DOE/EIA-M059(2006)
Part 1

EIA Model Documentation

PETROLEUM MARKET MODEL OF THE NATIONAL ENERGY MODELING SYSTEM

Part 1 - Report and Appendix A

March 2006

Oil and Gas Division
Office of Integrated Analysis and Forecasting
Energy Information Administration

For Further Information...

The Petroleum Market Model (PMM) of the National Energy Modeling System is developed and maintained by the Energy Information Administration (EIA), Office of Integrated Analysis and Forecasting. General questions about the use of the model can be addressed to James Kendell (202) 586-9646, Director of the Oil and Gas Division. Specific questions concerning the PMM may be addressed to:

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This report documents the archived version of the PMM that was used to produce the petroleum forecasts presented in the *Annual Energy Outlook 2006*, (DOE/EIA-0383(2006). The purpose of this report is to provide a reference document for model analysts, users, and the public that defines the objectives of the model, describes its basic approach, and provides detail on the methodology employed. The model documentation is updated annually to reflect significant model methodology and software changes that take place as the model develops. The next version of the documentation is planned to be released in the first quarter of 2007.

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Acronyms and Abbreviations

AEO	EIA Annual Energy Outlook
API	American Petroleum Institute
ASTM	American Society of Testing Materials
BAU	Business As Usual
bbl	Barrel
bbl/cd	Barrels Per Calendar Day
Bcf	Billion cubic feet
Btu	British thermal unit
BTX	Benzene, Toluene, and Xylene Aromatics
BPSD	Barrels Per Stream Day
CAAA	Clean Air Act Amendments
CARB	California Air Resources Board
CD	Census Division
CG	Conventional Gasoline (referred to as TRG in the PMM code)
CHP	Combined Heat and Power
Cn	Represents a hydrocarbon stream containing n atoms of carbon, i.e. C1 is methane, C2 is ethane, C3 is propane, C4 is butane, etc.
CTL	Coal-To-Liquids (converting coal through syngas to diesel-grade blending streams)
COE	Crude Oil Equivalent
DOE	Department of Energy
E85	Gasoline blend of 85 percent ethanol and 15 percent conventional gasoline (annual average of ethanol content in E85 is lower when factoring in cold start need in winter)
EIA	Energy Information Administration
EOR	Enhanced Oil Recovery
EPA	Environmental Protection Agency
ETBE	Ethyl Tertiary Butyl Ether
FCC	Fluid Catalytic Cracker
FOE	Fuel Oil Equivalent
GWh	Gigawatthour
GTL	Gas-To-Liquids (converting natural gas through syngas to diesel-grade blending streams)
IEA	International Energy Agency
IEO	EIA International Energy Outlook
ISBL	Inside the battery limit
KWh	Kilowatthour
LP	Linear Programming
LPG	Liquefied Petroleum Gas
M85	Gasoline blend of 85 percent methanol and 15 percent conventional gasoline
M-B	Mansfield-Blackman methodology for new technology market penetration
Mbbl/cd	Thousand Barrels Per Calendar Day
Mbtu	Thousand British Thermal Units
Mcf	Thousand cubic feet
MG	Motor gasoline
MMbbl/cd	Million Barrels Per Calendar Day
MMbtu	Million British Thermal Units
MTBE	Methyl Tertiary Butyl Ether
MRM	Multi-Refining Model

MW	Megawatts, electric generation capacity
N2H	No. 2 Heating Oil
NACOD	North American Crude Oil Distribution
NEMS	National Energy Modeling System
NES	National Energy Strategy
NETL	National Energy Technology Laboratory
NGL	Natural Gas Liquid
NIPER	National Institute for Petroleum and Energy Research
NOx	Nitrogen Oxide
NPC	National Petroleum Council
NPRA	National Petrochemical and Refiners Association
OB1	Optimization with Barriers 1
OGSM	Oil and Gas Supply Module
OML	Optimization and Modeling Libraries
ORNL	Oak Ridge National Laboratory
OVC	Other Variable Costs
PADD	Petroleum Administration for Defense District
PCF	Petrochemical Feed
PGS	Still gas
Petcoke	Petroleum Coke
PMM	Petroleum Market Model
ppm	Parts per million
PSA	Petroleum Supply Annual
RFG	Reformulated Gasoline
RFS	Renewable Fuels Standard (optional for regulatory analysis purposes)
RHS	Right-hand side
RVP	Reid Vapor Pressure
RYM	Refinery Yield Model (EIA)
SCF	Standard Cubic Feet
SIC	Standard Industrial Classification
SPR	Strategic Petroleum Reserve
STEO	Short Term Energy Outlook
Syngas	Gaseous products from hydrocarbons (e.g., natural gas, petroleum coke, or coal) reacting with steam/O_2, mostly consisting of CO and H_2
TAME	Tertiary amyl methyl ether
TAP	Toxic Air Pollutant
TAPS	Trans-Alaska Pipeline System
TRG	Conventional gasoline (replacing old nomenclature for traditional gasoline)
ULSD	Ultra-Low Sulfur Diesel
VOC	Volatile Organic Compound
WOP	World Oil Price
WORLD	World Oil Refining Logistics Demand (model)

1. Introduction

1.1 Purpose of this Report

The purpose of this report is to define the objectives of the Petroleum Market Model (PMM), describe its basic approach, and provide details on how it works. This report is intended as a reference document for model analysts and users. Documentation of the model is in accordance with EIA's legal obligation to provide adequate documentation in support of its models (Public Law 94-385, section 57.b.2). An overview of the PMM and its major assumptions can also be found in two related literature: *The National Energy Modeling System: An Overview 2003, DOE/EIA-0581(2003)* and *Assumptions to the Annual Energy Outlook of 2006, DOE/EIA-0554(2006)*. This volume documents the version of the PMM used for the *Annual Energy Outlook 2006* (*AEO2006*) and thus supersedes all previous versions of the documentation.

1.2 Model Summary

The PMM models petroleum refining activities, the marketing of petroleum products to consumption regions, the production of natural gas liquids in gas processing plants, domestic methanol and ethanol production, and gas-to-liquids and coal-to-liquids production. The PMM projects petroleum product prices and sources of supply for meeting petroleum product demand. The sources of supply include domestic and imported crude oil; other inputs including alcohols, biodiesel, and ethers; domestic natural gas plant liquids production; petroleum product imports; unfinished oil imports. 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.

1.3 Model Archival Citation

The PMM is archived as part of the National Energy Modeling System (NEMS) for *AEO2006*. The model contact is:

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1.4 Report Organization

The remainder of this report is organized as follows: Chapter 2, Model Purpose; Chapter 3, Model Overview and Rationale; Chapter 4, Model Structure; Appendix A, PMM Data and Outputs; Appendix B, Mathematical Description of Model; Appendix C, Bibliography; Appendix D, Model Abstract; Appendix E, Data Quality; Appendix F, Estimation Methodologies; Appendix G, Matrix Generator Documentation; Appendix H, Historical Data Processing; Appendix I, Ethanol Supply Model; and Appendix J, Biodiesel Supply Model.

2. Model Purpose

2.1 Model Objectives

The Petroleum Market Model (PMM) models petroleum refining and marketing. The purpose of the PMM is to project petroleum product prices, refining activities, and movements of petroleum into the United States and among domestic regions. In addition, the PMM estimates capacity expansion and fuel consumption in the refining industry. The PMM is also used to analyze a wide variety of petroleum-related issues and policies, in order to foster better understanding of the petroleum refining and marketing industry and the effects of certain policies and regulations.

The PMM simulates the operation of petroleum refineries in the United States,[1] including the supply and transportation of crude oil to refineries, the regional processing of these raw materials into petroleum products, and the distribution of petroleum products to meet regional demands. The production of natural gas liquids from gas processing plants, the production of distillate blending streams from either natural gas (gas-to-liquids, or GTL) in Alaska or from coal (coal-to-liquids, or CTL), and petroleum coke (petcoke) gasification technologies are also represented. The essential outputs of this model are product prices, a petroleum supply/demand balance, demands for refinery fuel use, and capacity expansion.

PMM inputs include petroleum product demands, domestic crude oil production levels, and information on the costs and available quantities of imports of crude oil and petroleum products. In addition, the costs of refinery inputs such as natural gas and electricity are needed, as well as the costs and available quantities of blending components such as ethanol and methyl tertiary butyl ether (MTBE). Yield coefficients for crude oil distillation and other processing units, processing unit capacities, investment costs for capacity additions, capacities and costs for pipeline and other transportation modes, and product specifications are other essential model inputs.

From these inputs, PMM produces a slate of prices for petroleum products, the quantity of domestic crude oil production, imports of crude oil and petroleum products, estimates of other refinery inputs and processing gain, domestic refinery capacity expansion, and refinery fuel consumption.

The PMM is used to represent the petroleum refining and marketing sector in projections published in the *Annual Energy Outlook*. The model is also used for analysis of a wide variety of petroleum-related issues. The PMM is able to project the impact on refinery operations and on the marginal costs of refined products associated with changes in any demands for various kinds of petroleum products; crude oil prices; refinery processing unit capacities; changes in certain petroleum product specifications; energy policies and regulations; and taxes, tariffs, and subsidies. Since *AEO2002*, the model has been enhanced to incorporate new legislation

[1]The International Energy Model (IEM) contains representation for foreign refinery operations.

affecting product specifications or tax credits: such as the highway and nonroad ultra-low-sulfur diesel (ULSD) rules requiring 15 ppm diesel starting mid-2006; American Jobs Creation Act of 2004; and Energy Policy Act of 2005 (EPACT2005). Alternative fuels such as gas-to-liquids (GTL), coal-to-liquids (CTL), ethanol (corn and cellulose), and biodiesel are also represented in the model to reflect the growing potential for such fuels in transportation.

The PMM is comprised of five geographical regions, defined by the five Petroleum Administration for Defense Districts (PADDs). Individual refineries in each PADD are aggregated into one refinery representation for that region. Product demands are input at the Census Division level and end-use product prices are produced by Census Division. A transportation structure linking the PADD refining regions to the Census Division demand regions is also represented. The PMM produces annual projections from 2007 through 2030.

2.2 Relationship to Other Models

The PMM is part of the National Energy Modeling System (NEMS), representing the petroleum refining and marketing sector. The PMM projects prices and sources of supplies of petroleum products. These projections are generated as part of a NEMS supply/demand/price equilibrium solution. The PMM does not examine inventories or inventory changes between projection years.

Several other models in NEMS provide inputs to the PMM. These inputs include:

- Demands for petroleum products are provided by the Residential, Commercial, Industrial, Transportation, and Electricity Market Models. The demands include motor gasoline, jet fuel, kerosene, heating oil, low- and ultra-low-sulfur diesel fuels, low- and high-sulfur residual fuel, liquefied petroleum gases (LPG), petrochemical feedstocks, petroleum coke, and other petroleum products.

- Imported crude oil and petroleum product supply curves are provided by the International Energy Model (IEM). The crude oil supply curves are provided for each of the five PADDs for five types of crude defined by sulfur and gravity characteristics. The prices on the crude oil supply curves are based on the world oil price, which is determined in the IEM. Petroleum product import supply curves are provided for conventional and reformulated gasoline, reformulated blendstock for Oxygenate Blending (RBOB), heating oil, low- and ultra-low-sulfur diesel fuels, jet fuel, low- and high-sulfur residual fuel, LPG, petrochemical feedstocks, methanol, and other petroleum including unfinished oils. This information is used to evaluate the tradeoff between domestic product production and imports.

- Domestic crude oil production levels are provided by the Oil and Gas Supply Module (OGSM). The crude oil is categorized into the same five types incorporated into the import supply curves. Natural gas liquids, which are among the non-crude inputs to refineries, are estimated using domestic natural gas production from the Natural Gas Transmission and Distribution Module (NGTDM).

- Natural gas and electricity prices are provided by the NGTDM and the Electricity Market Module (EMM), respectively. The PMM estimates the refinery consumption of these energy sources.

- Certain macroeconomic parameters from the Macroeconomic Activity Model (MAM). The Baa average corporate bond rate is used for the cost of debt calculation, and the 10-year Treasury note rate is used for the cost of equity calculation. Both rates are used in estimating the capital-related financial charges for refinery investments.

- The market shares of oxygenated, reformulated, conventional, and California specification gasoline are estimated offline and input to the PMM.[2] In a similar fashion, the shares of low- and ultra-low-sulfur diesel fuels and heating oil are provided to the PMM. The shares change over time, based on assumptions about market penetration (see Appendix F for more details), and applicable regulations such as the ultra-low-sulfur diesel (ULSD) rules for highway and nonroad diesel. By breaking gasoline and distillate into these categories, the PMM is able to account for additional costs of producing products that meet Clean Air Act (CAA), and Clean Air Act Amendments (CAAA) requirements.

- Cellulosic feedstock prices and quantities are provided by the Renewable Fuels Module (RFM).

The PMM also provides information to other NEMS modules. The output variables include petroleum product prices, petroleum supply sources, refinery fuel consumption, and capacity expansion.

Output variables include:

- Prices of petroleum products, passed to the Residential, Commercial, Industrial, Transportation, Electricity Market, and Natural Gas Transmission and Distribution Modules. The prices are used to estimate end-use demands for the various fuels.

- Supply balance quantities, including crude oil production, non-crude refinery inputs, and processing gain, provided for reporting purposes.

- Capacity expansion and utilization rates at refineries (mainly for reporting purposes).

- Fuel consumption from refineries. This information is passed on to the Industrial Demand Module for inclusion in the industrial sector totals. In addition, refinery combined heat and power (CHP) capacity and generation levels are also sent to the Industrial Demand Module.

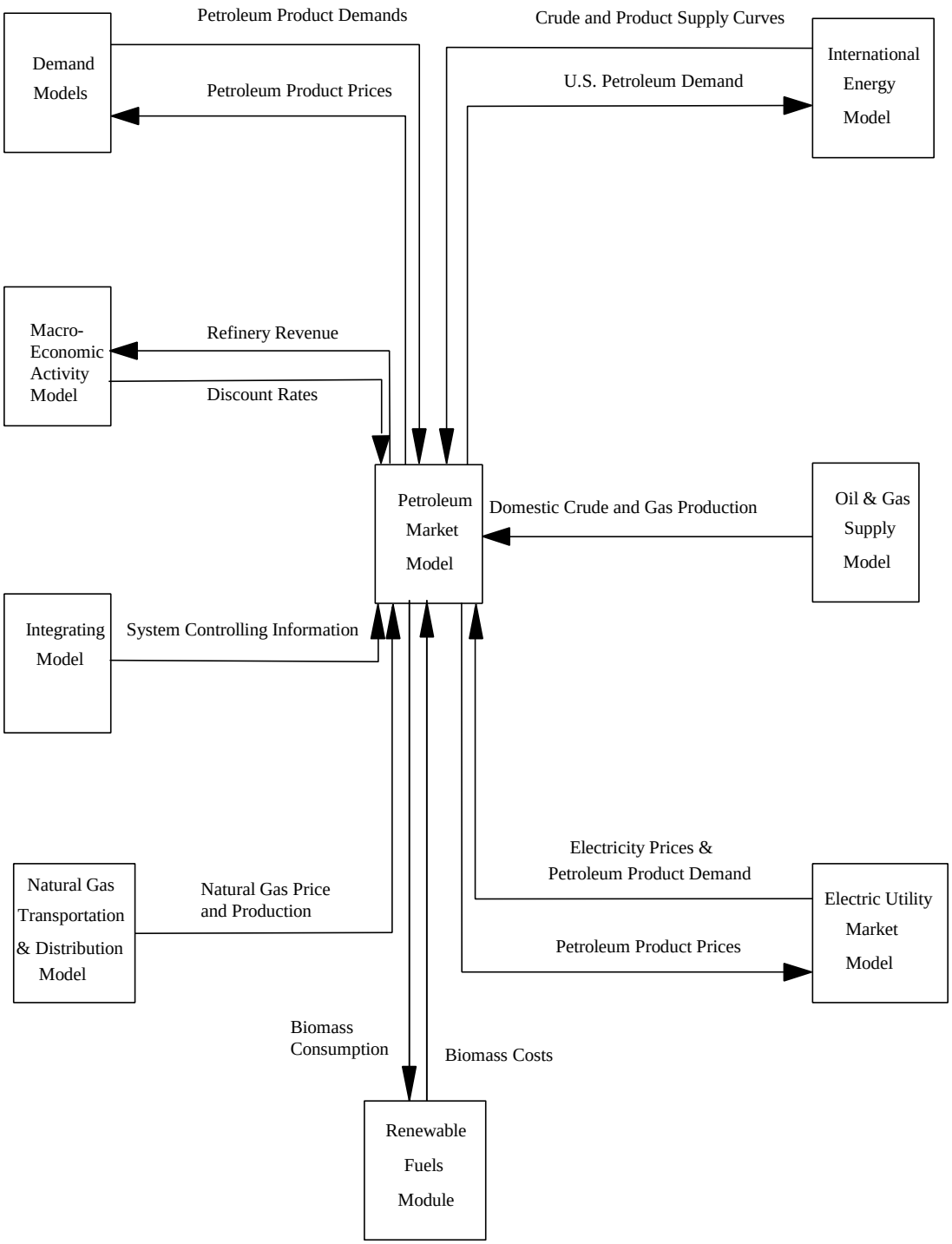
- The market prices and consumption of ethanol and methanol.

- Cellulosic feedstock consumption.

Figure 2.1 provides a detailed PMM Input/Output flow diagram.

[2] The splits of oxygenated, reformulated and other types of gasoline are computed from state level volumetric sales as reported in the *Petroleum Marketing Monthly*.

Figure 2.1 PMM Input – Output Flow Diagram



3. Model Overview and Rationale

3.1 Theoretical Approach

The National Energy Modeling System (NEMS) iteratively produces a general energy-economy equilibrium solution for quantities and prices of fuels delivered at end-use. The solution algorithm is iterative because the model is very large. For example, the various demand modules use the petroleum product prices from PMM to estimate product demands. The PMM then takes the petroleum product demands as given, and estimates petroleum product prices. When successive solutions of energy quantities demanded and delivered prices are within a pre-specified percentage (convergence tolerance), the NEMS solution is declared converged. If the computed prices have not converged, new demand quantities are computed, passed to PMM, and the cycle is repeated. This process continues until a converged solution is found. See the description of the integrating module for NEMS for a more complete description of the iterative process and convergence tests.

Within the PMM, the refinery sector is modeled by a linear program. A linear programming model is developed for five refining regions (Petroleum Administration for Defense Districts, or PADDs, I through V). Each model region represents an aggregation of the individual refineries in the region. The PMM linear programming model also contains a transportation structure to move crude oils to the refining regions and products from the refining regions to the Census Division demand regions. Because a single demand region can be supplied by more than one refining region (if the transportation connections exist), changes in one refining region can affect operations in other refining regions. An optimal solution is found by maximizing a proxy for net profits while meeting the demands in all 5 regions combined. Revenues are derived from prices and product sales in the previous iteration, and costs are incurred from the purchase and processing of raw materials and the transportation of finished products to the market. The refining activities are constrained by material balance requirements on the crude oil and intermediate streams, product specifications, processing and transportation capacities, and demand. Economic forces also govern the decision to import crude oil or refined products into the regions. See Appendix B for a complete description of the column activities and constraints.

3.2 Fundamental Assumptions

The PMM assumes the petroleum refining and marketing industry is competitive. The market will move toward lower-cost refiners who have access to crude oil and markets. The selection of crude oils, refinery process utilization, and logistics will adjust to minimize the overall cost of supplying the market with petroleum products. Although the petroleum market responds to pressures, it rarely strays from the underlying refining costs and economics for long periods of time. If petroleum product demand is unusually high in one region, the price will increase, driving down demand and providing economic incentives for bringing supplies

in from other regions, thus restoring the supply/demand balance. Because PMM is an annual model, it cannot be used to analyze intricate short-term petroleum market supply/demand/price issues.

The PMM represents five refining regions: PADDs I through V. Each refining region is treated as a single refinery. Because of how the PMM aggregates refineries, the model is not suited to analyze rationalization of small refineries. Rationalization can only be dealt with on a disaggregate basis. Capacity is allowed to expand, with some limitations, but the model does not distinguish between additions to existing refineries or the building of new facilities. Investment criteria and the decision to invest are endogenous. The model uses the best available information concerning future prices, demands, and market conditions as the basis for investment decisions.

Existing regulations concerning product types and specifications, the cost of environmental compliance, and Federal and State taxes are also modeled in the PMM.[1] The PMM reflects recent National and regional legislative and regulatory changes that will affect future petroleum supply and product prices. It incorporates taxes imposed by the 1993 Budget Reconciliation Act and the 1997 Tax Payer Relief Act, as well as costs resulting from the Clean Air Act Amendments (CAAA) of 1990 and other environmental legislation such as lowering the sulfur content in both gasoline and diesel. Recent legislations such as the American Jobs Creation Act of 2004 and the Energy Policy Act of 2005 are also included.

The costs of producing new formulations of gasoline and diesel fuel that are required by State and Federal regulations are determined within the linear programming (LP) representation by incorporating specifications and demands for these fuels. The PMM assumes that the specifications for gasoline will remain the same as specified in current legislation, except that the sulfur content of all gasoline will be phased down to 30 ppm to reflect new regulations published by EPA in February 2000.[2] The PMM includes a new type of ultra-low-sulfur diesel (ULSD, with a maximum cap of 15 ppm sulfur content) to represent the phase-in of USLD in both the highway diesel and the nonroad diesel in the next few years. Proposed fuel changes can be modeled by changing the specifications used by the PMM.

Motor Gasoline Specifications

The PMM models the production and distribution of four different types of gasoline: conventional, oxygenated, reformulated, and gasoline that meets California Air Resource Board (CARB) standards (referred herein as CARB gasoline). The following specifications are included in the 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).

[1] The PMM is an annual model. Thus, product specifications are modeled as annual averages, rather than taking into account the seasonal variations (particularly for gasoline specifications).
[3]U.S. EPA, *Tier2" Motor Vehicle Emissions Standards and Gasoline Sulfur Control Requirements*, Feb. 2000, Washington, D.C.

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 30 ppm in 2004. 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.

The specifications for conventional gasoline reflect the Environmental Protection Agency's (EPA) latest available survey data on gasoline properties.[3] 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. The PMM reflects "Phase 2" of the Complex Model requirements which began in 2000. The PMM uses a set of specifications that meet the Complex Model requirements, but it does not attempt to determine the optimal specifications that meet the Complex Model. In addition, *AEO2006* also reflects the "over-compliance" nature of gasoline in general by adopting the EPA survey of RFG properties in 2003.[5] 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 "CARB3" requirements.

AEO2006 reflects legislation which bans or limits the use of MTBE in 24 additional States: Arizona, 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. The oxygen requirement on RFG is no longer required after the passage of the Energy Policy Act of 2005 so the decision to keep blending oxygenate in RFG would be largely based on the economics between the oxygenate and other gasoline blending components. Furthermore, MTBE is assumed to phase out by the end of 2008 as a result of Energy Policy Act of 2005 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.

[3] *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

Except for California, the PMM assumes that ethanol is blended into RFG at 10 percent per volume where MTBE is banned. In California, 5.7 percent per volume of ethanol is assumed for RFG due to stricter CARB gasoline specifications.

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 gasoline 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.

RVP limitations are effective during summer months, which are defined differently in different regions. In addition, different RVP specifications apply within each refining region, or PADD. The PMM assumes that these variations in RVP are captured in the annual average specifications, which are based on summer RVP limits, winter RVP estimates, and seasonal weights.

Motor Gasoline Market Shares

Within the PMM, total gasoline demand is disaggregated into demand for conventional, oxygenated, reformulated, and CARB gasolines by applying user-specified 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 2004 level, with minor adjustments reflecting known changes in oxygenated or reformulated gasoline programs.

In Census Division 9, 60 percent of gasoline is assumed to be reformulated. Starting in 2004 when MTBE was banned in California, this portion of reformulated gasoline is broken out into two groups: CARB gasoline that does not require compliance to the Federal RFG program and gasoline in the four areas of California covered by the Federal RFG program (Los Angeles, San Diego, Sacramento, and San Joaquin Valley). 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 CARB standards.

Although the shares are assumed to remain constant after 2006, the PMM structure allows for them to change over time based 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.

Diesel Fuel Specifications and Market Shares

In order to account for CAAA90 diesel desulfurization regulations, current highway-grade diesel is differentiated from other distillates. Diesel fuel 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.[4] Diesel fuel in Census Division 9 is assumed to meet CARB standards which limit sulfur content to 500 ppm and aromatics to 10 percent by volume.[5]

A second type of "cleaner" diesel has been incorporated into PMM to model "ultra-low-sulfur diesel" (ULSD) regulations issued in January 2001 for highway applications and in June 2004 for nonroad applications.[6] By definition ULSD is diesel that contains no more than 15 parts per million (ppm) of sulfur at the pump. The regulation contains an "80/20" rule which 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. Nonroad applications, which also contain separate provisions for locomotive and for marine applications, are on a separate timeline from 2010 to 2014. The nonroad implementation schedule is more fully described in Section F.8. Because NEMS is an annual average model, the full impact of the 80/20 rule cannot be seen until 2007 and the impact of the 100 percent requirement cannot be seen until 2011 for highway diesel. Similarly, full impacts for nonroad applications correspond to that individual staggered phase-in schedule. Major assumptions related to implementation of the ULSD rules include:

- Highway diesel at the refinery gate will contain a maximum of 7.5 ppm sulfur starting in 2006, then phasing down to 7 ppm by 2010. Although sulfur content is limited to 15 ppm at the pump, there is a general consensus that refineries will need to produce diesel below 10 ppm in order to allow for contamination during the pipeline distribution process.

- The amount of ULSD downgraded to a lower value product because of sulfur contamination in the distribution system is assumed to be 10 percent at the onset of the program, declining to 4.4 percent at full implementation. The decline reflects an expectation that, with experience, the distribution system will become more efficient at handling ULSD.

- The PMM has been recalibrated to reflect individual fuel uses for 500 and 15 ppm distillate fuels in the various market sectors including highway, commercial, and industrial, and key subsectors including nonroad, farm, locomotive, marine, and military.

- ULSD production is modeled through improved distillate hydrotreating. Revamping (retrofitting) existing units to produce ULSD would be undertaken by refineries representing two-thirds of highway diesel production; the remaining refineries would build new units. The capital cost of a revamp is assumed to be 50 percent of the cost of adding a new unit.

- There is no significant change in the sulfur level of nonroad diesel compared to highway diesel over the long term other than residential heating oil which is allowed to retain high sulfur concentrations but represents a small market share. The EPA has finalized nonroad diesel standards which effectively

[6]Federal regulations require either a maximum 35 percent (volume) aromatics or a cetane index of 40.

[7]http://www.arb.ca.gov/fuels/diesel/diesel.htm

[6] U.S. Environmental Protection Agency, Control of Emissions of Air Pollution From Nonroad Diesel Engines and Fuel; Final Rule, 40 CFR Parts 9, 69, et al., June 29, 2004.

parallel highway standards but lag by several years in implementation time.

End-Use Product Prices

End-use petroleum product prices are based on marginal costs of production, plus transportation costs, distribution costs, and taxes on transportation fuels. The marginal costs of production are determined by the model and represent both fixed and variable costs of production including additional costs for meeting Tier 2 gasoline and ULSD regulations. Investments related to reducing emissions at refineries are represented in other variable costs (OVCs) associated with each refining unit.

The costs of distributing and marketing petroleum products are represented by adding distribution costs to the wholesale prices of products. The distribution costs are applied at the Census Division level and are assumed to be constant throughout the forecast and across scenarios. Distribution costs for each product, sector, and Census Division represent average historical differences between end-use (excluding taxes) and wholesale prices. The costs for kerosene are the average difference between end-use prices of kerosene and wholesale distillate prices. Additional distribution costs are added to the historical average diesel costs to account for increase capital and operating costs related to ULSD requirements. End-use prices also include a variable which calibrates model results to historical levels. The calibration variable is specified by product and region.

State and Federal taxes are also added to transportation fuels to determine final end-use prices. Tax trend analysis indicated that State taxes increase at the rate of inflation, while Federal taxes do not.[7] In the PMM, therefore, State taxes are held constant in real terms throughout the forecast while Federal taxes are deflated at the rate of inflation. The local taxes of transportation fuels are assumed to be a small percentage of the wholesale fuel prices that are updated every year.

Crude Oil Quality

In the PMM, the quality of crude oil is characterized by average gravity and sulfur levels. Both domestic and imported crude oils are divided into five categories as defined by the ranges of gravity and sulfur shown in Table A2 in Appendix A. A composite crude oil with the appropriate yields and qualities is developed for each category by averaging the characteristics of specific crude oil streams that fall into each category. While the domestic and foreign crude types have the same definitions, the composite crude oils for each category may differ because different crude streams make up the composites. For domestic crude oil, an estimate of total production is made first, then shared out to each of the five categories based on historical data. For imported crude oil, a separate supply curve is provided for each of the five categories.

Regional Assumptions

[7] Energy Information Administration, *Issues in Midterm Analysis and Forecasting 1998 – Motor Fuels Tax Trends and Assumptions*, by Stacy Macintyre.

The PMM includes five refining regions, representing the five Petroleum Administration for Defense Districts (PADDs). Individual refineries are aggregated into one linear programming representation for each region. In order to interact with other NEMS modules with different regional representations, certain PMM inputs and outputs are converted from a PMM region to a non-PMM regional structure and vice versa.

Capacity Expansion Assumptions

PMM allows for capacity expansion of all processing units including distillation capacity, vacuum distillation, hydrotreating, coking, fluid catalytic cracking, hydrocracking, alkylation, and MTBE manufacture. Capacity expansion occurs by processing unit, starting from base year capacities established from historical data for each region. Expansion of the atmospheric crude unit (ACU) is limited to 2.8 million barrels per day in each refining region through 2030.

Expansion proceeds in the PMM when the value received from the additional product sales exceeds the investment and operating costs of the new unit. The investment hurdle rate for a new unit build is calculated by the weighted average of 40 percent debt to 60 percent equity financing. The cost of equity is assumed to be the 10-year Treasury note rates plus a "risk premium and the cost of debt is determined by forecast of the Moody's Baa Industrial bond rate (IBR) reported by the Macroeconomic Activity Model in the year of the build decision. The operational rate of return is determined in the same manner. Investment for gasification technologies is calculated at 8.5 percent for debt and 17 percent for equity because of the higher economic risks involved. These variables may be adjusted for sensitivity analysis, and the assumed hurdle rate and the rate of return may be different. Investment calculations are more fully described in Appendix F.

Capacity expansion is done in 3-year increments. For example, the PMM looks ahead in 2004 and determines the optimal capacities needed to meet the expected petroleum product demands and expected prices for the 2007 forecast year. The PMM then allows one-third of that capacity to be built in each of the forecast years 2005, 2006, and 2007. At the end of 2007, the cycle begins anew, looking ahead to 2010. AEO2006 was also benchmarked to the September 2005 Short-Term Energy Outlook (STEO) and STEO forecasts for 2005 and 2006 were used to overwrite PMM projections for those two years.

Strategic Petroleum Reserve Fill Rate

The PMM assumes no additions for the Strategic Petroleum Reserve (SPR) during the forecast period. Any SPR draw is assumed to be in the form of a swap with a zero net annual change. However, additions to the SPR could be made for sensitivity analysis.

Legislation

The PMM reflects recent national and regional legislative and regulatory changes that will affect future petroleum supply and product prices. It incorporates taxes imposed by the 1993 Budget Reconciliation Act and the 1997 Tax Payer Relief Act, as well as costs resulting from environmental legislation.

The Budget Reconciliation Act imposes a tax increase of 4.3 cents per gallon on transportation fuels including gasoline, diesel, liquefied petroleum gases, and jet fuel. The tax has been in effect since October 1, 1993, for all fuels but jet fuel. Onset of the jet fuel tax was delayed until 1996. The American Jobs Creation Act of 2004 signed into law in October 2004, however, will phase out the 4.3 cent fuel tax on railroads and inland waterway transportation between January 1, 2005, and January 1, 2007. AEO2006 reflects the ongoing absence of these excise taxes into the future.

The Tax Payer Relief Act of 1997 reduced excise taxes on liquefied petroleum gases and methanol produced from natural gas. The reductions set taxes on these products equal to the Federal gasoline tax in terms of energy content (in Btu's).

With a goal of reducing tailpipe emissions in areas failing to meet Federal air quality standards (nonattainment areas), Title II of the CAAA90 established regulations for gasoline formulation. Starting in November 1992, gasoline sold during the winter in carbon monoxide nonattainment areas was required to be oxygenated.[8] Starting in 1995, gasoline sold in major U.S. cities which are the most severe ozone nonattainment areas must be reformulated to reduce volatile organic compounds (which contribute to ozone formation) and toxic air pollutants, as well as meet a number of other new specifications. Additional areas with less severe ozone problems have chosen to "opt- in" to the reformulated gasoline requirement. Since 1998 reformulated gasoline has been required to meet a performance based definition, "the Complex Model." The more stringent "Phase 2" Complex Model performance measures have been in effect since January 2000.

Title II of the CAAA90 also established regulations on the sulfur and aromatics content of diesel fuel that took effect on October 1, 1993. All diesel fuel sold for use on highways now contains less sulfur and meets new aromatics or cetane level standards.

"Tier2" Motor Vehicle Emissions Standards and Gasoline Sulfur Control Requirements were finalized by EPA in February 2000. This regulation requires that the average annual sulfur content of all gasoline used in the United States be phased-down to 30 ppm between the years 2004 and 2007. The 30 ppm annual average standard is not fully realized in conventional gasoline until 2008 due to allowances for small refineries.

The Federal Highway Bill of 1998 extended the current tax credit for ethanol through 2007 but stipulated that the 52 cents per gallon credit be reduced to 51 cents in 2005. The American Jobs Creation Act of 2004 extended the ethanol tax credit until 2010. The Act also instituted income tax credits for biodiesel blending until 2006, which was again extended by the Energy Policy Act of 2005 to 2008. Both provisions are modeled

[8]Oxygenated gasoline must contain an oxygen content of 2.7 percent by weight.

in the PMM. The PMM reflects an assumption that the ethanol credit will be extended at the nominal level of 51 cents per gallon through 2030.

A number of pieces of legislation are aimed at controlling air, water, and waste emissions from refineries themselves. The PMM incorporates related environmental investments as refinery fixed costs. The estimated expenditures are based on results of the 1993 National Petroleum Council Study.[9] These investments reflect compliance with Titles I, III, and V of CAAA90, the Clean Water Act, the Resource Conservation and Recovery Act, and anticipated regulations including the phase out of hydrofluoric acid and a broad-based requirement for corrective action. No costs for remediation beyond the refinery site are included.

AEO2006 represents major provisions in the Energy Policy Act of 2005 concerning the petroleum industry, including: 1) 7.5 billion gallons of renewable fuels (mostly ethanol) by 2012; 2) removal of oxygenate requirement in RFG; and 3) extension of tax credit of $1 per gallon for soybean oil biodiesel and $0.50 per gallon for yellow grease biodiesel through 2008.

[9]National Petroleum Council, *U.S. Petroleum Refining - Meeting Requirements for Cleaner Fuels and Refineries*, Volume I (Washington, DC, August 1993).

4. Model Structure

During each NEMS iterative solution, product demand quantities and other variables supplied by the other NEMS demand and supply modules are used to update the PMM linear programming (LP) matrix. An optimal solution is obtained from the updated LP matrix where marginal petroleum product prices and other material balance information are extracted. Post-processing takes place on the petroleum product prices and refinery input and output volumes, system variables are updated, and reports are produced. The modification and optimization of the PMM LP matrix are both accomplished by executing FORTRAN callable LP subroutines available from a LP subroutine library. Appendix B describes the formulation of the linear programming representation in the PMM.

The linear programming portion of PMM is prepared offline in the form of an MPS[1] file prior to NEMS processing. Offline generation of the PMM matrix is performed using a data-driven mathematical programming language. The control program and optimizer are compatible with the MPS matrix format. FORTRAN and FORTRAN callable subroutines for data table manipulation, matrix generation, and solution retrieval programs for report writing are currently being used. Appendix A describes the input data tables used to develop the input LP matrix of the PMM. Appendix G documents the LP matrix generator source code and data tables.

The REFINE subroutine is the main controlling subroutine for the PMM. The following paragraph describes the REFINE process flow, which is illustrated by Figures 4.1 through 4.5. The flow diagrams use descriptive text and make reference to PMM FORTRAN subroutine names, which are described in detail in sections 4.1 through 4.4. Additionally, the REFINE calls the ETHANOL subroutine, which provides the PMM with supply curves for ethanol and biodiesel. The ETHANOL subroutine is documented in Appendix I.

The REFINE subroutine initializes variables and reads fixed data during the first year and first iteration of any NEMS run (Figure 4.1). The subroutine then follows one of five branches depending on the type of NEMS iteration as follows:

- **(Setup)** If the history switch is on and it is the first year and first iteration, historical values are read and the LP matrix is loaded into memory to await processing in the PMM base year.

- **(History Year)[2]** If the history switch (a FORTRAN conditional variable) is on and it is a historical year after the first year and first iteration, then the PMM performs no operations but simply returns to the NEMS system operations. No operations are performed because all historical data were retrieved and variables were updated on the first iteration of the first year.

[1]Mathematical Programming System (MPS) is proprietary to Ketron Management Science, which provides the optimizer and FORTRAN callable library used by the PMM.

[2] For *AEO2006*, year 2007 and earlier are historical years.

- **(Iterative NEMS Solution)** If the history switch is on, it is not a historical year, and it is not a reporting iteration; or if the history switch is off and it is not a reporting iteration; then the PMM LP matrix is updated with data from other NEMS models and static PMM input data variables and an optimal solution is calculated (Figures 4.1, 4.2, 4.3, and 4.5). Petroleum product prices and other PMM output data are retrieved from the LP optimal solutions and output variables are updated.

- **(Reporting/Capacity Expansion)** If it is a reporting iteration, the history switch is on, and it is not a historical year; or if it is a reporting iteration and the history switch is off; then several internal PMM analyst reports are updated. If it is also a capacity expansion year, then the PMM LP is solved using input data representing expectation values for a future year to determine processing unit expansion for the intervening years (Figures 4.1, 4.4, and 4.5). The capacity expansion methodology is described in more detail below.

- **(Pre-Base Year Capacity Expansion)** If it is a reporting iteration, the Short Term Energy Outlook (STEO) benchmarking switch is on, and it is NEMS year 15 (2004); then the PMM LP is solved using input data representing expectation values for a future year to determine processing unit expansion for the intervening years (Figures 4.1 and 4.4).

Capacity Expansion Methodology

PMM models capacity expansion for all the refinery processing units which include but are not limited to distillation capacity, vacuum distillation, hydrotreating, coking, fluid catalytic cracking, hydrocracking, alkylation, and ether manufacture. Capacity expansion occurs by processing unit, starting from base year capacities established for each PADD using historical data. Expansion is determined by the LP when the value received from the additional product sales exceeds the investment and operating costs of the new unit. The investment costs are based on a 20-year plant life and a rate of return calculated by assuming 60 percent equity and 40 percent debt. For more details on the calculation of the investment costs, refer to Appendix F.1 on Refinery Investment Recovery Factors.

Capacities in 2004 are determined by the existing capacities, and for 2005 and 2006 are benchmarked to EIA's September 2005 Short-Term Energy Outlook (STEO). Typically, the capacity expansion in the PMM is done in 3-year increments. The PMM looks ahead in a particular year and determines the optimal capacities given the estimated demands and prices expected three years into the future. The PMM then allows one-third of that capacity to be built in each of three future forecast years.[3] At the end of the third year the cycle begins anew.

[3]The capacity expansion rates for select processing units were adjusted to be consistent with applicable regulatory requirements such as the Ultra-Low-Sulfur Diesel Rule.

Figure 4.1 PMM Flow Diagram

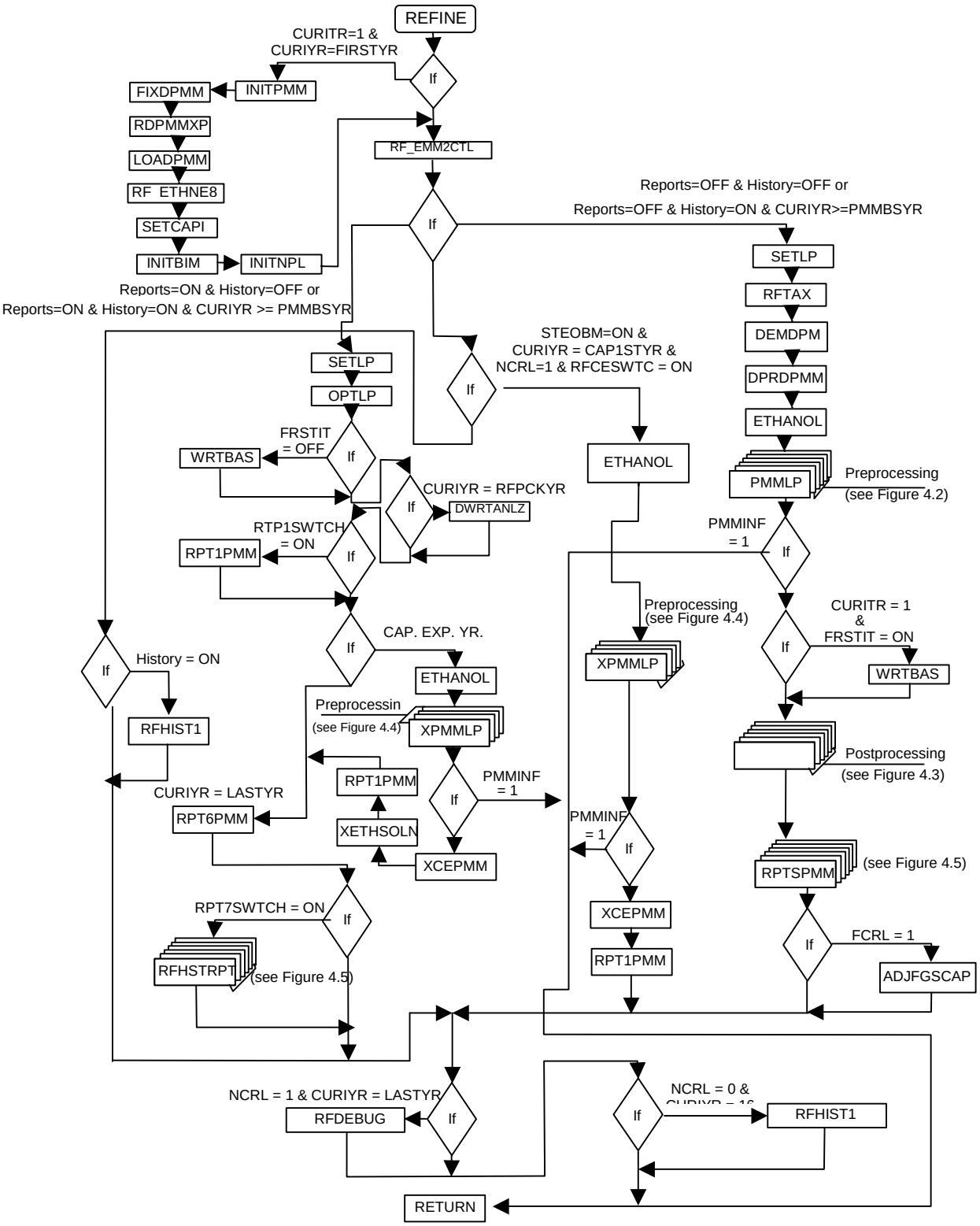


Figure 4.2 Matrix Preprocessing Subroutines (PMMLP)

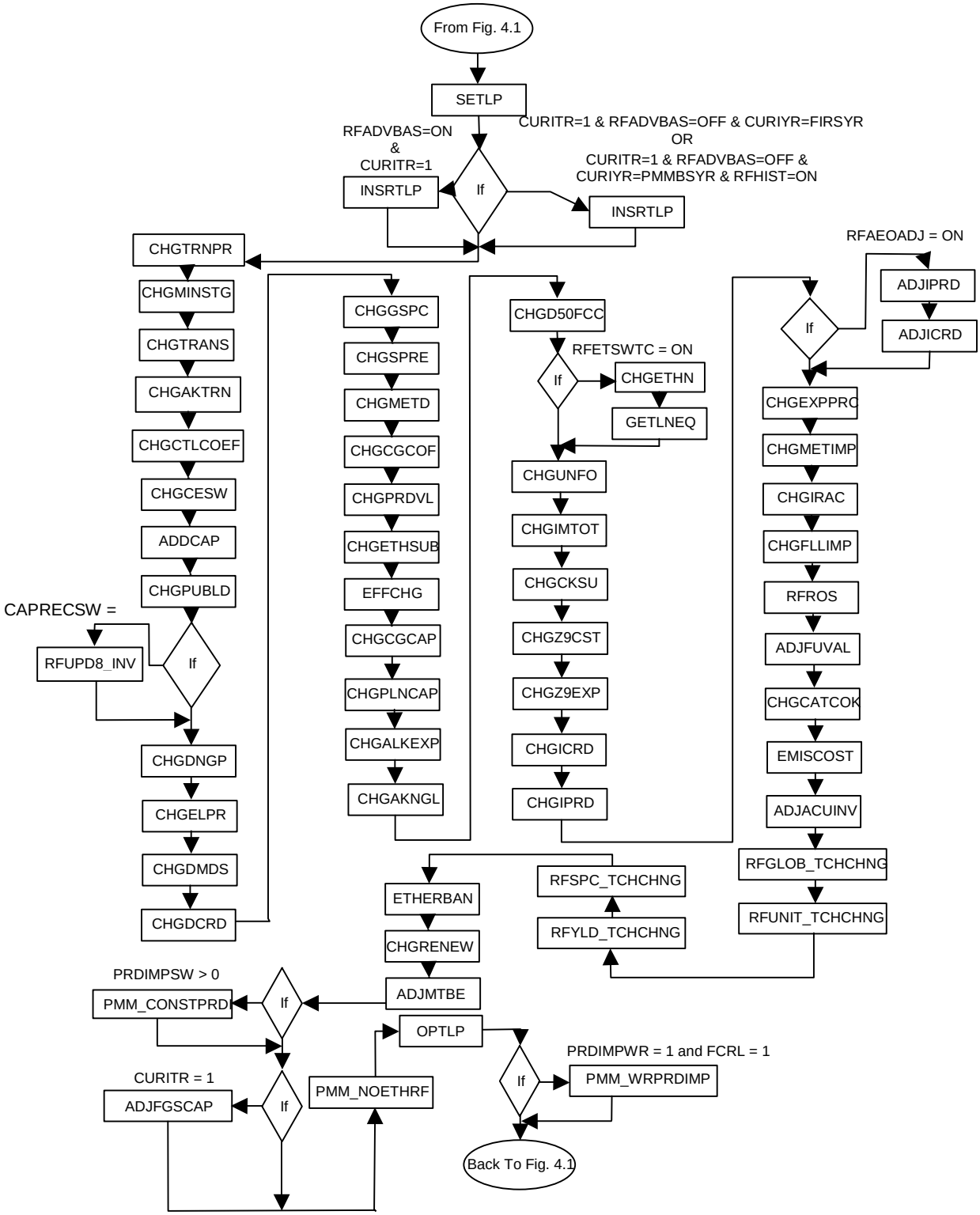


Figure 4.3 Matrix Postprocessing Subroutines

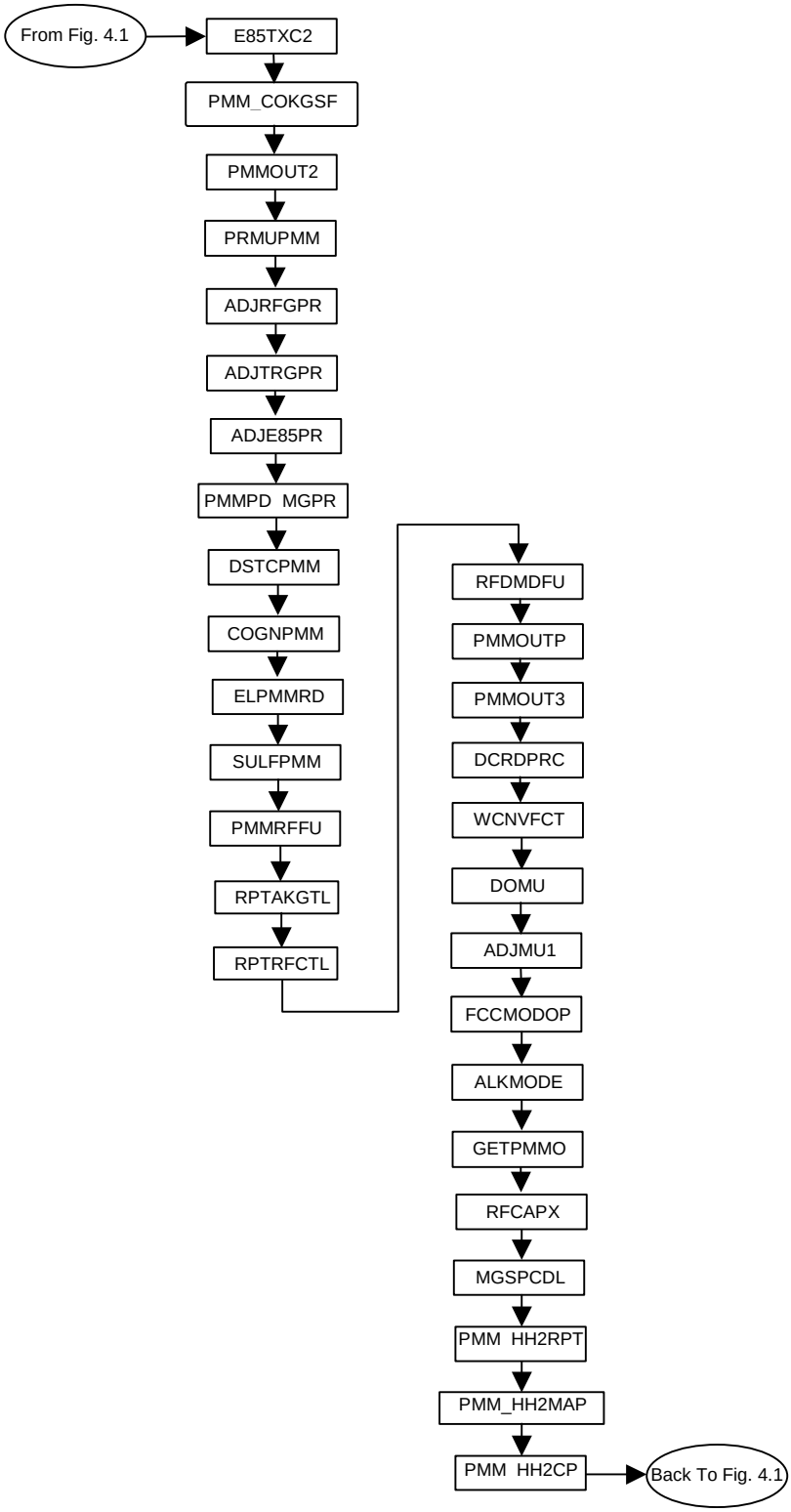


Figure 4.4 Capacity Expansion Subroutines (XPMMLP)

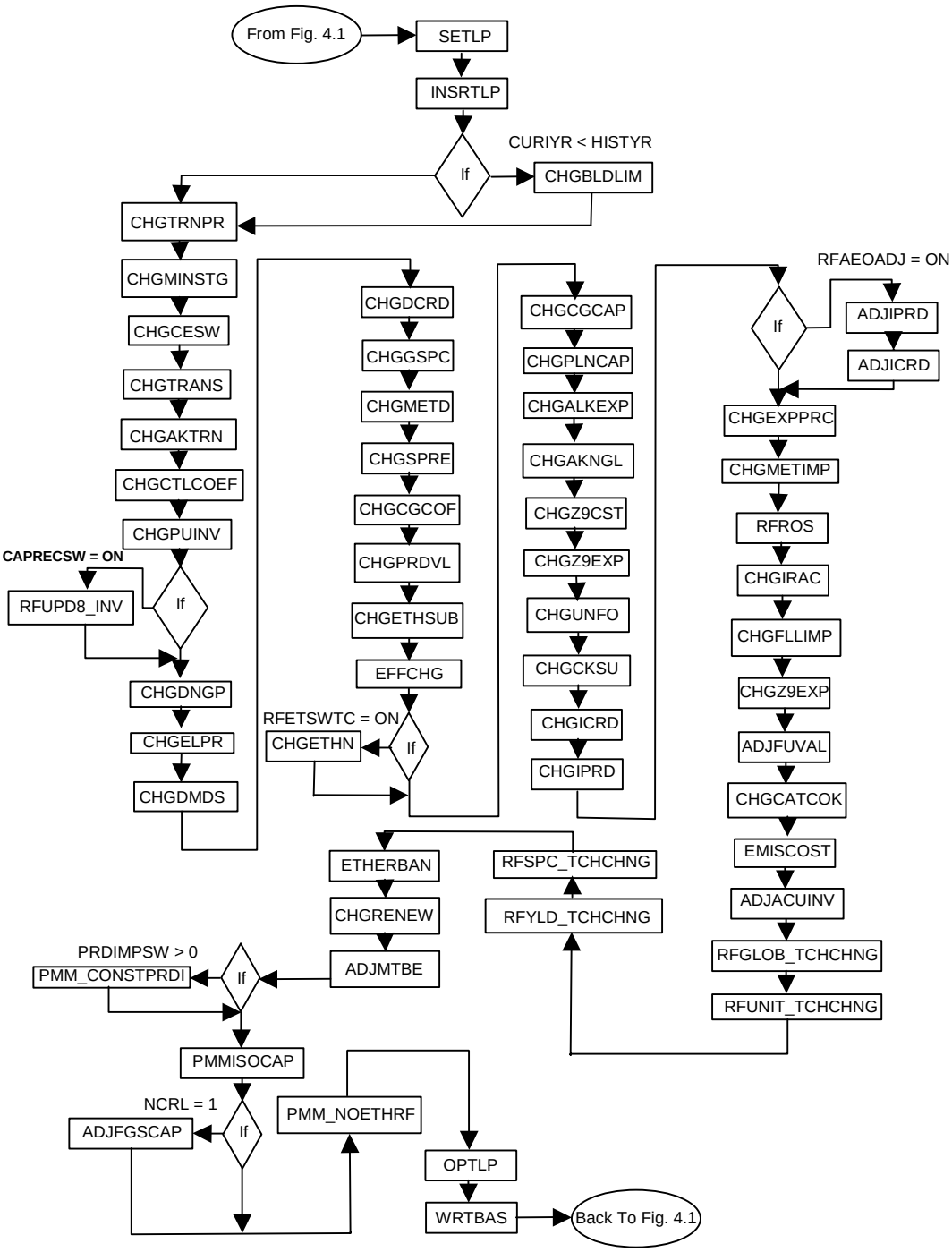
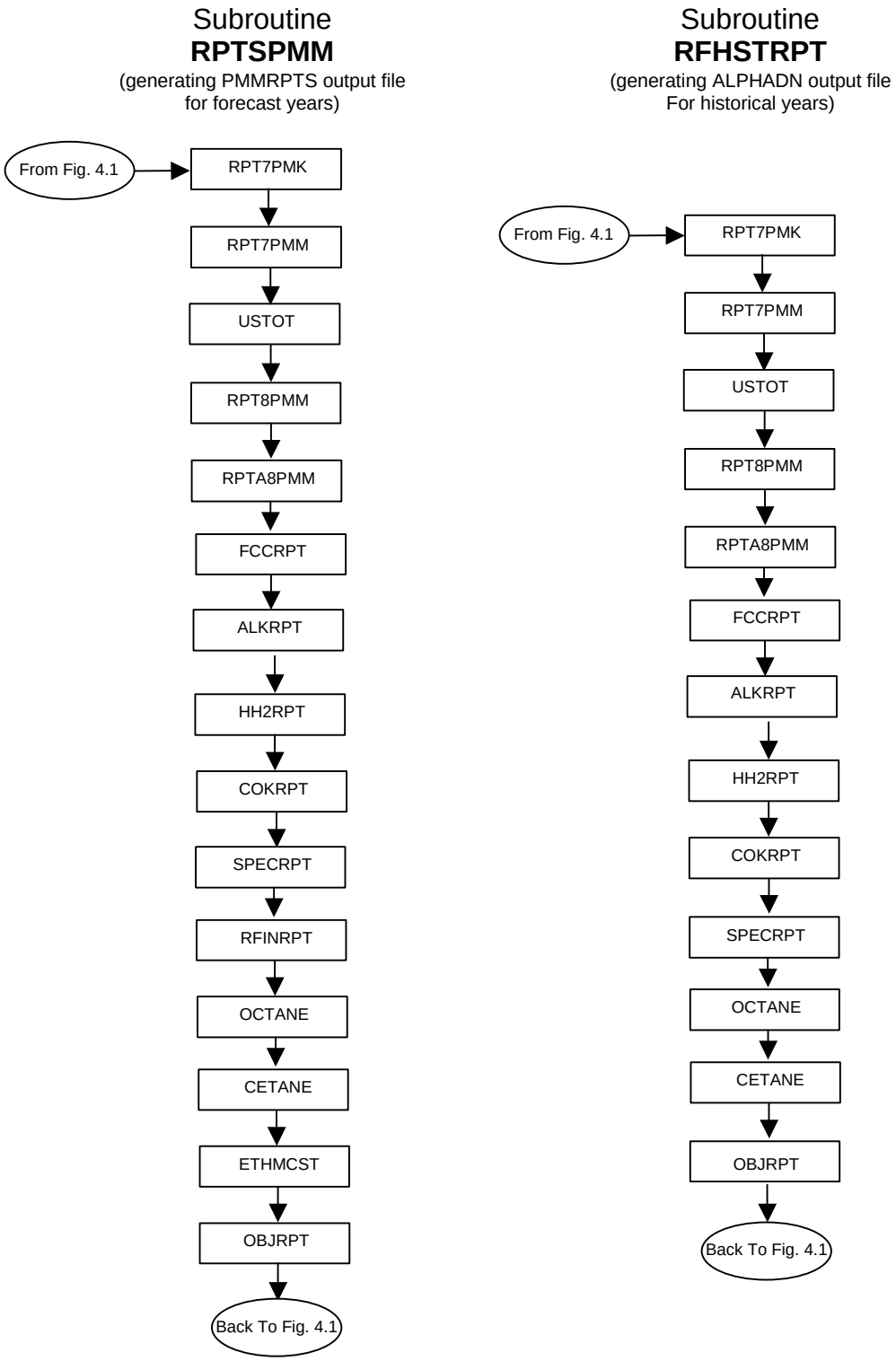


Figure 4.5 Report Subroutines



4.1 Main Subroutines

Section 4.1 describes the functions of the subroutines in Figure 4.1, the main controlling subroutines.

(REFINE) Main controlling subroutine for the PMM.

Purpose: REFINE is the driver subroutine for the PMM. It uses basic FORTRAN controlling structure, NEMS integrating model common variables, and PMM internal variables to set up and process the PMM LP and to update NEMS variables based on an optimal LP solution.

Equations:

```
CAPYR1ST    = 15              ! 1st model yr for capacity expansion
BLDPD       = 3               ! number of yrs btwn capacity expansion
NEMSYR1     = 1990            ! NEMS 1st model year
CFN2HQ      = CFDSQ                 ! init conv fac for heating oil
CFDSLQ      = 0.993 *CFN2HQ         ! init conv fac for low S diesel
CFDSUQ      = 0.995 *CFDSLQ         ! init conv fac for ultra-low-sulfur diesel
CFETQ       = 3.50                  ! conv fac for E85
CFMEQT      = 2.70                  ! conv fac for M85
```

(INITPMM) Initialize variables.

Purpose: Opens PMM iteration report file and PMM solution print file, and initializes certain variables.

Equations:

$QBMET_{cd,yr} = 0.0$
$PUCUM_{pd,pu,yr} = 0.0$
$PUINV_{pd,pu,yr} = 0.0$
$RFQDINPTOT_{pd,yr} = 0.0$
$PRDDMD_{pd,yr,pr} = 0.0$
$CRDOTHOT_{pd,yr} = 0.0$
$CRDUNACC_{pd,yr} = 0.0$
$CRDSTWDR_{pd,yr} = 0.0$
$CRDPRDSUP_{pd,yr} = 0.0$
$PRDSTKWDR_{pd,yr} = 0.0$
$BLDIMP_{pd,yr} = 0.0$
$QEXCRDIN_{pd,yr,pu} = 0.0$
$PUBASE_{pd,yr,pu} = 0.0$
$PUBASEUT_{pd,yr,pu} = 0.0$

$CFRGQ_{yr} = 5.253$	Conversion factor Reformulated Gasoline, MMBtu/Bbl
$CFTGQ_{yr} = 5.253$	Conversion factor Conventional Gasoline, MMBtu/Bbl
$CFDSRS_{yr} = CFDSQ$	initial conv factor for residential distillate
$CFDSCM_{yr} = CFDSQ$	initial conv factor for commercial distillate
$CFDSIN_{yr} = CFDSQ$	initial conv factor for industrial distillate
$CFDSTR_{yr} = CFDSQ$	initial conv factor for transportation distillate
$CFDSEL_{yr} = CFDSQ$	initial conv factor for elec utility distillate
$PETTR_{cd,6} = 10.95$	E85 price for history and STEO years, $/MMBtu
$PETTR_{cd,7} = 11.39$	
$PETTR_{cd,8} = 11.51$	
$PETTR_{cd,9} = 9.41$	
$PETTR_{cd,10} = 9.51$	
$PETTR_{cd,11} = 11.60$	
$PETTR_{cd,12} = 11.03$	
$PETTR_{cd,13} = 10.12$	
$PETTR_{cd,14} = 11.21$	
$PETTR_{cd,15} = 13.58$	
$PETTR_{cd,16} = 15.00$	
$PETTR_{cd,17} = 15.16$	
$PMETR_{cd,6} = 9.23$	M85 price for history and STEO years, $/MMBtu
$PMETR_{cd,7} = 8.33$	
$PMETR_{cd,8} = 9.87$	
$PMETR_{cd,9} = 6.63$	
$PMETR_{cd,10} = 7.71$	
$PMETR_{cd,11} = 9.99$	
$PMETR_{cd,12} = 9.99$	
$PMETR_{cd,13} = 9.99$	
$PMETR_{cd,14} = 9.99$	
$PMETR_{cd,15} = 9.99$	
$PMETR_{cd,16} = 9.99$	
$PMETR_{cd,17} = 9.99$	

where:

pd = 1,2,3,4,5: refinery regions (PADDs I, II, III, IV, V)
cd = 1,2,...11: Census Division, CA, and totals
pu = 1,2,...87: Processing unit identifier index
yr = 1,2,...41: NEMS year index
pr = 1,2,...24: PMM product identifier index

(FIXDPMM) Read fixed inputs.

Purpose: FIXDPMM reads in and initializes internal data required for processing the PMM. Also, calls subroutines RFREAD_TCHCHNG, RFREAD_BLDSPLT, RFREAD_INVST, and PMMREAD_PRDIMP to read specific data.

Equations: Add 2% locality tax to mogas tax data (transportation sector)

$MGMUTR_{pd,yr,2}=MGMUTR_{pd,yr,2}+ (PMGTR_{pd,yr}*.02)$

Historical $MUFTAX_{yr,pr}$

$MUFTAX_{5,1}=2.00$ (Nominal $/MMbtu)
$MUFTAX_{6,1}=2.00$
$MUFTAX_{7,1}=2.00$
$MUFTAX_{8,1}=2.00$
$MUFTAX_{1,2}=0.76$
$MUFTAX_{2,2}=1.13$
$MUFTAX_{3,2}=1.13$
$MUFTAX_{4,2}=1.21$
$MUFTAX_{5,2}=1.47$
$MUFTAX_{6,2}=1.47$
$MUFTAX_{7,2}=1.39$
$MUFTAX_{8,2}=1.47$
$MUFTAX_{7,3}=0.32$
$MUFTAX_{8,3}=0.32$
$MUFTAX_{1,10}=1.11$
$MUFTAX_{2,10}=1.45$
$MUFTAX_{3,10}=1.45$
$MUFTAX_{4,10}=1.52$
$MUFTAX_{5,10}=1.75$
$MUFTAX_{6,10}=1.75$
$MUFTAX_{7,10}=1.68$
$MUFTAX_{8,10}=1.75$

Input File:

MU1PRDS	Sectoral end-use markups
MU2PRDS	Tax input data
QDCRDCF	Fixed Data input file; includes control variables for ULSD and other rulings, capacity expansion signals, and definition of scenarios for special studies
RFINVEST	Investment Data input file; includes GTL and CTL unit data

(RFREAD_TCHCHNG) Read inputs.

Purpose: RFREAD_TCHCHNG reads user-specified technology improvements information.

Equations: None.

Input File: QDCRDCF Fixed Data input file; also allows definition of scenarios

(RFREAD_BLDSPLT) Read inputs.

Purpose: RFREAD_BLDSPLT reads information to define capacity expansion ratios for specified units during a 3-year expansion cycle.

Equations: None.

Input File: QDCRDCF Fixed Data input file; also allows definition of scenarios

(RFREAD_INVST) Read inputs.

Purpose: RFREAD_INVST reads refinery investment information, GTL and CTL input data, and some coefficient info for coke gasification processing.

Equations: None.

Input File: RFINVEST Fixed Data input file.

(PMMREAD_PRDIMP) Read inputs.

Purpose: PMMREAD_PRDIMP reads product import results from a previous run -- only if the scenario prescribes constant product imports.

Equations: None.

Input File: RFPRDIMP Fixed Data input file containing product imports, by year, region

(RDPMMXP) Read in the PMM specific expectation values from an input file.

Purpose: The RDPMMXP subroutine reads the SPRFLRT input file (which is generated from a previous PMM capacity expansion cycle) and updates PMM specific expectation values. These values are used for refinery capacity planning.

Equations: None.

Input file: SPRFLRT PMM specific expectations input file.

(LOADPMM) Set up the PMM LP for processing by the OML.

Purpose: This subroutine defines the Optimization Modeling Library (OML) model space for PMM LP matrix. Loads the PMM LP matrix into memory and initializes OML model specific variables.

Equations: None.

(RF_ETHNE85) Define percent ethanol and TRG in E85.

Purpose: Define variables ETHNE85 and TRGNE85 (% ethanol and % TRG in E85) to be consistent with coefficient used in the PMM LP matrix (column X(cd)ETHE85, row D(cd)ETH).

Equations: None.

(DEFLP) Define the OML LP matrix model space and initialize common control variables for a given model.

Purpose: Defines and OML LP matrix model space and initializes common control variables for a given model using the OML function WFDEF.

Equations: None.

Data Passed: MODEL, model name, SIZE, model size

(MPSINLP) Convert a model from the MPS format file and stores it in the model database.

Purpose: Converts a model from and MPS format file to an OML model format and stores it in the model database using the OML function WFMSPIN.

Equations: None.

(LOADLP) Load the LP model from the database into memory.

Purpose: Loads the LP model from the OML model database into memory and prepares it for optimization using the OML function WFLOAD.

Equations: None.

(SETCAPI) Set initial refinery unit capacity.

Purpose: SETCAPI retrieves the existing capacity value and puts it into a variable PMMCAPI. Lower bound set for ACU based on historical utilization. Also, processing units not allowed to build (as defined in the qdcrdcf.txt file) are initialized with upper bound on builds equal to zero.

Equations: None.

(INITBIM) Initialize the supply curve for biomass diesel.

Purpose: INITBIM initializes the biomass diesel supply to zero.

Equations: None.

(INITNPL) Set maximum flow of PGS from gas plant to CC1 and to LPG.

Purpose: Limit the transfer of PGS to CC1 and LPG at the gas plant to realistic, historical levels (25% of total PGS for each limit).

Equations: None.

(RFHIST1) Read in history data and STEO data for 1990 through 2005.

Purpose: RFHIST1 reads in history data from an external file and updates PMM output data for history years 1990 to 2004 and STEO years 2005 and 2006. Set consumption of electricity, natural gas, and coal at ethanol plant. Determine historical fuel use splits (nationally) at refineries and percent of refinery-generated electricity (CHP) sold to the grid. The historical data between 1990 and 1994 are not reported by the NEMS, however.

Equations: None.

Input File: ELCGPUR PMM historical data input file

(PMM_NEXTDATA) Advance file pointer one record.

Purpose: This subroutine is used to automate reading the historical data file. It advances the file pointer one record until the historical data record is located.

Equations: None.

(RF_EMM2CTL) Map cogenerated electricity transmission cost data from NERC regions to PADDs.

Purpose: RF_EMM2CTL maps the overnight and fixed charge factors associated with the cogenerated electricity transmission cost data from NERC to PADD regions.

Equations: None.

(RFTAX) Aggregate State and Federal petroleum product taxes.

Purpose: RFTAX aggregates the States' and Federal petroleum taxes.

Equations: Total petroleum product taxes are set equal to the State tax plus the nominal dollars federal tax.

(RFTAXHIST) Set historical State petroleum product taxes and national markups.

Purpose: RFTAXHIST sets historical States' petroleum taxes and national markups.

Equations: Regional and national petroleum product taxes are set based on State tax.

(DEMDPMM) Convert system demands.

Purpose: Convert NEMS demands from trillion Btu to thousands of barrels per day for input into the refinery LP. Disaggregate gasoline and distillate fuel into types. Calculate U.S. total petroleum product demand by sectors.

Equations: The conversion from trillion Btu to Mbbl/d is as follows:

$$PRDDMD_{cd,yr,pd} = (((Q(PR)AS_{cd,yr}-Q(FPR)RF_{cd,yr})/CF(PR)Q_{yr})/365)*1000 \quad (1)$$

The conversion from trillion Btu to MMbbl/d is captured in the following variables:

$$RFQ(PR)_{cd} = (Q(PR)AS_{cd,yr}/CF(PR)Q_{yr}) / 365 \quad (2)$$

The shares of M85 and E85 in motor vehicle use are also added to the total motor gasoline demands such that:

$$RFQMG_{cd} = ((QMGAS_{cd}+QMETR_{cd}*0.15+QETTR_{cd}*TRGNE85)/CFMGQ/ 365 \quad (3)$$

where;

PRDDMD = product demand by Census Division (Mbbl/d)
RFQ(PR) = product demand by Census Division (MMbbl/d)
Q(PR)AS = product demand in all sectors (Trill Btu/yr)
Q(FPR)RF = product consumed for refinery fuel (applies only to products LG, RL, RH, DS, PC, SG, and OT), (Trill Btu/yr)
CF(PR)Q = conversion factor (MMBtu/bbl)
(PR) = product types
(FPR) = refinery fuel products identifier
cd = Census Divisions 1 through 9
pd = refinery regions 1,2,3,4,5 (PADDs I, II, III, IV, V)
yr = forecast year
0.15 = Motor gasoline share of M85
TRGNE85 = Motor gasoline share of E85 (0.26 was used for annual E85 average)
365 = days per year
1000 = millions to thousands

Refinery fuel consumption, Q(FPR)RF, is subtracted from the product demands since the refinery model is designed to meet demand for saleable products. The variables RFQ(PR), Q(PR)AS, and Q(FPR)RF, and CF(PR)Q are defined explicitly in Appendix A 1.2, Refine Module Variables.

Four types of gasoline are derived from total gasoline demand by applying market share estimates:

$$PRDDMD_{cd,yr,t+1} = ((QMGAS_{cd,yr}/CFMGQCD) / 365 * 1000) * MGSHR_{yr,t,cd} \quad (4)$$

where;

PRDDMD = product demand by Census Division
CFMGQCD = average motor gasoline conversion factor (mmBTU/bbl)
t = motor gasoline product designator index (1,2,3,4)
MGSHR = motor gasoline market shares

Refer to Appendix F (F.7) for more information on the derivation of the gasoline market shares, MGSHR.

Heating oil, low-sulfur (500 ppm) diesel, and ultra-low-sulfur (15 ppm) diesel demands are determined as a share of regional distillate demand (using subroutines PMM_DIESEL and PMMPRDEXP), adjusted for expected downgrade contamination, as follows:

$$PRDDMD_{cd,yr,7} = DMDN2H_{cd,yr} - DSULOS \quad \text{! heating oil} \quad (5)$$

$$PRDDMD_{cd,yr,13} = DMDDSL_{cd,yr} \quad \text{! DSL}$$
$$PRDDMD_{cd,yr,24} = DMDDSU_{cd,yr} + DSULOS \quad \text{! DSU}$$

$$DSULOS = DMDDSU_{cd,yr} + PEXPDS_{cd,yr} * PCT\_DWNGRD_{yr} / (1. - PCT\_ DWNGRD_{yr}) \quad \text{! adj due to downgrade}$$

where:

PRDDMD = product demand (M bbl/cd)
7, 13, 24 = product index for heating oil, low S diesel (DSL), ultra-low-sulfur diesel (DSU)
$DMDDSU_{cd,yr}$ = Actual ultra-low-sulfur diesel demand (M bbl/cd)
$DMDDSL_{cd,yr}$ = Actual low-sulfur diesel demand (M bbl/cd)
$DMDN2H_{cd,yr}$ = Actual heating oil demand (M bbl/cd)
DSULOS = adjustment due to expected downgrade (M bbl/cd)
PCT_DWNGRD_{yr} = expected percent downgrade (fraction)

Methanol consumed in the transportation sector is assumed to be a blend of 85 percent methanol and 15 percent gasoline. E85 is assumed to be a blend of 74 percent ethanol (ETHNE85) and 26 percent gasoline (TRGNE85) from the annual average when taking into account the wintermonths' drivability consideration which requires more gasoline blending than 15 percent. Therefore, the demands for transportation ethanol and methanol in the PMM use the respective percentages of total transportation alcohol demands, with the balance percentages of the total transportation alcohol demands added to gasoline demand.

Finally, U.S. totals are calculated:

$$PRDDMD_{11,yr,pr} = \Sigma\, PRDDMD_{cd,yr,pr} \quad (6)$$

where;

11 = total U.S. demand index
pr = product index 1 through 24
cd = Census divisions 1 through 9
yr = NEMS year index 1 through 41

(PMM_DIESEL) Disaggregate distillate demand into heating oil, low S diesel, and ultra-low-sulfur diesel demands.

Purpose: Use historical demand splits to define heating oil, low S diesel, and ultra-low-sulfur diesel demands from regional distillate demand totals provided by the demand models. Set

average heat content of distillate by sector. (Refer to Appendix F-9, Estimation of Diesel Market Shares, for more details.)

Equations:

Use QDCRDCF.txt input data to split regional distillate demand totals into sector and fuel type (i.e., non-road diesel to commercial sector, heating oil fuel to residential sector, etc.). The data from the qdcrdcf.txt file are:

HOFTRN	HOFIND	HOFCOM
OLMTRN	OLMIND	OLMCOM
ONRTRN	ONRIND	ONRCOM
HWYTRN	HWYIND	HWYCOM
N2HPCT_OLM	DSLPCT_OLM	DSUPCT_OLM
N2HPCT_ONR	DSLPCT_ONR	DSUPCT_ONR
N2HPCT_HWY	DSLPCT_HWY	DSUPCT_HWY

Where,

HOF = heating oil fuel
OLM = off-road Locomotive and Marine fuel
ONR = off-road non-road fuel
HWY = highway (on-road) fuel
TRN = transportation sector
IND = industrial sector
COM = commercial sector
N2H = heating oil
DSL = low-sulfur diesel
DSU = ultra-low-sulfur diesel

(DPRDPMM) Update domestic crude wellhead price and gas plant fuel consumption.

Purpose: Update domestic crude wellhead price and gas plant fuel consumption for the Oil and Gas Supply Model and Natural Gas Transmission and Distribution Model.

Equations: Percent of NG production consumed as fuel at gas plant for forecast years through 2025, for PADDs I-V,

$PCTPLT\_PADD_{1,yr} = 1.24$
$PCTPLT\_PADD_{2,yr} = 2.27$
$PCTPLT\_PADD_{3,yr} = 2.31$
$PCTPLT\_PADD_{4,yr} = 2.72$
$PCTPLT\_PADD_{5,yr} = 4.84$

(ETHANOL) Calculate the ethanol supply and biodiesel supply step functions.

Purpose: Calculates the ethanol supply step functions for both corn and biomass based ethanol. Ethanol is used in the manufacture of gasoline, E85, and ETBE. Also determines the biodiesel supply step function for virgin (soybean oil) and non-virgin (yellow grease) feedstock.

Equations: See Appendices I and J for a more detailed description of the biofuels' supply submodules.

(PMMLP) Solve PMM LP.

Purpose: PMMLP calls many subroutines that perform updates to the LP bounds, RHS, and input costs and optimizes the matrix.

Equations: Refer to Appendix B.

(WRTBAS) Write advance basis.

Purpose: WRTBAS writes the basis for the LP optimal solution to an external file for any given NEMS year by calling the PUNCHLP subroutine.

Equations: None.
Output File: BASPMM1 and BAXPMM1 (for capacity expansion) PMM basis output file

(SETLP) Activate a specified OML model memory space for processing.

Purpose: Sets a given OML model space to be active using the WFSET function, such that any OML routines called will be applied to the given model.

Equations: None.

(OPTLP) Optimize the model.

Purpose: Optimizes the model using the OML function WFOPT.

Equations: None.

(WRTANLZ) Write an ANALYZE packed LP matrix and solution file.

Purpose: WRTANLZ writes an ANALYZE packed LP matrix and solution file the LP matrix and solution specified in memory using the GOMOT subroutine.

Equations: None.

Output File: PACKPMM PMM ANALYZE output file

(DWRTANLZ) Write an ANALYZE packed LP matrix and solution file.

Purpose: DWRTANLZ writes an ANALYZE packed LP matrix and solution file from the LP matrix and solution specified in memory using the GOMOT subroutine.

Equations: None.

Output File: PACKPMM PMM ANALYZE output file

(XCEPMM) Retrieve and calculate processing unit capacity expansion investment bounds.

Purpose: XCEPMM retrieves the expected processing investment activity level by using the SCOLLP subroutine and calculates the processing unit build and investment bounds.

Equations: Processing unit cumulative builds and investment bounds are calculated such that:

$$PUINV_{pd,yr+1,pu} = BLD_{pd,pu,yr+3} / 3 \quad (7)$$
$$PUINV_{pd,yr+2,pu} = BLD_{pd,pu,yr+3} / 3 \quad (8)$$
$$PUINV_{pd,yr+3,pu} = BLD_{pd,pu,yr+3} / 3 \quad (9)$$

where:

PUINV = processing unit investment bound, Mbbl/cd
$BLD_{pd,pu,yr+3}$ = processing unit expansion as determined in expansion year yr
pu = processing unit index, 1 through 87
pd = refinery regions 1,2,3,4,5 (PADDs I, II, III, IV, V)
yr = NEMS index years 15,18,21,24,27,30,33,36,39

The decision to allow one-third of the expansion to come on line in each of the expansion years was made because expansions in individual refineries would most likely be spread out evenly over time as the PMM assumes an aggregated refinery for each PADD. However, the capacity expansion rates for select processing units can be adjusted (input file, qdcrdcf.txt) so that they are consistent with the capacities needed to meet certain regulatory requirements such as the Ultra-Low-Sulfur-Diesel Rule. Also, capacity expansion for the crude distillation unit has been limited

to 2,800 MBCD for each refining region for all cases except the LWOP and HMAC, where the ACU build limit is set to 2600 MBCD.

Processing unit cumulative builds, PUCUM is:

$$PUCUM_{pd,pu,yr} = 0; \text{ when } yr = 13 \quad (10)$$

$$PUCUM_{pd,pu,yr+2} = PUCUM_{pd,pu,yr+1} + PUINV_{pd,pu,yr+1} \quad (11)$$

$$PUCUM_{pd,pu,yr+3} = PUCUM_{pd,pu,yr+2} + PUINV_{pd,pu,yr+2} \quad (12)$$

$$PUCUM_{pd,pu,yr+4} = PUCUM_{pd,pu,yr+3} + PUINV_{pd,pu,yr+3} \quad (13)$$

pu = processing unit index, 1 through 87
pd = refinery regions 1,2,3,4,5 (PADDs I, II, III, IV, V)
yr = NEMS index years 15,18,21,24,27,30,33,36,39

(RPT1PMM) Write report 1, LP solution.

Purpose: RPT1PMM writes the LP solution to an external file.

Equations: None.

Output File: PMMPRNT PMM solution output file

(RFPRTINF) Write entire solution, if infeasible.

Purpose: If the LP solution is determined to be infeasible, and error message and the infeasible components are written to the NEMS output file.

Equations: None.

Output File: nohup.out NEMS output message file

(XETHSOLN) Update Common Block Variables for ethanol production

Purpose: Updates the PMM and NEMS system common block values of ethanol production volumes by NEMS by type of feedstock. This is done for each iteration and for every projection year.

Equations: Column activity solution values of the PMM LP, representing total ethanol production are read and corresponding common block variables are updated.

(RPT6PMM) Write report 6, OML formatted tables, supply curves and demands.

Purpose: RPT6PMM writes OML tables used for stand-alone PMM matrix generation.

Equations: None.

Output File: IMPCURV OML data table output file

(RFHSTRPT) Write ALPHADN reports for history data.

Purpose: This subroutine calls the report writer subroutines (including RPT7PMK, RPT7PMM, USTOT, RPT8PMM, RPTA8PMM, FCCRPT, ALKRPT, HH2RPT, COKRPT, SPECRPT, OCTANE, CETANE, OBJRPT) and overwrites to an external file (PMM analyst reports) each NEMS iteration and at the end of a NEMS run.

Equations: None.

Output File: PMMRPTS PMM reports output file

(RPTSPMM) Write additional reports, PMM forecast reports.

Purpose: This subroutine calls the report writer subroutines (including RPT7PMK, RPT7PMM, USTOT, RPT8PMM, RPTA8PMM, FCCRPT, ALKRPT, HH2RPT, COKRPT, SPECRPT, RFINRPT, OCTANE, CETANE, OBJRPT) and overwrites to an external file (PMM analyst reports) each NEMS iteration and at the end of a NEMS run.

Equations: None.

Output File: PMMRPTS PMM reports output file

(ADJFGSCAP) Update the upper limit on the FGS unit.

Purpose: ADJFGSCAP increases the upper limit on the gasoline fractionation (FGS) processing unit each year based on its utilization in the previous years (beginning after 2006).

Equations: $FGS\_UL_{pd,yr} = FGS\_SOL_{pd} * (1. + FGS\_PCT_{pd})$ (14)

$FGS\_UL_{pd,yr}$ = upper limit for FGS (Mbbl/cd)
FGS_SOL_{pd} = solution for FGS capacity of previous year (Mbbl/cd)
FGS_PCT_{pd} = annual percent increase in FGS upper limit (currently at 15% for each PADD)
pd = refinery regions 1,2,3,4,5 (PADDs I, II, III, IV, V)

yr = forecast year

(RFDEBUG) Write debug information concerning GTL results.

Purpose: RFDEBUG writes GTL information (e.g., AK natural gas consumption for GTL, GTL production, and GTL exports) to a debug output file.

Equations: None.

Output File: PMMDBG.txt output file

(RPT7PMM) Write report 7 (U.S. end-use prices without carbon tax), PMM forecast reports.

Purpose: RPT7PMM extracts solution values from the LP using the SCOLLP and SROWLP subroutines and overwrites to an external file (PMM analyst reports) at the end of a NEMS run.

Equations: Solution values are extracted from solution matrix, reformatted and converted to the proper units.

Output File: PMMRPTS PMM reports output file

(RPT7PMK) Write report 7 (U.S. end-use prices with carbon tax), PMM forecast reports.

Purpose: RPT7PMK extracts solution values from the LP using the SCOLLP and SROWLP subroutines and overwrites to an external file (PMM analyst reports) at the end of a NEMS run.

Equations: Solution values are extracted from solution matrix, reformatted and converted to the proper units.

Output File: PMMRPTS PMM reports output file

(USTOT) Calculate totals by PADD, Census Division, and U.S. for RPT7PMM, RPT8PMM, and RPTA8PMM.

Purpose: Totals various PMM output data.

Equations: Performs units conversions on some of the totals.

(RPT8PMM) Write report 8 - continuation of report 7 (RPT7PMM).

Purpose: RPT8PMM pulls solution values from the LP using the SCOLLP and SROWLP subroutines and writes to an external file PMM analyst reports at the end of a NEMS run.

Equations: Solution values are extracted from solution matrix, reformatted, and converted to the proper units.

Output File: PMMRPTS PMM reports output file

(RPTA8PMM) Write report A8 - continuation of report 8 (RPTA8PMM).

Purpose: RPTA8PMM pulls solution values from the LP using the SCOLLP and SROWLP subroutines and writes to an external file PMM analyst reports at the end of a NEMS run.

Equations: Solution values are extracted from solution matrix, reformatted, and converted to the proper units.

Output File: PMMRPTS PMM reports output file

(FCCRPT) Report the fluid catalytic cracker's level of operations.

Purpose: This subroutine reports the levels of operations for the modes of operation of the fluidized catalytic cracker.

Equations: None.

Output File: PMMRPTS PMM reports output file.

(ALKRPT) Print the alkylation report to the PMM forecast reports.

Purpose: Solution values extracted using the subroutine ALKMODE are reformatted and printed to an output file.

Output File: PMMRPTS PMM reports output file.

(HH2RPT) Print the hydrogen production and consumption report to the PMM forecast reports.

Purpose: Solution values extracted using the subroutine PMM_HH2RPT are reformatted and printed as Table 48 to an output file.

Output File: PMMRPTS PMM reports output file.

(COKRPT) Print the petroleum coke gasification results to the PMM reports.

Purpose: Solution values extracted using the subroutine PMM_COKGSF are reformatted and printed as Table 48a to an output file.

Output File: PMMRPTS PMM reports output file.

(RFINRPT) Print the refinery financial information report to the PMM forecast reports.

Purpose: Refinery financial information (including revenues, raw materials, energy costs, petroleum products, operating expenses, blending components, and investment costs) are reformatted and printed as Table 50 to an output file.

Output File: PMMRPTS PMM reports output file.

(SPECRPT) Print the motor gasoline specifications report.

Purpose: SPECRPT print the motor gasoline specification report to the detailed PMM reports.

Equations: None.

Output File: PMMRPTS PMM reports output file.

(OCTANE) Print the octane report for motor gasoline

Purpose: Detemine the motor and research octane averages for RFG and TRG.

Equations: None.

Output File: PMMRPTS PMM reports output file.

(CETANE) Print the cetane report for low and ultra-low-sulfur diesel fuels.

Purpose: Determine the cetane averages for DSL and DSU.

Equations: None.

Output File: PMMRPTS PMM reports output file.

(ETHMCST) Define the marginal cost of ethanol at motor gasoline blend point in each CD

Purpose: This routine steps through the PMM regional network and determines the marginal cost of ethanol available to each CD. The process first defines the supply price in each ethanol supply region (CD). Then transportation costs are added to each supply source available in a region (CD). The marginal cost (PETHM) is defined by the highest priced source that actually provided ethanol to that region (marginal supplier).

Equations: None.

Output File: PMMRPTS PMM reports output file.

(OBJRPT) Print the objective function report.

Purpose: OBJRPT print the objective function of the PMM for the NEMS forecast to the PMM detailed reports output file.

Equations: None.

Output File: PMMRPTS PMM reports output file.

(WRTPSARPT) Print refinery capacities formatted according to the Petroleum Supply Annual.

Purpose: Create a output table reporting refinery capacity aggregated into the same processing unit categories defined in the PSA.

Equations: None.

Output File: PMMRPTS PMM reports Table 22x.

(PMMRPTHD, PMMRPTHD1) Print the detailed PMM reports header.

Purpose: PMMRPTHD print the NEMS scenario name, date key, and reporting years as a header to each reporting the detailed PMM reports. PMMRPTHD1 uses a slightly different print format.

Equations: None.

Output File: PMMRPTS PMM reports output file.

(PMMRPTRW) Rewind the record pointer during the PMM iterations report.

Purpose: PMMRPTRW rewinds the record pointer for the PMM iterations reports such that only each years final iteration reports are retained.

Equations: None.

Output File: ALPHADN PMM reports output file.

4.2 Matrix Preprocessing Subroutines

Section 4.2 describes the function of the subroutines in Figure 4.2, preprocessing of the PMM matrix.

(INSRTLP) Load an advance basis into the LP model.

Purpose: Loads a standard format basis from a file into the LP model using the OML function WFINSRT.

Equations: None.

(CHGTRNPR) Adjust the transit tariff along transit routes that use diesel.

Purpose: The transit cost along routes that use diesel should reflect the impact of the WOP.

Equations: The transit cost is changed by 1% for every 10 cent change in transportation distillate price (reflecting the WOP change) off the 2002 base year. The change is costs are defined discretely: even if the distillate price changes by 16 cents, the transport change will still only be 1%.

(CHGTRANS) Update the transportation costs of crude and product.

Purpose: Update the crude and product transportation cost within the United States.

Equations: Cost for moving crude and products from the supply regions to the demand regions are updated to reflect changes in the world oil price, WOP. A factor called price delta (PCNTDLT) is calculated as the change between the current year WOP and the previous year's WOP. The price delta is used to adjust the transportation cost for domestic crude and product shipments as the fractional change in price.

(CHGMINSTG) Set limit on still gas, residual fuel, other, and LPG for fuel used at the refinery.

Purpose: Maintain a reasonable split in refinery fuel use based on historical levels.

Equations:

Total still gas used at the refinery is set to an historical minimum, which grows at 0.3 percent annually (for HWOP only).

Total residual fuel used at the refinery is set to an historical maximum, which grows at a rate based on the national growth of ACU capacity (RFDSTCAP).

Total "other" fuel used at the refinery is set to an historical minimum, which grows at 0.3 percent annually.

Total LPG used at the refinery set to an historical maximum, which grows annually at the rates defined below:

Ref case:	10 percent
LWOP case:	12 percent
HWOP case:	6 percent
LMAC case:	8 percent
HMAC case:	11 percent

(CHGAKTRN) Update the transportation costs of Alaska crude and GTLs from Alaska N. Slope to Valdez.

Purpose: CHGAKTRN updates the transportation costs for Alaska crude and GTLs from Alaska N. Slope to Valdez. Also defines the natural gas supply curve and maximum supply (using function CUM_AKNGCRV), the remaining capacity for GTL, and GTL subsidies that apply. Also calls subroutine RFGTLCAP to get GTL processing unit capacity used to estimate flows along TAPS.

Equations: Transportation costs are based on fixed costs for the TransAlaska Pipeline System (TAPS), variables charge, estimated flows, and GTL subsidies. The annual NG supply curve is represented as a cumulative supply curve, and a cumulative maximum is defined exogenously. The GTL subsidy is based on the Alaska oil price and economics associated with TAPS. (See Appendix F.17 for details and equations.)

(CHGCTLCOEF) Update the coefficients on the CTL input components.

Purpose: CHGCTLCOEF updates the coal supply curve used to generate liquids and CHP generation from CTL processing units. CHP credits and CTL transportation costs are defined. Also, regional coal conversion ratios are set.

Equations: The coal supply curve (including transportation costs) is based on quantities, prices, and elasticities provided by the coal supply module. CHP credits are a function of the electricity price to the industrial sector. Finally, regional coal conversion ratios are based on the higher heating values of the respective coals, and an average conversion rate. (See Appendix F-18 for more details and equations.)

(CHGNGCRV) Update the natural gas supply curve for refinery fuel use (currently not used).

Purpose: Updates the bounds on the first point of the eight-step natural gas supply curve using the CBNDLP subroutine.

Equations: The lower bound on step one of the supply curves is set at 50 percent of the sum of the upper bounds on the last four steps of the supply curve. The upper bound on step one of the supply curve is set at 80 percent of the sum of the upper bounds on the last four steps of the supply curve during any first iteration of a NEMS year or the capacity planning iteration. During any other NEMS iteration the upper bound on the first step of the supply curve is set at the difference between the sum of the upper bounds of the last four steps on the supply curve and the difference between the sum of the upper bounds on the first four steps of the supply curve and the sum of activity levels on all steps of the supply curve from the previous NEMS iteration solution. If the upper bound on the first step of the supply curve, just described falls below the lower bound on the first step of the curve, then the upper bound is set at value 1 percent above the lower bound on the first step of the curve. This methodology effectively re-centers the natural gas supply step function during each NEMS iteration.

(CHGCESW) Update Capacity Expansion Switch.

Purpose: CHGCESW changes the LP constraint that allows investment in processing unit capacities to compete with imported products by using the CRHSLP subroutine.

Equations: None.

(ADDCAP) Update Capacity.

Purpose: ADDCAP changes the capacity expansion investment and build bounds using the CBNDLP subroutine with values obtained from the XCEPMM subroutine.

Equations: None.

(CHGPUBLD) Update the bounds on the processing unit investment columns.

Purpose: If the STEO benchmarking switch is off, this subroutine sets the upper and lower bounds for the processing units investment columns to zero during initial model startup. During the first year that the PMM model is run, the CHGPUBLD subroutine insures that the model will not build any additional capacity. Capacity additions are handled by the capacity expansion portion of the PMM.

Equations: None.

(RFUPD8_INV) Update investment coefficients for capacity build and investment variables.

Purpose: This subroutine generates new capital recovery, fixed operating cost, and investment information (using subroutine RFINVST) and updates the capacity build and investment coefficients in the LP objective function row and other constraint rows (using subroutine CVALLP).

Equations: The subroutine RFINVST uses "Refinery Investment Recovery Thresholds" methodology defined in Appendix F.1 to generate the capital recovery, fixed operating cost, and total investment information. The first two components are then added and multiplied by an investment location factor (CTL and GTL only) and an environmental factor (and by -1). Next, in order to maintain an accounting of previous investment levels, this value is averaged using the function ADJBLD_COEF. The objective function row coefficients identified above are updated using these results. However, if the model is being set up for capacity expansion, then the original value, not the averaged value, is used to update the investment coefficient only. The original fixed cost and investment information are also used to update other row constraint coefficients that intersect the investment variable.

(CHGDNGP) Update natural gas production and prices.

Purpose: Natural gas production and prices come from the Natural Gas Transmission and Distribution Model and are inputs to the gas plant portion of the model. This subroutine updates these LP inputs using the CBNDLP and CVALLP subroutines. During the capacity expansion iteration the CHGDNGP subroutine uses the expected natural gas production and prices as inputs into the LP model.

Equations: Unconventional gas such as coalbed methane (CBM) and shale are not to be processed by the gas plant. Thus, the fraction (CBSHALPCT) of total NG supplied (PRNG_PADD) from CBM and shale is calculated and used to determine the total NG processed (dried) by the gas plant. The industrial interruptible price of natural gas (PGIIN) is used for the price of gas to refineries in each PADD, translated into the five refinery regions. These prices are converted to dollar per thousand cubic feet ($/MCF). During the capacity expansion iteration the expected industrial interruptible price of natural gas (XRFNGP) and expected domestic production of natural gas (XPRNG_PAD) are used as inputs into the LP matrix.

(CHGELPR) Update electricity costs.

Purpose: CHGELPR updates the cost of electricity in each of the refinery regions using industrial price of electricity using the CVALLP subroutine. During the capacity planning iteration the CHGELPR subroutine uses the expected cost of electricity in each of the refinery regions.

Equations: Industry price of electricity (PELIN, XRFELP) is mapped from Census division to refining region, and units are converted to dollar per kilowatt-hour ($/kWh).

(CHGDMDS) Update product demands for the LP.

Purpose: CHGDMDS sets the upper and lower bounds for product demands. For most products, the upper and lower bounds are equal. The bounds are set at the level of demand for each product in each Census Division. During the capacity expansion iteration, the CHGDMDS updates bounds using the expected demands variables. CHGDMDS is also used to set bounds for product(s) subject to current laws and regulation, such as MTBE ban in California, New York, and Connecticut starting in 2004.

Equations: None.

(CHGDCRD) Update domestic crude production.

Purpose: CHGDCRD updates the LP domestic crude production variables using the CBNDLP subroutines. During the capacity planning iteration, the CHGDCRD subroutine updates the domestic crude production bounds using the expected crude production variables.

Equations: U.S. crude production and units are converted to Mbbl/cd. Crude exports (QEXCRDIN) are defined as a function of total L-48 crude production (RFQTDCRD).

(CHGGSPC) Updates the motor gasoline specifications.

Purpose: CHGGSPC updates motor gasoline specifications using the CVALLP subroutine.

Equations: Sub-specification blends of reformulated and high-oxygenated-conventional gasoline are calculated for ethanol blends for these fuels using the percent ethanol blended.

(CHGSPRE) Change Strategic Petroleum Reserve (SPR) quantities in the LP.

Purpose: Sets the upper and lower bounds for SPR additions. The upper and lower bounds are equal and are set using the CBNDLP subroutine. The bounds on SPR additions are set as exogenous inputs to the program (RFSPRFR).

Equations: None.

(CHGMETD) Change methanol demand for the LP.

Purpose: Sets the upper and lower bounds for methanol demand (PRDDMDME). The upper and lower bounds are equal. During the capacity expansion iteration, the expected methanol demand (XPRDDMDME) is used to update the bounds.

Equations: None.

(CHGCGCOF) Updates the CHP sales to grid price credit coefficients and "own use" accounting for the combined heat and power processing unit.

Purpose: Updates the CHP sales to grid price credit coefficients and "own use" accounting using the CVALLP subroutine for the combined heat and power processing unit.

Equation: Price coef for CHP unit associated with coke gasification:

$$COEF_{pd,yr} = CGPCGRDPD_{pd} * PELAS_{cd,yr} * CFELBK \quad (15a)$$

Price coef for CHP at the refinery and merchant plant:

$$COEF_{pd,yr} = CGPCGRDPD_{pd} * PELIN_{cd,yr} * CFELBK \quad (15b)$$

where:
COEF = sales to grid coefficient
CGPCGRDPD = Percent sales to grid for each refinery region *pd* based on historical data (see Appendix F.14).
PELAS = Prices of electricity to all sectors (87$/MMBTU)
CFELBK = conversion factor, $3412 * 10^{-6}$ MMBtu/KWh
pd = refinery regions 1,2,3,4,5 (PADDs I, II,, III, IV, V)
cd = Census Division index
yr = year index

(CHGPRDVL) Update the objective row of the product demands column.

Purpose: This subroutine updates the objective row value for the product demand columns.

Equations: The coefficients for the product demand columns in the objective row are updated as a function of corresponding end-use prices resulting from the previous NEMS iteration. For coke, the update is a function of two times the world oil price.

(CHGETHSUB) Update LP coefficient that handles the ethanol tax incentive.

Purpose: This subroutine updates the LP coefficient for the ethanol tax incentive (from corn or cellulose) blended into motor gasoline. Only the ethanol portion of E85 receives the ethanol tax incentive.

Equations: The ethanol incentive is set at $21.42 /Bbl for 2005 and beyond (nominal dollars). All these prices are converted to 1987 dollars (using the macroeconomic GDP deflator) before being put into the matrix; therefore, the model sees the ethanol incentive declining in real terms over the entire forecast.

(EFFCHG) Update the efficiencies for steam, electricity, and natural gas.

Purpose: This subroutine updates the efficiency coefficients for steam, electricity, and natural gas in the NEMS hi-tech scenario only (using subroutine CVALLP).

Equations: Sets percentage efficiency improvement based on estimated total carbon emissions.

(CHGCGCAP) Update the refinery combined heat and power (CHP) capacities.

Purpose: This subroutine updates the base refinery CHP capacities with the planned additions.

Equations: No planned additions for *AEO2006* due to unavailable CHP data.

(CHGPLNCAP) Add planned capacity for selected processing units.

Purpose: Planned capacity for the fluid and delayed coker processing units are added to the upper limit on the K(r)(uns)CAP variable in the LP.

Equations: None.

(CHGALKEXP) Update the LP Alaskan export crude supply curve.

Purpose: The LP Alaskan export crude supply curve is updated.

Equations: The price steps on the supply curve are set as a function of world oil prices such that the price is 8.32 percent of the world oil price. Total Alaskan exports are set as a percent (PCTEXCRD) of total crude exports, with each step of the supply curve (six steps total) representing one-sixth of this volume. These prices and volumes were set based on analyst judgment.

(CHGAKNGL) Update Alaskan natural gas liquids production.

Purpose: This subroutine updates the LP Alaskan natural gas liquid bounds using the OGSM variable OGNGLAK.

Equations: None

(CHGD50FCC) Update the minimum flow constraint on the D50 (winter) mode in the FCC.

Purpose: This subroutine updates the minimum percentage flow constraint on the D50 mode in the fluid catalytic cracker.

Equations: Set the constraint at a minimum of 7.5 percent of throughput. This value was made based on analyst judgment to meet the minimum winter mode of operation for the FCC unit.

(CHGETHN) Update ethanol supply curves in LP for both corn and cellulose sources.

Purpose: CHGETHN updates the LP ethanol supply curve representation with values obtained from the Renewable Fuels Model by using the CBNDLP and CVALLP subroutines. The ethanol supply curves are represented in the LP by a stepwise function comprised of five price/quantity pairs. See Appendix I for a more detailed description of the ethanol supply curves.

Equations: None.

(GETLNEQ) Defines slope and intercept for the ethanol supply curves in CD's 3,4. (called by CHGETHN)

Purpose: This routine uses two points in the 4-step ethanol supply curve in CD's 3 and 4 to define a linear representation (slope and intercept) to be used to expand the curve to 9 steps.

Equations: None.

(CHGUNFO) Update unfinished oil costs.

Purpose: CHGUNFO updates the cost of unfinished oils using the CVALLP subroutine.

Equations: Unfinished oils costs are set at a value based on typical refinery gate prices for the streams heavy gas oil medium sulfur (HGM), naphtha paraffinic (NPP), and atmospheric residual type B (ARB) as a function of crude oil price where:

$$ARB_{yr} = 0.90 * WOP_{yr} \quad (16)$$

$$NPP_{yr} = 1.14 * WOP_{yr} \quad (17)$$

$$HGM_{yr} = 0.90 * WOP_{yr} \quad (18)$$

where

ARB = Atmospheric residual type B cost
NPP = Naphtha paraffinic cost
HGM = heavy gas oil medium sulfur cost
WOP = World oil price
yr = NEMS year, 1 through 41

(CHGIMTOT) Update total product imported constraint.

Purpose: CHGIMTOT updates the LP constraint for total maximum imported product using the CRHSLP subroutine.

Equations: Set to 9,900 Mbbl/cd. This value is based on analyst judgment and is currently set high enough that the constraint is not expected to be reached.

(CHGCKSU) Update petroleum coke and sulfur costs.

Purpose: CHGCKSU updates the cost of petroleum coke, export and distress export petroleum coke costs, and the cost of sulfur using the CVALLP subroutine.

Equations: Petroleum coke prices are based on a 1991 price of $20/ton for low sulfur coke and $15/ton for high sulfur coke. These prices are converted to $/bbl and scaled by the 1991 world oil price (WOP). The results are values of 0.203 and 0.152, which are multiplied by the current year WOP to set the price of coke. The price of exported coke is set at 4.75 times the high sulfur coke prices (3.5 times for HWOP), with an 80% adjustment factor to better match historical prices, and an annual 10% expected decline in price. Distress export price of petroleum coke is set at 10 percent of the coke export price. The average price of saleable sulfur is set to $24.47 /ton (in 87$), which was based on the average of USGS average U.S. annual prices for elemental sulfur from 1993 through 1999.

(CHGZ9CST) Update the distress product imports supply vectors input cost.

Purpose: Updates the distress product imports supply vectors input cost using the CVALLP subroutine.

Equations: The distress product imports input cost a set at five times the WOP.

(CHGZ9EXP) Update the distress product exports supply vectors input cost.

Purpose: Updates the distress product exports supply vectors input cost using the CVALLP subroutine.

Equations: The distress product exports input cost a set at 10 percent (WOPZ9EXP) of the WOP.

(CHGICRD) Update imported crude supply curve in the LP.

Purpose: CHGICRD updates the LP imported crude supply curves using values obtained from the International Model. Also, crude import limits are set for Canadian crude import into PADD's II and IV.

Equations: The International Energy Model provides imported crude supply curves for each refining region (PADDs I through V) and five crude types to the PMM. These imported crude supply curves represent five price-quantity relationships for each imported crude in each refining region. Quantity steps two through five for each supply curve are incremental supply volumes. The prices related to these incremental supply volumes are absolute prices. During the capacity expansion look-ahead iteration, CHGICRD updates imported supply curve bounds with the expected imported crude supply variables. Canadian crude import limits into PADD's II and IV are set based on an annual growth rate (CANGRW) applied to 2005 import levels (1212 Mbbl/cd for PADD II, 266 Mbbl/cd for PADD IV). The growth rate (based on analyst judgment) is set to 0.8% annually (1.1% for HWOP).

(ADJICRD) Disables the lower limit on total crude imports (only for HWOP case).

Purpose: This subroutine sets the lower limit on total crude imports (A@CRDIMP) to zero for the HWOP case only. This routine no longer makes adjustments to the international crude supply curve prices.

Equations: None.

(CHGIPRD) Update the 9-step imported product supply curves in the LP.

Purpose: CHGIPRD updates the 9-step imported product supply curves in the LP using the 5-step P/Q values passed from the International Model.

Equations: The International Energy Model provides imported product supply curves to the PMM for each product and each refining region. These imported product supply curves represent five price-quantity relationships for each imported product. Quantity steps two through five on the supply curves are incremental supply volumes. The prices related to these incremental supply volumes are absolute prices. This subroutine fills steps one through five of the nine product import steps in the LP, while subroutine RF3SPRDSIM fills steps six through nine. Canadian

product import limits into PADDs II and IV are set based on an annual growth rate (CANGRW) applied to 2005 import levels (108 Mbbl/cd for PADD II, 15.6 Mbbl/cd for PADD IV). The growth rate (based on analyst judgment) is set to 3 percent annually (4 percent for HWOP). Finally, the upper limit on SSR imports into New Jersey (PADD I) is set for the period 2005 through 2013 based on initial import levels in 2004 (77 Mbbl/cd), and an annual relaxation rate of 5 percent. No limit applies after 2013. This limit is implemented in conjunction with the 2004 MTBE ban in New York and Connecticut.

(ADJIPRD) Adjust the international product supply curves.

Purpose: This subroutine allows adjustments to the international supply curve prices and/or volumes.

Equations: Adjusts the prices on the imported product supply curves to calibrate the petroleum product imports to values indicated in the *Petroleum Supply Annual 2004.* Adjustments are made to import volumes and prices. Note: volume adjustments only apply to step 1 on the product import supply curves.

(CHGEXPPRC) Update exported petroleum product prices and demand limits.

Purpose: This subroutine updates the objective row and upper and lower bounds for each exported petroleum product (except coke).

Equations: Set prices for exported products (excluding coke) to 90 percent (110% for OTH in west) of the imported product prices defined on the first step of the import supply curve. Also, set the upper and lower bounds on exported products (excluding coke) as a function of regional product demand (SUBROUTINE PMMPRDEXP and REAL FUNCTION PMMEXPEQ), as follows:

$$LOWBND = 0.65 * EXPRDDMD_{xpr,pd} * EXPRAT * EXPMIN_{xpr,pd} / 100. \quad (19)$$
$$UPBND = 0.65 * EXPRDDMD_{xpr,pd} * EXPRAT * EXPMAX_{xpr,pd} / 100. \quad (20)$$

for years 1996, EXPRAT = 1
for years > 1996, EXPRAT = DUMTOT1 / DUMTOT2

Using regression analyses:

$$DUMTOT1 = [7.942 - (0.4073 * (RFPQIPRDT_{6,yr,2} / RFQPRDT_{11,yr})) * RFQPRDT_{11,yr} * 10^6 \quad (21)$$
$$DUMTOT2 = [7.942 - (0.4073 * (RFPQIPRDT_{6,y-1r,2} / RFQPRDT_{11,yr-1})) * RFQPRDT_{11,yr-1} * 10^6 \quad (22)$$

where,

UPBND = upper bound on export product demands

LOWBND = lower bound on export product demands
EXPRDDMD = product demand accumulated into PADDs (I - V)
EXPMIN = factor to establish minimum product export range
EXPMAX = factor to establish maximum product export range
EXPRAT = ratio of estimated exports for year yr and yr-1
DUMTOT1 = estimated exports in year yr
DUMTOT2 = estimated exports in year yr-1
RFPQIPRDT = total imports for each product
RFQPRDT = total supply for each product
yr = year index
xpr = exported product index
pd = PADD containing Census Division export region (I=>2, II=>3, III=>7, IV=>8, V=>9)

(CHGMETIMP) Update the methanol imports supply function.

Purpose: This subroutine updates the methanol import supply curve costs and volumes.

Equations: The import supply curve prices are updated as a function of world oil price. Quantity adjustments (on the third step only) were made based on analyst judgment.

(CHGIRAC) Update average refinery acquisition cost parameters.

Purpose: CHGIRAC updates the average refinery acquisition cost constraints using the CVALLP subroutine.

Equations: Cost of crudes in each PADD are updated and the minimum and maximum tolerance for the average acquisition cost are set to $0.50/bbl (IRACBND) off the world oil price. This tolerance level was chosen based on analyst judgment.

(CHGFLLIMP) Set and phase out the national level import of light, sweet crude.

Purpose: This routine sets the lower limit on the national import of light, sweet crude (FLL) based on 2004 levels, and phased out over the forecast.

Equations: FLLRHS = FLLBASE *((1.-FLLREDC)**(L-FLLYR))
where,

FLLBASE = base level imports (nationally) of FLL (1200 M bbl/cd)
FLLREDC = rate at which the lower limit on FLL imports declines (5% /yr)
FLLYR = base year (2004)

(RFROS) Update the renewable oxygenates constraint.

Purpose: RFROS updates the renewable oxygenates specification (ROS) constraints for motor gasoline using the CVALLP subroutine.

Equations: The motor gasoline minimum renewable oxygenates constraints is set at 30 percent if the ROS switch is on. If the ROS switch is off the constraint is set to zero. For the *AEO2006* the ROS was off.

(ADJFUVAL) Adjust refinery fuel use coefficient on all refinery fuels.

Purpose: This subroutine is used to calibrate refinery fuel consumption (including electricity) with historical estimates. For the *AEO2006* this factor was 0.90 for fuel use, and 0.95 for electricity use. The expected fuel and electricity use improvement is 0.3% per year.

Equations: None.

(CHGCATCOK) Update catalytic coke coefficient. (Not used.)

Purpose: This subroutine updates the catalytic coke LP coefficient.

Equations: The coefficient is updated once at the beginning of the NEMS forecast and then remains constant throughout the NEMS forecast. The updated coefficient is set at 90 percent of the current value in the PMM database. This value is calibrated to reflect catalytic coke use as reported by the *Petroleum Supply Annual 2004.*

(EMISCOST) Update the refinery emission cost vector.

Purpose: If the emission cost switch (EMISCSSW) is ON, then this routine updates the input cost of the vector of petroleum products burned in the refinery using the CVALLP subroutine. (Currently, EMISCSSW='OFF'.)

Equations: Emission input costs are set at values determined by the Emission Policy Module (JNGIN, JPCIN, JOTIN, JRLIN, JRHEL, JSGIN, JLGIN).

(ADJACUINV) Update the crude units investment costs

Purpose: This subroutine updates the atmospheric distillation unit investment costs.

Equations: The investment coefficient is updated once at the beginning of the NEMS forecast and then remains constant throughout the NEMS forecast.

(RFGLOB_TCHCHNG) Model technology changes as reflected by other variable cost (OVC) adjustment in all process units.

Purpose: This subroutine approximates technology changes in the refining industry by adjusting the OVC coefficient (by a user-specified amount) in the OVC constraint row for all process units (in the refinery, merchant, and gas plant).

Equations: If the global technology switch is on and the model year lies between the beginning and end phase-in year, then the original OVC price coefficients for all processing units (except those also flagged for unit-specific technology improvement updates) included in the OVC constraint row are updated gradually during the phase-in years.

(RFUNIT_TCHCHNG) Model technology changes as reflected by other variable cost (OVC) adjustment only in specified process units.

Purpose: This subroutine approximates technology changes for specific processing units in the refining industry by adjusting the corresponding OVC coefficient in the OVC constraint row by a user-specified amount.

Equations: If the unit-specific technology switch is on and the model year lies between the beginning and end phase-in year, then the original OVC price coefficients for the specified unit(s) included in the OVC constraint row are updated gradually during the phase-in years.

(RFYLD_TCHCHNG) Model technology changes as reflected by process stream adjustment in a process unit.

Purpose: This subroutine approximates technology changes in the refining industry by adjusting the process stream yields coefficient (by a user-specified amount) of a user-defined process unit.

Equations: None.

(RFSPC_TCHCHNG) Model technology changes as reflected by process stream quality adjustment.

Purpose: This subroutine approximates technology changes in the refining industry by adjusting the process stream qualities (by a user-specified amount).

Equations: None.

(ETHERBAN) Update motor gasoline blending constraints to eliminate ether blending in PADD V refineries.

Purpose: This subroutine updates PADD V gasoline blending constraints to eliminate ether blending into gasoline. This constraint takes effect in 2004 for California gasolines. It also models the oxygen waiver in RFG and RFH gasoline. Remove ETBE from RFG and TRG blend components.

Equations: None.

(CHGRENEW) Update the minimum renewable fuels requirement in motor gasolines and on-road diesel.

Purpose: This subroutine sets the RHS of the minimum renewable fuels constraint and the biomass diesel production level.

Equations: The biomass diesel production is currently set exogenously. The minimum renewable fuels requirement is a percent (REN_RAT) of the total (US) gasoline, diesel, and E85 demands (MGDIESUM). Total biomass diesel is split among regions as follows:

CD=3: 9% of total biomass (virgin biodiesel
CD=4: 81% of total biomass (virgin biodiesel
CD=5: 5% of total biomass (nonvirgin biodiesel)
CD=9: 5% of total biomass (nonvirgin biodiesel)

(ADJMTBE) Implement MTBE phaseout

Purpose: Limit and phase out the total MTBE consumption through the constraint that A@MTBPRD must be less than an upper limit (MTBEPRD).

Equations: IF(I.EQ.18)MTBEPRD = 27.5
IF(I.EQ.19)MTBEPRD = 3.7
IF(I.GT.19)MTBEPRD = 0.0
where, I=NEMS forecast year.

(PMM_CONSTPRDI) Set product imports to a constant level.

Purpose: This subroutine sets product imports to a constant level to allow for sensitivity runs without the impact of changing imports. Control switch: PRDIMPSW.

Equations: None.

(PMM_WRPRDIMP) Write product import results to an output file.

Purpose: This subroutine writes product import results to an output file to be used as input for a run requiring constant product imports. Control switch: PRDIMPWR.

Output file: PMMDBG.txt

(PMM_NOETHRF) Prevent ethanol blending at the refinery.

Purpose: This subroutine prevents ethanol transfers to the refinery since ethanol is usually splash blended into gasoline at the end-use location.

Equations: None.

(ADJULGAIN) Set a limit on GAIN increase from year to year. (Not used for *AEO2006*.)

Purpose: This subroutine defines a range of increase for GAIN each year.

Equations: The allowed rate of increase is defined exogenously, and applied cumulatively to a base level of gain in a specified forecast year.

RHSGAIN = -1000. * RFQPRCG(6,GYR)/10. * (1.+GAINRAT)**(K-GYR) (23)

RNGGAIN = -1000. * RFQPRCG(6,GYR) /10. * [(1. - GAINRAT)**(K-GYR)] - RHSGAIN (24)

where

RFQPRCG = processing gain in year GYR

GAINRAT = rate of annual gain increase

GYR = year defined for base gain level

K = current year

Compared to history, A@GAIN = ~ 1/10 of RFQPRCG

4.3 Matrix Postprocessing Subroutines

Section 4.3 describes the function of the subroutines in figure 4.3, postprocessing of the optimized PMM matrix.

(E85TXC2) Calculate ethanol consumption and E85 tax incentive adjustment.

Purpose: This subroutine retrieves the quantity and cost of ethanol from corn and cellulose using the SCOLLP subroutine; and calculates ethanol consumption and the E85 tax incentive adjustment for carbon mitigation.

Equations: Daily ethanol consumption from cellulose is converted into MMgal/yr. The E85 tax incentive adjustment in dollars per barrel ($/bbl) is calculated as the difference between the cost of ethanol from cellulose and the cost of ethanol from corn. (It is not allowed to go negative.)

(PMM_COKGSF) Defines Coke gasification activity.

Purpose: This subroutine retrieves information from the solution LP (related to coke gasification) to define coke gasification levels, hydrogen and syngas production, steam and electricity production, and natural gas consumption, and puts the information into variables for reporting.

Equations: Yields and consumption coefficients, conversion factors, and processing levels are used to calculate syngas and hydrogen production, electricity and steam CHP production, and coke and natural gas consumption by the coke gasification and CHP units at the refinery. Variables include QCOKPRD, QASTPRD, QSGSPRD, QHH2PRD, QKWHPRD, QSTMPRD, and QNGSPRD.

(PMMOUT2) Update Common Block Variables

Purpose: Updates the PMM and NEMS system common block values of refinery production volumes by NEMS refinery product and by PADD. Also updates the total U.S. production volumes by product. This is done at each iteration for every projection year.

Equations: Row activity solution values of the PMM LP, representing total refinery production by PADD by refined product are sequentially retrieved, and corresponding common block variables are set to the matrix solution values or to sums of several values as appropriate. For instance, the common block variable to be updated may be LPG production for PADD I. Then the solution activity for the LP row that controls LPG production volume in PADD I is accessed from the LP solution area and the corresponding common block variable is set equal to that value.

(PRMUPMM) Add refinery fixed costs.

Purpose: Retrieves the marginal petroleum product prices from LP using the SROWLP subroutine and adds on the refinery fixed costs to determine the wholesale petroleum product costs. Demands are summed, and weighted average prices for each product by Census Division and total United States are calculated. The wholesale costs of residual fuel are determined using an econometric equation. Wholesale kerosene prices are set using the wholesale distillate prices.

Equations: Marginal prices for each gasoline are retrieved from the LP solution and refinery fixed costs are added to the marginal prices of each product. (For products RFG, TRG, and E85, the VALUE term is replaced with a term (RFS(prd)PR) that is calculated in subroutines ADJRFGPR, ADJTRGPR, and ADJE85PR, respectively, presented later below.)

$$P_{pr,cd,yr} = VALUE_{pr,cd} + RFPRDFX_{cd,yr,pr} * FXPCT \quad (25)$$

$$RFDL(pr)_{cd,yr} = VALUE_{pr,cd} \quad (26)$$

where:

RFDL(pr)	= refinery marginal prices for each petroleum product pr (w/o markup)
P	= refinery gate price of petroleum product pr [PMG(pr) and P(pr)] (w/ markup)
VALUE	= the marginal value of petroleum product pr
RFPRDFX	= the refinery fixed costs, including refinery operating costs, return on investment, and environmental control costs (see Appendix F).
FXPCT	= percentage allocated of the fixed cost. Fixed costs are allocated only at 80, 80, 90, and 100 percent during the years 2003 to 2006 respectively. This lag in applying total fixed costs takes into account the expected time frame in refinery investment for environmental control costs.
pr	= product
cd	= Census Division
yr	= NEMS index years

If the flag N6XEQSW='ON ', then the wholesale prices of residual fuel are determined as a function of WOP and residual demand fraction, such that:

$$P_{pr,cd,yr} = 42 * (INTCP + SLP * (WOP_{yr}/42) + (CNSNT * ((QRL_{cd,yr} + QRH_{cd,yr})/QPRD_{cd,yr}))) \quad (27)$$

where:

P	= refinery gate price of low and high sulfur residual fuel [PRLEQ, PRHEQ, PRLUTEQ, PRHUTEQ]
INTCP	= -0.057507 or -.117698 for low and high sulfur residual respectively
SLP	= 0.979872 OR 1.001313 for low and high sulfur residual respectively

WOP = World oil price
CNSNT = 0.297792 or 0.42297 for low and high sulfur residual respectively
QRL = Demand for low sulfur residual fuel
QRH = Demand for high sulfur residual fuel
QPRD = Total petroleum product demand
pr = product (N6I, N6B, N67, N68)
cd = Census Division
42 = gallons per barrel
yr = NEMS index years

Demands for all four types of gasoline are summed by Census Division, and a national gasoline total is estimated by summing across Census Divisions:

$$MGDMDT_{cd} = \sum_{t=2,3,4,5} PRDDMD_{cd,yr,t} \quad (28)$$

$$MGDMDGT = \sum_{cd=1,9} MGDMDT_{cd} \quad (29)$$

where:
cd = Census Division 1 through 9
t = motor gasoline index type 2,3,4,5
yr = NEMS year index

National demand for each type of gasoline is estimated by:

$$MGDMD(t) = \sum_{cd=1,9} PRDDMD_{cd,yr,t} \quad (30)$$

where:
cd = Census Division 1 through 9
t = motor gasoline index type 2,3,4,5
yr = NEMS year index

A weighted average gasoline price (with and without markups) is calculated for each Census Division based on prices of the various types of gasoline.

$$PALMG_{cd,yr} = \sum_{pr=2,3,4,5} ((PMG(pr)_{yr,cd} * PRDDMD_{pr,yr,cd})/MGDMDT_{pr}) \quad (31)$$

$$RFDLMG_{cd,yr} = \sum_{pr=2,3,4,5} ((RFDL(pr)_{yr,cd} * PRDDMD_{pr,yr,cd})/MGDMDT_{pr}) \quad (32)$$

where:
PALMG = weighted average gasoline price, with markups

RFDLMG = weighted average gasoline price, without markups
PMG(pr) = refinery gate price of motor gasoline product pr
PRDDMD = product demand (motor gasoline only) by Census Division
MGDMDT = total motor gasoline demand by Census Division
RFDL(pr) = refinery marginal prices for motor gasoline (pr) product only
pr = motor gasoline index 2,3,4,5
cd = Census Division 1 through 9
yr = NEMS year index

National average prices for each product including individual types of gasoline are estimated by:

$$P_{pr,t,yr} = \sum_{cd=1,9} (P_{pr,cd,yr} * PRDDMD_{pr,yr,cd})/PRDDMD_{pr,yr,t} \quad (33)$$

$$RFDL(pr)_{t,yr} = \sum_{cd=1,9} (RFDL(pr)_{cd,yr} * PRDDMD_{pr,yr,cd})/PRDDMD_{pr,yr,t} \quad (34)$$

where:

P = refinery gate price of petroleum product pr [PMG(pr) and P(pr)] (w/ markup)
RFDL(pr) = refinery marginal prices for each petroleum product pr (w/o markup)
PRDDMD = product demand by Census Division
MGDMDT = total motor gasoline demand by Census Division
pr = petroleum product index 1 through 20
cd = Census Division 1 through 9
t = total (across CD) product demand index, 11, for product pr

A composite national average gasoline price is estimated by:

$$PALMG_{t,yr} = \sum_{prx=2,3,4,5} (PMG(pr)_{t,yr} * MGDMD(prx) / MGDMDGT) \quad (35)$$

$$RFDLMG_{t,yr} = \sum_{prx=2,3,4,5} ((RFDL(pr)_{t,yr} * MGDMD(prx) / MGDMDGT) \quad (36)$$

where:

PALMG = national weighted average gasoline price, with markups
RFDLMG = national weighted average gasoline price, without markups
PMG(pr) = refinery gate price of motor gasoline product pr
MGDMD(t) = national demand for each gasoline type (t)
MGDMDGT = total national motor gasoline demand
RFDL(pr) = refinery marginal prices for motor gasoline (pr) product only
pr = motor gasoline ID
prx = motor gasoline index, 2,3,4,5

yr = NEMS year index
t = total (across CD) product demand index, 11, for product pr

(ADJRFGPR) Adjusts the RFG mogas prices based on the dual associated with the Renewable Fuels Standard constraint. (Called by PRMUPMM.)

Purpose: This routine adjusts the RFG mogas price using a weighting (ethanol content in RFG) of the dual on the renewable fuels standard (RFS) constraint (A@ETHBIO), if this constraint is binding. This is required because of the RFS binding constraint and its impact on duals of other constraints linked by common column variables.

Equations: None

(ADJTRGPR) Adjusts the TRG mogas prices based on the dual associated with the Renewable Fuels Standard constraint. (Called by PRMUPMM.)

Purpose: This routine adjusts the TRG mogas price using a weighting (ethanol content in TRG) of the dual on the renewable fuels standard (RFS) constraint (A@ETHBIO), if this constraint is binding. This is required because of the RFS binding constraint and its impact on duals of other constraints linked by common column variables.

Equations: None

(ADJE85PR) Adjusts the E85 prices based on the dual associated with the Renewable Fuels Standard constraint. (Called by PRMUPMM.)

Purpose: This routine adjusts the E85 price using a weighting (ethanol content in E85) of the dual on the renewable fuels standard (RFS) constraint (A@ETHBIO), if this constraint is binding. This is required because of the RFS binding constraint and its impact on duals of other constraints linked by common column variables.

Equations: None

(PMMPD_MGPR) Set Mogas price by PADD using average CD markups. (Called by PRMUPMM.)

Purpose: Set Mogas prices by PADD based on average CD prices and markups.

Equations: Marginal prices [row D(d)(prd)] and demand levels [col D(d)(prd)S1] for each gasoline are retrieved from the LP solution by CD and averaged into PADD level prices.

(DSTCPMM) Estimate atmospheric distillation capacity and refinery utilization.

Purpose: Extracts capacity expansion information from LP. Estimates annual distillation capacity, utilization, and annual and cumulative capacity expansion. Totals refinery region (PADDs I through V) estimates to produce national estimates.

Equations: Refinery distillation capacity is defined as a percentage (ranging from 93 percent to 96 percent for *AEO2006* of total capacity to account for over-optimization in the LP. Units are converted to MMBCD and the U.S. total is determined.

(COGNPMM) Estimate refinery combined heat and power (CHP) generation.

Purpose: Retrieves refinery capacity, investments, and generation from the LP solution using the SCOLLP subroutine.

Equations: Results are shared out to Census Divisions, fuel categories, and self or grid categories. U.S. and PADD totals are calculated. Estimates are converted to trillion Btu. PADD level estimates for CHP, CHP capacity, refinery fuel consumption, generation for self and for the grid are then allocated to the various Census Divisions. The estimates for fuel consumption, capacity, and generation are desegregated by fuel type and by generation to grid versus to self. Includes CHP associated with CTL production and coke gasification. Census Division estimates are summed to U.S. totals. Note: 1)since syngas (feed to the CHP) is derived from coke, which is derived from oil, the syngas used for cogen by the CHP is reported in the "oil" category; and 2)coal used for CTL conversion and cogen production is reported in the "other" category.

(COGNCHP) Estimate refinery CHP from syngas produced by coke gasification units. (Called by COGNPMM.)

Purpose: Retrieves capacity and generation from the CHP unit that uses syngas produced by the coke gasification units.

Equations: PADD and U.S. total electricity generated from CHP is obtained from the solution; fuel consumed for CHP is calculated for syngas and natural gas; and corresponding generating capacity additions are determined in terms of MW.

(ELPMMRD) Calculate electricity consumption data.

Purpose: ELPMMRD retrieves the electricity consumption activity from the LP using the SCOLLP subroutine.

Equations: Converts units to KWh and disaggregates refinery region (PADDs) data to the Census Divisions.

(PMMRFFU) Estimate refinery fuel use.

Purpose: Estimates refinery consumption of distillate, residual fuel, coal, LPGs, natural gas, still gas, petroleum coke (cat coke and gasified coke), and other petroleum products by refinery regions.

Equations: Retrieve fuel use values from the LP using the SCOLLP subroutine and converts units to MMBtu. Sums refinery region data to U.S. totals and determines total U.S refinery petroleum fuel use (minus natural gas fuel use).

(RPTAKGTL) Retrieve Alaska GTL production and natural gas consumption for GTL production from model results (for reporting).

Purpose: This subroutine retrieves the GTL-related information from the LP solution and processes it into variables for reporting.

Equations: Retrieves the natural gas consumption results from the LP solution, totals across steps, converts to BCF/yr, and stores results in the report variable AKGTL_NGCNS. Retrieves GTL production levels from the LP solution, totals across types, and stores in the report variable Q_GTLPRD. Also sets the Alaska GTL production variable AKGTLPRD and the export variable AKGTLEXP (=0).

(RPTRFCTL) Retrieve CTL production and coal consumption used for CTL production from model results (for reporting).

Purpose: This subroutine defines the CTL production level and the corresponding coal consumption level used in reports.

Equations: CTL processing level results are retrieved from the LP solution to define the CTL production level. It also retrieves the coal consumption level from the CTL coal supply curve results and defines the corresponding coal consumption level (QCLRFPD). Coal prices (CLMINEP) are obtained from the dual on the coal balance constraint, reduced by the coal transfer costs, as well as carbon, mercury, and SO2 emissions allowance costs. Also, corresponding CHP production is recorded.

(RFDMDFU) Convert refinery fuel use to Census Division demands.

Purpose: Converts refinery region (PADDs) level estimates for refinery fuel consumption to Census Division demands.

Equations: Calculates refinery fuel consumption in each Census Division based on refinery region estimates.

(PMMOUTP) Update the Common Block Variables and renewable fuels demanded by refineries.

Purpose: Updates a number of NEMS common block price and volume variables whose values are determined by output of the PMM LP, including product prices, crude prices, import prices, fuel use, gain, etc. Also, accounts for renewable fuels demanded for blending into gasoline and diesel fuel. This subroutine is run each NEMS iteration.

Equations: Various values are sequentially pulled out of the LP solution area, and corresponding common block variables are set to various functions of the solution values.

The row matrix solution values accessed are activity, slack, lower bound, upper bound, and pi. The column values are for activity, cost, lower bound, upper bound, and DJ. For instance, the common block variable to be updated may be total product imports. For this result, the activity for the LP row that controls product imports is obtained from the solution and the corresponding common block variable is set equal to that value adjusted for any difference in units of measure.

(PMMOUT3) Update Common Block Variables

Purpose: Updates the PMM and NEMS system common block values related to refinery production volumes (by NEMS refinery product and by PADD). Also updates the total U.S. production volumes (by product). This is done everey iteration and projection year. This routine also determines crude and product quantities, LPG, and other product movements along transfer links for the PMMRPTS report file.

Equations: Row activity solution values of the PMM LP, representing total refinery production by refining region and by refined product, are sequentially read; and, corresponding common block variables are set to the matrix solution values, or to sums of several values, as appropriate. Similarly, crude and product quantities are extracted from the PMM LP solution and put into report variables. LPG and product movements are totaled for each transport link and transport mode (subroutines PMM_LPGMOVE and PMM_PRODMOVE).

(DCRDPRC) Retrieves domestic crude marginal prices from the LP solution.

Purpose: DCRDPRC retrieves the marginal values of domestic crude (by OGSM region and crude type) by using the SROWLP subroutine.

Equations: None.

(WCNVFCT) Calculates the heat rates for petroleum product imports and exports and motor gasoline.

Purpose: WCNFCT calculates the quantity weighted average heat rates for petroleum product imports and exports, natural gas liquids, and motor gasoline.

Equations: The average heat rate for imported petroleum product is calculated using the weighted average of each product's heat rate. This methodology is also used to calculate calculation is also performed for the exported petroleum product's average heat rate and the natural gas liquids' average heat rate. The heat rate for each motor gasoline (e.g., RFG, RFH, TRG, TRH) 's heat rate is used to calculate the quantity weighted average aggregate gasoline heat rate.

For example, given a list of product imports (LPG, conventional and reformulated gasoline, jet fuel, distillate, residual fuel (high and low sulfur), petrochemical feed, ULSD, and other petroleum products), the weighted average equation is:

$$CF = [\Sigma_p (qty_p * CF_p)] / \Sigma_p (qty_p) \quad (37)$$

where, p = type of product imported
qty_p = quantity of product p
CF_p = heat rate of product p
CF = average heat rate of total imported product

(DOMU) Calculate end-use prices by sector.

Purpose: DOMU breaks wholesale petroleum products prices into sectoral end-use product prices.

Equations: Sectoral end-use prices are calculated by adding two sectoral markups, one for taxes (MU2) and the other for transportation costs (MU1), to the wholesale prices for each petroleum product. Units are converted to $/MMBTU and the motor gasoline price is calculated as the quantity weighted average price of the four motor gasoline types.

(ADJMU1) Reset markups (MU1) as a function of the 2003 ratio of a product's original markup to the citygate Price. (called by DOMU, if current itereation =1)

Purpose: This routine sets the non-tax markup (MU1) for each refinery product (by Census Division) as a percent of wholesale price (WHSP). This markup ratio (MU1RAT) is calculated from 2003 historical data (P=end-use price, MU2=tax markup). The ratio is then applied to the wholesale price to define the non-tax markup.

Equations: using 2003 data,

$$WHSP_{s,cd,p} = P_{s,cd,y} - (MU1_{s,cd,p} + MU2_{s,cd,p})$$
$$MU1RAT_{s,cd,p} = MU1_{s,cd,p} / WHSP_{s,cd,p}$$

each forecast year:

$$MU1_{s,cd,p} = MU1RAT_{s,cd,p} * WHSP_{s,ccd,p}$$

(FCCMODOP) Retrieves the fluid catalytic crackers' modes of operations activity level from the LP solution.

Purpose: This subroutine retrieves the activity level and the reduced cost information from the FCC modes of operations columns in the LP solution.

Equations: None.

(ALKMODE) Retrieves the operating level for the sulfuric acid alkylation units.

Purpose: This subroutine retrieves the operating level of the sulfuric acid alkylation unit (for each operating mode) from the LP solution.

Equations: None.

(GETPMMO) Retrieve objective function values from the LP solution.

Purpose: This subroutine retrieves the objective function value from the LP solutions for reporting in the detailed PMM reports.

Equations: None.

(RFCAPX) Calculate refinery capital expenditure.

Purpose: RFCAPX calculates refinery capital expenditure (RFREV). (Variable RFREV no longer used in NEMS.)

Equations: $$RFREV_{yr} = RFREV_{yr-1} * 1.023 \quad (38)$$

RFREV = refinery revenue (0.4 in 1990)
yr = NEMS year
1.023 = growth rate

(MGSPCDL) Retrieves motor gasoline specification information.

Purpose: This subroutine retrieves the motor gasoline specifications LP row status and dual value for reporting.

Equations: None.

(PMM_HH2RPT) Defines hydrogen produced and consumed at the refinery, for reporting.

Purpose: This subroutine calls the routines (PMM_HH2MAP, PMM_HH2CP) that define hydrogen production and consumption at the refinery and puts the information into variables for reporting. There are three qualities of hydrogen present at the refinery: HYL (low), HYM (medium), and HYH (high).

Equations: None.

(PMM_HH2MAP) Identifies which processing units produce and consume hydrogen. (called by PMM_HH2RPT)

Purpose: Fills variables used to map which processing units produce and consume hydrogen. Variables include: HH2_RUNITP, HH2_UNITP, HH2_RUNITC, HH2_UNITC, HH2_HUNITP, HH2_HUNITC (the latter 2 pertain to merchant plant units)

Equations: none.

(PMM_HH2CP) Aggregates hydrogen production and consumption by processing unit, PADD, year. (called by PMM_HH2RPT)

Purpose: This routine extracts operating results (related to processing units that produce and consume hydrogen) from the LP solution and puts the totals into report variable (HH2_CONS, HH2_PROD), organized by processing unit, PADD, and year.

Equations: Yield and consumption coefficients, processing levels, and other factors are used to calculate hydrogen production and consumption at the refinery. Units producing and consuming hydrogen had to be identified.

4.4 Capacity Expansion Subroutine

Section 4.4 describes the function of the subroutines in figure 4.4, preprocessing the PMM matrix for capacity expansion expectation. Since most of the subroutines used for capacity expansion are also used in section 4.2, the subroutines presented below represent routines ONLY used for capacity expansion. Therefore, refer to section 4.2 for the remainder of the subroutines listed in Figure 4.4.

(XPMMLP) Set up and solve expected PMM LP for capacity expansion loop.

Purpose: XPMMLP calls numerous subroutines to set up the LP for the capacity expansion look ahead year, solves the LP, and writes the basis for that solution.

Equations: None.

(CHGPUINV) Update bounds on processing unit investment capacities.

Purpose: CHGPUINV updates the processing unit investment and cumulative build limits (bounds) in the LP during the capacity expansion iteration.

Equations: Processing unit investments are generically upper bounded at 1000 Mbbl/cd [except: cogen (CGX) at 2400 MWh/cd, steam plant (STG) at 20 MM lb/cd, units producing ULSD streams (PSZ, HD1, HD2, HS2) at 850 M bbl/cd, and CTL units in Padd 3 at 6*CTL_BASSIZ]. Cumulative builds are fixed bounded based on the processing unit builds to date. (M=1000)

(CHGBLDLIM) Set initial capacity build limit

Purpose: CHGBLDLIM sets the initial capacity build limit to correspond to the flags set in the qdcrdcf.txt input file. If flag says no build allowed, then UL set to 0; if build allowed, then UL is initially set to 800 M bbl/cd.

Equations: None.

(PMMCTL_BLDLIM) Set minimum and maximum builds allowed for CTLs. (Called by CHGPUINV.)

Purpose: PMMCTL_BLDLIM sets the minimum and maximum builds allowed nationally for CTLs if the Mansfield-Blackman penetration model is used.

Equations: Appendix F, Section F.18 presents the equations related to the Mansfield-Blackman penetration model used by the PMM.

(PMMISOCAP) Sets IsoOctane production capacity limits as a function of MTBE capacity reduction.

Purpose: If MTBE is banned, then maximum build levels for IsoOctane units are set as a function of MTBE production units decommissioned. (Called only during capacity expansion decision, before optimization occurs.)

Equations: Allow IsoOctane build as a fraction of MTBE production capacity, with a growth rate of 1.7% annually (over the 3-year expansion horizon) to reflect the average annual growth rate in petroleum consumption through the forecast period.

$$CAPIOT(I) = MTBEcap * ISOCVRTX * (1.017**3) \quad (39)$$

Where, MTBEcap is the decommissioned MTBE production capacity
ISOCVRTX is the capacity conversion rate (70% maximum)

4.5 OML Specific Subroutines

Additional subroutines used to perform Optimization Modeling Library (OML) specific LP matrix operations during the matrix pre- and post-processing are presented below.

(CBNDLP) Update LP column bounds.

Purpose: The LP column bounds are updated with using the OML function WFCBND.

Equations: None.

Data Passed: COLNAME, column name, LWBD, lower bound, UPBD, upper bound

(CNAMELP) Retrieve LP column name.

Purpose: Retrieves LP column name using the OML function WFCNAME.

Equations: None.

Data Passed: I, column index, NAME, column name

(CRNGLP) Update a LP RHS range with the specified value.

Purpose: Updates the range of an LP matrix RHS using the OML function WFCRNG

Equations: None.

Data Passed: ROWNAME, row name, RNGVAL, range value

(CRHSLP) Update a LP RHS with the specified value.

Purpose: Updates an LP matrix RHS using the OML function WFCRHS

Equations: None.

Data Passed: ROWNAME, row name, RHSVAL, right hand value

(RRHSLP) Retrieve RHS value in the LP matrix.

Purpose: Retrieves RHS value in the LP matrix using the OML function WFCRHS

Equations: None.

Data Passed: ROWNAME, row name, RHSVAL, right hand value

(CMASKLP) Obtain a set of column variable names from the LP.

Purpose: Obtain a set of column variable names from the LP to loop over for variable updates.

Equations: None.

Data Passed: NAMIN, partial column name (mask), NAMOUT, full column name

(CVALLP) Update coefficient value in the LP matrix.

Purpose: Updates coefficient value in the LP matrix using the OML function WFCVAL.

Equations: None.

Data Passed: COLNAME, column name, ROWNAME, row name, VAL, coefficient value

(RVALLP) Retrieve coefficient value in the LP matrix.

Purpose: Retrieves coefficient value in the LP matrix using the OML function WFRVAL.

Equations: None.

Data Passed: COLNAME, column name, ROWNAME, row name, VAL, coefficient value

(MPSINLP) Load the PMM LP matrix file into an OML matrix file.

Purpose: This subroutine calls an OML function which reformats an MPS formatted file into an OML LP matrix format.

Equations: None.

(PUNCHLP) Save the current basis to a file.

Purpose: Saves the current basis to a file using the OML function WFPUNCH.

Equations: None.

(RBNDLP) Retrieve bound values from a column.

Purpose: Retrieves bound values from a column using the OML WFRBND function.

Equations: None.

Data Passed: COLNAME, column name, LWBD, lower bound, UPBD, upper bound

(RNAMELP) Retrieve row names from the matrix LP.

Purpose: Retrieves row names from the matrix LP using the OML function WFRNAME.

Equations: None.

Data Passed: I, row index, NAME, row name

(SCOLLP) Retrieve solution column values from the LP solution.

Purpose: Retrieves solution column values from the LP solution using the OML function WFSCOL.

Equations: None.

Data Passed: COLNAME, column name, SLCT selected range, STATC, status value,VALUE, values

(SROWLP) Retrieve the current solution row from memory.

Purpose: Retrieves the current solution row from memory using the OML function WFSROW, which retrieves the specified solution (activity, slack, lower limit, upper limit, PI value) and status (basic, upper limited, lower limited, equal, free) into a predefined array.

Equations: None.

APPENDIX A

PMM Data and Outputs

APPENDIX A PMM Data and Outputs

This appendix is divided in three parts: Section A.1 lists the variables and definitions used in the PMM, Section A.2 lists the data sources, and Section A.3 lists the data tables (and their structures) used by the MRM (Multi-Refining Model) to create the initial PMM matrix that is loaded into the NEMS environment. These data tables constitute the major portion of the PMM data as they represent the refining process unit technology and capacities, quality characteristics, and specifications used in each of the five refining regions (1= PADD I, 2= PADD II, 3= PADD III, 4= PADD IV, 5= PADD V).

(Note: Only 3 regions were modeled between *AEO98* and *AEO03*, 1= PADD I, 2= PADDs II,III,IV, 3= PADD V).

A.1 PMM Variables and Definitions

This section presents the PMM variable names and definitions associated with the linear programming (LP) matrix, PMM outputs, PMM inputs, and internally used variables.

A.1.1 PMM LP and NEMS Variable Names Cross References

A cross reference listing between the PMM LP matrix names and NEMS variable names is shown in Table A1. The dimensional units are based on the PMM LP variables. The NEMS variable units may vary to conform to NEMS standards. Abreviations are defined in the Legend at the end of the table.

Table A1. PMM/NEMS Cross References

PMM LP Variable	LP Units	NEMS Variable
A (pd) CHPCGN	MkWh/cd	CHP_CGGENPD
A (cd) G08TRH	Mbbl/cd	SBG08TRH, RFETHMGS(MMbbl/cd)
A (cd) G08TRG	Mbbl/cd	SBG08TRG, RFETHMGS(MMbbl/cd)
A (cd) G08RFH	Mbbl/cd	SBG08RFH, RFETHMGS(MMbbl/cd)
A (cd) G08RFG	Mbbl/cd	SBG08RFG, RFETHMGS(MMbbl/cd)
A (pd) (prd)	Mbbl/cd	RFDPRD(prd),QPRDRF
A (pd) SST	Mbbl/cd	RFDPRDTRG, QPRDRF
A (pd) SSR	Mbbl/cd	RFDPRDRFG, QPRDRF
A (pd) SSE	Mbbl/cd	RFDPRDTRG, QPRDRF
A (pd) STM	M lb /cd	STMDMD
A (pd) ETHRFN (incl merchant)	Mbbl/cd	RFETHETB(net merchant)(MMbbl/cd)
A (pd) (gbc)RFG	Mbbl/cd	RFGBCRFG
A (pd) (gbc)TRG	Mbbl/cd	RFGBCTRG
A (pd) DSLCTI	CETANE	DSLCTI
A (pd) DSUCTI	CETANE	DSUCTI
A (pd) RFGM00	OCTANE	OCTRFGM00
A (pd) RFGR00	OCTANE	OCTRFGR00
A (pd) TRGM00	OCTANE	OCTTRGM00
A (pd) TRGR00	OCTANE	OCTTRGR00
A@CRDDCR	Mbbl/cd	RFCRDDCR
A@CRDEXP	Mbbl/cd	RFQEXCRD
A@CRDL48	Mbbl/cd	RFCRDL48

NAME	LP Units	NEMS Variable
A@CRDAKA	Mbbl/cd	RFCRDAKA
A@CRDTOT	Mbbl/cd	RFCRDTOT (MMbbl/cd)
A@CRDFCR	Mbbl/cd	RFQICRD (MMbbl/cd), RFIMCR(MMbbl/cd)
A@ETHPRD	Mbbl/cd	RFETHD (MMbbl/cd)
A@FUEL	Mbbl/cd	QCDUPD (MMbbl/cd)
A@GAIN, A@PETCOK, A@SULSAL, P(r)COK	Mbbl/cd	RFQPRCGo (MMbbl/cd)
A@INVST	M$87/cd	RFCAPEXP
A@MTBIMP	Mbbl/cd	RFMTBI (MMbbl/cd)
A@METIMP	Mbbl/cd	RFMETI (MMbbl/cd)
A@METDEM	Mbbl/cd	RFMETCHM (MMbbl/cd)
A@METM85	Mbbl/cd	RFMETM85 (MMbbl/cd)
A@NGFTOT	Mbbl/cd	RFNGFTOT
A@NGLPRD	Mbbl/cd	RFPQNGL (MMbbl/cd)
A@NGLRFN	Mbbl/cd	RFQNGLRF (MMbbl/cd), NGLRF (MMbbl/cd)
A@NGSH2P	Mbbl/cd	RFHCXH2IN (MMbbl/cd)
A@PRDEXP	Mbbl/cd	RFQEXPRDT (MMbbl/cd)
A@PRDIMP	Mbbl/cd	RFPQIPRDT (MMbbl/cd)
A@PETCOK	Mbbl/cd	RFQPRCG (MMbbl/cd)
A@UNFIMP	Mbbl/cd	RFPQUFC (MMbbl/cd)
B (pd) TRGETH, B(r)RFGETH	Mbbl/cd	BLDETHRF
B (pd) ETB	$87/bbl (dual)	PETB
B (pd) TAE	$87/bbl (dual)	PTAE
B (pd) THE	$87/bbl (dual)	PTHE
B (pd) MTB	$87/bbl (dual)	PMTB25
B (pd) THM	$87/bbl (dual)	PTHM
B (pd) TAM	$87/bbl (dual)	PTAM
B (pd) SRI	$87/bbl (dual)	PSRI
B (pd) FC8	$87/bbl (dual)	PFC8
B (pd) R10	$87/bbl (dual)	PR10
B (pd) ALB	$87/bbl (dual)	PALB
B (pd) KHL	$87/bbl (dual)	PKHL
B (pd) 2HL	$87/bbl (dual)	P2HL
B (pd) RSI	$87/bbl (dual)	PVAF
B (pd) (oxy)	$87/bbl (dual)	P(oxy)RFBL
B (pd) IC4	$87/bbl (dual)	PGPLTRF
B (pd) NC4	$87/bbl (dual)	PGPLTRF
C@ETHBIO	$87/bbl (dual)	PETHRFS, ETHBIODUAL
CAA (crd)	$87/bbl (dual)	PCRDRF, RFDCRDP, CRDTYPEP,WLLHDPR
C (pd) D (crdtype)	$87/bbl (dual)	PCRDRF,RFDCRDP,CRDTYPEP,WLLHDPR
C (cd) ETHR (q(k))	Mbbl/cd,[$87/bbl]	WQETOH,SQETOH,CRNETHCD,[CRNCSTCD]
C (cd) ETCR (q(k))	Mbbl/cd,[$87/bbl]	WQETOH,SQETOH,CLLETHCD,CLLCAPCD, [CLLCSTCD]
C (cd) BIMR (q(k))	Mbbl/cd,[$87/bbl]	WQBDSL, BIMQTYCD, RFBIOD, [WPBDSL, BIMCSTCD]
C (cd) BINR (q(k))	Mbbl/cd,[$87/bbl]	WQBDSL, BIMQTYCD, RFBIOD, [WPBDSL, BIMCSTCD]
C(pd)CTLTOT	Mbbl/cd	Q_CTLPRD, RFCTLPRD
C (pd) F (crdtype)	$87/bbl (dual)	PCRDRF
D (cd) ETH	$87/bbl (dual)	PETHANOL,RENADJPR, RENETHPR
D (cd)(prd) N (q(K))	Mbbl/cd,$87/bbl	QN,PN
D (cd)(prd) P (q(k))	Mbbl/cd,$87/bbl	QP,PP
D (cd)(prd) S1	Mbbl/cd	PRDDMD
D (cd) (prd) SX	Mbbl/cd	QPRDEX
D (cd) COKSX	$87/bbl, [Mbbl coe/cd]	RFWOP, PCOKH, [RFQEXPRDT, COKEXUL (MMbbl coe/cd)]
D (cd) (prd) Z9	Mbbl/cd, [87$/bbl]	QPRDEXD, [RFWOP,WOPZ9EXP]

NAME	LP Units	NEMS Variable
D (cd) (prd)	$87/bbl (dual)	RFDL(prd), P(prd)
D (cd) BIM	$87/bbl (dual)	BIMMCSTCD
D (cd) (prd)	$87/bbl (dual)	RFDL(prd), P(prd)
D (cd) (mogas)	$87/bbl (dual)	RFGT(mogas), RFGTMG
D@METS1	Mbbl/cd	PRDDMDME
E (pd) ACUINV	Mbbl/cd	RFDSTCAP, RFDSTUTL, RFDSCUM (MMbbl/cd)
E (pd) CGNINV	Mkwh/cd	EINVPD
E (pd) CGXINV	Mkwh/cd	EXINVPD
E (pd) CHPINV	Mbbl FOE/cd feed	CHP_UNPLNCPD (MW)
E (pd) (prcunit)INV	Mbbl/cd	PUBASEUT, PUBASE, PUINV
E (pd) (emissn) (emisst)	M lb/cd	RFEMISST (MMton/yr)
G (pd) CC3LPG	Mbbl/cd	QGPLTRF
G (pd) IC4LPG	Mbbl/cd	QGPLTRF
G (pd) NC4LPG	Mbbl/cd	QGPLTRF
G (pd) NATOTH	Mbbl/cd	QGPLTRF
G (pd) NATPCF	Mbbl/cd	QGPLTRF
G (pd) DGR	Bcf/cd	QGPLTRF
G (pd) GPL01	Bcf/cd	QGPLTRF
G (pd) IC4RFN	Mbbl/cd	QGPLTRF
G (pd) MOH01	Mbbl/cd	RFMETD (MMbbl/cd), RFMETETH (MMbbl/cd)
G (pd) NC4RFN	Mbbl/cd	QGPLTRF
G (pd) NATRFN	Mbbl/cd	QGPLTRF
G (pd) PGSLPG	Mbbl/cd	QGPLTRF
G (pd) PGSPCF	Mbbl/cd	QGPLTRF
G (pd) SC2CC1	Mbbl/cd	QGPLTRF
G (pd) SC3CC1	Mbbl/cd	QGPLTRF
G (pd) METRFN	Mbbl/cd	QMETRFN
H (pd) RFMPEH	Mbbl/cd	RFETHMCT (MMbbl/cd)
H (pd) RFMPMT	Mbbl/cd	RFMETMCT (MMbbl/cd), RFMETETH (MMbbl/cd), QRFMPMT
H (pd) CTX(mod), H(pd)CTZ(mod)	Mbbl/cd	RFCTLLIQ
	$87/s-ton (dual)	P_CTLCOAL, CLMINEP
H (pd) ETXETB	Mbbl/cd	RFETBMCT (MMbbl/cd)
H (pd) ETXMTB	Mbbl/cd	RFMTBMCT (MMbbl/cd)
H (pd) GPMPI4	Mbbl/cd	QGPLTRF
H (pd) GPMPN4	Mbbl/cd	QGPLTRF
H (pd) SMD(mod), H(pd)SOD(mod)	Mbbl/cd	Q_GTLPRD
I (pd) (prd) Z9	Mbbl/cd	QPRDIMD
I (pd) (iprd) R (q(k))	Mbbl/cd,[$87/bbl]	QI(iprd), PI (iprd), QPRDIMP
I (pd) (iprd) R (q(k))	$87/bbl,Mbbl/cd	RFIPQ??, ITIM??SC, q(prd), p(prd), where ?? = LG, MG(GS), RG, DL(LD), DS, DU, RL, RH, JF, OT, PF, ME, MT
I (pd) MTBR (q(k))	Mbbl/cd	RETHRIMP
K (pd) (prcunit) CAP	Mbbl/cd	PUBASEUT, PUBASE
K (pd) ACUCAP	Mbbl/cd	DSTCAP, DSTUTL, RFBDSTCAP (MMbbl/cd)
K (pd) CGNCAP	Mkwh/cd	RFCGCAPPD (MW)
K (pd) CGXCAP	Mkwh/cd	RFCXCAPPD, RFCGCAPPD (MW)
K (pd) CHPCAP	Mbbl FOE/cd feed	CHP_CGCAPPD (MW)
K (pd) FGSCAP	Mbbl/cd	FGS_UL, FGS_SOL
L (pd) (prcunit)BLD	Mbbl/cd	PUBASEUT, PUBASE, PUCUM , PUINV
L (pd) ACUBLD	Mbbl/cd	RFDSTCAP, RFDSTUTL,RFDSCUM (MMbbl/cd)
L (pd) CGNBLD	Mkwh/cd	LBLDPD
L (pd) CGXBLD	Mkwh/cd	LXBLDPD
L (pd) CHPBLD	Mbbl FOE/cd feed	CHP_UNPLNCPD (MW)
L (pd) CTXBLD	Mbbl/cd	CTLBLT
M (pd) (prd)	$87/bbl (dual)	RFGT (prd)

NAME	LP Units	NEMS Variable
N (pd) (coal) (q(k))	Mton/cd, 87$/ton	Q_CTLCOAL, QCLRFPD (tril Btu/yr),
N (pd) NGKN (q(k))	Mbbl foe/cd	AKGTL_NGCNS(BCF/yr), AKNG_SUPCRV(BCF/yr), Q_GTLGAS (BCF/yr)
N (pd) NGRFP (q(k))	MMcf/cd	NGRFUPIT, NGRFUTOT
N (pd) NGRFN (q(k))	MMcf/cd	NGRFUPIT, NGRFUTOT
N (pd) DGP	Bcf/day	PRNG_PADD, QNGPD
NZAMHP(q(k)), NZAMHN(q(k))	Mbbl/cd	ALKEXPTOT
OBJ	M $87/cd	PMMOBJ
O@CRDSPR	Mbbl/cd	RFSPRFR
O@CRDEXP	Mbbl/cd	QEXCRDIN
P (pd) COK	Mbbl foe/cd	QCDUPD(MMbbl foe/cd), RFQPRCG (MMbbl foe/cd), QCOKFU
PANGLQ1	Mbbl/cd	QGPLTRF, OGNGLAK
P (og) DCRQ1	Mbbl/cd, ($87/bbl)	RFQTDCRD, RFDCRDP ($87/bbl), CRDTYPEP($87/bbl)
P (pd)F(crdtype)Q(q(k)	Mbbl/cd,$87/bbl	RFIPQC (crdtype), QICRD, PICRD, Q_ITIMCRSC, ITIMCRGN
P (pd) PFU	MFOED	PRPFU(5)
P (pd) PFF	MFOED	PRPFF(5)
Q (pd) RFG (spec)	$87/bbl (dual)	RFGSPCDL
Q (pd) TRG (spec)	$87/bbl (dual)	TRGSPCDL
Q(pd)(prd)(spec)(minmax)	Many	MGSPCS
R (pd) ALK (mode)	Mbbl/cd	ALKACT
R (pd) ACUF (crdtype)	Mbbl/cd	QCRDRF
R (pd) ACUD (crdtype)	Mbbl/cd	QCRDRF
R (pd) ACUA (crdtype)	Mbbl/cd	QCRDRF
R (pd) CHP(mode)	Mbbl FOE/cd	CHP_NGFUELPD, CHP_SGFUELPD, QNGSPRD
R (pd) CHP(mode)	Mbbl FOE/cd	KWHCHP(mode), QKWHPRD (MkWh/cd), QSTMPRD (M lb /cd)
R (pd) CGNCGN	M kwh/cd	RFCGGENPD
R (pd) CGXCGN	M kwh/cd	RFCXGENPD
R (pd) ETHMTB	Mbbl/cd	RFMTBD (MMbbl/cd)
R (pd) ETHETB	Mbbl/cd	RFETBD (MMbbl/cd)
R (pd) ETMTAE	Mbbl/cd	RFTAED (MMbbl/cd)
R (pd) ETMTAM	Mbbl/cd	RFTAMD (MMbbl/cd)
R (pd) ETMTHE	Mbbl/cd	RFTHED (MMbbl/cd)
R (pd) ETMTHM	Mbbl/cd	RFTHMD (MMbbl/cd)
R (pd) FUMN2H	Mbbl/cd	QDISFU
R (pd) FCC(mod)	Mbbl/cd, ($87/bbl)	FCC (mod), FCCACT, FCCDUAL ($87/bbl)
R (pd) FUMN6I	Mbbl/cd	QRESFU
R (pd) FUMN6A	Mbbl/cd	QRESFU
R (pd) FUMN6B	Mbbl/cd	QRESFU
R (pd) FUMCC3	Mbbl/cd	QLPGFU
R (pd) FUMUC3	Mbbl/cd	QLPGFU
R (pd) FUMIC4	Mbbl/cd	QLPGFU
R (pd) FUMUC4	Mbbl/cd	QLPGFU
R (pd) FUMNC4	Mbbl/cd	QLPGFU
R (pd) FUMC2E	Mbbl/cd	QSTGFU
R (pd) FUMPGS	Mbbl/cd	QSTGFU
R (pd) FUMCC2	Mbbl/cd	QSTGFU
R (pd) FUMCC2	Mbbl/cd	QSTGFU
R (pd) FUMPGU	Mbbl/cd	QSTGFU
R (pd) FUMPGX	Mbbl/cd	QSTGFU
R (pd) FUMPGT	Mbbl/cd	QSTGFU
R (pd) FUMNGS	Mbbl/cd	QNTGFU
R (pd) FUM (rfothfu)	Mbbl/cd	QOTHFU
R (pd) FUM (pnfut)	Mbbl/cd	RFFMT
R (pd) GSF (mode)	M s-ton/cd	QCOKPRD, QSGSPRD (M bbl foe/cd)
R (pd) GSH (mode)	M s-ton/cd	QCOKPRD, QHH2PRD (M bbl FOE/cd)

NAME	LP Units	NEMS Variable
TAGTLTOT	Mbbl/cd	AKGTLPRD, MINGTLNS
T(r)OVCOBJ	1000 $87/cd	RFOPEXP
T (pd) UNFNPP	$87/bbl	RFWOP, NPPCOEF
T (pd) UNFHGM	$87/bbl	RFWOP, HGMCOEF
T (pd) UNFARB	$87/bbl	RFWOP, ARBCOEF
U (pd) KWH (column)	MkWh/cd	RFELPURPD (MMkwh/cd), QELRF (Tril Btu/yr)
U (pd) KWH (row)	$87/ MkWh (dual)	PRFELPURPD ($87/M kWh)
U (pd) NGF (row)	$87/MMcf (dual)	PRFNGFU, PGININ, OGWPRNG
VTPC (crd)	Mbbl/cd	FLOWCRD, CAPCRD (utz)
VTPP (crd)	Mbbl/cd	FLOWPRD, CAPPRD (utz)
VTPL (crd)	Mbbl/cd	FLOWLPG, CAPLPG
W (pd) (prd) J (cd)	Mbbl/cd	FLOWPD_CT
W (pd) (prd) 4 (cd)	Mbbl/cd	FLOWPD_DT
W (pd) (prd) B (cd)	Mbbl/cd	FLOWPD_CB, FLOWPD_ECB
W (pd) (prd) V (cd)	Mbbl/cd	FLOWPD_EDB, FLOWPD_DB
W (cd) ETH M (pd)	Mbbl/cd	FLOWPD_DB
W (pd) (prd) O (cd)	Mbbl/cd	FLOWPD_LT
W3ETH(m)(pd), W4ETH(m),(pd)	Mbbl/cd	QETHRFN
X (pd) AST0	M bbl FOE/cd	QASTPRD
X (pd) CKLCOK	$87/bbl	RFWOP, PCOKL
X (pd) CKHCOK	$87/bbl	RFWOP, PCOLH, [QCOKPRD (M s-ton/cd)]
X (pd) SULSAL	1000 sTon/cd	QSULSAL
X (cd) ETHE85	Mbbl/cd	RFETHE85 (MMbbl/cd), ETHE85CD
X (cd) ETHRFG	Mbbl/cd	SBRFGRFG
X (cd) ETHRFH	Mbbl/cd	SBRFGRFH
X (cd) ETHTRG	Mbbl/cd	SBTRGTRG
X (cd) ETHTRH	Mbbl/cd	SBTRGTRH
ZZAMHTOT	Mbbl/cd	Function of WOP
Z (cd) ETHTAX	Mbbl/cd, $87/bbl	CORNETH, CORNSUB
Z (cd) ETCTAX	Mbbl/cd, $87/bbl	CELLETH, CELLSUB
Z@IRACX	$87/bbl	RFWOP
Z@IRACN	$87/bbl	RFWOP
Z@TOTCRD	$87/bbl	RFWOP, IRACN, IRACX

Legend for Codes

Code	Name	Values	No. in Set
(cd)	Census Divisions	1-9	9
(coal)	Coal Types	regional	3
(crdtype)	Crude Types	LL-HV	5
(emissn)	Emissions	VOC-CAR	6
(emisst)	Combustion/Noncombustion	C,N	
(gbc)	Gasoline Blend Component	00-12	13
(iprd)	Imported Products	LPG-DSL	12
(minmax)	Minimum or Maximum	N,X	
(mod)	Operating mode	many	many
(oxy)	Oxygenate	ETH, MET, MTB	3
(og)	Oil and Gas Divisions	1-6,A	7
(pd)	Refinery Regions	E, C, G, M, W	5
(pnfut)	Refinery Fuels	NGS-JNH	30
(prcunit)	Process Units	ACU-PFA	37
(prd)	Products	LPG-M85	20
(q(k))	Quantities	1-9	9
(rfothfu)	Refinery Fuel for Other	JIH-NPN	19
(spec)	Product Specificatons	RV-BZ	6

Code	Name	Values	No. in Set
DS	Imported product	Distillate	
MG, GS	Imported product	Conventional mogas	
JF	Imported product	Jet Fuel	
DL, LD	Imported product	Low sulfur diesel	
DU	Imported product	Ultra-low-sulfur diesel	
LG	Imported product	LPG	
OT	Imported product	Other	
PF	Imported product	Petrochemical Feeds	
RG	Imported product	Reformulated mogas	
RH	Imported product	High sulfur residual	
RL	Imported product	Low sulfur residual	
ME	Imported product	Methanol	
MT	Imported product	MTBE	

A.1.2 PMM Output Variables

REFINERY MODULE OUTPUT VARIABLES (pmmout)

NAME	UNITS	DEFINITION
AKGTLEXP(MJUMPYR)	Mbbl/cd	GTL exported from Alaska
AKGTLPRP(MJUMPYR)	Mbbl/cd	GTL produced in Alaska
AKGTL_NGCNS(MJUMPYR)	BCF	Natural gas consumed in GTL process
DCRDWHP(MNUMOR,MJUMPYR)	$87/bbl	Dometic crude wellhead price
ETHNE85	Fraction	Percent ethanol in E85
TRGNE85	Fraction	Percent TRG in E85
PCTPLT_PADD(MNUMPR,MJUMPYR)	BCF	Gas plant fuel cons./Total NG production
QCLRFPD(MNUMPR,MJUMPYR)	Tril BTU/yr	Quantity of coal for CTL
RFBIOD(2,MJUMPYR)	Mbbl/cd	Vol biodiesel for blend into diesel and heating oil (1=soybean oil, 2=yellow grease)
RFCAPEXP(MJUMPYR)	MM$87/Day	Rf capital expenditures
RFCTLPRD(MJUMPYR)	Mbbl/Day	Quantity of liquids from coal
RFDCRDP(MNUMOR,MJUMPYR,5)	$87/bbl	Domestic crude price by crude type
RFPQNGL(MNUMPR,MJUMPYR,6,2)	$87/bbl,Mbbl/cd	Prc/quan of ngl by PAD district
RFQDCRD(MNUMOR+2,MJUMPYR)	MMbbl/yr	Domestic conventional crude
RFQDINPOT(MNUMPR,MJUMPYR)	MMbbl/cd	Quantity other input to refin.
RFQPRCG(MNUMPR,MJUMPYR)	MMbbl/cd	Quantity of processing gains
RFQPRDT(MNUMCR, MJUMPYR)	MMbbl/cd	Total product supplied
RFQTDCRD(MNUMOR+2,MJUMPYR)	MMbbl/yr	Total domestic crude
RFREV(MJUMPYR)	MM$87/Day	Refinery revenues
RFSAL(MJUMPYR)	Tons/yr	Sulfur allowances
RFSPRFR(MJUMPYR)	MMbbl/cd	Rf spr fill rate
RFSPRIM(MJUMPYR)	MMbbl/cd	Spr imports
XDCRDWHP(MNUMOR,MJUMPYR)	$87/bbl	Expected domestic crude wellhd price
XRFQDCRD(MNUMOR,MJUMPYR)	MMbbl/yr	Expected domestic crude production

REFINERY REPORT OUTPUT VARIABLES (pmmrpt)

NAME	UNITS	DEFINITION
BLDIMP(MNUMPR,MJUMPYR)	MMbbl/cd	Blending component imports
CLLETHCD(MNUMCR,MJUMPYR)	Mbbl/cd	Ethanol produced from cellulose
CRNETHCD(MNUMCR,MJUMPYR)	Mbbl/cd	Ethanol produced from corn
DSMURS(MNUMCR,MJUMPYR,2)	$87/bbl	Residential Distillate Markups
DSMUTR(MNUMCR,MJUMPYR,2)	$87/bbl	Transportation Distillate Markups
DSSTTX(MNUMCR)	$87/bbl	Diesel State Tax
GRSMRGN(MNUMPR,MJUMPYR)	$87/yr	Gross margin

NAME	UNITS	DEFINITION
JFMUTR(MNUMCR,MJUMPYR,2)	$87/bbl	Transportation Jet Fuel Markups
JFSTTX(MNUMCR)	$87/bbl	Jet Fuel State Tax
MGMUTR(MNUMCR,MJUMPYR,2)	$87/bbl	Transportation Gasoline Markups
MGSTTX(MNUMCR)	$87/bbl	Gasoline State Tax
MUFTAX(MJUMPYR,15)	$87/MMBtu	Federal motorgasoline tax
NETMRGN(MNUMPR,MJUMPYR)	$87/yr	Net margin
PALMG(MNUMCR,MJUMPYR)	$87/bbl	Motor gasoline all combined
PDS(MNUMCR,MJUMPYR)	$87/bbl	Distillate fuel oil
PDSL(MNUMCR,MJUMPYR)	$87/bbl	Low sulfur diesel
PETHM(MNUMCR,MNUMYR)	$87/bbl	Marginal price for ethanol
PJF(MNUMCR,MJUMPYR)	$87/bbl	Jet fuel
PSA_TAB(35,MNUMPR,MNUMYR)	--	Refinery balance rows from PSA report
QPRDRF(MNUMPR,MJUMPYR,30)	Mbbl/cd	Refinery production volumes
QPRDEX(MNUMCR,30,MJUMPYR)	Mbbl/cd	Refinery production exported
RFBDSTCAP(MNUMPR,MJUMPYR)	MMbbl/cd	Refinery base distillation capacity
RFCGCAPADDPD(MNUMPR,MJUMPYR)	KW	CHP. capacity by PAD District
RFCGCAPCD(MNUMCR,NMUMYR)	MW	CHP. capacity by Cen. Div.
RFCGCAPPD(MNUMPR,MJUMPYR)	MW	CHP. capacity by PAD District
RFCRDOTH(MNUMPR,MJUMPYR	MMbbl/cd	Other crude imports by PAD District
RFDPRDAST(MNUMPR,MJUMPYR)	Mbbl/cd	Refinery prd; asphalt & road oil
RFDPRDCOK(MNUMPR,MJUMPYR)	Mbbl/cd	Refinery prd; petroleum coke
RFDPRDDSL(MNUMPR,MJUMPYR)	Mbbl/cd	Refinery prd; low sulfur diesel
RFDPRDDSU(MNUMPR,MJUMPYR)	Mbbl/cd	Refinery prd; ultra low sulfur diesel
RFDPRDJTA(MNUMPR,MJUMPYR)	Mbbl/cd	Refinery prd; jet fuel
RFDPRDKER(MNUMPR,MJUMPYR)	Mbbl/cd	Refinery prd; kerosene
RFDPRDLPG(MNUMPR,MJUMPYR)	Mbbl/cd	Refinery production; LPG
RFDPRDN2H(MNUMPR,MJUMPYR)	Mbbl/cd	Refinery prd; no. 2 distillate
RFDPRDN6B(MNUMPR,MJUMPYR)	Mbbl/cd	Refinery prd; high sulfur oil
RFDPRDN6I(MNUMPR,MJUMPYR)	Mbbl/cd	Refinery prd; low sulfur resid oil
RFDPRDOTH(MNUMPR,MJUMPYR)	Mbbl/cd	Refinery prd; other petroleum
RFDPRDPCF(MNUMPR,MJUMPYR)	Mbbl/cd	Refinery prd; petrochemical feeds
RFDPRDRFG(MNUMPR,MJUMPYR)	Mbbl/cd	Refinery prd; reformulated mogas
RFDPRDRFH(MNUMPR,MJUMPYR)	Mbbl/cd	Refinery prd; reform. hi oxyg. mogas
RFDPRDSTG(MNUMPR,MJUMPYR)	Mbbl/cd	Refinery prd; still gas
RFDPRDTRG(MNUMPR,MJUMPYR)	Mbbl/cd	Refinery prd; motor gasoline
RFDPRDTRH(MNUMPR,MJUMPYR)	Mbbl/cd	Refinery prd; high oxygenated mogas
RFDPRDTRL(MNUMPR,MJUMPYR)	Mbbl/cd	Domestic Production of Low Sulfur Gasoline
RFDSCUM(MNUMPR,MJUMPYR)	MMbbl/cd	Processin unit cumulative cap. expansion
RFDSTCAP(MNUMPR,MJUMPYR)	Mbbl/cd	Refinery distillation capacity
RFDSTUTL(MNUMPR,MJUMPYR)	Percent	Capacity utilization rate
RFELPURPD(MNUMPR,MJUMPYR)	$87/kWh	Electricity purchased by PAD District
RFENVFX(MNUMCR,MJUMPYR,20)	$87/bbl	Refinery Environmental Fixed Costs
RFETHD(MJUMPYR)	MMbbl/cd	Domestic ethanol
RFETHE85(MNUMPR,MJUMPYR)	MMbbl/cd	Ethanol for E85 production
RFIMCR(MNUMPR,MJUMPYR)	MMbbl/YR	Crude net imports
RFIMTP(MNUMPR,MJUMPYR)	MMbbl/YR	Total prod net imports
RFIPQCHH(MNUMPR,MJUMPYR,2)	$87/bbl,Mbbl/cd	Import crude-high sulfur heavy
RFIPQCHL(MNUMPR,MJUMPYR,2)	$87/bbl,Mbbl/cd	Import crude-high sulfur light
RFIPQCHV(MNUMPR,MJUMPYR,2)	$87/bbl,Mbbl/cd	Import crude-high sulfur very heavy
RFIPQCLL(MNUMPR,MJUMPYR,2)	$87/bbl,Mbbl/cd	Import crude-low sulfur light (P,Q)
RFIPQCMH(MNUMPR,MJUMPYR,2)	$87/bbl,Mbbl/cd	Import crude-medium sulfur heavy
RFIPQDL(MNUMPR,MJUMPYR,2)	$87/bbl,Mbbl/cd	Imported low sulfur distillate (P,Q)
RFIPQDS(MNUMPR,MJUMPYR,2)	$87/bbl,Mbbl/cd	Imports distillate (P,Q)
RFIPQDU(MNUMPR,MJUMPYR,2)	$87/bbl,Mbbl/cd	Imports ultra low sulfur distillate (P,Q)
RFIPQJF(MNUMPR,MJUMPYR,2)	$87/bbl,Mbbl/cd	Imports jet fuel (P,Q)
RFIPQLG(MNUMPR,MJUMPYR,2)	$87/bbl,Mbbl/cd	Imports lpg (P,Q)

NAME	UNITS	DEFINITION
RFIPQME(MNUMPR,MJUMPYR,2)	$87/bbl,Mbbl/cd	Imports methanol (P,Q)
RFIPQMG(MNUMPR,MJUMPYR,2)	$87/bbl,Mbbl/cd	Imports motor gasoline (P,Q)
RFIPQMT(MNUMPR,MJUMPYR,2)	$87/bbl,Mbbl/cd	Imports mtbe (P,Q)
RFIPQOT(MNUMPR,MJUMPYR,2)	$87/bbl,Mbbl/cd	Imported other (P,Q)
RFIPQPF(MNUMPR,MJUMPYR,2)	$87/bbl,Mbbl/cd	Imported petrochem feeds (P,Q)
RFIPQRG(MNUMPR,MJUMPYR,2)	$87/bbl,Mbbl/cd	Imported reformulated mogas (P,Q)
RFIPQRH(MNUMPR,MJUMPYR,2)	$87/bbl,Mbbl/cd	Imports high sulfur resid (P,Q)
RFIPQRL(MNUMPR,MJUMPYR,2)	$87/bbl,Mbbl/cd	Imports low sulfur resid (P,Q)
RFMETCHM(MNUMPR,MJUMPYR)	MMbbl/cd	Chem. Demand for methanol
RFMETD(MJUMPYR)	MMbbl/cd	Domestic methanol
RFMETI(MNUMPR,MJUMPYR)	MMbbl/cd	Imported methanol
RFMETM85(MNUMPR,MJUMPYR)	MMbbl/cd	Methonal for M85 production
RFMTBD(MNUMPR,MJUMPYR)	MMbbl/cd	Domestic MTBE production.
RFMTBI(MNUMPR,MJUMPYR)	MMbbl/cd	Imported MTBE
RFPQIPRDT(MNUMPR,MJUMPYR,2)	$87/bbl,MMbbl/cd	Total imported product
RFPQUFC(MNUMPR,MJUMPYR,2)	MMbbl/cd	Total imports of unfinished crude
RFQARO(MNUMCR,MJUMPYR)	MMbbl/cd	Quantity of asphalpt and road oil
RFQDS(MNUMCR,MJUMPYR)	MMbbl/cd	Quantity of distillate fuel oil
RFQEL(MJUMPYR)	MMbbl/cd	Utility product demand
RFQEXCRD(MNUMPR,MJUMPYR)	MMbbl/cd	Crude exported
RFQEXPRDT(MNUMPR,MJUMPYR)	MMbbl/cd	Total product exported
RFQICRD(MNUMPR,MJUMPYR)	MMbbl/cd	Imported total crude
RFQIN(MJUMPYR)	MMbbl/cd	Industrial product demand
RFQJF(MNUMCR,MJUMPYR)	MMbbl/cd	Quantity of jet fuel
RFQKS(MNUMCR,MJUMPYR)	MMbbl/cd	Quantity of kerosene
RFQLG(MNUMCR,MJUMPYR)	MMbbl/cd	Quantity of lpg
RFQMG(MNUMCR,MJUMPYR)	MMbbl/cd	Quantity of motor gasoline
RFQOTH(MNUMCR,MJUMPYR)	MMbbl/cd	Quantity of other
RFQPCK(MNUMCR,MJUMPYR)	MMbbl/cd	Quantity of petroleum coke
RFQPF(MNUMCR,MJUMPYR)	MMbbl/cd	Quantity of petrochem feedstocks
RFQRC(MJUMPYR)	MMbbl/cd	Residential/Commercial product demand
RFQRH(MNUMCR,MJUMPYR)	MMbbl/cd	Quantity of resid high sulfur
RFQRL(MNUMCR,MJUMPYR)	MMbbl/cd	Quantity of resid low sulfur
RFQSECT(MJUMPYR)	MMbbl/cd	Total sectoral demand
RFQSTG(MNUMCR,MJUMPYR)	MMbbl/cd	Quantity of still gas
RFQTR(MJUMPYR)	MMbbl/cd	Transportion product demand
TOTPRD(MNUMPR,MJUMPYR)	MMbbl/cd	Total refinery product sold

PRICE VARIABLES (mpblk)

NAME	UNITS	DEFINITION
PASIN(MNUMCR,MJUMPYR)	$87/MMBtu	Asphalt, Road Oil, Industrial
PDSAS(MNUMCR,MJUMPYR)	$87/MMBtu	Distillate, All Sectors
PDSCM(MNUMCR,MJUMPYR)	$87/MMBtu	Distillate, Commercial
PDSEL(MNUMCR,MJUMPYR)	$87/MMBtu	Distillate, Electricity (+petroleum coke)
PDSIN(MNUMCR,MJUMPYR)	$87/MMBtu	Distillate, Industrial
PDSRS(MNUMCR,MJUMPYR)	$87/MMBtu	Distillate, Residential
PDSTR(MNUMCR,MJUMPYR)	$87/MMBtu	Distillate, Transportation
PETTR(MNUMCR,MJUMPYR)	$87/MMBtu	Ethanol, Transportation
PJFTR(MNUMCR,MJUMPYR)	$87/MMBtu	Jet Fuel, Transportation
PKSAS(MNUMCR,MJUMPYR)	$87/MMBtu	Kerosene, All Sectors
PKSCM(MNUMCR,MJUMPYR)	$87/MMBtu	Kerosene, Commercial
PKSIN(MNUMCR,MJUMPYR)	$87/MMBtu	Kerosene, Industrial
PKSRS(MNUMCR,MJUMPYR)	$87/MMBtu	Kerosene, Residential
PLGAS(MNUMCR,MJUMPYR)	$87/MMBtu	Liquid Petroleum Gases, All Sectors
PLGCM(MNUMCR,MJUMPYR)	$87/MMBtu	Liquid Petroleum Gases, Commercial

NAME	UNITS	DEFINITION
PLGIN(MNUMCR,MJUMPYR)	$87/MMBtu	Liquid Petroleum Gases, Industrial
PLGRS(MNUMCR,MJUMPYR)	$87/MMBtu	Liquid Petroleum Gases, Residential
PLGTR(MNUMCR,MJUMPYR)	$87/MMBtu	Liquid Petroleum Gases, Transportation
PMETR(MNUMCR,MJUMPYR)	$87/MMBtu	Methanol, Transportation
PMGAS(MNUMCR,MJUMPYR)	$87/MMBtu	Motor Gasoline, All Sectors
PMGCM(MNUMCR,MJUMPYR)	$87/MMBtu	Motor Gasoline, Commercial
PMGIN(MNUMCR,MJUMPYR)	$87/MMBtu	Motor Gasoline, Industrial
PMGTR(MNUMCR,MJUMPYR)	$87/MMBtu	Motor Gasoline, Transportation
POTAS(MNUMCR,MJUMPYR)	$87/MMBtu	Other Petroleum, Industrial
POTIN(MNUMCR,MJUMPYR)	$87/MMBtu	Other Petroleum, Industrial
POTTR(MNUMCR,MJUMPYR)	$87/MMBtu	Other Petroleum, Transportation
PPFIN(MNUMCR,MJUMPYR)	$87/MMBtu	Petrochemical Feedstocks, Industrial
PRHAS(MNUMCR,MJUMPYR)	$87/MMBtu	Residual Fuel, High Sulfur, All Sectors
PRHEL(MNUMCR,MJUMPYR)	$87/MMBtu	Residual Fuel, High Sulfur, Electricity
PRHTR(MNUMCR,MJUMPYR)	$87/MMBtu	Residual Fuel, High Sulfur, Transp.
PRLAS(MNUMCR,MJUMPYR)	$87/MMBtu	Residual Fuel, Low Sulfur, All Sectors
PRLCM(MNUMCR,MJUMPYR)	$87/MMBtu	Residual Fuel, Low Sulfur, Commercial
PRLEL(MNUMCR,MJUMPYR)	$87/MMBtu	Residual Fuel, Low Sulfur, Electricity
PRLIN(MNUMCR,MJUMPYR)	$87/MMBtu	Residual Fuel, Low Sulfur, Industrial
PRLTR(MNUMCR,MJUMPYR)	$87/MMBtu	Resid. Fuel, Low Sulfur, Transportation

QUANTITY VARIABLES (qblk)

NAME	UNITS	DEFINITION
QELRF(MNUMCR,MJUMPYR)	Tril Btu/Yr	Purch. Elec. Refinery
QNGRF(MNUMCR,MJUMPYR)	Tril Btu/Yr	Natural Gas, Refinery
QDSRF(MNUMCR,MJUMPYR)	Tril Btu/Yr	Distillate, Refinery
QLGRF(MNUMCR,MJUMPYR)	Tril Btu/Yr	Liquid Petroleum Gases, Refinery
QRLRF(MNUMCR,MJUMPYR)	Tril Btu/Yr	Residual Fuel, Low Sulfur, Refinery
QRSRF(MNUMCR,MJUMPYR)	Tril Btu/Yr	Residual Fuel, Refinery
QSGRF(MNUMCR,MJUMPYR)	Tril Btu/Yr	Still Gas, Refinery
QPCRF(MNUMCR,MJUMPYR)	Tril Btu/Yr	Petroleum Coke, Refinery
QOTRF(MNUMCR,MJUMPYR)	Tril Btu/Yr	Other Petroleum, Refinery

OIL AND GAS SUPPLY MODEL VARIABLES (ogsmout)

NAME	UNITS	DEFINITION
AKNG_SUPCRV(3,2,MJUMPYR)	$87/mcf, Bcf	NG supply curve for GTL production in Alaska

CHP VARIABLES (cogen)

NAME	UNITS	DEFINITION
CGRECAP(MNUMCR,MJUMPYR,5,2,2)	MW	Refinery CHP Capacity
CGREGEN(MNUMCR,MJUMPYR,5,2)	GWh	Refinery CHP Generation
CGREQ(MNUMCR,MJUMPYR,5,2)	TrilBtu	Refinery Fuel Consumption

RENEWABLE VARIABLES (wrenew)

NAME	UNITS	DEFINITION
QCLETH(MJUMPYR,MNUMCR)	TrilBtu/yr	Coal total, Ethanol plants
QELETH(MJUMPYR,MNUMCR)	TrilBtu/yr	Purchased Electricity total, Ethanol plants
QNGETH(MJUMPYR,MNUMCR)	TrilBtu/yr	Natural gas total, Ethanol plants
QBMET(MNUMCR,MJUMPYR)	Mbbl/cd	Ethanol quantity

HIGHWAY DIESEL VARIABLES (ponroad,qonroad)

NAME	UNITS	DEFINITION
PDSTRHWY(MNUMCR,MJUMPYR)	$87/MMBtu	On-road distillate price, trans sector
QDSTRHWY(MNUMCR,MJUMPYR)	tril Btu/yr	On-road distillate quantity, trans sector
CFDSTRHWY(MJUMPYR)	MMBtu/bbl	On-road distillate conversion factor, trans sector

A.1.3 PMM Input Variables

QUANTITY VARIABLES (qblk, pq)

NAME	UNITS	DEFINITION
QCLRF(MNUMCR,MJUMPYR)	Tril Btu/Yr	Coal, Refinery
QMGCM(MNUMCR,MJUMPYR)	Tril Btu/Yr	Motor Gasoline, Commercial
QMGTR(MNUMCR,MJUMPYR)	Tril Btu/Yr	Motor Gasoline, Transportation
QMGIN(MNUMCR,MJUMPYR)	Tril Btu/Yr	Motor Gasoline, Industrial
QMGAS(MNUMCR,MJUMPYR)	Tril Btu/Yr	Motor Gasoline, All Sectors
QJFTR(MNUMCR,MJUMPYR)	Tril Btu/Yr	Jet Fuel, Transportation
QDSRS(MNUMCR,MJUMPYR)	Tril Btu/Yr	Distillate, Residential
QDSCM(MNUMCR,MJUMPYR)	Tril Btu/Yr	Distillate, Commercial
QDSTR(MNUMCR,MJUMPYR)	Tril Btu/Yr	Distillate, Transportation
QDSIN(MNUMCR,MJUMPYR)	Tril Btu/Yr	Distillate, Industrial
QDSEL(MNUMCR,MJUMPYR)	Tril Btu/Yr	Distillate, Electricity (+petroleum coke)
QDSAS(MNUMCR,MJUMPYR)	Tril Btu/Yr	Distillate, All Sectors
QKSRS(MNUMCR,MJUMPYR)	Tril Btu/Yr	Kerosene, Residential
QKSCM(MNUMCR,MJUMPYR)	Tril Btu/Yr	Kerosene, Commercial
QKSIN(MNUMCR,MJUMPYR)	Tril Btu/Yr	Kerosene, Industrial
QKSAS(MNUMCR,MJUMPYR)	Tril Btu/Yr	Kerosene, All Sectors
QLGRS(MNUMCR,MJUMPYR)	Tril Btu/Yr	Liquid Petroleum Gases, Residential
QLGCM(MNUMCR,MJUMPYR)	Tril Btu/Yr	Liquid Petroleum Gases, Commercial
QLGTR(MNUMCR,MJUMPYR)	Tril Btu/Yr	Liquid Petroleum Gases, Transportation
QLGIN(MNUMCR,MJUMPYR)	Tril Btu/Yr	Liquid Petroleum Gases, Industrial
QLGAS(MNUMCR,MJUMPYR)	Tril Btu/Yr	Liquid Petroleum Gases, All Sectors
QRLEL(MNUMCR,MJUMPYR)	Tril Btu/Yr	Residual Fuel, Low Sulfur, Electricity
QRLAS(MNUMCR,MJUMPYR)	Tril Btu/Yr	Residual Fuel, Low Sulfur, All Sectors
QRHEL(MNUMCR,MJUMPYR)	Tril Btu/Yr	Residual Fuel, High Sulfur, Electricity
QRHAS(MNUMCR,MJUMPYR)	Tril Btu/Yr	Residual Fuel, High Sulfur, All Sectors
QRSCM(MNUMCR,MJUMPYR)	Tril Btu/Yr	Residual Fuel, Commercial
QRSTR(MNUMCR,MJUMPYR)	Tril Btu/Yr	Residual Fuel, Transportation
QRSIN(MNUMCR,MJUMPYR)	Tril Btu/Yr	Residual Fuel, Industrial
QRSEL(MNUMCR,MJUMPYR)	Tril Btu/Yr	Residual Fuel, Electricity
QPFIN(MNUMCR,MJUMPYR)	Tril Btu/Yr	Petrochemical Feedstocks, Industrial
QSGIN(MNUMCR,MJUMPYR)	Tril Btu/Yr	Still Gas, Industrial
QPCIN(MNUMCR,MJUMPYR)	Tril Btu/Yr	Petroleum Coke, Industrial
QPCEL(MNUMCR,MJUMPYR)	Tril Btu/Yr	Petroleum Coke, Electricity
QPCAS(MNUMCR,MJUMPYR)	Tril Btu/Yr	Petroleum Coke, All Sectors
QASIN(MNUMCR,MJUMPYR)	Tril Btu/Yr	Asphalt and Road Oil, Industrial
QOTTR(MNUMCR,MJUMPYR)	Tril Btu/Yr	Other Petr. Transp, (lubes, aviation gas)
QOTIN(MNUMCR,MJUMPYR)	Tril Btu/Yr	Other Petroleum, Industrial
QOTAS(MNUMCR,MJUMPYR)	Tril Btu/Yr	Other Petroleum, All Sectors
QMETR(MNUMCR,MJUMPYR)	Tril Btu/Yr	Methanol Transportation
QETTR(MNUMCR,MJUMPYR)	Tril Btu/Yr	Ethanol Transportation

PRICE VARIABLES (mpblk, efpout, pq)

NAME	UNITS	DEFINITION
PELIN(MNUMCR,MJUMPYR)	$87/MMBTU	Purch. Elec. Industrial
PNGIN(MNUMCR,MJUMPYR)	$87/MMBTU	Natural Gas. Industrial
PGIIN(MNUMCR,MJUMPYR)	$87/MMBtu	Noncore industrial sector prices
PELAS(MNUMCR,MJUMPYR)	$87/MMBtu	Avg electricity prices for all sectors l
PCLIN(MNUMCR,MJUMPYR)	$87/ton	Coal Industrial prices

EMISSIONS VARIABLES (emablk)

NAME	UNITS	DEFINITION
JNGIN(MJUMPYR)	$87/MMBTU	NG Prices w/ emiss penalty, industrial
JCLIN(MJUMPYR)	$87/MMBtu	Coal Prices w/ emiss penalty, industrial
JLGIN(MJUMPYR)	$87/MMBtu	Liquid Petroleum Gases w/ emiss pen, Industrial
JRLIN(MJUMPYR)	$87/MMBtu	Resid Fuel, low sulf, w/ emiss penalty, Industrial
JRHEL(MJUMPYR)	$87/MMBtu	Resid Fuel, High Sulf, w/ emiss penalty, electricity
JOTIN(MJUMPYR)	$87/MMBtu	Other petroleum, w/ emiss penalty, industrial
JPCIN(MJUMPYR)	$87/MMBtu	Pet Coke, w/ emiss penalty, industrial
JSGIN(MJUMPYR)	$87/MMBtu	Still Gas, w/ emiss penalty, industrial

INTERNATIONAL MARKET MODEL VARIABLES (intout)

NAME	UNITS	DEFINITION
IT_WOP(MJUMPYR,2)	$87/bbl	World oil price (2--units)
Q_ITIMCRSC(MJUMPYR,5,5,3)	Mbbl/cd	Crude import supply curve quant.
P_ITIMCRSC(MJUMPYR,5,5,3)	$87/bbl	Crude import supply curve prices
Imported Product Supply Curves (P,Q)		
ITIMRGSC(MJUMPYR,5,PRDSTEP,2)	$87/bbl,Mbbl/cd	Reformulated mogas
ITIMGSSC(MJUMPYR,5, PRDSTEP,2)	$87/bbl,Mbbl/cd	Tradition mogas
ITIMDSSC(MJUMPYR,5, PRDSTEP,2)	$87/bbl,Mbbl/cd	Distillate
ITIMLDSC(MJUMPYR,5, PRDSTEP,2)	$87/bbl,Mbbl/cd	Low sulfur distillate
ITIMLRSC(MJUMPYR,5, PRDSTEP,2)	$87/bbl,Mbbl/cd	Low sulfur. Resid.
ITIMHRSC(MJUMPYR,5, PRDSTEP,2)	$87/bbl,Mbbl/cd	High sulfur Resid.
ITIMJFSC(MJUMPYR,5, PRDSTEP,2)	$87/bbl,Mbbl/cd	Jet fuel
ITIMLPSC(MJUMPYR,5, PRDSTEP,2)	$87/bbl,Mbbl/cd	LPG
ITIMPFSC(MJUMPYR,5, PRDSTEP,2)	$87/bbl,Mbbl/cd	Petchemical Feedstocks
ITIMOTSC(MJUMPYR,5, PRDSTEP,2)	$87/bbl,Mbbl/cd	Other
ITIMMESC(MJUMPYR,5, PRDSTEP,2)	$87/bbl,Mbbl/cd	Methanol
ITIMMTSC(MJUMPYR,5, PRDSTEP,2)	$87/bbl,Mbbl/cd	MTBE
ITIMXGSC(MJUMPYR,5, PRDSTEP,2)	$87/bbl,Mbbl/cd	RBOB
ITIMXDSC(MJUMPYR,5, PRDSTEP,2)	$87/bbl,Mbbl/cd	Ultra Low S Diesel
ITIMUOSC(MNUMYR,5,PRDSTEPS,2,3)	87$/bbl,Mbbl/cd	Unfinished oil imports (3 types)

OIL AND GAS SUPPLY MODEL VARIABLES (ogsmout)

NAME	UNITS	DEFINITION
OGNGLAK(MJUMPYR)	Mbbl/cd	NGL from Alaska
OGQNGREP(MNOGCAT,MJUMPYR)	Bcf/Yr	NG production by gas category

NATURAL GAS TRANSMISSION AND DISTRIBUTION MODEL VARIABLES (ngtdmout)

NAME	UNITS	DEFINITION
PRNG_PADD(MNUMPR,MJUMPYR)	Bcf/Yr	Total dry gas production (W/L&P)

NATURAL GAS TRANSMISSION AND DISTRIBUTION MODEL VARIABLES (ngtdmrep)

NAME	UNITS	DEFINITION
OGPRDNG(MNUMOR,MJUMPYR)	Bcf/Yr	Domestic dry gas production (W/L&P)

RENEWABLE VARIABLES (wrenew)

NAME	UNITS	DEFINITION
WPETOH(MNCROP,MNUMCR,MJUMPYR,MNETOH)	$87/bbl	Ethanol price/step, from refeth.f
WQETOH(MNCROP,MNUMCR,MJUMPYR,MNETOH)	Mbbl/cd	Ethanol quan/step, from refeth.f
PBMET(MNUMCR,MJUMPYR)	$87/MMBTU	Ethanol price
WQTOT(MNUMCR,MNETOH)	Mbbl/cd	Incremental ethanol quantity, fr refeth.f
ETHCL(MJUMPYR,MNETOH)	MMBtu/gal	Coal by step
ETHEL(MJUMPYR,MNETOH)	MMBtu/gal	Electricity by step
ETHNG(MJUMPYR,MNETOH)	MMBtu/gal	NG by step

ECONOMIC VARIABLES (macout)

NAME	UNITS	DEFINITION
MC_PJGDP(-2:MJUMPYR)	Index	chained price index- gross domestic product; 1987=1.0
MC_RMCORPBAA(MJUMPYR)	Percent	Industrial Baa Bond rate
MC_RMTCM10Y(MJUMPYR)	Percent	10 year treasury note yield; percent per year, ave of daily rates

COAL VARIABLES (coalout)

NAME	UNITS	DEFINITION
LCVELAS(MNUMPR,MJUMPYR)	---	Elasticity for CTL coal supply curve
LCVTONQ(MNUMPR,MJUMPYR)	MMton/yr	CTL coal supply curve production
LCVTONP(MNUMPR,MJUMPYR)	$87/ton	CTL coal supply curve delivered price
LCVBTU(MNUMPR,MJUMPYR)	MMbtu/ton	CTL coal supply curve heat content
LTRNTON(MNUMPR,MJUMPYR)	$87/ton	Coal transportation rate to CTL facility
PCLRFPD(MNUMPR,MJUMPYR)	$87/MMBtu	Price of coal for CTL
L_SO2P(MNUMPR,MNUMYR)	$87/MMBtu coal	Incremental cost of coal due to SO2 allowance price
L_HGP(MNUMPR,MNUMYR)	$87/MMBtu coal	Incremental cost of coal due to Hg allowance price

EMISSIONS VARIABLES (emission)

NAME	UNITS	DEFINITION
EMCMC(MNUMCR,MNPOLLUT,MJUMPYR)	M tons/yr	Emissions by Region, commercial
EMELC(MNUMCR,MNPOLLUT,MJUMPYR)	M tons/yr	Emissions by Region, electric util
EMETAX(15,MJUMPYR)	$87/ton	Excise (Consumption) Tax by Fuel
EMINCN(MNUMCR,MNPOLLUT,MJUMPYR)	M tons/yr	Non-comb emissions by region, industrial
EMNT(MNUMCR,MNPOLLUT,MJUMPYR)	M tons/yr	NGTDM Emissions by Region
EMPMCC(MNUMCR,MNPOLLUT,MJUMPYR)	M tons/yr	PMM Emis by Regn-Comb
EMPMCN(MNUMCR,MNPOLLUT,MJUMPYR)	M tons/yr	PMM Emis by Reg-Noncomb
EMRSC(MNUMCR,MNPOLLUT,MJUMPYR)	M tons/yr	Residential Emissions by Region
EMTRC(MNUMCR,MNPOLLUT,MJUMPYR)	M tons/yr	Trans Emissions by Region

A.1.4 Other PMM Variables

VARIABLES USED INTERNALLY IN PMM (pmmcom1)

NAME	UNITS	DEFINITION
	PMM parameters	
PUNITSN	= 87	Number of refinery processing units
CTL_NLIQ	= 10	Max number of liquid streams out of CTL
XPRDSTEPS	= 9	expanded steps on prd imp curv in LP
	Refinery products prices	
PAS(MNUMCR,MJUMPYR)	$87/bbl	Asphalt and road oil
PDSC(MNUMCR,MJUMPYR)	$87/bbl	Avg pr btwn DSU and DSL (not used)
PDSI(MNUMCR,MJUMPYR)	$87/bbl	Avg pr for DS for IND
PDST(MNUMCR,MJUMPYR)	$87/bbl	Avg pr for DS for TRN
PDSLTR(MNUMCR,MJUMPYR)	$87/MMBtu	Low sulfur diesel (DSL), tran price
PDSU(MNUMCR,MJUMPYR)	$87/bbl	Ultra low sulfur diesel (DSU)
PDSUTR(MNUMCR,MJUMPYR)	$87/MMBtu	Ultra low sulfur diesel (DSU), tran price
PE85(MNUMCR,MJUMPYR)	$87/bbl	E85
PKS(MNUMCR,MJUMPYR)	$87/bbl	Kerosene
PLG(MNUMCR,MJUMPYR)	$87/bbl	LPG
PM85(MNUMCR,MJUMPYR)	$87/bbl	M85
PMG2TR(MNUMCR,MJUMPYR)	$87/bbl	TRG mogas with markup
PMG3TR(MNUMCR,MJUMPYR)	$87/bbl	RFG mogas with markup
PMG4TR(MNUMCR,MJUMPYR)	$87/bbl	TRH mogas with markup
PMG5TR(MNUMCR,MJUMPYR)	$87/bbl	RFH mogas with mu
PMGRFG(MNUMCR,MJUMPYR)	$87/bbl	RFG mogas
PMGRFH(MNUMCR,MJUMPYR)	$87/bbl	RFH mogas
PMGTRG(MNUMCR,MJUMPYR)	$87/bbl	Conventional mogas
PMGTRH(MNUMCR,MJUMPYR)	$87/bbl	TRH mogas
PN2HTR(MNUMCR,MJUMPYR)	$87/MMBtu	2370ppm DEISEL, TRN PRICE
POTH(MNUMCR,MJUMPYR)	$87/bbl	Other
PPC(MNUMCR,MJUMPYR)	$87/bbl	Petroleum coke
PPF(MNUMCR,MJUMPYR)	$87/bbl	Petrochemical feedstocks
PRH(MNUMCR,MJUMPYR)	$87/bbl	High sulfur resid.
PRHUT(MNUMCR,MJUMPYR)	$87/bbl	High sulfur utiltiy resid.
PRL(MNUMCR,MJUMPYR)	$87/bbl	Residual fuel oil low sulfur
PRLUT(MNUMCR,MJUMPYR)	$87/bbl	Low sulfur utility resid.
	Refinery fuel use	
QCDUPD(MJUMPYR)	MMbbl/cd	Fuel burned (including pet coke)
QCOKFU(MNUMPR,MJUMPYR)	Mbbl/cd	Petroleum coke
QCOLFU(MNUMPR,MJUMPYR)	Mbbl/cd	Coal
QDISFU(MNUMPR,MJUMPYR)	Mbbl/cd	Distillate
QLPGFU(MNUMPR,MJUMPYR)	Mbbl/cd	LPG
QNTGFU(MNUMPR,MJUMPYR)	Mbbl/cd	Natural gas
QOTHFU(MNUMPR,MJUMPYR)	Mbbl/cd	Other
QRESFU(MNUMPR,MJUMPYR)	Mbbl/cd	Resid.
QSTGFU(MNUMPR,MJUMPYR)	Mbbl/cd	Still gas
	End use markups by sector	
ASMUIN(MNUMCR,MJUMPYR,2)	$87/MMBtu	Asphalt and road oil, industrial
DSMUAS(MNUMCR,MJUMPYR,2)	$87/MMBtu	Distillate, all sectors
DSMUCM(MNUMCR,MJUMPYR,2)	$87/MMBtu	Distillate, commercial sector
DSMUEL(MNUMCR,MJUMPYR,2)	$87/MMBtu	Distillate, electricity generation
DSMUIN(MNUMCR,MJUMPYR,2)	$87/MMBtu	Distillate, industrial sector

NAME	UNITS	DEFINITION
ETMUTR(MNUMCR,MJUMPYR,2)	$87/MMBtu	E85, transportation sector
ETSTTX(MNUMCR)	$87/MMBtu	Same as ETMUTR above
KSMUAS(MNUMCR,MJUMPYR,2)	$87/MMBtu	Kerosene, all sectors
KSMUCM(MNUMCR,MJUMPYR,2)	$87/MMBtu	Kerosene, commercial sector
KSMUIN(MNUMCR,MJUMPYR,2)	$87/MMBtu	Kerosene, industrial sector
KSMURS(MNUMCR,MJUMPYR,2)	$87/MMBtu	Kerosene, residential sector
LGMUAS(MNUMCR,MJUMPYR,2)	$87/MMBtu	LPG, all sectors
LGMUCM(MNUMCR,MJUMPYR,2)	$87/MMBtu	LPG, commercial sector
LGMUIN(MNUMCR,MJUMPYR,2)	$87/MMBtu	LPG, industrial sector
LGMURS(MNUMCR,MJUMPYR,2)	$87/MMBtu	LPG, residential sector
LGMUTR(MNUMCR,MJUMPYR,2)	$87/MMBtu	LPG, transporation sector
LGSTTX(MNUMCR)	$87/MMBtu	Same as LGMUTR above
MEMUTR(MNUMCR,MJUMPYR,2)	$87/MMBtu	M85, transportation sector
MESTTX(MNUMCR)	$87/MMBtu	Same as MEMUTR above
MGMUAS(MNUMCR,MJUMPYR,2)	$87/MMBtu	Motor gasoline, all sectors
MGMUCM(MNUMCR,MJUMPYR,2)	$87/MMBtu	Motor gasoline, commercial sector
MGMUIN(MNUMCR,MJUMPYR,2)	$87/MMBtu	Motor gasoline, industrial sector
OTMUAS(MNUMCR,MJUMPYR,2)	$87/MMBtu	Other, all sectors
OTMUCM(MNUMCR,MJUMPYR,2)	$87/MMBtu	Other, commercial sector
OTMUEL(MNUMCR,MJUMPYR,2)	$87/MMBtu	Other, electricity generation
OTMUIN(MNUMCR,MJUMPYR,2)	$87/MMBtu	Other, industrial sector
OTMURS(MNUMCR,MJUMPYR,2)	$87/MMBtu	Other, residential sector
OTMUTR(MNUMCR,MJUMPYR,2)	$87/MMBtu	Other markups transportation sector
PFMUIN(MNUMCR,MJUMPYR,2)	$87/MMBtu	Petrochemical feedstocks
RFBMAST(MNUMCR)	$87/bbl	AST benchmarking factor
RFBMCOK(MNUMCR)	$87/bbl	COK benchmarking factor
RFBMDSL(MNUMCR)	$87/bbl	DSL benchmarking factor
RFBMDSU(MNUMCR)	$87/bbl	DSU benchmarking factor
RFBME85(MNUMCR)	$87/bbl	E85 benchmarking factor
RFBMJTA(MNUMCR)	$87/bbl	JTA benchmarking factor
RFBMKER(MNUMCR)	$87/bbl	KER benchmarking factor
RFBMLPG(MNUMCR)	$87/bbl	LPG benchmarking factor
RFBMM85(MNUMCR)	$87/bbl	M85 benchmarking factor
RFBMN2H(MNUMCR)	$87/bbl	N2H benchmarking factor
RFBMN67(MNUMCR)	$87/bbl	N67 benchmarking factor
RFBMN68(MNUMCR)	$87/bbl	N68 benchmarking factor
RFBMN6B(MNUMCR)	$87/bbl	N6B benchmarking factor
RFBMN6I(MNUMCR)	$87/bbl	N6I benchmarking factor
RFBMOTH(MNUMCR)	$87/bbl	OTH benchmarking factor
RFBMPCF(MNUMCR)	$87/bbl	PCF benchmarking factor
RFBMRFG(MNUMCR)	$87/bbl	RFG benchmarking factor
RFBMRFH(MNUMCR)	$87/bbl	RFH benchmarking factor
RFBMTRG(MNUMCR)	$87/bbl	TRG benchmarking factor
RFBMTRH(MNUMCR)	$87/bbl	TRH benchmarking factor
RHMUAS(MNUMCR,MJUMPYR,2)	$87/MMBtu	High sulfur resid., all sectors
RHMUEL(MNUMCR,MJUMPYR,2)	$87/MMBtu	High sulfur resid., electricity generation
RHMUTR(MNUMCR,MJUMPYR,2)	$87/MMBtu	High sulfur resid., transportation sector
RHSTTX(MNUMCR)	$87/MMBtu	Same as RHMUTR above
RLMUAS(MNUMCR,MJUMPYR,2)	$87/MMBtu	Low sulfur resid., all sectors
RLMUCM(MNUMCR,MJUMPYR,2)	$87/MMBtu	Low sulfur resid., commercial sector
RLMUEL(MNUMCR,MJUMPYR,2)	$87/MMBtu	Low sulfur resid., electricity generation
RLMUIN(MNUMCR,MJUMPYR,2)	$87/MMBtu	Low sulfur resid., industrial sector
RLMUTR(MNUMCR,MJUMPYR,2)	$87/MMBtu	Low sulfur resid., transportation sector
RLSTTX(MNUMCR)	$87/MMBtu	Same as RLMUTR above

NAME	UNITS	DEFINITION
	Delivered petroleum product prices	
RFDLAST(MNUMCR,MJUMPYR)	$87/bbl	AST
RFDLCOK(MNUMCR,MJUMPYR)	$87/bbl	COK
RFDLDSL(MNUMCR,MJUMPYR)	$87/bbl	DSL
RFDLDSU(MNUMCR,MJUMPYR)	$87/bbl	DSU
RFDLE85(MNUMCR,MJUMPYR)	$87/bbl	E85
RFDLJTA(MNUMCR,MJUMPYR)	$87/bbl	JTA
RFDLKER(MNUMCR,MJUMPYR)	$87/bbl	KER
RFDLLPG(MNUMCR,MJUMPYR)	$87/bbl	LPG
RFDLM85(MNUMCR,MJUMPYR)	$87/bbl	M85
RFDLMG(MNUMCR,MJUMPYR)	$87/bbl	Motor gasoline
RFDLN2H(MNUMCR,MJUMPYR)	$87/bbl	N2H
RFDLN67(MNUMCR,MJUMPYR)	$87/bbl	N67
RFDLN68(MNUMCR,MJUMPYR)	$87/bbl	N68
RFDLN6B(MNUMCR,MJUMPYR)	$87/bbl	N6B
RFDLN6I(MNUMCR,MJUMPYR)	$87/bbl	N6I
RFDLOTH(MNUMCR,MJUMPYR)	$87/bbl	OTH
RFDLPCF(MNUMCR,MJUMPYR)	$87/bbl	PCF
RFDLRFG(MNUMCR,MJUMPYR)	$87/bbl	RFG
RFDLRFH(MNUMCR,MJUMPYR)	$87/bbl	RFH
RFDLTRG(MNUMCR,MJUMPYR)	$87/bbl	TRG
RFDLTRH(MNUMCR,MJUMPYR)	$87/bbl	TRH
	Refinery Gate product prices	
RFGTAST(MNUMPR+1,MJUMPYR)	$87/bbl	AST
RFGTCOK(MNUMPR+1,MJUMPYR)	$87/bbl	COK
RFGTDSL(MNUMPR+1,MJUMPYR)	$87/bbl	DSL
RFGTDSU(MNUMPR+1,MJUMPYR)	$87/bbl	DSU
RFGTJTA(MNUMPR+1,MJUMPYR)	$87/bbl	JTA
RFGTKER(MNUMPR+1,MJUMPYR)	$87/bbl	KER
RFGTLPG(MNUMPR+1,MJUMPYR)	$87/bbl	LPG
RFGTMG(MNUMPR+1,MJUMPYR)	$87/bbl	Motor gasoline
RFGTN2H(MNUMPR+1,MJUMPYR)	$87/bbl	N2H
RFGTN6B(MNUMPR+1,MJUMPYR)	$87/bbl	N6B
RFGTN6I(MNUMPR+1,MJUMPYR)	$87/bbl	N6I
RFGTOTH(MNUMPR+1,MJUMPYR)	$87/bbl	OTH
RFGTPCF(MNUMPR+1,MJUMPYR)	$87/bbl	PCF
RFGTRFG(MNUMPR+1,MJUMPYR)	$87/bbl	RFG
RFGTRFH(MNUMPR+1,MJUMPYR)	$87/bbl	RFH
RFGTTRG(MNUMPR+1,MJUMPYR)	$87/bbl	TRG
RFGTTRH(MNUMPR+1,MJUMPYR)	$87/bbl	TRH
	Crude Variables	
CRDOTHTOT(MNUMPR,MJUMPYR)	MMbbl/cd	Total other crude suplied
CRDPRDSUP(MNUMPR,MJUMPYR)	MMbbl/cd	Crude product withdrawals
CRDSTWDR(MNUMPR,MJUMPYR)	MMbbl/cd	Crude stock withdrawals
CRDUNACC(MNUNPR,MJUMPYR)	MMbbl/cd	Unnaccouted crude
FHLADD(MNUMPR)	Mbbl/cd	Additonal supply imports of HL crude
OLEOYRS(MNUMOR,MJUMPYR)	MMbbl	End of year reserves for oil
OLEXTRT(MNUMOR,MJUMPYR)	MMbbl/day/MMbbl	Production Ratio
OLPELC(MNUMOR)	Dimensionless	Price elasticity beta
OLWHP(MNUMOR)	$87/bbl	Well head price for (year - 1)
OLALP(MNUMOR)	Dimensionless	Well head price alpha
OLBTA(MNUMOR)	Dimensionless	Well head price beta
PCRDRF(MNUMPR,MJUMPYR,5,3)	$87/bbl	Price of crude, refinery gate
PICRD(MJUMPYR,MNUMPR,5,9)	$87/bbl	Price of imported crude

NAME	UNITS	DEFINITION
PQEXCRDIN(MNUMPR,MJUMPYR)	Mbbl/cd	Exported crude except Alaskan
PQUFC1(MNUMPR,MJUMPYR,2)	$87/bbl,Mbbl/cd	Unfinished crude 1
PQUFC2(MNUMPR,MJUMPYR,2)	$87/bbl,Mbbl/cd	Unfinished crude 2
PQUFC3(MNUMPR,MJUMPYR,2)	$87/bbl,Mbbl/cd	Unfinished crude 3
PQUFC4(MNUMPR,MJUMPYR,2)	$87/bbl,Mbbl/cd	Unfinished crude 4
PQUFC5(MNUMPR,MJUMPYR,2)	$87/bbl,Mbbl/cd	Unfinished crude 5
PQUFC6(MNUMPR,MJUMPYR,2)	$87/bbl,Mbbl/cd	Unfinished crude 6
PQUFC7(MNUMPR,MJUMPYR,2)	$87/bbl,Mbbl/cd	Unfinished crude 7
PQUFC8(MNUMPR,MJUMPYR,2)	$87/bbl,Mbbl/cd	Unfinished crude 8
PQUFC9(MNUMPR,MJUMPYR,2)	$87/bbl,Mbbl/cd	Unfinished crude 9
PQUFC10(MNUMPR,MJUMPYR,2)	$87/bbl,Mbbl/cd	Unfinished crude 10
PCTEXCRD(0:6)	percent	AK % of tot US crd exports (0=AK, 1-6=OG)
QCRDRF(MNUMPR,MJUMPYR,6,4)	Mbbl/cd	Quantity of crude, refinery gate
QICRD(MJUMPYR,MNUMPR,5,9)	Mbbl	Imported crude
RFCRDDCR(MJUMPYR)	Mbbl/cd	Domestic crude production
RFCRDAKA(MJUMPYR)	Mbbl/cd	Alaskan crude production
RFCRDL48(MJUMPYR)	Mbbl/cd	Lower 48 crude production
RFCRDTOT(MJUMPYR)	MMbbl/cd	Total crude production
TOTCRDIN(MNUMPR,MJUMPYR)	MMbbl/cd	Total crude input to refinery
TOTUFOIN(MNUMPR,MJUMPYR)	MMbbl/cd	Total crude input to refinery
WLLHDPR(MNUMOR,MJUMPYR)	$87/Bbl	Domestic crude well head price
XRFWOP(MJUMPYR,2)	MMbbl/cd	Local expected WOP
	Investment Variables	
BLDYRS	Years	Construction period for proc units
BM_ISBL(PUNITSN)	$M	B&M ISBL (convert fr 93$ to 87$ in code)
BM_LABOR(PUNITSN)	$/cd	B&M Labor (convert fr 93$ to 87$ in code)
BEQ_BLDAVG	Percent	Equity beta for build decision, avg risk
BEQ_BLDHRSK	Percent	Equity beta for build decision, highrisk
BEQ_OPRAVG	Percent	Equity beta for operating decision, avg risk
BEQ_OPRHRSK	Percent	Equity beta for operating decision, highrisk
CAPREC(PUNITSN)	$87/bbl/cd	Capital recovery
CAPRECSW	Integer	Capital recovery switch for investment
CUMINSTRF(MNUMPR,PUNITSN+1,MJUMPYR)	$MM	Total refinery investment
EMRP_BLDAVG	Percent	Exp mkt risk prem for bld decision, avg risk
EMRP_BLDHRSK	Percent	Exp mkt risk prem for bld decision, highrisk
EMRP_OPRAVG	Percent	Exp mkt risk prem for opr decision, avg risk
EMRP_OPRHRSK	Percent	Exp mkt risk prem for opr decision, highrisk
ENV_FAC	Percent	Yearly environ, % of P&E
EQUITY	Percent	Average equity
EQUITY_BLDAVG	Percent	Equity for build decision, avg risk
EQUITY_BLDHRSK	Percent	Eequity for build decision, highrisk
EQUITY_OPRAVG	Percent	Equity for operating decision, avg risk
EQUITY_OPRHRSK	Percent	Equity for operating decision, highrisk
FTAXRAT(MJUMPYR)	Fraction	FED income tax rate
FXOC(PUNITSN)	$87/bbl	Fixed operating costs
INFLRAT(MJUMPYR)	Fraction	Inflation rate
INS_FAC	Percentage	Yearly insurance, % of P&E
INV(MNUMPR,PUNITSN)	$87/bbl/cd	Proc unit investment
INVENV(PUNITSN)	--	Environment invst cost factor
INVLOC(PUNITSN)	--	Location invst penalty factor
INVST_MX1(MNUMPR)	M $87/cd	Initial total maximum investment for capacity expansion
INVST_MX2(MNUMPR)	M $87/cd	Final total maximum investment for capacity expansion

NAME	UNITS	DEFINITION
INVST_YR1(MNUMPR)	Year	Beginning year for limit on total capacity expansion investment
INVST_YR2(MNUMPR)	Year	End year for growth of limit on total capacity expansion investment
INVST0_FIN(MNUMPR, PUNITSN)	$87/bbl/cd	Final investment
LABORLOC(MNUMPR)	Fraction	Location factor for labor
MAINT_FAC	Percentage	Yearly maintenance, % of P&E
OH_FAC	Percentage	Yearly overhead, % of P&E
OH_LCFAC	Percentage	OH op cost, as % of Labor+Staff
OSBLFAC	--	Ratio of OSBL/ISBL
OTH_FAC	Fraction	Supplies, OH, Env as func of fixed cap invest
PCTCNTG	Percentage	Contingency
PCTENV	Percentage	ENV: % of core P&E
PCTLND	Percentage	LAND cost: % of core P&E
PCTOFS	Percentage	OFFSITES: % of core P&E
PCTLOC	Percentage	Location factor
PCTUTL	Percentage	UTIL cost: % of core P&E
PCTSPECL	Percentage	Special costs
PCTWC	Percentage	Working capital
PRJINFL	Fraction	Rate of inflation during construction
PRJLIFE	Years	Project life for proc units
PRJSDECOM	MM 87$	Salvage value less depreciation
PUCAP(PUNITSN)	Mbbl/cd	Proc unit capacity used for investment
RFDC((PUNITSN)	MM 87$	Total field direct costs (ISBL+OSBL)
RFCI(PUNITSN)	MM 87$	Fixed capital investment
RQBLDRAT(MJUMPYR)	Fraction	Req. recovery rate for builds
ROTC(PUNITSN)	MM 87$	One-time costs
RQOPRRAT(MJUMPYR)	Fraction	Req. recovery rate for operation
RQRECRAT	Fraction	Req. recovery rate
RTDI(PUNITSN)	MM 87$	Total depreciable investment
RTPI(PUNITSN)	MM 87$	Total project investment
SPRPTYR$4	Year	FTAB Year $ for pmmrpts 1a,b,c,d
STAFF_LCFAC	Percentage	Staff Op cost, as % of Labor
STAXRAT(MNUMPR,MJUMPYR)	Fraction	ST income tax rate
SUP_FAC	Percentage	Yearly supplies, % of P&E
TAX_FAC	Percentage	Local tax rate, % of P&E
Technology Improvement Variables		
TYR1	Year	First yr of tech change phase-in--GLOBAL
TYR2	Year	Last yr of tech change phase-in--GLOBAL
UYR1(50)	Year	First yr of tech change phase-in--PROC UNIT
UYR2(50)	Year	Last year of tech change phase-in-PROCUNIT
UTCHCNT	Text	Number of proc units w/ tech chng defined
PCT_CHNG(MJUMPYR)	Fraction	Percent chng off base coef due to tech--GLOBAL
UPCT_CHNG(50,MJUMPYR)	Fraction	Percent chng off base coef due to tech--PROCUNIT
PUNIT	Integer	Number of proc. units with tech improvements
UNAMID(50)	Text	Proc. unit name
GLOBTECH	--	Flag to perform tech chng GLOBALLY
UNITTECH	--	Flag to perform tech chng for PROC UNIT
YLDUNIT(10)	Text	Proc. unit name for yield improvement
YLDYR(10)	Integer	Start year for yield improvement
MNAMID(50)	Text	Proc. unit mode name
PMODE(10)	Integer	Number of proc. unit modes for yield improvement
YLDMODE(10,10)	Text	Proc. unit mode ID for yield improvement
PSTRM(10,10)	Integer	Number of stream for yield improvement
YLDSTRM(10,10,11)	Text	Stream ID for yield improvement

NAME	UNITS	DEFINITION
CHNGYLD(10,10,10)	Real	New yield coeff for yield improvement
FLGGRX(50)	Integer	Flag for gravity spec improvement
FLGSLX(50)	Integer	Flag for sulfur spec improvement
SPCYR(50)	Integer	Year for spec improvement
SSPEC(50)	Integer	# of strm specs for spec improvement
SSPECID(50,10)	Text	Stream spec ID for spec improvement
SSTRM	Integer	# of strm for speck improvement
SSTRMID(50)	Text	Stream ID for speck improvement
CHNGSPC(50,10)	Real	New yield coeff for spec improvement
	Coal to Liquids (CTL) Variables	
CTL_BASHHV	MMbtu/ton	Coal HHV
CTL_BASSIZ	Mbbl/cd (liq out)	Base size for CTL unit
CTL_BASCOL	M ton/cd (coal)	Base level coal consumption for CTL
CTL_BASCGS	MW	Base CHP for self consumption (from CTL)
CTL_BASCGG	MW	Base CHP sold to grid (from CTL)
CTL_BASCGF	Fraction	CHP capacity factor (from CTL)
CTLBLDX	Number	Max number of CTL units allowed
CTL_CO2FAC(MNUMPR,MJUMPYR)	Ratio	Lbs CO2 emiss per bbl CTL liq produced
CTL_CGTFAC(MNUMPR,MJUMPYR)	Ratio	Tot kWh elec CHP per bbl CTL liq produced
CTL_CGGFAC(MNUMPR,MJUMPYR)	Ratio	KWh elec CHP to grid per bbl CTL liq produced
CTL_CGCTOT(MNUMPR,MJUMPYR)	MW	Total CHP capacity from CTL processing
CTL_CGCGD(MNUMPR,MJUMPYR)	MW	CHP capacity from CTL, to grid
CTL_CGCSF(MNUMPR,MJUMPYR)	MW	CHP capacity from CTL, to self
CTL_CGGTOT(MNUMPR,MJUMPYR)	MWh/cd	Total CHP elec gen from CTL processing
CTL_CGGGD(MNUMPR,MJUMPYR)	MWh/cd	CHP elec gen from CTL, to grid
CTL_CGGSF(MNUMPR,MJUMPYR)	MWh/cd	CHP elec gen from CTL, to self
CTL_CO2EM(MNUMPR,MJUMPYR)	M lbs/cd	CO2 emissions from CTL processing
CTL_CSTFAC(MNUMPR)	Factor	Cap/op cost factor for CTL processing unit costs
CTL_DCLCAPCST	Fraction	Annual decline rate for cap rec due to imprv tech
CTL_DCLOPRCST	Fraction	Annual decline rate for opr cost due to imprv tech
CTL_FXREC	Rate	Fixed cost recovery factor
CTL_INCBLD	M bbl/cd	Incremental build size for CTL processing units
CTL_INVCST	$87/bbl	CTL investment
CTL_LIQNAM(CTL_NLIQ)	Char*3	CTL liquid stream ID (1-3)
CTL_LIQNCL	Integer	Number of CTL liquid stream types
CTLMINP(MNUMPR,MJUMPYR)	$87/ton	Minemouth price of coal for CTL
CTL_NAM(MNUMPR)	Char*4	Coal ID + PADD (1-3,4)
CTL_NCL	Integer	Number of coal types for CTL processing
CTL_PLNBLD(MNUMPR,MJUMPYR)	M bbl/cd	Max CTL build capacity
CTLTXCR(MJUMPYR)	Nominal$/bbl	CTL tax credit
IINDX	Index	Mansfield-Blackman innovation index
PINDX	Index	Mansfield-Blackman relative profitability index
P_CTLCOAL(MNUMPR,MJUMPYR)	$87/ton	Price of coal used for CTL
Q_CTLCOAL(MNUMPR,MJUMPYR)	M ton/cd	Quantity of coal used for CTL
P_CTLTRN(CTL_NLIQ,MNUMPR,MJUMPYR)	$87/bbl	Cost to transfer CTL to refinery
P_CTLINV(MNUMPR,MJUMPYR)	MM $87/yr	Investment cost for CTL builds/production
Q_CTLPRD(MNUMPR,MJUMPYR)	M bbl/cd	Quantity of liquids produced from coal via CTL
RFCTLFCF(MNUMPR)	fraction	Avg fixed cost fac for CHP (fr EMM, TRCTLFCF)
RFCTLLIQ(CTL_NLIQ)	M bbl/cd	CTL production, by liq type
RFCTLOVR(MNUMPR)	87$/kW	Avg overnight cst for CHP (fr EMM, TRCTLOVR)
SINVST	Index	Mansfield-Blackman relative investment size
XLCVELAS(MNUMPR,MJUMPYR)	---	Elasticity for CTL coal supply curve
XLCVTONQ(MNUMPR,MJUMPYR)	MMton/yr	CTL coal supply curve production
XLCVTONP(MNUMPR,MJUMPYR)	$87/ton	CTL coal supply curve delivered price
XLCVBTU(MNUMPR,MJUMPYR)	MMbtu/ton	CTL coal supply curve heat content
XLTRNTON(MNUMPR,MJUMPYR)	$87/ton	Coal transportation rate to CTL facility

NAME	UNITS	DEFINITION
	Coke Gasification Variables	
CHP_CGGENPD(MNUMPR,MJUMPYR)	MkWh/cd	Electricity generation from coke gasifier's CHP
CHP_CGCAPPD(MNUMPR,MJUMPYR)	MW	Capacity of CHP w/ syngas from coke gasifier
CHP_UNPLNCPD(MNUMPR,MJUMPYR)	MW	Capacity added for CHP w/ syngas from coke gasifier
CHP_NGFUELPD(MNUMPR,MJUMPYR)	Mbbl FOE/cd	NG consumed at CHP (burned w/ syngas)
CHP_SGFUELPD(MNUMPR,MJUMPYR)	Mbbl FOE/cd	Syngas consumed at CHP (burned w/ NG)
COKEXUL(MNUMCR)	MMbbl COE/cd	Initial quantity of coke exported
NAME	**UNITS**	**DEFINITION**
CHPCC1	KWh/bbl feed	Electricity generated at CHP per bbl of feed for mode CC1
CHPCO1	KWh/bbl feed	Electricity generated at CHP per bbl of feed for mode CO1
NGSCHP	Fraction	Fraction of NG (vs syngas) in feed to CHP
QASTPRD(4,MNUMPR,MJUMPYR)	M bbl FOE/cd	Total asphalt production
QCOKPRD(4,MNUMPR,MJUMPYR)	M s-ton/cd	Total coke production
QHH2PRD(MNUMPR,MJUMPYR)	M bbl FOE/cd	Total hydrogen production from coke gasification
QKWHPRD(2,MNUMPR,MJUMPYR)	M kWh/cd	Electricity production from CHP using syngas/NG feed
QSGSPRD(MNUMPR,MJUMPYR)	M bbl FOE/cd	Total syngas production from coke gasification
QNGSPRD(2,MNUMPR,MJUMPYR)	M bbl FOE/cd	Ttotal syngas production from coke gasification
QSTMPRD(MNUMPR,MJUMPYR)	M lb/cd	Steam production from CHP using syngas/NG feed
	Renewables in Fuel Variables	
BIMMCSTCD(MNUMCR,MJUMPYR)	$87/bbl	Marginal price for biomass for diesel
BIMCSTCD(2,MNUMCR,MJUMPYR)	$87/bbl	Average price for biomass for diesel (1=soybean, 2=yellow grease)
BIMQTYCD(2,MNUMCR,MJUMPYR)	M bbl/cd	Quantity of biomass used for diesel (1=soybean, 2=yellow grease)
BIMSUP(MJUMPYR)	Bil gal/yr	Quantity of Biomass diesel required as product
DMDE85ADJP(MNUMCR,MJUMPYR)	$87/bbl	adj to DMDE85DUAL
DMDE85DUAL(MNUMCR,MJUMPYR)	$87/bbl	dual of D(cd)E85
DMDE85RFSP(MNUMCR,MJUMPYR)	$87/bbl	DMDE85DUAL+adj
ETHBIODUAL(MNUMCR,MJUMPYR)	$87/bbl	dual of C@ETHBIO
ETHRVP(MNUMPR,MJUMPYR,2)	Value	Effective RVP for ethanol (1=SSR, 2=SST)
FEDSUBV(MJUMPYR)	$87/bbl	Fed subsidy for virgin oil (soybean)
FEDSUBNV(MJUMPYR)	$87/bbl	Fed subsidy for non-virgin oil (yellow grease)
ISOCVRTN	Fraction	Min frac for convers of MTBE units to ISO-units
ISOCVRTX	Fraction	Max frac for convers of MTBE units to ISO-units
MINREN(MJUMPYR)	Bil gal/yr	Minimum renewables in total gasoline & diesel
RENADJPR(MNUMCR,MJUMPYR)	$87/bbl	Price adj for rfg,rfh due to renew min requirement
RENETHPR(MNUMCR,MJUMPYR)	$87/bbl	Base ethanol price before adj due to renew min requirement
REN_RAT	Fraction	Min frac of renewables in total gasoline & diesel
SS_FRAC(4,MNUMCR)	Fraction	Fraction of ethanol in RFG, RFH, TRG, TRH splash blend
STMTBVAL(MNUMCR)	Fraction	Fraction of product demand for state MTBE ban
WPBDSL (2,MNUMCR,MJUMPYR)	$87/bbl	Price, Biomass supply curve (1=soybean, 2=yellow grease)
WQBDSL (2,MNUMCR,MJUMPYR)	$87/bbl	Quantity, Biomass supply curve (1=soybean, 2=yellow grease)
	DSL/DSU Variables	
CFDUQLOS	Percent	Percent loss of BTU content (fr DSL to DSU)
CFN2HQ	MMbtu/bbl	BTU content of N2H (heating oil)

NAME	UNITS	DEFINITION
DMDN2H(MNUMCR,MJUMPYR)	Mbbl/cd	Dmd for distillate, by CD
DSLCHAR(40)	Character	Distillate/spec variable ID
DSSPCS(40,MJUMPYR)	??/bbl	Spec requirement for distillates
DSUPCT(MJUMPYR)	Percent	Percent DSU of total diesel demand (not used)
PCT_DWNGRD(MJUMPYR)	Percent	Percent of DSU downgraded at CD due to transp
PEXPDS(MNUMCR,MJUMPYR)	Mbbl/cd	DSL exports, by CD
QDSUTR(MNUMCR,MJUMPYR)	TrilBTU/yr	Ultra-low-sulfur diesel, TRN qty
QDSLTR(MNUMCR,MJUMPYR)	TrilBTU/yr	Low-sulfur diesel, TRN qty
QN2HTR(MNUMCR,MJUMPYR)	TrilBTU/yr	2370ppm DEISEL, TRN qty
QDSUIN(MNUMCR,MJUMPYR)	TrilBTU/yr	Ultra-low-sulfur diesel, IND qty
QDSLIN(MNUMCR,MJUMPYR)	TrilBTU/yr	Low-sulfur diesel, IND qty
QN2HIN(MNUMCR,MJUMPYR)	TrilBTU/yr	2370ppm DEISEL, IND qty
QDSUCM(MNUMCR,MJUMPYR)	TrilBTU/yr	Ultra-low-sulfur diesel, COM qty
QDSLCM(MNUMCR,MJUMPYR)	TrilBTU/yr	Low-sulfur diesel, COM qty
QN2HCM(MNUMCR,MJUMPYR)	TrilBTU/yr	2370ppm DEISEL, COM qty
TDIESEL(MNUMCR,MJUMPYR)	Mbbl/cd	Total Highway diesel (DSU+DSL)
CFDSUQ	MMBtu/bbl	BTU content of DSU (ultra low S diesel)
CFDSLQ	MMBtu/bbl	BTU content of DSL (low S diesel)
CFN2HQ	MMBtu/bbl	BTU content of N2H (heating oil)
DSU_CSTFAC	--	Cap cost fac for HD1,HD2,HS2 DSU proc units
ODSPCT	Percent	Off-Rd frac of (Off-Rd +N2H) DSL
NRDPCT	Percent	Non-Rd frac of Off-Rd diesel, DSL
ON2HPCT(MJUMPYR)	Percent	Frac of nonroad diesel put into N2H
ODSUPCT(MJUMPYR)	Percent	Frac of nonroad diesel convt to DSU
N2HPCT_OLM(MJUMPYR)	Percent	N2H frac of off-LM diesel
N2HPCT_ONR(MJUMPYR)	Percent	N2H frac of off-NR diesel
N2HPCT_HWY(MJUMPYR)	Percent	N2H frac of hwy diesel
DSLPCT_OLM(MJUMPYR)	Percent	DSL frac of off-LM diesel
DSLPCT_ONR(MJUMPYR)	Percent	DSL frac of off-NR diesel
DSLPCT_HWY(MJUMPYR)	Percent	DSL frac of hwy diesel
DSUPCT_OLM(MJUMPYR)	Percent	DSU frac of off-LM diesel
DSUPCT_ONR(MJUMPYR)	Percent	DSU frac of off-NR diesel
DSUPCT_HWY(MJUMPYR)	Percent	DSU frac of hwy diesel
HOFTRN	Percent	FRAC heating oil, TRN
OLMTRN	Percent	FRAC rail/marine diesel, TRN
ONRTRN	Percent	FRAC nonroad diesel, TRN
HWYTRN	Percent	FRAC highway diesel, TRN
HOFIND	Percent	FRAC heating oil, IND
OLMIND	Percent	FRAC rail/marine diesel, IND
ONRIND	Percent	FRAC non-road diesel, IND
HWYIND	Percent	FRAC highway diesel, IND
HOFCOM	Percent	FRAC heating oil, COM
OLMCOM	Percent	FRAC rail/marine diesel, COM
ONRCOM	Percent	FRAC non-road diesel, COM
HWYCOM	Percent	FRAC highway diesel, COM
TRHWYPCT_N2H(MNUMCR,MJUMPYR)	Percent	N2H percentage of HWY TRN dist dmd
TRHWYPCT_DSL(MNUMCR,MJUMPYR)	Percent	DSL percentage of HWY TRN dist dmd
TRHWYPCT_DSU(MNUMCR,MJUMPYR)	Percent	DSU percentage of HWY TRN dist dmd
TRPCT_N2H(MNUMCR,MJUMPYR)	Percent	N2H percentage of TRN distillate dmd
TRPCT_DSL(MNUMCR,MJUMPYR)	Percent	DSL percentage of TRN distillate dmd
TRPCT_DSU(MNUMCR,MJUMPYR)	Percent	DSU percentage of TRN distillate dmd
INPCT_N2H(MNUMCR,MJUMPYR)	Percent	N2H percentage of IND distillate dmd
INPCT_DSL(MNUMCR,MJUMPYR)	Percent	DSL percantage of IND distillate dmd
INPCT_DSU(MNUMCR,MJUMPYR)	Percent	DSU percantage of IND distillate dmd
CMPCT_N2H(MNUMCR,MJUMPYR)	Percent	N2H percentage of COM distillate dmd
CMPCT_DSL(MNUMCR,MJUMPYR)	Percent	DSL percentage of COM distillate dmd
CMPCT_DSU(MNUMCR,MJUMPYR)	Percent	DSU percentage of COM distillate dmd

NAME	UNITS	DEFINITION
OLMN2H(MNUMCR,MJUMPYR)	M bbl/cd	2370ppm for Locom/Rail dsl
OLMDSL(MNUMCR,MJUMPYR)	M bbl/cd	500ppm for Locom/Rail dsl
OLMDSU(MNUMCR,MJUMPYR)	M bbl/cd	15ppm for Locom/Rail dsl
ONRN2H(MNUMCR,MJUMPYR)	M bbl/cd	2370ppm for Non-Rd dsl
ONRDSL(MNUMCR,MJUMPYR)	M bbl/cd	500ppm for Non-Rd dsl
ONRDSU(MNUMCR,MJUMPYR)	M bbl/cd	15ppm for Non-Rd dsl
HWYN2H(MNUMCR,MJUMPYR)	M bbl/cd	2370ppm for hwy diesel
HWYDSL(MNUMCR,MJUMPYR)	M bbl/cd	500ppm for hwy diesel
HWYDSU(MNUMCR,MJUMPYR)	M bbl/cd	15ppm for hwy diesel
HOFN2H(MNUMCR,MJUMPYR)	M bbl/cd	2370ppm for #2 heat oil
BQN2H4EXP(MNUMCR,MJUMPYR)	M bbl/cd	Base N2H used to define N2H exp
	Miscellaneous Variables	
ALFA	Fraction	Weight for industrial electricity purchase
ALKACT(MNUMPR,MJUMPYR,9)	Mbbl/cd	Alkylation unit activity variable by mode
ALKMOD(9)	Text	Alkylation unit mode
ARG(MNUMCR,MJUMPYR)	Real	Coeff in ethanol equation (tech dependent)
BLDETHRF(MNUMPR,MJUMPYR)	Mbbl/cd	Ethanol blended at refinery
BLDPRD(MNUMPR,MJUMPYR)	MMbbl/cd	Product blending component
BLDREFIN(MNUMPR,MJUMPYR)	MM bbl/cd	BLENDING COMP RF INPUT
BLDSPLT(MJUMPYR,PUNITSN,MJUMPYR+3)	Percent	Build splits for specific units (data)
CAPCRD(MJUMPYR,35)	Percent	Crude pipeline utilization
CAPCSTCL(MJUMPYR)	$87	Capital costs for Biomass conversion
CAPEXPFCT(5,60,MJUMPYR)	Percent	Processing unit capacity expansions factor
CAPGTLNS(MJUMPYR)	Mbbl/cd	Total GTL capacity
CAPLPG(MJUMPYR,12)	Percent	LPG pipeline utilization
CAPPRD(MJUMPYR,51)	Pecerent	Product pipeline utilization
CD2CD_CB(2,100)	Integer	CD To CD Via Clean Barge
CD2CD_CT(2,100)	Integer	CD To CD Via Clean Tanker
CD2CD_DB(2,100)	Integer	CD To CD Via Dirty Barge
CD2CD_DT(2,100)	Integer	CD To CD Via Dirty Tanker
CD2CD_ECB(2,100)	Integer	CD To CD Via Clean Barge (Eth)
CD2CD_EDB(2,100)	Integer	CD To CD Via Dirty Barge (Eth)
CD2CD_LT(2,100)	Integer	CD To CD Via Tanker (LPG)
CF_ACUMIN(MNUMPR)	Fraction	Minimum capacity utiliz for ACU base capacity
CGPCGRDPD(MNUMPR)	Fraction	Percent split of CHP to grid, by PADD
CGPCGRDCD(MNUMPR)	Fraction	Percent split of CHP to grid, by CD
CHG_BLDSPLT(PUNITSN)	Integer	Flag to change build splits (0=no, 1=yes)
CLLCAPCD(MNUMCR,MJUMPYR)	Mbbl/d	Biomass capacity--cellulose
CLLCSTCD(MNUMCR,MJUMPYR)	$/bbl	Biomass cost--cellulose
CONEFF(MJUMPYR)	Fraction	Biomass conversion efficiency
CRNCSTCD(MNUMCR,MJUMPYR)	$/bbl	Biomass cost—corn
DEF_BLDSPLT(MNUMPR,3)	Percent	Build splits for specific units (data)
DSLCTI(MNUMPR,MJUMPYR)	Cetane	Avg CETANE in DSL
DSUCTI(MNUMPR,MJUMPYR)	Cetane	Avg CETANE in DSU
E85TXPCT	Fraction	E85 component of cellulose subsidy
ETH4ETHR(MNUMPR,MJUMPYR)	Mbbl/cd	Ethanol used to produce ethers
ETHE85CD(MNUMCR,MJUMPYR)	Mbbl/cd	Tot ethanol used for E85 production
ETHICSTCD(MNUMCR,MJUMPYR)	87$/bbl	ethanol import cost
ETHPRIC(2,MJUMPYR)	$87/bbl	Cost coef for ETH, E85
ETHR_O2(7)	Fraction	Wt. Fraction O2 in ethers/ETH
ETHR_SG	--	Specific gravity of ethers/ETH
ETHSUB(MJUMPYR)	$/bbl	Ethanol subsidy
ETHTOTCD(MNUMCR,MJUMPYR)	Mbbl/cd	Tot ethanol used
ETHTOTPR(MNUMCR,MJUMPYR)		Total ethanol production - corn + cellulose
EXPMAX(11,5)	Mbbl/cd	Maximum product export quantity
EXPMIN(11,5)	Mbbl/cd	Minimum product export quantity

NAME	UNITS	DEFINITION
EXPRAT	--	Product export ratio used in regression
EXPRD(11)	Text	List of product exports
EXPRDDMD(11,5)	Mbbl/cd	Prod dmd grouped by exort reg for exp prod only
FCCACT(MNUMPR,MJUMPYR,116)	Mbbl/cd	FCC unit activity variable by mode
FCCDUAL(MNUMPR,MJUMPYR,116)	$87/bbl	RFG specification row dual activity
FCCMOD(116)	Text	FCC unit modes
FLOWCD_CB(MJUMPYR,100)	Mbblcd	Flow From CD To CD Via Clean Barge
FLOWCD_CT(MJUMPYR,100)	Mbblcd	Flow From CD To CD Via Clean Tanker
FLOWCD_DB(MJUMPYR,100)	Mbblcd	Flow From CD To CD Via Dirty Barge
FLOWCD_DT(MJUMPYR,100)	Mbblcd	Flow From CD To CD Via Dirty Tanker
FLOWCD_ECB(MJUMPYR,100)	Mbblcd	Eth Flow From CD To CD Via Clean Barge
FLOWCD_EDB(MJUMPYR,100)	Mbblcd	Eth Flow From CD To CD Via Dirty Barge
FLOWCD_LT(MJUMPYR,100)	Mbblcd	LPG Flow From CD To CD Via Tanker
FLOWCRD(MJUMPYR,35)	Mbbl/cd	Crude pipeline flow
FLOWLPG(MJUMPYR,12)	Mbbl/cd	LPG pipeline flow
FLOWPD_CB(MJUMPYR,100)	Mbblcd	Flow From PADD To CD Via Clean Barge
FLOWPD_CT(MJUMPYR,100)	Mbblcd	Flow From PADD To CD Via Clean Tanker
FLOWPD_DB(MJUMPYR,100)	Mbblcd	Flow From PADD To CD Via Dirty Barge
FLOWPD_DT(MJUMPYR,100)	Mbblcd	Flow From PADD To CD Via Dirty Tanker
FLOWPD_ECB(MJUMPYR,100)	Mbblcd	Eth Flow From PADDo CD Via Clean Barge
FLOWPD_EDB(MJUMPYR,100)	Mbblcd	Eth Flow From PADDo CD Via Dirty Barge
FLOWPD_LT(MJUMPYR,100)	Mbblcd	Lpg Flow From PADD To CD Via Tanker
FLOWPRD(MJUMPYR,51)	Mbbl/cd	Product pipeline flow
FSCSTCL(MNUMCR,MJUMPYR)	$87	Costs
GAINPCT(MJUMPYR)	Percent	Gain as percent of total crd input (not used AEO2006)
GPRDIMP(MNUMPR,14)	Fraction	Growth rate for product imports
GTL_INCBLD	Mbbl/cd	Incremental build level allowed for GTL units
HH2_CONS(MNUMPR,PUNITSN+1,MJUMPYR)	Mbbl(foe)/cd	Hydrogen consumption, by reg, unit, yr
HH2_FUXC(MNUMPR,MJUMPYR)	Mbbl(foe)/cd	Hydrogen consumed by fuel plant (FUX)
HH2_FUXP(MNUMPR,MJUMPYR)	Mbbl(foe)/cd	Hydrogen produced by other units
HH2_FUXUC(MNUMPR)	Integer	Flag indicating H2 consumed by FUX in region
HH2_FUXUP(MNUMPR)	Integer	Flag indicating H2 produced by FUX in region
HH2_PROD(MNUMPR,PUNITSN+1,MJUMPYR)	Mbbl(foe)/cd	Hydrogen produced, by reg, unit, yr
HH2_UNITC(MNUMPR,PUNITSN)	Integer	Flag indicating units consuming H2 in region
HH2_UNITP(MNUMPR,PUNITSN)	Integer	Flag indicating units producing H2 in region
IMPBOB(MJUMPYR)	M bbl/cd	National total for Imported RBOB
IRACBND(2)	$87/bbl	Imported Ref. Acquisition Costs (IRAC) bounds
IRACN	$87/bbl	Refiner acquisition cost min. tolerance
IRACX	$87/bbl	Refiner acquisition cost max. tolerance
N6XPRC(9)	Fraction	Price step adjustment for N6I/B
N6XQNT(9)	Fraction	Supply step adjustment for N6I/B
LLPRDEXP(11,5,MJUMPYR)	Mbbl/cd	Lower bound on prod exports (for cap expan)
LOWBND	None	Variable for passing data to OML
MARKET((MNUMCR,MJUMPYR)	Real	Factor in ethanol equation
MGSBCHAR(5,11)	Text	Gasoline blend category for SSR, SST, RFH, TRH, SSE (TYP,BLND)
MGSBLND(5,5,11,5)	??/bbl	Gasoline blend specs for SSR, SST, RFH, TRH, SSE (PADD,TYP,BLND,YR)
MGSPCS(80,MJUMPYR)	Many	Motor gasoline specifications
MGSHR(MJUMPYR,6,MNUMCR)	Percent	Motor gasoline market shares
MISCINP(MNUMPR,MJUMPYR)	MMbbl/cd	Miscellaneous inputs
MOGAS_O2N	Fraction	Wt. Fraction O2 in mogas
MOGAS_SG	--	Specific gravity of mogas
MTBERFGX	Wt. Fraction	Max oxygenate in RFG allowed to be MTBE
MTBETRGX	Wt. Fraction	Max oxygenate in TRG allowed to be MTBE

NAME	UNITS	DEFINITION
MITIMRGSC(MJUMPYR,5,9,3)	Mbbl/cd, $87/bbl	REF. GAS., expanded imp supply curve
MITIMGSSC(MJUMPYR,5,9,3)	Mbbl/cd, $87/bbl	GASOLINE, expanded imp supply curve
MITIMDSSC(MJUMPYR,5,9,3)	Mbbl/cd, $87/bbl	DISTILLATE, expanded imp supply curve
MITIMLDSC(MJUMPYR,5,9,3)	Mbbl/cd, $87/bbl	LOW SUL. DIS. , expanded imp supply curve
MITIMLRSC(MJUMPYR,5,9,3)	Mbbl/cd, $87/bbl	LOW SUL. RES. , expanded imp supply curve
MITIMHRSC(MJUMPYR,5,9,3)	Mbbl/cd, $87/bbl	HIGH SUL. RES. , expanded imp supply curve
MITIMJFSC(MJUMPYR,5,9,3)	Mbbl/cd, $87/bbl	JET FUEL, expanded imp supply curve
MITIMLPSC(MJUMPYR,5,9,3)	Mbbl/cd, $87/bbl	LPG, expanded imp supply curve
MITIMPFSC(MJUMPYR,5,9,3)	Mbbl/cd, $87/bbl	PETCHEM. FEED, expanded imp supply curve
MITIMOTSC(MJUMPYR,5,9,3)	Mbbl/cd, $87/bbl	OTHER, expanded imp supply curve
MITIMMESC(MJUMPYR,5,9,3)	Mbbl/cd, $87/bbl	METHANOL, expanded imp supply curve
MITIMMTSC(MJUMPYR,5,9,3)	Mbbl/cd, $87/bbl	MTBE, expanded imp supply curve
MITIMXGSC(MJUMPYR,5,9,3)	Mbbl/cd, $87/bbl	RBOB, expanded imp supply curve
MITIMXDSC(MJUMPYR,5,9,3)	Mbbl/cd, $87/bbl	LOW SULFUR DIESEL, expanded imp supply curve
MXITIMRGSC(MNXYR,5,9,3)	Mbbl/cd, $87/bbl	REF. GAS., expanded imp supply curve
MXITIMGSSC(MNXYR,5,9,3)	Mbbl/cd, $87/bbl	GASOLINE, expanded imp supply curve
MXITIMDSSC(MNXYR,5,9,3)	Mbbl/cd, $87/bbl	DISTILLATE, expanded imp supply curve
MXITIMLDSC(MNXYR,5,9,3)	Mbbl/cd, $87/bbl	LOW SUL. DIS. , expanded imp supply curve
MXITIMLRSC(MNXYR,5,9,3)	Mbbl/cd, $87/bbl	LOW SUL. RES. , expanded imp supply curve
MXITIMHRSC(MNXYR,5,9,3)	Mbbl/cd, $87/bbl	HIGH SUL. RES. , expanded imp supply curve
MXITIMJFSC(MNXYR,5,9,3)	Mbbl/cd, $87/bbl	JET FUEL, expanded imp supply curve
MXITIMLPSC(MNXYR,5,9,3)	Mbbl/cd, $87/bbl	LPG, expanded imp supply curve
MXITIMPFSC(MNXYR,5,9,3)	Mbbl/cd, $87/bbl	PETCHEM. FEED, expanded imp supply curve
MXITIMOTSC(MNXYR,5,9,3)	Mbbl/cd, $87/bbl	OTHER, expanded imp supply curve
MXITIMMESC(MNXYR,5,9,3)	Mbbl/cd, $87/bbl	METHANOL, expanded imp supply curve
MXITIMMTSC(MNXYR,5,9,3)	Mbbl/cd, $87/bbl	MTBE, expanded imp supply curve
MXITIMXGSC(MNXYR,5,9,3)	Mbbl/cd, $87/bbl	RBOB, expanded imp supply curve
MXITIMXDSC(MNXYR,5,9,3)	Mbbl/cd, $87/bbl	LOW SULFUR DIESEL, expanded imp supply curve
MQ_ITIMCRSC(MJUMPYR,5,5,9)	Mbbl/cd	Expanded crude imp supply curve, qty
MP_ITIMCRSC(MJUMPYR,5,5,9)	$87/bbl	Expanded crude imp supply curve, prc
NFLOWCRD(MJUMPYR,35)	Char*8	Names used in pmmrpts.txt table (refrpt.f)
NFLOWLPG(MJUMPYR,12)	Char*8	Names used in pmmrpts.txt table (refrpt.f)
NFLOWPRD(MJUMPYR,51)	Char*8	Names used in pmmrpts.txt table (refrpt.f)
NGASCOEF	Fraction	Percent of CHP fuel as Natural GAS
NGLEXP(MJUMPYR)	MM bbl/cd	NGL Exports (US Total LPG + pentanes plus
NGLIMP(MJUMPYR)	MM bbl/cd	NGL Imports (US Total LPG + pentanes plus
NGLMK(MNUMPR,MJUMPYR,6,2)	MMbbl/cd	NGL to market
NGLRF(MNUMPR,MJUMPYR,6,2)	MMbbl/cd	NGL to refinery
NGRFUPIT(MNUMPR)	MMbbl/cd	Natural gas fuel use previous iteration
OGASCOEF	Fraction	Percent of CHP fuel as OGAS
OILCOEF	Fraction	Percent of CHP fuel as OIL
OPCSTCL(MJUMPYR)	$87	Operating costs for Biomass conversion
OTHCOEF	Fraction	Percent of CHP fuel as OTHer
OTHLIQIN(MNUMPR,MJUMPYR)	MMbbl/cd	Total Other Liquids input into refiner
OTHOXY(MNUMPR,MJUMPYR)	MMbbl/cd	Other oxgenates
OTHOXYFP(MJUMPYR)	MM bbl/cd	OTHER OXGENATES Field Production
OTHOXYIMP(MNUMPR,MJUMPYR)	MM bbl/cd	OTHER OXGENATES IMPORTED
OTHPRDSP(MNUMPR,MJUMPYR)	MMbbl/cd	Total Other Liquids Product Supplied
P2HL(MNUMPR, MJUMPYR)	$87/bbl	Marg pr for stream 2HL
PADD2CD_CB(2,100)	Integer	PADD To CD Via Clean Barge
PADD2CD_CT(2,100)	Integer	PADD To CD Via Clean Tanker
PADD2CD_DB(2,100)	Integer	PADD To CD Via Dirty Barge
PADD2CD_DT(2,100)	Integer	PADD To CD Via Dirty Tanker
PADD2CD_ECB(2,100)	Integer	PADD To CD Via Clean Barge (Eth)
PADD2CD_EDB(2,100)	Integer	PADD To CD Via Dirty Barge (Eth)

NAME	UNITS	DEFINITION
PADD2CD_LT(2,100)	Integer	PADD To CD Via Tanker (Lpg)
PALB(MNUMPR, MJUMPYR)	$87/bbl	Marg pr for stream ALB
PCOKH	None	Variable for passing data to OML
PCOKL	None	Variable for passing data to OML
PCTCARB	Fraction	Projected 2010 carbon emissions relative to 1990
PD2CD1COEF	Fraction	Percent split of PADD 1 to CD 1
PD2CD2COEF	Fraction	Percent split of PADD 1 to CD 2
PD2CD3COEF	Fraction	Percent split of PADD 2 to CD 3
PD2CD4COEF	Fraction	Percent split of PADD 2 to CD 4
PD2CD5COEF	Fraction	Percent split of PADD 1 to CD 5
PD2CD6ACOEF	Fraction	Percent split of PADD 2 to CD 6
PD2CD6BCOEF	Fraction	Percent split of PADD 3 to CD 6
PD2CD7ACOEF	Fraction	Percent split of PADD 2 to CD 7
PD2CD7BCOEF	Fraction	Percent split of PADD 3 to CD 7
PD2CD8COEF	Fraction	Percent split of PADD 4 to CD 8
PD2CD9COEF	Fraction	Percent split of PADD 5 to CD 9
PETB(MNUMPR, MJUMPYR)	$87/bbl	Price of ETBE
PETHANOL(MNUMCR,MJUMPYR)	$87/bbl	Marginal cost for ethanol
PETHRFBL(MNUMPR,MJUMPYR)	$87/bbl	Refinery ethanol blending cost
PFC8(MNUMPR, MJUMPYR)	$87/bbl	Marg pr for stream FC8
PGPLTRF(MNUMPR,MJUMPYR,18)	$87/bbl	Refinery production costs
PKHL(MNUMPR, MJUMPYR)	$87/bbl	Marg pr for stream KHL
PMETRFBL(MNUMPR,MJUMPYR)	$87/bbl	Refinery methanol blending cost
PMMCAPI(MNUMPR,PUNITSN)	Mbbl/cd	Initial refinery unit capacity
PMMOBJ(MJUMPYR)	M$87/day	Objective function value by year
PMTB25(MNUMPR, MJUMPYR)	$87/bbl	Price of MTBE
PMMTRFBL(MNUMPR,MJUMPYR)	$87/bbl	Refinery MTBE blending cost
PR10(MNUMPR, MJUMPYR)	$87/bbl	Marg pr for stream R10
PRDDMD(MNUMCR,MJUMPYR,30)	Mbbl/cd	Product demand
PRDDMDME(MJUMPYR)	Mbbl/cd	Chemical methanol demand
PRDEXPTOT(MJUMPYR)	MMbbl/cd	Total allowable product exports
PRDSTKWDR(MNUMPR,MJUMPYR)	MMbbl/cd	Product stocks withdrawals
PRDTOT(MJUMPYR)	Mbbl/cd	Total product demand for report 4
PRFELPURPD(MNUMPR,MJUMPYR)	$87/kWh	Refinery electricity costs
PRFNGFU(MNUMPR,MJUMPYR)	$87/bbl (foe)	Refinery NG fuel cost
PRHEQ(MNUMCR,MJUMPYR)	Cents/gal	High sulfur resid (eq price)
PRHUTEQ(MNUMCR,MJUMPYR)	Cents/gal	High sulfur util. resid (eq price)
PRICLP	None	Variable for passing data to OML
PRLEQ(MNUMCR,MJUMPYR)	Cents/gal	Low sulfur resid (eq price)
PRLUTEQ(MNUMCR,MJUMPYR)	Cents/gal	Low sulfur util. resid (eq price)
PRPFF(5)	MFOEbbl/day	RHS value for resid. by PAD District
PRPFU(5)	MFOEbbl/day	RHS value for resid. by PAD District
PSRI(MNUMPR, MJUMPYR)	$87/bbl	Marg pr for stream SRI
PSULSAL(MNUMPR)	$87/s ton	Price of saleable sulfur
PTAE(MNUMPR, MJUMPYR)	$87/bbl	Price of TAEE
PTAM(MNUMPR, MJUMPYR)	$87/bbl	Price of TAME
PTHE(MNUMPR, MJUMPYR)	$87/bbl	Price of THEE
PTHM(MNUMPR, MJUMPYR)	$87/bbl	Price of THME
PUBASE(MNUMPR,60,MJUMPYR)	Mbbl/cd	Processing units base capacity
PUBASEUT(MNUMPR,60,MJUMPYR)	Percent	Processing units base utilization
PUCUM(MNUMPR,60,MJUMPYR+4)	Mbbl/cd	Process unit cumulative builds
PUINV(MNUMPR,60,MJUMPYR+4)	Mbbl/cd	Process unit investment builds
PWCRDCL(MJUMPYR)	$87	Costs for Biomass conversion
PVAF(MNUMPR, MJUMPYR)	$87/bbl	Marg pr for stream VAF
Q_GTLPRD(MNUMPR,MJUMPYR)	M bbl/cd	Qty of liquids produced from GTL processing
Q_GTLGAS(MNUMPR,MJUMPYR)	BCF/cd	Qty of NG consumed for GTL processing

NAME	UNITS	DEFINITION
QETHRFN(MNUMPR,MJUMPYR)	Mbbl/cd	Refinery ethanol blending volume
QGPLTRF(MNUMPR,MJUMPYR,18)	BCF/cd, Mbbl/cd	Refinery gas plant production volumes
QMETRFN(MNUMPR,MJUMPYR)	Mbbl/cd	Refinery methanol blending volume
QPRDEXD(MNUMPR,30,MJUMPYR)	Mbbl/cd	Production distress export by product
QPRDIMD(MNUMCR,30,MJUMPYR)	Mbbl/cd	Quantity of total distress product imports
QPRDIMP(MJUMPYR,MNUMPR,14,5)	Mbbl/d	Product imports
QPRDRFT(MJUMPYR)	Mbbl/cd	Total refinery production volumes
QRFMPMT(MNUMPR,MJUMPYR)	Mbbl/cd	Methanol qty transferred fr refinery to merchant
QSUBFU(MNUMPR,MJUMPYR)	MMbbl/cd	Subtotal refinery fuel use w/o nat. gas
QSULSAL(MNUMPR)	1000 s ton/yr	Quantity of saleable sulfur produced
QTOTFU(MNUMPR,MJUMPYR)	MMbbl/cd	Total refinery fuel use with natural gas
RETHRIMP(MNUMPR,MJUMPYR)	Mbbl/cd	Imported ethers
RFCAPREC(MNUMPR,PUNITSN,MJUMPYR)	$/bbl	Refinery processing unit capital recovery factor
RFCGCONS(MNUMPR,MJUMPYR)	TBtu	Refinery CHP PAD District
RFCGFUELCD(MNUMCR,MJUMPYR)	TBtu	Refinery CHP Fuel by Cenus Division
RFCGFUELPD(MNUMPR,MJUMPYR)	TBtu	Refinery CHP Fuel
RFCGGENCD(MNUMCR,MJUMPYR)	TBtu	Refinery CHP Generation
RFCGGENPD(MNUMPR,MJUMPYR)	TBtu	Refinery CHP by PAD Ditrict
RFCGGRIDCD(MNUMCR,MJUMPYR)	TBtu	Refinery CHP To grid by Cenus Division
RFCGGRIDPD(MNUMPR,MJUMPYR)	TBtu	Refinery CHP to grid by PAD District
RFCGREC(MNUMPR,MJUMPYR)	KWh	Receipts of electricity
RFCGSELFCD(MNUMCR,MJUMPYR)	TBtu	Refinery CHP Self by Cenus Division
RFCGSELFPD(MNUMPR,MJUMPYR)	TBtu	Refinery CHP Self
RFCGSTEAM(MNUMPR,MJUMPYR)	Percent	Steam, PAD District percent adjustment
RFCXCAPPD(MNUMPR,MJUMPYR)	Mkw/day	CHP capacity
RFCXGENPD(MNUMPR,MJUMPYR)	Mkwh/day	CHP generation
RFEMISST(MNUMPR,MJUMPYR,12)	Many	Total refinery emissions
RFETBD(MNUMPR,MJUMPYR)	MMbbl/cd	ETBE oxygenate quantity
RFETBMCT(MNUMPR,MJUMPYR)	MMbbl/cd	Merchant ETBE production
RFETHETB(MNUMPR,MJUMPYR)	MMbbl/cd	Ethanol for ETBE
RFETHMCT(MNUMPR,MJUMPYR)	MMbbl/cd	Merchant ethanol consumption
RFETHMGS(MNUMPR,MJUMPYR)	MMbbl/cd	Ethanol for motor gasoline
RFFMT(MNUMPR,MJUMPYR,34)	Percent	Refinery fuel mix
RFFPO(MJUMPYR)	MM bbl/cd	Field production of other liquids
RFFUELU(MJUMPYR)	MMbbl/cd	Total refinery fuel use w/o nat. gas
RFGBCRFG(MNUMPR,13,MJUMPYR)	Mbbl/cd	Gasoline blending composition (reform. & hioxygen)
RFGBCTRG(MNUMPR,13,MJUMPYR)	Mbbl/cd	Gasoline blending composition (conventional & hioxygen)
RFGM00(MNUMPR,MJUMPYR)	Octane	Avg motor octane in RFG pool
RFGR00(MNUMPR,MJUMPYR)	Octane	Avg research oct in RFG pool
RFGSPCDL(MNUMPR,MJUMPYR,9)	$87/bbl	RFG specification row dual activity
RFGSPCLM(MNUMPR,MJUMPYR,9)	Text	RFG specification row status
RFGSPEC(9)	Text	RFG specifications
RFHCXH2IN(MNUMPR,MJUMPYR)	MMbblFOE/cd	Total Hydrogen input into refinery
RFIPQDU(MNUMPR,MJUMPYR,2)	MMbbl/cd,$87/bbl	Imported DSU, P/Q
RFIPQSB(MNUMPR,MJUMPYR,2)	MMbbl/cd,$87/bbl	Subtotal imported product w/o Methanol
RFIPQTL(MNUMPR,MJUMPYR,2)	MMbbl/cd,$87/bbl	Total imported product with Methanol
RFMETETH(MNUMPR,MJUMPYR)	MMbbl/cd	Methanol for ether
RFMETMCT(MNUMPR,MJUMPYR)	MMbbl/cd	Merchant methanol comsumption
RFMTBEIN(MNUMPR,MJUMPYR)	MMbbl/cd	Total MTBE input into refinery
RFMTBMCT(MNUMPR,MJUMPYR)	MMbbl/cd	Merchant MTBE production
RFNETOLIMP(MJUMPYR)	MM bbl/cd	Net Other Liquids Imports
RFNGFTOT(MJUMPYR)	Mbbl/cd	Total natural gas production
RFOHOXYIN(MNUMPR,MJUMPYR)	MMbbl/cd	Total "Other" Oxygenates input into re
RFOPEXP(MNUMPR,MJUMPYR)	1000 $87/cd	Refinery operating expenses

NAME	UNITS	DEFINITION
RFQPRCGo(MNUMPR,MJUMPYR)	MMbbl/cd	Old Gain from Maxix or data sources
RFOTHFU(20)	Text	Refinery fuel use for OTH category (3-charID)
RFOXYIN(MNUMPR,MJUMPYR)	MMbbl/cd	Total Oxygenates input into refinery
RFPRDFX(MNUMCR,MJUMPYR,24)	$87/bbl	Refinery capital cost by product
RFQNGLRF(MNUMPR,MJUMPYR)	MMbbl/cd	Quantity of ngl inputs to refinery
RFSTEAM(MNUMPR,MJUMPYR)	MMlb/day	Steam by PAD District
RFTAED(MNUMPR,MJUMPYR)	MMbbl/cd	TAE oxygenate quantity
RFTAMD(MNUMPR,MJUMPYR)	MMbbl/cd	TAME oxygenate quantity
RFTHED(MNUMPR,MJUMPYR)	MMbbl/cd	THE oxygenate quantity
RFTHMD(MNUMPR,MJUMPYR)	MMbbl/cd	THM oxygenate quantity
ROXYTOT(MNUMPR,MJUMPYR)	MMbbl/cd	Total oxygenated volumes
RWOP(MJUMPYR)	$87/bbl	PMM local expected WOP
SBG08RFG(MNUMCR,MJUMPYR)	Mbbl/cd	Splash blnd Vol of ethanol for RFG
SBG08RFH(MNUMCR,MJUMPYR)	Mbbl/cd	Splash blnd Vol of ethanol for RFH
SBG08TOT(MNUMCR,MJUMPYR)	Mbbl/cd	Tot ethanol used for mogas blnd
SBG08TRG(MNUMCR,MJUMPYR)	Mbbl/cd	Splash blnd Vol of ethanol for TRG
SBG08TRH(MNUMCR,MJUMPYR)	Mbbl/cd	Splash blnd Vol of ethanol for TRH
SBRFGRFG(MNUMCR,MJUMPYR)	Mbbl/cd	Splash blnd Vol of RBOB for RFG
SBRFGRFH(MNUMCR,MJUMPYR)	Mbbl/cd	Splash blnd Vol of RBOB for RFH
SBTRGTRG(MNUMCR,MJUMPYR)	Mbbl/cd	Splash blnd Vol of SSE for TRG
SBTRGTRH(MNUMCR,MJUMPYR)	Mbbl/cd	Splash blnd Vol of TBOB for TRH
SPLTTYP(PUNITSN,MJUMPYR)	Integer	Represents %(=1) vs capacity(=2)
SQETOH(2,MNUMCR,MJUMPYR)	Mbbl/cd	Ethanol soln from cap expansion
STMDMD(MNUMPR,MJUMPYR)	lb/bbl	Steam consumption at ref
TAP_FIXCST	1000 $87/cd	Fixed transportation cost on TAPS
TAP_MAXCAP	MMbbl/cd	Max capacity on TAPS
TAP_MINSTVOL	MMbbl/cd	Min incremental vol above MINTHRU
TAP_MINTHRU	MMbbl/cd	Min economic throughput on TAPS
TAP_OILADJ	Percent	Min upward adjustment on Lift Cost
TAP_OILIFT	$87/bbl	Assumed oil lifting cost in AK
TAP_VARCHG	$87/bbl	Variable trans cost on TAPS
TOTPRD(MNUMPR,MJUMPYR)	MMbbl/cd	Total refinery products sold
TRANSCL(MJUMPYR)	$87	Transport costs for Biomass conversion
TRGR00(MNUMPR,MJUMPYR)	Octane	Avg research oct in TRG pool
TRGM00(MNUMPR,MJUMPYR)	Octane	Avg motor octane in TRG pool
TRGSPCDL(MNUMPR,MJUMPYR,7)	$87/bbl	RFG specification row dual activity
TRGSPCLM(MNUMPR,MJUMPYR,7)	Text	TRG specification row status
TRGSPEC(7)	Text	TRG specifications
ULPRDEXP(11,5,MJUMPYR)	Mbbl/cd	Upper bound on prod exports (for cap expan)
UPBND	None	Variable for passing data to OML
WOPMTPLY	Percent	Distress import price multiplier
WOPZ9EXP	Percent	Distress export price multiplier
XRFELP(MNUMCR,MJUMPYR)	MMbbl/cd	Local expected electricity price
XRFNGP(MNUMCR,MJUMPYR)	MMbbl/cd	Local expected natural gas price
XSTMDMD(MNUMPR,MJUMPYR)	lb/bbl	Forecast steam consumption at ref (not used)
	Identifier variables	
BLDPD	Integer	Build period look-ahead (3 years)
BNDS(2)	Text	Bounds character identifiers
CAPYR1ST	Integer	First year cap expansion is run
CRDLINKS	Integer	Crude transportation links
CRDTYP(5)	Text	Crude type character identifiers
DMDRGNS	Integer	PMM demand regions index
ETHERS(7)	Text	List of ethers
FO1PMM	None	Variable for file unit identifier
FO2PMM	None	Variable for file unit identifier

NAME	UNITS	DEFINITION
IPRD(14)	Text	Imported product chrctr identifers
MG_NAM(4)	Text	Mogas types created from splash blend (SS*)
MGSCHAR(80)	Text	Mogas share character identifiers
NEMSYR1	Integer	First NEMS year (1990)
NLV(9)	Text	Census division character identifers
NLV2(9)	Text	Domestic crude supply regn identifers
QNT(9)	Text	Quantity character identifiers
PADD(5)	Text	PAD District character identifiers
PMMDBG	Integer	PMM debug file unit ID
PMMRGNS	Integer	PMM refining regions index
PRCUNIT(60)	Text	Process unit character identifier
PRD(30)	Text	Product character identifiers
PRDIMP	Text	name for PRDIMP.txt input file
PRDLINKS	Integer	product transportation links
PRTYRS(5)	year	ID's 5 yrs to print data for MRM
RFOTHFU(20)	Text	Other fuel use character identifier
SPRPTYR$	Integer	Year $ for special tables 1a,b,c,d in pmmrpts.txt
SS_NAM(4)	Text	SS* names splash blended into 4 mogas types
SUBNM	Text	Subroutine name index
SUBNMX	Text	Passing subroutine name index
Z9EXPRD(11)	Text	Distress export index list
	Switches	
ATRHSW	Integer	Switch for alternate cal of TRH price
CTL_FSTYR	Year	First year CTL allowed to be built
CTLMB_SW	Integer	Switch to apply Mansfield-Blackman model
CTLTXSW	Integer	Switch to apply CTL tax credit
CTLTXYR1	Year	First year to apply CTL tax credit
CTLTXYR2	Year	Last year to apply CTL tax credit increment
DSUYR1	Integer	First DSU phase-in year
DSUYR2	Integer	Final DSU phase-in year
ODSUYR1	Integer	First year NRLM DSL required
ODSUYR2	Integer	First year nonroad (NR) DSU required
ODSUYR3	Integer	First year loco./marine (LM) DSU required
EMISSCSSW	Integer	Switch for emissions cost adjustment
ETHSWTX	Integer	Switch for ethanol subsidy for carbon tax case
ETHTECSW	Integer	Hi tech switch for ethanol, cellulose
FRSTIT	Text	Write basis on first/last iteration switch
GTL_FSTYR	Integer	First possible start year for GTL builds
HISTLYR	Integer	PMM last history year
HITSWTC	Text	HiTech switch
IETHHT	Integer	Biomas switch for technology case
IMPCALIB	Text	Switch for import curve calibrations
IPMM	Integer	Switch for International updates (not active)
ISOFLAG	Integer	Flag allowing MTBE unit conversion to ISO-octane
ISOXGRNT	Integer	Flag for grant assisting merchant MTBE unit Conversion to ISO-octane
LHCDIST(2,MJUMPYR,7,30)	Percent	Model testing variable
LHCRUN	Integer	Model testing switch
MGOUTLR	Integer	Switch for gasoline price outliner
MPSSWTC	Text	MPS matrix load switch
MTBEO2WV	Integer	Flag for mininum O2 waiver, if MTBE banned
MTBEYR	Integer	First year of MTBE restriction in regions E,B
NRMSWTC	Text	NRM on/off switch
ONECESW	Integer	Switch for 1 cap expansion iteration
PMM_OR_MRM	Text	5 region to 3 region PMM switch
PMMBSYR	Integer	PMM base year, 1995

NAME	UNITS	DEFINITION
PMMINF	None	Infeasible solution switch
PMMSTEOBM	Text	Switch to turn on STEO benchmarking
PRCUNSWT(60)	None	Processing unit on/off switch for cap. expan.
PRDIMPSW	Integer	Switch for product import calc
PRDIMPWR	Integer	Switch for writing product import results
REN_YR	Year	First year for req %min renewables in gas/diesel
RENADJYR	Year	First year for adj rfg price due to renew in gas/diesel
RENITR	Iteration	First itr for adj rfg price due to renew in gas/diesel
RFADVBAS	Text	Advance basis load switch
RFAEOADJ	Text	Switch to turn on AEO adjustments
RFCESWTC	Text	Capacity expansion switch
RFETSWTC	Text	Ethanol supply curve switch
RFHIST	Text	History switch
RFPCKYR	Integer	Pack file year
RFROSSWTC	Text	ROS switch, on or off
RPT1SWTC	Text	Report 1 switch
RPT7SWTC	Text	Report 7 switch
RPT1YR1	Text	Report 1 switch
RPT1YR2	Text	Report 1 switch
RPT1YR3	Text	Report 1 switch
RPT1YR4	Text	Report 1 switch
RPT1YR5	Text	Report 1 switch
RPT1YR6	Text	Report 1 switch
RPTFY	Integer	Reporting first year
RPTLY	Integer	Reporting last year
STEOBMSW	Integer	STEO benchmarking switch
STMTBSWT(MNUMCR)	Integer	Flag for state MTBE ban (0=no ban)
STMTBYR(MNUMCR)	Year	First year of state MTBE ban
WTRGSW	Integer	Switch for alternate calculation of west coast TRG

Legend for Codes

MJUMPYR = NEMS year index, 1 through 31
MNUMCR = census region index, 1 through 11
MNUMPR = PAD District index, 1 through 6
MNUMOR = Oil and Gas Region Index, 1 through 13
MNCROP = Ethanol supply crop index, 1 and 2
MNETOH = Ethanol supply curve point index 1 through 5

A.2 Data Sources

The PMM data have been developed and updated by EIA and others since the first model database was provided by Turner, Mason Associates during 1975-76. The original data were used extensively during 1983-1986 in the EIA Refinery Yield Model (RYM). The RYM database underwent substantial review and update by oil industry experts when the National Petroleum Council (NPC) used the RYM during the development of their 1986 study on U.S. refining flexibility. To support a study for the U.S. Navy in 1985, EIA provided Oak Ridge National Laboratories (ORNL) and its consultant EnSys with the updated RYM/NPC data and OMNI matrix and report generator programs.[1] Most of the data used for this version of the PMM was provided by EnSys to EIA in June 2003 (no updates made in 2004) and is based on some EnSys in-house data sources. Other data were provided by DOE's National Energy Technology Lab (NETL) and its consultant John J. Marano (LLC). The various data sources include:

- The original Refinery Yield Model (RYM) Data Base provided by EIA in about 1981 to ORNL. This data was then combined with the 1985 RYM/NPC updates and used by their consultant, EnSys.
- *Oil & Gas Journal*, *Hydrocarbon Processing*, NPRA papers, API papers, ASTM specs and correlation methods, *Chemical Engineering*, Gary & Handwerk (mainly correlations), AIChE papers, *Petroleum Review*.
- An extensive review of foreign journals obtained with the aid of ORNL for the high-density jet fuel study.
- Contractor reports and data - M.W. Kellogg, UOP, IFP, Snam Projetti and Foster and Wheeler.
- Consultant reports and data as published - Bonner & Moore, A.D. Little, Chem Systems, Purvin & Gertz, and National Energy Technology Laboratory.
- Updated data tables for the alkylation units (HFA, SFA, and others), isooctane units (IOT, IOX), and petroleum coke gasifier (GSF, GSH, CHP), were all provided by DOE's National Energy Technology Laboratory and its consultant John J. Marano (LLC).
- John J. Marano (LLC) also provided new hydrogen stream data (associated with relevant processing units) such that a single hydrogen stream (HH2) was disaggregated into three hydrogen streams (HYL, HYM, HYH) that were distinguished by quality (low, medium, and high).

A.2.1 Process Technology and Cost Data

Refining process technology and cost data need periodic review and update. This is because environmental legislation, lighter product slates, and heavier crude slates have spurred new process technology developments affecting existing processes, new processes, and costs. Sources for new developments include research and other papers in industry journals, papers from industry conferences and surveys (such as NPRA), engineering and licensing contractor data, and published consultant studies.

[1]Oak Ridge National Laboratory, EnSys Energy and Systems, *Enhancement of EIA Refinery Evaluation Modeling System Refinery Yield Model Extension and Demonstration on Gasoline and Diesel Quality Issues*, (August 1988).

A.2.2 Refinery Capacity Construction and Utilization Data

The base capacity for refinery process units are derived principally from EIA data and annual surveys published in the *Oil & Gas Journal*. The approach used is to review all announced projects, but to only include as active those that have reached the engineering, construction, or start-up stage. (Unit capacity is measured in volume per calendar day.) Historical process unit utilization is derived from the EIA *Petroleum Supply Annual*.

It is also necessary to track capacity for methyl tertiary butyl ether (MTBE) and tertiary amyl methyl ether (TAME) plants, both in-refinery and merchant. Principal sources for these data are EIA surveys, *Fuel Reformulation*, and the *Pace Petrochemical Service* publications.

A.2.3 Crude Supply and Product Demand Data

The crude oil supply is provided by two of the NEMS models: OGSM, which provides the production function to estimate the domestic oil production, including Alaska; and, the International Energy Model which provides volumes and prices of imported crude oils in the form of supply curves. Individual crude oil streams for both domestic and imported crude oils are grouped in five categories differentiated by API gravity, sulfur content, and the yield of material boiling at a temperature higher than 1050 degrees Fahrenheit. The import supply curve values are stored in the NEMS restart file. Each year of a NEMS run contains quantities and import prices for crude oil in five step supply increments for each of the importing PMM regions (E = PADD I, C = PADD II, G = PADD III, M = PADD IV, and W = PADD V).

Both domestic and imported crude oils are grouped in the five categories shown below. While the domestic and foreign categories have the same gravity and sulfur definitions, the composite characteristics of each type may differ because different crude streams make up the composites. The five domestic crude groups are tagged with the codes DLL, DMH, DHL, DHH, and DHV. The imported crude oil codes are FLL, FMH, FHL, FHH, and FHV. In addition, Alaska North Slope and Alaska South are included as individual crude oil streams for a total of 12 crude groups.

Table A2. Aggregate Crude Oil Categories for PMM/NEMS

Description	Code	API Gravity	Sulfur, Wt%	Bottoms Yield, 1050+ °F Vol %
Low Sulfur-Light	LL	25-60	0.5 MAX	< 15%
Medium Sulfur - Heavy	MH	26-40	0.35-1.1	> 15%
High Sulfur - Light	HL	> 32	> 1.1	< 15%
High Sulfur - Heavy	HH	24-33	> 1.1	> 15%
High Sulfur - Very Heavy	HV	< 23	> 0.9	> 15%

Source: Derived from analysis of EIA-810, Monthly Refining Report.

Natural Gas Liquids (NGLs)

The NGLs are produced by the gas plant model matrix that is a part of PMM. See Appendix F (section F.2).

Other Hydrocarbons and Alcohols

Other hydrocarbons, such as propane and butanes, are supplied by the output of the gas plant model. Ethanol and biodiesel are supplied by the Biofuels Supply Submodule within the PMM (Appendix I). Two sources of ethanol are modeled: ethanol from corn in Census Divisions 3, 4, 6, 8, and 9, and ethanol from cellulose in Census Divisions 2, 3, 4, 7, and 9. The supply of ethanol is represented as a step function with each increment of supply available at a higher price. Two sources of biodiesel are also modeled: virgin oil (soybean oil) and non-virgin oil (yellow grease). They are available from all Census Divisions, and are represented as step functions, with each increment of supply available at a higher price. Both virgin and non-virgin oil can be used to produce low-sulfur and ultra-low-sulfur diesel.

Methanol is used to produce M85 and methyl tertiary butyl ether (MTBE). It can either be imported or produced from natural gas by the methanol plant in each refining region.

Products

Product demands are available from the NEMS restart file (determined by NEMS demand and electricity models) for a given scenario by year as produced by the various demand models of NEMS.

A.2.4 Product Specification/Grade Split Data

For the United States, surveys by industry organizations such as NPRA, API, NPC, and NIPER, together with Government sources such as Department of Defense, provide relatively frequent and detailed insights into actual U.S. product qualities and grade splits. These data are important for establishing case studies.

A.2.5 Transportation Data

PMM transportation rates and capacity data for the United States were originally developed from the OSPR NACOD Model and updated for environmental costs (to reflect the Oil Pollution Control Act). The current transportation cost data were based on three sources; (1) The 1989 NPC study [2] (updated in 1999 based on FERC data for the oil pipelines), (2) The North American Crude Oil Distribution (NACOD) model prepared by ICF for the Office of Strategic Petroleum Reserves (OSPR) during 1990-91, and (3) updates provided by ICF in July 2003.

[2]National Petroleum Council, *Petroleum Storage and Distribution, Volume 5, Petroleum Liquids Transportation*, (April 1989).

A.2.6 Product Yield and Quality Blending Data

In addition to the general sources already mentioned, a number of further sources relating to specific properties are given below:

Cetane Number - API Refining Dept., Vol. 61, p.39 and appendix for the modified ASTM D976-80 Equation (George Unzelman).

Net Heat of Combustion - ASTM D3338 (API range 37.5 - 64.5) (relaxing ASTM D2382).

Wt. percent hydrogen - ASTM Method D3343 (replacing D1018)

Smoke point vs. hydrogen content - empirical correlation developed by EnSys Smoke point to Luminometer Number conversion, ASTM D1322.

Viscosity prediction - based on the work of PLI Associates (Dr. Paul S. Kydd) and from the Abbott, Kaufman and Domashe correlation of viscosities. (See PLI report- "Fuel and Engine Effect Correlations, Task 1.1, Computerize Fuel Property Correlations and Validate"). Viscosity interpolation included and based on computerized formulae for ASTM charts.

Viscosity blending indices - computerization of Gary & Handwerk formulae - p.172 (left hand side).

Static and Dynamic Surface Tensions - API Technical DataBook method.

Flash point Blending Index Numbers - Gary & Handwerk, p.173.

Pour Point blending Indices - ibid., p.175.

RVP blending indices have been gathered from several public and in-house sources and have been verified against Gary & Handwerk, p.166.

RON and MON blending deltas are reflective of base gasoline sensitivity have been drawn from many sources and averaged.

A.2.7 Units of Measurement

The general rule adopted in the model is that quantities of oil are in thousands of barrels per calendar day, prices or costs are in 1987 dollars per barrel, and quantities of money are, therefore, in thousands of 1987 dollars per calendar day.

Exceptions to the above rule are:

1. Gases lighter than propane are measured in thousands of barrels fuel oil equivalent (FOE) per day. These are based on the following conversion factors:

Gas stream	Code	bblFOE/lb	cf/bblFOE
Hydrogen	HYL,HYM,HYH	.009620	19,646
Hydrogen sulfide	H2S	.001040	10,145
Methane/natural gas	NGS	.003414	6,917

Gas stream	Code	bblFOE/lb	cf/bblFOE
Ethane	CC2	.003245	3,861
Process gas	PGS	.003245	3,861
Ethylene	C2E	.003219	4,180

One barrel FOE is 6.287 million Btu.

2. The assumed Btu content for other major refinery streams is shown below:

Stream	Code	MMBtu/bbl
Gasoline	TRG	5.202
Jet Fuel	JTA	5.670
No. 2 Heating Oil	N2H	5.825
Residual Oil	N6I,N6B	6.287
LPG	LPG	3.603

3. Yields of coke are measured in short tons per barrel and demands are in short tons per day. A factor of 5.0 crude oil equivalent (COE) barrels per short ton is used. Heat content is 6.024 MMBtu/bbl.

4. Yields of sulfur are also measured in short tons per barrel and demands are in short tons per day. A factor of 3.18 barrels per short ton is used.

5. Process unit capacities are generally measured in terms of feedstock volume. Exceptions are units, principally those with gaseous feeds and liquid products, whose capacities are measured in terms of product volume. These include: OLE, ETH, ETB, ETM, C24, IOT, ALK, CPL, DIP, DIM, ARP, C4I, SMD, SOD, MOH, H2P, H2X, and SUL. Also, STG, KWG, FUM.
Note also that the unit activity levels for H2P, H2X, and SUL represent the production of 0.1 thousand fuel oil equivalent barrels of hydrogen and 0.1 thousand short tons of sulfur per day, for a unit with 0.1 bbls/cd or tons/cd of capacity.

6. Quality and specification units are those specified in each ASTM test method or are dimensionless (as in the case of blending indices). Gasoline sulfur contents and specs, SPM, are in parts per million by weight, while those for distillates, SPC, are in percent weight.

7. Steam consumption is given in pounds per barrel (lb/bbl). Thus an activity in Mbbl/cd consumes steam in thousands of pounds per day (Mlb/day). Steam generation capacity is in millions of pounds per day (MMlb/day). The consumption of 0.00668 fuel oil equivalent barrels per day to raise 1 pound per hour of steam is equivalent to 1225 Btu per pound steam (assuming 70 percent energy conversion efficiency).

8. Electricity consumption is in kWh/bbl. Generation is in MWh/cd (megawatt-hrs/calendar day).

A.3 PMM Model Data Tables

This section describes in detail the function and content of the PMM model data tables used to generate the initial PMM matrix for NEMS. The entries in these tables are thousand barrels per calendar day (Mbbl/cd) for volume and 1987 dollars per barrel for costs, unless otherwise noted.[3] With the shift of computer processing to the EIA RS6000 in 1995, the original OMNI code was replaced with FORTRAN, and subroutines from the Optimization Modeling Library (OML) were used to build the LP structure. The data table formats used by OMNI were no longer valid which required a change in table format, organization and design from the *AEO95* version. These changes are incorporated into the data tables presented in this section. The tables have been grouped into nine categories: Matrix Control, Crude Oil Availability, Other Raw Materials Availability, Product Imports, Product Demands, Crude and Product Transportation, Refinery Capacities and Operations, Product Blending and Specifications, and Refining Technology. All data tables currently are located in a directory on EIA' s network NT server (nems-f8) named N:/default/input.

The **filename** (bold and in parenthesis below) referenced in the following pages refers to the individual file name with a **.dat** extension that contains the tables described. The symbols (R) and (D) used in the table names represent a PMM refining region (R) or Census division (D) where:

(R)*	Refining Region
E	PAD District I
C	PAD District II
G	PAD District III
M	PAD District IV
W	PAD District V

(D)	Census Division
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, including California

*Note: Beginning with *AEO2004*, the PMM refining regions once again represent the five PAD Districts, I, II, III, IV, and V. For a short duration (*AEO98* thru *AEO2003*), the number of PMM refining regions was changed from five to three, where PADDs I and V remained independent regions, and PADDs II, III, and IV were aggregated into a single region.

[3] The NEMS processes data internally in 1987 dollars. The results from NEMS are then converted to *AEO* report year dollars (for *AEO2006*, 2004 dollars) using the chain-type discount factors from the Macroeconomic Activity Model.

A.3.1 Matrix Control

This section describes the tables used to define the categories for the row constraints and column variables in the matrix, as well as the stipulations for the limits on individual constraints and variables. For example, the number of refining regions, demand regions, and export regions are defined, along with their ID's and mapping.

(refmain)

TABLE RFNREG LIST OF ACTIVE PMM REFINING REGIONS

Column names	One column, PAD.
Row names	One character region codes, E, C, G, M, W.
Entries	numeric value for PADDs 1-5.

TABLE DEMNDREG LIST OF ACTIVE CENSUS DIVISION DEMAND REGIONS

Column names	One column, REGION.
Row names	Two character codes, first character is demand region, second character is PMM refining region E, C, G, M, W. Links demand region to refinery region.
Entries	numeric value for Census Divisions 1-9.

TABLE RFNEXP LIST OF PMM REFINING REGIONS LINKED TO EXPORT REGIONS

Column names	One column, RFID.
Row names	Two character codes, first character is exporting Census Division, second character is PMM refining region E, C, G, M, W. Links exporting demand region to refinery region.
Entries	numeric value for export regions, 1-5.

TABLE EXPROD LIST OF EXPORT PRODUCTS

Column names	One column, DUMMY.
Row names	Three character product codes for products being exported.
Entries	none

TABLE FORCRD ***LIST OF FOREIGN IMPORT CRUDES***

Column names: One column, DUMMY.

Row names: Three character code for foreign crude group.

Entries: none

TABLE WOP ***WORLD OIL PRICE BY YEAR***

Column names: One column, WOP.

Row names: Numeric value for year, e.g. 6 for 1995.

Entries: World Oil Price in 1987 $/bbl.

TABLE USERYEAR ***YEAR FOR MODEL RUN***

Column names: One column, YEAR.

Row names: Three character code, e.g. Y96.

Entries: Numeric value for year, e.g. 7 for 1996.

TABLE YRDOLLAR ***CONVERSION FROM 1987 TO 2000 DOLLARS***

Column names: One column, 2000 (year dollars).

Row names: 1987

Entries: Numeric value for converting 1987$ to 2000$ (1.37912).

TABLE ZIRACFAC ***FACTOR FOR IRAC SPREAD***

Column names: One column, DELTA.

Row names: ZIRAC

Entries: Average variability range (+/-) off World Oil Price, $/bbl.

TABLE TRSOVC ***FACTOR TO CONVERT OVC FROM 1987$ TO 2000$***

Column names: One column, OVC.

Row names: One character PMM refining region code (E, C, G, M, W).

Entries: Factor to convert variable operating costs from 1987$ to 2000$ (1.37913).

TABLE INVFACT ***INVESTMENT LOCATION AND ENVIRONMENTAL FACTORS***

Column names: LOC, ENV

Row names: One character PMM refining region code (E, C, G, M, W).

Entries: Column LOC contains the investment location factor multiplier (variable across regions). Column ENV contains the environmental investment cost multiplier (currently set at 1.0 for all regions).

(akaexp)

TABLE EXPAKA ***PRICE/QUANTITY VALUES FOR ALASKA EXPORTS***

Column names: Two columns, P and Q

Row names: Six rows, three negative shifts N1, N2, N3 and three positive shifts, P4, P5, and P6.

Entries: P column is $/bbl shift from reference price, Q column is bound value on volume supplied.

TABLE PRQAKA ***NGL PRICE/ QUANTITY FROM ALASKA NORTH SLOPE***

Column names: VOL, TRP, and EXPPRC

Row names: OGSM code A for Alaska.

Entries: Volume limit on NGL supply, Mbbl/cd; Transportation cost to region W, $/bbl; pseudo supply price, $/bbl.

TABLE NGLAKA ***NGL COMPOSITION FROM ALASKA***

Column names: One column, PER.

Row names: Three character NGL stream codes.

Entries: Volume fraction composition of NGL's.

(avoids) (no longer used)

TABLE SADELQ ***DELTA FRACTION OF QUANTITIES FOR PRODUCT SHIFTS***

Column names: Six columns, three negative shifts N3, N2, N1 and three positive shifts, P1, P2, and P3.

Row names: First three characters finished product codes.

Entries	Percentage (as a fraction) of demand quantity Q0 as an upper bound. The quantities are based on price shifts of 1 percent, 3 percent, and 9 percent using an elasticity of 0.1 for light products gasoline, jet fuel, heating oil and diesel, and an elasticity of 0.3 for all other products.

(These column activities allow the shift of demands within a price range to help speed convergence in NEMS.)

TABLE SADELPX	***FRACTION OF PRICES FOR EACH QUANTITY SHIFT***
Column names	One column, FACTORS
Row names	Six rows, three negative shifts N1, N2, N3 and three positive shifts, P1, P2, and P3.
Entries	Percentage (as a fraction) of price of import step R3 for imported products.

TABLE PRDAVOID	***LIST OF PRODUCTS FOR AVOIDS***
Column names	One column, DUMMY
Row names	Three character product codes.
Entries	None.

(ngprod)

TABLE SPNGF	***SUPPLY STEP PRICES FOR NATURAL GAS TO REFINERY***
Column names	One column, ALLREG
Row names	Two character names, first character is N (negative shift) or P (positive shift), second character is a number from 1 to 8 representing steps on the supply curve.
Entries	Price increments in $/Mcf from reference wellhead price.

TABLE SQNGF	***SUPPLY STEP QUANTITIES FOR NATURAL GAS TO REFINERY***
Column names	Two columns, MAX and MIN
Row names	Two character names, first character is N (negative shift) or P (positive shift), second character is a number from 1 to 8 representing steps on the supply curve.
Entries	Percent (fraction) of total reference quantity supplied on each step.

TABLE SCVAL	***SUPPLY OF NATURAL GAS TO REFINERY***
Column names	Five columns, one for each PMM refining region (E, C, G, M, W).
Row names	One row, VOL.
Entries	Volume estimate reference quantity supply in mmcf/cd.

(unfinish)

TABLE UNFEQT	***COEFFICIENTS FOR UNFINISHED OIL IMPORTS***
Column names	Two columns, SLOPE, CONST, that describe the regression equation coefficients.
Row names	One row, XYZ
Entries	Slope and intercept for equation that correlates total unfinished oil imports to the U.S. with crude input.

TABLE UNFOIL	***UNFINISHED OIL IMPORT SHARES***
Column names	Three columns; E, G represent the PMM refining regions that import unfinished oils; and PD is the cost of the imports.
Row names	Rows NPP, HGM, and ARB represent three types of unfinished oil streams imported to the United States.
Entries	Coefficients under refining regions (E,G) represent volume fractions of Total U.S. unfinished oil imports. Column PD values are imported costs in $/bbl.

(emish)

TABLE EMUNS	***EMISSIONS FROM PROCESS UNITS***
Column names	Five columns, representing type of emission - VOC, CO1, NOX, SOX, and CAR (Carbon).
Row names	Three character process unit codes.
Entries	Emissions in Mlb/Mbbl for VOC, NOX, SOX. Units of MM lbs/Mbbl for CO1, CAR.

TABLE EMFUM	***EMISSIONS FROM FUEL BURNING***
Column names	Six columns, representing type of emission - VOC, CO1, CO2, NOX, SOX, and CAR (Carbon).
Row names	Three character stream codes burned in refinery fuel system.
Entries	Emissions in Mlb/Mbbl for VOC, NOX, SOX. Units of MM lbs/Mbbl for CO1, CO2, CAR.

(fixcols) (no longer used)

TABLES (R)RCOL	***LIST OF VARIABLES TO BE EXCLUDED FOR PMM REGION (R)***
Column names	One column, FCC
Row names	Three character FCC operating mode names
Entries	A 1.0 indicates that column will be fixed at level of 0.0

(distress)

TABLE ZPX	***MAPPING OF DISTRESS IMPORT COSTS***
Column names	One column, VALUE.
Row names	Three character product codes.
Entries	One character value to map distress import costs ($87/bbl): 0=$0; 1=0.1 * import price at import curve step 1; 2=$.99/bbl (for LPG); 3=$.201/bbl FOE (for COK).

A.3.2 Crude Oil Availability

Crude oil supply availability is provided from two sources: (1) domestic production from the Oil and Gas Supply Model (OGSM), and (2) foreign imports to each refining region with three supply step increments.

(domcrude)

TABLE DCRSUP	***DOMESTIC CRUDE OIL IMPORTS BY OGSM REGION***
Column names	Seven columns: one column for each OGSM region (including Alaska)
Row names	Rows for selected years from Y90 to Y10.
Entries	Domestic crude oil production volume in each OGSM region (Mbbl/d)

These values are available from the NEMS restart file for a given scenario.

TABLE DCRSHR	***SHARE BY LOWER 48 CRUDE GROUP***
Column names	Seven columns: one column for each OGSM region (including Alaska)
Row names	Five domestic aggregate crude groups plus two Alaskan groups.
Entries	Fractional share of production volume in each OGSM region

TABLE CREXP	***VOLUME OF CRUDE EXPORTS FROM UNITED STATES***
Column names	Two columns: CRDEXP represents crude oil exports, CRDSPR represents the SPR fill rate.
Row names	One row, VOL.
Entries	Volume in Mbbl/cd

(crdimprt)

TABLES ICR(crt)(R)	***CRUDE OIL IMPORTS BY FOREIGN CRUDE GROUP (crt) IN PMM REFINERY REGION (R)***
Column names	Six columns: C1,Q1,C2,Q2,C3,Q3
Row names	NEMS year code (1,2,3,etc)
Entries	Columns Q(n) represent the availability in Mbbl/cd of each crude. Columns C(n) show the landed price in 1987 dollars per barrel at each refining region.

(These values are available from the NEMS restart file for a given scenario.)

TABLE CRUDETYP	***TYPES OF FOREIGN CRUDE OIL***
Column names	One column, DUMMY
Row names	Three character codes for foreign crude type
Entries	None.

A.3.3 Other Raw Materials Availability

(ethanol)

TABLE SUPETH(D) ETHANOL SUPPLY BY CENSUS DIVISION (D)

Column names: Eight columns, C1,R1,C2,R2,C3,R3,C4,R4

Row names: NEMS Year code (1,2,3,etc)

Entries: Columns R(n) represent the availability of Mbbl/cd of Ethanol. Columns C(n) show the supply price in dollars per barrel in each Census Division. (n=supply step)

(These values are available from the NEMS restart file for a given scenario.)
(Note: T:ETHTAX presented in section A.3.5)

TABLE MINRENEW MINIMUM TOTAL RENEWABLES CONSUMED AT REFINERY

Column names: USMIN

Row names: NEMS Year code (1,2,3,etc)

Entries: Minimum total renewables (ethanol and virgin biodiesel) (all regions) consumed at the refinery (M bbl/cd)

TABLE SUPBIM PRICE/QTY SUPPLY CURVE FOR BIOFUEL (VIRGIN OIL)

Column names: Eight columns, C1,R1,C2,R2,C3,R3,C4,R4

Row names: Census Division demand region ID's (1-9)

Entries: Columns R(n) represent the availability in Mbbl/cd of virgin biodiesel. Columns C(n) show the supply price in dollars per barrel in each Census Division.

TABLE SUPBIN PRICE/QTY SUPPLY CURVE FOR BIOFUEL (NON-VIRGIN OIL)

Column names: Eight columns, C1,R1,C2,R2,C3,R3,C4,R4

Row names: Census Division demand region ID's (1-9)

Entries: Columns R(n) represent the availability in Mbbl/cd of non-virgin biodiesel. Columns C(n) show the supply price in dollars per barrel in each Census Division.

(utility)

TABLES (R)UAP	***UTILITY PURCHASES - PMM REFINERY REGION (R)***
Column names	One column, CST.
Row names	Three character codes for purchased utilities: KWH, STM, NGF. (Only STM used. KWH defined using T:VPELIN. NGF defined using T:VALPNG)
Entries	Column CST contains the purchase price of the utility (KWH=1987 dollars/KWh, STM=1987 dollars/lb, NGF=1987 dollars/mcf).

(Note: same tables also appear in mchproc.dat)

TABLE UTITRS	***NATURAL GAS PURCHASES***
Column names	One column, COEF.
Row names	One row, NGFNGS.
Entries	Barrels of fuel oil equivalent (0.162 BFOE/mcf--conversion factor) of Natural Gas.

TABLE VALPNG	***INDUSTRUAL PRICE OF NATURAL GAS***
Column names	Single character ID for PMM refinery regions (E, C, G, M, W).
Row names	NEMS year code (1,2,3, etc.).
Entries	Price of Natural Gas by PMM refinery region (1987 dollars/mcf).

TABLE VPELIN	***INDUSTRIAL ELECTRIC GENERATION PRICES***
Column names	Single character ID for PMM refinery regions (E, C, G, M, W).
Row names	NEMS year code (1,2,3, etc.).
Entries	Industrial electric utility prices (1987 dollars/KWh, given 3412 MMBtu/GWh).

A.3.4 Product Imports

(prdimprt)

TABLES IPR(prd)(R) PRODUCT IMPORTS TO PMM REFINERY REGION (R)

Column names: Six columns, C1,R1,C2,R2,C3,R3

Row names: NEMS Year code

Entries: For each imported product and import region, column R(n) represent the quantity available in Mbbl/cd, and columns C(n) is the landed price in 1987 dollars per barrel

(These values are available from the NEMS restart file for a given scenario.)

TABLE NEMSRSD IMPORTED RESIDUAL OIL SUPPLY QUANTITY AND PRICE

Column names: Two columns, R1B is fraction of step 1 import quantity, R1PR is multiplier of step 1 price.

Row names: R1 through R9. Step name increments for resid imports.

Entries: R1B is fraction of step 1 import level. R1PR is price factor for each step, relative to the step 1 price.

TABLE IMPLIM LIMIT ON U.S. PRODUCT IMPORTS

Column names: One column MAX

Row names: One row, @ implies all regions.

Entries: Limit on product imports in Mbbl/cd

TABLE PRODTYP LIST OF PETROLEUM PRODUCT IMPORTS

Column names: One column, DUMMY

Row names: Three character product name

Entries: None.

A.3.5 Product Demands

(demand)

TABLES (prd)	***PRODUCT DEMAND***
Column names	One column for each Census Division.
Row names	NEMS Year code.
Entries	Demand in Mbbl/cd

(These demands are available from the NEMS restart file for a given scenario.)
(Note: T:RFHA represents product RFH)

TABLE PRODLIST	***LIST OF PRODUCT FOR DEMANDS***
Column names	One column DUMMY
Row names	Three characters for finished product codes.
Entries	None.

(Note: RFHA represents product RFH. Changed here due to a table name conflict in data file **refproc**)

TABLE DEMMET	***CHEMICAL METHANOL DEMAND***
Column names	One column CHEM for volume demand by chemical industry.
Row names	NEMS Year code.
Entries	Demand volume in Mbbl/cd

(Note: T:CKSMIX is presented in section A.3.8)

(prdexp)

TABLE (D)PRDEXP	***PRODUCT EXPORTS FROM CENSUS DIVISION (D)***
Column names	Ten columns, a MIN and MAX for 5 years: MINY1, MAXY1, MINY2, MAXY2, MINY3, MAXY3, MINY4, MAXY4, MINY5, MAXY5
Row names	YEAR, and three character export finished product codes.
Entries	Export volume in Mbbl/cd

(Note: (D) represents CDs 2,3,7,8,9 only--product export regions)

TABLE EXPLIM	***LIMIT ON PRODUCT EXPORTS***
Column names	Two columns, YRPC and FIX for percent per year growth and fixed volume for the start year.
Row names	The start year, i.e. 1995
Entries	YRPC value is multiplier for growth. FIX column is in Mbbl/cd.

TABLE MULTEXPR	***PRICE MULTIPLIER FOR PRODUCT EXPORTS***
Column names	One column MULT.
Row names	Price
Entries	Multiplier for export price as function of step 1 import price.

(ethanol)

TABLE ETHTAX	***ETHANOL TAX INCENTIVE***
Column names	Two columns, TAXETH, TAXE85.
Row names	NEMS year code (1,2,3,etc)
Entries	Tax incentive (1987 dollars/bbl).

A.3.6 Crude and Product Transportation

Transportation links are specified for movements between all regions in the model; from domestic crude oil supply regions (Oil and Gas Supply Model - OGSM), crude oil import regions, refining regions, and demand regions. Modes of transportation are provided for marine vessel, pipeline, and barge/truck. Explicit pipelines were identified and aggregated where necessary to represent links from refining regions to Census Divisions. The table name structure uses the following first two characters to represent the corresponding modes of transportation - TP for tanker movements (except ethanol transport combines all modes), PL for pipeline, and BV for Barge/Truck. Characters 3 and 4 are CR for crude oil, PR for products, LG for LPG, BD for biodiesel, ET for ethanol, ME for methanol, and NK for product pseudo link. Shipping costs are in 1987 dollars per barrel from a source to a destination region. The value must be negative to allow movement. A positive value indicates a disallowed movement. An explicit zero indicates a no cost movement.

(transit)

TABLES TPCR(S)	***DOMESTIC CRUDE MOVEMENTS (TANKER) EXITING OGSM REGION (S)***
Column names	Crude group domestic, three characters; and GTL (gas to liquids stream).
Row names	First character is mode code; second character is code for destination refining region; and TAPS (Trans Alaska Pipeline System).
Entries	Shipping cost in dollars per barrel to destination region.
TABLES PLCR(S)	***DOMESTIC CRUDE MOVEMENTS (PIPELINE) EXITING OGSM REGION (S) OR PMM REGION (R)***
Column names	Crude group domestic, three characters.
Row names	First character is code for mode; second character is code for destination refining region.
Entries	Shipping cost in dollars per barrel to destination region.
TABLES TPPR(R)	***PRODUCT SHIPPING COSTS (TANKER) EXITING REGION (R)***
Column names	Codes for finished products that are shipped by tanker.
Row names	Transportation mode (one character) and destination region codes (one character) for a total of two characters.
Entries	Shipping cost in dollars per barrel.

TABLES PLPR(R)	***PRODUCT SHIPPING COSTS (PIPELINE) EXITING REGION (R) OR CENSUS DIVISION (D)***
Column names	Codes for finished products that are shipped by pipeline.
Row names	Transportation mode (one character) and destination region codes (one character) for a total of two characters.
Entries	Shipping cost in $/bbl.
TABLES BVPR(R)	***PRODUCT SHIPPING COSTS (BARGE/TRUCK) EXITING REGION (R)***
Column names	Finished product codes for shipments by barge and/or truck.
Row names	Transportation mode (one character) and destination region codes (one character) for a total of two characters.
Entries	Shipping cost in $/bbl.
TABLES TPME(R)	***METHANOL SHIPPING COSTS EXITING REGION (R)***
Column names	MET for methanol.
Row names	Transportation mode (one character) and destination region codes (one character) for a total of two characters.
Entries	Shipping cost in $/bbl.
TABLES TPET(D)	***ETHANOL SHIPPING COSTS EXITING CENSUS DIVISION (D)***
Column names	ETH for ethanol.
Row names	Transportation mode (one character) and destination region codes (one character) for a total of two characters.
Entries	Shipping cost in $/bbl. (Note: mode M represents qty-wt average of transport costs for modes rail, truck, vessel, barge.)
TABLES TPBD(D)	***BIOMASS DIESEL SHIPPING COSTS EXITING CENSUS DIVISION (D)***
Column names	BIM and BIN for biomass diesel (virgin and non-virgin, respectively).
Row names	Transportation mode (one character) and destination region codes (one character) for a total of two characters.
Entries	Shipping cost in $/bbl.

TABLES PLLG(R)	***LPG & PCF SHIPPING COSTS (PIPELINE) EXITING REGION (R)***
Column names	LPG and Petrochemical Feed (PCF) products that are shipped by pipeline.
Row names	Transportation mode (one character) and destination region codes (one character) for a total of two characters.
Entries	Shipping cost in $/bbl.
TABLE MVCCAP	***MARINE VESSEL (CRUDE AND PRODUCTS) CAPACITY***
Column names	MAX for maximum capacity
Row names	TVC(m)CP (for crude) or TVP(m)CP (for product), where m= single character transportation mode (5, 4, J, O)
Entries	Capacity in thousands of dead weight tons (DWT)
TABLE PLCCAP	***PIPELINE (CRUDE, PRODUCTS, AND LPG) CAPACITY***
Column names	MAX for maximum capacity
Row names	TPC (crude), TPP (products), or TPL (LPG), each followed by source region code (one character), transportation mode (one character) and destination region code (one character)
Entries	Capacity in Mbbl/cd
TABLE BVPCAP	***MARINE BARGE (PRODUCTS) CAPACITY***
Column names	MAX for maximum capacity
Row names	TVP(m)CP, where m= single character transportation mode (B or V)
Entries	Capacity in thousands of dead weight tons (DWT)
TABLE PLNK(R)	***PRODUCT PIPELINE TRANSPORT EXITING REGION (R) OR CENSUS DIVISION (D)***
Column names	Three character codes for finished products.
Row names	Transportation mode (one character) and destination region code (one character) for a total of two characters. Currently shipped from PADD 3 (G) and CD 6 to CD 5 and CD 6.
Entries	Cost of product pipeline transport in $/bbl

(Note: T:PDCEN not used)

A.3.7 Refinery Capacities and Operations

(refproc)

TABLES (R)CAP	***REFINING CAPACITIES - PMM REFINERY REGION (R)***
Column names	CAP, PUL, and BLD.
Row names	Process unit codes.
Entries	Column CAP contains existing unit capacities in thousands of barrels per calendar day capacity (MBbl/cd). -1 indicates no limit on capacity, typically applies to pseudo or ideal units. Column PUL contains fractional utilizations, which convert nameplate calendar day capacity to capacity available to the PMM model. The PUL factors represent actual utilizations and will vary from unit to unit, from region to region, and from case to case. These factors are used to control over optimization. Column BLD contains a 1.0 if a unit can be expanded, otherwise a 0 or -1 means no capacity expansion allowed for that unit.
TABLE MATBAL	***STREAMS REQUIRING MATERIAL BALANCE CONSTRAINTS***
Column names	One column, A (B not used).
Row names	Three character intermediate stream codes.
Entries	A flag (1=yes) indicating a need for material balance constraint on intermediate stream.
TABLES (uns)	***REFINERY PROCESS UNIT YIELDS AND OTHER OPERATIONS*** (See Section A.3.9 for detailed information on specific processing units.)
Column names	Three character process operating mode.
Row names	Three character input/output stream codes; three character utility codes; three character policy codes; and CAP.
Entries	Consumption and yield fractions for streams, utilities (bbl output/bbl input); costs for OVC (2000 dollars/bbl—converted in matrix to 1987 dollars using T(r)OVCOBJ variable and T:TRSOVC data for year 2000).

TABLE INV ***INVESTMENT PARAMETERS REFINERY UNITS***

Column names: INV, FXOC, CAPREC.

Row names: Process unit codes.

Entries: Column INV contains investment in 2000 dollars/bbl, FXOC has the fixed operating cost in 2000$/bbl, and CAPREC has the daily annualized investment cost 2000 dollars/bbl. (All dollars converted to 1987 dollars in MRM code using YRDOLLAR data.)

This table provides the investment parameters required for the total annualized cost of investment and fixed cost coefficients which are placed on the process unit expansion activities. These values are generated offline and used as initial investment parameters in the LP matrix. These values are updated in the refine.f code each year to reflect changes in investment costs (see Appendix F.1).

The capital recovery factor is built up from cost of capital, economic life, depreciation life and tax rate. Straight-line depreciation is assumed and depreciation is considered as an expense to be offset as a tax credit against the tax burden. The calculated capital recovery factor is on an after-tax basis and the resultant investment purchase vector costs are on the same basis.

TABLE SCL ***SCALE FACTORS FOR TABLE COEFFICIENTS***

Column name: Processing unit name (Three-Character code)

Row names: Intermediate stream or utility name (Three-Character code, e.g., FUL, OVC, LOS, HH2, etc).

Entries: Constants, multiples of 10 (e.g., 1000, 0.001, etc) to help control the size of the coefficient.

(Note: tables T:DEBOT, T:INFCST, T:INVGEN, T:INVUNT, T:REVAMP not used)

(limpol)

TABLE UNITPOL ***PROCESS UNITS WITH POLICY ROW CONSTRAINTS***

Column name DUMMY

Row names The three-character row names correspond to processing units that have policy limits. These units are described below as tables LIM(uns)(r).

Entries None.

(Note: the entries in tables LIM(uns)(r), which represent fraction of throughput, will appear as entries in the column Z(r)FLO(uns). The current set of (uns) are: FCC, RFL, RFH, DDS, FUM, KRF, ETH, and ETM.)

TABLE LIM(uns)(R) ***POLICY LIMITS FOR EACH PMM REFINERY REGION (R)***

Column name Three-character policy limit code.

Row names One row, DUM.

Entries A value representing a volume fraction of the process unit capacity for the restriction, i.e. 0.99 stipulates that this mode will be limited to 99 percent of the units total capacity. The total capacity is the sum of the existing capacity, builds, and new capacity expansion.

(accunit)

Atmospheric distillation refinery process unit. This unit characterizes the crude oils by differentiating the yields of the following fractions:

Name	Quality	Description	Stream Mnemonic code
GAS (C2 & lighter)			PGS
C3			CC3
IC4			IC4
NC4			NC4
LSR (C5-175)	LON	low octane	SRL
LSR (C5-175)	ION	intermediate octane	SRI
LSR (C5-175)	HON	high octane	SRH
LT NAPH (175-250)	P	paraffinic	LNP
LT NAPH (175-250)	I	intermediate	LNI
LT NAPH (175-250)	N	naphthenic	LNN
NAPH (250-325)	P	paraffinic	NPP
NAPH (250-325)	I	intermediate	NPI
NAPH (250-325)	N	naphthenic	NPN
H N/L J(325-375)	P/LF	paraffinic low freeze pt. index	JPL
H N/L J(325-375)	I/LF	intermediate low freeze pt. index	JIL
H N/L J(325-375)	N/LF	naphthenic low freeze pt. index	JNL
H N/L J(325-375)	P/HF	paraffinic high freeze pt. index	JPH
H N/L J(325-375)	I/HF	intermediate high freeze pt. index	JIH
H N/L J(325-375)	N/HF	naphthenic high freeze pt. index	JNH
KERO(375-500)	LF/LL/LS	low fz pt., low smoke pt., low sulfur	KLL
KERO(375-500)	LF/LL/HS	low fz pt., low smoke pt., high sulfur	KLH

Name	Quality	Description	Stream Mnemonic code
KERO(375-500)	LF/HL/LS	low fz pt., high smoke pt., low sulfur	KHL
KERO(375-500)	LF/HL/HS	low fz pt., high smoke pt., high sulfur	KHH
KERO(375-500)	HF/LL/LS	high fz pt., low smoke pt., low sulfur	1LL
KERO(375-500)	HF/LL/HS	high fz pt., low smoke pt., high sulfur	1LH
KERO(375-500)	HF/HL/LS	high fz pt., high smoke pt., low sulfur	1HL
KERO(375-500)	HF/HL/HS	high fz pt., high smoke pt., high sulfur	1HH
HKERO(500-550)	LF/LL/LS	low fz pt., low smoke pt., low sulfur	3LL
HKERO(500-550)	LF/LL/HS	low fz pt., low smoke pt., high sulfur	3LH
HKERO(500-550)	LF/HL/LS	low fz pt., high smoke pt., low sulfur	3HL
HKERO(500-550)	LF/HL/HS	high fz pt., low smoke pt., low sulfur	3HH
HKERO(500-550)	HF/LL/LS	high fz pt., low smoke pt., low sulfur	4LL
HKERO(500-550)	HF/LL/HS	high fz pt., low smoke pt., high sulfur	4LH
HKERO(500-550)	HF/HL/LS	high fz pt., high smoke pt., low sulfur	4HL
HKERO(500-550)	HF/HL/HS	high fz pt., high smoke pt., high sulfur	4HH
DSL B(550-650)	LP/LC/LS	low pour pt., low cetane index, low sulfur	DLL
DSL B(550-650)	LP/LC/HS	low pour pt., low cetane index, high sulfur	DLH
DSL B(550-650)	LP/LC/MS	low pour pt., low cetane index, medium sulfur	DLM
DSL B(550-650)	LP/HC/MS	low pour pt., high cetane index, medium sulfur	DHM
DSL B(550-650)	LP/HC/LS	low pour pt., high cetane index, low sulfur	DHL
DSL B(550-650)	LP/HC/HS	low pour pt., high cetane index, high sulfur	DHH
DSL B(550-650)	HP/LC/LS	high pour pt., low cetane index, low sulfur	2LL
DSL B(550-650)	HP/LC/MS	high pour pt., low cetane index, medium sulfur	2LM
DSL B(550-650)	HP/LC/HS	high pour pt., low cetane index, high sulfur	2LH
DSL B(550-650)	HP/HC/LS	high pour pt., high cetane index, low sulfur	2HL
DSL B(550-650)	HP/HC/MS	high pour pt., high cetane index, medium sulfur	2HM
DSL B(550-650)	HP/HC/HS	high pour pt., high cetane index, high sulfur	2HH
DSL C(650-690)	LP/HC/LS	low pour pt, high centane index, low sulfur	6HL
DSL C(650-690)	LP/HC/HS	low pour pt, high centane index, high sulfur	6HH
DSL C(650-690)	LP/LC/LS	low pour pt, low centane index, low sulfur	6LL
DSL C(650-690)	LP/LC/HS	low pour pt, low centane index, high sulfur	6LH
DSL C(650-690)	HP/LC/HS	high pour pt, low centane index, high sulfur	7LH
DSL C(650-690)	HP/HC/LS	high pour pt, high centane index, low sulfur	7HL
DSL C(650-690)	HP/HC/HS	high pour pt, high centane index, high sulfur	7HH
LGO (690-800)	N,LS	naphthenic, low sulfur	LGL
LGO (690-800)	N,MS	naphthenic, medium sulfur	LGM
LGO (690-800)	N,HS	naphthenic, high sulfur	LGH
LGO (690-800)	P,LS	paraffinic low sulfur	LGP
HGO FD(800-1050)	NAP,LS	naphthenic, low sulfur	HGL
HGO FD(800-1050)	NAP,MS	naphthenic, medium sulfur	HGM
HGO FD(800-1050)	PFN,LS	paraffinic low sulfur	HGP
VAC RES	V LO SUL (0.5)	very low sulfur	RSL
VAC RES	HI SUL (2.3)	high sulfur	RSH
ATMOS RED CRUDE	(A-M)	Type A through M	ARA-M

Data sources are the parent Turner Mason model data (vintage 1978) provided to ORNL by EIA (vintage 1985) and thereafter to EnSys and in-house EnSys assay data. These have been collected and compared from many sources and progressively built into the model. Assay data for stored SPR crude oils were obtained from U. S. Department of Energy, *"Strategic Petroleum Reserve Crude Oil Stream Quality Characteristics"*, August 1, 1990.

In the past, crude oil quality information resided in the **crdval.dat** data file used for PMM matrix generation. It has been transferred into two MSAccess database files residing on the EIA LAN at the following location:

\\FS-F1\L6007\PRJ\MSACCESS\CRD95GRP (MRM processing)
\\FS-F1\L6007\PRJ\MSACCESS\CRD95IND (ERM processing)

The database file contains quantity, API gravity, sulfur, grade, and source information on individual crude oil streams. Macro programs have been developed to process this data to generate the following set of tables now residing in the **accunit.dat** data file: ***Table ACUCUTS***, ***Table ACUPOL***, and ***Table ACUUTI***. Note that the

Table ACUCUTS yields have been volume balanced to 0; i.e., total yields equal 1.0 exactly. Process losses are accounted for using ***Tables PFA*** and ***REL***.

TABLE ACUCUTS	***ATMOSPHERIC DISTILLATION YIELD FOR CRUDE OILS***
Column names	Three character crude stream group code AMH for Alaska North Slope, ALL for Alaska Light, D(ll) for domestic crude oils and F(ll) for imported crude oils.
Row names	Three character intermediate stream codes.
Entries	Volume fractions (bbl Output/bbl Input).

TABLE ACUPOL	***ATMOSPHERIC DISTILLATION NON-YIELD VALUES FOR CRUDE OILS***
Column names	OVC for variable operating cost and LOS for losses
Row names	Three character crude stream group codes
Entries	OVC: 2000 dollars/bbl (converted in matrix to 1987 dollars using T(r)OVCOBJ variable and T:TRSOVC data for year 2000). Volume fractions (bbl Output/bbl Input) for LOS.

TABLE ACUUTI	***ATMOS. DISTILLATION UTILITY CONSUMPTION FOR CRUDE OILS***
Column names	KWH and STM
Row names	Three character crude stream group codes
Entries	Electricity (kWh/bbl) and steam (lb/bbl).

TABLE INVLIM	***INVESTMENT LIMIT BY REGION***
Column names	MAX
Row names	One character PMM refinery region code and @ for total United States.
Entries	Million dollars (1987) of total capacity expansion investment.

(setrows)

TABLES (R)POL ***REFINERY POLICY CONSTRAINTS - PMM REFINERY REGION (R)***

Column name TYPE.

Row names The three-character row names correspond to processing constraints (as discussed below).

Entries A non-blank entry in the TYPE column causes generation of a row of corresponding type, either a max (1.0), min (-1.0), fixed (0.0), or free (99.0).

The process constraint rows in the current formulation are as follows:

SVR, SVH, SVL, SVC limit severity on FCC, RFH, RFL and RFC respectively.

PFH, PFU, PFB limit H_2S, very low (0.3 percent), low (1 percent), and high (3 percent) sulfur fuel oil[4] to refinery fuel respectively.

FLX limits the use of flexicoking activities (which are actually depicted as modes of operation of the fluid coker) to the level of known flexicoker (KRF) capacities.

MSL, MSR, FCR, MSD, MSZ, are used to control FCC activities:

- MSL: maximum use of light olefin modes
- MSR: maximum low sulfur residue feed
- FCR: maximum high sulfur residue feed
- MSD: maximum distillate feed
- MSZ: maximum use of ZSM high octane catalyst

MXU, L00, L05, H00, H05, C05, control reformer operations (RFL, RFH):

- MXU: maximum use of R62 high octane catalyst on the RFL unit
- L00, L05: maximum use of 100 and 105 severity on the RFL unit
- H00, H05: maximum 100 and 105 severity on the RFH unit
- C05: maximum 105 severity operation of the RFC unit

DKU and DDU limit deep desulfurization of kerosene/heavy kerosene and of diesel/light cycle oil in the distillate desulfurizer (DDS).

(nrfplant)

TABLE INVMOH ***INVESTMENT PARAMETERS METHANOL PLANT***

Column names INV, CAPREC, FXOC

Row names Process unit MOH.

Entries Column INV contains investment in 2000 dollars/bbl, CAPREC has the daily annualized investment cost (2000 dollars), and FXOC has the fixed operating cost in

[4]PFH, PFU and PFB are used to set the amount of residual fuel input to refinery fuel, generally based on historical data. If left uncontrolled, resid input to refinery fuel can swing wildly and unrealistically.

2000 dollars/bbl. (All dollars converted to 1987 dollars in MRM code using YRDOLLAR data.)

Note: This table provides the methanol plant investment parameters required for the total annualized cost of investment and fixed cost coefficients which are placed on the process unit expansion activities. These values are generated offline.

TABLE MOHPLT	***METHANOL PLANT***
Column names	Five columns, (R)01 for each PMM refining region (R)=E,C,G,M,W.
Row names	CC1, (natural gas feed), MET methanol output, OVC operating cost, KWH electricity consumption.
Entries	CC1 natural gas feed coeff is in mcf/bbl MET produced, MET yields in Mbbl/cd of methanol, OVC in $87/bbl MET produced, KWH in kWh/bbl MET produced.
TABLE MOHCAP	***CAPACITY OF METHANOL PLANT***
Column names	Five columns, (R)01 for each PMM refining region (R)=E,C,G,M,W.
Row names	One row, CAP.
Entries	Plant capacity in Mbbl/cd.
TABLE GASPLT	***GAS LIQUIDS PROCESSING PLANT***
Column names	Five columns, (R)01 for each PMM refining region (R)=E,C,G,M,W.
Row names	DGP, (gas plant feed), PGS, CC3, IC4, NC4, NAT, (Natural Gas Liquids NGL's), OVC operating cost, LOS processing loss.
Entries	Gas plant feed (DGP) coeff is ratio of wet gas (Bcf/day) to dry gas (Bcf/day); natural gas liquids yield coefficients are Mbbl/Bcf of wet gas feed.
TABLE GASSHFT	***ALLOW SHIFT OF ETHANE AND PROPANE TO NATURAL GAS***
Column names	Two columns, SC2 for shift of ethane to wet natural gas, SC3 for shift of propane to wet natural gas.
Row names	CC1, (natural gas), LOS processing loss, and OBJ.
Entries	Conversion of barrels (ethane, propane) to cubic feet of wet gas (BCF /Mbbl) applied to quantity shifted from gas plant yield. OBJ represents credit for gas plant operating costs.
TABLE CC1CAP	***DRY GAS PRODUCTION (DGP) CAPACITY***
Column names	Five columns, (R)01 for each PMM refining region (R)=E,C,G,M,W.
Row names	NEMS year code (1,2,3,etc)
Entries	Dry gas production capacity in BCF/day.

TABLE GASCAP	***CAPACITY OF GAS PLANT***
Column names	Five columns, (R)01 for each PMM refining region (R)=E,C,G,M,W.
Row names	FAC, gas residue factor, CAP, gas plant capacity, LIM, limit on propane shift, PCU, percent utilization.
Entries	Gas plant feed and CAP in Bcf/day, FAC is volume fraction, LIM in Mbbl/cd, PCU is percent utilization.

(mchproc)

TABLE (R)CAPMCH	***MERCHANT PLANT CAPACITIES - PMM REFINING REGION (R)***
Column names	CAP, PUL, and BLD
Row names	Process unit codes - C4X, OLX, ETX, FUX, STX, SMD, SOD, IOX, CTX, CTZ.
Entries	Column CAP contains existing unit capacities in thousands of barrels per calendar day capacity (MBbl/cd). Column PUL contains fractional utilizations, which convert nameplate calendar day capacity to capacity available to the PMM model. The PUL factors represent actual utilizations and will vary from unit to unit, from region to region, and from case to case. These factors are used to control over optimization. Column BLD contains a 1.0 if a unit can be expanded, otherwise no capacity expansion allowed for that unit.

TABLES (uns)POL	***MERCHANT PLANT (uns) POLICY ROW CONSTRAINTS***
Column names	OVC for variable operating cost and LOS for losses
Row names	Three character mode.
Entries	OVC: 2000 dollars/bbl (converted in matrix to 1987 dollars using T(r)OVCOBJ variable and T:TRSOVC data for year 2000). LOSS: Volume fractions (bbl Output/bbl Input).

TABLES (uns)UTI	***MERCHANT PLANT (uns) UTILITY CONSUMPTION FOR PROCESSING***
Column names	KWH and STM
Row names	Three-character mode.
Entries	Electricity (kWh/bbl) and steam (lb/bbl).

TABLES (uns)CAP	***MERCHANT PLANT (uns) CAPACITY FACTOR***
Column names	One column, CAP
Row names	Three-character mode.
Entries	Capacity factor.

TABLES (uns)REP ***MERCHANT PLANT (uns) PROCESS YIELDS***

Column names — Three-character process mode codes.

Row names — Three-character intermediate stream codes.

Entries — Volume fractions (bbl output/bbl input).

TABLE TRANSFER ***MAPPING OF STREAM TRANSFERS BETWEEN PLANTS***

Column names — One column, DUMMY.

Row names — Two-character plant code - GP, MP, or RF.

Entries — No entry.

TABLES MPTRANS1 ***STREAM TRANSFER COSTS FOR GTL AND CTL OUTPUT STREAMS***

Column names — Three-character processing unit code - GTLRF and CTLRF (transfer to refinery).

Row names — Three-character intermediate stream codes.

Entries — Cost of transferring stream from offsite facility to refinery (dollars/bbl).

TABLES (xx)TRANS ***STREAM TRANSFER COSTS ACROSS PLANTS***

Column names — Two-character plant code - GP, MP, or RF.

Row names — Three-character intermediate stream codes.

Entries — Cost of transfering stream across plants (1987 dollars/bbl).

(xx = GP (gas plant), MP (merchant plant), RF (refinery).)

TABLE MCHINV ***INVESTMENT PARAMETERS FOR MERCHANT PLANT UNITS***

Column names — INV, FXOC, CAPREC.

Row names — Three-character process unit codes.

Entries — Column INV contains investment in 2000 dollars/bbl, FXOC has the fixed operating cost in 2000 dollars/bbl, and CAPREC has the daily annualized investment cost 2000 dollars/bbl. (All dollars converted to 1987 dollars in MRM code using YRDOLLAR data.)

(cogener)

TABLE CGNCAP	***REFINERY CHP PLANT CAPACITIES***
Column names	CAP, PUL, and BLD
Row names	One-character PMM refinery region ID (E,C,G,M,W).
Entries	Column CAP contains existing CHP capacities in MW. Column PUL contains fractional utilizations, which convert nameplate calendar day capacity to capacity available to the PMM model. The PUL factors represent actual utilizations and will vary from unit to unit, from region to region, and from case to case. These factors are used to control over-optimization and to convert MW to MkWh/cd. Column BLD contains a 1.0 if a unit can be expanded, otherwise no capacity expansion allowed.
TABLE CGNINV	***INVESTMENT PARAMETERS FOR REFINERY CHP UNITS***
Column names	Three columns: INV, FXOC, CAPREC
Row names	One-character PMM refinery region ID (E,C,G,M,W).
Entries	Column INV contains investment in 2000 dollars/bbl, FXOC has the fixed operating cost in 2000 dollars/bbl, and CAPREC has the daily annualized investment cost 2000 dollars/bbl. (All dollars converted to 1987 dollars in MRM code using YRDOLLAR data.)
TABLE CGNPOL	***REFINERY CHP POLICY ROW CONSTRAINTS***
Column names	OVC for variable operating cost.
Row names	One row, three-character mode - CGN.
Entries	OVC: 2000 dollars/bbl (converted in matrix to 1987 dollars using T(r)OVCOBJ variable and T:TRSOVC data for year 2000).
TABLE CGNUTI	***UTILITY PRODUCTION FOR REFINERY CHP***
Column names	KWH and STM
Row names	One-character PMM refinery region ID (E,C,G,M,W).
Entries	Electricity (kWh/bbl fuel) and steam (lb/bbl fuel).
TABLE CGNREP	***REFINERY CHP FUEL CONSUMPTION***
Column names	One column, CGN
Row names	One row, FUL
Entries	Fuel consumption (bbl/kWh)

TABLE SELCGN ***REFINERY CHP SALES BY PADD***

Column names: One column, SOLD

Row names: One character PMM refinery region ID (E,C,G,M,W).

Entries: Fraction sold in each PADD.

TABLE VPELAS ***ELECTRIC UTILITY PRICES FOR REFINERY CHP***

Column names: One-character PMM refinery region ID (E,C,G,M,W).

Row names: NEMS year code (1,2,3,etc).

Entries: Electric utility prices (1987 dollars/kWh, based on 3412 Btu/KWh).

TABLE CGXCAP ***MERCHANT CHP PLANT CAPACITIES***

Column names: CAP, PUL, and BLD

Row names: One-character PMM refinery region ID (E,C,G,M,W).

Entries: Column CAP contains existing CHP capacities in MW.
Column PUL contains fractional utilizations, which convert nameplate calendar day capacity to capacity available to the PMM model. The PUL factors represent actual utilizations and will vary from unit to unit, from region to region, and from case to case. These factors are used to control over-optimization and to convert MW to MKWh/cd.

Column BLD contains a 1.0 if a unit can be expanded, otherwise no capacity expansion allowed.

TABLE CGXINV ***INVESTMENT PARAMETERS FOR MERCHANT CHP UNITS***

Column names: Three columns: INV, FXOC, CAPREC

Row names: One-character PMM refinery region ID (E,C,G,M,W).

Entries: Column INV contains investment in 2000 dollars/bbl, FXOC has the fixed operating cost in 2000 dollars/bbl, and CAPREC has the daily annualized investment cost 2000 dollars/bbl. (All dollars converted to 1987 dollars in MRM code using YRDOLLAR data.)

TABLE CGXPOL ***MERCHANT CHP POLICY ROW CONSTRAINTS***

Column names: OVC for variable operating cost.

Row names: One row, three-character mode - CGN.

Entries: OVC: 2000 dollars/bbl (converted in matrix to 1987 dollars using T(r)OVCOBJ variable and T:TRSOVC data for year 2000).

TABLE CGXUTI ***UTILITY CONSUMPTION FOR MERCHANT CHP***

Column names	KWH and STM
Row names	One-character PMM refinery region ID (E,C,G,M,W).
Entries	Electricity (kWh/bbl fuel) and steam (lb/bbl fuel).

TABLE CGXREP ***MERCHANT CHP FUEL CONSUMPTION***

Column names	One column, CGX
Row names	One row, FUL
Entries	Fuel consumption (bbl/kWh)

TABLE SELCGX ***MERCHANT CHP SALES BY PADD***

Column names	One column, SOLD
Row names	One-character PMM refinery region ID (E,C,G,M,W).
Entries	Fraction sold in each PADD.

TABLE VPELWS ***ELECTRIC UTILITY PRICES FOR MERCHANT CHP***

Column names	One-character PMM refinery region ID (E,C,G,M,W).
Row names	NEMS year code (1,2,3,etc).
Entries	Electric utility prices (1987 dollars/kWh, based on 3412 Btu/kWh).

(stream)

TABLE TRS ***STREAM TO STREAM TRANSFERS***

Column names	Three columns, MIN, MAX, and CST
Row names	Six-character code, consisting of a three character intermediate stream code and another three-character intermediate stream code representing a from/to stream transfer; and OVCOBJ.
Entries	No entry; except CST column: -1 for OVCOBJ.

Table TRS allows the transfer of one refinery stream to another - the transfer vector names are in the form *xxxyyy* where *xxx* is the source stream code and *yyy* is the destination stream code.

Selected refinery minor finished product sales transfers are included in ***Table TRS***, namely:

- optional condensation of C_3 and C_4 streams into sales LPG. This is useful where data are not separately available for propane and butane sales (Would normally be de-activated through asterisks in *Column 1*.)
- condensation of benzene, toluene, and xylene into AROmatics and BTX sales.

Table TRS is also used for condensation of feed streams for several of the key refinery process units. This economizes on detail in refinery process unit representations at the expense of adding a relatively small number of LP transfer vectors.

The original transfers were derived from the parent Turner Mason model provided to EIA and has been amended and extended by EnSys and EIA.

TABLE XSALE	***STREAM TO PRODUCT TRANSFERS***
Column names	One column, DUMMY.
Row names	Six-character code, consisting of a three character intermediate stream code and a three-character product stream code.
Entries	-- blank --

A.3.8 Product Blending and Specifications

(gasoblnd)

Z:MAPGSLPD	***MAPPING OF CODE NAMES FOR GASOLINE***
Column names	TEXT
Row names	Three character code used by PMM to ID motor gasoline types produced at refinery
Entries	Three character code used by Ensys to ID motor gasoline types corresponding to PMM ID
Z:MAPGSLSP	***MAPPING OF CODE NAMES FOR SPEC CATEGORIES***
Column names	TEXT
Row names	Two character code used by PMM to ID gasoline quality spec categories
Entries	Three character code used by Ensys to ID gasoline quality spec categories corresponding to PMM ID
TABLES Q(R)GSL	***REGIONAL GASOLINE SPECIFICATIONS--PMM REGION (R)***
Column names	Finished gasoline codes (RFG and TRG)
Row names	Two character quality codes, followed by X (maximum) or N (minimum).
Entries	Columns contain specification levels for the corresponding qualities.
TABLES (R)SSR	***SUBSPEC RFG QUALITY SPECIFICATIONS--PMM REGION (R)***
Column names	Five columns: Y1,Y2,Y3,Y4,Y5--representing 5 transition years for changes in specifications.
Row names	Product qualities codes using six characters; the first three are RFG, the next two are quality codes, the last is either X for maximum or N for minimum; and a row YEAR to define the corresponding transition years.
Entries	Product quality specifications for each transition year. The quality coefficients of SSR reflect a reformulated gasoline that is to be blended with 7.8 percent ethanol and therefore has a lower octane and other qualities to accommodate the quality barrels delivered by ethanol.

TABLES (R)SST	***SUBSPEC TRG QUALITY SPECIFICATIONS--PMM REGION (R)***
Column names	Five columns: Y1,Y2,Y3,Y4,Y5--representing 5 transition years for changes in specifications.
Row names	Product qualities codes using six characters; the first three are TRG, the next two are quality codes, the last is either X for maximum or N for minimum; and a row YEAR to define the corresponding transition years.
Entries	Product quality specifications for each transition year. The quality coefficients of SST reflect a conventional gasoline that is to be blended with 7.8 percent ethanol and therefore has a lower octane and other qualities to accommodate the quality barrels delivered by ethanol.
TABLES (R)SSE	***SUBSPEC TRG QUALITY SPECIFICATIONS--PMM REGION (R)***
Column names	Five columns: Y1,Y2,Y3,Y4,Y5--representing 5 transition years for changes in specifications.
Row names	Product qualities codes using six characters; the first three are TRG, the next two are quality codes, the last is either X for maximum or N for minimum; and a row YEAR to define the corresponding transition years.
Entries	Product quality specifications for each transition year. The quality coefficients of SSE reflect a 10 percent ethanol blend.
TABLES (R)RFH	***SUBSPEC RFG QUALITY SPECIFICATIONS--PMM REGION (R)***
Column names	Five columns: Y1,Y2,Y3,Y4,Y5--representing 5 transition years for changes in specifications.
Row names	Product qualities codes using six characters; the first three are RFG, the next two are quality codes, the last is either X for maximum or N for minimum; and a row YEAR to define the corresponding transition years.
Entries	Product quality specifications for each transition year.
TABLES (R)TRH	***SUBSPEC TRG QUALITY SPECIFICATIONS--PMM REGION (R)***
Column names	Five columns: Y1,Y2,Y3,Y4,Y5--representing 5 transition years for changes in specifications.
Row names	Product qualities codes using six characters; the first three are TRG, the next two are quality codes, the last is either X for maximum or N for minimum; and a row YEAR to define the corresponding transition years.
Entries	Product quality specifications for each transition year.
TABLE GCB	***GASOLINE QUALITIES (EX OCTANE)***
Column names	Quality codes (except octane-- defined in ***Table MCO***)
Row names	Intermediate stream codes
Entries	Blend spec contribution associated with each stream and blend characteristic.

TABLE GCC ***GASOLINE COMPONENT USAGE CONTROL***

Column names: Finished product codes.

Row names: Intermediate stream codes

Entries: A non-blank entry indicates that the intermediate is allowed as a component to the finished blend.

(note: Ensys data did not include column RFM as needed by PMM; therefore, column RGC was copied into column RFM.)

Z:GASGROUP ***GAS GROUP CLASSIFICATION***

Column names: One column, TEXT(1).

Row names: Three character stream code matching those in ***Table GCB***.

Entries: Three character gas group classification: G00-G12.

TABLE GSLUTI ***GASOLINE BLEND UTILITIES***

Column names: One column, kWh-- Utility, electricity

Row names: Seven rows, three character gasoline type or blend ID.

Entries: KWh per barrel of gasoline type.

TABLE MCO ***GASOLINE COMPONENT OCTANE RATINGS***

Column names: Eight columns, R00, R05, R15, R30, M00, M05, M15, M30 of which the PMM model uses just two, R00 and M00 (lead-free research and motor octanes)

Row names: Intermediate stream gasoline component codes

Entries: Base research and motor octane blending numbers for each component at four levels of lead.

TABLES (xxx)BV ***GASOLINE (XXX) COMPONENT BONUS BLENDING VALUES***

Column names: Nine columns, R00, R05, R15, R30, M00, M05, M15, M30, TEL of which the PMM model uses just two, R00 and M00 (lead-free research and motor octanes)

Row names: Intermediate stream gasoline component codes

Entries: Bonus research and motor octane blending numbers for each component at four levels of lead. Non-zero entries are added to the base octanes from ***Table MCO*** and used in the relevant gasoline blend.
Since the PMM model reduces all gasoline grades to an equivalent lead-free basis, the only entries relevant in these "BV" tables are those under unleaded ROO and MOO octane columns.

(note: xxx = UNC and RFM (representing TRG and RFG, respectively).)

Z:MAPDFOPD	***MAPPING OF CODE NAMES FOR GASOLINE***
Column names	TEXT
Row names	Three character code used by PMM to ID distillate fuel types produced at refinery
Entries	Three character code used by Ensys to ID distillate fuel types corresponding to PMM ID
Z:MAPDFOSP	***MAPPING OF CODE NAMES FOR SPEC CATEGORIES***
Column names	TEXT
Row names	Two character code used by PMM to ID distillate fuel spec categories
Entries	Three character code used by Ensys to ID distillate fuel spec categories corresponding to PMM ID
TABLES Q(R)DFO	***REGIONAL DISTILLATE/FUEL OIL SPECIFICATIONS--PMM REFINERY REGION (R)***
Column names	Finished distillate fuel oil codes; Distillates JTA, N2H, DSL and residual fuel oils N6I,N6B.
Row names	Two character quality codes, followed by X (maximum) or N (minimum).
Entries	Columns contain specification levels for the corresponding qualities.
TABLE DCB	***DISTILLATE QUALITIES (EX OCTANE)***
Column names	Quality codes
Row names	Intermediate stream codes
Entries	Blending values
TABLE DCC	***DISTILLATE COMPONENT USAGE CONTROL***
Column names	Finished product codes.
Row names	Intermediate stream codes
Entries	A non-blank entry indicates that the intermediate is allowed as a component to the finished blend.
TABLE DFOUTI	***DISTILLATE BLENDING UTILITIES***
Column names	One column, STM, steam.
Row names	Five distillate fuel oil products: JTA, N2H, DSL, N6I, N6B.
Entries	Steam use per barrel of distillate fuel type (lbs/bbl).

(recipes)

TABLE RCP ***RECIPE BLEND CONTROL***

Column names: Multiple columns-- A, CST, and STM, plus intermediate stream codes.

Row names: Finished product codes followed by a number. The intention is to provide for different recipes for a given product. The row ending in a zero must be present.

Entries: A non-blank entry in column A activates the corresponding blend.
Column CST contains any cost met in making the blend, e.g. TEL cost for production of aviation gasoline.
The remaining columns contain the volume fractions of the components (column ID) making up the blend.

TABLE RCPEIA ***RECIPE BLEND CONTROL***

Column names: Seven columns, A, CST, and five selected product streams (JTA, N2H, SLP, CKH, CKL).

Row names: Special products: salable sulfur, low and high sulfur coke.

Entries: A non-blank entry in column A activates the corresponding blend (row KERSPG not activated).
Column CST contains any cost met in making the blend, e.g. TEL cost for production of aviation gasoline.
The remaining columns contain the volume fractions of the components (column ID) making up the blend (including unit conversions for coke).

(splash)

TABLES BLNSP(D) ***RECIPE BLENDING FOR KEROSENE AND RESIDUAL OIL TO UTILITIES--CENSUS DIVISION (D)***

Column names: Three columns, KER, N67, and N68.

Row names: Stream codes for components of each blend and blended product codes.

Entries: Volume fraction of each component in final blends.
(Note: Kerosene currently is not modeled separately in the PMM.)

TABLES BLOX(D)YXX ***RECIPE BLENDS FOR HIGH OXYGEN GASOLINES IN CENSUS DIVISION (D)***

Column names: Six columns, E85, M85, TRH, RFH, RFG, and TRG.

Row names: Stream codes for components of each blend and blended product codes plus OBJ row.

Entries: Volume fraction of each component in final blends. Row OBJ contains tax credit for blends.

TABLES BLBIOD(D) ***RECIPE BLENDS FOR BIODIESEL IN CENSUS DIVISION (D)***

Column names	Two columns, DSL and DSU
Row names	Stream codes for biodiesel blend components, BIM, BIN.
Entries	Volume fraction of each component in final blends.

TABLE HOXETH ***ETHANOL RECIPES FOR SPLASH BLENDING***

Column names	Four columns, TRH, RFH, RFG, TRG.
Row names	Gasoline blend streams.
Entries	Consumption and yield fractions for ethanol blending streams.

TABLE XETH ***OXYGEN CONTENT OF ETHANOL***

Column names	One column, PO.
Row names	One row, XETH.
Entries	Volume percent oxygen for ethanol.

TABLE SCB ***OXYGEN CONTENT OF OXYGENATES***

Column names	One column, PO.
Row names	Three character oxygenate (ethers) stream codes (ETB,MTB,TAE,TAM,THE,THM).
Entries	Volume percent oxygen for oxygenate streams.

(demand)

TABLE CKSMIX ***SALABLE COKE RECIPES***

Column names	Two columns, CKL and CKH for low sulfur and high sulfur coke, respectively.
Row names	Coke stream codes (CKL, CKH) and product coke (COK); OBJ is scaled for selling price for coke.
Entries	Ratio of coke price to WOP (to be multiplied by WOP). Conversion from tons to bblFOE of coke (0.217 s-tons/bblFOE), and 1.0 coefficient for material balance.

(note: other *demand.dat* tables presented in Section A.3.5)

(fuelmix)

TABLE GROUP ***FUEL MIX COMPONENTS***

Column names	One column, DUMMY.
Row names	Six character code, consisting of a three character intermediate stream code and a three character fuel stream code, indicating a transfer from intermediate stream to fuel stream.
Entries	No entry.

A.3.9 Refining Technology

The tables described in this section are essential to the representation of refining technology. All the tables are named (uns), representing the refining technology processing unit. The Column names represent modes of operation. The Row names represent refinery process input and output streams (intermediate streams), policy (OVC, LOS, etc.) cost information, and utility (KWH, STM) consumption. The table entries are volume fractions (bbl Output/bbl Input) for intermediate streams; costs ($/bbl) for policy information; and utility consumption rates (kWh/bbl and lb/bbl) for electricity and steam, respectively. Most of the following tables described in this section are located in the file named (**refproc**). The CHP refinery processing unit data is located in the file named (**cogener**).

(refproc)

TABLE VCU CRUDE VACUUM DISTILLATION UNIT

Vacuum distillation refinery process unit. This unit separates atmospheric distillation tower bottoms into the following fractions:

- Heavy diesel cut (650-690 degrees Fahrenheit), according to sulfur content, pour point and cetane index
- Light gas oil (690-800 degrees Fahrenheit), according to sulfur content
- Heavy gas oil (800-1050 degrees Fahrenheit), according to sulfur content
- Vacuum residuum (1050 + degrees Fahrenheit), according to sulfur content, with the high metal/asphaltene content residua being undercut below 1050 degrees Fahrenheit.

The atmospheric residua, which feed the vacuum distillation unit tower, are classified according to similar API gravity, sulfur content, viscosity, and gas oil content into 13 categories. These provide sufficient differentiation for the RYM regional model:

Table A3. Atmospheric Residual Oil Qualities

Stream Code	Atm Resid Sulfur	Atm Resid API
ARA	3.10	17.5
ARB	2.67	17.7
ARC	1.54	19.9
ARD	1.30	12.4
ARE	0.87	19.3
ARF	0.34	25.4
ARG	0.32	22.8
ARH	2.70	14.0
ARI	0.32	17.1
ARJ	1.22	21.7
ARK	0.70	21.2
ARL	4.54	8.2
ARM	3.92	15.0

Data sources are based on in-house EnSys data and EnSys calculations and estimates.

TABLE KRD DELAYED COKER

Delayed coking of vacuum residua and FCC decant oil streams produce petroleum market coke and lighter products. Care has been taken to weight balance the yields and to match both low and high sulfur coke productions against actual regional makes. The naphtha fractions produced are of necessity stabilized and reformed (the annualized cost of stabilizing the C5-175 fraction is included in the OVC unit operating cost row). The middle distillates require stabilization and hydrotreating before blending to distillate fuels. The coker gas oil produced may be desulfurized and routed either to FCC feed or residual fuel oil blending.

Data sources are in-house EnSys data gathered from a variety of published sources, including J. H. Gary and G.E. Handwerk, *"Petroleum Refining Technology and Economics"*, 1975 and the EIA RYM model data as provided to ORNL by EIA and thereafter to EnSys.

TABLE KRF FLUID AND FLEXI COKER

Fluid coking of vacuum residua to produce coke and lighter products. Care has been taken to weight balance the yields and to match both low and high sulfur coke productions against actual regional makes. The naphtha fractions produced are of necessity stabilized and reformed (the annualized cost of stabilizing the C5-175 fraction is included in the OVC unit operating cost row). The middle distillates require stabilization and hydrotreating before blending to distillate fuels. The coker gas oil produced may be desulfurized and routed either to FCC feed or residual fuel oil blending.

Flexicoking is also represented in this program module, reflecting the gasification of the coke produced to fuel gas.

The data sources include the following:

> Busch, R. A. et al, *"Flexicoking + Hydrotreating Processes for Quality Products"*, presented at the AIChE Spring Meeting, April 1979.
>
> Blaser, D. E. et al, *"Fluid Coking/Flexicoking, a Flexible Process for Upgrading Heavy Crudes"*, Exxon Research and Engineering Company, October 26, 1978.

TABLE SDA PROPANE DE-ASPHALTER

Residua produced by the vacuum distillation unit are solvent extracted to produce asphalt, FCC feed, and heavy fuel oil blending components. Data sources are in-house EnSys data gathered from a variety of published sources.

Because of the limited number of vacuum residua depicted in the model, it is not possible for this unit to convert one residuum into another, plus gas oil and retain reasonable volume, weight and sulfur balances. Accordingly, the model activities represent only the partial conversion of one residuum into another.

TABLE VBR VISBREAKER

Visbreaking of vacuum residua to produce lowered viscosity residual blendstocks. Visbreaking is a mild thermal cracking process and produces a proportion of lighter products.

Data sources are the EIA RYM model data provided to ORNL and thereafter to EnSys and in-house EnSys data. The range of potential feeds has been extended by EnSys.

TABLE NDS NAPHTHA HYDROTREATER

Hydrotreating of various refinery naphtha streams prior to reforming or blending with naphtha sales. The data source is the EIA RYM model data provided to ORNL and thereafter to EnSys and in-house EnSys data.

TABLE DDS HEAVY NAPHTHA, KEROSENE, AND MIDDLE AND HEAVY DISTILLATE DESULFURIZER

This unit represents the desulfurization of a broad and comprehensive set of refinery streams, ranging from 325 IBP to 690 EP degrees Fahrenheit. Various degrees of desulfurization intensity are also represented, ranging from

normal (90 percent desulfurization) to the ultra low sulfur mode for blending to meet 0.05 weight percent diesel fuel. The different modes are also reflected through the use of the CAP row, with coefficients ranging from 0.8 to 3.33 to represent the different catalyst to oil ratios required to achieve different degrees of desulfurization. The increase in the CAP coefficients is tantamount to forcing a reduction in unit throughput and space velocity to reduce the sulfur level of the product stream.

High, medium, and low sulfur (adequate for conventional, but not ultra-low-sulfur fuels) feeds are included in ***Table DDS***. These include virgin heavy naphtha; light and heavy kerosene fractions; diesel and Number 2 fuel oil streams; FCC light cycle oil streams, reflecting different FCC conversion levels and gas oil feed sulfur levels; middle distillate furfural extraction unit raffinates; de-waxed diesel fractions; and select JP8-X and JP11 cuts from specialty naphthenic crude oils used for producing high density jet fuels.

Data sources are the EIA RYM model data provided to ORNL and thereafter to EnSys and EnSys analysis of published sources. These include:

Shih, S. S. et al, *"Deep Desulfurization of Distillate Components"*, Paper 264B presented at the AIChE Fall Meeting, November 1990.

McCulloch, D. C. et al, *"Higher Severity Diesel Hydrotreating"*, Paper AM-87-58 presented at the NPRA Annual Meeting, March 1987.

Johnson, A. D., *"Study Shows Marginal Gains from Hydrotreating"*, Oil & Gas Journal, May 30, 1983, p.78.

Yoes, J. R. and Asim, M. Y., *"Confronting New Challenges in Distillate Hydrotreating"*, Paper AM-87-59 presented at the NPRA Annual Meeting, March 1987.

TABLE FDS GAS OIL DESULFURIZER/MILD HYDRO-CRACKER

This unit represents the desulfurization of light and heavy gas oils, including coker gas oil, to produce hydro-treated gas oils for FCC feed and heavy fuel oil blending. A light hydrocracking mode is also represented to produce a very low sulfur content gas oil for the purpose of removing sulfur from light and heavy catalytic gasolines in order to produce reformulated gasoline at the 50 ppm sulfur level.

Data sources are the EIA RYM model data provided to ORNL and thereafter to EnSys and in-house EnSys data. The mild gas oil hydrocracking data were obtained from:

Belt, B. A., *"New Approaches to FCC Hydrotreating"*, Paper 44C presented at the AIChE Spring Meeting, March 1990.

TABLE RDS RESIDUUM DESULFURIZER

This unit represents the desulfurization of vacuum and atmospheric residua, gas oils and asphalt. Two levels of desulfurization are represented: 77 percent and 85 percent desulfurization. The heavy products are generally in

the 0.5- to 1.0-weight percent sulfur content level and may be used as low sulfur residual fuel oil blendstocks, or to provide the FCC with feed for residuum cracking.

Data sources are the EIA RYM model data provided to ORNL and thereafter to EnSys, in-house EnSys data, and other published sources, including the following:

> Billon, A. et al, *"Hyvahl F and T Processes for High Conversion and Deep Refining of Residues"*, Paper AM-88-62 presented at the NPRA Annual Meeting, March 1988.

TABLE LUB LUBE OIL AND WAX PRODUCTION

This is a rather simplified representation which transfers 800-1050 degree Fahrenheit hydrofined gas oil and paraffin base gas oil to combined lube oil and wax sales. The unit contains the estimated fuel, power, steam, and operating cost requirements to produce these products.

Data sources are the EIA RYM model data.

TABLE HCR DISTILLATE HYDROCRACKER

This process unit hydrocracks a range of distillates to produce either predominantly light, medium, and heavy naphtha for gasoline blending and reformer feed, or distillate for jet fuel and middle distillate products (particularly low sulfur blends). These two modes of operation require large quantities of hydrogen, from 1800 to 3600 cf/bbl of feed, depending on the feedstock and severity of the operation. The primary feeds are light and heavy gas oils:

LGP, LGL,	paraffinic, low, medium, and high sulfur light gas oils,
LGM, and LGH:	690 to 800 degrees Fahrenheit.
HGP, HGL,	paraffinic, low, medium, and high sulfur heavy gas oils,
HGM, and HGH:	800 to 1050 degrees Fahrenheit.
LC6:	high aromatic content, high sulfur light cycle oil

The lighter virgin distillates may also be routed to hydrocracker feed. These streams are gathered into feeds HFL and HFH in ***Table TRS*** as follows:

DSL B(550-650)LP/LC/LS	CRACKER FD LO S	DLLHFL
DSL B(550-650)LP/HC/LS	CRACKER FD LO S	DHLHFL
DSL B(550-650)LP/HC/HS	CRACKER FD HI S	DHHHFH
DSL B(550-650)HP/LC/LS	CRACKER FD LO S	2LLHFL
DSL B(550-650)HP/HC/LS	CRACKER FD LO S	2HLHFL
DSL C(650-690)LP/LC/LS	CRACKER FD LO S	6LLHFL
DSL C(650-690)LP/HC/LS	CRACKER FD LO S	6HLHFL
DSL C(650-690)HP/LC/LS	CRACKER FD LO S	7LLHFL
DSL C(650-690)HP/HC/LS	CRACKER FD LO S	7HLHFL
DIST(550-650) HS/LM	CRACKER FEED	DHLHFH

DIST(650-690) HS/LM	CRACKER FEED	6HLHFH
LGO FD(690-800) PFFN	CRACKER FD LO S	LGPHFL
LGO FD(690-800) LO S	CRACKER FD LO S	LGLHFL
LGO FD(690-800) HI S	CRACKER FD HI S	LGHHFH
COKER DIST (375-620)	CRACKER FD HI S	CKDHFH
COKER DIST (375-570)	CRACKER FD HI S	CCLHFH
COKER DIST (575-620)	CRACKER FD HI S	CCHHFH
CKR DIST RAFFINATE	CRACKER FD HI S	CLRHFH
CKR DIST EXTRACT	CRACKER FD HI S	CLEHFH

Data sources are the EIA RYM model data provided to ORNL and thereafter to EnSys and in-house EnSys data. Published sources include the following:

Alcock, L. et al, *"BP Hydrocracks For Mid Distillates"*, Oil & Gas Journal, July 6, 1974, p.102.

J. H. Gary and G.E. Handwerk, *"Petroleum Refining Technology and Economics"*, 1975.

Logwinuk, A. K., *"The ART Process Offers Increased Refinery Flexibility"*, Petroleum Review, October 1985, p.41.

TABLE HCV RESIDUUM HYDROCRACKER

This unit hydrocracks a range of vacuum residua producing a synthetic crude containing the full range of streams from light gas oils to gas oil and bottoms fractions. Hydrogen consumption is of the order of 1500 cf/bbl net residuum feed. The feedstocks are vacuum resids produced by the vacuum distillation unit VCU and subsequently condensed to a smaller set of streams in ***Table TRS***:

VAC RES	V HI SUL(3.8)	RSV
VAC RES	HI SUL (2.3)	RSH
VAC RES	INT SUL (1.5)	RSM
VAC RES	LO SUL (0.9)	RSI
VAC RES	VLO SUL (0.5)	RSL

Data sources are the EIA RYM model data provided to ORNL and thereafter to EnSys and in-house EnSys data. Published sources include:

Seko, M. et al, *"Super Oil Cracking (SOC) Process for Upgrading Vacuum Residues"*, Paper AM-88-61 presented at the NPRA Annual Meeting, March 1988.

Suchanek, A.J. and Christian, B. R., *"New Diversity Shown for the ART Process"*, Paper AM-88-74 presented at the NPRA Annual Meeting, March 1988.

Boening, R.E. et al, *"Recent Data on Resid Hydrocracker"*, *Hydrocarbon Processing"*, September 1987, p.59.

TABLE HCN NAPHTHA HYDROCRACKER

This unit consumes on the order of 1500 cf/bbl of hydrogen to hydrocrack naphthas. The naphthas are hydrocracked to produce primarily propane, isobutane, and normal butane. While this process has a history of commercial operation, it is not in wide-spread use. However, the advent of reformulated gasoline has renewed interest because the naphtha hydocracker functions to supply feed to alkylation and oxygenate process units. The propane may be de-hydrogenated to produce alkylate feed or the ether DIPE, the isobutane may be used directly for alkylation plant feed or de-hydrogenated to produce isobutylene to make MTBE or ETBE and the normal butane may be isomerized to produce isobutane. An additional fit with reformulated gasoline production is the fact that naphtha is subtracted from the reformer feed, thus lowering the quantities of benzene and aromatics that are produced.

Data sources are based on in-house EnSys data, calculations and estimates.

TABLE TCG THERMAL CRACKER-LIGHT GAS STREAMS
TABLE TCN THERMAL CRACKER-(250-375) NAPHTHA STREAMS
TABLE TCV THERMAL CRACKER-DESULFURIZED VACUUM GAS OIL STREAMS

The above process units are olefin plant petrochemical units which are characteristic of petrochemical plant operations. They are included in the model because they have potential relevance to the production of reformulated gasoline since they produce light olefins (ethylene, propylene and iso and normal butylenes) for alkylation plant feed and (the isobutylene) for MTBE and ETBE plant feed. They can also be used directly in any representation of the petro-chemical sector via the **PMM** "oxy-refinery" feature.

Process unit TCG may use ethane, propane or iso or normal butanes as feedstocks.

Process unit TCN consumes reformer feed naphtha (which would otherwise produce high aromatics content reformate).

Process unit TCV consumes desulfurized light and heavy gas oils produced by process unit FDS.

Data sources are based on published data:

Zdonik, S. B. and Meilun, E. C., *"Olefin Feedstock and Product Flexibility"*, Chemical Engineering Progress, September 1983.

Barendrect, S. et al, *"BUTACRACKING - Steam Cracking For Butane Upgrading"*, Paper 26E, presented at the AIChE Spring Meeting, April 1991.

TABLE JPS JET FUEL CUT POINT ADJUSTMENT

This unit adjusts the cut point of the 375 to 500 degree Fahrenheit atmospheric tower kerosene cut to a 470-degree endpoint cut in order to make the freezing point specification for JP-8 and Jet A/A-1 jet fuels in the optimal manner conforming to industry practice. This can be regarded as a "pseudo-unit" corresponding to an atmospheric

tower cut point adjustment when making a jet fuel run, or as a real side-stream fractionator. Data sources are based on in-house EnSys data, calculations, and estimates.

TABLE JFP LIGHT CYCLE OIL/COKER DISTILLATE PRE-FRACTIONATION

This is a specialty unit which prepares cracked aromatic streams for furfural unit extraction and hydrogenation (units FEX and HDN) for the production of high density jet fuels. High density jet fuels are experimental fuels which increase the flight range of volume limited aircraft. The cuts are 70 Overhead/30 Bottoms for LCO and 80 Overhead/20 Bottoms for coker distillate. The fractionated streams may also be routed to conventional distillate products and heavy fuel oils, thus increasing blending flexibility.

Data sources are based on in-house EnSys data, calculations and estimates.

TABLE SYD DISTILLATE DEEP HYDROTREATER

(used to be identified as DHT prior to *AEO2001*)

This process hydrogenates middle distillate aromatics and achieves deep desulfurization (to levels beyond those available with conventional distillate desulfurization, see *Table DDS*). Potential feeds include kerosene, diesel, and light cycle oils, covering the boiling range from 375 to 650 degrees Fahrenheit. The deep hydrotreating process can be used to raise jet fuel smoke point, raise diesel fuel cetane number, and produce ultra low sulfur/aromatics fuels (less than 0.05 percent sulfur and less than 10 percent aromatics content). Conventional distillate desulfurization units, on the other hand, are generally capable of reducing the aromatics content by only 1 to 2 percent aromatics. This process is an alternative to middle distillate furfural extraction, but avoids the problem of aromatics disposition. However, hydrogen consumption is high, from 750 to 900 cf/bbl feed for virgin distillates and from 1100 to 2100 cf/bbl for the more aromatic FCC cycle oils.

This process may be linked to the production of reformulated gasoline since some reformulated gasoline production schemes involve very high conversion FCC operations, which in turn increase the aromaticity of the light cycle oils produced. Deep distillate hydrotreating makes it possible to more easily produce specification diesel fuel under these circumstances, without downgrading cycle oils to heavy residual fuel oil.

Data sources are in-house EnSys data and published data, including:

> Suchanek, A.J. and Hamilton, G. L., *"Diesel by SYNSAT - Low Pressure/Low Cost/Low Aromatics"*, Paper AM-91-35 presented at the NPRA Annual Meeting, March 1991.
>
> Nash, R.M., *"Meeting the Challenge of Low Aromatics Diesel"*, Paper AM-89-29 presented at the NPRA Annual Meeting, March 1989.

TABLE FEX DISTILLATE FURFURAL EXTRACTION

This process extracts aromatics from distillate with the aromatics being concentrated in the furfural phase. Furfural extraction also lowers the sulfur content of the treated raffinate. Potential feeds include kerosene, diesel fractions, light cycle oils, and coker distillates, covering the boiling range from 375 to 690 degrees Fahrenheit. The reduction in distillate aromatics content can be used to raise jet fuel smoke point and/or raise diesel fuel

cetane number and produce ultra low aromatics fuels (less than 10 percent aromatics content). Conventional desulfurization units, on the other hand, are generally capable of reducing the aromatics content by only 1 to 2 percent.

This process is an alternative to middle distillate deep hydrotreating, but necessitates the disposition of the aromatics produced, generally by attempting to dump to other distillates, or by using them to reduce the viscosity and perhaps the sulfur content of heavy residual fuel oils. However, the significant hydrogen consumption associated with deep hydrotreating is avoided, ranging from 750 to 900 cf/bbl feed for virgin distillates and from 1100 to 2100 cf/bbl for the more aromatic FCC cycle oils.

The furfural extraction unit is also used to extract aromatics from virgin distillate streams, FCC cycle oil and coker distillate overhead cuts prior to the hydrogenation of the aromatic extracts to produce distillate range naphthenes. The naphthenes are blended to produce experimental high density jet fuels.

Data sources are based on EnSys calculations and estimates and in-house EnSys data. Published data sources include:

> Refinery Handbook, Furfural Extraction of Gas Oils, Hydrocarbon Processing, September 1982, p.183.
>
> Benham, A. L. et al, *"REDEX Process Extracts Aromatics"*, Hydrocarbon Processing, September 1967, p.135.

TABLE RST RESID FUEL TRANSFERS

This can be regarded as a "pseudo-unit" that converts high sulfur fuel oil to marketable fuel oil. Data sources are based on in-house EnSys data, calculations, and estimates (updated June 2003).

TABLE HDN HIGH DENSITY JET FUEL HYDROPROCESSING

This unit hydroprocesses several types of streams to produce highly naphthenic blending components for high density jet fuel. The feedstocks are:

- light pyrolysis fuel oil
- FCC light cycle oil 70 percent overhead cuts
- the corresponding light cycle oil furfural extracts
- coker distillate 80 percent overhead cuts
- the corresponding coker distillate furfural extracts
- the aromatic furfural unit extracts produced from virgin distillate streams, ranging from 375 to 500 degree Fahrenheit boiling range.

This unit employs severe processing conditions and the fuel, power, and steam costs are high. Hydrogen consumption can reach 2400 cf/bbl for the virgin distillate stream aromatic extracts and 3500 cf/bbl for the other highly refractory streams.

The former Soviet Union has utilized high density jet fuels to increase the mission range of volume-limited military jet aircraft. Data were gathered and pieced together from several published Russian and other foreign sources with the help of ORNL. Other published sources used include:

Korosi, A. et al, *"Hydroprocessing of Light Pyrolysis Fuel Oil for Kerosene Jet Fuel"*, Technical Report AFWAL-TR-80-2012, February 1980.

Hall, L. W., *"Production of Jet Fuel Samples from Light Cycle and Light Pyrolysis Oil"*, Technical Report AFWAL-TR-87-2001, March 1987.

TABLE DEW CATALYTIC GAS OIL DEWAXING

This is a catalytic process based on the Mobil process for converting the paraffin wax components in intermediate and heavy middle distillate streams in order to meet the freezing and pour point specifications for low pour distillate and heavy fuel oils. This process is an alternative to solvent dewaxing, where finished refinery waxes are sold. It may accompany or replace the use of pour point depressants.

This unit feeds high pour refinery streams covering the range of 550 to 690 degrees Fahrenheit, where the high boiling paraffin waxes are concentrated. Approximately 200 cf/bbl of hydrogen is consumed.

Published sources include:

Collins, J. M. and Unzelman, G. H., *"Alternatives Available to Meet Diesel Cetane Quality Challenge"*, Oil & Gas Journal, May 30, 1983, p.71.

TABLE RFH REFORMER-SEMI REGENERATIVE-450 PSI REACTOR
TABLE RFL REFORMER-SEMI REGEN/CYCLIC-200 PSI REACTOR
TABLE RFC CONTINUOUS REFORMER LOW PRESS./HIGH DENSITY BIMET.CATALYST

Naphtha reforming refinery process units. These individual key processes represent the different stages of reformer technology development. Paraffinic, naphthenic, and intermediate naphtha feeds are represented to produce reformates spanning the range of 80 to 105 clear research octane number. The low end of the reforming severity range is geared to accommodating the lower aromatic content of reformulated gasoline; the high end represents the limit of current reforming technology. The effect of low through high reforming severity on reformer throughput capacity is represented in row CAP, with coefficients ranging from 0.9 to 1.2, with an entry of 1.0 representing 95-100 RONC reformate production.

The severity rows SVH, SVL and SVC contain the reformate RONC octane. Several operating mode limitation rows are also available in the reformer tables to link to ***Tables (R)POL*** constraints:

L00, H00 to limit maximum 100 RONC reforming severity
C05, L05, H05 to limit maximum 105 RONC reforming severity
MXU to limit the proportion of UOP type R-62 high density bimetallic reforming catalyst

RCU to limit very low pressure and low benzene advanced modes on the continuous reformer (RFC).

The specific reformer feed streams represented include the following:

158-175 degrees Fahrenheit	very light virgin naphtha
175-250 degrees Fahrenheit	light virgin naphtha
250-325 degrees Fahrenheit	intermediate virgin naphtha
325-375 degrees Fahrenheit	heavy virgin naphtha
250-400 degrees Fahrenheit	heavy FCC gasoline
175-375 degrees Fahrenheit	coker naphtha
250-325 degrees Fahrenheit	heavy hydrocrackate
215-250 degrees Fahrenheit	light virgin naphtha, prefractionated to remove benzene precursors.

The capability to reform 325-375 virgin naphtha feed stock is not immediately apparent in the reformer data tables because it is represented in ***Table TRS*** by combining naphtha desulfurizer feeds, namely:

H N/L J(325-375) P/LF	NAPHTHA(250-325) P	JPLNPP
H N/L J(325-375) I/LF	NAPHTHA(250-325) I	JILNPI
H N/L J(325-375) N/LF	NAPHTHA(250-325) N	JNLNPN
H N/L J(325-375) P/HF	NAPHTHA(250-325) P	JPHNPP
H N/L J(325-375) I/HF	NAPHTHA(250-325) I	JIHNPI
H N/L J(325-375) N/HF	NAPHTHA(250-325) N	JNHNPN

The reformer products include hydrogen (95 percent purity), fuel gas, LPG, and full boiling range reformate.

The gradation of reformate feed cut ranges is consistent with (a) maximizing reformer feed, e.g. for foreign regions where gasoline demand is high, but also (b) controlling benzene content of reformate for use in reformulated gasoline. This latter can be achieved in the model by eliminating the 158-175 fraction and, if necessary, the 175-250 fractions from reformer feed. In addition, the model now has the option to pre-fractionate light naphtha at 215 degrees Fahrenheit to produce feedstock to the RFC unit for very low benzene reformate production. (See ***Table GCB*** for comparison of reformate benzene contents.)

Altogether, the PMM model contains several methods for benzene reduction or removal:

1. Reformer feed pre-fractionation as discussed above,
2. Reformate splitting (***Table RES***)
3. Extraction of benzene (for sale) from reformate aromatics (***Table ARP***)
4. Very low pressure reformate operation (***Table RFC***)
5. Alkylation of benzene in reformate (***Table ALM***).

RFC unit ultra-low pressure reforming, at 90 psi, reduces the reformate benzene content by approximately 30 percent for reformulated gasoline production. Commercial plant data have not yet been obtained to verify the model reforming yields.

Data sources are the EIA RYM model data provided to ORNL and thereafter to EnSys and in-house EnSys data and published data compared and gathered from a variety of sources. Sources include:

> *"UOP Process Solutions for Reformulated Gasoline"*, Copyright 1991, UOP/RFG SK 05-91, provided by UOP to ORNL.
>
> van Broekhoven, E. B. et al, *"On the Reduction of Benzene in Reformate"*, Paper 28B presented at the AIChE Spring Meeting, March 1990.
>
> Jones, P. *"The Conversion Refinery: The Catalytic Magic Wand"*, Petroleum Review, May 1987.
>
> McClung, R. G. and Novak, W. J., *"Improve Reformer Operation with Trace Sulfur Removal"*, Paper AM-87-47 presented at the NPRA Annual Meeting, March 1987.
>
> Gerritsen, Dr. L. A., *"Catalytic Reforming of Heart Cut FCC Naphthas"*, Paper AM-85-56 presented at the NPRA Annual Meeting, March 1985.

TABLE SPL NAPHTHA SPLITTER

This is a feed preparation unit which fractionates light naphtha for reformer feed. C5-175 degrees Fahrenheit straight run gasoline is fractionated to produce C5-158 light gasoline for gasoline blending and 158-175 degrees Fahrenheit light naphtha for reformer feed. This represents the light end range of currently feasible reformer feed. The splitter now also enables splitting 175-250 degrees Fahrenheit light naphtha at 215 degrees Fahrenheit to produce a 175-215 degrees Fahrenheit light naphtha and a 215-250 degrees Fahrenheit low benzene reformer feedstock.

The fractionated light naphthas produced may also be blended to JP4 military jet fuel and to naphtha sales.

Data sources are in-house EnSys data and the following:

> *"UOP Process Solutions for Reformulated Gasoline"*, Copyright 1991, UOP/RFG SK 05-91, provided by UOP to ORNL.
>
> van Broekhoven, E. B. et al, *"On the Reduction of Benzene in Reformate"*, Paper 28B presented at the AIChE Spring Meeting, March 1990.

TABLE RES REFORMATE SPLITTER (not used)

This unit splits the reformates produced from 250-375 degrees Fahrenheit intermediate/heavy naphtha into an overhead and a bottoms cut. These fractions may be separately blended into conventional and reformulated gasolines to aid in meeting reformulated gasoline specifications. The aromatics concentrate in the bottoms cut and the benzene in the overhead.

Data sources are in-house EnSys data and EnSys calculations, estimates and published data, including:

van Broekhoven, E. B. et al, *"On the Reduction of Benzene in Reformate"*, Paper 28B presented at the AIChE Spring Meeting, March 1990.

"UOP Process Solutions for Reformulated Gasoline", Copyright 1991, UOP/RFG SK 05-91, provided by UOP to ORNL.

TABLE ARP AROMATICS EXTRACTION

This unit employs solvent extraction of reformate and reformate fractions to produce benzene, toluene, and xylene (BTX) aromatics for sale, and light and heavy raffinates for gasoline and jet/distillate fuel blending. All of the reformates produced in the semi-regenerative, continuous and cyclic reformers are potential unit feeds, along with their overhead and bottoms cuts produced in the reformate splitter.

Data sources are the EIA RYM model data provided to ORNL and thereafter to EnSys and in-house EnSys data and EnSys calculations and estimates.

TABLE ALM ALKYMAX (not used)

This unit is patterned after the UOP Alkymax process for alkylating benzene with C_2 and C_3 olefins (ethylene and propylene) to produce higher boiling aromatics. The reformates produced from 158-250 light/intermediate naphtha are reacted with fuel gas containing ethylene or with propylene to produce an essentially benzene-free reformate. These reformates are then blended to meet reformulated gasoline benzene specification. *(Note: the aromatics concentration in the gasoline blend is hardly altered.)*

Data sources include the following:

B. M. Wood et al, *"Alkylate Aromatics in the Gasoline via the UOP ALKYMAX Process"*, Copyright 1990, provided by UOP to ORNL.

"UOP Process Solutions for Reformulated Gasoline", Copyright 1991, UOP/RFG SK 05-91, provided by UOP to ORNL.

TABLE CYC CYCLAR

Cyclar refinery process unit is based on the UOP cyclar process to cyclarize propane and butane to produce BTX. A fractionated benzene stream is produced along with a TX (toluene, xylene) stream designated as cyclar gasoline. This is a de-hydrogenation process which produces approximately 2000 cf/bbl feed of hydrogen.

The data sources include the following:

Anderson, R. F. et al, *"Cyclar - One Step Processing of LPG to Aromatics and Hydrogen"*, Paper 83D presented at the AIChE Spring Meeting, March 1985.

TABLE FCC FLUID CATALYTIC CRACKER

This key process unit is capable of catalytically cracking gas oil, light gas oil, distillate and residua streams to produce light ends, FCC gasoline, light cycle oil (distillate) and decant oil (resid). The primary feeds represented are:

Feed stream	Description
HGP:	paraffinic low sulfur gas oil (800-1050 degrees Fahrenheit)
HGL:	low sulfur gas oil (800-1050 degrees Fahrenheit)
HGM:	medium sulfur gas oil (800-1050 degrees Fahrenheit)
HGH:	high sulfur gas oil (800-1050 degrees Fahrenheit)
GOH:	hydrofined gas oil (800-1050 degrees Fahrenheit)
GOU:	hydrofined gas oil (800-1050 degrees Fahrenheit) ultra low sulfur
DFF:	distillate feed (550-690 degrees Fahrenheit)
DHK:	desulfurized atmospheric residuum (1050 degrees Fahrenheit +). Produced by unit RDS.
HGX:	gas oil raffinate produced by propane solvent de-asphalting
Atmospheric Residua:	several residua of sufficiently low asphalt and metals content (which tend to be the lower sulfur content residua) to conform to current FCC technology limitations.

In order to contain the already large number of FCC feed vectors, several streams are composited into the above primary feeds in ***Table TRS*** as listed below:

DSL C(650-690) LO S N	HGO FD(800-1050) LO S N	6LLHGL
DSL C(650-690) LO S N	HGO FD(800-1050) LO S N	6HLHGL
DSL C(650-690) LO S N	HGO FD(800-1050) LO S N	7LLHGL
DSL C(650-690) PFFN	HGO FD(800-1050) PFFN	7HLLGP
COKER GAS OIL	HGO FD(800-1050) HI S N	CGOHGH
LGO FD(690-800) HI S N	HGO FD(800-1050) HI S N	LGHHGH
LGO FD(690 800) MD S N	HGO FD(800-1050) MD S N	LGMHGM
LGO FD(690-800) LO S N	HGO FD(800-1050) LO S N	LGLHGL
LGO FD(690-800) PFFN	HGO FD(800-1050) PFFN	LGPHGP
HGO FD(800 1050) LO S N	HYD G.O. LOS N UNH	HGLGOH
DIST LS/LM	DIST FCC FEED	DLLDFF
DSL B(550-650) HP/HC/LS	DIST FCC FEED	2HLDFF
DSL C(650-690) LP/HC/LS	H DIST FCC FEED	6HLDFF
DSL C(650-690) HP/HC/LS	H DIST FCC FEED	7HLDFF
DSL C(650-690) LO S N	HGO FD(800-1050) LO S N	6LLHGL
DSL C(650-690) LO S N	HGO FD(800-1050) LO S N	6HLHGL
DSL C(650-690) LO S N	HGO FD(800-1050) LO S N	7LLHGL

The FCC is characterized by several modes of operation and provision for activating restrictions on flexibility have been built in for constraining advanced FCC catalyst technology options and limiting over-optimization. The FCC representation now accurately equates FCC gasoline, distillates, and decant oil product sulfur with feed sulfur. The available options are:

Option	FCC gasoline codes	Constraints
Conventional zeolite catalyst		
high-sulfur feed/product	FI6, FI7, FI8	MSD, MSR, FCR
medium-sulfur feed/product	FC6, FC7, FC8	
low-sulfur feed/product	FR6, FR7, FR8	
ultra-low-sulfur feed/product	FQ6, FQ7, FQ8*	
High octane zeolite catalyst		
high-sulfur feed/product	ZI6, ZI7, ZI8	MSD,MSR,MSZ
medium-sulfur feed/product	ZC6, ZC7, ZC8	and FCR
low-sulfur feed/product	ZR6, ZR7, ZR8	
ultra-low-sulfur feed/product	RC6, RC7, RC8	
Low olefin content gasoline		
high-sulfur feed/product	6ZI, 7ZI, 8ZI	MSZ
medium-sulfur feed/product	6ZF, 7ZF, 8ZF	
low-sulfur feed/product	6ZR, 7ZR, 8ZR	
ultra-low-sulfur feed/product	6RF, 7RF, 8RF	
High light olefin yield		
high-sulfur feed/product	85I	MSL
medium-sulfur feed/product	85F	
low-sulfur feed/product	85R	
ultra-low-sulfur feed/product	85U	
Ultra-Low-Sulfur Modes		FCU
All Modes		SVR

* *This feed sulfur/catalyst mode currently not activated, although FCC gasoline properties are held in* ***Table GCB****, etc.*

MSD and MSR refer to constraints on distillate/light gas oil and atmospheric residuum proportions. A value of "1" in the FCR row signals a residuum which is eligible for FCC residuum cracking, generally higher than 20 API, with the associated sulfur content lower than 0.7 percent. MSZ and MSL limit the proportion of specialty zeolite catalysts. The above references to low sulfur FCC gasoline refer to the production of catalytic gasolines generally suited to making reformulated gasoline at the 50-ppm level. FCU is the constraint on all ultra-low-sulfur modes.

The low olefin content gasoline mode is directed at reducing the olefin content of reformulated gasoline by reducing the olefins in the catalytic gasoline, principally the light catalytic gasoline. This mode also lowers the octane somewhat and reduces the yield of C_5 and lighter olefins.

The high light-olefin yield operation takes a different approach to reformulated gasoline production and utilizes enhanced octane ZSM-5 catalyst with OHS additive to maximize the yield of light olefins to produce feedstocks for the oxygenate and alkylation refinery process units. The operating cost row OVC coefficient has been raised by $0.60/bbl of gas oil feed to account for the unit revamp and increased fractionation costs associated with this operation. This is a high conversion operation in the 80 to 85 percent range.

The FCC conversion range represented in the model is from 65 to 85 percent conversion to 430 degrees Fahrenheit- FCC gasoline. The SVR row may be used to constrain or report the overall conversion level. The light end yields contained in the model reflect an overall C3 recovery of 75 percent. Light cycle oil characterizations (qualities) are a function of conversion and FCC feed sulfur level. Decanted (clarified) oil characterizations are a function of sulfur level only:

LCO ULOW	0.05S 60P CONV LC7
LCO ULOW	0.05S 80P CONV LC8
LCO	0.25S 60P CONV LC1
LCO	0.25S 80P CONV LC2
LCO	0.85S 60P CONV LC3
LCO	0.85S 80P CONV LC4
LCO	2.00S 60P CONV LC5
LCO	2.00S 80P CONV LC6

CLARIFIED OIL	0.10 SUL	COX
CLARIFIED OIL	0.65 SUL	COL
CLARIFIED OIL	2.20 SUL	COM
CLARIFIED OIL	5.50 SUL	COH

The four levels of LCO and decant oil sulfur correspond to the four base levels of FCC feed sulfur, namely: 0.05 percent, 0.30 percent, 1.00 percent, 2.50 percent. Actual feeds may produce mixes of products depending upon actual feed sulfur level.

Weight fraction catalytic coke yields are contained in the model (row COK) and are set to be activated for checking the FCC weight balance and to provide input to any EIA type reports which contain FCC catalytic coke production.

Data sources are the EIA RYM model data provided to ORNL and thereafter to EnSys and in-house EnSys data include the following published data:

"Fuels for Tomorrow", staff article, Oil & Gas Journal, June 18, 1990, p.52.

Chin, A. A. et al, *"FCC Cracking of Coker Gas Oils"*, Paper 91C presented at the AIChE Fall Meeting, November 1989

Humphries, A. et al, *"The Resid Challenge: FCC Catalyst Technology Update"*, Paper 70C presented at the AIChE Spring Meeting, April 1991.

Stokes G. M. et al, *"Reformulated Gasoline Will Change FCC Operations and Catalysts"*, Oil & Gas Journal, July 2, 1990, p.58.

Keyworth, D. A. and Reid, T. A., *"Octane Enhancement From LPG"*, Paper 5A presented at the AIChE Summer Meeting, August 1989.

"Innovative Improvements Highlight FCC's Past and Future", staff article, Oil & Gas Journal, January 8, 1990, p.33.

Deady, J. et al, *"Strategies For Reducing FCC Gasoline Sensitivity"*, Paper AM-89-13 presented at the NPRA Annual Meeting, March 1989.

Dwyer, F.G. et al, *"Octane Enhancement In FCC Via ZSM-5"*, Paper AM-87-63 presented at the NPRA Annual Meeting, March 1987.

Yanik, S. J. et al, *"A Novel Approach to Octane Enhancement Via FCC Catalysis"*, Paper AM-85-48 presented at the NPRA Annual Meeting, March 1985.

Krikorian, K. V. and Brice, J. C., *"FCC's Effect on Refinery Yields"*, Hydrocarbon Processing, September 1987, p.63.

TABLE FGS GASOLINE FRACTIONATION

This idealized unit, representing a probable series of distillation towers, fractionates:

- Whole catalytic gasoline specific to the different FCC unit operating modes
- Coker naphtha produced by the coker units KRD and KRF
- Purchased natural gasoline.

The whole FCC gasoline is fractionated to produce reactive amylenes for alkylation and oxygenate plant feed; normal amylene for gasoline blending, alkylation or hydrogenation; reactive hexylenes for oxygenate plant feed; normal hexylene for gasoline blending or hydrogenation; light catalytic gasoline, containing isopentane, normal pentane and iso- and normal hexanes plus the C_7 to 250 degrees Fahrenheit fractions; heavy catalytic gasoline (250 - 400 degrees Fahrenheit) for reformer feed and gasoline blending; and the front end of light cycle oil for distillate blending.

Coker naphtha (175 - 375 degrees Fahrenheit) is fractionated to produce iso-amylene, the other reactive amylenes and reactive hexylenes, and the remaining naphtha bottoms.

Natural gasoline is fractionated to produce iso and normal butane and light and medium naphtha cuts.

Data sources are in-house EnSys data, calculations and estimates supported by the following:

Keefer, P. and Masters, K., *"Ultimate C4/C5 Olefin Processing Scheme for Maximizing Reformulated Gasoline Production"*, Paper AM-91-50 presented at the NPRA Annual Meeting, March 1991.

Stokes G. M. et al, *"Reformulated Gasoline Will Change FCC Operations and Catalysts"*, Oil & Gas Journal, July 2, 1990, p.58.

TABLE ETS ETHYLENE CRYOGENIC FRACTIONATION

This unit distills ethylene from refinery gas for alkylation plant feed using cryogenic (low temperature technology). All feed and product streams are in barrels of fuel oil equivalents (bblFOE) and the saturate co-product PGS (ethane) is used for refinery fuel gas and to meet any refinery sales requirements.

Data sources are based on in-house EnSys data, calculations, and estimates.

TABLE OLE C_2-C_5 DE-HYDROGENATION ("OLEX")

This process unit dehydrogenates saturated C2/C3/C4 and IC5 refinery streams to produce on the order of 1500 cf/bbl of hydrogen per bbl of feed and the corresponding olefin streams for alkylation and oxygenate plant feeds. The propylene may be used for alkylation (or ether DIPE) plant feed and petrochemical sales, the normal butylene for alkylation plant feed, the isobutylene for MTBE/ETBE oxygenate production and alkylation plant feed and the isoamylene for TAME/TAEE oxygenate production and alkylation plant feed. This process is suited for reformulated gasoline production and aids in RVP reduction through removing butane and isopentane from the gasoline pool.

Data sources include the following:

"UOP Process Solutions for Reformulated Gasoline", Copyright 1991, UOP/RFG SK 05-91, provided by UOP to ORNL.

Buonomo, G. et al, *"The Fluidized Bed Technology for Paraffins Dehydrogenation: Snam Progetti-Yarsintez Process"*, presented to DEWITT 1990 Petrochemical Review, Houston, Texas, March 27-29, 1990.

TABLE C4I BUTANE ISOMERIZATION

This unit isomerizes normal butane to produce isobutane. The isobutane may be used for alkylation plant feed and, potentially, for dehydrogenation to produce isobutylene for MTBE and ETBE production.

Data sources are the EIA RYM model data provided to ORNL and thereafter to EnSys and in-house EnSys data.

TABLE C4S BUTENE TRANSFER PSEUDO-UNIT

This unit splits FCC and coker total butylenes into 70 percent normal butylene (C4E) and 30 percent isobutylene (I4E). No costs are attached to this unit because the total stream is normally fed to MTBE/ETBE plants without

fractionation and only the isobutylene is consumed. The costs of processing the total butylene stream are included in the oxygenate plant costs.

The problem of reflecting the C4E/I4E split on alkylation plant costs is complex. The alkylate produced by normal butylene is approximately 4 RONC/MONC higher than that produced by isobutylene. Therefore, if the alkylation unit is preferentially consuming normal butylene from FCC/coker mixed butylenes, pre-fractionation costs should be attached to the alkylation plant for taking advantage of this option. However, if, as is often the case, oxygenate and alkylation units are both present in the LP solution (to produce reformulated gasoline), then the MTBE/ETBE unit is situated upstream of the alkylation unit so as to avoid the fractionation costs. The practice in this model is not to add additional alkylation plant feed pre-fractionation costs. This could cause over optimization (understate costs) for some cases.

Data sources are in-house EnSys data.

TABLE ETH,ETM OXYGENATE PRODUCTION

A process unit which consumes methanol or ethanol to produce a wide range of oxygenates. The olefin feeds and corresponding oxygenate products are:

Table A4. Oxygenate Products

Oxygenate Products				
Methanol Feed	Code	MTBE	TAME	THME
Isobutylene	I4E	X		
Reactive Amylenes	R5E		X	
Reactive Hexylenes	R6E			X
Ethanol Feed	Code	ETBE	TAEE	THEE
Isobutylene	I4E	X		
Reactive Amylenes	R5E		X	
Reactive Hexylenes	R6E			X

The ***Tables (R)POL*** constraint NME can be used to constrain or eliminate all modes other than iso-butylene/MTBE.

The data for THME and THEE were estimated by EnSys, since there is little or no commercial experience to provide operating data. Other data sources include the following:

Bakas, S.T. et al, *"Production of Ethers from Field Butanes and Refinery Streams"*, presented at the AIChE Summer Meeting in San Diego, California, August 1990.

Prichard, *"Novel Catalyst Widens Octane Opportunities"*, NPRA Annual Meeting, San Antonio, Texas, March 29-31, 1987.

Miller, D. J., *"Ethyl Tertiary Butyl Ether (ETBE) Production"*, Paper 42B presented at the AIChE Summer Meeting, August 1989.

Des Courieres, J., *"The Gasoline Ethers: MTBE, ETBE, TAME & TAEE: Their Production"*, Paper 13A presented at the AIChE Summer Meeting, August 1990.

Chemical Engineering Progress, August 1991, p.16.

Unzelman, G. W., *"Future Role of Ethers in U. S. Gasoline"*, Paper AM-89-06 presented at the NPRA Annual Meeting, March 1989.

Refinery Handbook, Ethers, Hydrocarbon Processing, November 1990, p.126.

"UOP Process Solutions for Reformulated Gasoline", Copyright 1991, UOP/RFG SK 05-91, provided by UOP to ORNL.

Prichard, G., *"Novel Catalyst Widens Octane Opportunities"*, Paper AM-87-48 presented at the NPRA Annual Meeting, March 1987.

TABLE DIP PROPYLENE OXYGENATE PRODUCTION (not used)

This unit is modeled after a recently announced Mobil process which reacts propylene and water to produce a propylene ether (DIPE).

TABLE C24 DIMERIZATION OF ETHYLENE TO 1-BUTENE

This unit dimerizes ethylene to 1-butene for alkylation plant feed. It produces a small byproduct quantity of 1-hexene.

Data sources are based on in-house EnSys data, calculations, and estimates.

TABLE C4T ISOMERIZATION OF BUTENE-1 TO BUTENE-2

This unit isomerizes butene-1 to butene-2 for the purpose of improving alkylate quality and reducing the alkylation plant acid consumption. Approximately 13 cf/bbl of hydrogen is consumed to hydrogenate butadiene

and reduce the mercaptan content. Alkylate octanes are increased 1.8 RONC and 0.8 MONC and alkylation plant operating costs are reduced by approximately 30 percent.

Data sources include the following:

Novalany, S. and McClung, R. G., *"Better Alky from Treated Olefins"*, Hydrocarbon Processing, September 1989, p.66.

TABLE ALK ALKYLATION (replaced with HFA and SFA)

The isobutane sulfuric acid alkylation of the following feed streams is represented:

ETHYLENE (FOE)	C2E
PROPYLENE	UC3
MIXED BUTYLENES	UC4
N-BUTYLENE	C4E
TRT/ISOM BUTENE-2	T4E
ISOBUTYLENE	I4E
NORMAL AMYLENE	C5E
REACTIVE AMYLENE(ISO)	R5E

The feedstocks are reacted with iso-butane to produce alkylate product. The range of feedstocks has been extended because of the high significance of alkylates as reformulated gasoline blendstocks.

Data sources are the EIA RYM model data provided to ORNL and thereafter to EnSys and in-house EnSys data. Published sources include:

Leonard, J. et al, *"What to do with Refinery Propylenes"*, Paper 5B, presented at the AIChE Summer Meeting, August 1989.

Masters, K. R., *"Alkylation's Role in Reformulated Gasoline"*, presented at the AIChE Spring Meeting, April 1991.

Masters, K. and Prohaska, E.A., *"Add MTBE Unit Ahead of Alkylation"*, Hydrocarbon Processing, August 1988, p.48.

"UOP Process Solutions for Reformulated Gasoline", Copyright 1991, UOP/RFG SK 05-91, provided by UOP to ORNL.

TABLE SFA SULFURIC ACID ALKYLATION

The sulfuric acid alkylation of the following feed streams is represented:

PROPYLENE	UC3
MIXED BUTYLENES	UC4
N-BUTYLENE	C4E
ISOBUTYLENE	I4E
TRT/ISOM BUTENE-2	T4E
OTHER AMYLENE	C5E
REACTIVE AMYLENES	R5E
TRT/ISOM AMYLENES	T5E
ISOBUTANE	IC4

The feed stocks are reacted with iso-butane to produce alkylate product. The range of feedstocks has been extended because of the high significance of alkylates as reformulated gasoline blendstocks. The operating temperature range for H_2SO_4 alkylation (SFA) is 30-70^{o}F. Pressures vary based on manufacturer (60-75 psia for the Stratco process and ~25psia for the XOM process). Isobutane-to-olefin ratios are typically lower than for the HFA process. Hydrogen transfer is not significant for C3 and C4 olefin feeds, and less than 20% of C5 olefins are converted to pentanes. Optimum acid concentration in the contactor is between 93-95% for the alkylation of C3 and C4 olefins and less than 90% for C5 olefin feeds. Feed drying is not critical and feed treatment is optional (depending on specific circumstances). Spent acid is typically set off-site for regeneration. Recently, co-catalysts have been employed with SFA to inhibit the production of heavy polymers (ASO) and to reduce acid make-up requirements.

The central data source was a paper written by John Marano for the DOE/NETL and DOE/EIA, which contains references to many other published sources.

Marano, John J. (Energy and Environmental Solutions, LLC), *"Refinery Technology Profiles: Alkylation "*, report prepared for the U.S. Department of Energy, National Energy Technology Lab, and Energy Information Administration, September 2002.

TABLE HFA HYDROFLUORIC ACID ALKYLATION

The hydrofluoric acid alkylation (HFA) of the following feed streams is represented:

PROPYLENE	UC3
MIXED BUTYLENES	UC4
N-BUTYLENE	C4E
ISOBUTYLENE	I4E
TRT/ISOM BUTENE-2	T4E
OTHER AMYLENE	C5E
REACTIVE AMYLENES	R5E
TRT/ISOM AMYLENES	T5E
ISOBUTANE	IC4

The feedstocks are reacted with iso-butane to produce alkylate product. The range of feedstocks has been extended because of the high significance of alkylates as reformulated gasoline blendstocks. The operating temperature range for HFA is higher than for the H_2SO_4 process, 70-100^{o}F. Pressures between 115-165 psia are sufficient to keep both the feed and acid in the liquid phase. High isobutene-to-olefin ratios minimize polymerization and raise alkylate octane number. High acid concentrations between 83-92% are needed to produce high quality alkylate, with concentrations of 86-90% preferred in the contactor. Feed drying using molecular sieves is required since any water present will have a large negative effect on catalyst activity. Other feed treatment is optional (depending on specific circumstances). Regeneration of the HF catalyst occurs within the plant by means of an HF re-run column, which separates HF from any heavy polymers (ASO) produced. Due to the toxicity of HF, all product and waste streams must be treated to remove HF.

The central data source was a paper written by John Marano for the DOE/NETL and DOE/EIA, which contains references to many other published sources.

Marano, John J. (Energy and Environmental Solutions, LLC), *"Refinery Technology Profiles: Alkylation "*, report prepared for the U.S. Department of Energy, National Energy Technology Lab, and Energy Information Administration, September 2002.

TABLE CPL CATALYTIC POLYMERIZATION

CPL is a process that uses solid phosphoric acid catalyst to polymerize propylene and butylenes to produce olefinic polymer gasoline.

Data sources are the EIA RYM model data provided to ORNL and thereafter to EnSys and in-house EnSys data.

TABLE DIM DIMERSOL

DIM is a process that uses liquid phosphoric acid catalyst to polymerize propylene to produce dimer, which is lighter and higher in octane than olefinic polymer gasoline.

Data sources include:

Leonard, J. et al, *"What to do with Refinery Propylenes"*, Paper 5B, presented at the AIChE Summer Meeting, August 1989.

TABLE H56 HYDROGENATION OF NORMAL AMYLENE AND HEXYLENE

This unit hydrogenates the normal C_5/C_6 olefins to produce low octane normal pentanes and hexanes for isomerizer unit feed, where the octanes are raised. Hydrogen consumptions are in the range of 1300-1500 cf/bbl.

Data sources are based on in-house EnSys data, calculations and estimates.

In an era of reformulated gasolines, this process provides a means of removing the reactive normal C_5 and C_6 olefins from the gasoline pool. As described elsewhere, the iso C_5 and C_6 olefins are likely to be dealt with by alkylation or etherification.

TABLE PHI PENTANE/HEXANE ISOMERIZATION

This is a partial recycle isomerizer (without molecular sieve) which produces isopentane- and isohexane-rich isomerates from the following potential feed streams:

NATURAL GASOLINE	NAT
C5/C6 ISOM LSR FD LON	SRL
LSR GASO(C5-175)ION	SRI
LSR GASO(C5-158)	SLI
NORMAL PENTANE	NC5
NORMAL HEXANE	NC6

Data sources are in-house EnSys data and the following sources:

Schmidt, R. J. et al, *"Catalyst and Engineering Innovations Improve Isomerization Techniques"*, Paper AM-87-61, presented at the NPRA Annual Meeting, March 1987.

"UOP Process Solutions for Reformulated Gasoline", Copyright 1991, UOP/RFG SK 05-91, provided by UOP to ORNL.

TABLE TRI PENTANE/HEXANE (TOTAL RECYCLE) ISOMERIZATION

This is a total recycle isomerizer with molecular sieve which produces a high octane isomerate, approximately 4 RONC and 7 MONC greater than produced by unit PHI. The capital and operating costs are also higher.

Data sources include the following:

Sager, T.C. et al, *"Cost Effective Isomerization Options for Tomorrow's Light Gasoline Processing Options"*, Paper AM-89-12, presented at the NPRA Annual Meeting, March 1989.

Refinery Handbook, Hysomer and TIP System, Hydrocarbon Processing, September 1984, p.21.

TABLE H2P HYDROGEN PRODUCTION VIA STEAM REFORMING
TABLE H2X HYDROGEN PRODUCTION VIA PARTIAL OXYDATION

These process units produce hydrogen by steam reforming and partial oxidation, respectively. The steam reforming feeds include natural gas, propane, butane, and light naphtha. The partial oxidation plant feeds include low, intermediate, and high sulfur fuel oils.

Hydrogen is expressed in bblFOE throughout the model. Correspondence is 19,646 cf/bblFOE, equivalent to 50.9 bblFOE/MMcf of hydrogen. The hydrogen is produced at 97 percent purity, containing 3 percent methane.

Data sources are in-house EnSys data.

TABLE HLO HYDROGEN TRANSFER TO FUEL

This is essentially a model calibration table which permits the downgrading of produced hydrogen (95 percent purity) to fuel gas. The transfer ratio is established by matching the refinery hydrogen plant usage against known utilized capacity and reflects the fact that not all produced hydrogen, notably from catalytic reforming, is reclaimed for hydrotreating refinery streams.

TABLE SUL SULFUR PLANT

This unit reacts hydrogen sulfide with steam over iron oxide catalyst to produce sales grade sulfur. The unit is modeled after the Claus process with the capability to add a Stretford unit to reduce the hydrogen sulfide in the tail gas. The sulfur quantity is expressed in short tons, and the coefficients for the unit are scaled by 0.1 to increase the LP solution efficiency.

Data sources are the EIA RYM model data provided to ORNL and thereafter to EnSys and in-house EnSys data.

TABLE FUM REFINERY FUEL PSEUDO-UNIT

Pseudo-unit for routing refinery streams to refinery fuel. This unit mixes refinery gases, naphthas, distillates and fuel oils to the model "FUL" row for internal refinery process unit fuel consumption. The feed coefficients reflect the bblFOE conversion factors.

The LP solution activities associated with this unit should be controlled and/or scrutinized since an over-constrained or otherwise infeasible model may be characterized by dumping high value streams to refinery fuel.

Data sources are not pertinent except for the bblFOE conversion factors. These are based on EnSys calculations and estimates.

TABLE STG STEAM GENERATION
TABLE KWG POWER GENERATION

These are steam and power generation refinery utility units. These represent the generation of steam (in units of Mlb/day) from refinery fuel (in bblFOE) and electricity (in kilowatthours) from steam (Mlb/day). An efficiency of 31 percent is assumed for power generation and 70 percent for steam generation. The power and steam are consumed in the various refinery process units.

Data sources are the EIA RYM model data provided to ORNL and thereafter to EnSys, in-house EnSys data and EnSys calculations and estimates.

TABLE REL REFINERY LOSS PSEUDO-UNIT

This pseudo-unit is used to represent refinery light end losses and to adjust refinery loss to match calibration cases. The unit's single vector allocates light ends loss, as a fraction (currently 0.5 percent) of the crude run, across the light ends streams namely process gas, C_3's, C_4's, and light naphtha. The loss vector is equated with crude run via row FRL which is generated in ***Tables (R)POL***. Each crude processing vector in ***Table ACUCUTS*** has a 1 entry against FRL.

Estimates of the loss factors are based on in-house EnSys data and estimates based on calibration runs and knowledge of refinery losses.

TABLE PFA PRODUCED FUEL ADJUSTMENT PSEUDO-UNIT

This pseudo-unit is used to represent refinery propane and butane losses to refinery fuel gas (C_2 and lighter). The unit's single vector allocates C_3 and C_4 losses (transfers) to fuel gas as a fraction (currently 0.4 percent) of total crude run. The transfer vector is equated with crude run via row APF which is generated in ***Table (R)POL***. Each crude processing vector in ***Table ACUCUTS*** has a one entry against APF. Estimates of the fuel adjustment factors are based on in-house EnSys data and estimates based on calibration runs and knowledge of refinery losses.

TABLE ARD ATMOSPHERIC RESIDUUM DESULFURIZATION

This is an atmospheric residuum desulfurization process which uses residuum as feed to produce high-value light products, such as transportation fuels, low-sulfur fuel oil (0.1 percent - 0.5 percent sulfur), RFCC feed (3-6 MCR, 5-15 ppm vanadium & nickel), and coker feed. Chevron manufactures a hydrogen-efficient, fixed-bed atmospheric RDS hydroprocessing unit.

Source: - ORNL

TABLE CDT CATALYTIC DESULFURIZATION

This is a catalytic distillation unit from CDTech. This process uses two stages of catalytic distillation to desulfurize FCC gasoline (as high as 95 percent reduction), while producing high yield and very little octane loss. The first stage (a CDHydro7 dehexanizer, combining fractionization with hydrogenation) receives FCC gasoline (C5+) to produce a C5/C6 overhead stream and a C7+ bottoms stream. The bottoms stream is further processed in the second stage (using CDHDS^{SM} technology, a catalytic distillation process combining hydrodesulfurization and distillation) to remove up to 95 percent of the sulfur. Octane number loss is limited to only 1.0 (R+M)/2. The output stream from the second stage is combined with the C5/C6 overhead stream from the first stage. Data sources are based on in-house Ensys data.

Source: - Rock, Kerry L., Richard Foley, and Hugh M. Putman, "Improvements in FCC Gasoline Desulfurization Via Catalytic Distillation," AM-98-37, presented at the 1998 NPRA Annual Meeting, March 15-17, 1998, San Francisco, California.

TABLE HCL LOW CONVERSION HYDROCRACKER

Added for additional processing flexibility to allow for low conversion hydrocracking. These units operate at pressure ranges of 800 to 1,200 psig, which is consistent with the typical design pressures for existing hydrotreating units. The diesel yield and quality are limited by constraints of existing equipment, and the primary objective is to improve the level of conversion and not product quality.

Source: - ORNL, in reference to "Hydrocarbon Processing," November 1999 Vol. 78 No. 11, "Use FCC feed pretreating methods to remove sulfur," by S. W. Shorey, D. A. Lomas, and W. H. Keesom, UOP LLC, Des Plaines, Illinois

TABLE SYG CATALYTIC NAPHTHA HYDROTREATER (not used)

Generic conventional cat naphtha desulfurization, producing 30-600 ppm sulfur cat naphtha product (depending on feed). A large drop in octane occurs. Data sources are based on in-house EnSys data.

Source: - EnSys technology database update, June 2002.

TABLE HS2 HYDRODESULFURIZER 2

A second-stage process to further desulfurizes the low sulfur output from the **HL1** process to produce a sub 10ppm sulfur distillate product stream. This has limited commercial applications. Data sources are based on in-house EnSys data and report to EIA.

Source: - EnSys technology database update, June 2002.

TABLE HD1 DEEP HYDRODESULFURIZER 1

A first stage processing of *high*-sulfur straight run streams and medium plus *high*-sulfur *high*-conversion LCO streams to desulfurize and produce a 20-30 ppm output stream. This output is then processed in a second strage

(**HD2**). This has limited commercial applicatoins. Data sources are based on in-house EnSys data and report to EIA.

Source: - EnSys technology database update, June 2002.

TABLE HD2 DEEP HYDRODESULFURIZER 2

A second-stage process to takes coker gas and high-sulfur high-conversion LCO stocks (from **HD1**) to further desulfurize and produce a sub 10-ppm sulfur distillate product stream. This has limited commercial applications. Data sources are based on in-house EnSys data and report to EIA.

Source: - EnSys technology database update, June 2002.

TABLE HCM HYDROCRACKER (PARTIAL)

This ExxonMobil process uses a hydrocracker to convert a variety of refinery feedstocks into high-quality, lighter products. The feedstock can include AGO, VGO, FCC light cycle oil, DAO, and Coker gas oil. The processing goal can be to maximize 1) conversion to naphtha for gasoline production, 2) production of specification jet fuel, and 3) production of middle distillates. Also, it can be used in partial conversion operations to produce highly upgraded, low-sulfur heavy gas oils. Single stage, once-through partial conversion, and two-stage processing designs are available. The single-stage, single-train reactor is designed to process in excess of 30,000 bpsd fresh feed capacity. The MAK process utilizes a dual catalyst system to react feedstock and hydrogen to achieve desulfurization, denitrogenation, demodulation, and hydrocracking. Optimal conditions are set depending on the processing goal. The product is gas oil with a 200-300 ppm sulfur content, with by-products produced at 50-100 ppm gasoline and 100-200 ppm sulfur distillate. Data sources are based on in-house EnSys data.

Sources: - EnSys technology database update, June 2002.

TABLE MOD CATALYTIC FLUIDIZED BED

A prospective commercial process by ExxonMobil to convert olefins to gasoline and distillate with 20 ppm sulfur content. ExxonMobil:s Olefin to Gasoline (MOG) is a catalytic fluidized bed reactor process which utilizes a ExxonMobil proprietary shape-selective zeolite catalyst (ZSM-5) to convert light olefins (in lower value refinery streams) into high octane gasoline (C5+ components), or distillate (MOD process). The feed to the MOG reactor can include reactive olefins (ethylene and propylene in FCC offgas), propylene in FCC C3 LPG cut, butenes in MTBE raffinate, and pentenes, hexenes, and heptenes in light FCC gasoline. The feed is converted into C5+ through oligomerization, carbon number redistribution, hydrogen transfer, aromatization, alkylation, and isomerization reactions. The quality of MOG gasoline produced depends on the processing severity and the feed olefins, with yields ranging from 60 - 75 percent of high octane gasoline blendstock. Typical qualities include: RONC (94 - 98), MONC (81 - 85), density (62 - 57 API), and RVP (7.2 psi/0.5 bar). The zeolite catalyst is considered to be environmentally safe, and can be reused in the FCC unit to increase octane quality.

Sources: - EnSys technology database update, June 2002.

TABLE MDH MOBIL HYDROGENATION (not used)

(renamed from MOH to MDH because PMM already had MOH defined for another unit)

This unit is an ancillary ExxonMobil process to saturate **MOD** distillate olefins. Produces a 20 ppm surfur distillate. Data sources are based on in-house EnSys data.

Source: - Ensys technology database update, June 2002.

TABLE OCT CATALYTIC FIXED-BED HYDROPROCESSOR

OCTGAIN is a commercially proven process from ExxonMobil which uses a proprietary catalyst system to selectively remove sulfur and saturate olefins from FCC naphtha or full range gasoline while maintaining (or even increasing) octane levels. Benzene content and vapor pressure in the product are nearly unchanged. The low mercaptan level of the desulfurized gasoline allows it to be directly blended into the refinery gasoline pool. There is a trade-off between C5+ yield and product octane (similar to naphtha reforming); however, the product yield has been increased with recent advancements in catalysts (OCT-220). The unit is a fixed-bed, low-pressure process that operates at essentially gasoline hydrofinishing conditions. Data sources are based on in-house EnSys data.

Source: - Shih, S.S., P.J. Owens, S. Palit, and D.A. Tryjankowski, "Mobil's OCTGAIN^{TM} Process: FCC Gasoline Desulfurization Reaches a New Performance Level," AM-99-30, presented at the 1999 NPRA Annual Meeting, 1999.
- EnSys technology database update, June 2002.

TABLE SOX CAUSTIC SOX SCRUBBER

This unit is an FCC regenerator gas caustic scrubber to meet current emission standards. Allows full benefit of FCC feed hydrodesulfurization. It has many commercial applications. Data sources are based on in-house EnSys data.

Source: - EnSys technology database update, July 1999.

TABLE MTO METHANOL TO OLEFINS FLUID BED (not used)

An Exxon Mobil fluid bed process which converts methanol to olefins (MTO), and by-product gasoline with 5 ppm sulfur content (via subsequent oligomerization of the light olefin product). Provides olefins for ExxonMobil's MOG/MOD process. The MTO process was demonstrated in a semi-works plant (100 barrels per day) in Germany in 1982-83, a prospective commercial process.

TABLE GSF/GSH COKE GASIFICATION

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 (identified as GSF and GSH, respectively). The product hydrogen is put into a pool stream to be used by other processing units at the refinery. The synthetic gas is sent to a combined heat and power unit (CHP) to produce steam and/or electricity. The byproduct H2S is also produced and sent to a pool stream. The design size of the coke gasification unit was set to

2000 short tons coke feed per calendar day (s-tons/cd). The capacity factor (or utilization rate) was assumed to be 0.85 for the gasification units. 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.

Source: - "Implementation of Petcoke Gasification in U.S. DOE's National Energy Modeling System (NEMS)," John J. Marano, PhD, Consultant, and Patricia A. Rawls, U.S. DOE (NETL), June 2003.
- Attachment file "PMM_GSF1.xls" in email from John Marano, Consultant for NETL to Han-Lin Lee, U.S. DOE and Elizabeth May, SAIC, April 2003.

TABLE CHP COMBINED HEAT/POWER UNIT WITH SYNGAS FEED

The combined heat and power unit operates on an annual basis with a 90% synthetic gas and 10% natural gas feed. The natural gas feed is used when the synthetic fuel is unavailable (estimated at 10% of the operating year). The CHP can produce electricity and steam, or electricity only. It's annual utilization rate is 96%. Similar to CGN, the CHP receives a credit for selling a specified % of its produced electricity to the grid. All steam is consumed by the refinery operations.

Source: - "Implementation of Petcoke Gasification in U.S. DOE's National Energy Modeling System (NEMS)," John J. Marano, PhD, Consultant, and Patricia A. Rawls, U.S. DOE (NETL), June 2003.
- Attachment file "PMM_GSF1.xls" in email from John Marano, Consultant for NETL to Han-Lin Lee, U.S. DOE and Elizabeth May, SAIC, April 2003.

TABLE IOT ISOOCTANE

The Isooctane process consists of a dimerization reactor, a separation unit, and an Olefin saturation unit (hydrogenation). The dimerization reactor and the separation unit convert the Olefin feed to Isooctene (in the presence of an acid catalyst). The hydrogenation section then uses hydrogen to convert the Isooctene to Isooctane. This also includes a feed pretreatment process (using hydrogen) to remove sulfur containing compounds. The Isooctane process serves to replace the MTBE process when the MTBE ban is enacted.

Source: - "Refinery Technology Profiles ISOOCTANE/ISOOCTENE and Related Technologies," John J. Marano, PhD, prepared for the U.S. DOE, January 2003.

- Attachment file "EnSys IOT Data.xls" in email from Martin Tallett, Ensys Energy & Systems Inc, to Han-Lin Lee, U.S. DOE, January 11, 2002.

TABLE PHS PHILLIPS S-ZORP ADSORPTION

The PHS process removes sulfur from the FCC naphtha stream. The naphtha stream is combined with a small quantity of hydrogen. The mixture is heated to vaporize the gasoline. The gasoline vapor passes through a fluid bed reactor where a proprietary sorbent is used to remove the sulfur from the hydrocarbon stream. The sweet

gasoline vapor is stripped from the sorbent, and is cooled. The sorbent passes through a regenerator where SO2 is removed and sent to a sulfur recovery unit. The cleaned sorbent is recycled to the fluid bed reactor. Hydrogen is consumed by this process.

Source: - Tallett, Martin, Ensys Energy & Systems Inc, "PMM Refinery Technology Update and Transportation Links Update, Subtask 3. PMM Refinery Technology Update," delivered to DOE/EIA, Contract DE-AF-01-03EI37625.A000, June 17, 2003.
- Phillips Petroleum Company, "S Zorb Process Overview," accessed Dec. 2003, http://www.fuelstechnology.com/szorb_processover.htm

(cogener)

TABLE CGN CHP UNIT

This refinery process unit is used to produce steam and generate electricity for sale to the power grid. The fraction sold is contained in input ***Table SELCGN***, the electricity not sold is consumed by refinery process units. Data sources are from EIA-906 survey form.

(mchproc)

The processing units identified here are located outside the refinery at merchant facilities. These facilities provide the refinery with additional processing streams which are merged into the refining process. The following processing units located at the merchant facilities correspond with the refinery processing units defined as follows:

Merchant Processing Unit ID	*Refinery Processing Unit ID*
C4X	C4I
OLX	OLE
ETX	ETH
IOX	IOT
FUX	FUL
STX	STG
CGX	CGN

For detailed descriptions of these merchant processing units, refer to the corresponding refinery processing units defined above.

TABLE SMD SHELL MIDDLE DISTILLATE SYSTHESIS

A Shell GTL (gas to liquids) process for converting natural gas into ultra clean middle distillates, including diesel, kerosene, and naphtha. These GTL's can be used as a blending stock to improve the quality of other products. GTL products have no sulfur, aromatics, nitrogen compounds, or particulates.

Source: - EnSys technology database update, June 2002

TABLE SOD SASOL MIDDLE DISTILLATE UNIT

This unit is a Sasol Ltd. GTL (gas to liquids) process for converting natural gas into ultra clean middle distillates.

Source: - EnSys technology database update, June 2002

TABLE PSA PRISM PRESSURE SWING ABSORPTION- H_2 PRURIFICATION

The PSA performs hydrogen recovery from refinery gas, and produces 95-99.999+% H_2 purity.

Source: - EnSys technology database update, June 2002
- Hydrocarbon Processing, May 2002.

TABLE HPM H_2 PRURIFICATION (not used)

The HPM performs hydrogen recovery from refinery gas using steam reforming.

Source: - EnSys technology database update, June 2002
- Hydrocarbon Processing, May 2002.

TABLE HCU HYDROCRACKER(GASOIL)- ADVANCED TECHNOLOGY

Represents an advanced state-of-the-art hydrocracking technology designed to increase middle distillate yield by 5 to 15%, with middle distillate 10 ppm sulfur level products, 5-15% aromatics content, and at the 60 cetane level. Employs an efficient means of recycling unconverted oil to the cracking reactor, an enhanced hot separator, and back-staged reactors.

Source: - EnSys technology database update, June 2002
- Hydrocarbon Processing, May 2002 (p. 117).

TABLE PSZ HYDRODESULFURIZATION (S ZORB) FOR DIESEL

The PSZ is a Phillips' sulfur removing technology. It uses a regenerative sorbent to chemically attract and remove sulfur from gasolines, diesel, and distillates to 10 ppm levels. Operates at a very low net chemical hydrogen consumption, and at lower pressures than hydrotreating processes. It's capable of removing difficult sulfur species, such as 4,6 Dimethyldibenzothiophene.

Source: - EnSys technology database update, June 2002
- Fuels Technology, www.fuelstechnology.com/szorbdiesel.htm

TABLE SUP SULPHCO SELECTIVE OXYDATION

Oxydation of sulfur containing components can effectively convert sulfur compounds. It is being investigated for practical use in refining. Oxidation can be very selective, and can be prformed at mild conditions.

Source: - EnSys technology database update, June 2002
- Sulphco website, www.sulphco.com/technology.htm

TABLE CTX/CTZ COAL-TO-LIQUIDS CONVERSION

The coal-to-liquids process used in the PMM was developed based on the methodology described in a Mitretek Technical Report (MP 2001-28): "Coproduction: A Green Coal Technology," by David Gray and Glen Tomlinson, March 2001. The process consists of a coal gasification unit, followed by a Fischer-Troupe liquefaction unit, with CHP. Specifically, the large-scale coproduction with no carbon sequestration (Figure 7 in the Report) is adopted as the generic facility for the CTL module. This CTL facility is capable of processing 16,400 TPD of bituminous coal (e.g., Illinois Basis) with an energy content of 23 MM Btu/ton, and generating 33,200 BPD fuels and 465.5 MW net CHP electricity for sale to the grid (46% efficiency). The capacity factor (or utilization rate) is assumed to be 0.9.

Source: - "Coproduction: A Green Coal Tehcnology," by David Gray and Glen Tomlinson