0.078	0.066	<- Industrial HO + No.1 + No.4 + "oil company"
Residential & Electric HO					0.430	0.441	0.474	0.504	0.435	0.418	<- Residential and Electric Power use 100% HO (or N2H)
Commercial	**(2005 data)**	27%	**(1998-2002 avg)** 32%	highway	0.063	0.060	0.069	0.079	0.066	0.054	<- Commerical Low-Sulfur
		18%	15%	off-highway	0.032	0.031	0.031	0.032	0.031	0.036	<- Commerical High-Sulfur (= Total commerc - sum of other constants)
		55%	53%	heating oil	0.104	0.104	0.120	0.118	0.102	0.109	<- Commercial HO + No.1 + No.4
Highway (Road) Diesel					2.155	2.278	2.369	2.402	2.448	2.692	
Non-Road (Off-Highway) Diesel					0.366	0.351	0.371	0.409	0.379	0.456	
Heating Oil (HO)					0.617	0.626	0.667	0.705	0.615	0.593	
Locomotive/Marine (LM)					0.323	0.317	0.331	0.330	0.334	0.377	

Data Sources:

Fuel Oil and Kerosene Sales with Data for 2006, *www.eia.doe.gov/oil_gas/petroleum/data_publications/fuel_oil_and_kerosene_sales/foks.html*

http://tonto.eia.doe.gov/dnav/pet/pet_cons_821usea_dcu_nus_a.htm

The ULSD regulation includes a phase-in period under the "80/20" rule that requires the production of 80 percent ULSD and 20 percent 500 ppm highway diesel between June 2006 and June 2010, and a 100 percent requirement for ULSD thereafter. The phase-in path for ULSD is determined in the input file RFCTRL.TXT. As NEMS is an annual average model, only a portion of the production of highway diesel in 2006 is subject to the 80/20 rule and the 100 percent requirement does not cover all highway diesel until 2011.

Heating oil is not subject to ULSD rules. Over two-thirds of all high sulfur distillate use after 2010 will be concentrated in the Northeast.

F.10 Estimation of Regional Conversion Coefficients

Differing regional definitions necessitate the conversions of certain variables from one regional structure to another. Regional conversions are not extensive in the PMM, but are needed for five refinery input prices, refinery fuel consumption, and cogeneration information. The factors are used to convert prices consumption, or cogeneration from census districts to the PADD level since the PMM was originally constructed by PADD.

Conversions for Prices of Refinery Inputs

PMM receives prices for refinery inputs of natural gas from the NGTDM by Census Division and must convert these into PADD level prices. Due to the proximity of refineries in PADDs II, III, and IV to the sources of natural gas supply, prices in these PADDs reflect wellhead natural gas prices in the corresponding Oil and Gas Production Regions. This is achieved by scaling the industrial price for natural gas by an appropriate factor (PNGADJ). Table F12 shows the source of PADD level natural gas prices.

Table F12. Source of PMM Natural Gas Prices

Correlation of Prices	
PADD	**Input Price**
I	Census Division 2 industrial price (PGIIN) * PNGADJ
II	Census Division 4 industrial price (PGIIN) * PNGADJ

III	Census Division 7 industrial price (PGIIN) * PNGADJ
IV	Census Division 8 industrial price (PGIIN) * PNGADJ
V	Census Division 9 industrial price (PGIIN) * PNGADJ

PMM receives prices for refinery inputs of electricity by Census division. PADD level prices are derived by assuming prices in intersecting Census divisions. Table F13 shows the correlation between PADD and Census division electricity input prices.

Table F13. Source of PMM Electricity Prices

Correlation of Prices	
PADD	**Input Price**
I	Census Division 2 industrial prices (PELIN)
II	Census Division 3 industrial prices (PELIN)
III	Census Division 7 industrial prices (PELIN)
IV	Census Division 8 industrial prices (PELIN)
V	Census Division 9 industrial prices (PELIN)

Conversions for Refinery Fuel Consumption

Refinery fuel consumption must be converted from the PADD to the Census division level. Each Census division consumption number will equal the consumption in the overlapping PADDs times a factor. The factors were developed using the last 5 years of historical Census Division consumption data, aggregated, averaged, and allocated over the PADDs. Resulting percentages were put into variables PD2CD(cd)COEFF, as shown in Table F14a below. The factors are interpreted as follows: The 0.840 at the intersection of Census Division 2 and PADD I indicates that 84.0 percent of the PADD I refinery fuel consumption is estimated (using refinery operating capacity as the estimator) to occur in Census Division 2. These values will change by small amounts as refinery capacities change, but the impact on model results will be small. The same coefficients are used to disaggregate refinery electricity purchase from PADD to CD.

Example: Census Division 7 fuel consumption =
(PADD II consumption * .057) + (PADD III consumption * .933)

Table F14a. PADD to Census Division Conversion Factors

	Census Division									
	1	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**SUM**
PADD 1	0.00	0.840			0.160					1.00
PADD 2			0. 634	0. 209		0.100	0.057			1.00
PADD 3						0.067	0.933			1.00
PADD 4								1.00		1.00
PADD 5									1.00	1.00

Conversions for Cogeneration

Information including cogeneration levels (RFCGGEN(CD)), cogeneration capacity (RFCGCAP(CD)), refinery fuel consumption (RFCGFUEL(CD)), self-generation (RFCGSELF(CD)), and generation for grid (RFCGGRID(CD)) must also be converted from PADD level to Census divisions. The same type of procedure used for refinery fuel consumption (described above) is also used to convert the cogeneration data. However, the methodology for defining the factors is different. The factors were developed using State-level refinery operating capacity and are shown in Table F14b.

Table F14b. PADD to Census Division Conversion Factors

	Census Division									
	1	2	3	4	5	6	7	8	9	SUM
PADD 1	0.00	0.563			0.437					1.00
PADD 2			0.789	0.034		0.034	0.143			1.00
PADD 3						0.002	0.998			1.00
PADD 4								1.00		1.00
PADD 5									1.00	1.00

Conversion coefficients for cogeneration information are estimated using &6007PRJ.PMM.CAPACITY.COEFS. Manual updates to the data file were made using data from the "Oil and Gas Journal Survey," along with some minor adjustments to the program that reads the data.

F.11 Unfinished Oil Imports Methodology

PADDs I and III are the primary recipients of unfinished oil imports into the United States. In recent years, PADD V has started receiving increasing volumes of Resid and Heavy Gas Oils. Accordingly, since AEO2005, PADD V has been added and allocation factors have been revised.

The mix of unfinished imported oils flowing into the United States has changed considerably in recent years. An analysis[1] is conducted periodically and maintained offline to gauge the relative distribution of principal unfinished oils into the applicable PADDs. Of the four product import categories that EIA publishes, light gas oils are insignificant and not modeled in PMM. Naphtha, Heavy Gas Oil (HGO), and Resid are tracked and modeled. The corresponding product percentage allocation factors by PADD are shown below:

	PADD III	PADD I	PADD V
PADD Allocation Factor	.72	.18	.10
Naphtha	.10	.08	.01
HGO	.60	.77	.33

[1] Energy Information Administration, *Petroleum Supply Annual,* June 2004, Tables 3, 5, 9, and 20.

Resid	.30	.15	.65

Total unfinished oil imports are estimated as a function of crude oil input to refineries. A regression equation using annual data was developed to represent this relationship and has served over the years despite the erratic timing, magnitude, distribution, and volatility of the various unfinished oil imports into the PADDs. The most significant fundamental shift in unfinished oil imports in recent years has been the dramatic reduction in Resid imports approaching 50 percent. Consequently, the original equation has been modified proportionally to reflect this new circumstance:

U.S. Unfinished Oil Imports = -1223.00.1223 * Crude Inputs)

Total U.S. unfinished oil imports are estimated from the equation; the PADD values are then allocated to PADDs I, III, and V using the values presented in the above table.

F.12 Product Pipeline Capacities and Tariffs

Three sources were used to obtain the product pipeline data; (1) The NPC study, [4] (2) The North American Crude Oil Distribution (NACOD) model prepared by ICF for the Office of Strategic Petroleum Reserves (OSPR) during 1990-91. (3) Updates to these sources prepared by ICF in July 2003.

NACOD data for the year 2000 were used for the petroleum product pipeline capacities and tariffs (1991$). The NPC study was used for LPG and NGL pipeline capacity data. The NACOD model defines 15 crude oil demand regions (including Canada and Puerto Rico/Virgin Islands) and the NPC study uses PADD regions. The links needed for PMM, as shown in Table F15, are based on PADDs for refining regions and Census Divisions for demands.

[4]National Petroleum Council, *Petroleum Storage and Distribution, Volume 5, Petroleum Liquids Transportation*, (April 1989).

Table F15. NACOD Regions and NEMS/PMM Census Regions

NACOD Regions		NEMS/PMM Regions	
Code	Locations	Code	Locations
1	New England	1	NE, New England
2	Includes MD, DE	2	MA, excludes MD, DE
3	WV to FL	5	SA, includes MD, DE
4	KS, OK	7	WSC, includes OK, KS
5	PADD II	3, 4	WNC, ENC, and KY, TN from
6	Texas Gulf Coast	7	WSC
7	LA Gulf Coast	7	WSC
8	West Texas, NM	7	WSC, excludes NM
9	AR, No. LA, No. MS, AL	6, 7	ESC, AR, LA, MS, AL
10	PADD IV, North- ID, MT	8	MNT
11	PADD IV, South-	8	MNT
12	Alaska	9	PAC
13	Hawaii	9	PAC
14	PADD V	9	PAC, excludes NV, AZ

Many of the links shown in Table F16 and Table F17 represent more than one pipeline. In some cases, we have retained more than one link from a source to a destination in order to have a better representation of product movements.

The product pipeline capacities, excluding LPG/NGL service, are shown in Table F16. The matrix formulation used in PMM allows for separate arcs for product movements. For example, to deliver a barrel of gasoline to Dorsey, Maryland (in Census Region 2) from PADD III, (Census Region 7), requires flow on the link from PADD III to Region 6 (capacity of 3,100 Mbbl/cd) at a cost of $0.89/bbl, flow on the link from Region 6 to Region 5 (capacity of 2,600 Mbbl/cd) at a cost of $1.19/bbl, and flow on the link from Region 5 to Region 2 (capacity of 2,000 Mbbl/cd) at a cost of $0.82/bbl. The total tariff is $2.90/bbl or 6.90 cents/gallon.

Table F16. Petroleum Product Pipeline Capacities and Tariffs

Link from Refinery PADD* to **Census District (CD)**			
From PADD	To CD	Capacity (Mbbl/cd)	Rate (Wt. avg $2007/bbl)
PAD District II	2	167	1.23
PAD District II	6	120	3.42
PAD District II	7	124	1.43
PAD District II	8	60	1.02
PAD District III	3	1,100	1.51
PAD District III	4	170	1.18
PAD District III	8	180	1.24
PAD District III	6	3100	0.89
PAD District IV	4	130	1.11
PAD District IV	9	73	1.04
CD 5	2	2000	0.82
CD 6	5	2,600	1.19

*Some census district source areas are included to represent pipelines that have terminals in more than one CD

Source: July 2003 ICF update...

The LPG/NGL pipelines are shown in Table F17.

Table F17. LPG/NGL Pipelines Capacities and Tariffs

Link from Refinery PADD* to **Census District (CD)**		**Capacity (Mbbl/cd)**	**Rate (Wt. avg $2002/bbl)**
From PADD	**To CD**		
PAD District I	CD 6	5	2.00
PAD District III	CD 4	50	1.34
PAD District III	CD 3	290	1.17
PAD District III	CD 6	109	0.24
PAD District II	CD 2	56	0.45
PAD District II	CD 7	165	2.48
PAD District II	CD 5	5	0.53
PAD District II	CD 8	5	0.53
PAD District IV	CD 7	160	1.15
PAD District IV	CD 4	60	1.15

*Some census district source areas are included to represent pipelines that have terminals in more than one CD

Source: July 2003 ICF update.

F.13 Cogeneration Methodology

Electricity consumption in the refinery is a function of the throughput of each unit. Sources of electricity consist of refinery power generation, utility purchases, refinery cogeneration, and merchant cogeneration. Power generators and cogenerators are modeled in the PMM Linear Program (LP) as separate units which are allowed to compete along with purchased electricity.

Refinery Cogeneration

The refinery cogeneration unit in the PMM LP was modeled using historical data as a guideline. Cogeneration activity for each refinery was aggregated to the PADD level for incorporation into the PMM LP. Cogeneration capacity, fuel consumption, and percent sales to the utility grid were estimated from the 2006 version of EIA-920 Combined Heat and Power Plant Report. The data covers all of SIC 29, not just SIC 2911. Cogeneration investment and operating costs were derived from the 1980 Office of Technology Assessment (OTA) report "Industrial Cogeneration."

Cogeneration capacity (including planned capacity) for each refining region was derived from the EIA-860B historical data base. The LP limits utilization to 90 percent of capacity. Cogeneration capacity is allowed to expand when the value received from the additional product exceeds the investment and operating costs of the new unit. The value of adding capacity includes revenues from sales to the utility grid and the displacement of purchases of electricity. Investment costs are derived from the OTA report. The capacity expansion methodology is described in detail in Chapter 4.

Forecasted refinery cogeneration fuel consumption was derived from the NEMS Industrial Model for small cogeneration systems. A 1,000 kW capacity unit was assumed to have an overall heat rate of 14,217 btu/KWh. Converted to fuel oil equivalent, consumption of 2.26 barrels of fuel oil produces approximately 1,000 KWh of electricity and 6,530 lbs of steam. Since the LP refinery consumes fuel in barrels of fuel oil equivalent, shares of individual fuels were determined from the historical data and computed post process. The shares are allocated as follows:

Oil	8.0%
Natural Gas	77.0%
Other Gaseous Fuels	15.0%
Other	0.0%.

In the past, shares of all petroleum based fuels were aggregated under Petroleum Products. This category has now been divided into Oil and Other Gaseous Fuels.

In general, refinery cogeneration units tend to be small, designed to supply the refinery's steam and electricity needs, with a small amount of leftover capacity sold to the grid. However, if it is profitable to sell cogeneration electricity, the LP will sell all of it. Likewise if it is not profitable, it will sell none of it. To model the situation more realistically, sales to the grid were modeled using percentages derived from the historical data base. The percentage of sales to the grid for each refining region (PADD) was calculated from the 2001 data as follows:

REGION	PERCENT SOLD TO GRID
E (PADD I)	61.3
C (PADD II)	0.8
G (PADD III)	2.2
M (PADD IV)	0.8
W (PADD V)	45.8

The LP is forced to sell electricity back to the grid in these percentages at a price equal to the average price of electricity. Fixed operating costs are calculated in the model as a function of cogeneration capacity while variable operating costs are determined as a function of electricity generated. The following rates were determined from the OTA report.

Annual Fixed Cost $7.32/kW
Variable Cost $0.00565/KWh

Data from the EIA-860B report obtained from an Access query by Alan Beamon. The resulting data were manipulated in New NUGS.MDB to obtain fuel use, capacity, and capacity factors for existing refinery co-gen units. Output tables become linked input tables for the PMM history file generator "Build ELGCPUR.MDB" described in Appendix H.

Merchant Cogeneration

Merchant cogeneration is also modeled in the PMM. Merchant cogenerators are defined as non-refiner owned facilities located near refineries to provide energy to the open market and to the neighboring refinery. The PMM merchant cogeneration model parameters are based on the Central & South West Energy Inc. (CSWE) facility located adjacent to the Phillips Petroleum Company in Sweeny, Texas. CSWE supplies all of the refinery's steam and electricity requirements and receives up to three quarters of their fuel from refinery waste gases.[5] Electricity not used by Phillips, about two-thirds of total capacity, is sold on the open market.

Fuel consumption parameters for the PMM merchant plant are based on the Sweeny facility. The PMM merchant cogeneration unit consumes 1.90 barrels of fuel oil equivalent to produce 1,000 KWh of electricity and 5,200 lbs. of steam.

Initial capacity in PMM PADDs II, III, and IV is 330 MW (Sweeny plant). Base capacity in all other regions is zero. Capacity expansion methodology is the same as in the refinery cogeneration model.

[5] CarolAnn Giovando, June 1998. *1998 Powerplant Awards Sweeny Cogeneration Facility*, Power.

Investment cost for a new cogeneration facility is $580 per kW of capacity. Annual fixed cost and variable operating cost are the same as for the refinery cogeneration model.

Unlike refinery cogeneration units, merchant facilities tend to be large units designed to sell a large portion of their electricity to the grid. The PMM merchant cogeneration model assumes 67 percent of electricity generated is sold to the grid in all regions, based on the Sweeny facility. The sale price is equal to the average of the generation price and the industrial price of electricity for each PMM region. Electricity prices are obtained from the Electricity Market Model.

F.14 Natural Gas Plant Fuel Consumption

The consumption of natural gas by natural gas processing plants is modeled as a function of dry gas production. Natural gas consumed at gas processing plants is calculated as a percentage of dry gas production using data from the *Natural Gas Annual 1992*. The ratios are calculated by PADD, except for PADD V where Alaska is computed separately from the rest of PADD V.

PADD I	1.36
PADD II	2.50
PADD III	2.43
PADD IV	2.61
PADD V	2.25
ALASKA	8.93

F.15 Crude Oil Exports/Total and Alaskan

Exports of crude oil have historically been linked to the level of domestic production. A significant amount of crude oil exports used to be from Alaska. Since 2001, however, Alaska has not exported any crude oil due to increasing domestic demand and decreasing crude production in Alaska. This trend is expected to continue. As a result, crude oil exports are represented in the PMM as a percentage of only the total lower 48-state crude oil production based on the latest available data.

R_CRDEXP = QEXCRDIN(MNUMPR,HISTLYR)/RFQTDCRD(15,HISTLYR)/1000
QEXCRDIN(MNUMPR,J) = R_CRDEXP * RFQTDCRD(15,J) * 1000
Non-Alaska exp= QEXCRDIN(MNUMPR,J) * (1. - PCTEXCRD(0))
O@CRDEXP = LP matrix column name representing total Non-Alaska exports

where,

R_CRDEXP	= Historical ratio of total crude exports to total US crude production
QEXCRDIN	= Total crude exports (M bbl/cd)
RFQTDCRD	= Total US crude production (MM bbl/cd)
PCTEXCRD(0)	= Alaska percent of crude exports (currently = 0%)
MNUMPR	= Total lower 48
J	= Model year
HISTLYR	= Last year for historical data

F.16 Technology Improvement Option

A number of mechanisms for representing technological progress for key PMM refinery processing units have been implemented in the PMM. The first option allows the PMM to represent process technology improvements that will impact operating costs on any or all active processing units and/or processing modes. Thus, the user defines the processing unit(s), corresponding processing mode(s), and percentage change in variable operating cost (OVC) (positive or negative), along with a range of years over which these are phased in. The second option allows the user to define a set of processing units and corresponding output streams whose yields would change due to technology improvements. The year in which the technology will come on and the corresponding yields are also included in the input data. The third option allows the user to upgrade the properties of intermediate streams beginning in any user-specified year. The user defines the stream ID, the spec ID(s), and the new spec value(s), along with the activation year for this change. The design for each of these options is modular in that the control data are located in a file separate from the current PMM refinery technology database, and the user defines the information needed to drive the technology change. Each of these options is summarized below.

For the first option, the user has the option to change the OVC data for all processing units (global), for any number of user-defined processing units, for both (with the user-defined unit data over riding the global data), for any set of processing modes, or for nothing at all. The user defines the period over which the OVC change is phased in, as well as the total percentage change (- for a decrease and + for an increase) that is desired over the period. For the user-specified option, the user also includes the 3-digit processing unit ID(s). The last record of data in the user-specified option must begin with a # symbol to signal the end of the list. To turn off either or both options, the phase-in begin and end years must be set to 0. The control data are located at the bottom of the PMM rfcrtl.txt data file. The format of this control data is as follows:

```
C Data for Global changes to reflect Technological Progress
C      |  Phase-in Period  | Chng over period
C      | BeginYR    EndYR  | Percent Chng
@      |      Y1        Y2  | TPCT_CHNG
             0         0      0.0000

C Data for Process Unit changes to reflect Technological Progress
C      | Phase-in Period   | Chng over period  | Name of ProcUnit/ Mode
C      | BeginYR    EndYR  | Percent Chng      | Three-letter ID
@      |      Y1        Y2  | TPCT_CHNG         | UNAMID     MNAMID
x            0         0      0.0000            FCC  75H
x            0         0      0.0000            ALK        C4A
#            0         0      0.0              ---        ---
```

To activate the option to *change stream yields* for a processing unit and mode of operation, the user is required to define the processing unit(s), mode(s) and stream(s) being affected, the corresponding new yield level(s), and an activation year (not phased in for this version). The number of processing units, modes, and streams must be included in the data file to act as controls for reading and processing the data. Up to ten modes and ten streams per mode can be changed for each processing unit defined. To deactivate this option, the number of processing units is set to zero. During the processing effort, the original yield and gain levels associated with the processing unit/mode combination are first retrieved from the LP matrix. Next, the yields corresponding to streams specified by the control data are updated based on the input data. Finally, the gain is recalculated and updated in the matrix. The data format representing an activated list of new yield levels is presented below:

```
C Data for Yield improvement to reflect Technological Progress
C   | Num/Name |      |       |    MAX MODES = 10
C   | ProcUnit | Tech | # of  |      1  new |      2  new |      3  new |      4  new
C   | 3-let ID | Year | modes | mode, coeff | mode, coeff | mode, coeff | mode, coeff|
@   | -------- | ---- | ----- | ----  ----- | ----  ----- | ----  ----- | ----  -----|
        1
       FCC       2005     2      80S           75H
                                  4             8
                                 RC8   .635    UC4   .064
                                 LC8   .099    UC3   .050
                                 UC4   .089    ZR8   .286
                                 COX   .051    ZR7   .286
                                 ---   .000    ZC7   .040
                                 ---   .000    ZC8   .040
                                 ---   .000    LC1   .054
                                 ---   .000    LC2   .055
```

To activate the option to *change spec values* of intermediate streams, the user is required to define the stream(s), spec ID(s), new spec levels, and an activation year (not phased in for this version). The number of streams and spec IDs must also be included in the data file to act as controls for reading and processing the data. Up to ten spec types can be changed for each stream defined. To deactivate this option, the number of streams is set to zero. During the processing effort, the coefficients corresponding to the product component stream columns (B* and F*) and the product spec requirement rows (Q*) are updated using the stream spec data. Note, however, that a special algorithm must be used when changing the gravity and sulfur specs for streams used for blending into products. The gravity spec (GRX) must be converted using the following equation before being used to update the LP matrix:

$$coef_{gravity} = 141.5 / (131.5 + CHNGSPC_{gravity})$$

The sulfur spec (SLX) data for streams used in blending gasoline and distillate products simply must be divided by 100 (to convert from percent to decimal).

The data format representing an activated list of new spec levels for intermediate streams is presented below:

```
C Data for Spec improvement to reflect Technological Progress
C
C  SELECT FROM THE FOLLOWING LIST OF SPEC IDS:
C      GASO: R0N, M0N, RVX, E2N, E3N, SLX, OLX, ARX, BZX, PON, POX
C      DIST: SLX, GRX, VBX, LMX, FLX, FZX, AR
C  REQUIRED: WHEN CHANGING SLX, MUST ALSO CHANGE GRX, AND VICE VERSA
C
C   |      |          |       |    MAX NUM OF SPECS = 10
C   | Tech |  Stream  | # of  |      1  new |      2  new |      3  new |      4  new|
C   | Year | 3-let ID | specs | spec, value | spec, value | spec, value | spec, value|
@   | ---- | -------- | ----- | ----  ----- | ----  ----- | ----  ----- | ----  -----|
                 5
      2005     ZL8        2      BZX  2.50     RVX  10.00
      2005     8LR        3      BZX  2.40     RVX  10.00    ARX  10.00
      2005     ZR8        3      BZX  0.88     GRX  65.00    SLX 200.00
      2005     OR8        3      BZX  2.56     GRX  75.00    SLX  80.00
      2005     BR8        3      BZX  0.18     GRX  50.00    SLX 320.00
```

F.17 GTL Representation in PMM

GTL process description and data sources

The GTL process involves three steps. First, natural gas is converted into a synthesis gas by steam reforming or partial oxidation. This is followed by the Fischer-Tropsch synthesis, which converts the synthesis gas into liquid hydrocarbons. The final step involves partial upgrading of these hydrocarbons to produce liquids boiling in the range of naphtha, kerosene (jet fuel) and diesel fuel. The overall process can be operated to maximize the production of jet or diesel fuel. Naphtha is also a by-product. Generally, the naphtha has a very low octane rating and is a poor feed or blend stock for the production of gasoline. However, it is a premium starting material for the production of various petrochemicals. The jet and diesel fuels produced are of very high quality, and can be used as neat fuels or can be blended into conventional petroleum-derived fuels to improve their quality. Commercial processes for GTL have been developed by Sasol and Shell.

In the PMM, the liquid product yield from GTL is 113 bbl per million scf of natural gas. In diesel mode, 71.5% of the liquid product is produced as diesel fuel, and in jet mode, 63% of the liquid is produced as a kerosene-jet fuel. The remaining liquid product in both modes is a naphtha fraction. For a GTL plant with a nominal capacity of 34,000 BPD, the total field cost of construction is $589.6 million (2007$), estimated from information reported by Sasol for their Oryx GTL project located in Qatar.

GTL representation in the PMM

In the PMM, a gas-to-liquids (GTL) facility can be built on the North Slope in Alaska. A minimum build requirement is 50,000 bbl/d of GTL production (gas: ~500MMCFD or 180 BCF a year). The investment and operating costs change very little over time (in constant 1987 dollars). The natural gas supply is represented as a three-step supply curve in the LP. During a forecast year, total quantity on the curve represents the natural gas converted into liquids by GTL facilities at current capacity. Corresponding prices on the curve are set using the function CUM_AKNGCRV, which takes into account cumulative North Slope gas production levels (for both GTL and pipeline). During a build decision year, total quantity on the curve is set to 1.3 times the maximum gas needed for GTLs at current capacity, and prices are set as a function of cumulative North Slope gas production levels that extend 15 years beyond the current forecast year. The CUM_AKNGCRV function contains the following cumulative production/price relationship (provided by the NGTDM team at EIA for *AEO2009*):

Cumulative production of North Slope NG	**Year 2000$/mcf**
≤ 31,000 BCF/yr	Price = $0.80 /mcf
≤ 36,000 BCF/yr	Price = $1.40 /mcf
≤ 50,019 BCF/yr	Price = $3.80 /mcf
≤ 55,276 BCF/yr	Price = $4.00 /mcf
≤ 60,971 BCF/yr	Price = $4.15 /mcf
≤ 70,171 BCF/yr	Price = $4.35 /mcf
≤ 72,362 BCF/yr	Price = $4.55 /mcf
≤ 76,743 BCF/yr	Price = $4.75 /mcf
≤ 78,933 BCF/yr	Price = $4.90 /mcf
≤ 83,314 BCF/yr	Price = $5.10 /mcf
≤ 85,505 BCF/yr	Price = $5.30 /mcf
≤ 87,257 BCF/yr	Price = $5.50 /mcf
≤ 88,133 BCF/yr	Price = $5.70 /mcf
≤ 92,952 BCF/yr	Price = $6.61 /mcf
> 92,952 BCF/yr	Price = $7.55 /mcf

GTL output streams can be transported from the North Slope, through Valdez, to any of the five PMM regions. GTL mixing losses (PMM input) due to transport with the oil along the Trans-Alaska Pipeline System (TAPS) are accounted for and added to the Alaska oil total to be processed in a US refinery. A maximum flow (oil plus gas) is defined along the TAPS pipeline. [A minimum flow could also be defined, but would force the build of a GTL facility if the oil flow is below the minimum.] GTL transport costs from the North Slope to Valdez (via TAPS) are calculated within the PMM as a function of a variable cost, a fixed cost (converted to a unit cost based on t-1 GTL and oil flow), and a subsidy factor (based on value of oil if total flow is below a pipeline minimum—currently deactivated). The fixed and variable costs are determined within the PMM based on input data. GTL transport costs from Valdez to California via vessel are also defined (PMM input).

GTL and the LP matrix

The following LP variables and coefficients are related to Alaska GTL (and oil) production, transport, and accounting:

TAAMHXZ	Volume of AMH (Alaska medium sulfur - heavy) crude transported from Alaska to Valdez for export to Canada
O@CRDEXP	Other Alaskan crude exports (from South Alaska)
YAAMH5(r)	Volume of AMH crude transported from North Slope to Valdez + to

	region (r)
YAALL5(r)	Volume of ALL (Alaska low sulfur - light) crude transported from S. AK to region (r)
PADCRQ1	Total Alaskan crude production
TAALLTOT	Total ALL oil produced in Alaska
TAAMHTOT	Total AMH oil produced in Alaska
TAGTLTOT	Total GTLs transported from Alaska North Slope to Valdez along TAPS
TANSOTOT	Total oil transported from Alaska North Slope to Valdez along TAPS
WAGTLJ(r)	Total GTLs transported from Valdez to US refinery regions (r)
GTLLOSS	Percent of GTLs lost due to mixing with Alaska oil during transport along TAPS
H(r)SMD(mod)	Operating level for the SMD GTL processing unit
H(r)SOD(mod)	Operating level for the SOD GTL processing unit
N(r)NGKN1	Alaska NG supply curve, step 1
N(r)NGKN2	Alaska NG supply curve, step 2
N(r)NGKN3	Alaska NG supply curve, step 3
H(r)MPRFSL	Quantity of GTL stream SNL transferred from North Slope to Valdez
H(r)MPRFSP	Quantity of GTL stream SNP transferred from North Slope to Valdez
H(r)MPRFSE	Quantity of GTL stream SKE transferred from North Slope to Valdez
H(r)MPRFSX	Quantity of GTL stream SDX transferred from North Slope to Valdez

The following new and modified equations define the relationships between the variables defined above as related to GTL production in Alaska.

Equation 1

Total GTLs produced in Alaska and transported from the Alaska North Slope to Valdez equals the sum of the individual GTL stream types (produced by each GTL unit's mode of operation) going to each of the 5 PMM regions. The corresponding TAPS transport cost (minus GTL subsidy, if applicable) is applied to the TAGTLTOT variable. The PRICNS is calculated in the refine.f, and presented in the "Changes to PMM" subsection below. Currently, the GTL subsidy has been deactivated.

$$\textbf{CAGTLTOT:}\quad \textbf{TAGTLTOT} \quad = \quad \Sigma_r\, \Sigma_{gtl}\, \textbf{H(r)MPRF(gtl)}$$

$$\textbf{OBJ:}\quad \textbf{- (PRICNS-GTLSUB) * TAGTLTOT}$$

Equation 2
Total GTLs being transported via a U.S. flag light product vessel from Valdez to PADD (r) equals the total GTLs produced in Alaska, minus the loss due to mixing with Alaskan oil during transport. The corresponding transport cost (cst) is applied to the WAGTLJ(r) variable, and initially is set to 3.7, 3.2, 3.2, 3.2, and 0.8 for PADDs 1-5, respectively, in $87/bbl. The transport cost (cst) changes annually at the rate of 1% for every 10 cent/gal (2002$) change in transportation distillate price (PDSTR in NEMS).

C(r)GTL: $\mathbf{WAGTLJ(r) = (1. - GTLLOSS) * \Sigma_{gtl}\, H(r)MPRF(gtl)}$

OBJ: $\mathbf{- cst * WAGTLJ(r)}$

Equation 3
The mass balance equation for AMH Alaskan crude includes a gain due to mixing of GTLs during transport. This gain is accounted for in the Alaska North Slope oil stream [YAAMH5(r)].

CAAMH: $\mathbf{TAAMHTOT + GLTLOSS * TAGTLTOT = TAAMHXZ + \Sigma_r\, YAAMH5(r)}$

Equation 4
Since total North Slope Alaska crude does not consist totally of AMH crude, a separate variable (TANSOTOT) is created to represent total North Slope Alaska crude, as defined within the balance row (CANSOTOT). The corresponding TAPS transportation cost for North Slope crude is applied to the TANSOTOT variable. [Note: The OBJ row coefficient on the Y variables represents other transportation costs from Valdez to the PMM regions.]

CANSOTOT: $\mathbf{TANSOTOT = TAAMHXZ + \Sigma_r\, YAAMH5(r) - GLTLOSS * TAGTLTOT}$

OBJ: $\mathbf{- PRICNS * TANSOTOT}$
OBJ: $\mathbf{- coef(r) * YAAMH5(r)}$

Equations 5,6,7
Two row constraints account for maximum and minimum flow requirements on TAPS; and, 1 row constraint accounts for maximum NG production in Alaska for GTL use.

TAOILGTX: $\mathbf{TANSOTOT + TAGTLTOT \leq TAPSUL}$
TAOILGTN: $\mathbf{TANSOTOT + TAGTLTOT \geq TAPSLL}$
TANGKGTX: $\mathbf{\Sigma_r\, \Sigma_s\, N(r)NGKN(s) <= NGKUL}$

Equations 8,9

Balance rows were defined for AMH and ALL Alaska crude.

CAAMHTOT: $\quad$ **TAAMHTOT = .9844 * PADCRQ1**

CAALLTOT: $\quad$ **TAALLTOT = .0156 * PADCRQ1**

Equations 10-13

Other mass balance equations that intersect GTL vectors include mass balance for the GTL stream at the refinery [B(r)(gtl)], mass balance for the GTL stream generated in Alaska [H(r)(gtl)], mass balance for the Alaskan natural gas stream [H(r)NGK], and a capacity limit on the transportation mode (J) [TVPJCP]:

B(r)(gtl): $\quad$ $(1. - GTLLOSS) * H(r)MPRF(gtl) = \Sigma_{unt}\,\Sigma_{mod}\,R(r)(unt)(mod) + \Sigma_{prd} F(r)(prd)(gtl) + \Sigma_{prd}\,B(r)(prd)(gtl) + T(r)(gtl)(str)$

H(r)(gtl): $\quad$ $\Sigma_{gtl}\,H(r)MPRF(gtl) = coef_{gtl} * \Sigma_{unt}\,\Sigma_{mod}\,H(r)(unt)(mod)$

H(r)NGK: $\quad$ $\Sigma_{s}\,N(r)NGKN(s) = coef_{ngk} * \Sigma_{unt}\,\Sigma_{mod}\,H(r)(unt)(mod)$

TVPJCP: $\quad$ $... + .002 * \Sigma_{r}\,WAGTL(r)$

where,

R(r)(unt)(mod)	Refinery unit (unt) operating level for mode (mod) in region (r)
B(r)(prd)(gtl)	Quantity of GTL (gtl) blended into motor gas. product (prd) in region (r)
F(r)(prd)(gtl)	Quantity of GTL (gtl) blended into distillate product (prd) in region (r)
T(r)(gtl)(str)	Quantity of GTL (gtl) transferred into blend component (str) in region (r)

GTL in the PMM code

Four subroutines (CHGAKTRN, RFGTLCAP, RPTAKGTL, CHGTRANS) and a function (CUM_AKNGCRV) in the refine.f code define the model characteristics for GTL production in Alaska. In addition, subroutines ADDCAP and CHGBLDLIM handle the PMM ability to specify which processing units are allowed to build. A set of data in the rfinvest.txt data file define GTL parameters and control flags. The data are included below, followed by a list of the GTL variables defined.

In equations 1 and 4 above, the transport price along TAPS (PRICNS) is based on the fixed costs (TAP_FIXCST) and variable costs (TAP_VARCHG).

$$\text{PRICNS} = (\text{TAP\_FIXCST} / (\text{PIPOILNS} + \text{PIPGTLNS})) + \text{TAP\_VARCHG}$$

GTL Data (from rfinvest.txt, version 1.54)

```
==========================================================================
PMM input data related to GTL
==========================================================================
      Data:          Parameters related to GTL process
      Variables:     GTL_INCBLD    -- incremental GTL output levels for building (Mbbl/d)
                     GTL_FSTYR     -- first possible start year for facility to come on-line
                     GTL_DCLCAPCST -- annual decline rate for capital recovery costs
                     GTL_DCLOPRCST -- annual decline rate for fixed operating costs
      Source: Analyst judgment
      Notes:
---------------------------------------------------------------------------
DOCUMENTATION UPDATES:  DATE--AUTHOR--COMMENT
---------------------------------------------------------------------------
NOTES:
---------------------------------------------------------------------------
@
      50.0    GTL_INCBLD
      2015    GTL_FSTYR
      0.000   GTL_DCLCAPCST
      0.000   GTL_DCLOPRCST

==========================================================================
      Data:          Parameters related to TAPS volumes
      Variables:     TAP_MAXCAP   -- maximum capacity on TAPS (Mbbl/d)
      `              TAP_MINTHRU  -- minimum economic throughput on TAPS (Mbbl/d)
                     TAP_MINSTVOL -- minimum incremental volume above min when subsidy
                     nonzero (Mbbl/d)
                     TAP_PGTLOIL  -- fraction of GTL volume transferred to oil in TAPS (fraction)
      Source:        TAP_MAXCAP   -- analyst’s judgment
                     TAP_MINTHRU  -- analyst’s judgment
                     TAP_MINSTVOL -- analyst's judgment
                     TAP_PGTLOIL  -- analyst's judgment
---------------------------------------------------------------------------
DOCUMENTATION UPDATES:  DATE--AUTHOR--COMMENT
---------------------------------------------------------------------------
NOTES:     Changes:  9-13-07 chgd TAP_MINTHRU fr 300 to 200 Mbbl/cd per P.Budzik,J.Benneche
```

@

3000.00	TAP_MAXCAP
2200.00	TAP_MINTHRU
100.00	TAP_MINSTVOL
0.10	TAP_PGTOIL

==

Data: Parameters related to TAPS costs/prices

Variables:
TAP_FIXCST -- fixed transportation cost on TAPS (1000 $/day)
TAP_VARCHG -- variable transportation cost on TAPS ($/bbl)
TAP_OILIFT -- assumed oil lifting cost in Alaska ($/bbl)
TAP_OILADJ -- minimum upward adjustment of lift cost to set total costs (e.g., including profit) (fraction)

Source:
TAP_FIXCST -- judgment based on Alaska Department of Natural Resources graph of tariff rates and volumes
TAP_VARCHG-- judgment based on Alaska Department of Natural Resources graph of tariff rates and volumes
TAP_OILIFT -- lifting cost for oil production in Alaska
TAP_OILADJ -- analyst's judgment

DOCUMENTATION UPDATES: DATE--AUTHOR--COMMENT

NOTES:

TAPS transportation costs (PMM sets oceanic shipping costs elsewhere)

TAPS tariff = (fixed cost / throughput) + variable charge

throughput = oil prod + GTL prod (mbbl/d)

for build decision:
GTL prod = current CAPgtlns + GTL_INCBLD
Oil prod = PCTAKAMH * 1000* ($XRFQTDCRD_{10}$ + $XRFQTDCRD_{11}$ + $XRFQTDCRD_{12}$) - QEXCRDIN
Oil prod = oil_prod(t) * (oil_prod(t) / oil_prod(t-1))**3.

in general
GTL prod = current CAPGTLNS
Oil prod = oil_prod(t) = PCTAKAMH*RFQTDCRD*1000 - QEXCRDIN

Parameters for calculating GTL subsidy from oil production
if (oil_prod(t) .le. (TAP_MINTHRU + TAP_MINSTVOL))
then subsidy = [(oil prod * oil price) - (lift cost * oil prod * (1.+min add)] /GTL prod

```
------------------------------------------------------------------------
@    year $     value
     1995      2055.    TAP_FIXCST
     1995      0.90     TAP_VARCHG
     1999      10.00    TAP_OILIFT
               0.20     TAP_OILADJ

==============================================================================
```

GTL Variables

! PUT INTO PMMCOM1 INCLUDE

```
CAPGTLNS(MNUMYR)           ! TOTAL GTL CAPACITY (bbl/d)
TAP_FIXCST                 ! FIXED TRANS CST ON TAPS, 1987 dollars
TAP_VARCHG                 ! VAR TRANS CST ON TAPS, 1987 dollars/BBL
TAP_OILIFT                 ! ASSUMED OIL LIFTING CST IN AK, 1987 dollars/BBL
TAP_OILADJ                 ! MIN UPWARD ADJ OF LIFT CST, 1987 dollars/bbl
TAP_MAXCAP                 ! MAX CAP ON TAPS, MMBBL/D
TAP_MINTHRU                ! MIN ECONOMIC THROUGHPUT ON TAPS, MMBBL/D
TAP_MINSTVOL               ! MIN INCR VOL ABOVE MINTHRU, MMBBL/D
GTL_INCBLD                 ! INCR GTL OUTPUT BLD LEVEL, MBBL/D
PMMCAPI(MNUMPR,PUNITSN)          ! INITIAL REF UNIT CAPACITY, MBBL/D
GTL_FSTYR                  ! FIRST POSSIBLE START YR FOR GTL BLD, 4-digit
GTLCAP(MNUMPR,MJUMPYR)           ! GTL capacity (Mbbl/CD)
GTLGEN(MNUMPR,MJUMPYR)           ! GTL operating level (Mbbl/CD)
GTLUTZ(MNUMPR,MJUMPYR)           ! GTL utilization
Q_GTLPRD(MNUMPR,MJUMPYR)         ! QTY liquids produced from GTL
Q_GTLGAS(MNUMPR,MJUMPYR)         ! QTY gas used for GTL
```

```
! PUT INTO PMMOUT INCLUDE

AKGTL_NGCNS(MNUMYR)  ! CONSUMP OF NG IN AK FOR GTL PROD, Bcf
AKGTLPRD(MNUMYR)             ! GTL PRODUCTION IN AK, Bbl/d
AKGTLEXP(MNUMYR)             ! AK GTL EXPORTS, Bbl/d

! PUT INTO OGSMOUT INCLUDE

AKNG_SUPCRV(3,2,mnumyr) ! ALASKA NG SUPPLY CURVE, 1987 dollars/mcf, bcf
                        ! where (x,1,y) is price, (x,2,y) is quantity
```

F.18 CTL Representation in PMM

The coal-to-liquids (CTL) process has been updated in the PMM for *AEO2008* and all future analyses. The previous model was based on the Mitretek Technical Report: *Coproduction: A Green Coal Technology, by David Gray and Glen Tomlinson, March 2001*. The new model is based on a more recent report by the National Energy Technology Laboratory entitled: *Baseline Technical and Economic Assessment of a Commercial Scale Fischer-Tropsch Liquids Facility (DOE/NETL-2007/1260)*, supplemented with information from a number of other studies. The later report contains more up-to-date projections for the cost and performance of CTL plants. In addition, the old and current analyses differ in their design basis. The Mitretek analysis assumes the CTL plant will co-produce both liquid fuels and significant export power; where as, the recent report by NETL (adapted into the PMM) assumes the CTL plant maximizes the production of liquid fuels, and only a small amount of excess power is exported to the electric grid. In addition to the liquid output, the current CTL unit produces a carbon dioxide stream (SCS), which can either be released to the atmosphere, or captured by a special unit (CTS) that compresses and otherwise prepares it for transfer and storage. For *AEO2009,* however, the carbon capture option is not activated in the reference scenario (but could be altered in the future for a carbon capture and sequestration case).

The CTL facility modeled is capable of processing 20,000 TPD bituminous coal (e.g., Illinois Basin) with an energy content of 26.25 MM Btu/ton (dry), and produces 45,000 BPD of liquid hydrocarbons and 104 MW net power for sale to the grid. The liquid product consists of 43% naphtha, which is sold as a petrochemical feedstock for the production of ethylene and propylene, and 57% distillate, which is marketed as clean-burning diesel fuel. For other feedstocks to the CTL plant, product yields are adjusted based on the energy content of the coal. The capacity factor (or utilization rate) for the CTL facility is assumed to be 90 percent. CTL facilities are assumed to be located at a site near the representative refinery in each PMM refining region. Thus, coal feed is delivered to the CTL plant and liquid products are transported at a small cost to downstream industries.

Cogeneration is accounted for at the CTL facility as a function of the liquids produced. The cogenerated (cogen) electricity is partially consumed in the facility, while the net cogen is assumed to be sold to the grid at wholesale market prices (EWSPRCN, 87$/MWh, from the EMM). The revenue from cogen sales is treated as a credit by the model to offset the costs (feedstock, fixed, and operation costs) of producing CTL "liquids." The annualized transmission cost for cogen sent to the grid is accounted for in the operating cost of the CTL facility. The coal types consumed at the CTL facilities in the PMM are defined by the Coal Market Module (CMM) and are based on economic availability. The following links between coal supply regions and PADD regions define the coal supply options available for CTL facilities.

PADD I	N. Appalachian
PADD II	Western Montana, Wyoming Powder River Basin, Eastern Interior

PADD III	Rocky Mountain, Wyoming Powder and Green River Basin
PADD IV	Dakota Lignite, Powder and Green River Basin
PADD V	Western Montana, Powder and Green River Basin

A set of 40 coal supply curves are defined in the CMM, each representing a combination of supply regions, coal rank (bituminous, sub bituminous, lignite, and premium), sulfur content (compliance/low, medium, high), and mining type (deep, surface, above ground, underground). These curves are linked to 14 coal demand regions, which are linked to the five PADDs, as follows:

PADD I	coal demand region 2
PADD II	coal demand region 6
PADD III	coal demand region 10
PADD IV	split 50/50 between coal demands regions 9 and 11
PADD V	coal demand region 14

The final quantity of coal demanded is aggregated at the PADD level (Q_CTLCOAL) and sent back to the CMM for feedback.

The Mansfield-Blackman model for market penetration has been incorporated to limit penetration of this technology to a rate consistent with other new technologies of high complexity and high capital costs.[6] The indices associated with this modeling algorithm are user inputs that define the characteristics of the CTL process. They include an innovation index of the industry (IINDX), the relative profitability of the investment within the industry (PINDX), the relative size of the investment (per plant) as a percentage of total company value (SINVST), and a maximum penetration level (total number of units, CTLBLDX).

Capital costs for the CTL facility are based on the cost information (fixed charges and other operating costs) provided in the NETL report, adjusted to be consistent with the costing and financial assumptions and methods used throughout the PMM. Process contingencies were also added to the plant cost estimate to reflect the complexity of the highly-integrated CTL plant and the current state of development and demonstration of the reactor technology used to produce the liquid products. To represent cost improvements over time (due to learning), a decline rate of 0.5% (CTL_DCLCAPCST) is applied to the original CTL capital costs after builds begin. However, once the capacity builds exceed 330,000 bbl/cd, a

[6] E. Mansfield, "Technical Change and the Rate of Imitation," *Econometrica*, Vol. 29, No. 4 (1961), pp. 741-765.
A.W. Blackman, "The Market Dynamics of Technological Substitution," *Technological Forecasting and Social Change*, Vol. 6 (1974), pp. 41-63.

supplemental algorithm is applied to increase costs in response to impending resource depletions (such as competition for water). The basic algorithm is defined in a memorandum from Andy Kydes (EIA) to William Brown (EIA), entitled "CTL run-- add to total CTLCST in ADJCTLCST sub," dated September 29, 2006. Coefficients in the algorithm that were actually used in the model were modified to speed up the dampening effect on CTL builds. The final algorithm is:

CSTADD = 15*tanH(0.4*max(0.,((CTLPRODC /0.2)-1.)))

Where CTLPRODC is the CTL production (million BPD) in the previous period, and CSTADD is the added cost ($87/bbl).

In addition to these cost assumptions, the EPACT2005 permits the gasifier component of the CTL facility to receive a credit up to a total of 350 MM$ (2006). This is modeled in the PMM by using a separate representation (CTZ) for the CTL processing units allowed to claim the credit. Assuming that the gasification costs are about 35% of total CTL costs, and the EPACT2005 credit is 20% of the gasification component, the credit was estimated to be 7% of the model's capital recovery cost. The dollar limit was used as an upper limit for CTZ capacity builds.

Currently, carbon dioxide emissions are handled by the NEMS integrating model by applying a CO_2 emissions coefficient to the coal consumed by the CTL unit.

CTL and the LP matrix

The following LP variables are directly related to CTL production, transport, and accounting:

rows:

C(r)CTLTOT	Total CTL liquids produced for refinery (1000 bbl/cd)
C(r)CTL(liq)	CTL liquids produced for refinery (1000 bbl/cd)
E@CTXMBX	Totals CTL capacity built in a forecast year (national) (1000 bbl/cd)
E@CTZEPC	Cumulative total CTL capacity built with EPACT2005 gasifier credit (1000 bbl/cd)
L(r)CTXCAP	CTL capacity balance net of incentive builds (1000 bbl/cd)
L(r)CTZCAP	CTL capacity balance from incentive builds (1000 bbl/cd)
H(r)(liq), B(r)(liq)	CTL liquids balance (1000 bbl/cd)
H(r)SCS	CO2 balance from CTL production (M s-ton/cd)
H(r)BIT	Coal (into CTL unit) balance (1000 MMBtu/cd)
CL(cdm)CTL	Coal balance between coal demand region and refinery regions (1000 MMBtu/cd)
S_CL(ccv)(ct)(st)	Coal balance for each supply curve into coal demand regions (1000 MMBtu/cd)
SO2_CTL_1	SO2 emissions from coal for emissions allowance (1000 tons SO2/cd)
SO2_CTL_2	SO2 emissions from coal for emissions allowance (1000 tons SO2/cd)
HG_CTL_U	Mercury emission from coal for emissions allowance (1/1000 tons/cd)
A(r)CTXGRD	Accounting row for electricity from CTL cogen sent to grid (MWh/cd)

columns:

B(r)(gaso)(liq)	CTL liquids blended into gasolines (M bbl/cd)
F(r)(dist)(liq)	CTL liquids blended into distillates (M bbl/cd) [DSL, DSU, JTA, N2H]
K(r)CTXCAP	Existing CTL processing unit capacity, =0 (M bbl/cd)
E@CTXINV	Total CTL capacity built in 1 forecast year (national), with UL set by M-B penetration algorithm (M bbl/cd)
E(r)CTXINV	CTL processing unit additions (M bbl/cd)
L(r)CTXBLD	Cumulative CTL unit additions (M bbl/cd)
H(r)CTX(mod)	Operating level for CTL (M bbl/cd)
K(r)CTZCAP	Existing planned CTL processing unit capacity, =0 (M bbl/cd)
E(r)CTZINV	planned CTL processing unit additions (M bbl/cd)
L(r)CTZBLD	Cumulative planned CTL unit additions (M bbl/cd)
H(r)CTZ(mod)	Operating level for planned CTL (M bbl/cd)
R(r)(unt)(mod)	New mode to process liquids from CTL units (M bbl/cd)
H(r)MPRF(liq)	Vol of CTL liquids transferred to refinery (M bbl/cd)

H(r)MPWH(liq)	CTL liquids sold wholesale to market (M bbl/cd) [DSU, PCF]
N(r)BITN1	Coal supplied to refinery region for CTL processing (1000 MMBtu coal/cd)
N(r)BITXX	Seeded demand (=0.1 MMBtu/cd) to activate flow to all PADDS (for marginal pricing)
CT(ccv)(cdm)(ct)(st)	Coal transferred from coal supply curve to coal demand region (1000 MMBtu/cd)
CP(ccv)(ct)(st)(step)	Steps on coal supply curve (1000 MMBtu/cd)
CP(ccv)OTXX	Non-refinery coal demand (not PMM demand) (1000 MMBtu/cd)

Where,

r	= PMM refinery region
unt	= processing unit (CTX, CTZ)
mod	= operating mode of unt
liq	= liquid stream produced by CTL unit
step	= step on supply curve
cdm	= coal demand region (1-14)
ccv	= coal supply curve number (1-40)
ct	= coal type (rank), bituminous, sub-bituminous, lignite, and premium)
st	= coal sulfur, compliance/low, medium, high

The following equations define the relationship between the variables defined above as related to CTL production.

Coal supply mass balance:

Equations 1, 2, 3

The coal consumed at the CTL units (including planned units) to produce liquids (by region/aggregate coal type) (*plus a small seeded demand*) must be less than or equal to the coal supplied to the refinery region.

H(r)BIT: $\boldsymbol{\Sigma_{mod}\, c_l * H(r)CTX(mod) + \Sigma_{mod}\, c_l * H(r)CTZ(mod) + \textit{N(r)BITXX}}$
[1000MMBtu/cd] $\boldsymbol{\leq\ N(r)BITN1}$

The coal supplied to the refinery region for CTL production must be less than or equal to the mix of coal supplied to the coal demand region.

CL(cdm)CTL: $\boldsymbol{\Sigma_{r \in cdm}\, N(r)BITN1 \leq \Sigma_{ccv}\, \Sigma_{ct}\, \Sigma_{st}\, CT(ccv)(cdm)(ct)(st)}$
[1000MMBtu/cd]

The coal (a specific curve, rank, sulfur) supplied to the coal demand region plus the coal (same curve, rank, sulfur) demanded by non-refinery consumers must be less than or equal to the corresponding coal supply curve.

S_CL(ccv)(ct)(st): $\mathbf{\Sigma_{cdm}\ CT(ccv)(cdm)(ct)(st) + CP(ccv)OTXX \leq \Sigma_s\ CT(ccv)(ct)(st)(s)}$
[1000MMBtu/cd]

Liquids production mass balance:

Equations 4, 5

Liquids produced at the CTL unit must equal the liquids transferred to the refinery or directly to market (by region and liquid type). CTL liquids transferred to the refinery are either consumed by other processing units, blended into motor gasoline, or blended into distillates (by region and liquid type).

H(r)(liq): $\mathbf{\Sigma_{mod}\ c_2 * H(r)CTX(mod) + \Sigma_{mod}\ c_2 * H(r)CTZ(mod) =}$
[1000 bbl/cd] $\mathbf{H(r)MPRF(liq) + H(r)MPWH(liq)}$

B(r)(liq): $\mathbf{H(r)MPRF(liq) = \Sigma_{dist}\ F(r)(dist)(liq)}$ **< distillates >**
[1000bbl/cd]

-- or --

$\mathbf{H(r)MPRF(liq) = \Sigma_{mgas}\ B(r)(mgas)(liq) + \Sigma_{unt}\ \Sigma_{mod}\ R(r)(unt)(mod)}$ **<mogas>**

CTL operating/capacity balance and penetration limit:

Equations 6, 7, 8

Total operating level of CTL must equal the operating level of existing CTL capacity, newly added capacity, and cumulative added capacity. Total operating level cannot exceed upper bounds on existing, newly added, and cumulative added capacity (by region).

For unt=CTX, CTZ only

L(r)(unt)CAP: $\mathbf{\Sigma_{mod}\ H(r)(unt)(mod) = K(r)(unt)CAP + cf*E(r)(unt)INV + cf*L(r)(unt)BLD}$
[1000bbl/cd]

Newly added CTL capacity is limited to a national level defined by the M-B penetration algorithm, set as the upper limit on the "total capacity" variable (E@CTXINV).

E@CTXMBX: $\mathbf{E@CTXINV = \Sigma_r\ E(r)CTXINV + \Sigma_r\ E(r)ZCTZINV +}$
[1000bbl/cd] $\mathbf{\Sigma_r\ L(r)CTXBLD + \Sigma_r\ L(r)ZCTZBLD +}$

$$\Sigma_r\ K(r)CTXCAP\ +\ \Sigma_r\ K(r)ZCTZCAP$$

The total CTL units built that received the EPACT2005 gasifier credit must be less than or equal to the total possible capacity that reflects the maximum national credit of $350 MM (2006).

E@CTZEPC: $K(r)CTZCAP + E(r)CTZINV + L(r)CTZBLD \leq RHS_{ctz}$
[1000bbl/cd]

Total CTL liquids and electricity produced:

Equations 9,10,11

The electricity from cogeneration sold to the grid is accounted for with the variable H(r)CTXKWH, which also intersects the objective function to account for sales credit.

A(r) CTXGRD: $\Sigma_{mod}\ H(r)CTX(mod) + H(r)CTZ(mod) = H(r)CTXKWH$
(1000 KWh/cd)

These unconstrained rows total CTL liquids produced (by region) and (by region and liq type), for reporting.

C(r)CTLTOT: $\Sigma_{liq}\ H(r)MPRF(liq)$
(1000 bbl/cd)

C(r)CTL(liq): $H(r)MPRF(liq)$
(1000 bbl/cd)

Objective function:

Equation 12

A credit is put in the objective function, attached to the CTL operating variable, to account for cogen produced at the CTL and sent to the grid. A cost is added to the objective function, attached to the transfer variables H(r)CTX(mod) and H(r)CTZ(mod), to account for the transfer tariffs from CTL facility to refinery. Variable operating costs and capital investment costs are included in the objective function for the E, L, and H variables. The cost of coal on each supply step is included in the objective function. Also included is the cost to transport the coal to each coal demand region.

OBJ: $\Sigma_{mod}\ \Sigma_r\ CgnCredit * H(r)CTXKWH$
[1000$/cd] $+\ \Sigma_{liq}\ tariff\_liq * H(r)MPRF(liq)$
$+\ inv\_cst*E(r)CTXINV + inv\_cst*L(r)CTXBLD$
$+\ inv\_cst*E(r)CTZINV + inv\_cst*L(r)CTZBLD$

$$+ \ \Sigma_{s}\ \Sigma_{ccv}\ \Sigma_{ct}\ \Sigma_{st}\ \textbf{coal\_cst}_{s,ccv,ct,st} * \textbf{CP(ccv)(ct)(st)(s)}$$
$$+ \ \Sigma_{ccv}\ \Sigma_{cdm}\ \Sigma_{ct}\ \Sigma_{st}\ \textbf{c\_tariff\_cst}_{s,ccv,ct,st} * \textbf{CT(ccv)(cdm)(ct)(st)}$$

where,

CogenCredit = RFEWSPRCN(J,N)/1000.
(87$/bbl liq)

coal_cst= from CMM coal supply curves [XCL_PECP]
(87$/MM Btu coal)

tariff_liq = from CMM [P_CTLTRN]
(87$/bbl liq)

inv_cst = calculated in refine.f from investment data (includes annualized transmission cost for
(87$/bbl liq) cogen to grid from CTL facility) (see Appendix F.1)

c_tariff_cst = from CMM [-CTL_TRATE(CRV,CRG) * XCL_1TESC(CRV,PYR,CURIYR,CRG)]
(87$/bbl liq)

Updates to the PMM refine.f code

Four subroutines (CHGCTLCOEF, PMMCTL_BLDLIM, CTL_COAL, and RPTRFCTL), along with other minor changes in the refine.f code, help to model the current CTL representation in the PMM. In addition, the rfinvest.txt data file contains CTL related data, parameters, and control flags used to define costs and other CTL components. The CTL data are included in the Attachment at the end of this section. Other coal related data used with CTL production are provided by the CMM.

The PMMCTL_BLDLIM subroutine sets the maximum build allowances for two classifications of CTL units (represented as CTX and CTZ in the model). The CTZ classification is allowed to receive a credit for the gasification component costs within the CTL unit, but only up to a maximum of $350 MM (2006$). This maximum credit is translated into a maximum CTZ capacity, as defined in the constraint row E@CTZEPC. In addition, a maximum build allowance for *total* CTL capacity (CTX + CTZ) is determined using the Mansfield-Blackman model for market penetration. It tracks the number of units built nationally to determine the maximum penetration allowed for the next build cycle. This is applied to the variable E@CTXINV which is defined in the equality row E@CTXMBX.

The CHGCTLCOEF subroutine calls the CTL_COAL subroutine and updates the relevant CTL coefficients with data provided by the CMM and the EMM. These include the coal supply curves' price and quantity levels, the tariff associated with transferring the coal from the supply regions to the coal demand regions, the credit and transmission costs for cogenerated electricity sent to the grid, and the tariff for transferring CTL liquids to the refinery. In addition, emissions allowances from coal production are modeled for SO2 and mercury.

The RPTRFCTL report subroutine retrieves CTL solution results from the LP matrix and stores them into special variables -- some are passed to the CMM or to FTAB for reporting, while others are used in the PMM output tables (pmmrpts.txt). These include:

```
CLMINEP(mnumpr,mnumyr)            ! minemouth CTL coal pr (87$/ton)
CTL_CGCGD(mnumpr,mnumyr)          ! CG cap from CTL--to grid (MW)
CTL_CGGGD(mnumpr,mnumyr)          ! CG gen from CTL--to grid (1000 KWh/cd)
P_CTLCOAL(mnumpr,mnumyr)          !        PR coal used for CTL (87$/ton)
Q_CTLCOAL(mnumpr,umnumyr)         ! QTY coal used for CTL (M ton/cd)
Q_CTLPRD(mnumpr,mnumyr)           ! QTY liquids produced from CTL (M bbl/cd)
CTLFRAC(4,mnumpr,mnumyr)          ! QTY of liquids produced from CTL (M bbl/cd)
QCLRFPD(mnumpr,mnumyr)            ! Quantity of coal for CTL (trillion Btu)
PCLRFPD(mnumpr,mnumyr)            ! Pr coal for CTL (87$/MM Btu)
RFCTLPRD(mnumyr)                  ! Quantity of liquids from coal (1000 bbl/cd)
RFCTLWH(mnumyr)                   ! Quantity of liquids from coal to market (1000 bbl/cd)
RFCTLLIQ(CTL_LIQNCL)              ! QTY of each liquid from coal (1000 bbl/cd)
```

Within the existing RFUPD8_INV subroutine, an annualized transmission cost for sending cogen to the grid (two charge factors provided by the EMM: TRCTLOVR, TRCTLFCF) was added to the cost coefficient.

(Note: The cogen from CTL was put into the "other" category in the variables CGREQ, CGRECAP, CGREGEN, but classified as coal for ftab reporting.)

CTL Data in the rfinvest.txt (version 1.72) input file

```
==========================================================================
                ==

PMM input data related to CTLs-- Coal-to-Liquids

==========================================================================
                ==

     Data:  Parameters related to CTL process
Variables:  CTL_INCBLD    -- incremental CTL output levels for building (Mbbl/d)
            CTL_FSTYR     -- first possible start year for facility to come on-line
            CTL_DCLCAPCST -- annual decline rate for capital recovery costs
            CTL_DCLOPRCST -- annual decline rate for fixed operating costs
            CTL_BASHHV,dry-- coal HHV (mmBTU/ton)-- use dry because CTL yields based
                   on dry
            CTL_BASSIZ    -- CTL base size (1000 bbl/cd liq output)
            CTL_BASCOL    -- CTL base coal consump (1000 tons/cd) -- bituminous
            CTL_BASCGS    -- CTL base cogen to self (MW)
            CTL_BASCGG    -- CTL base cogen to grid (MW)
            CTL_BASCGF    -- CTL base cogen capacity factor
            CTL_NAM       -- coal type ID for CTL
            CTL_CSELAS    -- elasticity for coal supply curve, by coal type
            CTL_CO2FAC    -- lbs CO2 emitted/bbl liq produced
            CTL_CGNFAC    -- Fac to est elec cogen to Grid fr CTL (KWh/bbl liq)
            CTL_CSTFAC    -- Fac to adj CTL cap/op cost based on coal type (10% for
                   LIG, SUBBIT vs BIT)
            CTL_CLHHV     -- coal HHV (mmBTU/ton)
            P_CTLTRN      -- Cost to transport CTL liq from facility to refinery
                   ($/bbl)
            CTL_LIQNAM    -- Name of liq streams from CTL process
            CTL_PLNBLD    -- CTL planned build series (cum # of units at base size)

        ****Investment info from "Coproduction: A Green Coal Technology" Mitretek
            CTL_YRCST     -- year $ for investment costs
            CTL_NFOPCST   -- Non-fuel operating costs (MM$/yr)
            CTL_CAPREQ    -- Total capital requirement (MM$)
            CTL_FXREC     -- Fixed cost recovery factor (rate)

        ****Mansfield-Blackman model variables****
            CTLMB_SW      -- switch to apply M-B model to max bld (1=yes)
            CTLBLDX       -- max CTL penetration
            IINDX         -- innovation index
            PINDX         -- relative profitability ratio
            SINVST        -- investment ratio

   Source:  Analyst's judgment
```

```
     Notes:

----------------------------------------------------------------------------

       CTL cost factors (do not use refinery ones listed at top of file)
       CTL_BLDYRS, CTL_OSBL,
       CTL_PCTENV, CTL_PCTCNTG, CTL_PCTLND, CTL_PCTSPECL, CTL_PCTWC
       CTL_STAFF_LCFAC, CTL_OH_LCFAC
       Source: J.Marano, AltFuels Submod Templates 072607.xls
@      ! except OSBL, all as percent of Total Field Cost (FDC)
           4          ! Construction years (updated 9-05-07)
          20          ! Project life (updated 9-05-07)
           0.00       ! ratio OSBL/ISBL
          10.0 %    !@! Home Office +Contractor's fee
          10.0 %      ! Contractor's +Owners Contingency (updated 9-05-07)
           4.0 %      ! Land
           5.0 %      ! Prepaid Royalties &License +Start-up costs
          10.0 %      ! Working Capital
          55.0 %      ! Supervisory & other Staffing (% of Op Labor)
          39.0 %      ! Benefits and other OH (% of Op Labor + Staffing)

@      ! other CTL control data
       2014       CTL_FSTYR
       50.0       CTL_INCBLD       (Mbbl/cd of liq produced), New 7-18-07 JMarano
       0.005      CTL_DCLCAPCST    (fraction)
       0.000      CTL_DCLOPRCST    (fraction)
       26.252     CTL_BASHHV       (mmBtu/ton coal)
       50.00      CTL_BASSIZ       (1000 bbl/cd liq produced)
       450.55     CTL_BASCGS       (MW per year), New 7-26-07 fr JMarano
       201.4      CTL_BASCGG       (MW per year), New 7-26-07 fr JMarano

     note: CTL_INVLOC based on INVLOC, except padd 3 set to 1.0 (vs 0.775)
           and CTL_CSTFAC no longer used@    CTL_CO2FAC CTL_CSTFAC CTL_INVLOC (added
                    7-24-07)
3
BITE    0.000      1.000   1.16
BITC    0.000      0.850   1.00
BITG    0.000      1.300   1.00
BITM    0.000      0.800   1.08
BITW    0.000      1.000   1.15

     Cumulative planned CTL builds (cum capacity Mbbl/day)
@  REG     YEAR   CAP
     1     2012    5.0
     3     2011    1.6
     3     2014   31.2
     4     2013   13.0
     1     0000    0.0   ! use year 0000 to end loop

     Source: Original Memo from Andy S. Kydes, March 23, 2002
             "Development of a model for optimistic growth rates for the
              coal-to-liquids (CTL) technology in NEMS"
```

```
              Adjustments made for AEO2009
@    Parameters for Mansfield-Blackman model for CTL bld series
         1        ! CTLMB_SW: switch to apply M-B model to max bld (1=yes)
       10.0       ! max number of CTL unit blds allowed (not capacity)
      -0.64       ! I: innovation index
       1.25       ! Pr: relative profitability ratio
       2.00       ! SI: size of investment ratio
```

F.19 Petroleum Coke Gasification Representation in PMM

The coke gasification processing unit represented in the PMM was designed by NETL, as described in their document to EIA, "Refinery Technology Profiles: Gasification and Supporting Technologies," June 2003.[7] NETL carried out extensive research on the gasification process and the PMM model design to generate data tables that realistically represented the coke gasification process (with a combined heat/power (CHP) option) that fit into the PMM process data structure. The data tables were reviewed and modified slightly by EIA to better integrate it into the PMM LP structure. The original design allowed either petroleum coke feed or asphalt feed; however, only the coke feed design was adapted into the PMM due to competition issues between the coke and asphalt feeds.

The coke gasification unit is designed to gasify high sulfur petroleum coke to produce either synthetic gas (SGS) or hydrogen (and synthetic gas). In order to properly represent the difference in investment costs between hydrogen and syngas production, separate gasification units are modeled in the LP (identified as GSH and GSF, respectively). The product hydrogen is put into a pool stream to be used by other processing units at the refinery. The product synthetic gas (with natural gas backup) is routed through a combined heat and power (CHP) unit to produce both steam and electricity, or electricity only. Based on NETL research, the CHP unit assumes a syngas to natural gas consumption ratio of 90:10 during a typical year. Also, a grid/self split was defined in the PMM input files to track the destination of cogen electricity produced by the CHP. The byproduct H2S is also produced for all options and sent to an H2S pool.

The design size of the coke gasification unit was set to 2000 short tons of coke feed per calendar day (s-tons/CD), at an ISBL cost of $160MM (syngas) and $194MM (hydrogen), in 1993$. The ISBL cost for the CHP was set to $134.9MM (1993$), for a standard 8.11 bbl FOE/cd (2044 MM BTU/cd) syngas/natural gas throughput. NETL also provided regional starting capacity for the coke gasification units (see below). These levels were used to establish initial capacity for the CHP units, where applicable. The capacity factor (or utilization rate) was assumed to be 0.85 for the gasification units and 0.96 for the CHP unit.

---

[7] Hohn, Marano, Ph.D.,"Refinery Technology Profiles: Gasification and Supporting Technologies," National Energy Technology Center, for DOE/EIA, June 2003.

Starting Coke Gasification Unit Capacities by PADD

	I	II	III*	IV	V	
GSF	2.10	0.17	0.123	0.00	0.308	(M s-tons/cd)
GSH	0.00	0.00	0.00	0.00	0.00	(M s-tons/cd)
CHP	8.10	0.70	0.50	0.00	1.20	(M bblFOE/cd)

** Minimally defined capacity to prevent infeasibility*

Mathematical Representation of Coke Gasification Process in the PMM

The coke gasification process added to the PMM consumes high sulfur petroleum coke (CKH-- typically from the delayed or fluid coker at the refinery) and produces hydrogen (HYH) and/or syngas (SGS) [and some hydrogen sulfide (H2S)]. The HYH and H2S are consumed or processed at the refinery, while the SGS (with natural gas as the backup fuel 10% of the year) is sent to the combined heat/power (CHP) unit to generate steam (STM) and/or electricity (KWH). Some of the electricity is sold to the grid, with the remaining consumed at the refinery. The LP variables and constraints created or modified to represent this entire process are presented below:

Definitions:

GSF	= coke gasifier unit producing synthetic gas
GSH	= coke gasifier unit producing hydrogen
CHP	= combined heat and power unit
CK1, CK2	= operating modes for coke gasifier units
CKH	= high sulfur petroleum coke
SGS	= synthetic gas
NGS	= natural gas
HYH	= hydrogen (high quality)
H2S	= hydrogen sulfide
FUL	= combined fuel pool
KWH	= electricity
STM	= steam
OVC	= variable operating costs
FXOC	= fixed operating costs
INVST	= capital investment costs
OBJ	= objective function row
R-var	= LP column variable for unit operating level
X-var	= LP column variable representing coke sent to meet demand
K-var	= LP column variable for unit operating level of initial capacity

E-var,L-var = LP column variable for unit operating level of new capacity
m, mod = operating mode
c = coefficient (all unique values)
r = PMM refinery regions (PADD)
d = Census demand regions

Stream/Utility Balance Rows:
These constraints require the supply levels for a stream to equal the demand levels for that stream, within each refinery region (r). This applies to coke (CKH), syngas (SGS), natural gas (NGS), hydrogen (HYH), hydrogen sulfide (H2S), fuel (FUL), electricity (KWH), and steam (STM).

B(r)CKH: Σ_m c*R(r)KRD(mod) - *R(r)GSFCK1*
[M s-ton/cd] +Σ_m c*R(r)KRF(mod) - *R(r)GSHCK2*
- c* X(r)CKHCOK = 0

B(r)SGS: *c* R(r)GSFCK1* - Σ_m *c*R(r)CHP(mod)*
[M bbl FOE/cd] +*c* R(r)GSHCK2* = *0*

B(r)NGS: . . . . . - Σ_m *c*R(r)CHP(mod)* = 0
[M bbl FOE/cd]

B(r)HYH: . . . . . + *c* R(r)GSHCK2* = 0
[M bbl FOE/cd]

B(r)H2S: . . . . . + *c* R(r)GSFCK1* + *c* R(r)GSHCK2* = 0
[M bbl FOE/cd]

B(r)FUL: . . . . . - *c* R(r)GSHCK2* = 0
[M bbl/cd]

U(r)KWH: . . . . . - *c* R(r)GSFCK1* - *c* R(r)GSHCK2*
[MWh/cd] + Σ_m *c*R(r)CHP(mod)* = 0

U(r)STM: . . . . . - *c* R(r)GSFCK1* - *c* R(r)GSHCK2*
[M lb/cd] + *c*R(r)CHPCO1* = 0

Capacity expansion/investment rows:
Capacity constraints are defined for the GSF, GSH, and CHP units. These constraints require the total operating level of each unit to be less than or equal to the total available capacity (existing +

new). The accounting row (A(r)CHPCGN) keeps track of total electricity generated by the CHP unit in each refinery region. The P(r)OVC row accumulates the OVC for each processing unit (defined in 2000 year dollars) and uses the variable T(r)OVCOBJ to convert to 87$ and put into the objective function. The FXOC and INVST rows are accounting rows for PMM reports. The objective function row (OBJ) includes the investment costs for the new processing units.

L(r)GSFCAP: *c* R(r)GSFCK1 - K(r)GSFCAP*
[M s-tons/cd] *- c* E(r)GSFINV -c* L(r)GSFBLD <= 0*

L(r)GSHCAP: *c* R(r)GSHCK2 - K(r)GSHCAP*
[M s-tons/cd] *- c* E(r)GSHINV -c* L(r)GSHBLD <= 0*

L(r)CHPCAP: Σ_m *c* R(r)CHP(mod) - K(r)CHPCAP*
[M bbl FOE/cd] *- c* E(r)CHPINV -c* L(r)CHPBLD <= 0*

A(r)CHPCGN: Σ_m *c* R(r)CHP(mod)* (accounting row)
[MWh/cd]

P(r)OVC: . . . . . *- c* R(r)GSFCK1 - c* R(r)GSHCK2*
[M $2000/cd] *-* Σ_m *c*R(r)CHP(mod)* + c* T(r)OVCOBJ = 0

A(r)FXOC: . . . . . *+ c* E(r)CHPINV + c* L(r)CHPBLD* (accounting row)
(A@FXOC, $\Sigma_{r..}$) *+ c* E(r)GSFINV + c* L(r)GSFBLD*
[M $87/cd] *+ c* E(r)GSHINV + c* L(r)GSHBLD*

A(r)INVST: . . . . . *+ c* E(r)CHPINV + c* E(r)GSFINV* (accounting row)
(A@INVST, $\Sigma_{r..}$) *+ c* E(r)GSHINV*
[M $87/cd]

OBJ: . . . . . Σ_r *[- c* E(r)CHPINV - c* L(r)CHPBLD*
[M $87/cd] *- c* E(r)GSFINV - c* L(r)GSFBLD*
- c E(r)GSHINV - c* L(r)GSHBLD*
+ Σ_m *c*R(r)CHP(mod)]*

Bounds put on the following variables:
The initial capacity for each of the new processing units is defined as upper limits on the K-variables. Added capacity for the new units is set as bounds on the E-variables (capacity added this year) and on the L-variables (accumulated capacity added in previous years).

[M s-ton/cd]	*K(r)GSFCAP*	*E(r)GSFINV*	*L(r)GSFBLD*
[M s-ton/cd]	*K(r)GSHCAP*	*E(r)GSHINV*	*L(r)GSHBLD*
[M bbl FOE/cd]	*K(r)CHPCAP*	*E(r)CHPINV*	*L(r)CHPBLD*

Updates to the PMM FORTRAN code

In addition to updating the LP matrix structure, various PMM code changes were needed for proper accounting and reporting, as well as for model consistency and stability. First, for FTAB reporting, the resulting cogen electricity production levels were categorized as grid vs self, and put into fuel type accounting totals. The variable used to define the regional grid vs self split is the same one used for other cogen accounting in the PMM: CGPCGRDPD(r). In addition, the following new inputs were added to the rfinvest.txt file to help with the cogen accounting.

CHPCC1	**= 992**	KWh/bbl FOE processed for mode CC1
CHPCO1	**= 722**	KWh/bbl FOE processed for mode CO1
NGSCHP	**= 0.10**	natural gas fraction fed to CHP

These values ***must*** be consistent with the KWH and the natural gas coefficients defined in the refproc.dat file in the T:CHP data table.

In addition, a new subroutine (PMM_COKGSF) was created in the refine.f code to transfer model results to report variables. Coke and natural gas consumption, syngas and hydrogen production, and electricity and steam production levels were processed into a PMM report table (48a). The report variables include:

QCOKPRD(3,r,yr)	M s-ton/cd
QASTPRD(3,r,yr)	M bbl FOE/cd
QSGSPRD(r,yr)	M bbl FOE/cd
QHH2PRD(r,yr)	M bbl FOE/cd
QKWHPRD(2,r,yr)	M KWh/cd
QSTMPRD(r,yr)	M lb/cd
QNGSPRD(2,r,yr)	M bbl FOE/cd

Finally, a special algorithm was defined to establish a petroleum coke export price that better matches historical levels of 45$/ton in 2001 dollars (~6$/bbl FOE in 1987 dollars) and to model an expected 5-10% decline rate. This is currently hard-coded in refine.f, subroutine CHGCKSU. Ultimately, the coke export price should be keyed off of coal prices. This will be designed and incorporated at a later date.

F.20 Saturated Gas Plant Representation in PMM

Mathematical Representation of Saturated Gas Plant in the PMM

The saturated gas plant (SGP) added to the PMM processes a set of refinery gas streams produced at specific processing units (PUs). To simplify the LP design, the component gas streams produced by the other PUs will also pass through the SGP and then on to their next processing destination. All other gas streams that are not sent to the SGP will go to the refinery fuel unit (FUM) and be used for fuel. To keep these two paths separate, two stream balance rows have been defined. The B(r)(ist) rows correspond to the processed saturated gases, while the R(r)(ist) rows correspond to the unprocessed gases that go directly to the fuel unit. The gas streams that are included in this special processing are:

CC1	methane gases
CC2	ethane gases
CC3	propane gases
IC4	iso-butane gases
NC4	n-butane gases
HYL	low quality hydrogen

The row constraints and corresponding processing units that can produce any or all of these gas streams include:

For saturated gas streams ready to be processed:

S(r)(ist): $\Sigma_{unt}\ \Sigma_{mod}$ c * R(r)(unt)(mod) - R(r)SGP(ist) = 0
[M bbl FOE/cd]

where (unt) $\in$ ACU, ARD, CDT, DDS, FCC, FDS, FGS, HCL, HCM, HCN, HCR, HCU, HCV, HD1, HD2, HFA, HS2, KRD, KRF, NDS, OCT, PHI, PHP, PHS, RDS, RFC, RFL, SFA, SYD, TRI, and VBR (see Table G-F in Appendix G).

For processed saturated gas streams:

B(r)(ist): R(r)SGPist) + G(r)(ist)RFN - c* R(r)FUM(ist) - H(r)RFMP(ist)
[M bbl FOE/cd] - $\Sigma_{unt}\ \Sigma_{mod}$ c'* R(r)(unt)(mod) - Σ_{mg} B(r)(mg)(ist) - Σ_{prd} T(r)(ist)(prd) = 0

where (unt) $\in$ C4I, CYC, H2P, HFA, OLE, PFA, REL, SDA, SFA, TCG (see Table G-F in Appendix G).

For unprocessed refinery gas streams:

R(r)(ist): $\Sigma_{unt}\,\Sigma_{mod}$ c* R(r)(unt)(mod) - c* R(r)FUMR(ist2) = 0
[M bbl FOE/cd]

where (unt) $\in$ ARP, C4I, DEW, ETS, H56, HDN, HLO, IOT, MOD, OLE, PSA, PSZ, RFH, and TCG (see Table G-F in Appendix G).
(ist2) = 1^{st} and 3^{rd} character of (ist); i.e., for (ist)=NC4, R(ist2) = RN4

Other row constraints related to the saturated gas plant are presented next.

Capacity constraint for SGP: In each refinery region, the total capacity utilized must equal the total operating level of each operating mode for the SGP. The total capacity utilized is defined by the column variables K(r)SGPCAP, E(r)SGPINV, L(r)SGPBLD, whose upper bounds represent existing and new capacity.

L(r)SGPCAP: K(r)SGPCAP + E(r)SGPINV + L(r)SGPBLD = Σ_{ist} R(r)SGP(ist)
[M bbl FOE/cd]

Utility/Fuel/OVC Balance Rows: The supply level for a utility (KWH) and fuel (FUL) must equal the usage level at the SGP. The OVC balance row serves to total OVCs (T(r)OVCOBJ) related to the SGP and other PUs operating levels and link the total to the OBJ row.

U(r)KWH: . . . . . - Σ_{ist} c* R(r)SGP(ist) + U(r)KWH = 0
[MWh/cd]

B(r)FUL: . . . . . - Σ_{ist} c* R(r)SGP(ist) + Σ_{mod} R(r)FUM(mod) = 0
[M bfoe/cd]

P(r)OVC: . . . . . - Σ_{ist} c* R(r)SGP(ist) + c* T(r)OVCOBJ = 0
[M $2000/cd]

F.21 BTL Representation in PMM

The BTL is similar to the CTL and GTL processes and involves three steps. First, biomass is converted into a synthesis gas via gasification. This is followed by the Fischer-Tropsch synthesis, which converts the synthesis gas into liquid hydrocarbons. The final step involves partial upgrading of these hydrocarbons to produce liquids boiling in the range of naphtha, kerosene (jet fuel) and diesel fuel. The overall process can be operated to maximize the production of jet or diesel fuel. Naphtha is also a by-product. Generally, the naphtha has a very low octane rating and is a poor feed or blend stock for the production of gasoline. However, it is a premium starting material for the production of various petrochemicals. The jet and diesel fuels produced are of very high quality, and can be used as neat fuels or can be blended into conventional petroleum-derived fuels to improve their quality. There are currently no BTL plants commercially in operation; though, the U.S. DOE is funding several demonstration projects as part of its Biorefining Initiative.

Given the 2007 Energy bill (EISA2007) requirement for a renewable fuels minimum of 36 billion gallons per year by 2022, biomass-to-liquids (BTL) added to the PMM as an option to meet that goal. For *AEO2009*, the BTL unit has been designed with two operating modes: diesel production and jet fuel production. Both modes convert 6.415 MM Btu's of biomass into one bbl of liquids. They also produce 103.6 KWh per bbl of liquid, as net cogeneration for sale to the grid at wholesale market prices. The capacity factor (or utilization rate) is assumed to be 90 percent. As with CTL, the liquids are represented by four streams: light naphtha, heavy naphtha tops, kerosene/jet, and diesel. For the diesel operating mode, 71.5 percent of the liquid stream is diesel fuel; and, for the jet operating mode, 63 percent of the liquid stream produced is jet fuel.. The biomass feed stream is linked to the biomass supply curve that also supplies feedstock for cellulosic ethanol production. Thus, BTL production competes with cellulosic ethanol production.

A separate Mansfield-Blackman model for market penetration of BTL was developed to properly reflect this new technology and its added appeal as a renewable fuels potential. The indices associated with this modeling algorithm are user inputs that define the characteristics of BTL production. They include an innovation index of the industry (BTL_IINDX), the relative profitability of the investment within the industry (BTL_PINDX), the relative size of the investment (per plant) as a percentage of total company value (BTL_SINVST), and a maximum penetration level (total number of units, BTLBLDX). These are defined in the PMM input file rfinvest.txt, and presented below.

```
@    Parameters for Mansfield-Blackman model for BTL build series
        2011     ! BTL_FSTYR: Year to start allowing builds
        1        ! BTLMB_SW: switch to apply M-B model to max build (1=yes)
        150.     ! BTL_BLDX: max number of CTL unit builds allowed (not capacity)
        -0.70    ! BTL_IINDX: innovation index
```

```
1.65      ! BTL_PINDX: relative profitability ratio
2.00      ! BTL_SINVST: size of investment ratio
```

These are used in the following set of equations (M-B penetration algorithm) to set the upper limit on BTL capacity penetration (E@BTLINV):

```
                                  ! CALC UL FOR BTL BLDS
NBTLBLT = 1.0
KFAC = -ALOG( (BTLBLDX/NBTLBLT) -1.0) ! ratio of # allowed/#blt
PHI = -.3165 + (0.23221*BTL_IINDX) +  &
        (0.533*BTL_PINDX) - (0.027*BTL_SINVST)
SHRBLD = 1./ (1.+ EXP(-KFAC-(B_EYR*PHI)))
BTLBND = BTLBLDX * SHRBLD                ! num units: UL on tot blds

LOWBND = 0.0
UPBND  = BTLRHSNUM*PUCAP(JBTL)                ! 1000 bbl/cd BTL

TBTXTC = 'E@BTLINV'
CALL CBNDLP(TBTXTC,LOWBND,UPBND,IRET)
```

F.22 E85 Infrastructure Representation in PMM

The large renewable fuel volumes mandated by the Energy Independence and Security and Security Act of 2007 effectively requires that a large increase in E-85 use in vehicles. By existing rules and regulations, ethanol can only enter the transportation fuel supply as E10 or E85. Once the E10 market is projected to be saturated (around 2010 or 2011), any ethanol used to meet the mandate would have to come into the market as E85. This required the building of necessary infrastructure.

Growth of the E85 demand market is assumed to largely develop first in the Midwest where most of the ethanol is being produced. Infrastructure costs for modifying the retailer equipment to dispense E85 fuel were estimated and amortized over the lifetime of the equipment. A logit model describing the interaction between E85 availability (i.e., percent of retail stations that provide E85 within a given region), the price differential between motor gasoline and E85, and the share of light duty vehicle fuel that is E85 is used.

Roughly 20% availability was assumed to provide for ample market penetration of E85. As the E85 market in the Midwest becomes saturated, E85 infrastructure growth is modeled in other regions such as the Southeast and West Coast. Ethanol distribution costs are higher in these regions, and this too affects the price of E85. All of these infrastructure development costs were spread over all transportation fuels; in effect, this “cross-subsidization” of E85 fuel was done in order to incentivize the E85 market demand required to fulfill the RFS mandate since ethanol beyond the 14 billion gallons or so needed to saturate the E10 market has no other market to go to other than E85.

APPENDIX G

Matrix Generator Documentation

Appendix G. Matrix Generator Documentation

G.1 Introduction

This appendix describes the program which generates the 5-region Multi-Refining Model (MRM); and provides detail on how it works. The program allows the user to create a 5-region representation of the entire United States refining industry using linear programming (LP).

The MRM models multiple refinery regions within the entire United States. The MRM is a collection of five refinery regions linked by a transportation network. The regions are defined by the five U.S. Petroleum Administration for Defense Districts (PADDs). Each region contains a representation of both a marginal and infra-marginal refinery. The MRM simulates the refinery operation in the United States, including crude oil supply and transportation to refineries, the regional processing of these raw materials into petroleum products, and the distribution of petroleum product to meet regional demands. The model identifies supply sources for domestic crude oils, alcohols, biofuels, ethers, coal, and natural gas, as well as import levels of crude oil and petroleum products. In addition to these quantities, the MRM projects petroleum product prices, refinery fuel consumption, and capacity expansion in each PADD. The 5-region MRM models the five U.S. PADDs, labeled as follows: E = PADD I, C = PADD II, G = PADD III, M = PADD IV, W = PADD V.

The program generates the linear programming matrix that represents the MRM, solves the LP, writes the solution, and packs the matrix for use by the analyst using the ANALYZE software. The program also produces an MPS file containing the LP matrix for input into the PMM/ NEMS. The PMM ultimately modifies the LP matrix to reflect industry changes and more detailed representation throughout the forecast. For example, more detailed coal supply links for CTLs are not created for the MRM, but are added within the PMM. These new LP variables and constraints are included in the row/column listings presented in section G.2 below.

G.2 Code

The program is written in Fortran and makes use of OML (Optimization and Modeling Libraries) to read in the data files, to generate the matrix representation of the model, to solve the problem, to store the solution, and to pack the matrix for use with ANALYZE. The program can also produce a report.

The program is data driven (filenames *.dat) and the user provides key information (files mrmparam and mrmpath), such as, the model chosen to be run, the location of the input data files, and the names of the output LP and solution files.

Variables and Constraints

The model consists of variables or activities (columns), constraints (rows), and bounds on activities and constraints. A unique name has been assigned to each variable and constraint. In the naming of the variables and rows, indices are used to represent items such as regions, crude types, etc. The following table displays the index set name and the number of elements in the set, gives a brief description of the set, and provides a partial listing of the set members.

Index	No. of Values	Description	Members
@	1	represents all regions	@
c	2	Constraint type	X: for max N: for min
d	9	Census divisions	1: New England 2: Mid Atlantic 3: East North Central 4: West North Central 5: South Atlantic 6: East South Central 7: West South Central 8: Mountain 9: Pacific
e	2	Emission source	C: Emission from fuel combustion N: Emission from process unit (non-combustion)
J	14	Coal demand regions (supply links to CTL production by PADD), based on the 9 Census Divisions, 4 of which have been divided to represent distinct sub-markets with special characteristics (as defined for the Coal Market Module). The Mountain CD has been divided three ways.	01-14 However, PMM refinery regions are only linked to 6 of them, as follows: PADD E coal demand region 02 PADD C coal demand region 06 PADD G coal demand region 10 PADD M coal demand regions 09, 11 PADD W coal demand region 14
k	7 (for CTL)	Coal characteristics: 1. rank: bituminous, sub-bituminous, lignite 2. sulfur content: compliance, medium, high	BL, BM, BH, LG, BL, SL, SM

Index	No. of Values	Description	Members
m	17	Transportation mode, function of material and means of movement	4: U.S. flag residual oil (dirty tanker) 5: Jones-Act crude tanker W: crude pipeline from supply reg 3 to PADD III B: Barge light products (clean barge) I: West Texas to PADD II J: U.S. flag light products (clean tanker) M: Aggregate/avg rail, truck, vessel, barge for ETH O: U.S. flag LPG R: PADD III loop to PADD II S: PADD III capline to PADD II T: Light product pipeline U: LPG, C4, CC5 pipeline V: Barge residual oil (dirty barge) X: Local transportation Y: Pipeline PADD II to demand region 6 Z: Pseudo link A: LOOP to PADD II
n	40	Coal supply sources (curves), characterized by 1. mine type: underground, surface 2. rank: premium, bituminous, sub-bituminous 3. sulfur content: compliance, medium, high	Note: indexes (n) and (k) are closely linked. The following list shows each of the possible values of n (01, 02, etc) **and** the corresponding values of k (BM, BH, etc). 01BM, 02BH, 04BM, 05BH, 06LG, 07BL, 08BM, 10BL 11BM, 13BM, 16BM, 17BM, 18BH, 19BM, 20BH, 22BH, 23LG, 24LG, 25LG 26SL, 27SL, 28SM, 29SL, 30SM, 31SL, 32SL, 33SL, 34SM, 35BL, 36SL, 38BL, 40SM The following eight supply sources are not available for CTL production:03, 09, 12, 14, 15, 21, 37, 39
o	7	OGSM regions	1: OGSM 1 North East + OGSM 7 Atlantic 2: OGSM 2 Gulf Coast + OGSM 8 Gulf Offshore 3: OGSM 3 Midcontinent 4: OGSM 4 Permian Basin 5: OGSM 5 Rocky Mountain 6: OGSM 6 West Coast + OGSM 9 Pacific A: OGSM A Alaska North
r	5	Refining regions	E: PADD I C: PADD II G: PADD III M: PADD IV W: PADD V
t	2	Type of transportation	V: Vessel P: Pipeline
x	5	Exporting regions	2: Export cd for PADD I (region E, cd 2) 3: Export cd for PADD II (region C, cd 3) 7: Export cd for PADD III (region G, cd 7) 8: Export cd for PADD IV (region M, cd 8) 9: Export cd for PADD V (region W, cd 9)

Index	No. of Values	Description	Members
cp	4	Co-products produced with ethanol or biodiesel	DDG, EDG: Distiller's grain solids WMC: Wet mill co-product GLY: Glycerin
Nn	3	Negative shift in demand	N1, N2, N3
On	8	Natural Gas refinery supply steps	N1, N2, N3, N4, P5, P6, P7, P8
Pn	3	Positive shift in demand	P1, P2, P3
qd	7	Quality code for distillate	AR: Aromatics FL: Flash point FZ: Freezing point GR: Gravity LM: Luminometer number SL: Sulfur VB: Viscosity
qm	11	Quality code for gasoline blending	AR: Aromatics BZ: Benzene E2: E 200 E3: E 300 M0: Motor octane PO: Percent oxygen OL: Olefin R0: Research octane RV: Reid vapor pressure SL: Sulfur RE: renewables component (due to required minimum contribution to oxygenates)
Qs	5	Step label for crude oil imports	Q1, Q2, Q3, Q4, Q5
Rs	9	Step label for product imports	R1, ..., R9
S1	1	Step label for product demands	S1
se	2	SO2 emissions regions	1, 2
Ss	3	Sub-Spec Products	SSR: Sub-spec Reformulated gasoline (RBOB) SST: Sub-spec High Oxygenate gasoline (BOB) SSE: Sub-spec Conventional gasoline (TBOB)
SX	1	Product exports	SX
Z9	1	Distress imports and exports	Z9
col	1	Aggregate coal types available for CTL processing, linked to 14 coal demand regions (from the Coal Market Module): Northern Appalachia, Central Appalachia, Southern Appalachia, East Interior, West Interior, Gulf Lignite, Dakota Lignite, Western Montana, Wyoming Northern PRB, Wyoming Southern PRB, Western Wyoming, Rocky Mountains, Southwest, Northwest	BIT

Index	No. of Values	Description	Members
crt	12	Crude groups by quality and origin	ALL: Alaskan, API 25-66, S<0.5, B<15 AMH: Alaskan, API 21-32, S<1.1, B>15 DLL: Domestic, API 25-66, S<0.5, B<15 DMH: Domestic, API 21-32, S<1.1, B>15 DHL: Domestic, API 29-56, S<1.99, B<15 DHH: Domestic, API 23-35, S<3.0, B>15 DHV: Domestic, API<23, S>0.7, B>15 FLL: Foreign, API 25-66, S<0.5, B<15 FMH: Foreign, API 21-32, S<1.1, B>15 FHL: Foreign API 29-56, S<1.99, B<15 FHH: Foreign, API 23-35, S<3.0, B>15 FHV: Foreign, API<23, S>0.7, B>15
dfo	6	Distillate fuel oil blends	JTA: Jet fuel N2H: Number 2 oil DSL: Low sulfur diesel DSU: Ultra low sulfur diesel N6I: Low sulfur resid N6B: High sulfur resid
emu	6	Emission type	CAR: Total carbon CO1: Carbon monoxide CO2: Carbon dioxide NOX: Nitrous oxides SOX: Sulfur oxides VOC: Volatile organic compounds
ist	825	Refinery intermediate streams	LNI: Light naphtha, (175-250) intermediate LNN: Light naphtha, (175-250) naphthenic LNP: Light naphtha, (175-250) paraffinic And many more...
lqc	4	Liquid streams from CTL	CDX: SMDS diesel (480-680F) CKE: SMDS kerosene (320-480F)' CNL: Gasoline Tops (110-175F) CNP: Naphtha Tops (175-320F)
lqg	4	Liquid streams from GTL	SDX: SMDS diesel (480-680F) SKE: SMDS kerosene (320-480F)' SNL: Gasoline Tops (110-175F) SNP: Naphtha Tops (175-320F)
mgb	4	Gasoline blends	TRG: Conventional gasoline RFG: Reformulated gasoline TRH: Conventional high oxygen gasoline RFH: Reformulated high oxygen gasoline

Index	No. of Values	Description	Members
gbt	12	Gasoline blending component type	G01: Butanes (NC4-I4E) G02: Naphthas (NAT-LNN) G03: Reformates (R80-V10) G04: FCC Gasolines (LF6-85H) G05: Other (C5E-R6E,ISO-HRA) G06: HCR Gasolines (LHG-MHV) G07: Alkylates (ALN-HAL) G08: Ethanol (ETH) G09: Ethanol Ethers (TAEE,THEE) G10: Ethylbenzene (ETBE) G11: MTBE (MTB) G12: Methanol Ethers (TAM,THM)
mod	many	Operating mode	C2A: Ethylene alkylate C3A: Propylene alkylate C4A: Butylene alkylate
ncr	12	Non crude purchase	ARB: Atmospheric resid of type B (unf oils) BIM: Biomass diesel (virgin oil, renewable) BIN: Biomass diesel (non virgin oil, renewable) CC3: Propane (gas plant) ETH: Ethanol (renewable) HGM: Heavy gas oil medium sulfur (unf oils) IC4: Isobutane (gas plant) MET: Methanol (methanol plant) MTB: M.T.B.E. (oxygenate) NAT: Natural gasoline (gas plant) NC4: Normal butane (gas plant) NPP: Paraffinic naphtha (unf oils)
pi9	19	Distress imports	AST, COK, DSL, DSU, E85, JTA, LPG, M85, N2H, N67, N68, N6B, N6I, OTH, PCF, RFG, RFH, TRG, TRH
pol	34	Policy type	LOS: Lost OVC: Other variable cost MSD: Maximum distillation feed, cat cracker MSR: Maximum low sulfur resid, cat cracker SVR: Maximum severity, cat cracker H00: Maximum 100 severity, HP reformer H05: Maximum 105 severity, HP reformer

Index	No. of Values	Description	Members
prd	21	Products	AST: Asphalt COK: Coke DSL: Low sulfur diesel DSU: Ultra low sulfur diesel E85: 74% Ethanol and 26% TRG FLG: LPG used as feedstock JTA: Jet fuel KER: Kerosene (aggregated into N2H in the LP matrix) LPG: Liquefied petroleum gas M85: 85% Methanol and 15% TRG N2H: Number 2 oil N67: Low sulfur resid to utilities N68: High sulfur resid to utilities N6B: High sulfur resid N6I: Low sulfur resid OTH: Other PCF: Petrochemical feed stock RFG: Reformulated gasoline RFH: Reformulated high oxygen gasoline TRG: Conventional gasoline TRH: Conventional high oxygen gasoline
pri	14	Product imports	DSL, DSU, JTA, LPG, MET, MTB, N2H, N6B, N6I, OTH, PCF, RFG, TRG, SSR
prx	11	Product exports	COK, DSL, DSU, JTA, LPG, N2H, N6B, N6I, OTH, PCF, TRG (and AST in Padd V)
px9	17	Distress exports	AST, COK, DSL, DSU, JTA, LPG, N2H, N67, N68, N6B, N6I, OTH, PCF, RFG, RFH, TRG, TRH
unf	3	Unfinished oil	ARB: Atmospheric residual bottom type B HGM: Heavy gas oil medium sulfur NPP: Medium naphtha paraffin
uns	90 (mrm)	Process unit	ACU: Atmospheric crude distillation See Appendix A.3.9 for complete list of processes
uuu	4	Utility	KWH: Kilowatt-hour NGF: Natural gas liquids STM: Steam COA: Coal (fuel for corn ethanol production)

In the naming of the columns and rows, the limit is a maximum of sixteen characters per name. The following two tables give the name of the variable (activity) and the row (constraint) represented.

The general name structure for columns is (v)(r)(abc)(def), where v is key code, r is region code, abc and def are 3 character names. Those variables marked with an asterisk (*) are created within the PMM, not by the MRM.

Name	Activity Represented
B(r)(mgb)(ist)	Blend stream (ist) to gasoline grade (mgb) in (r)
C(d)CRN(Rs)	Domestic corn (for ethanol production) from supply step (Rs) in (d)
C(d)SBO(Rs) C(d)YGR(Rs) C(d)WGR(Rs)	Virgin (SBO,WGR) and non virgin (YGR) oil/grease supply step (Rs) in (d) as feedstock for biodiesel production
C(d)BIO(Rs)	Biomass (for ethanol or BTL production) supply from step (Rs) in (d)
CP(n)(k)(q) *	Quantity of coal type (k) produced from coal supply source (n) at price (q)
CP(n)OTXX *	Quantity of coal demand for non-CTL use from coal supply source (n)
CT(n)(j)(k) *	Quantity of coal type (k) transferred from coal supply source (n) to coal demand region (j)
D@METS1	Total US chemical methanol demand
D(d)(prd)S1	Product (prd) demand in (d)
D(d)(prx)SX	Product (prx) exports from (d)
D(d)ETHSX(s)	Ethanol exports from (d) for demand step (s)
D(d)(px9)Z9	Distress product (px9) export from (d)
D(w)(xxx)(Snn)	Demand for (xxx=DIS,LPG,NAP,OTH,RES) at level (Snn) in international region (w).
E(r)(uns)INV E(d)(uns)INV	Investment in new capacity for process (uns) in (r) Investment in new capacity for process (uns) in (d)
E(r)CTZINV	Special representation of new CTL units built with EPACT05 credit in (r)
E@CTXINV	Total CTL capacity operating in US
E(d)CET(mod)	New corn ethanol capacity utilize in (d) for dry mill process type (mod), mod=DM1,DM2
F(r)(dfo)(ist)	Blend stream (ist) to distillate fuel oil (dfo) in (r)
G(r)(ist)(prd)	Gas plant output transfer of stream (ist) to product (prd) in (r)
G(r)DGR	Dry gas exiting gas plant in (r)
G(r)GPL01	Gas plant operations in (r)
G(r)(ist)RFN	Transfer of gas plant stream (ist) to refinery in (r)

Name	Activity Represented
G(r)LOS	Accounting row for gas plant loss in (r)
G(r)OVC	Variable costs for gas plant in (r)
G(r)RFNMET	Transfer of methanol from refinery to meet export demands in refinery in (r)
G(r)SC2CC1	Shift of ethane to natural gas in gas plant in (r)
G(r)SC3CC1	Shift of propane to natural gas in gas plant in (r)
G(r)MOH01	Methanol plant operations in (r)
G(r)METDEM	Methanol production from methanol plant in (r) to chemical industry
G(r)METRFN	Methanol production from methanol plant in (r) to refinery
H(r)SSE(m)(d) H(r)NAT(m)(d)	Denaturant (SSE, NAT) supplied by (r) to (d)
H(d)BD(x)CCT	Used to determine the carbon credit for biodiesel production in (d). The value of (x) denotes the feedstock: N = non-virgin grease; V = virgin grease; W = white grease.
H(d)BIMDMD H(d)BINDMD	Total virgin (BIM) biodiesel blended into DSL/DSU in (d). May be subject to upper/lower bounds. Total non-virgin (BIN) biodiesel blended into DSL/DSU in (d). May be subject to upper/lower bounds.
H(d)BIMTOT H(d)BINTOT	Total virgin (BIM) biodiesel production in (d) Total non-virgin (BIN) biodiesel production in (d)
H(d)ETHTOT	Total corn ethanol production in (d)
H(d)(cp)TOT	Total co-product (cp) associated with ethanol and biodiesel production in (d)
H(d)CET(mod)	Corn ethanol production in operating mode (mod) in (d)
H(d)CETCCT H(d)CLECCT H(d)CLEKWH H(d)CTXKWH	Used to determine carbon credit for corn ethanol production in (d). Used to determine carbon credit for cellulosic ethanol production in (d). Used to determine credit for electricity from cellulosic ethanol production which is sold to the grid in (d) Used to determine credit for electricity from CTL production which is sold to the grid in (d)
H(r)(uns)(mod)	Production from process (uns) in operating mode (mod) at merchant, CTL, or GTL plant in (r)
H(r)(aa)(bb)(ist)	Transfer from (aa) to (bb) of stream (ist) in (r) Note: (aa), (bb) = MP, GP, RF, where MP = Merchant plant, GP = Gas plant, RF = Refinery. For (ist), only the first and last character of (ist) are used
H(r)KWHMCH	Electricity purchased by merchant units in (r)

Name	Activity Represented
I(d)(pi9)Z9	Distress product (pi9) imports to (d)
I(r)(pri)(Rs) I(r)TRGT(s)	Imported product (pri) step (Rs) to region (r) Used to limit total imports of TRG and SSE at step (s) to region (r)
I@ETHM(d) I(d)ETH(Rs)	Imported ethanol from Brazil to (d) Ethanol import supply curve for step (Rs) to (d)
I(r)SSE(w)(s) I(r)SSETOT I(r)SSR(w)(s) I(r)SSRTOT I(r)(pri)(w)(s) I(r)(unf)(w)(s) I(r)(unf)(w)TOT I@UNFTOT	Note: sse is not a member of (pri).
J(d)DSUDSU J(d)DSLDSL	Quantity of diesel product not splash blended with biodiesel in (d)
K(r)(uns)CAP	Existing capacity for process (uns) in (r)
K(d)CETOLD	Existing capacity for corn ethanol units in (d)
K(d)CET(mod)	Cumulative corn ethanol capacity added in (d) for dry mill process type (mod) determined to be uneconomical to run in any year after built, mod=DM1,DM2
K(w)ILGCAP K(w)IUPCAP	Cumulative capacity added in region (w) for process types ILG and IUP
L(r)(uns)BLD	Cumulative addition to capacity for process (uns) in (r)
L(d)CET(mod)	Cumulative corn ethanol capacity added in (d) for dry mill process type (mod), mod=DM1,DM2
N(r)DGP	Dry gas supply in (r)
N(r)(col)N(s)	Quantity of coal type (col) transferred to refinery region (r) from its associated coal regions at price step (s). Note: s=1 (s=2 to 5 are not used)
N(r)NGKN(s)	Alaska NG supply curve step (s) for GTL processing for region (r)
N(r)NGRF(On)	Natural gas to refinery supply step (On) in (r)
NZAMH(On)	Export supply step (On) for Alaskan crude (6 steps only)
N(d)ETHCOA	Coal consumed as fuel at the corn ethanol plant in (d)
O@CRDEXP	Alaskan crude exports
O@CRDSPR	SPR (Strategic Petroleum Reserve) fill in US

Name	Activity Represented
P(o)DCRQ1	Domestic crude in (o)
P(r)(crt)(Qs)	Supply step (Qs) of imported crude (crt) to (r)
P@(crt)(Qs)	
PANGLQ1	Supply of natural gas liquids from Alaska North slope
PGLBNGL(Qs)	
PWRLD(Qs)	
P_SO2_(se) *	Quantity of SO2 emissions permits purchased in SO2 region (se) for coal used in coal to liquid (CTL) production
P_HG_US *	Quantity of mercury emission permits purchased for coal used in coal to liquid production
P(w)(xxx)DEX	(xxx=DIS,LPG,NAP,OTH,PCF) in international region (w)
P(w)(xxx)TMP	(xxx=DIS,LPG,NAP,OTH,PCF) in international region (w)
Q(r)(mgb), Q(r)(Ss)	Spec vector, total volume of (mgb) or (Ss) produced in (r)
Q(r)(dfo)	Spec vector, total volume of (dfo) produced in (r)
R(r)ACU(crt)	Volume of crude (crt) processed by the ACU unit in (r)
R(r)(uns)(mod)	Refinery process (uns) operation for mode (mod) in (r)
R(r)CGNCGN R(r)CGXCGN	Refinery (CGN) and Merchant (CGX) cogeneration plant operation in region (r)
R(w)(xxx)RES	Refinery transfers from (xxx = ARB, ARC, N6B, N6I) to RES in international region (w)
R(w)DIS(dfo’)	Refinery transfers from DIS to (dfo’ = DSL, DSU, JTA, N2H) in international region (w)
R(w)ILGL2D R(w)IUPN2D R(w)IUPRD1 R(w)IUPRD2	Refinery transfers based on additional processing of heavy streams in international region (w)

Name	Activity Represented
R(w)MARFLL R(w)MARIMC	Operating levels of marginal and infra-marginal refinery units in international region (w)
R(w)NAP(xxx)	Refinery transfers of NAP to (xxx-PCF, SEE, SSR, TRG) in international region (w)
RC(crt)DMD	Accounting of foreign crude type (crt) transferred to Canada via U.S. Padd 2 imports
T(r)(ist)(ist) T(r)(ist)(prd) T(r)(crt)TLL	Transfer of stream (ist) to stream (ist) in (r) Transfer of stream (ist) to product (prd) in (r) Transfer of crude (crt = DLL, FLL) to the marginal refinery in (r)
T@UNFTOT T(r)UNF(ist)	Total unfinished oils in US Unfinished oils from stream (ist) in region (r) (r = E, B only)
TAALLTOT	Total volume of type ALL crude produced in Alaska
TAAMHTOT	Total volume of type AMH crude produced in Alaska
TAAMHXZ	Volume of type AMH crude transported from Alaska to Valdez
TAGTLTOT	Total volume of GTLs transported from Alaska North Slope to Valdez via the Trans-Alaska Pipeline (TAPS)
TANSOTOT	Total volume of crude transported from Alaska North Slope to Valdez via Trans-Alaska Pipeline (TAPS)
T(r)CBNTAX	Carbon tax in (r)
T(r)OVCOBJ	Refinery plant operating variable costs in region (r)
T(r)GPLOVC	Gas plant operating variable costs in region (r)
T(r)MCHOVC	Merchant plant operating variable costs in region (r)
T(w)FLL T(w)IMC	Foreign crude (mix of FLL, FMH, FHL, FHH, FHV) processed by marginal refinery and infra-marginal refinery in international region (w)
U(r)(uuu)	Utility (uuu) purchased in (r)
VTPC(r)(m)(d)	Crude pipeline transportation capacity from (r) to (d) using mode (m)
VTPL(r)(m)(d)	LPG pipeline transportation capacity from (r) to (d) using mode (m)
VTPP(r)(m)(d) VTPP(d)(m)(r)	Product pipeline transportation capacity from (r) to (d) using mode (m) or from (d) to (r)

Name	Activity Represented
VTVC(m)CP	Vessel transportation capacity for crude for mode (m)
VTVP(m)CP	Vessel transportation capacity for products for mode (m)
WAGTLJ(r)	GTL transportation from Alaska (A) to region (r) using mode J
W(r)(prd)(m)(d) W(r)(ss)(m)(d) W(d')(prd)(m)(d) W(d')(ss)(m)(d)	Product (prd) or (ss) transportation via mode (m) from (r) to (d) or from (d') to (d)
W(d')(ncr)(m)(d)	Ethanol or biomass diesel (ncr) transportation from (d') to (d) using mode (m)
W(w)NGLLPG	LPG from NGL in international region (w)
W(w)(prd)(w')	Transfer of product (prd) from international region (w) to international region (w')
X(d)BIOT(r)	Transfer of ethanol from (d) to (r) for BTL production
X(d)(prd)SPG	Recipe blends of product (prd) for oxygenated fuels and electric utility residual oils in (d)
X(r)(ist)(prd)	Recipe blends of product (prd) from stream (ist) in region (r)
X(d)(ncr)(prd)	Splash blending of (prd) from (ncr) in (d)
X(r)(yyyy)**	Recipe blends (yyyy) for categories of products such as AST, AVG, GOP, JP5 in region (r)
Y(o)(crt)(m)(r) Y(r')(crt)(m)(r)	Crude (crt) transportation via mode (m) from (o) to (r) or from (r') to (r)
Z(r)FLO(uns')	Total flow through processing unit (uns') in region (r) Note: (uns') is a subset of (uns): DDS, ETH, ETM, FCC, FUM, KRF, RFH, RFL
Z(r)RFGOXY	Total OXY in RFG in region (r)
Z@TOTCRD	Total foreign crude imports
ZZAMHTOT	Total export volume of Alaskan crude oil

* Created by PMM, not MRM

The general name structure for rows is: (v)(r)(abc)(def), where (v) is key code, (r) is region code, (abc) and (def) are 3 character names. Those constraints marked with an asterisk (*) are created within the PMM, not by the MRM.

Most (but not all) of the constraints prefixed with “A” are free (not subject to upper or lower bounds). These free rows (clearly labeled as “accounting rows”) are ignored by the commercial LP solver.

Name	Constraint Represented
A(d)(prd)	Accounting row for demand of product (prd) in (d)
A@1YRBLD	New ACU capacity added in a look-ahead year
A(r)(prd)	Accounting row for product (prd) in (r)
A@AKAEXP	Accounting row for Alaskan crude oil exports from US
A(d)BIMDMD A(d)BINDMD	Defines variables H(d)BIMDMD, H(d)BINDMD for biodiesel blended into low and ultra-low sulfur diesel in (d). These variables may be subject to lower and upper bounds. BIM = virgin feedstock, BIN=non-virgin feedstock.
A(d)BIMPRD A@BIMPRD	Accounting row for virgin biodiesel in (d) and total US
A(d)BINPRD A@BINPRD	Accounting row for non-virgin biodiesel in (d) and total US
A(d)BDNCCT A(d)BDVCCT A(d)BDWCCT	Defines variables H(d)BD*CCT used set carbon credit for biodiesel production in (d). N=non-virgin grease feedstock, V=virgin grease feedstock, W=white grease feedstock.
A(d)SBOCNS A@SBOCNS A(d)WGRCNS A@WGRCNS A(d)YGRCNS A@YGRCNS	Accounting rows for oils/grease processed into biodiesel in (d), and in US (@) SBO=seed oil feedstock, WGR=white grease feedstock, YGR=yellow grease feedstock.
A(d)BIOCNS A@BIOCNS	Accounting row for biomass processed into ethanol and/or liquids in (d) and total US
A@BTL	Accounting row for liquids produced from biomass in US (@)
A(r)CHPCGN	Accounting row for combined heat/power from petroleum coke gasification in (r)
A(d)CETCCT A(d)CLECCT	Defines variables H(d)CETCCT, H(d)CLECCT used to set carbon credit for corn and cellulosic ethanol production in (d), respectively.
A(d)CLEGRD	Defines variable H(d)CLEKWH used to set credit for electricity (from cellulosic ethanol production) sold to the grid in (d)
A(d)CET(ful)	Accounting row for fuel (FUL) consumed in producing corn ethanol in (d)
A(d)CRNCNS A@CRNCNS	Accounting row for corn converted to ethanol in (d) and total US

Name	Constraint Represented
A(d)COKEXP	Accounting row for petroleum coke exports from (d).
A(r)COKEXP	Accounting row for petroleum coke exports from (r).
A@COKEXP	Total petroleum coke exports from US (may be subject to lower/upper bounds)
A@CRDAKA	Accounting row for Alaskan crude oil in US
A@CRDDCR	Accounting row for domestic crude oil in US
A@CRDEXP	Accounting row for crude oil export in US
A(r)CRDFCR A@CRDFCR	Accounting row for foreign crude oil in (r) and US
A(r)CRDIMP A@CRDIMP	Total crude imported into region (r) in US Total crude imported into US
A@CRDL48	Accounting row for lower 48 crude oil in US
A@CRDSPR	Accounting row for SPR (strategic petroleum reserve) crude oil in US
A@CRDTOT	Accounting row for total crude oil in US
A(r)CRX(crt)	Accounting row for crude oil (crt) in (r)
A(r)CTXGRD	Determines variable H(r)CTXKWH which is used to set the credit for electricity (from CTL production) sold to the grid in (r)
A@CLZPRD	Sets maximum subsidize coal-to-liquid units allowed nationally (via RHS setting)
A(r)CTLWH	Accounting row for liquids produced from coal that are blended directly into product in (d)
A(r)DSLCTI	Average cetane in DSL (low sulfur diesel), in region (r)
A(r)DSUCTI	Average cetane in DSU (ultra-low sulfur diesel), in region (r)
A@ETCPRD	Total ethanol from cellulose (including imports) in US.
A@ETHPRD	Total ethanol from both corn and cellulose (including imports) in US.
A(d)ETH	Accounting row for ethanol supply from (d) from both corn and cellulose
A@ETHEXP	Accounting row for ethanol exports from the US (@)
A@ETHE85	Accounting row for Total E85 produced by refineries in US
A@ETHRFG	Accounting row for total ethanol blended into RBOB for RFG in US
A@ETHRFH	Accounting row for total ethanol blended into RBOB for RFH in US
A@ETHTRG	Accounting row for total ethanol blended into TRG (for SSE) in US
A@ETHTRH	Accounting row for total ethanol blended into TBOB for TRH in US
A(r)ETHRFN	Accounting row for ethanol to refinery in (r)

Name	Constraint Represented
A(r)FUEL A@FUEL	Accounting row for refinery fuel use in (r) US total
A(r)FUM(xxx) A@FUM(xxx)	Accounting row for FUM in (r) for fuel type (xxx=LPG, N2H, N6B, N6I, NGS, OTH, STG) US total
A(r)FXOC A@FXOC	Accounting row for fixed cost (r) US total
A(d)G08(yyy)	Accounting row for gasoline blending in (d) for motor gasoline (yyy = TRG, TRH, and/or RFG, RFH)
A(r)G(gbt)(xxx) A@G(gbt)(xxx)	Accounting row for gasoline blend component type (gbt) in (r) for motor gasoline (xxx= TRG, RFG); US total
A(r)GAIN A@GAIN	Accounting row for process gain in (r) US total
A(r)GPLLPG	Accounting row for LPG from gas plant in (r)
A(r)GPLOTH A(r)GPLPCF	Accounting row for Natural Gasoline from gas plant in (r) to products OTH, PCF
A(r)GPFDLG	Accounting row for still gas from gas plant into LPG feedstock (FLG) in (r)
A(r)INVST A@INVST	Accounting row for investment in (r) US total
A@KWHRFN	Accounting row for refinery KWH usage in US
A@(xxx)FU	Limits fuel type (xxx) consumed as refinery fuel in US (xxx=LPG,OTH,RES,STG)
A@MARPRD	Accounting row for total yields from marginal refinery units in US (@)
A(r)MGTOT(s)	Defines variable I(r)TRGT(s) used to limit total imports of TRG and SSE at each import supply step (s) price in (r)
A@METDEM	Accounting row for methanol demand in US
A(r)METIMP A@METIMP	Accounting row for methanol imports in (r) US total
A@METM85	Accounting row for methanol used for M85 splash blending in US
A@METPRD	Accounting row methanol production in US
A(r)METRFN	Accounting row for methanol consumption by ETH refinery unit in (r)
A(r)MTBIMP A@MTBIMP A@MTBPRD	Accounting row for MTB refinery imports in (r) US total (redundant in *AEO2008*)
A(r)MTBRFN	Accounting row for MTB refinery imports in (r)
A@MTBPRD	Accounting row for MTB production in US

Name	Constraint Represented
A(r)NGFTOT A@NGFTOT	Accounting row for natural gas purchases in (r); US total
A(r)NGLRFN A@NGLRFN	Accounting row for NGL transfer from gas plant to refinery in (r); US total
A(r)NGLPRD A@NGLPRD	Accounting row for NGL (r); US total
A(r)NGSH2P A@NGSH2P	Accounting row for NGS consumption by H2P refinery unit in (r) Accounting row for NGS consumption by H2P refinery unit: US total
A(r)NGSMER A@NGSMER	Accounting row for methanol transfer from methanol plant to refinery in (r); US total
A(r)NGSMET A@NGSMET	Accounting row for methanol plant production in (r); US total
A(r)NGSRFN	Accounting row for purchased NG to refinery NGS stream in (r)
A(r)PETCOK A@PETCOK	Accounting row for high and low sulfur coke production at refinery in (r) US total
A(x)PRDEXP A@PRDEXP	Accounting row for product exports in (x = d, r) US total
A@PRDDEM	Accounting row for total product demand in US
A(r)PRDIMP A@PRDIMP	Product imports in (r)
A@PRDRFN	Accounting row for total product produced at refinery
A(r)SG2H2P	Accounting row for total still gas processed into hydrogen in (r)
A@SG2H2P	and US
A(d)RFG(yyy) A(d)TRG(yyy)	Accounting row for gasoline blending in (d) for motor gasoline (yyy = TRG, TRH, and/or RFG, RFH)
A(r)RFGM00 A(r)RFGR00	Accounting row for total motor (and research) octane in the reformulated (RFG) motor gasoline stream in refining region (r), based on contribution from each component blend stream.
A(r)TRGM00 A(r)TRGR00	Accounting row for total motor (and research) octane in the conventional (TRG) motor gasoline stream in refining region (r), based on contribution from each component blend stream.
A(r)SSRIMP	Total SSR imports into (r = E only) must be less than a maximum (currently unlimited)
A(r)SULSAL A@SULSAL	Accounting row for sulfur production in (r) US total
A(r)UNFIMP A@UNFIMP	Accounting row for unfinished oil (UNF) imports into (r) US total

Name	Constraint Represented
A@ZZEXP	Accounting row for total distress exports
A@ZZIMP	Accounting row for total distress imports
B(r)(ist)	Balance for intermediate stream (ist) in (r)
B(w)ARB	
B(w)ARC	
C(o)(crt)	Crude balance for crude type (crt) in (o)
C(r)(crt)	Crude balance for crude type (crt) in (r)
CAALLTOT	Balance for Alaska crude type ALL
CAAMHTOT	Balance for Alaska crude type AMH
C(r)TLL	Balance row for total low sulfur light (foreign and domestic) processed by the marginal refinery in (r)
C(d)BIMIMP	Defines variable I@BIMM(d) to represent total (virgin) biodiesel imported into (d)
C@BIMIMP	Balance row for total (virgin) biodiesel import supply curve and (virgin) biodiesel imported to US Census Divisions
C(d)ETHIMP	Defines variable I@ETHM(d) to represent total ethanol imported into (d)
C@ETHBRZ	Balance row for total ethanol import supply curve from Brazil and it's option to flow directly to the US or through CBI (Caribbean Basin initiative)
C@ETHCBI	Balance row for ethanol imports from the CBI made available for US imports
C@ETHIMP	Balance row for ethanol directly from Brazil or through CBI, imported to US Census Divisions
C@ETHBIO	Minimum renewables requirement in motor fuels (national)
C@CLLBIO	Minimum renewables from advanced processes requirement in motor fuels (national)
C@CLLTOT	Minimum renewables from biomass requirement in motor fuels (national)
C@BIOTOT	Minimum renewables biodiesel in motor fuels (national)
C(r)CTL(lqc)	Balance for CTLs by liquid type (lqc) and total produced in region (r)
C(r)CTLTOT	
C(r)GTL(lqg)	Balance for GTLs by liquid type (lqg) and total produced in Alaska region (r)
CAGTLTOT	
CANSOTOT	Balance for Alaska N. Slope crude
CC(xxx)	(xxx = FHL, FLL, FMH)
C(r)GTL	Balance for GTLs transported from Alaska to region (r)
C(d)PLMIMP	Defines variable I@PLMM(d) to represent total palm oil imported into (d)
C@PLMIMP	Balance row for total palm oil import supply curve and palm oil imported to US Census Divisions

Name	Constraint Represented
CZAMH	Alaskan crude exports
<>CL(j)CTL	Energy balance of total coal supplied to coal demand region (j) used to generate coal to liquids
D(d)(prd)	Final demand for product (prd) in (d)
D(w)(xxx)	Demand for product (xxx=DIS,LPG,NAP,OTH,RES) in (w)
D(d)E85CRV *	Balance row to represent E85 demands (D(d)E85TBL) as a demand curve in (d)
D(d)PRDEQU	Balance row to ensure total E85 plus motor gasoline demand is met via any quantity distribution of each in (d)
D(d)ETH D(d)BIM D(d)BIN	Final supply of renewables ETH, BIM, BIN in (d)
D(d)MET D@MET	Demand for methanol in (d) Total demand for methanol
D(d)SSL, D(d)SSU	Balance for diesel fuel supply (DSL, DSU) to blended and unblended product in (d)
DOMDDGMK	Sets upper limit (RHS) on DDG byproduct produced from corn ethanol production in US
E(r)(emu)(e)	Emission of (emu) from source (e) in (r)
E@BTLMAX	Balance to set Mansfield-Blackman national penetration rate (upper limit on build) for BTL production
E@CTXMBX	Balance to set Mansfield-Blackman national penetration rate (upper limit on build) for CTL units
E@CTZEPC	Accounting of CTL units built with EPACT05 credit in US
F@TOTCRD	Total crude balance for unfinished oil constraint in US
F(r)UNF(unf)	Unfinished oil balance for (unf) in (r)
G(r)(ist)	Gas plant balance for stream (ist) in (r)
G(r)(pol)	Gas plant policy (pol) accounting row in (r)
G(r)PGSLGX	Limit on transfer of PGS to LPG at Gas Plant in (r)
G(r)SC2C1X	Limit on transfer of CC2 to CC1 at Gas Plant in (r)
H(d)(cp)	Co-product (cp) balance row in (d), typically from ethanol and biodiesel production
H(d)(ist)	Corn ethanol, cellulosic ethanol, or biodiesel plant balance row for (ist) in (d)

Name	Constraint Represented
H(r)(ist)	Merchant oxygenate plant balance row for (ist) in (r) and off-site GTL and CTL balance row for (ist) in (r)
H(r)BIOCAP	Balance row for BTL production, allowing units to idle if economic, in refinery region (r)
H(r)BIT	Energy balance for coal from associated coal demand regions used to produce liquids in refinery region (r)
HG_CTL_U *	Mercury emissions balance for mercury emission from coal used for coal to liquids production
H(r)FUMCAP	Merchant oxygenate fuel balance row in (r)
H(r)LOS	Accounting row for merchant oxygenate plant loss in (r)
H(r)OVC	Merchant plant variable operating costs in (r)
H(r)(uuu)	Merchant oxygenate plant policy utility (uuu) accounting row in (r) (uuu) = COA, KWH, NGF, STM
I(r)DIS	Balance row to distribute distillate produced at the marginal refinery into N2H, DSL, DSU in (r)
I(r)GAS	Balance row to distribute motor gasoline produced at the marginal refinery into TRG, SSE, SSR in (r)
I(w)(xxx)	(xxx = FLL, IMC)
I@(crt)	Foreign crudes (crt)
I@GENCRD I@GLBNGL	
L(r)(uns)CAP	Process (uns) capacity in (r)
L(d)(uns)CAP	Process capacity in (d) for (uns) biodiesel, cellulosic ethanol
L(d)CETCAP	Accounting row for total corn ethanol capacity in (d)
L(d)CETCD1 L(d)CETCD2	Cumulative corn ethanol capacity in (d) for process type D1, D2 (DM1, DM2)
L(d)CETOLD	Existing corn ethanol capacity in (d) at start of forecast
L(w)ILGCAP L(w)IUPCAP	Final product (prd) demand balance at refinery (r) or CD (d)
M(r)(prd) M(d)(prd)	
M(r)MTBRFG	MTBE (and other ethers) limit in RFG motor gasolines in (r)
M(r)MTBTRG	MTBE (and other ethers) limit in TRG motor gasolines in (r)
M(w)(xxx)	(xxx = DIS,LPG,N6I,N6B,NAP,OTH,PCF,SSE,SSR,TRG) in international region (w)
O(o)(crt)	Domestic crude oil (crt) accounting in (o)

Name	Constraint Represented
OBJ	Objective function (maximize: revenues - costs)
OPAFLT(x)	(x = C,D,L,O)
P(r)(pol)	Policy (pol) constraint in (r)
P(r)CBNTAX	Total taxable carbon emissions in (r)
P(r)LOS	Accounting row for refinery loss in (r)
P(r)OVC	Total variable cost for the refinery in (r)
Q(r)(prd)(qd)(c) Q(r)(prd)(qm)(c)	Product (prd) specification for quality (qd) constraint type (c) in (r) Product (prd) specification for quality (qm) constraint type (c) in (r)
R(r)(ist)	Balance for intermediate refinery gas stream (ist) in (r) not processed by SGP (ist=cc1, cc2, cc3, nc4, ic4, hyl)
S(r)(mgb)E	Balance row for blending gasolines (mgb) in (r)
S(r)(dfo)E	Balance row for blending fuel oils (dfo) in (r)
S(r)RFGOXY	Constraint on renewable OXY limits in (r)
S_CL(n)(k) *	Energy balance of coal production to total coal demand for coal type (k) from coal supply curve (n)
SO2_CTL(se) *	SO2 emission balance for_SO2 emissions in SO2 region (se) from all coal used in coal to liquids production
TANGKGTX	Maximum NG production in Alaska for GTL use
TAOILGTN	Minimum flow requirement on Trans-Alaska Pipeline (TAPS) in Alaska
TAOILGTX	Maximum flow requirement on Trans-Alaska Pipeline (TAPS) in Alaska
TPC(b)(m)(r)	Crude pipeline transportation capacity balance row from (b=1-6,C) to (r) via mode type (m)
TPL(r)(m)(d)	LPG pipeline transportation capacity balance row (r) to (d) mode type (m)
TPP(r)(m)(d)	Product pipeline transportation capacity balance row (r) to (d) mode type (m)
TVC(m)CP	Crude oil vessel transportation capacity limits for mode (m)
TVP(m)CP	Product vessel transportation capacity limits for mode (m)
U(r)(uuu)	Utilities (uuu) in region (r)
X(d)MAXSPL	Balance row to put total blended motor gasoline into accounting variable X(d)MAXSPL (with UL) in (d)
Z(r)CAP(uns)	Balance row for total capacity of (uns) in (r)
Z(r)NGFSUM	Sum row for natural gas to refineries in (r)

Name	Constraint Represented
ZZAMHSUM	Sum row for Alaskan crude export
Z@FLLIMP	Set lower limit on national import level for FLL crude
Z@WOP	Current world oil price in value of RHS
Z@CRDTOT	Sum row for total crude in US
Z@YRITER	Iteration year
Z@IRAC(c)	Sum row of constraint type (c) to force average refinery crude cost within specified range
ZD(mmddyy)	Month, day, year of matrix generation

* Created in PMM, not MRM

The following Table gives the dimensions of the MRM model represented by the input data provided to the MRM program. Note, however, that during a NEMS forecast run, the LP representation is modified within the PMM throughout the forecast. For example, detailed coal supply curves are added to the matrix the year CTL units can be built. This enhanced model includes additional column and row variables not in the starting LP matrix. Thus, a second set of dimensions is included in the table below that reflects the LP solved in NEMS in 2030.

Model	**Columns**				**Rows**		
	Total	Fixed	Bound Upper	Bound Lower	Total	Fixed	RHS
MRM (5 regions)	21261	903	3057	15	7748	6175	34
NEMS run, 2030	22396	1446	3579	66	7862	6251	41

Subroutines

The program consists of several subroutines and a main program. The subroutines can be grouped as those that setup the OML environment, read in the data tables, form parts of the matrix representation of the model, solve the model, retrieve needed information for report writing, and write the reports. All the subroutines that generate part of the matrix representation of the model use input from data files in an OML format. These files have a .dat extension. Some subroutines use ASCII files as input, while others do not use any. The following table shows the source code/subroutine file names, the input data file names, and the purpose of the subroutines.

Source Code	Data file	Purpose
accunit.f	accunit.dat	Represents ACU unit
akaexp.f	akaexp.dat	Represents Alaskan exports
avoids.f	avoids.dat	Represents the avoids (not used)
cogener.f	cogener.dat	Represents the cogeneration
crdimprt.f	crdimprt.dat	Represents crude imports
demand.f	demand.dat	Represents demands
distblnd.f	distblnd.dat	Represents distillate blending
distress.f	distress.dat	Represents the distress imports and exports
domcrude.f	domcrude.dat	Represents crude inputs
emish.f	emish.dat	Represents emissions
ethanol.f	ethanol.dat	Represents corn ethanol processing units, and supply curves for biomass and biofuels production, and ethanol imports
fixcol.f	fixcol.dat	Fixes some columns (not used)
fuelmix.f	fuelmix.dat	Simulates fuel mixing
gasoblnd.f	gasoblnd.dat	Simulates gasoline blending
intlref.f	intrlref.dat	Defines the international refinery
limpol.f	limpol.dat	Puts limits on policy rows (not used)
lplookup.f		Retrieves solution
mrm.f	mrmparam, mrmpath refmain.dat	Program MPS2ANAL: Sets up the OML environment, reads in some main data, controls the program, calls subroutines to form matrix, solves problem, stores solution, writes reports, basis and packs matrix.
mrm.f	marfll.dat	Subroutine MARFLL: Sets up representation for domestic marginal refinery in each PADD
mchproc.f	mchproc.dat	Simulates the merchant plant, including CTL, GTL
ngprod.f	ngprod.dat	Provides gas supply steps to refinery
nrfplant.f	nrfplant.dat	Simulates the non refinery plant activities (gas plant, methanol plant)

Source Code	Data file	Purpose
output.f		Prints a report (not used)
prdexp.f	prdexp.dat	Simulates the product exports
prdimprt.f	prdimprt.dat	Simulates the product imports
recipes.f	recipes.dat	Specifies product recipe blends
refproc.f	refproc.dat	Simulates the refinery
setrows.f	setrows.dat	Sets some rows
splash.f	splash.dat	Simulates splash blending
stream.f	stream.dat	Simulates stream transfers
tabread.f		Reads data tables
transit5.f	transit.dat	Simulates product and crude oil transportation for 3-region representation of MRM
unfinished.f	unfinish.dat	Provide for unfinished oil imports
utility.f	utility.dat	Simulates utility purchased
world_demand.f	wrld_dem.dat	Defines international demand curves for petroleum products
wrldcrude.f	wrdcrude.dat	Defines international supply of crude oil
wrldprod.f	wrldprod.dat	Defines product transport links between international regions and U.S. regions

Most of the subroutines that constitute the program generate part of the matrix representation of the model. The following gives a representation of the submatrix generated by each subroutine in table form. Columns of the tables correspond to activities (vectors), and rows of the tables to constraints. The symbols x, -x or +-x represent matrix coefficients. Some parts of the LP matrix are generated within the PMM during a NEMS run. These are listed first (below), with the subroutine(s) identified that generate the submatrix presented.

Created in the PMM (subroutine CTL_COAL): simulates coal supply links to CTL facilities, using coal supply and demand data from the CMM.

	CT(n)(j)(k)	CP(n)OTXX	CP(n)(k)(q)	N(r)CL(r)N1	P_SO2_1	P_SO2_1	P_HG_US
S_CL(n)(k)	x	x	-x				
CL(j)CTL	-x			x			
SO2_CTL1	x				-x		
SO2_CTL2	x					-x	
HG_CTL_U	x						-x
OBJ	-x		-x		-x	-x	

Bounds: CP(n)((k)(q), CP(n)OTXX

Created in the PMM (subroutine CHGDMDS):

	D(d)E85S(s)	D(d)TRGTBL	D(d)RFGTBL	D(d)TRHTBL	D(d)RFHTBL	RHS
D(d)PRDEQU	x	x	x	x	x	x
D(d)RFGFRC (d≠9)		-x	x	-x	-x	
D(d)TRHFRC (not d=1,2,3,5,6)		-x	-x	x	-x	
D(d)RFHFRC (d=9)		-x	-x	-x	x	
OBJ	x					

Where s=01,02,…,56 (steps on E85 demand curve)
Bounds: D(d)E85S(s)

Continued:

	D(d) TRGS1	D(d) RFGS1	D(d) TRHS1	D(d) RFH5S1	D(d) TRGTBL	D(d) RFGTBL	D(d) TRHTBL	D(d) RFHTBL
D(d)TRGCRV	x				-x			
D(d)RFGCRV		x				-x		
D(d)TRHCRV			x				-x	
D(d)RFHCRV				x				-x
D(d)TRGCRV				x				

Continued:

	D(d)E85S(s)	D(d)E85TBL	X(d)ETHE85	I(d)E85Z9
D(d)E85CRV	-x	x		
D(d)E85		-x	x	x

Where s=01,02,…,56 (steps on E85 demand curve)

accunit.f: This subroutine simulates the ACU unit. It creates the following submatrix:

	R(r)ACU(crt)
A(r)CRDFCR*	x
A(r)STM	-x
A@CRDFCR*	x
A(r)CRX(crt)	x
A@CRDTOT	x
B(r)(ist)	+-x
C(r)(crt)	-x
S(r)(ist)	x
F@TOTCRD	x
L(r)ACUCAP	x
P(r)(pol)**	+-x
U(r)(uuu)	-x
Z@CRDTOT*	x

* for (crt) = FLL, FMH, FHL, FHH, and FHV
** for (pol) = OVC, FRL
RHS: A@INVST, A(r)INVST

Bounds: None

akaexp.f: This subroutine simulates the Alaskan exports. It creates the following submatrix:

	NZAMH(i)	ZZAMHTOT	TAAMHXZ	PANGLQ1
OBJ	+-x*	x	-x	-x
CAAMH			-x	

	NZAMH(i)	ZZAMHTOT	TAAMHXZ	PANGLQ1
CZAMH		-x	x	
BW(ist)				x
ZZAMHSUM	x	-x		
A@AKAEXP		x		
A@CRDEXP		x		
AANGLPRD				x
A@NGLPRD				x
AWNGLRFN				x

(i) = N1, N2, N3, P4, P5, P6
* : -x if i = N1, N2, N3; x if i = P4, P5, P6

Bounds: PANGLQ1, NZAMH(i)

avoids.f: This subroutine simulates the avoids. It is turned off. It creates the following submatrix:

	D(d)(prd)N(i)	D(d)(prd)P(i)
D(d)(prd)	x	-x
A(d)(prd)	-x	x
A@PRDDEM	-x	x
A@AVDNEG	x	
A@AVDPOS		x

(i) = 1, ..., 3

Bounds: D(d)(prd)N(i) and D(d)(prd)P(i)

cogener.f: This subroutine simulates the cogeneration unit. It creates the following submatrix:

	E(r)CGNINV	K(r)CGNCAP	L(r)CGNBLD	R(r)CGNCGN
B(r)FUL				-x
L(r)CGNCAP	-x	-x	-x	x
OBJ	-x		-x	x
P(r)OVC				-x
U(r)(uuu)				x
A@FXOC	x		x	
A(r)FXOC	x		x	
A@INVST	x			
A(r)INVST	x			
A@KWHRFN				x

	E(r)CGXINV	K(r)CGXCAP	L(r)CGXBLD	R(r)CGXCGN	R(r)CHP(mod)
B(r)FUL				-x	
L(r)CGXCAP	-x	-x	-x	x	
OBJ	-x		-x	x	x
P(r)OVC				-x	
U(r)(uuu)				x	x
A@FXOC	x		x		
A(r)FXOC	x		x		
A@INVST	x				
A(r)INVST	x				

	E(r)CGXINV	K(r)CGXCAP	L(r)CGXBLD	R(r)CGXCGN	R(r)CHP(mod)
A@KWHRFN				x	x
A(r)CHPCGN					x

Bounds: E(r)CGNINV, K(r)CGNCAP, L(r)CGNBLD, E(r)CGXINV, K(r)CGXCAP, L(r)CGXBLD

crdimprt.f: This subroutine simulates the crude imports into the United States:

	P(r)(crt)(Qs)
C(r)(crt)	x
OBJ	-x
Z@IRACN	x
Z@IRACX	x
A(r)CRDIMP*	x
A@CRDIMP	x
Z@FLLIMP**	x

(Qs) = supply step Q1,Q2,Q3
* (r)= PADDS II and IV only; **(crt)=FLL only
RHS: A(r)CRDIMP* A@CRDIMP Z@FLLIMP
Bounds: P(r)(crt)Q(s)

demand.f: This subroutine simulates product demands. It creates the following submatrix:

	D(d)(prd)S1	D@METS1	CUSCREDT	D(d)E85S(s)	ESCAPEVL
D(d)(prd)	-x				
OBJ	x		-x		-x
A(d)(prd)*	x				
A@METDEM		x			

	D(d)(prd)S1	D@METS1	CUSCREDT	D(d)E85S(s)	ESCAPEVL
A@PRDDEM	x				
D@MET		-x			
D(d)PRDEQU				x	
C@ETHBIO			x		
C@CLLBIO			x		
C@CLLTOT			x		
C@ETHVOL	-x**				x

* for (prd) not equal to E85 or M85
** only for (prd) = E85, TRG,RFG,TRH,RFH,DSL,DSU

Bounds: D@METS1 and D(r)(prd)S1

distblnd.f: This subroutine simulates the distillate blending. It creates the following matrix:

	F(r)(dfo)(ist)	Q(r)(prd)*
A(r)(prd)*		x
A(r)STM		-x
A@PRDRFN		x
B(r)(ist)	+-x	
M(r)(prd)*		x
Q(r)(prd)*(qd)(c)	+-x	-x
S(r)(dfo)E	x	-x
U(r)STM		-x
A(r)(dfo)CTI**	x	

* (prd) = (dfo) only
** (dfo) = DSL, DSU only

Bounds: None

distress.f: This subroutine simulates product distresses. It creates the following submatrix:

	I(d)(pi9)Z9	D(z)(px9)Z9
OBJ	-x	+-x
D(d)(pi9)	x	
A@ZZIMP	x	
D(d)(px9)		-x
A@ZZEXP		x

(z) = export demand regions (d) 2,3,7,8,9
Bounds: None

domcrude.f: This subroutine simulates domestic crudes. It creates the following submatrix:

	P(o)DCRQ1	PADCRQ1	TAALLTOT	TAAMHTOT	O@CRDEXP	O@CRDSPR
OBJ	-x	-x				
C(o)(crt)	x					
CAALLTOT		x	-x			
CAAMHTOT		x		-x		
CAALL			x			
CAAMH				x		
CBFHL						-x
A@CRDDCR	x	x				
A@CRDAKA		x				
A@CRDL48	x					
A@CRDEXP					x	

	P(o)DCRQ1	PADCRQ1	TAALLTOT	TAAMHTOT	O@CRDEXP	O@CRDSPR
A@CRDSPR						x
A@CRDFCR						x
O(o)(crt)	x	x				

(o) : except A
Bounds: P(o)DCRQ1, PADCRQ1, O@CRDEXP, O@CRDSPR

emish.f: This subroutine simulates emissions. It creates the following submatrix:

	K(r)(uns)CAP	R(r)FUM(ist)
E(r)(emu)N	x	
E(r)(emu)C		x

where, uns = FCC, VBR, VCU, KRF
Bounds: None

ethanol.f: This subroutine represents ethanol supply and prices. It creates the following submatrix:

	C(d)CRNR(i)	H(d)CET(mod)	H(cd)(ist)TOT	H(r)(iii)(m)(d)	H(d)CETCCT	N(d)ETHCOA
OBJ	-x		+-x		x	-x
H(d)CRN	x	-x				
A(d)CRNCNS	x					
A@CRNCNS	x					
L(d)CETOLD*		x				
L(d)CETCAP						
L(d)CETCD(#)		x				
H(d)(ist)		+-x	-x			
H(r)(uuu)		-x				x

	C(d)CRNR(i)	H(d)CET(mod)	H(cd)(ist)TOT	H(r)(iii)(m)(d)	H(d)CETCCT	N(d)ETHCOA
H(r)OVC		-x				
A(d)CET(uuu)		-x				
A@CET(uuu)		-x				
H(d)DEN				x		
M(r)SSE				-x		
G(r)NAT				-x		
A(d)CETCCT		-x			x	

	K(d)CET(mod)**	K(d)CETOLD	L(d)CET(mod)**	E(d)CET(mod)**	
OBJ			-x	-x	
L(d)CETCD(#)	-x		-x	-x	
L(d)CETCAP	x	x	x	x	
L(d)CETOLD		-x			
A(r)INVST				x	
A@INVST				x	

	C(d)BIOR(s)	H(d)CLELIG	H(d)CLZLIG	C(d)SBOR(s)	H(d)BDVSBO	I@PLMM(d)
OBJ	-x			-x		-x
H(d)BIO	x	-x	-x			
A(d)BIOCNS	x					
A@BIOCNS	x					
H(d)SBO				x	-x	x
A(d)SBOCNS				x		
A@SBOCNS				x		

	C(d)BIOR(s)	H(d)CLELIG	H(d)CLZLIG	C(d)SBOR(s)	H(d)BDVSBO	I@PLMM(d)
H(d)DEN		-x	-x			

	H(d)CLELIG	H(d)CLZLIG	E(d)CLEINV	L(d)CLEBLD	K(d)CLECAP	E(d)CLZINV	K(d)CLZCAP
OBJ			-x	-x		-x	
L(d)CLECAP	x		-x	-x	-x		
L(d)CLZCAP		x				-x	-x
A@CLZPRD						x	x
A(r)INVST			x			x	
A@INVST			x			x	

	H(d)CLECCT	H(d)CLELIG	H(d)CLZLIG	H(d)CLEKWH	H(d)DDGTOT	H(d)EDGTOT
OBJ	x			x	x	x
A(d)CLECCT	x	-x	-x			
A(d)CLEGRD		-x	-x	x		
DOMDDGMK					x	
H(d)DDG					-x	-x

	E(d)(bbb)INV	K(d)(bbb)CAP	L(d)(bbb)BLD	H(d)(bbb)(ccc)	H(d)(bbb)CCT	H(d)(bbb)TOT
OBJ	-x		-x			
L(d)(bbb)CAP	-x	-x	-x	x		
A(r)INVST	x					
A@INVST	x					
H(d)SBO				x	-x	
A(d)SBOCNS				x		

	E(d)(bbb)INV	K(d)(bbb)CAP	L(d)(bbb)BLD	H(d)(bbb)(ccc)	H(d)(bbb)CCT	H(d)(bbb)TOT
A@SBOCNS				x		
A(d)(bbb)CCT (bbb ≠ BDW)				-x	x	
H(d)(bbb)				x		-x
A(d)(bbb)KWH				-x		
A(d)(bbb)STM				-x		
D(d)MET				-x		
H(d)GLY				x		
H(r)KWH				-x		
H(r)OVC				-x		
H(r)STM				-x		

	C(d)WGRR(s)	H(d)BDWWGR	C(d)YGRR(s)	H(d)BDNYGR	D(d')ETHSX(s)	X(d)ETHE85
OBJ	-x		-x		x	x
H(d)WGR	x	-x				
A(d)WGRCNS	x					
A@WGRCNS	x					
H(d)YGR			x	-x		
A(d)YGRCNS			x			
A@YGRCNS			x			
A@ETHEXP					x	
C@ETHBIO					-x	
D(d')ETH					-x	

	H(d)BDVSBO	H(d)BDWWGR	H(d)BIMTOT	H(d)BDNYGR	H(d)BINTOT	X(d)BIMDSL X(d)BIMDSU	X(d)BINDSL X(d)BINDSU
OBJ							
H(d)BIN				x	-x		
H(d)BIM	x	x	-x				
D(d)BIN					x		
D(d)BIM			x				
A(d)BIMPRD			x				
A@BIMPRD			x				
A(d)BINPRD					x		
A@BINPRD					x		
C@BIOTOT			x		x		
C@CLLBIO			x		x		
C@ETHBIO			x		x		

	H(d) ETHTOT	H(d) ETCTOT	I@ ETHM(d)	I(d) ETH(Rs)	I@ ETH(Rs)	I@ ETHCBI	I@ ETHUSB	I@ ETHCBB	I@ ETHCBD
OBJ				+-x	-x		-x	-x	
C@ETHBIO	x	x	x						
C@CLLBIO		x	x						
C@CLLTOT		x							
A(d)ETH	x	x	x						
D(d)ETH	x	x	x						
H(d)ETH	-x								
H(d)ETC		-x							

	H(d) ETHTOT	H(d) ETCTOT	I@ ETHM(d)	I(d) ETH(Rs)	I@ ETH(Rs)	I@ ETHCBI	I@ ETHUSB	I@ ETHCBB	I@ ETHCBD
A@ETHPRD	x	x	x						
A@ETCPRD		x							
C@ETHIMP			-x			x	x		
C(d)ETHIMP			-x	x					
C@ETHCBI						-x		x	x
C@ETHBRZ					x		-x	-x	

	I@PLMM(d)	I(d)PLMR(s)	I@PLMR(s)	I@BIMM(d)	I@BIMR(s)	I(d)BIMR(s)
OBJ	-x	+-x	-x		-x	+-x
C(d)PLMIMP	-x	x				
C@PLMIMP	-x		x			
A@BIMPRD				x		
C(d)BIMIMP				-x		x
C@BIMIMP				-x	x	
C@ETHBIO				x		
C@CLLBIO				x		
C@BIOTOT				x		
D(d)BIM				x		

i = 1, ..., 4; s=1,…,5; #=1,2 for DM1,DM2; ist=DDG,WMC,DEN,ETH; iii=SSE,NAT
* for mod=DME,WME only; ** for mod=DM1,DM2 only; uuu=COA only; d'=cd 3,4 only;
when bbb=BDV, BDW, BDN, then ccc=SBO, WGR, YGR, respectively;
Bounds: C(d)ETHR(i), C(d)ETCR(i), C(d)BIMR(i), C(d)BINR(I), C(d)CRNR(i), H(d)CET(mod)*, E(d)CET(mod)**, C(d)BIOR(s), C(d)(ccc)R(s), K(d)CLECAP, K(d)CLZCAP, K(d)(bbb)CAP, I(d)ETHR(s), I(d)PLMR(s), I(d)BIMR(s), I@BIMR(s), I@ETHR(s), I@PLMR(s), D(d)ETHSX(s)
RHS: row A@ETCPRD, A@ETHPRD, A@CLZPRD, DOMDDGMK

fixcols.f: This subroutine fixes some variables or activity. No submatrix is generated.

Bounds: R(r)FCC(ist)

fuelmix.f: This subroutine simulates fuel mixing. It creates the following submatrix:

	R(r)FUM(mod)	T(r)CBNTAX	K(r)FUMCAP
OBJ		-x	
P(r)CBNTAX		x	
A(r)FUM(xxx)	x		
A@FUM(xxx)	x		
A(r)FUEL			x
A@FUEL			x

(xxx) = fuel type, LPG, OTH, N2H, NGS, STG, N6I, N6B
Bounds: None

gasoblnd.f: This subroutine simulates gasoline blending. It creates the following submatrix:

	B(r)(mgb)(ist)	Q(r)(mgb)	Q(r)(dfo)	Z(r)RFGOXY
OBJ		-x	-x	
A(r)(xxx)(mgb)	x			
A@(xxx)(mgb)	x			
A(r)(prd)*		x		
A@PRDRFN		x		
A(r)(mgb)M00	x			
A(r)(mgb)R00	x			
B(r)(ist)	-x			
M(r)(prd)		x		

	B(r)(mgb)(ist)	Q(r)(mgb)	Q(r)(dfo)	Z(r)RFGOXY
M(r)MTB(mgb)	x **			
Q(r)RFGREN				-x
Q(r)(mgb)(qq)(c)	x	-x		
S(r)(mgb)E	x	-x		
S(r)RFGOXY				-x
U(r)KWH		-x		

* (prd) = (mgb) only; **ist=MTB,ETB,TAE,TAM,THE,THM only; (xxx) = GO1, ..., G12

Bounds: B(r)RFG(ist) and B(r)TRG(ist) where ist= ETB, MTB, TAE, TAM, THE, THM, Q(r)RFG

intlref.f: This subroutine simulates refineries in the international regions (w = A,N,R,U).

	R(w)ARBRES	R(w)ARCRES	R(w)N6BRES	R(w)N6IRES
OBJ			-x	-x
B(w)ARB	-x			
B(w)ARC		-x		
M(w)N6B			-x	
M(w)N6I				-x
M(w)RES	x	x	x	x

	R(w)DISDSL	R(w)DISDSU	R(w)DISJTA	R(w)DISN2H
OBJ	-x	+x/-x (*)	+x/-x (*)	+x/-x (**)
M(w)DIS	-x	-x	-x	-x
M(w)DSL	x			
M(w)DSU		x		
M(w)JTA			x	
M(w)N2H				x

* positive for (w)=A,N,U; negative for (w)=R
** positive for (w)=U; negative for (w)=A,N,R

	K(w)ILGCAP	K(w)IUPCAP
L(w)ILGCAP	-x	
L(w)IUPCAP		-x

Bounds: K(w)ILGCAP, K(w)IUPCAP

	R(w)ILGL2D	R(w)IUPN2D	R(w)IUPRD1	R(w)IUPRD2
OBJ	-x	-x	-x	-x
B(w)ARB			-x	
L(w)ILGCAP	x			
L(w)IUPCAP		x	x	x
M(w)DIS	x	x	x	x
M(w)LPG	-x			
M(w)N6I				-x
M(w)NAP		-x	x	x
M(w)OTH			x	x

	R(w)NAPPCF	R(w)NAPSSE	R(w)NAPSSR	R(w)NAPTRG
OBJ	-x/+x (*)	x (**)	-x	-x
M(w)NAP	-x	-x	-x	-x
M(w)PCF	x			
M(w)SSE		x		
M(w)SSR			x	
M(w)TRG				x

* positive for (w) = A; negative for (w) = N,R,U
** positive for (w) = U; 0.0 for (w) = A,N,R

	R(w)MARFLL	R(w)MARIMC
OBJ	-x	-x
B(w)ARB		x
B(w)ARC	x	
I(w)FLL	-x	
I(w)IMC		-x
M(w)DIS	x	x
M(w)LPG	x	x
M(w)N6B	x	
M(w)N6I		x
M(w)NAP	x	x
M(w)OTH	x	x

Bounds: R(w)MARFLL, R(w)MARIMC

	T(w)FLL	T(W)IMC
I@FHH		-x
I@FHL		-x
I@FHV		-x
I@FLL	-x	
I@FMH		-x
I(w)FLL	x	
I(w)IMC		x

limpol.f: This subroutine defines policy conditions. It creates the following submatrix:

	K(r)(uns)CAP	E(r)(uns)INV	L(r)(uns)BLD	Z(r)FLO(uns)

	K(r)(uns)CAP	E(r)(uns)INV	L(r)(uns)BLD	Z(r)FLO(uns)
Z(r)CAP(uns)	x	x	x	-x
P(r)(pol)				-x

(uns) = specific units under policy controls (FCC, KRF, RFL, DDS, ETH, ETM, FUM)

Bounds: None

lplookup.f: Retrieves solution values and stores them in arrays. (Not updated for 5-padd model.)

mrm.f: (main)This subroutine reads in the mrmparam file that has the information relative to the model to run; initializes the OML subroutine library environment; opens the database; specifies a problem in the database for processing; initializes the matrix processing; reads in the path file, the refmain.dat file that contains some global variables such as the refinery, the exporting, and demand regions code; calls the subroutines that generate the matrix; puts bounds (MRM_ADDBND) on selected variables to allow in-memory changes; ends the matrix processing; writes out the MPS file; inserts the advanced basis; solves the matrix; puts the solution in output; writes the optimal basis; prints reports; packs the matrix; and closes the database.

	Z@TOTCRD
OBJ	
Z@WOP	
Z@CRDTOT	-x
Z@IRACN	-x
Z@IRACX	-x
Z@YRITER	
ZD120106	

mchproc.f: This subroutine represents the merchant plant. It creates the following submatrix:

	K(r)(uns)CAP	E(r)(uns)INV	L(r)(uns)BLD	T(r)MCHOVC	E@CTXINV	H(r)ETXIDL

	K(r)(uns)CAP	E(r)(uns)INV	L(r)(uns)BLD	T(r)MCHOVC	E@CTXINV	H(r)ETXIDL
L(r)(uns)CAP	-x	-x	-x			
L(r)ETXCAP		+-x*****				`x
OBJ		-x	-x	-x		
H(r)OVC				x		
A@FXOC		x	x			
A(r)FXOC		x	x			
A@INVST		x				
A(r)INVST		x[a]				
E@CTXMBX	-x***	-x***	-x***		x	
E@CTZEPC	x****	x****	x****			

	H(r)BIOCAP	H(r)CTXBIO	H(r)CTXIDL	H(r)CTXBIT	H(r)CTXKWH	H(r)CTZBIT
OBJ		-x			x	
H(r)BIOCAP	x	-x	-x			
A@BTL		x				
A(r)CTXGRD		-x		-x	x	-x
C@ETHBIO		x				
C@CLLBIO		x				
C@CLLTOT		x				
E@BTLMAX		x				
L(r)CTXCAP		x	x	x		

	H(r)(aa)(bb)(ist) ******	H(r)MPWH(ist) ******	N(r)SCSN(s)	X(d)BIOT(r)		

	H(r)(aa)(bb)(ist) ******	H(r)MPWH(ist) ******	N(r)SCSN(s)	X(d)BIOT(r)		
OBJ	-x		-x			
C@ETHCRD	x	x				
C(r)CTL(ist)	x	x				
C(r)CTLTOT	x	x				
A(r)CTLWH		x				
H(r)(ist)		-x				
M(r)DSU or M(r)PCF		x				
H(r)SCS			-x			
H(r)BIO				x		
H(d)BIO				-x		

mchproc.f (Continued)

		H(r)FUX(mod)	K(r)FUXCAP	H(r)KWHMCH	H(r)(aa)(bb)(ist)*
H(r)(ist)		-x			+-x
H(r)(uuu)		+x			
H(r)(pol)		+x			
G(r)(ist)					+-x
B(r)(ist)					+-x
H(r)KWH				x	
H(r)OVC					
A@MTBPRD					

		H(r)FUX(mod)	K(r)FUXCAP	H(r)KWHMCH	H(r)(aa)(bb)(ist)*
A@NGLPRD					x
OBJ				-x	-x
H(r)FUMCAP		x	-x		
L(r)(uns)CAP					

mchproc.f (Continued)

	TANSOTOT	TAGTLTOT	N(r)NGKN(s)	N(r)(col)N(s)	H(r)(aa)(bb)(ist)*
OBJ			-x	-x	
H(r)(ist)			x		
H(r)(col)				x	
TANGKGTX			x		
TAOILGTN	x	x			
TAOILGTX	x	x			
CAAMH		x			
CAGTLTOT		-x			x
CANSOTOT		-x			
C(r)GTL					-x

*: first and last character of (ist); (aa) and (bb) = MP, GP, RF
where MP = Merchant plant, GP = Gas plant, and RF = Refinery
** for uns=ETX and mod=ETM,MTB
*** for uns=CTX,CTZ; **** for uns=CTZ; ***** for uns=IOX,ETX
****** for CTL ist=CKE, CNL, CNP, CDX
[a] not for CTX,CTZ,CTS
Bounds: K(r)(uns)CAP, E(r)(uns)INV, L(r)(uns)BLD, H(r)GPMP(ist) and H(r)RFMP(ist) = 0;
N(r)NGKN(s), N(r)SCSN(s), H(r)BIOCAP (in refine.f), H(r)CTXBIO, E@CTXINV
RHS: rows TANGKGTX, TAOILGTN, TAOILGTX, A@MTBPRD, E@CTZEPC, E@BTLMAX

ngprod.f: This subroutine represents the gas supply steps to refinery. It creates the following submatrix:

	N(r)NGRF(ij)*
OBJ	+-x**
Z(r)NGFSUM	x

* (ij) = N1, N2, N3, N4, P5, P6, P7, P8
** +x for N1, N2, N3, N4 and -x for P5, P6, P7, P8

Bounds: N(r)NGRF(ij)

nrfplant.f: This subroutine simulates the non refinery plant. It creates the following submatrix:

	G(r)DGR	G(r)GPL01	T(r)GPLOVC	N(r)DGP	G(r)SC2CC1	G(r)PGSLPG
G(r)OVC	-x		x			
G(r)DGP	x	-x				
G(r)LOS	-x	-x				
G(r)(xxx)		x				
G(r)CC1	-x			x		
OBJ			-x			
G(r)SC2C1X		-x			x	
G(r)PGSLGX		-x				x

nrfplant.f (Continued)

	G(r)NATOTH	G(r)(ist)PCF****	G(r)(xxx)*LPG	G(r)(xxx)**RFN
G(r)(xxx)	-x	-x	-x	-x
OBJ	-x	-x	-x	-x
A(r)GPL(xxx)***	x	x	x	
A(r)NGLRFN				x

	G(r)NATOTH	G(r)(ist)PCF****	G(r)(xxx)*LPG	G(r)(xxx)**RFN
A@NGLRFN				x
B(r)(xxx)**				x
M(r)(prd)***	x	x	x	
A(r)NGLPRD	x	x	x	x
A@NGLPRD	x	x	x	X

nrfplant.f (Continued)

	G(r)SC2CC1	G(r)SC3CC1	G(r)METRFN	G(r)METDEM	G(r)RFNMET
G(r)CC1	x	x			
G(r)CC3		-x			
G(r)LOS	x	x			
G(r)PGS	-x				
OBJ	x	x	-x	-x	
A(r)NGSMER			x		
A@NGSMER			x		
B(r)MET			x		-x
G(r)MET			-x	-x	x
D@MET				x	

nrfplant.f (Continued)

	E(r)MOHINV	L(r)MOHBLD	K(r)MOHCAP	G(r)MOH01
L(r)MOHCAP	-x	-x	-x	x
G(r)MET				x
G(r)OVC				-x

	E(r)MOHINV	L(r)MOHBLD	K(r)MOHCAP	G(r)MOH01
U(r)NGF				-x
U(r)KWH				-x
A(r)NGSMET				x
A@NGSMET				x
A@METPRD				x
OBJ	-x	-x		
A(r)INVST	x			
A@INVST	x			
A(r)FXOC	x	x		
A@FXOC	x	x		

(xxx) : PGS, CC3, IC4, NC4, NAT
* : (xxx) except NAT ; **: (xxx) except PGS, CC3;
*** LPG, FLG OTH, PCF; **** ist = NAT, PGS

Bounds: G(r)SC3CC1, N(r)DGP, E(r)MOHINV, K(r)MOHCAP, L(r)MOHBLD

output.f: This subroutine prints reports.

prdexp.f: Simulates product exports. It creates the following submatrix:

	D(z)(prx)*SX	D(z)COKSX	D(z)ASTSX
D(z)(prx)	-x	-x	-x**
OBJ	x	x	
A@COKEXP		x	
A(d)PRDEXP	x		x**
A@PRDEXP	x		x**

*: All (prx) except COK and AST; (z) = export demand regions (d) 2,3,7,8,9
**: d = z = CD 9 only

Bounds: D(z)(prx)SX, except for (prx) = COK, MTB
RHS: A@COKEXP

prdimprt.f : This subroutine simulates product imports. It creates the following submatrix:

	I(r)(pri)*R(s)	I(r)(pri)**R(s)	I(r)SSRR(s)	I(r)TRGT(s)
A@(pri)*IMP	x			
A(r)(pri)*IMP	x			
B(r)(pri)*	x			
A(r)(pri)RFN	x***			
A(r)PRDIMP[a]		x		
A@PRDIMP[a]		x		
M(r)(pri)**		x		
M(r)FLG		x*****		
M(r)SSR			x	
OBJ	-x	-x	-x	
A(r)SSRIMP			x****	
A(r)MGTOT(s)		-x******		x

* : for (pri) = MET and MTB; **: for all (pri) except MET and MTB;
*** for (pri) = MTB only; **** (r) = PADD I only (E), ***** for pri=LPG
****** for pri=SSE,TRG only
[a] not SSE,SSR
(s) = product import steps 1-9

RHS: A@PRDIMP, A(r)PRDIMP [(r) = PADDs II, IV only], A(r)SSRIMP****
Bounds: I(r)(pri)R(s)

recipes.f: This subroutine simulates product recipe blending. It creates the following submatrix:

	X(r)(xxx)(yyy)	X(r)(yyyy)
B(r)(ist)	-x	-x
M(r)(yyy)	x (1)	x
OBJ	x	-x (3)
U(r)STM		-x (4)
A(r)STM		-x (4)
A(r)(yyy)	x (1)	x
A(r)SULSAL	x (2)	
A@SULSAL	x (2)	
A(r)PETCOK	x (1)	
A@PETCOK	x (1)	
A@PRDRFN	x (1)	x

(xxx)(yyy) = CKHCOK, CKLCOK, SULSAL
(yyyy) = AST0, AST1, AVG0, GOP0, JP50
(1): for (yyy) = COK; (2): for (yyy) = SAL

(3): for (yyyy) = AVG0; (4) for (yyyy) = AST0

refproc.f: This subroutine simulates the refinery processes. It creates the following submatrix:

	E(r)(uns)INV	K(r)(uns)CAP	L(r)(uns)BLD	T(r)OVCOBJ	R(r)(uns)(mod)	R(r)SGP(ist)
OBJ	-x		-x	-x		
A@1YRBLD	x*******					
A(r)INVST	x					
A@INVST	x					
A(r)FXOC	x		x			
A@FXOC	x		x			

	E(r)(uns)INV	K(r)(uns)CAP	L(r)(uns)BLD	T(r)OVCOBJ	R(r)(uns)(mod)	R(r)SGP(ist)
A(r)GAIN					+-x	
A@GAIN					+-x	
A(r)METRFN					x**	
A(r)NGSH2P					x***	
A@NGSH2P					x***	
A@MTBPRD					x****	
A(r)STM					-x	
A@(fff)FU					x*****	
B(r)(ist)					+-x	
S(r)(ist)					+-x	
L(r)(uns)CAP	-x	-x	-x		x	
M(r)(prd)******					-x	
P(r)(pol)				x*	+-x	-x*
P(r)CBNTAX*****					-x*****	
U(r)(uuu)					+-x	
U(r)KWH						-x
B(r)FUL						-x
L(r)SGPCAP						x
S(r)SGP(ist)*******					x	-x*******

+	E(r)SGPINV	K(r)SGPCAP	L(r)SGPBLD	R(r)SGP(mod)
L(r)SGPCAP	-x	-x	-x	x
B(r)(ist)				x
S(r)(ist)				-x

+	E(r)SGPINV	K(r)SGPCAP	L(r)SGPBLD	R(r)SGP(mod)
P(r)OVC				-x
U(r)KWH				-x

*: (pol)=OVC; **: (uns)=ETH; ***: (uns)=H2P; ****: (uns)=ETH and (mod) = MTB;
*****: (uns)=FUM only; ******: (prd)=N6I, N6B only; (fff)=LPG, STG, RES, OTH;
*******: (uns) = ACU only;   ******* for (ist) = CC1,CC2,CC3,IC4,NC4,HYL only

Bounds: K(r)(uns)CAP, E(r)(uns)INV, L(r)(uns)BLD,
R(r)FUM(mod) where (r)=PADD V only, (mod)=NPI,NPN,NPP,SRC,SRH,SRI,SRL,
R(r)FCC(mod) where mod = 70H,70M,70U,H70,M70,U70
RHS: rows A@STGFU, A@LPGFU, A@RESFU, A@OTHFU, A@1YRBLD

setrows.f: This subroutine sets the row types (G, L, E, N) for rows P(r)(pol).

splash.f: This subroutine simulates splash blending. It creates the following submatrix:

	X(d)ETH(xxx)	X(d)METM85	X(d)(www)SPG	Q(r)(mgb)	B(r)RFG(sss)	B(r)RFG(rrr)
D(d)(xxx)	x	-x****				
D(d)ETH	-x					
D(d)(yyy)	-x					
D(d)M85		x				
D(d)MET		-x				
A(d)G08(xxx)	x*					
A@ETH(xxx)	x					
A@METM85		x				
A(d)RFG(xxx)** not linked to col						
A(d)TRG(xxx)	x***					

	X(d)ETH(xxx)	X(d)METM85	X(d)(www)SPG	Q(r)(mgb)	B(r)RFG(sss)	B(r)RFG(rrr)
D(d)(www)			x			
D(d)(ttt)			-x			
Q(r)RFGREN	x**				x	
S(r)RFGOXY	x**					x
C@ETHCRD	x					
C@ETHVOL	x					
M(r)MTB(mgb)				-x		

	J(d)DS(j)DS(j)	H(d)BINDMD	H(d)BIMDMD	X(d)BINDS(j)	X(d)BIMDS(j)
D(d)DS(j)	x			x	x
D(d)SS(j)	-x			-x	-x
D(d)BIN				-x	
D(d)BIM					-x
A(d)BIMDMD			x		-x
A(d)BINDMD		x		-x	
C@ETHCRD				x	x
C@ETHVOL				x	x

	X(d)ETH(xxx)	X(d)MAXSPL	RHS
X(d)MAXSPL*	-x	x	
C@ETHBIO			x
C@CLLBIO			x
C@CLLTOT			x

	X(d)ETH(xxx)	X(d)MAXSPL	RHS
C@BIOTOT			x

(rrr) = ETB, MTB, TAE, TAM, THE, THM; (sss) = ETB, TAE, THE;
(ttt) = N6B, N6I; (www) = N67, N68; (xxx) = E85, RFG, RFH, TRH, TRG;
(yyy)=SSR when (xxx)=RFG, RFH and (yyy)=SST when (xxx)=TRH and
(yyy)=SSE when (xxx)=TRG; (j)=l, u (for DSL, DSU);
*: (xxx) not E85; **: (xxx)=RFG, RFH only;
:(xxx)=TRG, TRH only; *:(xxx)=TRG only
Bounds: X(d)MAXSPL col

stream.f: This subroutine simulates stream transfers. It creates the following submatrix:

	T(r)(ist)(ist)	T(r)(ist)(prd)
B(r)(ist)	+-x	-x
M(r)(prd)		x
A(r)(prd)		x
A@PRDRFN		x

tabread.f: This subroutine prints the data file names, the number of tables and lists the names of the tables that are read.

transit5.f: This subroutine simulates the transportation network for MRM 3-region:

	Y(o)*(crt)(m)(r)	W(d)ETH(m)(r)	W(r)MET(m)(d)	W(s)(prd)(m)(d)	V(xxxxxx)
C(o)(crt)	-x				
C(r)(crt)	x				
OBJ	-x	-x	-x	+-x****	
TPC(o)*(m)(r)	x				-x
TVC(m)CP	x				-x

	Y(o)*(crt)(m)(r)	W(d)ETH(m)(r)	W(r)MET(m)(d)	W(s)(prd)(m)(d)	V(xxxxxx)
TVP(m)CP				x	-x
TPP(s)(m)(d)				x***	-x
TPL(s)(m)(d)				x****	-x
B(r)ETH		x			
D(d)ETH		-x			
A(r)ETHRFN		x			
B(r)MET			-x		
D(d)MET			x		
D(d)(prd)				x	
M(r)(prd)				-x	
M(d)(prd)				x	
(xxxxxx)					-x

transit5.f: (continued)

	Y(o)*(crt)(m)(r)	TANSOTOT	TAAMHXZ	TAGTLTOT	W(d)(nrc)(m)(s)
C(r)GTL					
CANSOTOT	x	-x	x		
OBJ		-x		-x	-x
B(r)(nrc)*****					x
D(d)(nrc)*****					-x

transit5.f: (continued)

	WAGTLJ(r)	W(s)DS(j)(m)(d)	W(s)BIN(m)(d)	W(s)BIM(m)(d)	W(s)CRN(m)(d)

	WAGTLJ(r)	W(s)DS(j)(m)(d)	W(s)BIN(m)(d)	W(s)BIM(m)(d)	W(s)CRN(m)(d)
C(r)GTL	x				
M(r)(prd)		-x			
OBJ	-x		-x	-x	
TVPJCP	x				
D(d)SS(j)		x			
D(d)BIN D(s)BIN			+-x		
D(d)BIM D(s)BIM				+-x	
H(d)CRN H(s)CRN					+-x

(j)=l, u (for DSL, DSU)
* OGSM supply (o) and refinery (r) regions; ** for (r)=Census Division
*** for (prd) different than MET, ETH; **** for (prd) = LPG and PCF;
***** for (nrc) = BIM, BIN only; (s) = refinery (r) and demand (d) regions;
(xxxxxx) = TVC5CP, TVPJCP, ...

Bounds: V(xxxxxx), W(d)ETH(m)(r)

unfinished.f: This subroutine simulates the unfinished oil process. It creates the following submatrix:

	T(r)U(ist)R(s)	T@UNFTOT
B(r)(ist)	x	
F(r)UNF(ist)	-x	x
OBJ	-x	
A(r)UNF	x	
A@UNFIMP	x	
A(r)UNFIMP	x	

	T(r)U(ist)R(s)	T@UNFTOT
F@TOTCRD		-x

RHS: F@TOTCRD
Bounds: T(r)U(ist)R(s)

utility.f: This subroutine represents the utility. It creates the following submatrix:

	U(r)(uuu)	R(r)KWGPGN	T(r)NGFNGS
U(r)(uuu)	x		-x***
OBJ	-x		
A@KWHRFN	x*	x	
B(r)NGS			x
A(r)NGSRFN			x
A@NGFTOT	x***		
A(r)NGFTOT	x***		
Z(r)NGFSUM	-x***		

*: for (uuu) = KWH ;***: for (uuu) = NGF

world_demand.f: This subroutine simulates demand in the international regions (w=A,N,R,U):

	D(w)(xxx)(Snn)	P(w)(xxx)DEX	P(w)(xxx)TMP
OBJ	x	-x	-x
D(w)(xxx)	-x	-x	x

(xxx) = DIS, LPG, NAP, OTH, RES
(Snn) = S01..S09
Bounds: D(w)(xxx)(Snn)

wrldcrude.f: This subroutine simulates world supplies of crude, NGL, and LPG:

	P@(fcr)(Qs)	P(r)(fcr)(Qs)	PGLBNGL(s)	PWRLD(Qs)	W(w)NGLLPG
OBJ	x		-x	-x	
D(w)LPG					x
I@(fcr)	x	-x			
I@GENCRD	-x			x	
I@GLBNGL			x		-x

(fcr)=FHH,FHL,FHV,FLL,FMH
(Qs)=Q1…Q5;   (s)=1…9;   (w)=A,N,R,U
Bounds: P@(fcr)(Qs); PGLBNGL(s); PWRLD(Qs)

	RCFHLDMD	RCFLLDMD	RCFMHDMD
CCFHL	-x		
CCFLL		-x	
CCFMH			-x

Bounds: RCFHLDMD, RCFLLDMD, RCFMHDMD

	RCFHLDMD	RCFLLDMD	RCFMHDMD
CCFHL	-x		
CCFLL			
CCFMH			

Bounds: RC(xxx)DMD

wrldprod.f: This subroutine simulates international supplies and demands of products (prq). Note: (prq) comprises finished products (prd), unfinished oils (unf), and sub-spec products (Ssp).

	I(r)(prq)(w)(s)	I(r)(prq)TOT

OBJ	-x	
A@PRDIMP	x	
A(r)PRDIMP	x	
I(r)(prq)IMP	x	-x
M(r)(prq)		x
M(w)(prq)	-x	
OPAFLTC	x (1)	
OPAFLTD	x (2)	
OPAFLTL	x (3)	
OPAFLTO	x (4)	

(prq) = (prd) + (Ssp) + (unf)
(1) DSL,DSU,JTA,PCF
(2) N2H,N6B,N6I
(3) LPG
(4) OTH
Bounds: I(r)(prq)(w)(s)
RHS: A@PRDIMP, ACPRDIMP, AMPRDIMP

	I(r)MET(w)(s)
OBJ	-x
A@METIMP	x
A(r)METIMP	x
B(r)MET	x

Bounds: I(r)MET(w)(s)

	I(r)SSE(w)(s)	I(r)SSETOT	I(r)SSR(w)(s)	I(r)SSRTOT	I(r)TRG(w)(s) *	I(r)TRGT(s)	I(r)TRGTOT

OBJ	-x		-x		-x		
A(r)MGTOT(s)	-x				-x	x	
A@PRDIMP					x		
A(r)PRDIMP					x		
I(r)(prd)IMP	x	-x	x	-x	x		-x
M(r)(prd)		x		x			x
M(w)(prd)	-x		-x		-x		
OPAFLTC	x		x		x		

* w = A,N,U only
Bounds: I(r)SSE(w)(s), I(r)SSR(w)(s), I(r)TRG(w)(s)

	I(r)(unf)(w)(s)	I(r)(unf)TOT	T(@UNFTOT
OBJ	-x		
A@UNFIMP		-x	x
A(r)UNFIMP		x	
B(r)(prd)		x	
I(r)(prd)IMP	x	-x	
M(w)DIS	-x **		
OPAFLTC	X *		
OPAFLTD	x		

* NPP
** ARB,HGM
Bounds: I(r)(unf)(w)(s)

	W(w)(prq)(w')	W(w)NGLLPG

OBJ	-x *	
M(w)(prd)	-x	
D(w')(prd)	X	
D(w)LPG		x
I@GLBNGL		-x

* (w) = A,N,U only
Bounds: W(w)(prd)(w')

All the FORTRAN files are located in the directory m:/default/source/ on the EIA NT server.

Common Blocks

Variables shared by several subroutines are set up in common. There are four files that contain the common blocks used by the program. Some of the files consist of several common blocks.

The following table lists the common block names, gives a brief description and the location of the block.

Common	**Description**	**Location**
IPMMREAL	Common for real variables shared by subroutines that generate sub-matrices	/default/includes/ipmmtest
IPMMINT	Common for integer variables shared by subroutines that generate sub-matrices	/default/includes/ipmmtest
IPMMCHAR	Common for character variables shared by subroutines that generate sub-matrices	/default/includes/ipmmtest
LPTAB	Common used for solution retrieval and report writing	/refine/pmm_lp_gen/includes/lpout
OMLREAL	Common for real variables used to set LP memory size	/default/includes/omlspace
OMLINT	Common for integer variables used to set LP memory size	/default/includes/omlspace
DFINC2	Common for OML database functions	/default/includes/dfinc2
WCR	Common for the WHIZ optimizer	/default/includes/wfinc2

A list of the common blocks and the variables that constitute them is given in Appendix G-D.

G.3 Data

Most of the data that the program uses is provided in files with a .dat extension. There is a one to one correspondence between the FORTRAN files that form part of the matrix and the *.dat* data files (e.g., accunit.f gets its input from accunit.dat). In each of the *.dat* files, the data is arranged in an OML format that consists of data tables. Each table consists of a table name, row (or stub) and column (or head) names, and values at the intersection of rows and columns. In addition there are ASCII files. These ASCII files are for control of the program. The following is the description of each input file.

Data Sets

.dat files

accunit.dat (v1.4)

Table Name	Columns	Rows	Description
ACUCUTS	(crt)	(ist); FUL	Crude distillation yield; fuel consumption
ACUPOL	OVC, LOS	(crt)	ACU policy table
ACUUTI	STM, KWH	(crt)	ACU utility consumption
INVLIM	MAX	(r) , @	Maximum investment

akaexp.dat (v1.2)

Table name	Columns	Rows	Description
EXPAKA	P, Q	N1, N2, N3, P4, P5, P6	Price and quantity of Alaskan crude exports.
NGLAKA	PER	PGS, CC3, NC4, IC4, and NAT	Yield of NGL
PRQAKA	VOL, TRP, EXPPRC	A	Volume, and transportation and expected cost for Alaskan crude exports

avoids.dat (no longer used)

Table	Columns	Rows	Description
SADELPX	FACTORS	N1, N2, N3, P1, P2, P3	Price differentiate
PRDAVOID	DUMMY	(prd)	Product list
SADELQ	N1, N2, N3, P1, P2, P3	(prd)	Demand shift quality fraction

cogener.dat (v1.8)

Table	Columns	Rows	Description
CGNCAP	CAP, PUL, BLD	(r)	Refinery cogeneration capacity, %utilization and build
CGNINV	INV, FXOC, CAPREC	(r)	Refinery cogeneration investment, fixed cost and capital recovery
CGNPOL	OVC	CGN	Refinery cogeneration policy
CGNREP	CGN	FUL	Refinery cogeneration yields
CGNUTI	(uuu)*	(r)	Refinery cogeneration utility usage
SELCGN	SOLD	(r)	% cogeneration sold to grid from Refinery
VPELAS	(r)	(year)	Electric utility prices for Refinery cogeneration (87$/KWh)
CGXCAP	CAP, PUL, BLD	(r)	Merchant plant cogeneration capacity, %utilization and build
CGXINV	INV, FXOC, CAPREC	(r)	Merchant plant cogeneration investment, fixed cost and capital recovery
CGXPOL	OVC	CGN	Merchant plant cogeneration policy
CGXREP	CGX	FUL	Merchant plant cogeneration yields
CGXUTI	(uuu)*	(r)	Merchant plant cogeneration utility usage
SELCGX	SOLD	(r)	% cogeneration sold to grid from Merchant plant
VPELWS	(r)	(year)	Electric utility prices for Merchant cogen (87$/KWh)

* except NGF

crdimprt.dat (v1.3)

Table	Columns	Rows	Description
CRUDETYP	DUMMY	(crt)*	Foreign crude types
ICR(crt)*(r)	C1, Q1, C2, Q2, C3, Q3, C4,Q4,C5,Q5	(year)	Price and quantity available for crude imports.

*: for (crt) = FLL, FMH, FHL, FHH, FHV (i.e. foreign crude only)

demand.dat (v1.3)

Table	Columns	Rows	Description
CKSMIX	CKL, CKH	OBJ, CKL, CKH, COK	Coke price and conversion factor
PRODLIST	DUMMY	(prd)	List of products
(prd)*	(d)	(year)	Product (prd) demand
DEMMET	CHEM	(year)	MET demand by Chemical Industry

* RFH mapping and corresponding table renamed to RFHA due to duplicate table name elsewhere.

distblnd.dat (v1.17)

Table	Columns	Rows	Description
Q(r)DFO	(dfo)	(spec)	Distillate fuel oil blend specs
DFOUTI	STM	(dfo)	Distillate blend steam use.
DCC	(dfo)*	(ist)	Distillate recipe blend.
DCB	spec categories **	(ist)	Distillate blend intermediate stream quality specification.

* from Z:MAPDFOPD
** from Z:MAPDFOSP

distress.dat (v1.2)

Table	Columns	Rows	Description
ZPX	VALUE	(prd)	Distress code for pricing

domcrude.dat (v1.3)

Table	Columns	Rows	Description
DCRSUP	(o)	Y96	Historical crude supplies by OGSM region
DCRSHR	(o)	(crt)*	Domestic crude share by OGSM region

Table	Columns	Rows	Description
CREXP	CRDEXP, CRDSPR	VOL	Crude exports and SPR

*: (crt) except FLL, FMH, FHL, FHH, FHV

emish.dat (v1.2)

Table	Columns	Rows	Description
EMUNS	(emu)*	Process unit	Emission by process unit
EMFUM	(emu)	Fuel stream burned	Emission by fuel burned

* except CO2

ethanol.dat (v1.27)

Table	Columns	Rows	Description
Z:CDMAP	DUMMY	(d)	Mapping of CD to numeric ID
XDENETH	(d)	(r)	Transfer costs of denaturant; mapping of transfer links between PADD and CD (0 cost= no link), 87$/bbl
CCT	PU ID for renewable fuels production (CET, CEL, BDV, BDN)	(d)	Carbon Tax credit for renewable resources turned into fuel (corn, cellulose, seed oil, yellow grease) 87$/bbl
CET	(mod) = WME, DME, DM1, DM2	(ist), (uuu), (prd), OVC	Corn to Ethanol Processing Unit (PU) (basis: 1 bbl/cd eth)
CETCOPRC	PRPERTON	DDG, WMC, EDG (co-products)	Price for corn ethanol co-product (87$/ton)
CETCAP	CAP, PUL, BLD, WME, DME	(d)	Existing Capacity (1000 bbl/cd denatured ethanol) for total, WME (wet mill), DME (dry mill), and process utilization, build flag

Table	Columns	Rows	Description
ETHINV	INV, FXOC, CAPREC	CET (corn ethanol PU) CLE (cellulosic ethanol PU)	Corn and cellulosic ethanol process unit investment cost
SUPCRN	C1, R1, C2, R2, C3, R3, C4, R4, C5, R5	(d)	Corn supply curves for corn ethanol production (1000 bushels/cd; 87$/bushel)
CLE	(mod) = LIG	(ist), (uuu), (prd), OVC	Cellulose to Ethanol Processing Unit (PU) inputs and yields (basis: 1 bbl/cd eth)
CLECOGEN	PRICE	KWH	Price of Cogeneration Electricity sold to grid, 87$/KWh
CLECAP	CAP, PUL, BLD	(d)	Existing Capacity (1000 bbl/cd denatured ethanol), process utilization, build flag
SUPBIO	C1, R1, C2, R2, C3, R3, C4, R4, C5, R5	(d)	Corn supply curves for corn ethanol production (1000 bushels/cd; 87$/bushel)
IMPETH	C1, R1, C2, R2, C3, R3, C4, R4, C5,R5	(year)	Corn ethanol import supply curves
ETHICST	@	(d), import location	Transit cost of ethanol imports (87$/bbl)
EXPETH	C1, R1, C2, R2, C3, R3, C4, R4, C5,R5	(d)	Corn ethanol export demand curves (1000 bbl/cd, 87$/bbl)
IMPBIM	C1, R1, C2, R2, C3, R3, C4, R4, C5, R5	(d)	Biodiesel import supply curve for processing at BDV unit (1000 bbl/cd; 87$/bbl)
BIMICST	@	(d), import location	Transit cost of biodiesel imports (87$/bbl)
IMPPLM	C1, R1, C2, R2, C3, R3, C4, R4, C5, R5	(d)	Palm oil import supply curve for processing at BDV unit (1000 bbl/cd; 87$/bbl)
PLMICST	@	(d), import location	Transit cost of palm oil imports (87$/bbl)
IMPSBO	C1, R1, C2, R2,	(d)	Soybean oil import supply curve (not used)

Table	Columns	Rows	Description
	C3, R3, C4, R4, C5, R5		(1000 bbl/cd; 87$/bbl)
ETHTAX	TAXETH, TAXE85	(year)	Ethanol taxes; tax subsidy
MINRENEW	USMIN	(year)	Min renewables required in gasoline (US total)
BDV	(mod) = SBO	(ist), (uuu), (prd), OVC	virgin biodiesel Processing Unit (PU) inputs and yields (basis: 1 bbl/cd biodiesel)
BDVCAP	CAP, PUL, BLD, INV, FXOC, CAPREC	(d)	Existing Capacity (1000 bbl/cd biodiesel), process utilization, build flag, and process unit investment cost (87$/bbl)
SUP(mod)	C1, R1, C2, R2, C3, R3, C4, R4, C5, R5	(d)	Input supply curve for seed oil (SBO) (1000 bbl/cd, 87$/bbl)
BDW	(mod) = WGR	(ist), (uuu), (prd), OVC	White grease biodiesel Processing Unit (PU) inputs and yields (basis: 1 bbl/cd biodiesel)
BDWCAP	CAP, PUL, BLD, INV, FXOC, CAPREC	(d)	Existing Capacity (1000 bbl/cd biodiesel), process utilization, build flag, and process unit investment cost (87$/bbl)
SUP(mod)	C1, R1, C2, R2, C3, R3, C4, R4, C5, R5	(d)	Input supply curve for white grease (WGR) (1000 bbl/cd, 87$/bbl)
BDN	(mod) = YGR	(ist), (uuu), (prd), OVC	Non-virgin biodiesel Processing Unit (PU) inputs and yields (basis: 1 bbl/cd biodiesel)
BDNCAP	CAP, PUL, BLD, INV, FXOC, CAPREC	(d)	Existing Capacity (1000 bbl/cd biodiesel), process utilization, build flag, and process unit investment cost (87$/bbl)
SUP(mod)	C1, R1, C2, R2, C3, R3, C4, R4, C5, R5	(d)	Input supply curve for yellow grease (YGR) (1000 bbl/cd, 87$/bbl)
SUPBIM	C1, R1, C2, R2,	(d)	Biomass diesel supply curves (virgin oil)

Table	Columns	Rows	Description
	C3, R3, C4, R4		
SUPBIN	C1, R1, C2, R2, C3, R3, C4, R4	(d)	Biomass diesel supply curves (non-virgin oil)

* (d) from Z:CDMAP

fixcols.dat (no longer used)

Table	Columns	Rows	Description
FIXCOL	R	Dummy	First letter of column to fix
(r)RCOL	FCC	(mod)	Column to fix to zero

fuelmix.dat (v1.1)

Table	Columns	Rows	Description
GROUP	DUMMY	Fuel stream	List of fuel stream

gasoblnd.dat (v1.16)

Table	Columns	Rows	Description
Z:MAPGSLPD	ENSYS CODE	TRG, RFG	Map Ensys motor gasoline ID to EIA motor gasoline ID
Z:MAPGSLSP	ENSYS CODE	EIA codes	Map Ensys spec ID to EIA spec ID
Q(r)GSL	TRG, RFG	(spec)	TRG, RFG specs
(r)SSR	Y1, Y2, Y3, Y4, Y5	RFG(spec); YEAR	Gasoline specs for sub-spec SSR ; year of data
(r)SST	Y1, Y2, Y3, Y4, Y5	TRG(spec); YEAR	Gasoline specs for sub-spec SST; year of data
(r)SSE	Y1, Y2, Y3, Y4, Y5	TRG(spec); YEAR	Gasoline specs for sub-spec SSE; year of data
(r)RFH	Y1, Y2, Y3, Y4, Y5	RFG(spec); YEAR	Gasoline spec for RFH; year of data
(r)TRH	Y1, Y2, Y3, Y4, Y5	TRG(spec); YEAR	Gasoline spec for TRH; year of data
Z:GASGROUP	TEXT(1)	(ist)	List of blending streams specially grouped
GCB	Quality codes	(ist)	Gasoline blend intermediate stream quality spec.

Table	Columns	Rows	Description
GCC	Gasoline type	(ist)	Gasoline recipe blend.
MCO	Motor octane codes*	(ist)	Gasoline component base octane ratings
(xxx)BV	Motor octane codes**	(ist)	Gasoline component blending values
GSLUTI	KWH	(prd), SSE, SST, SSR	Gasoline utility use.
GSPETH	RE	RFGN	Gasoline specs for ETH

(spec) = 2 character quality code followed by X (maximum) or N (minimum).
(xxx) = many exist, however, PMM uses UNC and RFM defined by Z:MAPGSLPD (representing TRG and RFG, respectively).
* R00, R05, R15, R30, M00, M05, M15, M30, of which only R00 and M00 are used by the PMM.
** same as *, except column TEL added (but not used by the PMM).

intlref.dat (v1.14)

Table	Columns	Rows	Description
ICRUDE	(w)	FLL, FMH	OBJ coefficient
TIMCSPLT	(w)	FHL, FMH, FHH	Crude splits
TFLLSPLT	(w)	FLL	Crude splits
IEXSTFLL	(w)	CAP, UTZ	Capacity and utilization
IESTFMH	(w)	CAP, UTZ	Capacity and utilization
IFLLSPLT	(w)	LPG, N6B, OTH	Product splits
IFMHSPLT	(w)	LPG, N6I, OTH	Product splits
IXTRASPL	(w)	NAP, DIS	Product splits
IXTRANAP	(w)	TRG, SSE, SSR, PCF	Product splits
IXTRADIS	(w)	N2H, DSL, DSU, JTA	Product splits
EXSTMAP	UNIT	IUP, ILG	Defines unit process names
EXSTIUP	(w)	CAP, UTZ	Capacity and utilization
EXSTILG	(w)	CAP, UTZ	Capacity and utilization

IFLLBROW	(w)	ARC	Stream inputs/outputs
IFMHBROW	(w)	ARC	Stream inputs/outputs
OPCSTIUP	(w)	ARBRD1,N6IRD2NAPN2D	Operating cost
OPCSTILG	(w)	LPGL2D	Operating cost

limpol.dat (v1.3)

Table	Columns	Rows	Description
UNITPOL	DUMMY	(uns)	List of processes that have a limit on POL
LIM(uns)(r)	(ist)	DUM	Limit on (ist)

marfll.dat (v1.3)

Table	Columns	Rows	Description
CRUDE	(r)	FLL	Operating cost and mode (crude type) for US Marginal refinery, cost (87$/bbl)
EXISTFLL	(r)	CAP, UTZ	Existing capacity and utilization (1000 bbl/cd)
FLLSPLT	(r)	(prd)=LPG, JTA, N6I, OTH, PCF	Non-gasoline and diesel product yields per unit of crude in (bbl/bbl)
XTRASPLT	(r)	GAS, DIS	Gasoline and distillate product yields per unit of crude in (bbl/bbl)
XTRAGAS	(r)	(prd)=TRG, SSE, SSR	List of component gasoline products, and added cost to produce (87$/bbl)
XTRADIS	(r)	(prd)=DSL, DSU, N2H	List of component distillate products, and added cost to produce (87$/bbl)
FLLBROW	(r)	FUL, HYH, ARB, STG, COK	Additional consumption and intermediate yield streams (bbl/bbl crude)
FLLUROW	(r)	KWH, STM	Utility consumption (KWh/bbl crude, lb/bbl crude)

refmain.dat (v1.4)

Table	Columns	Rows	Description
EXPROD	DUMMY	(prx)	List of product exports

Table	Columns	Rows	Description
INVFACT	LOC, ENV	(r)	Location and environment factors
TRSOVC	OVC	(r)	Year $ conversion factor for operating cost
FORCRD	DUMMY	(crt)*	List of foreign crude
YRDOLLAR	2000	1987	Year $ conversion factor
ZIRACFAC	DELTA	ZIRAC	Range of price differential for IRAC
WOP	WOP	(year)	World oil price (87$)
RFNREG	PAD	(r)	List of refinery regions vs PADD
RFNEXP	RFID	Linked list of refinery and export regions	List of exporting regions
DEMNDREG	REGION	Linked list of refinery and demand regions	List of demand region
USERYEAR	YEAR	Y96	Year to run model

* FFL, FMH, FHL, FHH, FHV

mchproc.dat (v1.20)

Table	Columns	Rows	Description
MCHINV	INV, FXOC, CAPREC	(uns)	Merchant plant investment, fixed cost and capital recovering
(r)CAPMCH	CAP, PUL, BLD	(uns)	Merchant plant processes capacity, % utilization and build.
(uns)POL*	(pol)	(ist)	Merchant plant processes policy
(uns)CAP*	(uns)CAP	(ist)	Merchant plant process capacity
(uns)REP*	(mod)	(ist)	Merchant plant process yields
(uns)UTI*	(uuu)	(ist)	Merchant plant process utility usage
TRANSFER	Dummy	GP, MP, RF	Transfer allowed
RFTRANS	MP	(ist)	Refinery transfer to merchant plant
GPTRANS	MP	(ist)	Gas plant transfer to merchant plant
MPTRANS	GP, RF	(ist)	Merchant plant transfer to gas plant and refinery

Table	Columns	Rows	Description
MPTRANS1	GTLRF, CTLRF,CTLWH	(ist)**	Merchant plant transfer to refinery, or directly to sales (WH)
(r)UAP	CST	(uuu)	Utility purchases

* uns defined by T:MCHINV
** (ist) related to GTL and CTL liquid streams

ngprod.dat (v1.2)

Table	Columns	Rows	Description
SPNGF	ALLREG	N1, .., N4, P5, ..., P8	Price steps for gas supply
SQNGF	MAX, MIN	N1, .., N4, P5, ..., P8	Quantity steps for gas supply
SCVAL	(r)	VOL	Volume limits on each step

nrfplant.dat (v1.11)

Table	Columns	Rows	Description
INVMOH	INV, CAPREC, FXOC	MOH	Non refinery plant process investment, capital recovery, and fixed cost.
MOHPLT	(r)01	CC1, MET, OVC, KWH	Production of methanol
MOHCAP	(r)01	CAP	Methanol capacity
GASPLT	(r)01	(ist), (pol)	Yield from gas plant
GASSHFT	SC2, SC3	CC1, LOS, OBJ	Shift of ethane and propane to methane
GASCAP	(r)01	FAC, CAP, LIM, PCU	Gas plant capacity limits
CC1CAP	(r)01	(year)	Dry gas production capacity

prdexp.dat (v1.3)

Table	Columns	Rows	Description
(x)PRDEXP	MINY1, MAXY1, MINY2, MAXY2, ... MINY5, MAXY5	(prx), YEAR	Limit on volume to export; year of data

Table	Columns	Rows	Description
EXPLIM	YRPC, FIX	1995	Limit on volume and yearly increase
MULTEXPR	MULT	PRICE	Price for exports as function of imports

(x) = export regions (CDs 2,3,7,8,9).

prdimprt.dat (v1.5)

Table	Columns	Rows	Description
PRODTYP	DUMMY	(pri)	List of product import
IMPLIM	MAX	@	Maximum imports into USA
IPR(pri)(r)	C1, R1, ..., C9, R9	(year)	Product import supply curve
NEMSRSD	R1B, R1PR	R1, ..., R9	Residual fuel import supply curve

recipes.dat (v1.5)

Table	Columns	Rows	Description
RCPEIA	A, CST, JTA, N2H, SLP, CKH, CKL	KERSPG, SULSAL, CKHCOK, CKLCOK	Cost of sulfur and coke; kerosene split; unit conversions.
RCP	A, CST, component stream, STM	Recipe blended products	Recipe blends (fractions)

refproc.dat (v1.39)

Table	Columns	Rows	Description
(r)CAP	CAP, PUL, BLD	(uns)	CAP, PUL and BLD values
(uns)	(mod)	(ist), (uuu), CAP, (pol)	Refinery process yields, utility usage, capacity factor, policy
MATBAL	A, B	(ist)	Streams requiring material balance
INV	INV, FXOC, CAPREC	(uns)	Refinery processes investment, fixed cost and capital recovery
SCL	selected processing units	selected streams/utilities	selected factors applied to selected coefficient in T: (uns)

setrows.dat (v1.2)

Table	Columns	Rows	Description
(r)POL	TYPE	(pol)	Row type

splash.dat (v1.9)

Table	Columns	Rows	Description
HOXETH	TRH, RFH, RFG,TRG	Gasoline stream	Ethanol recipe for splash blending
BLBIOD(d)	DSL, DSU	BIN, BIM	Blend composition recipe for biodiesel
BLNSP(d)	KER, N67, N68	JTA, N2H, KER, N6I, N6B, N67, N68	Blend composition recipe
BLOX(d)YXX	E85, M85, TRH, RFH, RFG, TRG	Gasoline stream	Recipe blend composition
XETH	PO	XETH	Oxygen content of ethanol
SCB	PO	Oxygenate stream	Oxygen content of oxygenates

stream.dat (v1.9)

Table	Columns	Rows	Description
XSALE	DUMMY	(ist)(prd)	Linked list of stream transfer to products
TRS	MIN, MAX, CST	(ist)(ist)	Linked list of stream to stream transfers
XGASLIQ	PCF, FLG	C2E, CC2, PGS	Energy conversion from gas (bfoe) to liq

transit.dat (v1.24)

Table	Columns	Rows	Description
MVCCAP	MAX	TVC(m)CP, TVP(m)CP	Marine vessel capacity for crude & product
BVPCAP	MAX	TVP(m)CP	Marine barge capacity for product
PLCCAP	MAX	TPC(o)(m)(r) TPP(r)**(m)(d) TPL(r)**(m)(d)	Pipeline capacity for (C) crude (P) product (L) LPG

Table	Columns	Rows	Description
TPCRLIST	DUMMY	(o)	Domestic crude supply regions for transportation
TPCR(o)	(crt); GTL	(m)(r); TAPS	Crude oil transportation cost from domestic supply region (o) to refinery region (r)
PLCRLIST	DUMMY	(o)	List of domestic crude oil supply regions for pipeline
PLCR(o)	(crt)	(m)(r)	Crude pipeline transportation cost from (o) to (r)
BVPR(r)	(prd)	(m)(d)	Product barge/truck transportation cost from (r) to (d)
TPPR(r)	(prd)	(m)(d)	Product marine transportation cost from (r) to (d)
TPME(r)	MET	(m)(d)	Methanol transportation cost from (r) to (d)
TPCNLIST	DUMMY	(d)	List of Census Divisions for corn transportation source
TPCN(d)	CRN	(m)(d')	Corn transportation cost from (d) to (d')
TPETLIST	DUMMY	(d)	List of Census Divisions for ethanol transportation source
TPET(d)	ETH	(m)(r)**	Ethanol transportation cost from (d) to (r)
PLPRLIST	DUMMY	(d)	List linked census divisions for product pipeline from region B to East Coast
PLPR(r)**	(prd), SSE, SST, SSR	(m)(d)	Product pipeline transportation cost from (r)** to (d)
PLLG(r)**	LPG, PCF, FLG	(m)(d)	LPG transportation cost from (r) to (d)
PLNKLIST	DUMMY	(r)**	List of product pipeline originations.
PLNK(r)**	(prd), SSE, SST, SSR	(m)(r)**	Product pipeline transport connections and costs from (r)** to (r)**
TPBDLIST	DUMMY	(d)	List of Census Divisions for biomass diesel transportation source
TPBD(d)	BIN, BIM	(m)(d')	Biomass diesel transportation cost from (d')

** refinery (r) and/or demand (d) regions

unfinish.dat (v1.8)

Table	Columns	Rows	Description

Table	Columns	Rows	Description
UNFOIL	E, G, W, PD	streams: NPP, HGM, ARB	Types (3) of unfinished oil imports into the U.S.
UNFEQT	SLOPE, CONST	XYZ	eq. parameters that correlate unfinished oil imports to crude input

utility.dat (v1.2)

Table	Columns	Rows	Description
UTITRS	COEF	NGFNGS	BFOE natural gas.
(r)UAP	CST	(uuu)	Utility costs.
VALPNG	(r)	(year)	Industrial price of natural gas.
VPELIN	(r)	(year)	Industrial elec utility prices (87$/KWh)

wrdcrude.dat (v1.4)

Table	Columns	Rows	Description
IGENCRD	Q1-Q9, P1-P9	1-41	Global crude supply
CRDFRAC	FLL,FMH,FHL,FHH,FHV	1-41	Crude fractions
TYPEMAR	Q1-Q5	FLL,FMH,FHL,FHH,FHV	Set quantity for import curves
IGLBNGL	Q1-Q9, P1-P9	LPG	NGL supply curve

wrld_dem.dat (v1.3)

Table	Columns	Rows	Description
WD_STEP	Prc_Pcnt	S01-S09	Demand curve steps
WD_ELAS	NAP,DIS,RES,OTH,LPG	(w)	Elasticity
WD_PRC	NAP,DIS,RES,OTH,LPG	(w)	2006$
WD_QTY	NAP,DIS,RES,OTH,LPG	(w)	2006 data
CHG_PRC	NAP,DIS,RES,OTH,LPG	(w)	1987$

CHG_QTY	NAP,DIS,RES,OTH,LPG	(w)	2008 projections

wrldprod.dat (v1.13)

Table	Columns	Rows	Description
IMPLIM	MAX	@, C, M	Max product imports
METCAP	-9	(r)	MET import curve: quantity
METCST	-9	(r)	MET import curve: cost
IPRDCAP(r)	(w)	(prd), (Ssp), (unf)	International product capacities, PADD (r)
IPRDCST(r)	(w)	(prd), (Ssp), (unf)	International product costs, PADD I
OPAFLTEX	(w)	DSU,SSE,SSR,TRG	Transport exceptions
OPATFLT	CLEAN,DIRTY, LPG, OTHER	(prd), (Ssp), (unf)	Transport mode exceptions
WLDPTRN	FLAG	(w)	Transport links
WLDPTRN(w)	(w)	NAPX,DISX,RESX,LPGX,OTHX	Transport costs
WLDPCAP(w)	(w)	NAPX,DISX,RESX,LPGX,OTHX	Transport capacity

Other input files

1. **mrmparam** file

The mrmparam file is a control file read by mrm.f to map input and output file names and instructions. In the mrmparam, the user chooses the model that he wants to run; the names for the problem, solution, path file, basis, mps file, and packed matrix; the model title; and the location and name of the starting basis and optimal basis. The following table lists the information that is to be supplied in the mrmparam file.

Variable name	Variable length	Variable purpose	Restrictions

Variable name	Variable length	Variable purpose	Restrictions
MODELN	8	Model to be run	MRM5
ACTPROB	8	Act problem	
SOLNAME	8	Solution name	
PATHNF	7	Name of file where data files paths are stored.	
TITLE	48	Problem title	
INBASISN*	48	Location and name of advanced basis	
OUTBASIS	10	Name of optimal basis	
BASISN	10	Basis name	Must be name in INBASISN file
MPSOUTN**	10	MPS file name	Prefer mpsnrm.txt
PAKCN**	10	Packed matrix file name	.PCK extension
TRACE	3	Toggle Trace Utility	

*: If no name or a file does not exist, the program will operate without an advanced basis.
**: if "NULL" or "null" is provided, the program will skip the part of the program that generates the file.

The above variables have to be provided in the order they are listed in the above Table and should start at column 18. Appendix G-A provides an example of an mrmparam file. The mrmparam file has to be in the subdirectory where the model is executed.

2. **mrmpath** file:

In this file the user provides the program with the location and name of the data files. The order in which the names appear is important. See Appendix G-B for an example of a path file. The path file has to be in the directory from which the model is executed. This file format is that of an OML table.

3. **Advanced basis** file:

In this file the user provides an advanced basis to the model. If the user does not provide one or provides one whose name does not coincide with the basis name provided in the mrmparam, the program will not use it.

G.4 Submission of a Run

In order to run the model, one has to first compile and link the different FORTRAN source files to form an executable. Once the executable is created, the user submits a run that uses the mrmparam and an mrmpath files. The execution of the program will solve the problem and create:

- An ACTFILE file
- An MPS file
- A SYSPRINT file (solution)
- An out basis file
- A packed matrix file
- Reports (only for MRM5)

The following are the files created by a run:

	MRM
ACTFILE	ACTFILE.act
MPS file	Name provided by user in the mrmparam file
Solution file	SYSPRINT
Out basis	Name provided by user in the mrmparam file
Packed matrix	Name provided by user in the mrmparam file
Report	reports5, fort.75

All the files used for the MRM matrix generation reside within the NEMS default directories on EIA's NEMS NT servers, as defined next. The source files that encompass the program are on m:/default/source/. The user must create and link the object files to form the mrm executable (mrm.exe) to be located in the user's directory. The *Compaq Developer's Studio* (a debugging package for the PC) is used by the user to compile, link, execute, debug, and manage files. Instructions on how to use this package, in connection with the mrm, are defined below.

The mrmparam file and the mrmpath file used for the MRM model are located in the m:/default/scripts/ directory. To run the model, the mrmparam and mrmpath files must be copied to the user's Debug directory. The path files point to the default data files (*.dat) that are stored in m:/default/input/ directory, as defined in the mrmpath file.

Runs

Connect to the NEMS-F8 via a terminal server client, and open a korn shell. You are now operating within a UNIX environment. All runs will be made using the *Compaq Developer's Studio*.

1. Set up and run the default (no changes):
    a. Create a scenario directory in your user directory, and then create the following directories within the scenario directory: Source, Data, Debug
    b. In the Debug directory, *nemsco* the default **mrmparam** and **mrmpath** files.
    c. In the scenario directory, *nemsco* mrmmps.dsp (a *Developer's Studio* project file).
    d. Double-click the *Developer's Studio* icon on your NEMS-F8 terminal server desktop.
    -- from the FILE, OPEN menu, set file type to *.dsp, and select the mrmmps.dsp file. (This creates two more files in the scenario directory: mrmmps.dsw and mrmmps.opt.)
    -- from the PROJECT, SETTINGS menu, click on the Debug tab. Highlight the path defined in the "Executable for debug session" display, and copy it to the "Working directory" display just below. HOWEVER, go to the "Working directory" display and delete "\mrmmps.exe" portion of the path just created. Click OK.
    e. To compile and link all default mrm code and DLLs, go to the BUILD menu, and select "Rebuild All." A message will appear in the lower window that the executable has been created. (Note: Lately, a single warning appears, which can be ignored.)
    f. To execute the default, go the BUILD menu, and select "Execute." A pop-up window will show the progress of the mrm run. When finished, the pop-up window will instruct the user to press any key to continue.
    g. The resulting mps file will be called mpsnrm.txt (as defined in the mrmparam) and will be located in the Debug directory.

2. Make changes to an mrm data file and rerun mrm:
    a. In the Data directory, *nemsco* the data file the user wants to change.
    b. Edit, change, and resave.
    c. In the Debug directory, edit the **mrmpath** file.
    -- modify the path of the updated data file to point to the new location in the Data directory, and resave
    -- delete (remove) the following files that were created from a previous mrm run: mpsnrm.txt, mrmpack, ACTFILE.act, and SYSPRINT
    d. Double-click the *Developer's Studio* icon on your NEMS-F8 terminal server desktop.
    -- from the FILE, OPEN menu, set file type to *.dsw, and select the mrmmps.dsw file from the scenario directory (created in step 1d above)
    e. To execute [assuming source code has already been compiled], go the BUILD menu, and select "Execute." A pop-up window will show the progress of the mrm run. When finished, the pop-up window will instruct the user to press any key to continue.
    f. The resulting mps file will be called mpsnrm.txt (as defined in the mrmparam) and will be located in the Debug directory.

    REMEMBER: After a new data file is defaulted, the corresponding data file name in the **mrmpath** file must be updated to map the proper default version. Then, the **mrmpath** file must be defaulted.

3. Make changes to an mrm source code and rerun mrm:
   a. In the Source directory, *nemsco* the source code one wants to change.
   b. Edit, change, and resave.
   c. In the Debug directory, delete (remove) the following files that were created from a previous mrm run: mpsnrm.txt, mrmpack, ACTFILE.act and SYSPRINT
   d. Double-click the *Developer's Studio* icon on the NEMS-F8 terminal server desktop.
      -- from the FILE, OPEN menu, set file type to *.dsw, and select the mrmmps.dsw file from the scenario directory (created in step 1d above)
   e. [Need to do only once.] In the workspace window, double-click on the **mrmmps files** listing, and then on the **Source Files** listing.
      -- find the source code filename, right-click on the filename, and select **Properties** from this sub-menu: a pop-up window entitled "Source File Properties" appears
      -- within the pop-up window, modify the path of the source code (in the "Persist as" line) to point to the new location in the source directory
      -- close the pop-up window by clicking on the 'x' in this window
   f. To recompile updated code and link to other code, go to the BUILD menu, and select "Rebuild All." A message will appear in the lower window that the executable has been created.
   g. To execute, go the BUILD menu, and select "Execute." A pop-up window will show the progress of the mrm run. When finished, the pop-up window will instruct the user to press any key to continue.
   h. The resulting mps file will be called mpsnrm.txt (as defined in the mrmparam) and will be located in the Debug directory.

G.5 MRM Data Conversion

With only a few exceptions, the data currently used in the MRM have either been provided by Ensys, or updated by an EIA contractor using the Jacobs/PACE refinery database. Data provided for corn and cellulosic ethanol production (ethanol.dat) were developed by EIA from various sources, including USDA's “1998 Ethanol Cost-of-Production Survey,” the “RFA Industry Outlook” (Feb. 2003), and a chemical industry consultant. EIA also developed the data provided to describe the virgin and non-virgin biodiesel production units, biomass to liquids production, and the NGL yields from the natural gas plant. The following describes the updates made for *AEO2009* using the Jacobs/PACE data, and the process used to convert the old Ensys data into the *.dat files used by the MRM.

For *AEO2009*, a new renewable diesel hydrotreater unit was added to the refproc.dat file to represent the production of green diesel and naphtha at the refinery. This new unit processes seed oil or grease into mostly green diesel, with some naphtha co-product. Some data in gasoblnd.dat and stream.dat were updated to correspond with the PU changes. In the mchproc.dat file, the biomass-to-liquids PU was updated using Jacobs/PACE data. New input and yield ratios were established, with a new stream added to represent CO2 ready for capture for sale or sequestration.

Most of the current Ensys data used in the MRM were last updated using the Jun2003 data (referred to as ENSYS03Jun). (No updates using Ensys data were made since *AEO2004*.) Due to the differences in data format (OMNI vs. OML) and naming conventions, the ENSYS03Jun data had to undergo conversion; and, new mapping data tables had to be added to the MRM files prior to being used by the MRM.

The updated OMNI data files provided by ENSYS and used to update the mrm data tables are located in the directory m:/ogs/pmm_prj/ensys/ensys03_Jun/data/ , and include:

R-GCB.DAT
R-MPROC.DAT
R-NPROC1.DAT
R-NPROC2.DAT
R-PROC1.DAT
R-PROC2.DAT
Table INUNIT Revised 0703.xls

The following provides a summary of the effort it took to convert the ENSYS03Jun OMNI data tables (*.DAT) into OML RTB tables (to be read by the matrix generation code). A shareware c-compiler called LCC-win32 was used. The omni2rtb.c program is located in the directory m:/ogs/pmm_prj/ensys/ ensys03_Jun/source/. The c-compiler may be installed on a local PC by executing the installation program M:\ogs\pmm_prj\C-Compiler\LCC-Win32.exe.

To compile on the PC:

1. Put the omni2rtb.c file in the directory you want to run from:
   c:\Documents and Settings\EM4\mydocs\c-test\
2. From the START menu, click on Programs, lcc-win32, lcc-win32.exe
3. From within the LCC program window, OPEN the omni2rtb.c file located in the c-test directory.
4. If no changes are needed, click on the COMPILER menu and select REBUILD ALL. This will create an omni2rtb.exe file in a new lcc directory within the c-test directory.

To execute on the PC:

1. Go to the newly created lcc directory, put the Ensys *.DAT files into this directory, and open a DOS window (Command Prompt). In this window, move to the ...c-test/lcc/ directory and type

   omni2rtb <input file path/name> <output file path/name>

   i.e., omni2rtb R-GCB.DAT gcb.out

G.6 Refinery Processes

Refinery Process	Abbreviation
Atmospheric crude distillation	ACU
Atmospheric Residuum Desulfurization	ARD
Aromatic recovery	ARP
Biomass-to-Liquids	BTL
C2E to C4E dimerization (capacity=0)	C24*
Butane isomerization	C4I
Butane splitter	C4S**
Alkylation feed butane isomer (capacity=0)	C4T*
Butane isomerization	C4X***
Catalytic Distillation Technology	CDT
Corn Ethanol Unit	CET
Cogeneration unit	CGN**
Cogeneration unit, merchant	CGX**
Combined Heat/Power burning syngas from Petroleum Coke	CHP**
Polymerization	CPL
Coal to Liquids process	CTX, CTZ
CO2 capture for transport or sequestration	CTS
Cyclar	CYC
Distillate desulfurizer	DDS
Gas oil dewaxer (capacity=0)	DEW
Dimersol	DIM
Ethanol	ETH, ETM
Cryogenic C2 fractionation	ETS*
Ethanol unit	ETX***
Fluid cat cracker	FCC
FCC feed hydrofiner	FDS
Mid-distillate furfural treating (capacity=0)	FEX
FCC gasoline fractionation units	FGS
Fuel plant	FUM**
Fuel plant	FUX***
Renewable (green) diesel hydrotreater	GDT
Petroleum Coke gasification (produces syngas)	GSF

Refinery Process	Abbreviation
Petroleum Coke gasification (produces hydrogen)	GSH
Hydrogenation normal pentenes/hexenes (capacity=0)	H56*
H2-stream reformer	H2P
H2-partial oxidizer	H2X
Low Conversion Hydrocracking	HCL****
Hydrocracker (partial)	HCM (old MAK)
Naphtha hydrocracker	HCN
Gas oil hydrocracker	HCR
Hydrocracker (Gasoil)- advanced technology	HCU
Residuum hydrocracker	HCV
Hydrodesulfurizer 1	HD1****
Hydrodesulfurizer 2	HD2, HS2****
High density jet fuel hydrotreating	HDN
Hydrofluoric Acid Alkylation	HFA
Hydrogen/fuel gas reformer hydrogen	HLO**
Hydrogen Purification	HPM
Iso-octane unit converted from MTBE	IOT
Iso-octane unit converted from MTBE, merchant	IOX
High density jet fuel pre-factionation (capacity=0)	JFP
Recut for JTA	JPS**
Delayed-coker	KRD
Fluid/flexi-coker	KRF
Power generation	KWG**
Lubricants and waxes	LUB
Olefin Saturation Process (MOH fr Ensys)	MDH****
Catalytic Fluidized Bed	MOD****
Naphtha hydrotreater	NDS
OCTGAIN Catalytic Hydroprocessor	OCT
C2-C5 dehydrogenation	OLE*
C2-C5 dehydrogenation	OLX***
Produced Fuel Adjustment (capacity=0)	PFA**
Pentane/hexane isomerization	PHI
UOP PENEX Plus	PHP
Phillips Szorb	PHS
Prism Pressure Swing Absorption- H_2 Purification	PSA
Hydrodesulphurization (S-Zorb) for diesel	PSZ
Residuum desulfurizer	RDS

Refinery Process	Abbreviation
Refinery Loss	REL**
LP continuous reformer	RFC
HP semi-regenerative reformer (capacity=0)	RFH
LP cyclic reformer	RFL
Resid Fuel Transfer	RST **
Solvent deasphalting	SDA
Sulfuric Acid Alkylation	SFA
Saturated Gas Plant	SGP
Shell Middle Distillate	SMD
Syntroleum GTL Process	SOD
Caustic SOx Scrubber (capacity=0)	SOX****
Naphtha splitter (capacity=0)	SPL
Steam generation, lbs/hr	STG**
Sulfur, short tons/day	SUL
Sulphco Selective Oxidation	SUP
Mid-distillate deep hydrotreater	SYD
Thermal cracker C2-C4 feed (capacity=0)	TCG*
Thermal cracker naphtha feed (capacity=0)	TCN*
Thermal cracker gas oil feed	TCV*
Total recycle isomerization	TRI*
Visbreaker/thermal cracker	VBR
Vacuum distillation	VCU

* : Processes involved in reformulated gasoline manufacturing
**: Utilities and pseudo-units
***: Processes represented in OXY-Refineries
****: Not made available for *AEO2009*

APPENDIX H

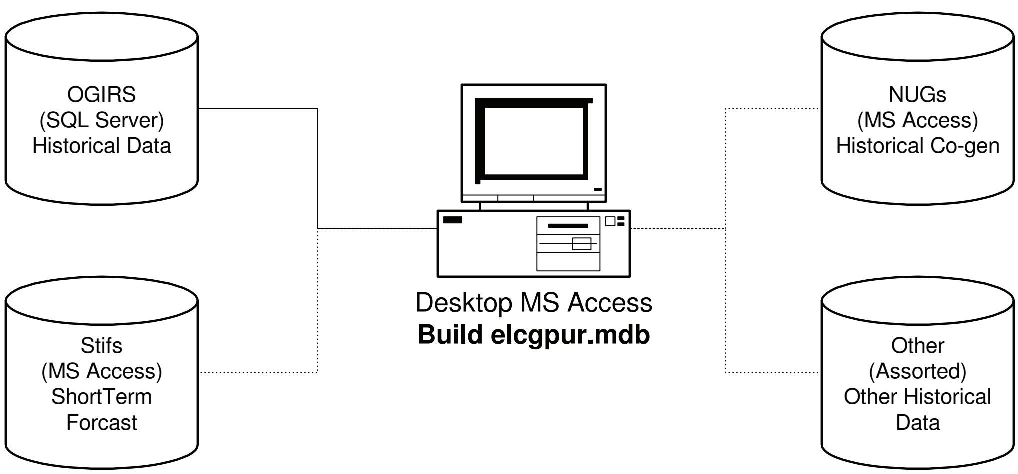
Historical Data Processing

Appendix H. Historical Data Processing

H.1 Processing Data for PMM History File

The PMM uses historical data from a variety of sources. The Microsoft Access database "Build Elgcpur.mdb" collects and aggregates this data to prepare the PMM input file Elcgpur.txt. The three principle databases it collects from (see Figure H.1) are the Oil and Gas Information Reporting System (OGIRS) which contains most historical wholesale price and volume information, the Non-Utility Generators (NUGs) database which contains refinery co-generation information, and the Short-Term Integrated Forecasting System (STIFS) database which contains data from the end of the historical period until the PMM forecast is available. Additional individual data elements are added as tables to the Elcgpur.mdb database as described below.

Figure H.1   Database Linkages



Accessing Data:

The file "Build Elcgpur.mdb" currently resides in the PMM Project folder on nems-f8 ("M" drive) in the folder M:\ogs\pmm_prj\Database\History (History folder). The following explains how to connect to the component databases that are used in processing the historical input file.

- OGIRS: The OGIRS database is called via a short Visual Basic Application (VBA) script called "modOgirsFunction." This script searches the table "tblParkList" for the OGIRS keys and frequency of the data required to form a request to the main OGIRS server. Executing this function creates the local table "dbo_Ogidata" (**Ogidata**) with all data for the requested keys and frequency. For example, to pull annual data for kerosene-based jet fuel production for all the U.S. PAD Districts enter the OGIRS Sourcekeys for the data series in the Sourcekey column and an "A" (for annual) in the "FrqncName" column as shown in Table H.1 . While it is unnecessary to complete the "SERIES" field, having a local reference to the Sourcekey definition is advisable. A partial list of Sourcekeys available can be found in the database "OGIRS keys.mdb" in the History folder.

Table H.1 Park List Sample

SOURCEKEY	SERIES	FrqncName
MKJRPP12	PADD I Jet Fuel Kero Refinery Production (Mbbl/d)	A
MKJRPP22	PADD II Jet Fuel Kero Refinery Production (Mbbl/d)	A
MKJRPP32	PADD III Jet Fuel Kero Refinery Production (Mbbl/d)	A
MKJRPP42	PADD IV Jet Fuel Kero Refinery Production (Mbbl/d)	A
MKJRPP52	PADD V Jet Fuel Kero Refinery Production (Mbbl/d)	A
MKJRPUS2	US Jet Fuel Kero Refinery Production (Mbbl/d)	A

Most of data used by PMM is pulled from OGIRS as an annual number. The only time monthly data are used is for the computation of Refinery Operable Capacity. For this value the January data are used to record the previous year's capacity.

The OGIRS database is mostly complete; however, there are a few missing fields in the database. To prevent errors from occurring when the queries are executed, the short list of missing values can be appended to **Ogidata** by running the query "Add Missing Keys to data." This query pulls known missing data [57] from the table "Missing Keys." An even rarer occurrence is when data are incorrect in OGIRS. Should this be discovered, the correct values can be placed in the table "Data Errors" which will update **Ogidata** when the query "Update data" is executed. All new missing or incorrect data should be reported to the OGIRS database administrator (currently Jaime Chan 202-586-1515). It is also worthwhile to check that keys are, in fact, still missing. The query "Check still missing" will display any duplicate keys in **Ogidata.**

[1] The last version of OGIRS is missing some of the elements of refinery production: nfrpp1-p5(naphtha feedstocks), otrpp1-p5 (other oils for feedstock), msrpp1-us(miscellaneous products for non-fuel use), and pfrp-us(total petrochemical feedstocks).

Assuming correct entries in the tables “Missing Keys” and “Data Errors,” the entire download process can accomplished automatically by running the “Update From OGIRS and add missing Keys” Macro.

- STIFS: The Current Month’s Stifs database is located on the EIA LAN at: \\fs-f1\L6489\PRJ\STEO Web Query Database\stifs.mdb. Assistance in obtaining access to this file can be arranged with Tancred Lidderdale (202-586-7321). After obtaining a local copy (typically stored in the History directory), open “Build Elcgpur.mdb” and from the “Tools” menu select “Data base Utilities” and then Linked table manager. Check the tables “Dates” and “Table_PA” and the box “prompt for new location.” Click OK and Browse to the location of Stifs.mdb. This enables the database to extract the latest STEO database.

- NUGs: A connection to the Coal Nuclear and Electric and Alternate Fuels Oracle “feeder” database housing the final non-utility generation information has been established. These tables are “linked” in the manner described above to the file “Nugs.mdb” which manipulates this data to extract refinery specific data. Each of the flowing tables then becomes a linked table to “Build Elcgpur.mdb.”

- Gen Grid

- Gen Own

- Grid Gen Cap

- Own Gen Cap

- Data Grid Fuel Use

- Data Own Fuel Use

- Tbl Grid Gen Percent

- Other Data: Additional sources are used for creation of the PMM history data file.

- Manually update fuel consumption data in Table 47 of the *Petroleum Supply Annual* to table “PSA Table 47.”

- Global Database Variables: STEOYEAR, HISOYEAR, and STEOYEARS must be reset each year the History file generator is used. Running the Macro "STEO-HISTO" will prompt the user to enter the last Historical information year and the remaining keys will be updated automatically.

- Index for GDP Price deflators for the forecast period is stored in table "GDP87." These are generally updated each year by the Macro team and can be found in Table 101 of the Ftab report.

- Ethanol plant energy costs are derived by Mac Statton (202-586- 7105) and stored in Table "Ethanol Energy Costs."

- Historical Petroleum Product Prices are from the *State Energy Data 2007: Prices* *(SEDP)* and stored in the "Product price data" Table. For *AEO2008,* aggregated CD level data from the previous year was used through 2006. For years 2007 through 2009 these prices were scaled by the change in the equivalent national numbers reported in the September 2008 *Short Term Energy Outlook*.

Data Processing Queries:

After all the data from the different sources have been input (or linked) to the database several queries (see examples in Figure H.2) are executed to manipulate the data into PMM variables. The numbers correspond with the position of the variable being generated in the Elcgpur.txt file. This code should not need to be changed absent a change in the definition of PMM variable it represents. Should this occur the individual variable query can be examined and edited.

Figure H.2 Sample Database Queries

PMM variables are linked to variables in input databases (primarily OGIRS and STIFS) by table "Map PMM to OGIRS." A complete list of mappings for both historical and STEO years is available in Table H1. Multiple entries for a PMM variable indicate that more than one OGIRS or STEO variable is needed to calculate the value for these variables. The multiple entries are summed to obtain the PMM variable. For example the OGIRS keys for RFPRDOTH are the sum of the keys in that row (Aviation Fuel, Lubes, Naphtha, and Waxes). In the case where a (-) appears before a variable, the key is multiplied by -1 before summation. A "Δ" before a key refers to the difference between the current and previous years value for that key.

Table H.2 Components of PMM Variables

PMM Variable	Definition	Historical Years	Description	STEO Years
RFQEXCRD	CRUDE EXPORTS IN MBD	OGIRS- MCREXPx2 (Where x is PADD#)	PADD x Averages/Totals Crude Oil Exports (Mbbl/d)	Assume last historical year
RFQICRD	CRUDE IMPORTS IN MMBD	OGIRS- MCRIMPx2 (Where x is PADD#)	PADD x Averages/Totals Crude Oil Imports (Mbbl/d)	CONXPUS use last historical year % to parse to PADDs
RFPQNGL	NGL PRODUCTION IN MMBD	OGIRS- MLPSNPx1 (Where x is PADD#)	PADD x Averages/Totals Natural Gas Liquids and LRGs Totals Field Production (Mbbl/	NLPRPUS use last historical year % to parse to PADDs
RFBDSTCAP	BASE DISTILLATION CAPACITY MBCD	OGIRS- MOCLEPx1 (Where x is PADD#)	PADD x Averages/Totals Refinery Operable Capacity (Mbbl/d) - January Value	Not available use most recent historical year -proxy: CODIPUS
RFDSTUTL	DIST UTILIZATION RATE IN MBD	OGIRS- MOPUEPx2 (Where x is PADD#)	PADD x Averages/Totals Other Petroleum Products % Utilization Ref	CODIPUS/Last historical years Capacity
RFQEXPRDT	PRODUCT EXPORTS IN MMBD	OGIRS- MTTEXPx2 (Where x is PADD#)	PADD x Averages/Totals Total Crude Oil and Petroleum Products Exports (Mbbl/d)	Last years exports of Petroleum Products
		(-)OGIRS-MCREXPx2 (Where x is PADD#)	PADD x Averages/Totals Crude Oil Exports (Mbbl/d)	
RFPQIPRDT	PRODUCT IMPORTS IN MMBD	OGIRS- MTPIMPx2 (Where x is PADD#)	PADD x Finished Petroleum Products Imports (Mbbl/d)	PANIPUS
		OGIRS- MNGIMPx2 (Where x is PADD#)	PADD x Averages/Totals Natural Gas Liquids and LRGs Totals Imports (Mbbl/d)	Last years exports of Petroleum Products
RFDPRDAST (AST)	Asphalt Refinery Production (Mbbl/d)	OGIRS- MAPRPPx2 (Where x is PADD#)	PADD x Asphalt Refinery Production (Mbbl/d)	Use 10 year average growth
RFDPRDCOK (COK)	Pet Coke Refinery Production (Mbbl/d)	OGIRS- MCKRPPx2 (Where x is PADD#)	PADD x Petroleum Coke Refinery Production (Mbbl/d)	Use 10 year average growth
RFDPRDJTA (JTA)	Jet Fuel Kero Refinery Production (Mbbl/d)	OGIRS- MKJRPPx2 (Where x is PADD#)	PADD x Jet Fuel Kero Refinery Production (Mbbl/d)	JFROPUS* Last Histo Year PADD Splits
RFDPRDKER (KER)	Kerosene Refinery Production (Mbbl/d)	OGIRS- MKERPx2 (Where x is PADD#)	PADD x Kerosene Refinery Production (Mbbl/d)	Use 10 year average growth
RFDPRDLPG (LPG	Refinery production; LPG	OGIRS- MLPRPPx2 (Where x is PADD#)	PADD x Liquefied Petroleum Gases Refinery Production (Mbbl/d)	LGROPUS* Last Histo Year PADD Splits
RFDPRDN2H (N2H)	Refinery prd; no. 2 distillate	OGIRS- MDIRPPx2 (Where x is PADD#)	PADD x Total Distillate Refinery Production (Mbbl/d)	DFROPUS* Last Histo Year PADD Splits
RFDPRDN6B (N6B)	Refinery prd; high sulfur oil	OGIRS- MRGNPPx2 (Where x is PADD#)	PADD x Averages/Totals Residual Fuel Oil Sulfur > 1.0 Net Production (Mbbl)	RFROPUS*Histo year Sulfur Split and PADD
RFDPRDN6I (N6I)	Refinery prd; low sulfur resid oil	OGIRS- MRLNPPx2 (Where x is PADD#)	PADD x Averages/Totals Residual Fuel Oil Sulfur 0-0.3 Net Production (Mbbl/d)	RFROPUS*Histo year Sulfur Split and PADD
		OGIRS- MRMNPPx2 (Where x is PADD#)	PADD x Averages/Totals Residual Fuel Oil Sulfur .31-100 Net Production (Mbbl/d)	
RFDPRDOTH (OTH)	Refinery prd; other petroleum	OGIRS- MGARPPx2 (Where x is PADD#)	PADD x Averages/Totals Aviation Gasoline Refinery Production (Mbbl/d)	Use 10 year average growth
		OGIRS- MLURPPx2 (Where x is PADD#)	PADD x Averages/Totals Lubes Refinery Production (Mbbl/d)	
		OGIRS- MNSRPPx2 (Where x is PADD#)	PADD x Averages/Totals Naphtha Special Refinery Production (Mbbl/d)	
		OGIRS- MWXRPPx2 (Where x is PADD#)	PADD x Averages/Totals Waxes Refinery Production (Mbbl/d)	
RFDPRDPCF (PCF)	Refinery prd; petrochemical feeds	OGIRS- MPFRPPx2 (Where x is PADD#)	PADD x Averages/Totals Petroleum Products Refinery Production (Mbbl/d)	Use 10 year average growth
RFDPRDSTG (STG)	Refinery prd; still gas	OGIRS- MSGRPPx2 (Where x is PADD#)	PADD x Still Gas Refinery Production (Mbbl/d)	Use 10 year average growth
RFDPRDTRG (TRG)	Refinery prd; motor gasoline	OGIRS- MGFRPPx2 (Where x is PADD#)	PADD x Finished Gasoline Refinery Production (Mbbl/d)	MGROPUS* Last Histo Year PADD Splits
CRDUNACC	Unaccounted crude	OGIRS- MCRAUPx2 (Where x is PADD#)	PADD x Averages/Totals Crude Oil Unaccounted for (Mbbl/d)	COUNPUS
CRDSTWDR	Crude stock withdrawals	OGIRS- MCRSCPx2 (Where x is PADD#)	PADD x Averages/Totals Crude Oil Stock Change (Mbbl/d)	CONQPUS
				ΔCOSXPUS/365
TOTCRDIN	Crude Oil: refinery inputs	OGIRS- MCRRIUS2	US Crude Oil Input into Refineries (Mbbl/d)	0
RFQPRCG1	PROCESSING GAIN IN MMBD	OGIRS- MPGNPUS1/365	US Processing Gain Net Production (Mbbl)	PAGLPUS
BLDIMP	Blending component imports	OGIRS- MBCIMUS2	US Blending Components Gasoline Imports (Mbbl/d)	MBNIPUS
BLDPRD	Product blending component	OGIRS- MBCFPUS2	US Blending Components Gasoline Field Production (Mbbl/d)	MBFPPUS
BLDREF_BIN	Net Product blending component used at refinery/blenders	MBCRIUS2	US Blending Components Gasoline Input into Refineries (Mbbl/d)	
		MBARIUS2	US Blending Components Av-Gas Input into Refineries (Mbbl/d)	
NGLRF(2)	NGL input to refinery and blenders	OGIRS- MNGRIUS2	U.S. Refinery and Blender Net Inputs of Natural Gas Liquids and Liquefied Refinery Ga (Thousand Barrels)	
BLDREFINC	Conventional Product blending component used at refinery	OGIRS - mo5ro_nus_1	U.S. Conventional Gasoline Blending Components Refinery Net Input (M Barrels)	
BLDREFINR	Reformulated Product blending component used at refinery	OGIRS - mo1ro_nus_1	U.S. Reformulated Gasoline Blending Components Refinery Net Input (Thousand Barre	
BLDRFGPRD		OGIRS - mgrrz_nus_2	U.S. Reformulated Gasoline Blenders Net Production (MMbbl/day)	
BLDTRGPRD		OGIRS - mg4rz_nus_2	U.S. Conventional Gasoline Blenders Net Production (MMbbl/day)	
BLDREFIN	Product blending component used at refinery	NA		
NGLIMP		OGIRS - MNGIMUS2	NGL Imports	
NGLRF(1)	NGL input to refinery	OGIRS – mngro_nus_1	US Natural Gas Liquids and LRGs Totals Input into Refineries (Mbbl/d)	LGRIPUS
				PPRIPUS
OTHOXY	Other oxygenates	OGIRS- mohro_nus_1	US Other Hydrocarbons/Oxygenates Field Production (Mbbl/d)	OHRIPUS
OTHOXYFP	Other oxygenates (Field production)	OGIRS – mohua_nus_2		
OTHOXYIMP	Imported oxygenates	OGIRS – MOHIMUS2		

Table H.2 Components of PMM Variables

PMM Variable	Definition	Historical Years	Description	STEO Years
RFHCXH2IN	Merchant Hydrogen	OGIRS – MOYRIUS2		
RFOHOXYIN	Oxygenates Other Inputs into Refineries	OGIRS – MOORIUS2		
RFOXYIN	Oxygenates Net Input into Refineries	OGIRS – moxro_nus_1		
OTHPRDSP	Other Liquids Product Supplied	OGIRS – MOLUPUS2		
PRDSTKWDR	Product stocks withdrawals	OGIRS- MTTSCUS2	United States Total Crude Oil and Petroleum Products Stock Change (Mbbl/d)	Assume Zero
		(-)OGIRS-MCRSCPx2 (Where x is PADD#)	PADD x Averages/Totals Crude Oil Stock Change (Mbbl/d)	
RFETHETB	zeros			
RFETHE85	Ethanol for E85 production	Hart	Oxy Fuel News Data	Oxy Fuel News Data
RFETHMGS	Ethanol for motor gasoline	OGIRS- OFETPUS2	US Oxygenates Fuel Ethanol Production (Mbbl/d)	EOFPPUS
RFMETETH	Methanol for ether	Historical Quantities not tracked	Zeros	Assume Zero
RFMTBI	Imported MTBE	OGIRS- MMTIMUS2	US Oxygenates MTBE Imports (Mbbl/d)	Assume Zero
RFETHIN	Total Ethanol into Refinery	OGIRS – mfero_nus_1		
RFMTBEIN	MTBE Input into Refinery	OGIRS – mmtro_nus_1		
RFPQUFC	Total imports of unfinished crude	OGIRS- MUOIMUS2	US Unfinished Oils Imports (Mbbl/d)	UORIPUS
TOTUFOIN	Total Unfinished Oils into Refinery	OGIRS – MUORO_NUS_1		
RFFPO	Other Liquids Field Production	OGIRS – MOLUA_NUS_1		
RFNETOLIMP	Other Liquids Net imports	OGIRS – MOLNTUS2		
RFSPRFR	SPR fill rate	OGIRS- -MCSSCUS1/365	US Crude Oil Stock Change SPR (Mbbl)	CONQPUS
RFQDINPOT	Other fuels input			
TDIESEL	Transportation Diesel Product Supplied	OGIRS – md1up_xxx_2 & md0up_xxx_2	STEO Years are calculated as prior years TDIESEL % of total distillate	
AST	Asphalt Product Supplied (Mbbl/d)	OGIRS- MAPUPPx2 (Where x is PADD#)	PADD x Averages/Totals Asphalt Product Supplied (Mbbl/d)	ARTCPUS
COK	Petroleum Coke Product Supplied (Mbbl/d)	OGIRS- MCKUPPx2 (Where x is PADD#)	PADD x Averages/Totals Petroleum Coke Product Supplied (Mbbl/d)	PCTCPUS
JTA	Jet Fuel Kero Product Supplied (Mbbl/d)	OGIRS- MKJUPPx2 (Where x is PADD#)	PADD x Averages/Totals Jet Fuel Kero Product Supplied (Mbbl/d)	JFTCPUS
KER	Kerosene Product Supplied (Mbbl/d)	OGIRS- MKEUPPx2 (Where x is PADD#)	PADD x Averages/Totals Kerosene Product Supplied (Mbbl/d)	KSTCPUS
LPG	Product Supplied; LPG	OGIRS- MLPUPPx2 (Where x is PADD#)	PADD x Averages/Totals Liquefied Petroleum Gases Product Supplied (Mbbl/d)	LGTCPUS
N2H	Product Supplied; no. 2 distillate	OGIRS- MDIUPPx2 (Where x is PADD#)	PADD x Averages/Totals Total Distillate Product Supplied (Mbbl/d)	DFTCPUS
N6B	Product Supplied; high sulfur oil	Computed- MRSUPHx2 (Where x is PAD#)	PADD x Averages/Totals Residual Fuel Oil Sulfur > 1.0 Product Supplied (Mbbl/d)	RFTCPUS * High%
N6I	Product Supplied; low sulfur residual oil	Computed- MRSUPLx2 (Where x is PAD#)	PADD x Averages/Totals Residual Fuel Oil Sulfur < 1.0 Product Supplied (Mbbl/d)	RFTCPUS* Low%
OTH	Product Supplied; other petroleum	OGIRS- MGAUPPx2 (Where x is PADD#)	PADD x Averages/Totals Aviation Gasoline Product Supplied (Mbbl/d)	AVTCPUS
		OGIRS- MLUUPPx2 (Where x is PADD#)	PADD x Averages/Totals Lubes Product Supplied (Mbbl/d)	LUTCPUS
		OGIRS- MNSUPPx2 (Where x is PADD#)	PADD x Averages/Totals Naphtha Special Product Supplied (Mbbl/d)	SNTCPUS
		OGIRS- MWXUPPx2 (Where x is PADD#)	PADD x Averages/Totals Waxes Product Supplied (Mbbl/d)	WXTCPUS
PCF	Product Supplied; petrochemical feeds	OGIRS- MPFUPPx2 (Where x is PADD#)	PADD x Averages/Totals Petroleum Products Product Supplied (Mbbl/d)	FETCPUS
STG	Product Supplied; still gas	OGIRS- MSGUPPx2 (Where x is PADD#)	PADD x Averages/Totals Still Gas Product Supplied (Mbbl/d)	SGTCPUS
RFQPRDT	Total product supplied	OGIRS- MTTUPPx2 (Where x is PADD#)	PADD x Averages/Totals Total Crude Oil and Pet Products Supplied (Mbbl/d)	Sum STEO Product Quantities
		(-)OGIRS-MCRUPPx2 (Where x is PADD#)	PADD x Averages/Totals Crude Oil Product Supplied (Mbbl/d)	
TRG	Product Supplied; motor gasoline	OGIRS- MGFUPPx2 (Where x is PADD#)	PADD x Averages/Totals Finished Gasoline Product Supplied (Mbbl/d)	MGTCPUS
QELETH	Historical Electricity use at Ethanol plants -	Multiply EOFPPUS ethanol production by Tony Radich's formulas for energy consumption		
QNGETH	Historical Nat Gas use at Ethanol plants			
QCLETH	Historical Coal use at Ethanol plants			
PETHM	Historical Ethanol price			
ETHEXP	Historical Ethanol Exports			
QCLRF	Refinery Fuel –Coal	Paste in from table 47 of PSA	Use In MMBTU	Assume last Historical Year ratio of fuel to production Average refiner price of residual fuel oil
QDSRF	Refinery Fuel -Distillate Fuel Oil	Paste in from table 47 of PSA	Use In MMBTU	
QELRF	Refinery Fuel -Purchased Elec.	Paste in from table 47 of PSA	Use In MMBTU	
QLGRF	Refinery Fuel –LPG	Paste in from table 47 of PSA	Use In MMBTU	
QNGRF	Refinery Fuel -Nat Gas	Paste in from table 47 of PSA	Use In MMBTU	
QOTRF	Refinery Fuel –Other	Paste in from table 47 of PSA	Use In MMBTU	
QPCRF	Refinery Fuel -Pet Coke	Paste in from table 47 of PSA	Use In MMBTU	
QRSRF	Refinery Fuel -Residual Fuel	Paste in from table 47 of PSA	Use In MMBTU	
QSGRF	Refinery Fuel -Still Gas	Paste in from table 47 of PSA	Use In MMBTU	

Table H.2 Components of PMM Variables

PMM Variable	Definition	Historical Years	Description	STEO Years
PASIN	Asphalt, Road Oil, Industrial		PRODUCT PRICES IN 87$ PER MMBTU	RFTCUUS
PDSCM	Distillate, Commercial		PRODUCT PRICES IN 87$ PER MMBTU	DSTCUUS
PDSEL	Distillate, Electricity (+petroleum coke)		PRODUCT PRICES IN 87$ PER MMBTU	PRODUCT PRICES IN 87$ PER MMBTU
PDSIN	Distillate, Industrial	SEDS	PRODUCT PRICES IN 87$ PER MMBTU	DSTCUUS
PDSRS	Distillate, Residential	SEDS	PRODUCT PRICES IN 87$ PER MMBTU	DSTCUUS
PDSTR	Distillate, Transportation	SEDS	PRODUCT PRICES IN 87$ PER MMBTU	DSTCUUS
PJFTR	Jet Fuel, Transportation	SEDS	PRODUCT PRICES IN 87$ PER MMBTU	JKTCUUS
PKSCM	Kerosene, Commercial	SEDS	PRODUCT PRICES IN 87$ PER MMBTU	JKTCUUS
PKSIN	Kerosene, Industrial	SEDS	PRODUCT PRICES IN 87$ PER MMBTU	JKTCUUS
PKSRS	Kerosene, Residential	SEDS	PRODUCT PRICES IN 87$ PER MMBTU	JKTCUUS
PLGCM	Liquid Petroleum Gases, Commercial	SEDS	PRODUCT PRICES IN 87$ PER MMBTU	PRTCUUS
PLGIN	Liquid Petroleum Gases, Industrial	SEDS	PRODUCT PRICES IN 87$ PER MMBTU	PRTCUUS
PLGRS	Liquid Petroleum Gases, Residential	SEDS	PRODUCT PRICES IN 87$ PER MMBTU	PRTCUUS
PLGTR	Liquid Petroleum Gases, Transportation	SEDS	PRODUCT PRICES IN 87$ PER MMBTU	PRTCUUS
PMGCM	Motor Gasoline, Commercial	SEDS	PRODUCT PRICES IN 87$ PER MMBTU	MGEIRUS
PMGIN	Motor Gasoline, Industrial	SEDS	PRODUCT PRICES IN 87$ PER MMBTU	MGEIRUS
PMGTR	Motor Gasoline, Transportation	SEDS	PRODUCT PRICES IN 87$ PER MMBTU	MGEIRUS
PPFIN	Petrochemical Feedstocks, Industrial	SEDS	PRODUCT PRICES IN 87$ PER MMBTU	PRTCUUS
PRHEL	Residual Fuel, High Sulfur, Electricity	SEDS	PRODUCT PRICES IN 87$ PER MMBTU	RFTCUUS
PRHTR	Residual Fuel, High Sulfur, Transp.	SEDS	PRODUCT PRICES IN 87$ PER MMBTU	RFTCUUS
PRLCM	Residual Fuel, Low Sulfur, Commercial	SEDS	PRODUCT PRICES IN 87$ PER MMBTU	RFTCUUS
PRLEL	Residual Fuel, Low Sulfur, Electricity	SEDS	PRODUCT PRICES IN 87$ PER MMBTU	RFTCUUS
PRLIN	Residual Fuel, Low Sulfur, Industrial	SEDS	PRODUCT PRICES IN 87$ PER MMBTU	RFTCUUS
OG GEN GRID90	COGENERATION IN MMBTU	NUGs Database (CNEAF)	Aggregates plant data to CD regions	Use Last Historical Year for STEO Years 1 & 2
PT GEN GRID90	COGENERATION IN MMBTU	NUGs Database (CNEAF)	Aggregates plant data to CD regions	Use Last Historical Year for STEO Years 1 & 2
NG GEN GRID90	COGENERATION IN MMBTU	NUGs Database (CNEAF)	Aggregates plant data to CD regions	Use Last Historical Year for STEO Years 1 & 2
OT GEN GRID90	COGENERATION IN MMBTU	NUGs Database (CNEAF)	Aggregates plant data to CD regions	Use Last Historical Year for STEO Years 1 & 2
OG GEN OWN 90	COGENERATION IN MMBTU	NUGs Database (CNEAF)	Aggregates plant data to CD regions	Use Last Historical Year for STEO Years 1 & 2
PT GEN OWN 90	COGENERATION IN MMBTU	NUGs Database (CNEAF)	Aggregates plant data to CD regions	Use Last Historical Year for STEO Years 1 & 2
NG GEN OWN 90	COGENERATION IN MMBTU	NUGs Database (CNEAF)	Aggregates plant data to CD regions	Use Last Historical Year for STEO Years 1 & 2
OT GEN OWN 90	COGENERATION IN MMBTU	NUGs Database (CNEAF)	Aggregates plant data to CD regions	Use Last Historical Year for STEO Years 1 & 2
OG CAP GRID90	Capacity MW	NUGs Database (CNEAF)	Aggregates plant data to CD regions	Use Last Historical Year for STEO Years 1 & 2
PT CAP GRID90	Capacity MW	NUGs Database (CNEAF)	Aggregates plant data to CD regions	Use Last Historical Year for STEO Years 1 & 2
NG CAP GRID90	Capacity MW	NUGs Database (CNEAF)	Aggregates plant data to CD regions	Use Last Historical Year for STEO Years 1 & 2
OT CAP GRID90	Capacity MW	NUGs Database (CNEAF)	Aggregates plant data to CD regions	Use Last Historical Year for STEO Years 1 & 2
OG CAP OWN 90	Capacity MW	NUGs Database (CNEAF)	Aggregates plant data to CD regions	Use Last Historical Year for STEO Years 1 & 2
PT CAP OWN 90	Capacity MW	NUGs Database (CNEAF)	Aggregates plant data to CD regions	Use Last Historical Year for STEO Years 1 & 2
NG CAP OWN 90	Capacity MW	NUGs Database (CNEAF)	Aggregates plant data to CD regions	Use Last Historical Year for STEO Years 1 & 2
OT CAP OWN 90	Capacity MW	NUGs Database (CNEAF)	Aggregates plant data to CD regions	Use Last Historical Year for STEO Years 1 & 2
OG FUL GRID90	Cogen Fuel consumption	NUGs Database (CNEAF)	Aggregates plant data to CD regions	Use Last Historical Year for STEO Years 1 & 2
PT FUL GRID90	Cogen Fuel consumption	NUGs Database (CNEAF)	Aggregates plant data to CD regions	Use Last Historical Year for STEO Years 1 & 2
NG FUL GRID90	Cogen Fuel consumption	NUGs Database (CNEAF)	Aggregates plant data to CD regions	Use Last Historical Year for STEO Years 1 & 2
OT FUL GRID90	Cogen Fuel consumption	NUGs Database (CNEAF)	Aggregates plant data to CD regions	Use Last Historical Year for STEO Years 1 & 2
OG FUL OWN 90	Cogen Fuel consumption	NUGs Database (CNEAF)	Aggregates plant data to CD regions	Use Last Historical Year for STEO Years 1 & 2
PT FUL OWN 90	Cogen Fuel consumption	NUGs Database (CNEAF)	Aggregates plant data to CD regions	Use Last Historical Year for STEO Years 1 & 2
NG FUL OWN 90	Cogen Fuel consumption	NUGs Database (CNEAF)	Aggregates plant data to CD regions	Use Last Historical Year for STEO Years 1 & 2
OT FUL OWN 90	Cogen Fuel consumption	NUGs Database (CNEAF)	Aggregates plant data to CD regions	Use Last Historical Year for STEO Years 1 & 2
DCRDWHP	WELLHEADD CRUDE OIL PRICES	From Ted McCallister's Calculations.	IN $/BBL	Assume Region's price changes as Δ of WOP
RFQDCRD	CONVENTIONAL CRUDE PRODUCTION	From Ted McCallister's Calculations.	IN MBD	Assume Region's Production changes as Δ of COPRPUS
RFQTDCRD	TOTAL CRUDE PRODUCTION	From Ted McCallister's Calculations.	IN MMBD	Assume Region's Production changes as Δ of COPRPUS

Creating PMM Flat-file:

To create the final elcgpur.txt, file query results are called by the access report writer. For each variable or collection of variables a report formats the results of the data queries into the exact FORTRAN fixed format position necessary to be read into the PMM. The most often employed method for this is to have a report with the historical data include a sub-report which appends the STEO year data to it. These individual reports are all then included in the master report "zz- Generate Elcgpur" in the appropriate sequence. This file is then exported from the database as a text file.

Because Access formats reports to a specific printer (page size), additional lines appear where there are breaks in pages. To remove them a Short VBA script was written (eat space) that removes all of the blank lines from the file. All of the report generation and subsequent post-processing can be done automatically by first running the macro "Update Everything – Including STEO years – Final" and then "Make Elcgpur." The resulting file will be placed in the local c:\ directory of the desktop computer running the macro. Formatting inconsistencies occur when using newer versions of Access. To avoid the inconsistencies, run the report in Access 2000.

H.2 Processing Other Historical Data

In addition to developing an input history file (described in Appendix H-1), the PMM utilizes other historical data to develop some inputs and to support analysis of the model results. This section describes the updating of these data, which is usually done on an annual basis.

Petroleum Product Price Data

Data on petroleum product prices is obtained from the EIA-782 surveys. The EIA-782A survey contains only refiner data, the EIA-782B survey includes petroleum marketers. Prices and volumes are produced monthly for the *Petroleum Marketing Monthly* and updated for annual publication in the *Petroleum Marketing Annual* available in the summer of each year. This information is also available as series of OGIRS keys from which the state level data by product can be retrieved. By matching equivalent product volume and price information for each state a weighted average for each Census District can be determined.

Historical Prices and Margins

Historical wholesale and end-use prices from the EIA-782 are aggregated and presented in tabular form by product type and Census Division. The end-use transportation prices include State and Federal taxes but for jet fuel and LPGs the State taxes are not included prior to 1995.

Differentials with the world oil price (the refiner acquisition cost of imported oil from the EIA-14) are also calculated by product type and Census Division and presented in tabular form for analyzing similar margin calculations from the PMM. The margins include the 1 percent local tax that is currently being added to gasoline price projections.

Appendix I. Ethanol Supply Model

I.1 Model Purpose

The ethanol supply module is a component of the Petroleum Market Module (PMM) within NEMS. Its objective is to represent the production of ethanol from corn and cellulosic biomass, linked in the PMM to the refinery products market, thus allowing the PMM to forecast transportation ethanol demand throughout the NEMS forecast period. The ethanol production units are part of the PMM linear program (LP), characterized by capital and operating costs, input and output requirements, feedstock supply curves, capacity limits, and market penetration rates. These combine to produce an ethanol supply price (plus transport costs) at which quantities of transportation ethanol are expected to be available for production into E85 or blended with gasoline (E10) within the LP.

The majority of ethanol currently produced in the United States is made from corn and is produced in the East North Central and the West North Central Census Divisions (NEMS regions 3 and 4, respectively). Smaller amounts are available in the South Atlantic, East South Central, West South Central, Mountain, and the Pacific Census Divisions (NEMS regions 5, 6, 7, 8, and 9, respectively). Ethanol from biomass is also available in all Census Divisions beginning in 2009. Biomass (cellulosic material) used to produce ethanol includes regionally-available agriculture residues, forestry waste, and energy crops such as switchgrass and hybrid poplar. The delivered prices of feedstock (corn and cellulosic biomass) are provided to the ethanol supply model in the form of separate supply curves for each of the nine U.S. Census Divisions. The development of these curves is described later in this appendix.

I.2 Fundamental Assumptions

Corn-Based Ethanol

The cost of corn ethanol is subdivided into capital cost, feedstock cost, operating cost, energy cost, and a credit for marketable coproducts of ethanol production. Energy costs include the cost of energy needed to grow and transport corn to market and the cost of energy needed to run the ethanol plant. The sum of these costs contributes to the total value of ethanol, as determined by the LP solution.

Conversion of corn to ethanol is accomplished by either a wet milling or dry milling process. The coproducts produced from the wet milling process are corn gluten feed (CGF), corn gluten meal (CGM), and corn oil, while the dry milling process produces distillers' dried grains with solubles (DDGS). Initial coproduct credits for wet mills and dry mills are estimated from ethanol industry financial data, with some updates made as a function of corn costs in forecast years.

The price of corn at the farm is projected from *The U.S. Farm Economic Effects of a 6 Billion Gallon Renewable Fuel Standard, a 8 Billion Gallon Renewable Fuel Standard, and Elimination of the Federal Ethanol Tax Credit*, Department of Agriculture, July 2005. This paper estimates the effect on agricultural markets of expanding ethanol production by 6 or 8 billion gallons over baseline levels by 2012. For each case, the authors constructed two agricultural market forecasts, one with a baseline level of ethanol production from corn and another with higher levels of ethanol production from corn. The forecasts include corn prices and quantity of corn input to ethanol production for each forecast year. The results of the 8-billion-gallon case are used in PMM. The difference between corn prices and the difference between quantities of corn used for ethanol production gives the rate of change of corn prices with respect to quantity of corn input to ethanol production. The most current baseline corn prices and corn ethanol production were obtained from *USDA Agricultural Baseline Projections to 2015.* (http://www.ers.usda.gov/Publications/OCE061/) The baseline forecast and the estimated rate of change are used to construct a model of the farm price of corn as a function of the quantity of corn demanded for ethanol production.

Wet milling accounted for about 21 percent of all ethanol production in 2005 (http://www.ethanolrfa.org/objects/pdf/outlook/outlook_2006.pdf). The remainder of the existing facilities and all new corn ethanol facilities are projected to be dry milling plants The variability of the market price for the feedstock corn and the conversion by-products and the variable influences of competitive uses for corn (e.g., for producing corn syrup) give rise to broad fluctuations in net corn feedstock prices. As ethanol production from corn increases, land becomes scarcer, causing both land and feedstock costs to increase. These factors are included in the Agriculture model.

In addition to feedstock prices and quantities, the model requires capital cost, feedstock conversion cost (non-energy operating cost), and energy cost data. The cost data were derived from several sources which are documented in the Inventory of Variables, Data, and Parameters section of this report. Note that with this theoretical approach, only the agricultural, or feedstock production costs are modeled as a function of the total quantity of ethanol produced. The conversion plant process costs, (capital, operating, and process energy) are independent of production quantities.

Capital and conversion costs were assumed to be constant across all Census Divisions and for all forecast years. Energy costs vary across Census Divisions as a function of industrial-sector coal, natural gas, and electricity prices. Natural gas prices are obtained from the NEMS Natural Gas Transmission and Distribution Model, coal prices are from the NEMS Coal Market Model, and electricity prices are from the NEMS Electricity Market Model.

There are currently two Federal tax incentives for blending ethanol into gasoline. One is a credit against the Federal motor fuels excise tax on gasoline, and the other is a business income tax credit for ethanol blended into gasoline. The excise tax reduction and income tax credit are of equal value, 51 nominal cents per gallon of ethanol. However, as the excise tax reduction is utilized, the income tax credit is reduced by that amount. Thus, only one credit is represented in the model. These credits are set to expire after 2010.

Cellulose-Based Ethanol

The cost of cellulosic ethanol is subdivided into capital cost, feedstock (biomass) cost, operating cost, and a credit for excess electricity generated at the ethanol plant. As with the corn model, each of the above factors contributes to a part of the total price of ethanol.

Biomass feedstock supply is not modeled in the Petroleum Market Model ethanol model. Biomass price/quantity data are obtained from the Renewable Fuels Model of NEMS and are used as input to the ethanol model. The Model Documentation: Renewable Fuels Module of the National Energy Modeling System@, DOE/EIA-M069(2009) contains a complete description of the approach and assumptions used in generating the biomass feedstock supply functions.

Briefly, the biomass use in NEMS is modeled as two distinct markets, the captive and non-captive biomass markets. The captive market pertains to users with dedicated biomass supplies that obtain energy by burning biomass byproducts resulting from the manufacturing process. The non-captive market is defined to include the residential, commercial, transportation, and electric utility sectors, as well as the resources marketed in the industrial sector.

EIA developed a fairly simple model structure consisting of one supply schedule per region. This schedule defines the quantity and cost relationships of biomass resources accessible by all non-captive, non-residential consumers. It is based on an aggregation of supply/price information from U.S. Forest Service and forest product experts. The wood portion of the cost-supply schedule is static throughout the model period. Energy crop cost-supply schedules are also developed and superimposed onto the wood total.

A basic assumption for the biomass feedstock is that the supply price for non-captive biomass energy is the same across all sectors. Biomass feedstock costs are input from the NEMS Renewable Fuels Model at the Census Division level. Biomass usage by the PMM ethanol model is fed back to the Renewable Fuels Model. At lower prices, the NEMS biomass supply is mostly urban wood waste. Cellulose ethanol technology, however, is being developed for agricultural residue, forestry residue, and purpose-grown energy crops. Therefore, the NEMS biomass supply to cellulose ethanol production excludes urban wood waste.

An important modeling consideration for cellulose ethanol production is the imposition of a constraint on the amount of ethanol production capacity assumed for the early years of the forecast. Ethanol from cellulose is a relatively new technology and ethanol production from cellulose is currently at the demonstration level. By assumption, commercial cellulose ethanol production begins in 2009 in the *AEO2009* reference case. A constraint on cellulose ethanol production prevents unrealistically large increases in production capacity from occurring suddenly in response to favorable market prices.

For *AEO2009*, the upper limit is determined using the Mansfield-Blackman model for market penetration. This algorithm tracks the number of units (1 unit is 50 MM gal/yr, or 3.26 Mbbl/cd) built nationally in order to determine the maximum penetration allowed for the next build cycle. The key parameters used in this algorithm to define the characteristic of the cellulosic production process include the innovation index (0.25), the relative profitability ratio (1.55), size of the investment ratio (2.0), and the maximum total number of units (300). This algorithm is incorporated in the refeth.f code in the PMM, and presented in section I.3.

In addition to feedstock prices and quantities input from the Renewable Fuels Model, the ethanol model requires feedstock conversion and energy cost data, and capital and operating cost data. The conversion and capital cost data were derived from a joint study by the Dept. of Agriculture and the Dept. of Energy, *Determining the Cost of Producing Ethanol from Corn Starch and Lignocellulosic Feedstocks.*

Ethanol production costs are assumed to be constant across the United States. However, feedstock availability and price varies from Census Division to Census Division. Ethanol production in Census Divisions 2 and 7 is expected to be based on forest residue. Census Divisions 3 and 4 have corn stover in large volume. The feedstocks available in Census Division 9 are forest residue and rice straw. The Federal tax incentives for blending ethanol also apply to ethanol from cellulose.

Technology Penetration is taken into account in modeling cellulose-based ethanol. The initial estimate of the capital cost of a cellulosic ethanol plant was adjusted by two other factors: technological optimism and learning-by-doing. In *AEO2009,* commercial cellulosic ethanol production is considered a new technology. As a result, capital costs are based on engineering estimates (in particular, the quoted IOGEN estimate). The difference between this initial engineering estimate and the final first-of-a-kind costs may be characterized as technological optimism. In *AEO2009*, a factor of 1.25 was used to represent technological optimism.

Learning-by-doing represents the decrease in capital cost of a plant component as more experience is gained through the construction of additional plants. Learning in the experimental portion of the cellulosic ethanol plant is represented by three stages; early rapid learning, normal learning and extended learning. In *AEO2009*, early rapid learning encompasses the first five (subsidized) plants. At the completion of the five subsidized plants, the overnight cost is 110% of the engineering estimate. It was assumed that two thirds of the cost of the proposed plant is considered conventional technology, while the remaining one third is considered experimental. Normal learning occurs through the 32nd plant, at a rate of 25% per doubling. Finally, extended learning continues at a rate of 10% per doubling. Learning for the conventional technology proceeded at 1% per doubling.

Even if no unsubsidized plants were constructed, some learning would occur. In *AEO2009,* overnight costs were reduced by 0.5% per year while no unsubsidized plants were being built.

I. 3 Key Computations and Equations

Corn-Based Ethanol

The ethanol price, in 1987 $ per barrel, is determined by the LP model solution, based on feedstock costs, capital and operating costs, transport costs, and subsidies. Operating costs and other parameters are data inputs, defined in the *Inventory of Variables, Data, and Parameters* section below. Feedstock costs are represented as price/quantity supply curves. Capital costs are calculated from economic parameters.

The feedstock supply curve is defined by a price/quantity (P/Q) relationship, and represented in the LP as five segmented P/Q steps. The first three steps represent the quantity of corn consumed in the previous year (CRNCD), with the first step defined as 80 percent of CRNCD, and subsequent steps based on 95%, 100%, 105%, and 130% of CRNCD, set as incremental quantities. The EIA corn price model is approximated by a two-part function in PMM. The parameters used below are defined in Section I.4. For corn use at or below 4.7 billion bushels, the farm price of corn (1987 dollars per bushel) is given by:

$$FC_{t,e} = Intercept + Slope * X + 0.15$$

For corn use greater than 4.7 bushels, the farm price of corn is given by:

$$FC_{t,e} = Base * EXP\ (Exponential\ Coefficient * X) + 0.15$$

where:

X	=	National total corn use for ethanol production (billion bushels per year), adjusted regionally to shift curve upward (3.03 for CD=3, 1.515 for CD=4)
0.15	=	Charge added to the farm price of corn to represent the cost of delivering corn to ethanol plants (1987 dollars per bushel)

The annualized capital cost coefficient (**$CAPCST1_e$**) for each of the new dry mill units is calculated from the following equations:

$BNDRET1_e$ = (1. + $MC\_RMCORPBAA_t$ /100. + $BNDPREM1_e$ /100. /

$$MC\_JPGDP_t \; / \; MC\_JPGDP_{t-1}$$

$$BNDCRF1_e = BNDRET1_e \; /(1. - (1. /(1. + BNDRET1_e) ** CRNLIFE_t))$$

$$EQRET1_e = (1. + MC\_RMTCM10Y_t \; /100. + BETA1_e * EQPREM1_e \; /100. \; / \; (MC\_JPGDP_t \; / \; MC\_JPGDP_{t-1}) - 1.$$

$$EQCRF1_e = EQRET1_e \; / (1. - (1. / (1. + EQRET1_e) ** CRNLIFE_e))$$

$$\mathbf{CAPCST1_e} = BNDCRF1_e * CRNDEBT_e \; /100. + EQCRF1_e * (100. - CRNDEBT_e \; /100.) * CRNCAP_e$$

where,

e	=	4 for new dry mill
e	=	5 for new advanced dry mill
$CAPCST1_e$	=	Capital cost recovery for corn conversion technology for plant type *e*. Plants are assumed to run at full nameplate capacity.
$CRNDEBT_e$	=	Debt fraction (percent) for plant type *e* , data in *rfrenew.txt*
$CRNCAP_e$	=	Capital cost for plant type *e*, 1987$/ annual gallon ethanol produced, data in *rfrenew.txt*
$CRNLIFE_e$	=	Asset life for plant type *e*, data in *rfrenew.txt*
$BNDCRF1_e$	=	Annualized representation of debt factor for plant type *e*
$BNDRET1_e$	=	Debt factor for plant type *e*
$BNDPREM1_e$	=	Bond premium (percent) for plant type *e* , data in *rfrenew.txt*
$EQCRF1_e$	=	Annualized representation of equity factor for plant type *e*
$EQRET1_e$	=	Equity factor for plant type *e*
$EQPREM1_e$	=	Equity premium (percent) for plant type *e*, data in *rfrenew.txt*
$BETA1_e$	=	Equity premium beta for plant type *e*, data in *rfrenew.txt*
MC_JPGDP_t	=	GDP chained price index in year *t* (1987=1), generated by the Macroeconomic Activity Model. Located in Macroeconomic common block MACOUT.
$MC\_RMCORPBAA_t$	=	Baa average corporate bond rate in year t, generated by the Macroeconomic Activity Model. Located in Macroeconomic common block MACOUT.
$MC\_RMTCM10Y_t$	=	Ten year treasury note rate in year t, generated by the Macroeconomic Activity Model. Located in Macroeconomic common block MACOUT.

The price of co-product from the dry mill corn ethanol plants are determined in each year of the model, and are based on the corn supply price associated with the corn quantity consumed in the previous year (step 3 on the corn supply curve), as represented in the equation below:

$$PRICLP = CRNSPRICE_3 *2000/56$$

The price of energy for each process unit type is taken from the following NEMS variables:

$PGIIN_{cd,t}$	=	Industrial sector price of interruptible natural gas for Census Division *cd* in year *t* (1987 dollars per million Btu)
$PCLIN_{cd,t}$	=	Industrial price of coal for Census Division *cd* in year *t* (1987 dollars per million Btu). Generated by the Coal Market Model. Located in the Price common block MPBLK.
$INPELIN_{cd,t}$	=	Industrial sector price of electricity for Census Division *cd* in year *t*. Value is $0.035 per KWh (1987 $)

Cellulose-Based Ethanol

As with corn ethanol production, the price of ethanol from biomass, in 1987 $ per barrel, is determined by the LP model solution, based on feedstock costs, capital and operating costs, transport costs, and subsidies. Operating costs and other parameters are data inputs, defined in the *Inventory of Variables, Data, and Parameters* section below. Feedstock costs are represented as price/quantity supply curves. Capital costs are calculated from economic parameters.

CAPITAL COSTS: Capital cost is calculated as follows:

$$CLLBNDRETCLL = (1 + MC\_RMCORPBAA_t/100 + BNDPREM2/100)/(MC\_JPGDP_t/MC\_JPGDP_{t-1}) - 1$$

$$CLLBNDCRFCLL = BNDRETCLL/(1 - 1/(1 + CLLBNDRETCLL)^{**}CLLLIFE)$$

$$EQRETCLL = (1 + MC\_RMTCM10Y_t/100 + BETA2^*EQPREM2/100)/(MC\_JPGDP_t/MC\_JPGDP_{t-1}) - 1$$

$$CLLEQCRFCLL = EQRETCLL/(1 - 1/(1 + CLLEQRETCLL)^{**}CLLLIFE)$$

$$CAPCSTCLL = (BNDCRFCLL^*CLLDEBT/100 + CLLEQCRFCLL^*(100 - CLLDEBT)/100)^*CLLCAP^*CLLLNRATE^*ETHPLNTFACT$$

$$\mathbf{CAPCSTCLL} = \mathrm{CAPCSTCLL} + \mathrm{FXOCCLL}$$

where:

CLLBNDRETCLL	=	*Real return on debt required for cellulose ethanol plants*

$MC\_RMCORPBAA_t$	=	*Nominal yield of BAA-rated corporate bonds in year t*
BNDPREM2	=	*Bond premium required for cellulose ethanol plants*
MC_JPGDP_t	=	*GDP chained price index in year t*
CLLBNDCRFCLL	=	*Bond capital recovery factor*
CLLLIFE	=	*Capital recovery period for cellulose ethanol plants*
EQRETCLL	=	*Real return on equity required for corn ethanol plants*
$MC\_RMTCM10Y_t$	=	*Nominal yield on 10-year treasury note in year t*
BETA2	=	*Cellulose ethanol specific multiplier applied to equity risk premium*
EQPREM2	=	*Market risk premium for equity*
EQCRFCLL	=	*Equity capital recovery factor*
CLLDEBT	=	*Debt fraction of cellulose ethanol plant finance*
CLLCAP	=	*Capital cost per annual gallon of capacity for cellulose ethanol plant*
CLLLNRATE	=	*Learning factor*
ETHPLNTFACT	=	*Autonomous learning factor*
FXOCCLL	=	fixed operating cost

LEARNING PARAMETERS: The learning parameters are calculated as follows:

*CLLLNRATE = PhaseIa * MAXPLTNUM**PhaseIb*

where:

MAXPLNTNUM = Number of plants constructed

PhaseIa = a coefficient in phase I (I=1-3)

PhaseIb = b coefficient in phase I

If no unsubsidized plants have been built, the autonomous learning parameters are:

ETHPLNTFACT = 1 for CURIYR < 24

and:

ETHPLNTFACT = (1 - .005 * (CURIYR – 23)) for CURIYR >= 24

BIOMASS FEEDSTOCK: The feedstock supply curve is defined by a price/quantity (P/Q) relationship provided by the Renewable Fuels Model, and represented as five segmented P/Q steps (PBMET, QBMET) in the LP. The first three steps for QBMET represent the quantity of cellulose consumed in the previous year (BIOCD), with the first step defined as 80 percent of BIOCD, and subsequent steps based on 95%, 100%, 105%, and 120% of BIOCD. However, if the BIOCD is greater than step 18 on the Renewable Fuels Model supply curve, these percentages will be different (0.95, 0.995, 1.0, 1.005, 1.05 times BIOCD). PBMET is defined by the Renewable Fuels Model based on QBMET values. The PMM uses these variables as follows:

$$FQ_{2,t,,e} = (QBMET_{cd,q,t} - QBMET_{cd,q-1,t}) * 1000. / 365.$$

$$FC_{2,t,,e} = PBMET_{cd,q,t}$$

where:

$PBMET_{cd.q,t}$	=	Biomass feedstock cost for Census Division *cd* in year *t* for step q on the curve (1987 $/MMBtu)
$QBMET_{cd,q,t}$	=	Total biomass feedstock quantity for Census Division *cd* in year *t* for step q on the curve (1987 $/MMBtu)
Notes:		17.2 = MMBtu of biomass per short ton of biomass. P/Q variables for biomass curve generated by the Renewable Fuels Model are wdpmmcurvq and wdpmmcurvp.

CAPACITY LIMIT. The upper limit on cellulose ethanol capacity is determined using the Mansfield-Blackman model for market penetration and the basic unit size (50 MM gal/yr, or 3.26 M bbl/cd), as presented below.

Mansfield-Blackman Algorithm:

```
KFAC         = -ALOG( (CLLBLDX/NCLLBLT) -1.0)    ! ratio of # allowed/#blt
PHI          = -.3165 + (0.23221*CLLIINDX) + (0.533*CLLPINDX) - (0.027*CLLSINVST)
SHRBLD       = 1./ (1.+ EXP(-KFAC-(EYR*PHI)))
CLLRHSNUM    = CLLBLDX * SHRBLD
```

Resulting upper limit on cellulose ethanol capacity:

Maximum CLL capacity = CLLRHSNUM * CLLSIZE

where:

KFAC = relationship between the number of units allowed (CLLBLDX) and number of units built (NCLLBLT)
CLLIINDX = M-B innovation index (=0.25)
CLLPINDX = M-B relative profitability ratio (=1.55)
CLLSINVST = M-B size investment ratio (=2.0)
PHI = combined M-B index factors
EYR = cumulative years of build
CLLBLDX/NCLLBLT = ratio of number allowed / number built (number allowed = 300)
SHRBLD = fraction of total number of units allowed (M-B penetration algorithm)
CLLRHSNUM = maximum total number of units allowed to date

I. 4 Inventory of Variables, Data, and Parameters

Corn-Based Ethanol

Tables I.1 and I.2 provide information related to the cost components and parameters for corn ethanol production.

Table I.1 Corn Price Function (CF in section I.2) Parameters by Year

	Intercept	*Slope*	*Base*	*Exponential Coefficient*
2007	0.450486	0.9783	0.916	0.2867
2008	0.444854	0.8389	0.968	0.2272
2009	0.432428	0.8958	0.993	0.1991
2010	0.402423	0.7508	0.880	0.2198
2011	0.148058	1.4368	0.849	0.2191
2012	0.138455	1.4505	0.816	0.2124
2013	0.126094	1.4783	0.796	0.2095
2014	0.126094	1.4372	0.794	0.2089
2015	0.126094	1.4624	0.791	0.2083
2016	0.126094	1.4575	0.856	0.1837
2017	0.126094	1.4472	0.853	0.1831
2018	0.126094	1.4368	0.850	0.1825
2019	0.126094	1.4264	0.847	0.1819
2020	0.126094	1.4160	0.880	0.1767
2021	0.126094	1.4055	0.877	0.1761
2022	0.126094	1.3950	0.884	0.1676
2023	0.126094	1.3845	0.881	0.167
2024	0.126094	1.3739	0.878	0.1664
2025	0.126094	1.3632	0.942	0.1531
2026	0.126094	1.3526	0.939	0.1526
2027	0.126094	1.3419	0.910	0.1427
2028	0.126094	1.3311	0.885	0.1495
2029	0.126094	1.3204	0.827	0.163
2030	0.126094	1.3096	0.866	0.157

Table I.2 Cost Components and Parameters by Corn Ethanol Plant Type

	Existing Wet Mill	Existing Dry Mill	New Dry Mill	Advanced Dry Mill
$CRNCAP_e$	n/a	n/a	0.868 $87/ann gal	0.868 $87/ann gal
$CRNLIFE_e$	n/a	n/a	20 years	20 years
$CRNDEBT_e$	n/a	n/a	40%	40%
$BNDPREM1_e$	n/a	n/a	0.25%	0.25%
$EQPREM1_e$	n/a	n/a	6.75%	6.75%
$BETA1_e$	n/a	n/a	1.5	1.5
$OPCST_e$	5.477 $87/bbl	5.477 $87/bbl	5.477 $87/bbl	5.477 $87/bbl

Cellulose-Based Ethanol

Table I.3 provides information related to the cost components and parameters for cellulosic ethanol production.

Table I.3 Cost Components and Parameters for Cellulose Ethanol Plant

PMM variable	Value
CLLCAP	3.170 $87/ann gal
CLLLIFE	15
CLLDEBT	40%
BNDPREM2	0.5%
EQPREM2	7.0%
BETA2	1.5
FXOC	0.169 $87/gal
OPCST	17.98 $87/bbl

MODEL INPUT: $MC\_RMCORPBAA_t$, $MC\_RMTCM10Y_t$
DEFINITION: Nominal yields of BAA-rated corporate bonds and 10-year treasury notes, respectively, in year *t*
SOURCE: Generated by the Macroeconomic Model. Located in Macroeconomic common block MACOUT.

MODEL INPUT: MC_JPGDP_t
DEFINITION: GDP chained price index in year *t*. 1987=1.

SOURCE: Generated by the Macroeconomic Model. Located in Macroeconomic common block MACOUT.

MODEL INPUT: *CLLLIFE*
DEFINITION: Capital recovery period for cellulose ethanol plants. Value is 15 years.
SOURCE: Spreadsheet AEO2008 Final Discount Rates.xls, by Thomas Lee of OIAF.

MODEL INPUT: *CLLBNDPREMCLL*
DEFINITION: Bond premium required for corn ethanol plants. Value is 0.5 percent.
SOURCE: Spreadsheet AEO2008 Final Discount Rates.xls.

MODEL INPUT: *CLLEQPREMCLL*
DEFINITION: Market risk premium for equity investment. Value is 7.00 percent for all equity investments.
SOURCE: Spreadsheet: Cellulosic Ethanol 062407-correction.xls.

MODEL INPUT: *BETA2*
DEFINITION: Cellulose ethanol-specific multiplier applied to equity risk premium. Value is 1.5.
SOURCE: Spreadsheet: Cellulosic Ethanol 062407-correction.xls.

MODEL INPUT: *CLLDEBT*
DEFINITION: Debt fraction of cellulose ethanol plant finance. Value is 40 percent.
SOURCE: Spreadsheet: Cellulosic Ethanol 062407-correction.xls.

MODEL INPUT: *CLLCAP*
DEFINITION: Capital cost per annual gallon of capacity for cellulose ethanol plant. Value is $3.17 per gallon per year of capacity (1987 $).
SOURCE: Marano, John, "Cellulosic Ethanol Technology Data Profile", March 2008.(Draft)

MODEL INPUT: $FC_{2,t,,e}$
DEFINITION: Cellulose feedstock cost in year t (1987 $/gal). The prices for biomass were chosen to reflect adequate supplies of higher-quality biomass for the step quantity of cellulose ethanol. Cellulose ethanol plants are assumed to use forest wastes, crop residues, and energy crops. It is assumed that they will not use urban wood waste, because its quality is too variable.
SOURCE: National Energy Modeling System common block WRENEW. Input from the Renewable Fuels Model.

MODEL INPUT: $OPCSTCL_e$, $PWRCDCL_e$

DEFINITION: $OPCSTCL_e$ is $0.428 per gallon, and $PWRCDCL_e$ is $-0.082 per gallon (1987 $).

SOURCE: McAloon, Andrew; Taylor, Frank; Yee, Winnie. *Determining the Cost of Producing Ethanol from Corn Starch and Lignocellulosic Feedstocks.* National Renewable Energy Laboratory, October 2000. Located in the RFRENEW.TXT input data file.

MODEL INPUT: $PBMET_{cd,t}$

DEFINITION: Biomass feedstock cost for Census Division *cd* in year *t*.

SOURCE: National Energy Modeling System common block WRENEW. Input from the Renewable Fuels Model.

MODEL INPUT: $SUBETHSUB_t$

DEFINITION: Value of Federal tax incentive in year *t*, in nominal dollars. The incentive is 52 cents per gallon in 2004 and 51 cents per gallon thereafter, ending after 2010.

SOURCE: Located in the RFRENEW.TXT data input file.

I.5 Ethanol Transportation Costs

The most comprehensive work regarding ethanol distribution infrastructure and costs is a report by Downstream Alternatives, Inc. (DAI), *Infrastructure Requirements for an Expanded Ethanol Industry,* June 2002, performed for the Department of Energy Office of Energy Efficiency and Renewable Energy. This source was used to develop cost estimates for transporting ethanol between and within Census Divisions (CD's).

The DAI study estimates the infrastructure investment costs and the transportation costs that would likely be incurred if ethanol demand reached 5.0 billion gallons per year (BGY) by 2012. The infrastructure costs are incremental and represent additional expenditures from an established baseline level of 1.5 BGY. Transportation costs are the largest category of costs, far larger than the amortized costs of modifications to petroleum terminals and retail stations for blends of 10 percent ethanol or less. Rail and water are the modes of ethanol transport that are considered, as pipeline shipment is not currently considered a cost-effective method of transport due to special handling requirements of ethanol.

The DAI study examines the costs and ethanol demand by PADD. The links needed for PMM, as shown in Table I.4, are based on Census Divisions for demands. There are some discrepancies between the PADD and CD mapping in terms of states; however, for the purpose of ethanol transportation cost estimates between the CD's, the following table is not expected to introduce significant error to the modeling results.

Table I.4 DAI Regions and NEMS Regions

DAI Regions		**NEMS/PMM Regions**	
Code	Locations	Code	Locations
1	PADD 1	1, 2, 5	CDs 1, 2, and 5
2	PADD 2	3, 4	CDs 3 and 4
3	PADD 3	6, 7	CDs 6 and 7
4	PADD 4	8	CD 8
5	PADD 5	9	CD 9

Most ethanol is produced in either CD 3 or 4, and transported by rail, barge, ship, or truck. Ethanol produced and consumed in the same CD is assumed to be shipped by truck at a freight cost of 4 cents/gallon. Starting with the baseline of existing ethanol sales from year 2000, the DAI study examines the costs and ethanol demand for the years 2004, 2007, and 2012. The corresponding demands in the PMM model for each mode of transportation and the estimated freight costs are shown for these 3 years in Tables I.5, I.6, and I.7.

The average cents per gallon in Tables I.5 through I.7 are provided on an amortized, cost per gallon of ethanol basis. Costs for capital improvement are included in the PMM model but are not included in the freight costs shown below. (Amortized capital improvement costs range from 0.52 cents per gallon to 0.87 cents per gallon, with a nationwide average of 0.66 cents per gallon)

Table I.5 2004 New Ethanol Shipments and Freight Costs by Census Divisions

From	To	Mode of Transport	Amount of New Ethanol Shipped (mgy)	Freight Costs (cents/gallon)
CD 3	CD 1	Rail	44.8	9.0
CD 3	CD 1	Ship	25.1	11.0
CD 3	CD 2	Rail	160.5	8.0
CD 3	CD 2	Ship	89.9	11.0
CD 3	CD 3	Barge	103.2	4.0
CD 3	CD 5	Rail	44.7	8.0
CD 3	CD 5	Ship	25.0	11.0
CD 4	CD 3	Rail	52.0	4.0
CD 4	CD 3	Truck	52.0	4.0
CD 4	CD 4	Truck	103.3	4.0
CD 4	CD 9	Rail	84.0	13.0
CD 4	CD 9	Ship	70.0	13.0

Source: Based on data from Downstream Alternatives Inc., *Transportation and Infrastructure Requirements for a Renewable Fuels Standard*, (June 2002), and personal communication with author (Robert Reynolds, August 2002

Note: Costs shown reflect 2000 dollars.

Table I.6 2007 New Ethanol Shipments and Freight Costs by Census Divisions

From	To	Mode of Transport	Amount of New Ethanol Shipped (mgy)	Freight Costs (cents/gallon)
CD 3	CD 1	Rail	34.8	9.0
CD 3	CD 1	Ship	18.8	11.0
CD 3	CD 2	Rail	124.5	9.0
CD 3	CD 2	Ship	67.4	11.0
CD 3	CD 3	Truck	38.6	4.0
CD 3	CD 5	Rail	34.7	9.0
CD 3	CD 5	Ship	18.8	11.0
CD 3	CD 6	Barge	12.2	3.5
CD 3	CD 6	Rail	24.9	7.0
CD 4	CD 3	Truck	38.6	4.0
CD 4	CD 4	Truck	38.6	4.0
CD 4	CD 6	Barge	4.1	3.5
CD 4	CD 6	Rail	8.3	7.0
CD 4	CD 7	Barge	43.7	3.5
CD 4	CD 7	Rail	88.8	7.0
CD 4	CD 9	Rail	195.0	13.0
CD 4	CD 9	Ship	105.0	13.0

Source: Based on data from Downstream Alternatives Inc., *Transportation and Infrastructure Requirements for a Renewable Fuels Standard*, (June 2002), and personal communication with author (Robert Reynolds, August 2002

Table I.7 2012 New Ethanol Shipments and Freight Costs by Census Divisions

From	To	Mode of Transport	Amount of New Ethanol Shipped (mgy)	Freight Costs (cents/gallon)
CD 3	CD 1	Rail	71.8	9.0
CD 3	CD 1	Ship	43.1	11.0
CD 3	CD 2	Rail	256.8	9.0
CD 3	CD 2	Ship	154.1	11.0
CD 3	CD 3	Barge	16.8	4.0
CD 3	CD 3	Truck	146.3	4.0
CD 3	CD 3	Rail	10.0	4.0
CD 3	CD 5	Rail	71.5	9.0
CD 3	CD 5	Ship	42.9	11.0
CD 3	CD 6	Barge	20.6	3.5
CD 3	CD 6	Rail	11.4	7.0
CD 3	CD 9	Rail	25.0	14.0
CD 3	CD 9	Ship	15.0	14.0
CD 4	CD 1	Rail	17.9	11.0
CD 4	CD 1	Ship	10.8	12.0
CD 4	CD 2	Rail	64.2	11.0
CD 4	CD 2	Ship	38.5	12.0
CD 4	CD 3	Barge	33.6	4.0
CD 4	CD 3	Rail	20.0	4.0
CD 4	CD 3	Truck	36.6	4.0
CD 4	CD 4	Truck	36.6	4.0
CD 4	CD 5	Rail	17.9	11.0
CD 4	CD 5	Ship	10.7	12.0
CD 4	CD 6	Barge	20.6	3.5
CD 4	CD 6	Rail	11.4	7.0
CD 4	CD 7	Barge	110.1	3.5
CD 4	CD 7	Rail	61.0	7.0
CD 4	CD 8	Rail	35.0	4.5
CD 4	CD 9	Rail	225.0	13.0
CD 4	CD 9	Ship	135.0	13.0

Source: Based on data from Downstream Alternatives Inc., *Transportation and Infrastructure Requirements for a Renewable Fuels Standard*, (June 2002), and personal communication with author (Robert Reynolds), August 2002

APPENDIX J

Biodiesel Supply Model

Appendix J. Biodiesel Supply Model

J.1   Model Purpose

The objective of the biodiesel supply model is to provide the NEMS Petroleum Market Model (PMM) with supply curves for virgin and recycled vegetable oils and fats. The model provides plant-gate biodiesel prices as a function of quantity for each Census Division and each forecast year. The curves, derived from a biodiesel production cost function, represent the prices at which biodiesel is expected to be available for blending into distillate and highway diesel.

J. 2   Fundamental Assumptions

PMM can choose up to approximately 1.7 billion gallons of biodiesel from virgin vegetable oil and up to approximately 222 million gallons of biodiesel from recycled vegetable oils which are sold as yellow grease. Virgin oil supplies to biodiesel producers consist of regional quantities of soybean, cottonseed, canola, and sunflower oils. Yellow grease consists primarily of used cooking oil from restaurants. As such, its availability is nationwide and is assumed to grow at the same rate that population grows. Biodiesel production capacity by feedstock is allocated among Census Divisions in PMM according to the National Biodiesel Board's map of existing and potential producers and according to potential feedstock supplies.[1]

1 http://www.nbb.org/buyingbiodiesel/producers_marketers/ProducersMap-Existing.pdf and http://www.nbb.org/buyingbiodiesel/producers_marketers/ProducersMap-Construction.pdf as of July 2006.

The biodiesel model uses a process costing approach to model the impacts of net feedstock production costs plus capital and operating costs. Biodiesel is produced in a type of chemical reaction called a transesterification. Fats or oils are reacted with an alcohol, usually methanol, to produce esters of the fat or oil (biodiesel) and glycerin (byproduct).

For AEO2009, soybean oil prices were econometrically linked with corn prices via the following relation:

SOYPRICE(M,J) = 7.29*CRNPERLB(M,J-1)-3.23*CRNPERLB(M,J-2) +
2.29*CRNPERLB(M,J-4)-1.08*CRNPERLB(M,J-6)

Thus, the soybean oil price in each region M for a given year J is related to the corn price in years J-1, J-2, J-4, and J-6. After converting the price from cents per pound to 1987$ per barrel via the equation

SOYPRICE(M,J)=SOYPRICE(M,J)*7.72*42/100,

costs for other virgin oils (cotton seed, sunflower, and canola) are defined as a function of the soybean oil price:

COTPRICE(M,J)=SOYPRICE(M,J)+3.68
SUNPRICE(M,J)=SOYPRICE(M,J)+9.09
CNLPRICE(M,J)=SOYPRICE(M,J)+11.25

These relationships are based on historical comparisons between these other virgin oils (cotton seed, sunflower, and canola) with respect to soybean oil. Associated with these costs for each of the possible virgin oil biodiesel feedstocks is a supply step on the incremental “supply curve” for virgin feedstocks (presented in Table J.1).

Table J.1 Quantities on Supply Steps for Virgin Feedstocks

```
4-23-07, temp keep biodiesel(v) data,  !@!
but convt to soybean oil (SBO) qty in code
by multiplying by .991 (coef in t:sbo table)
Incremental biodiesel V quantity by step and CD, Mbbl/day
1       2       3       4       5       Supply curve point index
@                                       CD
 0.00    0.00    0.00    0.02    0.00   1
 0.19    0.00    0.00    0.27    0.00   2
 5.70    2.64    0.89    5.80    0.00   3
18.76    0.24    4.70    35.89   0.00   4
 1.20    1.18    0.00    0.00    0.00   5
 1.50    1.14    0.00    0.00    0.00   6
 1.63    3.76    3.90    5.88    0.00   7
 0.00    0.14    1.19    10.50   0.00   8
 0.00    0.31    0.20    4.75    0.00   9
```

The module refeth.f stores this table in WQTOTV(M,L), where M = 1 to 9 (the census district) and L = 1 to 5. (WQTOTV(M,5) = 0.00 is a dummy value.)

The data from the WQTOTV table (Table J.1) represents finished biodiesel, not the feedstock. Feedstock quantities are calculated by FSQTYV = 0.991 WQTOTV:

Table J.2 Available Virgin Feedstock (Soybean Oil, Cotton Seed Oil, Sunflower Oil, Canola Oil)

	1	2	3	4
1	0.00000	0.00000	0.00000	0.01982
2	0.18829	0.00000	0.00000	0.26757
3	5.64870	2.61624	0.88199	5.74780
4	18.59116	0.23784	4.65770	35.56699
5	1.18920	1.16938	0.00000	0.00000
6	1.48650	1.12974	0.00000	0.00000
7	1.61533	3.72616	3.86490	5.82708
8	0.00000	0.13874	1.17929	10.40550
9	0.00000	0.30721	0.19820	4.70725

In Table J.2, column 1 represents soybean oil, column 2 represents cotton seed oil, column 3 represents sunflower oil, and column 4 represents canola. The total virgin feedstock available is the sum of the individual feedstock availabilities.

The price curve, developed by Peter Gross, is an exponential curve based on (1) the price and quantity of feedstock if biodiesel consumed the entire soybean oil supply and (2) the price and quantity of feedstock if biodiesel consumed the entire virgin oil supply (soybean, cottonseed, sunflower, and canola). This exponential curve is then divided into 99 linear steps.

In addition to feedstock prices and quantities, the model requires capital and operating costs. The cost data are documented in the Inventory of Variables, Data, and Parameters section of this report. Note that with this theoretical approach, only the agricultural, or feedstock production costs are modeled as a function of the total quantity of ethanol produced. The conversion plant process costs are independent of production quantities.

J. 3 Key Computations and Equations

Biodiesel costs including subsidies are calculated in a separate spreadsheet (NEMSbiodieselsupplycurve.xls, maintained by Mike Cole of EIA). These costs are tabulated as functions of biodiesel production quantities. The prices for biodiesel are calculated from the following equations:

$$WPBDSL_{1,cd,t,e} = [FC_{1,t,e} + CAPBDSL + OPBDSL - GLYCVAL_t - FEDSUBV_t/MC\_JPGDP_t]*42$$

$$WPBDSL_{2,cd,t,e} = [FC_{2,t,e} + CAPBDSL + OPBDSL - GLYCVAL_t - FEDSUBNV_t/MC\_JPGDP_t]*42$$

Where:

i=feedstock index; 1≡virgin oil biodiesel, 2≡yellow grease biodiesel

$PBDSL_{i,cd,t,e}$= Delivered price of biodiesel produced from feedstock i in Census Division cd in year t for volume step e (1987 $/barrel),

$FC_{i,t,e}$= Net cost of feedstock i in year t for volume step e (1987 $/gal),

$CAPBDSL$ =Capital cost for conversion technology (1987 $/gal),

$OPBDSL$=Operating cost for biodiesel production (1987 $/gal),

$GLYCVAL_t$=Value of glycerin byproduct per gallon of biodiesel produced (1987 $/gal).

$FEDSUBV_t$=Federal excise tax exemption for biodiesel from soybean oil in year t (nominal $/gal).

$FEDSUBNV_t$=Federal excise tax exemption for biodiesel from yellow grease in year t (nominal $/gal).

MC_JPGDP_t=GDP chained price index in year t (1987=1)

42=number of gallons per barrel

J. 4 Inventory of Variables, Data, and Parameters

MODEL INPUT: *CAPBDSL*
DEFINITION: Capital cost of biodiesel plants.
A new biodiesel plant costs $0.756 per gallon per year of capacity (1987 $), discounted at 9.2 percent over 20 years. Located in spreadsheet NEMSbiodieselsupplycurve.xls.
SOURCE: National Renewable Energy Laboratory estimate

MODEL INPUT: *OPBDSL*

DEFINITION: Operating cost of biodiesel plants, including energy
Value is $0.308 per gallon (1987 $).
SOURCE: R. Teall, *Study to Evaluate the Feasibility of Biodiesel Production Facilities in Nevada &California Utilizing Grease Trap&Waste Cooking Oils as Feedstocks* (Las Vegas, NV: Biodiesel Industries, March 19, 2002), Appendix #3—Feasibility Study, pp. 38-42, web site www.westbioenergy.org/reports /55034/55034fin.pdf)

MODEL INPUT: $GLYCVAL_t$
DEFINITION: Value of glycerin byproduct per gallon of biodiesel produced in year t. Value is $0.11 per gallon (1987 $)
SOURCE: R. Teall, *Study to Evaluate the Feasibility of Biodiesel Production Facilities in Nevada &California Utilizing Grease Trap & Waste Cooking Oils as Feedstocks* (Las Vegas, NV: Biodiesel Industries, March 19, 2002), Appendix #3—Feasibility Study, pp. 38-42, web site www.westbioenergy.org/reports /55034/55034fin.pdf)

MODEL INPUT: *FEDSUBV*$_t$
DEFINITION: Value of Federal tax incentive for virgin oil (e.g. soybean oil) biodiesel in year *t*. Value is $1.00 per gallon (nominal $) through 2008 and zero thereafter. Located in the RFRENEW data input file.

MODEL INPUT: *FEDSUBNV*$_t$
DEFINITION: Value of Federal tax incentive for non-virgin oil (e.g. yellow grease) biodiesel in year *t*.
Value is 50 cents per gallon (nominal cents) through 2008 and zero thereafter. Located in the RFRENEW data input file.

MODEL INPUT: *MC_JPGDP*$_t$
DEFINITION: GDP chained price index in year *t*. 1987=1.
SOURCE: Generated by the Macroeconomic Model. Located in Macroeconomic common block MACOUT