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EIA MODEL DOCUMENTATION:

PETROLEUM MARKET MODEL

OF THE

NATIONAL ENERGY MODELING SYSTEM

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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
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
CG	Conventional Gasoline
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.
DOE	Department of Energy
EIA	Energy Information Administration
EOR	Enhanced Oil Recovery
EPA	Environmental Protection Agency
ETBE	Ethyl Tertiary Butyl Ether
IEA	International Energy Agency
IEO	EIA International Energy Outlook
LP	Linear Program
LPG	Liquefied Petroleum Gas
Mbbl/cd	Thousand Barrels Per Calendar Day
MMbbl/cd	Million Barrels Per Calendar Day
MTBE	Methyl Tertiary Butyl Ether
NACOD	North American Crude Oil Distribution
NEMS	National Energy Modeling System
NES	National Energy Strategy
NGL	Natural Gas Liquid
NIPER	National Institute for Petroleum and Energy Research
NOx	Nitrogen Oxide
NPC	National Petroleum Council
NPRA	National Petroleum Refiners Association
OB1	Optimization with Barriers 1
OSL	Optimization Subroutine Library
ORNL	Oak Ridge National Laboratory
PADD	Petroleum Administration for Defense District
PCF	Petrochemical Feed
PMM	Petroleum Market Module
RFG	Reformulated Gasoline
Rvp	Reid Vapor Pressure
RYM	Refinery Yield Model (EIA)
SCF	Standard Cubic Feet
SIC	Standard Industrial Classification
SPR	Strategic Petroleum Reserve
TAP	Toxic Air Pollutant
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 detail on how it works. This report is intended as a reference document for model analysts, users, and the public. 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).

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

1.3 Model Archival Citation

The PMM is archived as part of the National Energy Modeling System. 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, Inventory of Input Data, Parameter Estimates, and Model Outputs; Appendix B, Detailed Mathematical Description of the Model; Appendix C, Bibliography; Appendix D, Model Abstract; and Appendix E, Data Quality; and Appendix F, Estimation Methodologies.

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 is 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, parameters for production functions which estimate the amount of domestic crude oil production, 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, methanol, 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

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

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 determine the impact on refinery operations and on the marginal costs of refined products of changes in any one or several variables including 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.

The PMM is comprised of five geographical regions, defined by the Petroleum Administration for Defense (PAD) Districts. Individual refineries are aggregated into one refinery representation for each PAD District. Product demands are input at the Census division level and end-use product prices are produced by Census division. A transportation structure linking the PAD District refining regions to the Census division demand regions is also represented. The PMM produces annual results, currently from 1990 through 2010.

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.

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

- Demands for petroleum products from the Residential, Commercial, Industrial, Transportation, and Electricity Market Models. The demands include motor gasoline, jet fuel, kerosene, distillate fuel, low- and high-sulfur residual fuel, liquefied petroleum gases (LPG), petrochemical feedstocks, petroleum coke, and other petroleum.

- Import supply curves for crude oil and petroleum products from the International Energy Model (IEM). The crude oil supply curves are provided for each of the PAD Districts 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 traditional and reformulated gasoline, distillate fuel, low-sulfur diesel fuel, jet fuel, low- and high-sulfur residual fuel, LPG, petrochemical feedstocks, and other petroleum. This information is used to evaluate the tradeoff between domestic product production and imports.

- Import supply curves for methanol and MTBE provided by the International Energy Model and ethanol supply curves from the Renewable Fuels Model. The use of methanol and ethanol in the PMM takes into account the consumption of alcohol fuels in the transportation sector (E85 and M85), and the chemical use of methanol.

- Parameters for production functions from the Oil and Gas Supply Model for estimating domestic production of crude oil. 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 natural gas production from the Natural Gas Transmission and Distribution Model.

- Prices for natural gas and electricity from the Natural Gas Transmission and Distribution Model and the Electricity Market Model, respectively. The PMM estimates the refinery consumption of these energy sources.

- The market shares of oxygenated, reformulated, conventional, and California specification gasoline. These parameters are estimated offline and input to the PMM. In a similar fashion, the shares of low-sulfur diesel and distillate fuel are provided to the PMM. The shares change over time, based on assumptions about market penetration (see Appendix F for more details). 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.

The PMM also provides information to other NEMS models. 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 Models. The prices are used to estimate 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.

- Fuel consumption from refineries. This information is passed on to the Industrial Model for inclusion in the industrial sector totals. In addition, refinery cogeneration capacity and generation levels are also sent to the Industrial Model.

- The amount of sulfur allowances earned by small refiners, as described in the CAAA.

- The market prices and consumption of ethanol and methanol.

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

Figure 2.1 PMM Input - Output Flow Diagram
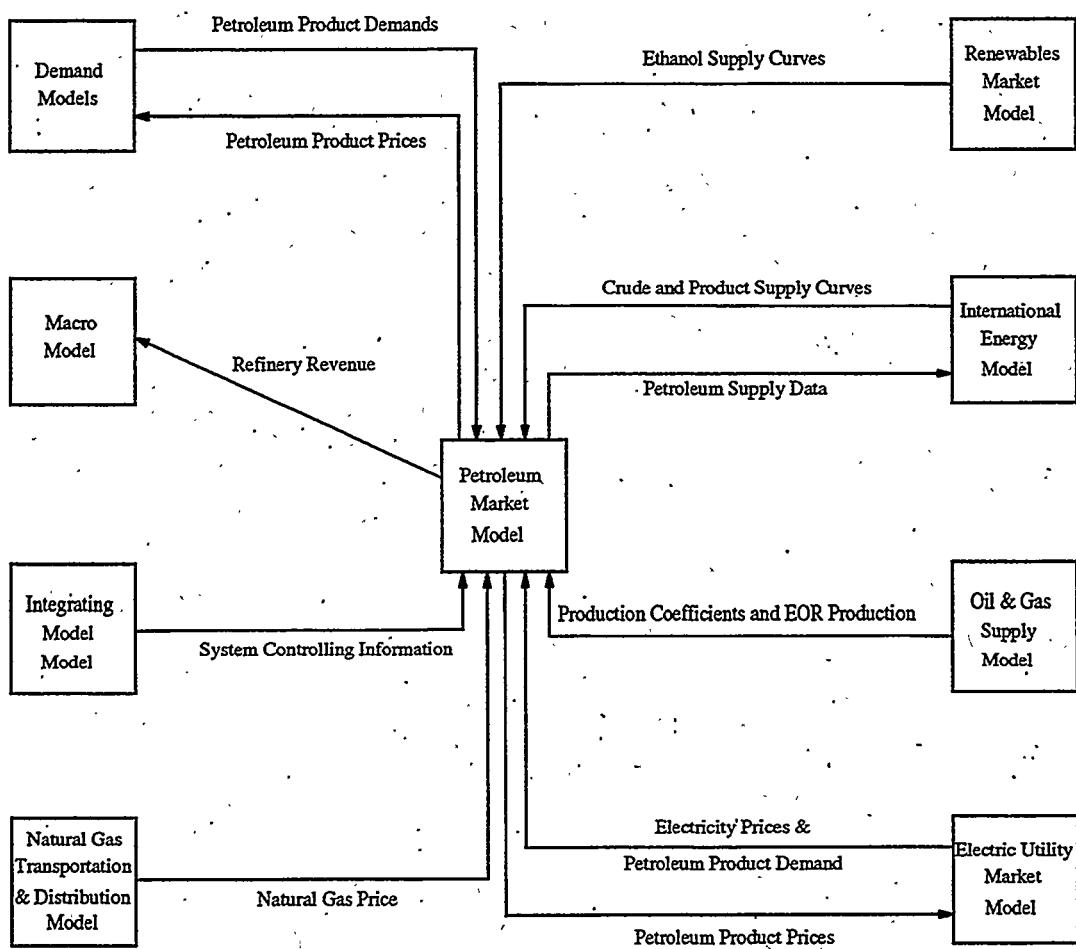
3. Model Overview and Rationale

3.1 Philosophical or Theoretical Approach

The National Energy Modeling System, as a whole, produces a general equilibrium solution by iterating until convergence to a stable result occurs. For example, the various demand models 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. If the computed prices from PMM converge to within the specified tolerance, the NEMS iteration is complete and the next yearly NEMS cycle begins. If the computed prices have not converged, new demand quantities are computed, passed to PMM, and the cycle is repeated. This process continues until a stable solution is found.

Within the PMM, the refinery sector is modeled by a linear programming representation. A linear programming model is developed for each of the five Petroleum Administration for Defense (PAD) Districts and represents an aggregation of the individual refineries in the PAD District. The PMM linear programming model also contains a transportation structure to move 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 for the five PAD District representation as a whole is found by minimizing the costs of meeting the demands. Revenues are derived from product sales, and costs are incurred from the purchase and processing of raw materials and the transportation of finished products to the market. The model chooses a set of petroleum industry activities (e.g. crude oils, processing units, etc.) to produce a product mix that maximizes the refinery's economic benefits. The 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 Comparison with Oil Market Module

The inclusion of a linear programming model directly into the integrated refining and marketing representation is a significant change from predecessor models. The Oil Market Module (OMM), which represents petroleum refining and marketing in the Intermediate Future Forecasting System, uses econometric equations to represent the relationship between refinery production costs (product costs) and product yields. The econometric equations are estimated from pseudodata derived from a refinery linear programming model. Pseudodata were developed by running a refinery LP for hundreds of scenarios where the yield of a reduced set of petroleum products was recorded in response to independently varying product prices over a predefined range. This was done for a base case and three representative world oil prices (WOP). Additionally, a number of runs ultimately were made where prices of all products were simultaneously increased for each WOP. In total, nearly 400 runs were made to create the pseudodata. An accounting/econometric framework is used to estimate sources of supply to meet demand. Product imports are calculated as the difference between demand and domestic supply.

The decision to change the approach for PMM within NEMS resulted from the identification of several disadvantages for using the OMM approach.[1]

- The econometric equations produce only national level refinery gate (or wholesale) prices for the product slate defined, with regional end-use prices being estimated from predefined regionally specific distribution cost characteristics. Thus, regional differences in input costs or product specifications are not being reflected in the results since regional production levels are not represented.

- Product imports are used as balancing items, thus preventing both a realistic assessment of import dependence and a realistic analysis of import restrictions or tariffs.

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[1] Energy Information Administration, *A Critique of the Oil Market Module*, internal study by S. MacIntyre, Energy Supply and Conversion Division, Office of Integrated Analysis and Forecasting (Washington, DC, January 1992).

- The current OMM cannot model changes in product specifications such as those included in the CAAA.

- The OMM lacks the capability to decide between domestic and foreign capacity expansion efforts. This is an important decision activity directly affecting import levels.

- The OMM cannot be used to analyze the impact of requiring oxygenates in gasoline and the competition between oxygenates.

In addition, any changes to refinery operating scenarios within OMM (whether significant or minor) would involve a three-step process -- (1) modify the linear programming model to reflect the changes, (2) rerun the LP model to generate new pseudodata (involving several hundred runs), and (3) reestimate the econometric equation coefficients. This is a resource-intensive process.

3.3 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 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.

Each PAD District is treated as a single firm. This restricts the ability to deal with issues such as 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 are developed exogenously, although the decision to invest is endogenous. The model does not require foresight to be perfect, but 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. 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 as well as costs resulting from the Clean Air Act Amendments of 1990 (CAAA90) and other environmental legislation.

The costs of producing new formulations of gasoline and diesel fuel that will be phased in as a result of the CAAA90 are determined within the linear programming (LP) representation by incorporating specifications and demands for these fuels. The PMM assumes that the specifications for these new fuels will remain the same as specified in current legislation.

Motor Gasoline Specifiations

The PMM models the production and distribution of four different types of gasoline: traditional, oxygenated, reformulated, and reformulated/high-oxygen. The following specifications are included in PMM to differentiate between traditional and reformulated gasoline blends: octane, oxygen content, Reid vapor pressure (Rvp), benzene content, aromatic content, sulfur content, and olefin content.

Starting in 1998 the specifications for traditional gasoline reflect the Environmental Protection Agency's (EPA) "1990 baseline." These specifications prevent the quality of traditional 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 a oxygen content of 2.7 percent by weight. Some areas that require oxygenated gasoline will also require reformulated gasoline. In those overlapping areas, reformulated-high oxygen gasoline containing 2.7 percent oxygen will be required. Oxygenated gasoline is assumed to have specifications identical to traditional gasoline with the exception of a higher oxygen requirement. Similarly, the oxygen requirement is assumed to be the only difference between the reformulated/high oxygen and reformulated gasoline blends.

Beginning in 1995, many areas of the country will require reformulated gasoline. Between 1995 and 1997, the Environmental Protection Agency (EPA) will certify reformulated gasoline according to either the "simple" or "complex" models. The PMM assumes that reformulated gasoline during this time period will meet the EPA's "simple model" definition, which allows no lead content, limits benzene content to 1.0 percent and aromatics content to 25 percent by volume, requires an oxygen content of 2.0 percent by weight, and caps nitrogen oxide emissions at a baseline level. Beginning in 1998, the EPA will only certify 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 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." Specifications such as Rvp, aromatics, sulfur, and olefin content change in the year 2000 reflecting further emissions reductions required by CAAA90.

The CAAA90 provided for special treatment of California that would allow different specifications for oxygenated and reformulated gasoline in that State. In 1992, California requested a waiver from the winter oxygen requirements of 2.7 percent to reduce the requirement to a range of 1.8 to 2.2 percent. The PMM assumes that PAD District V refiners must meet the California specifications. Therefore, for 1993-1994, the specifications for oxygenated gasoline in PAD District V meet a 2.0-percent standard. Starting in 1996, the specifications for reformulated gasoline in PAD District V are the same as California standards.

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 Petroleum Administration for Defense (PAD) district. 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 traditional, oxygenated, reformulated, and reformulated/high-oxygen gasolines by applying

assumptions about the annual market shares for each type. The shares change over time based on assumptions about the market penetration of new fuels. Annual assumptions for each region account for the seasonal and city-by-city nature of the regulations. The market shares reflect the mandated use of reformulated blends in nonattainment areas as well as assumptions about opt-in and spillover demand from outside these areas. The PMM assumes a 3-percent spillover of oxygenated and reformulated gasoline into attainment areas.

The oxygenated gasoline shares throughout the forecast assume wintertime participation of 39 carbon monoxide nonattainment areas. Year-round consumption of oxygenated gasoline in Minnesota is assumed beginning in 1997 in accordance with State legislation. The PMM also assumes that, starting in 1995, reformulated gasoline will be consumed in the nine required areas plus areas that had petitioned the EPA to opt in as of January 1994.[2] Nonattainment areas in Wisconsin and Atlanta, Georgia, are assumed to opt into the program starting in 1996.

Diesel Fuel Specifications and Market Shares

In order to account for diesel desulfurization regulations, low-sulfur diesel is differentiated from other distillates. Diesel fuel in Census divisions 1 through 9 is assumed to meet Federal specifications.

The PMM contains a sharing methodology to allocate distillate demands between low and high sulfur. Market shares for low-sulfur diesel and distillate fuel are estimated based on data from EIA's annual *Fuel Oil and Kerosene Sales Report 1992* (DOE/EIA-0535(92), October 1993). Since about 20 percent of current demand in the transportation sector is off highway, 80 percent of transportation demand for distillate fuel is assumed to be low sulfur. Consumption of low-sulfur distillate outside of the transportation sector is assumed to be zero.

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[2]Required areas: Baltimore, Chicago, Hartford, Houston, Los Angeles, Milwaukee, New York City, Philadelphia, and San Diego. 1995 Opt-ins: Texas, District of Columbia, New Jersey, Maryland, Delaware, New York, Connecticut, Virginia, New Hampshire, Massachusetts, Pennsylvania, Maine, and Rhode Island.

End-Use Product Prices

End-use petroleum product prices are based on marginal costs of production plus production-related fixed costs plus distribution costs and taxes. The marginal costs of production are determined by the model and represent variable costs of production including additional costs for meeting reformulated fuels provisions of the CAAA90. Fixed refinery costs include fixed operating costs,[3] a 4-percent return on assets, and environmental costs associated with controlling pollution at refineries[4]. Assuming that refinery-related fixed costs are recovered in the prices of light products, fixed costs are allocated among the prices of liquefied petroleum gases, gasoline, distillate, kerosene, and jet fuel. These costs are based on average annual estimates and are assumed to remain constant over the forecast period.

The costs of distributing and marketing petroleum products are represented by adding fixed distribution costs to the marginal and refinery fixed costs 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 and wholesale prices. The costs for kerosene are the average difference between end-use prices of kerosene and wholesale distillate prices.

State and Federal taxes are also added to transportation fuels to determine final end-use prices. Recent tax trend analysis indicated that State taxes increase at the rate of inflation, while Federal taxes do not. 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.

Crude Oil Quality

In the PMM, the quality of crude oil is characterized by average gravity and sulfur levels. Both domestic and imported crude oil are divided into five categories as defined by the ranges of gravity and sulfur shown in Table A2 in Appendix A.

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[3]Fixed operating costs include payroll, maintenance, labor and materials, depreciation, and other expenses.

[4]Environmental cost estimates are based on National Petroleum Council, *U.S. Petroleum Refining - Meeting Requirements for Cleaner Fuels and Refineries,* Volume I (Washington, DC, August 1993).

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 crudes 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

PMM refining regions are the five Petroleum Administration for Defense (PAD) districts. Individual refineries are aggregated into one linear programming representation for each PAD district region. In order to interact with other NEMS modules with different regional representations, certain PMM inputs and outputs are converted from a PAD district to a non-PAD district 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 methyl tertiary butyl ether (MTBE) manufacture. Capacity expansion occurs by processing unit, starting from base year capacities established by PAD district using historical data. Expansion of distillation capacity is limited to 600 thousand barrels per day in each PAD district, reflecting an assumption that capacity additions will be limited to existing sites.

Expansion is determined when the value received from the additional product sales exceeds the investment and operating costs of the new unit. The investment costs assume a 15-percent rate of return over a 15-year plant life. Expansion through 1994 is determined by adding to the existing capacities of units planned and under construction that are expected to begin operating during this time. Capacity expansion is done in 3-year increments. For example, after the model has reached a solution for forecast year 1994, the PMM looks ahead and determines the optimal

capacities given the demands and prices existing in the 1997 forecast year. The PMM then allows 50 percent of that capacity to be built in forecast year 1995, 25 percent in 1996, and 25 percent in 1997. At the end of 1997, the cycle begins anew.

Strategic Petroleum Reserve Fill Rate

The PMM assumes no additions for the Strategic Petroleum Reserve during the forecast period. Additions to the Strategic Petroleum Reserve have not been included in recent budgets.

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 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. Except for jet fuel, the tax began on October 1, 1993, and takes effect in the PMM in forecast year 1994. Jet fuel has been granted a 2-year delay.

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 39 carbon monoxide nonattainment areas was required to be oxygenated.[5] Starting in 1995, gasoline sold in nine 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 may choose to "opt in" to the reformulated gasoline requirement. In a few metropolitan areas with both ozone and carbon monoxide problems, the requirements

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

for oxygenated and reformulated gasoline will overlap. In other words, during the winter months a reformulated/high oxygen gasoline will be required.[6]

The PMM reformulated gasoline projections assume that the Renewable Oxygenated Standard (ROS) promulgated by EPA in 1994 will be implemented. In 1995, ROS requires renewable oxygenates such as ethanol and ethyl tertiary butyl ether (ETBE) to be used in 15 percent of reformulated gasoline. The renewable oxygenate requirement will then be increased to 30 percent of reformulated gasoline in 1996. The implementation of ROS is uncertain because the U.S. Court of Appeals has ordered a stay on the ROS pending further legal review. At a minimum, the stay will delay the implementation of ROS.

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.

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.[7] 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.

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[6]Gasoline that meets the requirements of reformulated gasoline and has an oxygen content of 2.7 percent by weight.

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

3.4   Alternative Approaches and Reasons for Selection

In any model design a tradeoff must be made between finding an acceptable level of detail and preserving a manageable framework for providing information in a timely fashion. The PMM was developed not only for forecasting purposes, but also to provide a policy analysis tool. These dual objectives were key to deciding the approach taken in the PMM. Various alternatives are discussed below followed by a summary of the reasons for choosing the linear programming approach.

3.5   Pseudodata/Econometric Equation Approach

The OMM, as described above, uses a pseudodata/econometric equation approach. The objective of this approach is to retain the advantages of a large, complex refinery model, with the capability of responding to a wide variety of issues, in an integrated environment. The response surface generated by the large number of model runs represents the output of the LP for given sets of inputs, and the econometric equations provide a means to quickly access the results.

Two primary problems with this approach are inaccuracy and preparation time. The model runs must be devised so that the pseudodata adequately cover the range of each of the inputs. Since the exact combination of inputs cannot usually be anticipated, the pseudodata only provide an approximation of the model response. Moreover, the econometric equations are only an approximation of the shape of the response surface.

Preparation time (i.e., the time required before the model is ready for integrated runs) can be significant for this approach. The design, the generation of pseudodata, and the estimation of the equations all require substantial time and effort. The OMM equations were reestimated only about once every 4 years. However, because NEMS will be used for analytical studies as well as mid-range forecasting, the equations may have to be updated for each particular study.

In addition, the capabilities of the PMM, compared to the OMM, especially the increased regionality, the explicit treatment of imports, and the new products and product specifications, would increase considerably the number of runs required to

adequately cover the range of each input variable. For these reasons, the pseudodata/econometric equation approach was not considered as a basis for PMM.

3.6 Linear Approximation Approach

Another type of pseudodata approach, called the linear approximation or lookup approach, was considered. Pseudodata would still need to be generated. The output of several hundred model runs would be placed in a database, with each record containing the refinery output quantities and prices associated with a given set of product demand levels and input prices. The runs would cover the expected range of product demands and input prices.

In the integrated environment, the inputs to the PMM (a vector of demands and input prices) would be used to choose a specified number of data records (e.g. 10) from the database. The data records chosen would be those (10) that minimized the Euclidean distance to the input data vector. The output quantities and prices would then be estimated from a linear combination of the chosen set of data records.

Several advantages over the OMM approach are noteworthy. The econometric equations would not need to be reestimated with each new set of pseudodata, considerably reducing model preparation time. Furthermore, the output variables could include more than just product prices. Any variable generated by the use of an LP model could be placed in the database and accessed by the linear approximation method.

However, the same pseudodata criticisms cited above apply to this method as well. Any study or scenario involving unanticipated changes to the refinery operating scheme would require regeneration of several hundred data records using a detailed model. In addition, the number of required runs would rise above the roughly 400 used in the past, due to regionality and the increased interactions between PMM and other models. The number of runs must be sufficient to adequately cover the expected range of each input variable, so it increases substantially with each additional input. Also, the accuracy of this method relative to the other approaches

has not been established, but is considered to be less accurate than even the pseudodata/econometric equation approach.[8]

3.7 Abbreviated Linear Programming Approach

Extreme point modeling is similar to the pseudodata approach in that a detailed model is used to generate output vectors. The results of each run are expressed as column vectors of input/output coefficients derived over a range of cases designed to span the potential solution space.[9]

A linear programming refinery model can be appreciably condensed through the technique of extreme point vectors. The extreme point representation models the refinery as series of operating modes or plans. A slate of products is produced per barrel of processed crude oil. An illustration of two typical extreme point vectors is shown in Table 3.1. Each column of the table represents an operating mode for the refinery, such as maximum production of gasoline or distillate (No. 2 heating oil and diesel fuel). For each solution of the detailed refinery model, the crude oils consumed as inputs are divided by the total crude oil processed to provide a volume fraction of each crude oil, which will sum to 1.0 as shown in the row labeled "Total Crude." Each solution also provides the product volumes produced as outputs, which are also divided by the total crude oil processed. After accounting for fuel burned and losses, not shown in the table, the sum of the outputs will also sum to 1.0. The result is a representation of a feasible and optimal operating plan expressed as inputs and outputs per barrel of total crude oil processed by the refinery model. Extreme point vectors typically have less than 50 equations for each refining region, including crude oil balance equations, refinery unit capacity equations, and product balance equations.

The operating modes, such as maximum gasoline and maximum distillate, are created by successive solutions of the detailed refinery model responding to increased prices for the product to be maximized. Some typical modes to be generated may be:

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[8]   Energy Information Administration, *Approaches to Estimating PMM*, internal memorandum by J. Kendell, Energy Supply and Conversion Division; Office of Integrated Analysis and Forecasting (Washington, D.C., November 1991).

[9]   Linear Programming, Inc., *PAL/REMS Integration Methodology Study*, final report prepared for the EIA Office of Statistical Standards, Contract No. DE-AC01-84EI-19633 (Washington, D.C., April 1987).

- maximum/minimum production of each grade of gasoline,
- maximum/minimum production of jet fuel,
- maximum/minimum production of No. 2 heating oil,
- maximum/minimum production of low sulfur highway diesel fuel, or
- maximum/minimum production of residual fuel oil.

The extreme point representations can be expanded to differentiate between various crude oil operating modes, such as incremental volumes of Arab Light or incremental volumes of West Texas Intermediate (WTI).

Table 3.1. Example of Extreme Point Vectors
Yields per Barrel of Total Crude Flow

Mode	Max Gasoline	Max Distillate
Crude 1	0.5	0.5
Crude 2 Sum Other Crudes	0.2 0.3	0.2 0.3
Total Crude	1.0	1.0
Gasoline Grade 1	0.14	0.10
Gasoline Grade 2-5	0.35	0.25
No. 2 Heating Oil	0.14	0.30
Resid. <1%S	0.09	0.10
Sum of Other Products	0.28	0.25
Operating Cost ($/bbl)	0.94	1.00

The difference from the pseudodata approach is that these vectors are then placed in a linear programming environment. The extreme points are not just output quantities and prices from the LP model runs, as in the pseudodata approach, but coefficients which break input quantities into outputs of products, taking into account the associated costs. Solutions are derived by maximizing profits or minimizing costs

using linear combinations of these extreme point column vectors to represent the refinery LP. A second important difference is that the required amount of extreme points numbers in the tens rather than the hundreds.

The advantage of using extreme point vectors to represent refining operations is that the resulting model is smaller and solves faster than a detailed refinery model. The disadvantage is that the analyst must create enough extreme points to span most of the possible modes and product yields that might be required in an equilibrium pricing model such as NEMS. Moreover, extreme points should probably be regenerated for each new forecast and each particular analytical study. This would be a time-consuming process. Extreme points have also been criticized for inaccurately representing refinery operations,[10] although increasing the range and number of the modes can respond in part to this criticism.

3.8 Detailed Linear Programming Approach

Detailed linear programming models have been very successful at modeling refinery problems. The particular advantage of using linear programming models to represent refinery processes is that they allow refinery managers to calculate the marginal costs of products while simultaneously indicating the required operating conditions for maximum profitability. Furthermore, linear programming process models contain detailed engineering structure directly related to the refinery processes and product quality, and can therefore readily incorporate new technologies and technological change.

A linear programming approach in the PMM allows more flexibility for dealing with analytical issues than the other approaches considered. Changes to product specifications, the addition of new products or refinery inputs, and/or changes in processing unit costs or capacities can be handled directly in the linear programming structure. Many of the shortcomings of the pseudodata and extreme point approaches are not problems for a linear programming approach. The biggest drawbacks to LP models are size and execution time. The linear programming representation currently in the PMM will have to be reduced in size in order to achieve acceptable execution times.

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[10]   Ibid., pp. 25-39.

4. Model Structure

During each NEMS iteration, product demand quantities and other variables supplied by NEMS models are used to update the PMM matrix. An optimal solution is obtained from the updated 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 matrix are both accomplished by executing FORTRAN callable LP subroutines available from an 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. The OMNI programming language is currently being used. This language was selected because EIA has existing matrix generator and report generator OMNI programs that can be readily adapted for use by PMM. In the future, it will be possible to convert to completely FORTRAN callable subroutines for data table manipulation, matrix generation, and solution retrieval programs for report writing. Appendix A describes the input data tables used to develop the input matrix of the PMM.

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, 4.2, 4.3, and 4.4. The flow diagrams use descriptive text and make reference to PMM FORTRAN subroutine names, which are described in detail in sections 4.1, 4.2, 4.3, and 4.4.

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 four branches during any NEMS iteration.

- If the history switch is on and it is the first year and first iteration,

---

[1]   Mathematical Programming System format.

Figure 4.1 PMM Flow Diagram
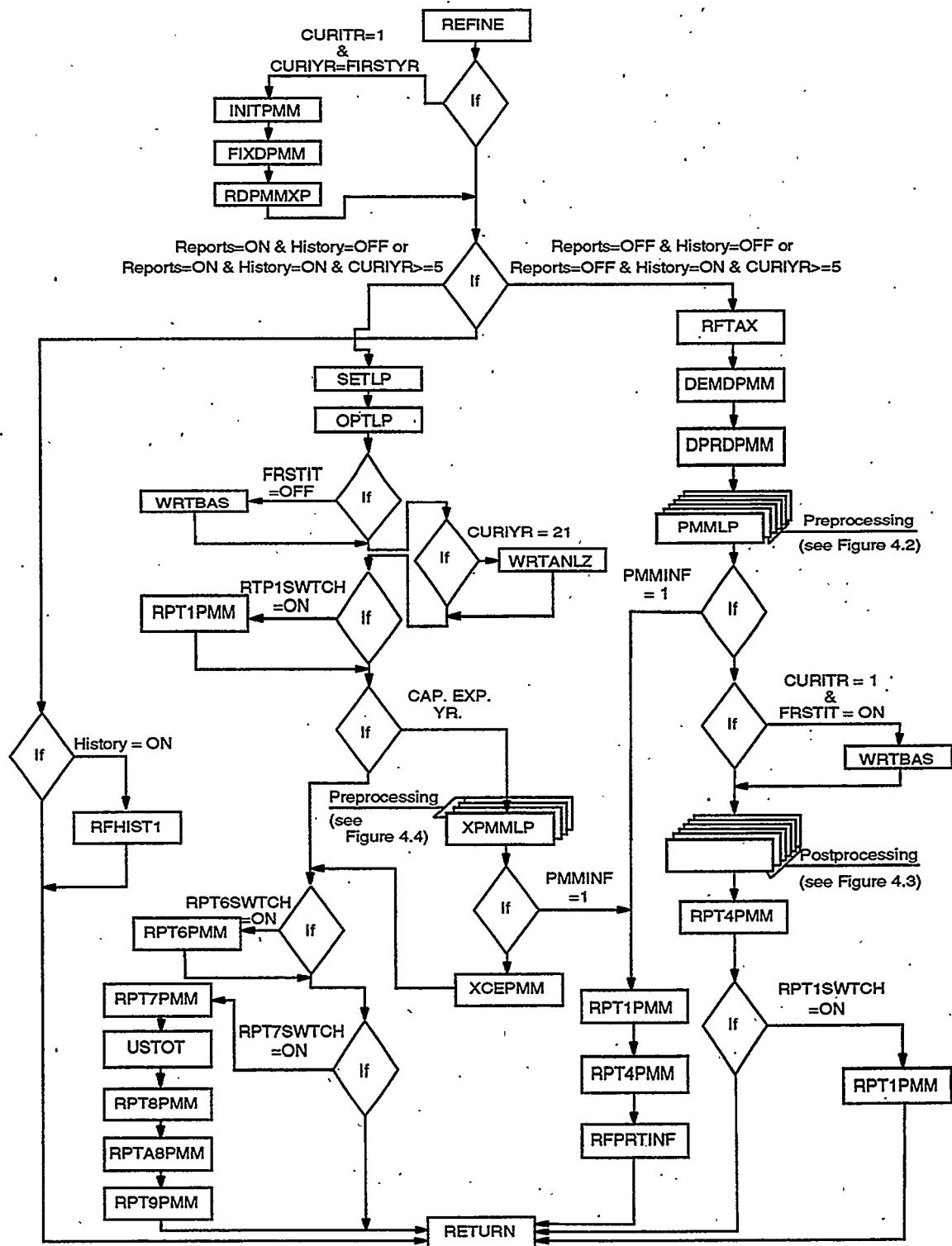
Figure 4.3 Matrix Postprocessing Subroutines

```
              │
              ▼
        ┌───────────┐
        │  PRMUPMM  │
        └───────────┘
              │
              ▼
        ┌───────────┐
        │  DSTCPMM  │
        └───────────┘
              │
              ▼
        ┌───────────┐
        │  COGNPMM  │
        └───────────┘
              │
              ▼
        ┌───────────┐
        │  ELPMMRD  │
        └───────────┘
              │
              ▼
        ┌───────────┐
        │  SULFPMM  │
        └───────────┘
              │
              ▼
        ┌───────────┐
        │  PMMRFFU  │
        └───────────┘
              │
              ▼
        ┌───────────┐
        │  RFDMDFU  │
        └───────────┘
              │
              ▼
        ┌───────────┐
        │  PMMOUTP  │
        └───────────┘
              │
              ▼
        ┌───────────┐
        │  PMMOUT2  │
        └───────────┘
              │
              ▼
        ┌───────────┐
        │  DCRDPRC  │
        └───────────┘
              │
              ▼
        ┌───────────┐
        │   DOMU    │
        └───────────┘
              │
              ▼
        ┌───────────┐
        │  RFCAPX   │
        └───────────┘
              │
              ▼
```

Figure 4.2 Matrix Preprocessing Subroutines

```
                                    ┌──────────┐
                                    │  PMMLP   │
                                    └──────────┘
                                         │
CURITR=1 & CURYR=FIRSYR                  ▼
        OR                  ┌────────┐  ◇
CURITR=1 & CURIYR=5 & HISTORY=ON │ DEFLP │◄─ If ◇
                            └────────┘   │
                                │        ▼
        MPSSWTC            ┌────┐   ┌──────────┐
        = ON             ◇ If ◇   │  SETLP   │
┌──────────┐◄─────── ◇        └──────────┘
│ MPSINLP  │              │         │
└──────────┘              ▼         ▼
                      ┌────────┐
   RFADVBAS=ON        │ LOADLP │   CURITR=1 & RFADVBAS=OFF & CURIYR=FIRSYR
       &              └────────┘            OR
    CURITR=1              ◇ If ◇    CURIYR=5 & RFHIST=ON
              ┌──────────┐     ┌──────────┐
              │ INSRTLP  │     │ INSRTLP  │
              └──────────┘     └──────────┘
```

CHGNGCRV	CHGIPRD	CHGIRAC
CHGCESW	CHGEXPRD	CHGCGCOF
ADDCAP	CHGIMTOT	EMISCOST
CHGPUBLD	CHGGSPC	CHGZ9CST
CHGDNGP	CHGUNFO	CHGZ9EXP
CHGELPR	CHGCKSU	RFROS
CHGDMDS	CHGSPRE	
CHGDCRD	CHGMETD	
CHGICRD		

RFETSWTC = ON ──► CHGETHN

PMMAVD

OPTLP

Figure 4.4 Capacity Expansion Subroutines

```
                              XPMMLP
                                 │
                                 ▼
                              SETLP
                                 │
                                 ▼
                              LOADB
                                 │
                                 ▼
                                ◇        RFETSWTC = ON
                               If ──────────────────────►  CHGETHN
                                 │                             │
                                 ▼                             │
                              CHGCESW ◄───────────────────────┘
                                 │
        ┌────────────────────────┼────────────────────────┐
        ▼                        ▼                         ▼
    CHGNGCRV                 CHGIPRD                    CHGIRAC
        │                        │                         │
        ▼                        ▼                         ▼
    CHGPUINV                 CHGEXPRD                   PMMAVD
        │                        │                         │
        ▼                        ▼                         ▼
    CHGELPR                  CHGGSPC                    CHGSPRE
        │                        │                         │
        ▼                        ▼                         ▼
    CHGDMDS                  CHGUNFO                    RFROS
        │                        │                         │
        ▼                        ▼                         ▼
    CHGDCRD                  CHGCKSU                    CHGCGCOF
        │                        │                         │
        ▼                        ▼                         ▼
    CHGICRD                  CHGMETD                    EMISCOST
        │                        │                         │
        └────────────────────────┼─────────────────────────┘
                                 ▼
                             CHGZ9CST
                                 │
                                 ▼
                             CHGZ9EXP
                                 │
                                 ▼
                              OPTLP
                                 │
                                 ▼
                             WRTBAS
                                 │
                                 ▼
```

historical values are read from an input file.

- If the history switch 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 system operations. No operations are performed because all historical data were retrieved and variables were updated on the first iteration of the first year.

- 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 input files and an optimal solution is calculated (Figures 4.1, 4.2, and 4.3). Petroleum product prices and other PMM output data are retrieved from the LP optimal solutions and output variables are updated.

- 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 using expectation values for a future year to determine processing unit expansion for the intervening years (Figures 4.1 and 4.4). The capacity expansion methodology is described in more detail below.

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 MTBE manufacture. Capacity expansion occurs by processing unit, starting from base year capacities established by PAD District 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 assume a 15-percent rate of return over a 15-year plant life. For more details on the calculation of the investment costs, refer to the Appendix F section on Refinery Investment Recovery Factors.

Expansion through 1994 is determined by adding to the existing capacities those units planned and under construction that are expected to begin operating during this time. Starting in forecast year 1995, capacity expansion is done in three year increments. For example, after the model has reached a solution for forecast year 1994, the PMM looks ahead and determines the optimal capacities given the estimated demands and prices existing in the 1997 forecast year. The PMM then allows 50 percent of that capacity to be built in forecast year 1995, 25 percent in 1996 and 25 percent in 1997. At the end of 1997, the cycle begins anew.

Additions to crude oil distillation capacity or downstream processing units are assumed to be limited due to environmental restrictions and difficulty in obtaining permits. For AEO95, a limit on capacity expansion of 600 thousand barrels per day was assumed for each refining region (for the entire forecast). Only one region, PAD District III, reached this constraint, but not until the final few years of the forecast.

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: None.

(INITPMM) Initialize variables.

Purpose: Initializes certain variables.

Equations:

$$PUCUM_{pr,pu,yr} = 0.0$$
$$PUINV_{pr,pu,yr} = 0.0$$
$$RFQDINPOT_{pr,yr} = 0.0$$
$$PRDDMD_{pr,yr,prd} = 0.0$$
$$CRDOTHOT_{pr,yr} = 0.0$$
$$CRDUNACC_{pr,yr} = 0.0$$
$$CRDSTWDR_{pr,yr} = 0.0$$
$$CRDPRDSUP_{pr,yr} = 0.0$$
$$PRDSTKWDR_{pr,yr} = 0.0$$
$$BLDIMP_{pr,yr} = 0.0$$
$$PUBASE_{pr,yr,pu} = 0.0$$
$$PUBASEUT_{pr,yr,pu} = 0.0$$

where:
   pr = 1,2,3,4,5: PAD District

pu = 1,2,...40: Processing unit identifier index

yr = 1,2,...29: NEMS year index

prd = 1,2,...20: PMM product identifier index

(FIXDPMM) Read fixed inputs.

Purpose: FIXDPMM reads in and initializes internal data required for processing the PMM.

Equations: None.

Input Files: MU1PRDS   Tax input data

MU2PPRDS   Sectoral end-use markups

QDCRDCF   Fixed Data input file

(RFHIST1) Read in history data for 1990 through 1993.

Purpose: RFHIST1 reads in history data from an external file and updates PMM output data for history years 1990 to 1993.

Equations: None.

Input File: ELCGPUR   PMM historical data input file

(RDPMMXP) Reads in the PMM specific expectation values from a input file.

Purpose: The RDPMMXP subroutine read the SPRFLRT input file and updates PMM specific expectations values. These values are used for refinery capacity planning.

Equations: None.

Input file: SPRFLRT   PMM specific expectations input file.

(RFTAX) Aggregates state and federal petroleum product taxes.

Purpose: RFTAX aggregates the states and federal petroleum taxes.

Equations: Total petroleum product tax are set at the state tax plus the nominal dollars federal tax.

(DEMDPMM) Convert system demands.

Purpose: Convert NEMS demands from trillion Btu to thousands of barrels per day for input into the refinery LP. Desegregates gasoline and distillate fuel into types. Calculates U.S. totals.

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

$$RFQ(PR)_{cd}=(((Q(PR)AS_{cd}-Q(FPR)RF_{cd})/CF(PR)Q)/365)*1000$$
$$PRDDMD_{cd,pd} = RFQ(PR)_{cd}$$

The motor gasoline share of M85 and E85 transportation fuels are also added to the total motor gasoline demands such that:

$$RFQMG_{cd}=(((QMGAS_{cd}+QMETR_{cd}*0.15+QMETR_{cd}*0.15)/CFMG\ Q/365)*1000$$

where;

$RFQ(PR)$ = product demand by Census division
$PRDDMD$ = product demand by Census division
$Q(PR)AS$ = product demand in all sectors
$Q(FPR)RF$ = product consumed for refinery fuel
$CF(PR)Q$ = conversion factor from MMBtu/bbl
(PR) = product types
(FPR) = refinery fuel products identifier
cd = Census divisions 1 through 9
pd = PAD Districts 1 through 5
0.15 = Motor gasoline share of the alternate transportation fuel
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:

$$PRDDMD_{cd,t} = RFQMG_{cd} * MGSHR_{cd,t}$$

where;

PRDDMD = product demand by Census division
t = motor gasoline product designator index, 2,3,4,5
MGSHR = motor gasoline market shares

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

Low-sulfur diesel fuel is determined as a share of transportation distillate demand (Refer to Appendix F, Estimation of Low-Sulfur Diesel Market Shares, for more details):

$$PRDDMD_{cd,14} = DSLSPLT*((QDSTR_{cd}/CFDSQ)/365)*1000$$

where;

14 = product index for low sulfur diesel (DSL)
DSLSPLT = 0.8
QDSTR = quantity of transportation distillate
CFDSQ = conversion factor for DSL MMBTU/bbl
365 = days per year
1000 = millions to thousands

Ethanol and methanol consumed in the transportation sector are assumed to

be blends of 85 percent alcohol and 15 percent gasoline. Therefore, the demand for transportation ethanol and methanol in the PMM are 85 percent of the transportation demand total, and 15 percent is added to gasoline demand. Finally, U.S. totals are calculated:

$$PRDDMD_{11,pr,yr} = \sum PRDDMD_{cd,pr,yr}$$

where;

> 11 = total U.S. demand index
> pr = product index 1 through 19
> cd = Census divisions 1 through 9
> yr = NEMS year index 1 through 21

(DPRDPMM) Estimate domestic crude oil production.

Purpose: Estimates domestic crude oil production.

Equations: Conventual domestic crude production are calculated for the nine lower 48 oil gas regions. Alaskan production and Enhanced Oil Recovery (EOR) production are obtained from the Oil Gas Supply Model (OGSM). Conventional lower 48 production is a function of wellhead price, beginning of year reserves, and the draw down rate such that:

$$RFQDCRD_{or,yr} = (OGPRRCO_{or,yr} *$$

$$((DCRWHP_{or,yr}/DCRCWHP_{or,yr-1})^{OGELSCO_{or,yr}}) *$$

$$OGRESCO_{or,yr})/365$$

and

$$DCRDWHP_{or,yr} = OLALP_{or} * (WOP_{yr}-0.50)^{OLBTA_{or}}$$

where;

RFQDCRD = conventional domestic crude production, MMbbl/cd
DCRDWHP = domestic crude well-head price
OGPRRCO = production ratio, supplied by OGSM
OGELSCO = production elasticity, supplied by OGSM
OGRESCO = beginning of year reserves, supplied by OGSM
OLALP = regression constant, supplied by OGSM
WOP = World Oil Price, supplied by International
OLBTA = Wellhead to WOP price elasticity, from OGSM
0.5 = benchmark constant to adjust WOP, supplied by OGSM
or = Oil and gas region index, 1 through 9
yr = NEMS year index, 1 through 21
365 = Day per year

Total domestic production is then calculated by adding conventional production with the EOR production such that;

$$RFQTDCRD_{or,yr} = RFQDCRD_{or,yr} +$$

$$((OGQEORPR_{or,yr}/1000)/365)$$

where;

RFQTDCRD = Total domestic production, MMbbl/cd
OGQEORPR = EOR production, MBCY, supplied by OGSM
1000 = thousands to millions
365 = days per year
or = oil and gas regions, 1 through 6
yr = NEMS year index, 1 through 21

(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 PMM basis output file

(SETLP) Activates 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) Optimizes the model.

Purpose: Optimizes the model using the OML function WFOPT.

Equations: None.

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

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

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

$$PUINV_{pd,yr+1,pu} = PUEXP_{pd,yr+3,pu} / 2$$
$$PUINV_{pd,yr+2,pu} = PUEXP_{pd,yr+3,pu} / 4$$
$$PUINV_{pd,yr+3,pu} = PUEXP_{pd,yr+3,pu} / 4$$

where;

$PUINV$ = processing unit investment bound, Mbbl/cd
$PUEXP_{pd,yr+3,pu}$ = processing unit expansion as
      determined in expansion year yr
pu = processing unit index, 1 through 27
pd = PAD District index 1 through 5
yr = NEMS index years 5,8,11,14,17,20

The decision to allow half of the expansion to come on line in the first year of each three year period was made because of problems experienced in early testing of the model. This area of the model will be more thoroughly tested and the constraint may be changed.

Processing unit cumulative builds, PUBLD is:

$$PUBLD_{pd,yr,pu} = 0; \text{ when } yr = 5$$
$$PUBLD_{pd,yr,pu} = PUBLD_{pd,yr-1,pu} + PUINV_{pd,yr-1,pu}$$

where $yr > $ NEMS index year 5
pu = processing unit index, 1 through 27
pd = PAD District index 1 through 5
yr = NEMS index years 5,8,11,14,17,20

(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

(RPT4PMM) Write report 4, PMM iteration reports.

Purpose: RPT4PMM pulls solution values from the LP using SROWLP, SCOLLP subroutines and writes to an external file PMM analyst reports during each NEMS iteration.

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

Output File: ALPHADN Iteration reports output file

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

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

Equations: None.

Output File: IMPCURV OMNI data table output file

(RPT7PMM) Write report 7, PMM forecast reports.

Purpose: RPT7PMM extracts 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

(USTOT) Calculates totals by PAD District, 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.

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

(RPT9PMM) Write report 9 to an output file.

Purpose: Writes the petroleum product wholesale product prices by PAD District and year and petroleum product demands by Census division and year.

Equations: None.

Output File: PMMRPTS PMM reports output file

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

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

(RFPRTINF) Prints "LP infeasible" message and lists infeasible rows and columns.

Purpose: RFPRPTINF prints and error message to the job unit and list row and columns that had infeasibilities.

Equations: None.

Output File: The default system output device, the screen or mainframe job unit

(WRTANLZ) Writes 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

4.2 Matrix Preprocessing Subroutines

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

(PMMLP) Solve 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.

(DEFLP) Defines and OML LP matrix model space and initializes 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) Converts a model from and MPS format file and stores it in the model database.

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

> Equations: None.

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

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

> Equations: None.

(INSRTLP)   Loads 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.

(CHGCESW) Update Capacity Expansion Switch.

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

>   Equations: None.

(CHGNGCRV) Updates the natural gas supply curve for refinery fuel use.

>   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 curve is set at fifty 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 eighty 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 point 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 points of the supply curve and the sum of activity levels on all points of the supply curve from the previous NEMS iteration solution. If the upper bound on the first point of the supply curve, just described falls below the lower bound on the first point of the curve, then the upper bound is set at value one percent above the lower bound on the first point of the curve.

(ADDCAP) Update Capacity.

Purpose: ADDCAP changes the capacity expansion investment and build bounds using the CBNDLP subroutine with values obtained from the XCEPMM subroutine. The upper investment bounds on the aromatics recovery processing unit (ARP) are set at 1000 MBCD during years seven and nine in PAD District five to alleviate the bottleneck on processing unit expansion inherent with the three year look-ahead methodology.

Equations: None.

(CHGPUBLD) Limit 1994 Capacity Expansion.

Purpose: Processing unit capacities in the PMM start from a 1994 base, which includes units under construction that are planned to be operational by the end of 1994. Therefore, no capacity expansion is allowed in 1994. This subroutine sets the 1994 expansion limits at zero by using the CBNDLP subroutine.

Equations: None.

(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: The industrial interruptable price of natural gas is used for the prices of gas to refineries in PAD Districts I and V. PAD District III refinery natural gas prices are calculated as the quantity weighted average natural gas well-head price in NGTDM regions two, four, and eight. Natural gas well-head prices in NGTDM regions three and five are used for PAD Districts II and IV respectively. These prices are converted to $/MCF. During the capacity expansion iteration the expected industrial interuptable price of natural gas and expected domestic production of natural gas is used as inputs into the LP matrix.

(CHGELPR) Update electricity costs.

Purpose: CHGELPR updates the cost of electricity in each of the five PAD Districts 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 five PAD Districts.

Equations: Industry price of electricity is mapped from Census division to PAD District and units are converted to kWh.

(CHGDMDS) Update product demands for the LP.

Purpose: CHGDMDS sets the upper and lower bounds for product demands. For all products except petroleum coke and "other," the upper and lower bounds are equal. The bounds are set at the level of demand for each product in each Census division. For petroleum coke and "other," the lower bound is zero and the upper bound is product demand in the Census division and year. This was done to provide more refining production flexibility and minimize infeasibilities. During the capacity expansion iteration the CHGDMDS updates bounds using the expected demands variables.

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: Conventional and Enhanced Oil Recovery (EOR) production are combined for the total U.S. crude production and units are converted to Mbbl/cd.

(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.

Equations: The International Model provides imported crude supply curves for each PAD District and five crude types to the PMM. These imported crude supply curves represent three price-quantity relationships for each imported crude in each PAD District. The second and third quantity steps for each supply curve are incremental supply volumes. The prices related to these incremental supply volumes are absolute prices. Additional volumes listed below are added to the third step of the of the imported crude supply curve for the high sulfur light (HL) crude in each PAD District. The values are estimated based on analyst judgement to satisfy expected imported crude demand. During the capacity expansion look ahead iteration CHGICRD updates imported supply curve bounds with the expected imported crude supply variables.

> PAD District I: 100 Mbbl/cd
> PAD District II: 50 Mbbl/cd
> PAD District III: 1000 Mbbl/cd
> PAD District IV: 99 Mbbl/cd
> PAD District V: 900 Mbbl/cd

(CHGIPRD) Update imported product supply curves.

Purpose: CHGIPRD updates LP imported product supply curves using values passed from the International Model.

Equations: The International Model provides imported product supply curves to the PMM for each product and each PAD District. These imported product supply curves represent price-quantity relationships for each imported product. The second and third quantity steps on the supply curves are incremental supply volumes. The prices related to these incremental supply volumes are absolute prices. Additional volumes are added to third imported product supply curve step volume for liquid petroleum gas (LPG) at 100 Mbbl/cd respectively. Low sulfur distillate (DSL) is set at $1.95/bbl and $3.01/bbl above the price of No. 2 Heating Oil (N2H) in PAD Districts one through four and PAD District five respectively, which is the midrange of the expected cost increase for low sulfur diesel fuel. PAD District five prices for reformulated gasoline (RFG) are set at $4.72/bbl above the traditional imported motor gasoline price in PAD District five. PAD District five prices for MTBE are set at $5.252/bbl above the traditional imported motor gasoline price in PAD District five. PAD District five prices for low sulfur diesel (DSL) are set at $3.01/bbl above the No. 2 distillate (N2H) imported price in PAD District five. PAD District one through four prices for low sulfur diesel (DSL) are set at $1.95/bbl above the No. 2 distillate (N2H) imported price in PAD Districts one through four respectively. PAD Districts one through four prices for MTBE are set at $2.84/bbl above the traditional imported motor gasoline price in PAD Districts one through four respectively. The supply curve prices in PAD District five for traditional gasoline (TRG), jet fuel (JTA), No. 2 distillate (N2H), and high sulfur residual fuel (N6B) are increased by $2.41/bbl, $ 1.27/bbl, $ 1.03/bbl, and $1.03/bbl respectively.

(CHGEXPRD) Update total exported product.

Purpose: CHGEXPRD updates the total product export LP constraint by using the CRHSLP subroutine.

Equations: Total product exports are related to total petroleum product demand and inversely related to total imported petroleum products such that:

$$PRDEXP = (5.21E\text{-}08\ /TOTPRDIMP^{1.51}) * ((TOTPRDDMD^{3.51}) * 1E06)$$

where,

PRDEXP = Total product exports

5.21E-08 = Log intercept

TOTPRDIMP = Total petroleum product imports

TOTPRDDMD = Total petroleum product demands

3.51 = Regression coefficient

1E06 = Unit conversion

(CHGIMTOT) Update total product imported constraint.

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

Equations: Set to 9900 Mbbl/cd. This value is based on analyst judgement and is currently set high enough that the constraint is not expected to be reached.

(CHGGSPC) Updates the motor gasoline specifications.

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

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:

$$ARB_{yr} = 1.1 * WOP_{yr}$$
$$NPP_{yr} = 1.2 * WOP_{yr}$$
$$HGM_{yr} = 1.15 * WOP_{yr}$$

where

> ARB = Atmospheric residual type B cost
> NPP = Naphta parafinic cost
> HGM = heavy gas oil medium sulfur cost
> WOP = World oil price
> yr = NEMS year, 1 through 21

(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 costs 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 cost of coke. Distress export of petroleum coke cost is set at 10.0 percent of the high sulfur coke costs. A similar approach is used for sulfur, with a cost of $90/ton transformed into value of 5.0 times the WOP.

(CHGSPRE) Change Strategic Petroleum Reserve (SPR) and Crude Oil Exports for the LP.

Purpose: Sets the upper and lower bounds for SPR additions and crude oil exports. For both items, the upper and lower bounds are equal and are set using the CBNDLP subroutine. They are set as exogenous inputs to the program.

Equations: None.

(CHGMETD) Change methanol demand for the LP.

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

Equations: None.

(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 PAD District are updated and the minimum and maximum tolerance for the average acquisition cost are set $1.99/bbl. This value was chosen based on analyst judgement.

(CHGCGCOF) Updates the cogeneration sales to grid coefficients for the cogeneration procssing unit.

Purpose: Updates the cogeneration sales to grid coefficients using the CVALLP subroutine for the cogeneration procssing unit.

Equation: $COEF_{cd,yr} = CNST_{cd} * PELAS_{cd,yr}$

where:
COEF = sales to grid coefficient
CNST = Percentage constant, 0.8368, 0.0009, 0.3090, 0.7170, 0.6025 for each PAD District I-V respectively.
PELAS = Prices of electricity to all sectors
cd = census division index
yr = year index

(CHGETHN) Update ethanol supply curves in LP.

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.

Equations: Ethanol supply curve data are only available for Census divisions 3 and 4. In addition, the supply curves for Census divisions 3 and 4 have data

for only the last four steps of the supply curve. The ethanol supply curve quantity units are converted to Mbbl/cd and the supply curve steps are converted from absolute quantities to differential step quantities.

(EMISCOST) Updates the refinery emission cost vector.

Purpose: Update the input cost of the vector of the burning petroleum products in the refinery using the CVALLP subroutine.

Equations: Emission input costs are set at value determine by the Emission Policy Module.

(CHGZ9CST) Updates 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 time the WOP.

(CHGZ9EXP) Updates 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 ten percent of the WOP.

(RFROS) Updates the renewable oxygenates constraint.

Purpose: RFROS update the renewable oxygenates constraints for motor gasoline using the CVALLP subroutine.

Equations: The motor gasoline minimum renewable oxygenates constraints are set at zero, fifteen, and thirty percent for the NEMS years 1994, 1995, 1996

and beyond respectively.

(PMMAVD) Update PMM supply curve avoids.

Purpose: PMMAVD updates the demand shift structure for six petroleum products: liquid petroleum gas (LPG), jet fuel, (JTA), No. 2 heating oil (N2H), No. 6 low sulfur residual (N6I), No. 6 high sulfur residual (N6B), reformulated motor gasoline (RFG), other (OTH), and petrochemical feedstocks (PCF). The demand shift structure was implemented to assist in convergence by prohibiting small product demand fluctuations to severely influence product prices.

Equations: Po_j = price of the product j

$$Pp_{i,j} = Po * (1 - PK_{i,j})$$

$$Pn_{i,j} = Po * (1 + PK_{i,j})$$

Qo_j = demand for the product j

$$Qn_{i,j} = Qo_j * (Pn_{i,j}/Po_j)^{-AVDBTA_j}$$

$$Qp_{i,j} = Qo_j * (Pp_{i,j}/Po_j)^{-AVDBTA_j}$$

where;

i = demand shift curve points, 1, 2, and 3

j = product index, 1 through 19

PK_i = price shift for i, 0.01, 0.03, 0.09
$Pp_{i,j}$ = positive price shift
$Pn_{i,j}$ = negative price shift
$Qp_{i,j}$ = positive quantity shift

$Qn_{i,j}$ = negative quantity shift

$AVDBTA_j = 0.1$ demand shift elasticity for products TRG, JTA, N2H, DSL, RFG

$AVDBTA_j = 0.3$ demand shift elasticity for products OTH, PCF, N67, N68, LPG, N6I, N6B

4.3 Matrix Postprocessing Subroutines

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

(PRMUPMM) Add refinery fixed costs.

<u>Purpose:</u> 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.

<u>Equations:</u> Refinery fixed costs are added to the marginal prices of each product:

$$P_{pr,cd} = VALUE_{pr,cd} + RFPRDFX_{pr,cd} * FXPCT$$

where:

P = refinery gate price of petroleum product pr

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. Fix cost are allocated only at 30, 50, 70, 90, and 100 percent during the years 1994 to 1998 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

Wholesale prices of residual fuel are determined as a function of WOP and residual demand fraction such that:

$$P_{pr,cd} = 42 * (INTCP + SLP * (WOP/42) + (CNSNT * ((QRL + QRH)/QPRD)))$$

where:

P = refinery gate price of low and high sulfur residual fuel

INTCP = -0.57507 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

cd = Census division

42 = gallons per barrel

Demands for all four types of gasoline are summed by Census division:

$$MGDMD_{cd} = \sum_{t=2,3,4,5} PRDDMD_{cd,t}$$

where:

cd = Census division 1 through 9

t = motor gasoline index type 2,3,4,5

A national gasoline total is estimated by summing Census division totals:

$$MGDMD_{us} = \sum_{cd=1,9} MGDMD_{cd}$$

where:

us = U.S. total index 11

cd = Census division 1 through 9

National demand for each type of gasoline is estimated by:

$$\text{MGDMD}_{pr} = \sum_{cd=1,9} \text{MGDMD}_{pr,cd}$$

where:
pr = motor gasoline index 2,3,4,5
cd = Census division 1 through 9

A weighted average gasoline price is calculated for each Census division based on prices of the various types of gasoline:

$$\text{PALMG}_{cd} = \sum_{pr=2,3,4,5} ((\text{PMGDMD}_{pr,cd} * \text{PRDDMD}_{pr,cd})/\text{MGDMD}_{pr})$$

where:
pr = motor gasoline index 2,3,4,5
cd = Census division 1 through 9

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

$$P_{pr,t} = \sum_{cd=1,9} (P_{pr,cd} * \text{PRDDMD}_{pr,cd})/\text{PRDDMD}_{pr,t}$$

where:
pr = petroleum product index 1 through 19
cd = Census division 1 through 9
t = total product demand index, 11, for product pr

A composite national average gasoline price is estimated by:

$$\text{PALMG}_{t} = \sum_{pr=2,3,4,5} (\text{PMG}_{pr} * \text{MGDMD}_{pr}/\text{PRDDMD}_{pr,t})$$

where:
PMGDMD = motor gasoline price
PRDDMD = product demand
MGDMD = motor gasoline demand
P = price of product
PMG = price of motor gasoline of type pr
pr = product index

cd = Census division

t = national total index

(DSTCPMM) Estimate distillation capacity and refinery utilization.

Purpose: Extracts capacity expansion information from LP. Estimates annual distillation capacity, utilization and annual and cumulative capacity expansion. Totals PAD District estimates to national estimates.

Equations: Refinery distillation capacity is taken at ninety percent total capacity to account for over optimization and in the LP. Units are converted to MMBCD and U.S. total are determined.

(COGNPMM) Estimate refinery cogeneration.

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

Equations: Results are shared out to Census divisions, fuel categories, and self or grid categories. U.S. and PAD District totals are calculated.

Electricity sales to grid are estimated in kWh:

$$RFCGGRIDPD_P = RFCGGENPD_P * PCGRDPD_P$$

Electricity used by refineries is estimated in kWh:

$$RFCGSELFPD_P = RFCGGENPD_P - RFCGGRIDPD_P$$

Estimates are converted to trillion Btu. PAD District level estimates for cogeneration, cogeneration 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, generation are desegregated by fuel

type and by generation to grid versus to self. Census division estimates are summed to U.S. totals.

(ELPMMRD) Calculate electricity consumption data.

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

Equations: Convert units to KWh and desegregates PAD District data to the Census divisions.

(SULFPMM) Estimate sulfur allowances.

Purpose: Estimates sulfur allowances awarded to small diesel refiners for years 1993 through 1999.

Equations: Calculate the possible allowance volumes from small refiners eligible for allowances in million barrels per year:

$$PAV = (QDSAS/CFDSQ) * 0.128 * 0.59$$

where:

QDSAS is the quantity of distillate produced
CFDSQ is distillate conversion factor MMBtu/bbl

The ratio factor 0.128 represents the proportion of distillate produced at small refineries and 0.59 represents the proportion of distillate that is diesel fuel.

Possible allowance volumes (PAV) are converted to possible allowance weight (PAW):

$$PAW = PAV * 302/2000$$

Requested allowances (REQALLOW) are estimated based on the weight of possible allowances:

$$REQALLOW = PAW * 0.00224 * 1000000 * 2$$

Refiner's sulfur allowances (RFSAL) are set equal to the minimum of the estimated amount (REQALLOW) or maximum allowable amount of 35,000.

$$RFSAL = MIN (REQALLOW,35000)$$

Allowances for 1993 are calculated as one-fourth of RFSAL due to the October 1993 start date.

(PMMRFFU) Estimate refinery fuel use.

Purpose: Estimates refinery consumption of distillate, residual fuel, coal, LPG's, natural gas, still gas, petroleum coke, and other petroleum products by PAD District.

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

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

Purpose: Converts PAD District level estimates for refinery consumption to Census division demands.

Equations: Calculates refinery fuel consumption in each Census division based on PAD District estimates.

(PMMOUTP) Update the Common Block Variables

Purpose: Updates a number of NEMS common block price and volume variables whose values are determined by output of the PMM LP. This subroutine is run at 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. Then 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.

(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 PAD District. 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 PAD District 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. For instance, the common block variable to be updated may be LPG production for PAD District I. Then the solution activity for the LP row that controls LPG production volume in PAD District I is accessed from the LP solution area and the corresponding common block variable is set equal to that value.

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

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

Equations: None.

(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 the other for transportation costs, to the refinery gate 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.

(RFCAPX) Calculate refinery capital expenditure.

Purpose: RFCAPX calculates refinery capital expenditure.

Equations: $RFREV_{yr} = RFREV_{yr-1} * 1.023$

where:

RFREV = refinery revenue
yr = NEMS year
1.023 = growth rate

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.

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

Purpose: XPMMLP calls 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 processing unit investment capacities bounds.

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

Equations: Processing unit investments are upper bounded by 1000 Mbbl/cd and cumulative builds are fixed bounded based on the processing unit builds to date.

The remainder of the subroutines in figure 4.4 have been presented in section 4.2, the matrix preprocessing subroutine.

4.5 OML Specific Subroutines

Additional subroutines used to perform OML specific matrix operations during the matrix pre and post processing are presented below.

(CBNDLP) Updates 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) Retrieves LP column name.

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

> Equations: None.

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

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

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

> Equations: None.

> Data Passed: COLNAME, column name, RHSVAL, right hand value

(CVALLP) Updates 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

(PUNCHLP) Saves the current basis to a file.

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

Equations: None.

(RBNDLP) Retrieves 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) Retrieves 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) Retrieves solution column values from the LP solution.

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

<u>Equations:</u> None.

<u>Data Passed:</u>   COLNAME, column name, SLCT selected range, STATC, status value,VALUE, values

(SROWLP) Retrieve the current solution row from memory.

<u>Purpose:</u> 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.

<u>Equations:</u> None.

APPENDIX A

PMM Model Data, Parameters, and Outputs

APPENDIX A   PMM Data and Outputs

A.1   PMM Variables and Data Sources

This appendix is divided in two parts; Section A.1 lists the variables and definitions used in the PMM, Section A.2 lists the data tables and their sources used in the creation of the initial PMM matrix that is loaded to 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.

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.

Table A1.   PMM/NEMS Cross References

PMM LP Variable	LP Units	NEMS Variable
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@METS1	Mbbl/cd	PRDDMDMD
O@CRDEXP	Mbbl/cd	RFQEXCRD
O@CRDSPR	Mbbl/cd	RFSPRFR
U (pd) KWH	$87/kWh	PELIN
C (cd) ETHR (q(k))	Mbbl/cd,$87/bbl	WQETOH, WPETOH
N (pd) DGP	Bcf/day	PRNG_PADD
U (pd) NGF	$87/MMcf	PGININ, OGWPRNG
P (og) DCRQ1	Mbbl/cd	RFQDCRD, OGQEORPR
A@INVST	MM$87/Yr	Constants 0 or 50000
A@PRDIMP	Mbbl/cd	Constant 9900
P (pd) PFU	MFOED	PRPFU
P (pd) PFF	MFOED	PRPFF
E (pd) (prcunit)INV	Mbbl/cd	PUINV, or Constants of 0, 1000
L (pd) (prcunit)BLD	Mbbl/cd	0.0 PUCUM PUINV
P(pd)F(crdtype)Q(q(k)	Mbbl/cd,$87/bbl	Q_ITIMCRSC, FHLADD, P_ITIMCRSC
D (cd) (prd) Z9	$87/bbl	ITIM??SC DISTPRC WHERE ?? = LG GS RF LD DS RL RH JF OT PF
I(pd)(iprd)R(q(k))	Mbbl/cd,$87/bbl	ITIM??SC WHERE ?? = LG GS RF LD DS RL RH JF OT PF

PMM LP Variable	LP Units	NEMS Variable
A@PRDEXP	Mbbl/cd	Constant 879
D (cd)(prd) SX	Mbbl/cd $87/bbl	No change
Q(pd)(prd)(spec)(minmax)	Many	MGSPCS
T (pd) UNFNPP	$87/bbl	IT_WOP, NPPCOEF
T (pd) UNFHGM	$87/bbl	IT_WOP, HGMCOEF
T (pd) UNFARB	$87/bbl	IT_WOP, ARBCOEF
X (pd) CKLCOK	$87/bbl	IT_WOP, PCOKL
X (pd) CKHCOK	$87/bbl	IT_WOP, PCOLH
X (pd) SULSAL	$87/bbl	IT_WOP, SULSAL
D (cd) COKZ9	$87/bbl	IT_WOP, PCOKH, PRCPCNT
D (cd) COKSX	$87/bbl	IT_WOP, PCOKH
Z@IRACX	$87/bbl	IT_WOP
Z@IRACN	$87/bbl	IT_WOP
Z@TOTCRD	$87/bbl	IT_WOP, IRACN, IRACX
D (cd) (prd)	$87/bbl	P(prd) or constant 0.99
K (pd) ACUCAP	Mbbl/cd	DSTCAP, DSTUTL
E (pd) ACUINV	Mbbl/cd	RFDSTCAP, RFDSTUTL
L (pd) ACUBLD	Mbbl/cd	RFDSTCAP, RFDSTUTL, RFDSCUM
A (pd) (prd)	Mbbl/cd	RFDPRD(prd)
A@CRDFCR	Mbbl/cd	RFQICRD
A@PRDIMP	Mbbl/cd	RFPQIPRDT
A@UNFIMP	Mbbl/cd	RFQUFC
A@PRDDEM	Mbbl/cd	RFQPRDT
A@PRDEXP	Mbbl/cd	RFQEXPRDT
A@NGLPRD	Mbbl/cd	RFPQNGL
A@GAIN	Mbbl/cd	RFQPRCG
A@NGLRFN	Mbbl/cd	RFQNGLRF
A@PETCOK	Mbbl/cd	RFQPRCG
A@SULSAL	Mbbl/cd	RFQPRCG
A@FUEL	Mbbl/cd	QCDUUPD
P (pd) COK	Mbbl/cd	QCDUPD
A@INVST	MM$87/Yr	RFCAPEXP
A@ETHPRD	Mbbl/cd	RFQDINPOT RFETHD
A@MTBIMP	Mbbl/cd	RFQDINPOT RFMTBI
A@METIMP	Mbbl/cd	RFQDINPOT RFMETI
G (pd) MOH01	Mbbl/cd	RFQDINPOT RFMETD
A@METDEM	Mbbl/cd	RFQDINPOT RFMETCHM
A@METM85	Mbbl/cd	RFQDINPOT RFMTBM85
A@CRDDCR	Mbbl/cd	RFCRDDCR
A@CRDL48	Mbbl/cd	RFCRDL48
A@CRDAKA	Mbbl/cd	RFCRDAKA
A@CRDTOT	Mbbl/cd	RFCRDTOT
A@NGFTOT	Mbbl/cd	RFNGFTOT
R (pd) ETHMTB	Mbbl/cd	RFMTBD
R (pd) ACUF (crdtype)	Mbbl/cd	RFIPQC(crdtype)
C (pd) F (crdtype)	$87/bbl	RFIPQC(crdtype)
I (pd) (iprd) R (q(k))	$87/bbl,Mbbl/cd	RFIPQ(iprd)
R (pd) FUMN2H	Mbbl/cd	QDISFU
R (pd) FUMN6I	Mbbl/cd	QRESFU
R (pd) FUMN6B	Mbbl/cd	QRESFU
R (pd) FUMCC3	Mbbl/cd	QLPGFU
R (pd) FUMC2E	Mbbl/cd	QLPGFU
R (pd) FUMUC3	Mbbl/cd	QLPGFU
R (pd) FUMIC4	Mbbl/cd	QLPGFU
R (pd) FUMUC4	Mbbl/cd	QLPGFU
R (pd) FUMPGS	Mbbl/cd	QSTGFU
R (pd) FUMNC4	Mbbl/cd	QLPGFU
R (pd) FUMNGS	Mbbl/cd	QNTGFU
R (pd) FUMPGT	Mbbl/cd	QSTGFU
R (pd) FUM (rfothfu)	Mbbl/cd	QOTHFU
P (pd) COK	Mbbl/cd	QCOKFU
K (pd) STGCAP	MMlb/Day	RFSTEAM
D (cd) (prd)	$87/bbl	PVALUE

PMM LP Variable	LP Units	NEMS Variable
C (pd) D (crdtype)	$87/bbl	PCRDRF
C (pd) F (crdtype)	$87/bbl	PCRDRF
C (pd) ALL	$87/bbl	PCRDRF
C (pd) AMH	$87/bbl	PCRDRF
R (pd) ACUF (crdtype)	Mbbl/cd	QCRDRF
R (pd) ACUD (crdtype)	Mbbl/cd	QCRDRF
R (pd) ACUA (crdtype)	Mbbl/cd	QCRDRF
G (pd) DGR	Bcf	QGPLTRF
G (pd) GPL01	Bcf	QGPLTRF
G (pd) PGSLPG	Mbbl/cd	QGPLTRF
G (pd) SC2CC1	Mbbl/cd	QGPLTRF
G (pd) SC3CC1	Mbbl/cd	QGPLTRF
G (pd) IC4RFN	Mbbl/cd	QGPLTRF
G (pd) NC4RFN	Mbbl/cd	QGPLTRF
G (pd) NATRFN	Mbbl/cd	QGPLTRF
D (cd) (prd) SX	Mbbl/cd	QPRDEX
D (cd) (prd) Z9	Mbbl/cd	QPRDEXD
A@ZZIMP	Mbbl/cd	QPRDIMD
E (pd) (emissn) (emisst)	MMton	RFEMISST
R (pd) FUM (pnfut)	Mbbl/cd	RFFMT

Legend for Codes

Code	Name	Values	No. in Set
(cd)	Census Divisions	1-9	9
(og)	Oil and Gas Divisions	1-6,A	7
(prd)	Products	LPG-M85	20
(q(k))	Quantities	1-9	9
(prcunit)	Process Units	ACU-PFA	37
(crdtype)	Crude Types	LL-HV	5
(iprd)	Imported Products	LPG-DSL	12
(spec)	Product Specificatons	RV-BZ	6
(minmax)	Minimum or Maximum	N,X	
(emissn)	Emissions	VOC-CAR	6
(emisst)	Combustion/Noncombustion	C,N	
(pnfut)	Refinery Fuels	NGS-JNH	30
(rfothfu)	Refinery Fuel for Other	JIH-NPN	19
LG	Imported product	LPG	
GS	Imported product	Traditional mogas	
RF	Imported product	Reformulated mogas	
LD	Imported product	Low sulfur diesel	
DS	Imported product	Distillate	
RL	Imported product	Low sulfur residual	
RH	Imported product	High sulfur residual	
JF	Imported product	Jet Fuel	
OT	Imported product	Other	
PF	Imported product	Petrochemical Feeds	

A.1.2 PMM Output Variables

REFINERY MODULE OUTPUT VARIABLES

NAME	UNITS	DEFINITION
RFREV(MNUMYR)	MM87$87/Day	Refinery revenues
RFQPRDT(MNUMCR, MNUMYR)	MMbbl/cd	Total product supplied
RFQDCRD(MNUMOR+2,MNUMYR)	MMbbl/yr	Domestic conventional crude
RFSPRFR(MNUMYR)	MMbbl/cd	Rf spr fill rate
RFSPRIM(MNUMYR)	MMbbl/cd	Spr imports
RFCAPEXP(MNUMYR)	MM$87/Day	Rf capital expenditures
RFSAL(MNUMYR)	Tons/yr	Sulfur allowances
RFPQNGL(MNUMPR,MNUMYR,6,2)	$87/bbl,Mbbl/cd	Prc/quan of ngl by PAD district

NAME	UNITS	DEFINITION
RFQDINPOT(MNUMPR,MNUMYR)	MMbbl/cd	Quantity other input to refin.
RFQPRCG(MNUMPR,MNUMYR)	MMbbl/cd	Quantity of processing gains
PCTPLT_PADD(MNUMPR,MNUMYR)	BCF	Gas plant fuel cons./Total NG production
DCRDWHP(MNUMOR,MNUMYR)	$87/bbl	Dometic crude wellhead price
XDCRDWHP(MNUMOR,MNUMYR)	$87/bbl	Expected domestic crude wellhd price
XRFQDCRD(MNUMOR,MNUMYR)	MMbbl/yr	Expected domestic crude production
RFQTDCRD(MNUMOR+2,MNUMYR)	MMbbl/yr	Total domestic crude (incl EOR)
RFDCRDP(MNUMOR,MNUMYR,5)	$87/bbl	Domestic crude price by crude type

REFINERY REPORT OUTPUT VARIABLES

NAME	UNITS	DEFINITION
RFELPURPD(MNUMPR,MNUMYR)	$87/kWh	Electricity purchased by PAD District
RFCGCAPCD(MNUMCR,NMUMYR)	mW	Cogen. capacity by Cen. Div.
RFCGCAPPD(MNUMPR,MNUMYR)	mW	Cogen. capacity by PAD District
RFCGCAPPADDPD(MNUMPR,MNUMYR)	kW/yr	Cogen. capacity by PAD District
RFDSTCAP(MNUMPR,MNUMYR)	Mbbl/cd	Refinery distillation capacity
RFDSTUTL(MNUMPR,MNUMYR)	Percent	Capacity utilization rate
RFIPQCLL(MNUMPR,MNUMYR,2)	$87/bbl,Mbbl/cd	Import crude-low sulfur light (P,Q)
RFIPQCMH(MNUMPR,MNUMYR,2)	$87/bbl,Mbbl/cd	Import crude-medium sulfur heavy
RFIPQCHL(MNUMPR,MNUMYR,2)	$87/bbl,Mbbl/cd	Import crude-high sulfur light
RFIPQCHH(MNUMPR,MNUMYR,2)	$87/bbl,Mbbl/cd	Import crude-high sulfur heavy
RFIPQCHV(MNUMPR,MNUMYR,2)	$87/bbl,Mbbl/cd	Import crude-high sulfur very heavy
RFIPQMG(MNUMPR,MNUMYR,2)	$87/bbl,Mbbl/cd	Imports motor gasoline (P,Q)
RFIPQDS(MNUMPR,MNUMYR,2)	$87/bbl,Mbbl/cd	Imports distillate (P,Q)
RFIPQRL(MNUMPR,MNUMYR,2)	$87/bbl,Mbbl/cd	Imports low sulfur resid (P,Q)
RFIPQRH(MNUMPR,MNUMYR,2)	$87/bbl,Mbbl/cd	Imports high sulfur resid (P,Q)
RFIPQJF(MNUMPR,MNUMYR,2)	$87/bbl,Mbbl/cd	Imports jet fuel (P,Q)
RFIPQLG(MNUMPR,MNUMYR,2)	$87/bbl,Mbbl/cd	Imports lpg (P,Q)
RFIPQME(MNUMPR,MNUMYR,2)	$87/bbl,Mbbl/cd	Imports methanol (P,Q)
RFIPQMT(MNUMPR,MNUMYR,2)	$87/bbl,Mbbl/cd	Imports mtbe (P,Q)
RFIMCR(MNUMPR,MNUMYR)	MMbbl/YR	Crude net imports
RFIMTP(MNUMPR,MNUMYR)	MMbbl/YR	Total prod net imports
RFQMG(MNUMCR,MNUMYR)	MMbbl/cd	Quantity of motor gasoline
RFQDS(MNUMCR,MNUMYR)	MMbbl/cd	Quantity of distillate fuel oil
RFQJF(MNUMCR,MNUMYR)	MMbbl/cd	Quantity of jet fuel
RFQRL(MNUMCR,MNUMYR)	MMbbl/cd	Quantity of resid low sulfur
RFQRH(MNUMCR,MNUMYR)	MMbbl/cd	Quantity of resid high sulfur
RFQLG(MNUMCR,MNUMYR)	MMbbl/cd	Quantity of lpg
RFQPF(MNUMCR,MNUMYR)	MMbbl/cd	Quantity of petrochem feedstocks
RFQKS(MNUMCR,MNUMYR)	MMbbl/cd	Quantity of kerosene
RFQOTH(MNUMCR,MNUMYR)	MMbbl/cd	Quantity of other
RFQARO(MNUMCR,MNUMYR)	MMbbl/cd	Quantity of asphalpt and road oil
RFQSTG(MNUMCR,MNUMYR)	MMbbl/cd	Quantity of still gas
RFQPCK(MNUMCR,MNUMYR)	MMbbl/cd	Quantity of petroleum coke
RFPQIPRDT(MNUMPR,MNUMYR,2)	$87/bbl,MMbbl/cd	Total imported product
RFQEXPRDT(MNUMPR,MNUMYR)	MMbbl/cd	Total product exported
RFQEXCRD(MNUMPR,MNUMYR)	MMbbl/cd	Crude exported
RFQICRD(MNUMPR,MNUMYR)	MMbbl/cd	Imported total crude
RFPQUFC(MNUMPR,MNUMYR,2)	MMbbl/cd	Total imports of unfinished crude
RFQIN(MNUMYR)	MMbbl/cd	Industrial product demand
RFQTR(MNUMYR)	MMbbl/cd	Transportion product demand
RFQRC(MNUMYR)	MMbbl/cd	Residential/Commercial product demand
RFQEL(MNUMYR)	MMbbl/cd	Utility product demand
RFQSECT(MNUMYR)	MMbbl/cd	Total sectoral demand
RFDPRDLPG(MNUMPR,MNUMYR)	Mbbl/cd	Refinery production; LPG
RFDPRDTRG(MNUMPR,MNUMYR)	Mbbl/cd	Refinery prd; motor gasoline
RFDPRDRFG(MNUMPR,MNUMYR)	Mbbl/cd	Refinery prd; reformulated mogas
RFDPRDTRH(MNUMPR,MNUMYR)	Mbbl/cd	Refinery prd; high oxygenated mogas
RFDPRDRFH(MNUMPR,MNUMYR)	Mbbl/cd	Refinery prd; reform. hi oxyg. mogas
RFDPRDJTA(MNUMPR,MNUMYR)	Mbbl/cd	Refinery prd; jet fuel
RFDPRDKER(MNUMPR,MNUMYR)	Mbbl/cd	Refinery prd; kerosene

NAME	UNITS	DEFINITION
RFDPRDN2H(MNUMPR,MNUMYR)	Mbbl/cd	Refinery prd; no. 2 distillate
RFDPRDN6I(MNUMPR,MNUMYR)	Mbbl/cd	Refinery prd; low sulfur resid oil
RFDPRDN6B(MNUMPR,MNUMYR)	Mbbl/cd	Refinery prd; high sulfur oil
RFDPRDOTH(MNUMPR,MNUMYR)	Mbbl/cd	Refinery prd; other petroleum
RFDPRDPCF(MNUMPR,MNUMYR)	Mbbl/cd	Refinery prd; petrochemical feeds
RFDPRDAST(MNUMPR,MNUMYR)	Mbbl/cd	Refinery prd; asphalt & road oil
RFDPRDDSL(MNUMPR,MNUMYR)	Mbbl/cd	Refinery prd; low sulfur diesel
RFDPRDSTG(MNUMPR,MNUMYR)	Mbbl/cd	Refinery prd; still gas
RFDPRDCOK(MNUMPR,MNUMYR)	Mbbl/cd	Refinery prd; petroleum coke
RFDSCUM(MNUMPR,MNUMYR)	MMbbl/cd	Processin unit cumulative cap. expansion
RFBDSTCAP(MNUMPR,MNUMYR)	MMbbl/cd	Refinery base distillation capacity
RFETHD(MNUMYR)	MMbbl/cd	Domestic ethanol
RFMETD(MNUMYR)	MMbbl/cd	Domestic methanol
RFMETCHM(MNUMPR,MNUMYR)	MMbbl/cd	Chem. Demand for methanol
RFIPQRG(MNUMPR,MNUMYR,2)	$87/bbl,Mbbl/cd	Imported reformulated mogas (P,Q)
RFIPQOT(MNUMPR,MNUMYR,2)	$87/bbl,Mbbl/cd	Imported other (P,Q)
RFIPQPF(MNUMPR,MNUMYR,2)	$87/bbl,Mbbl/cd	Imported petrochem feeds (P,Q)
RFIPQDL(MNUMPR,MNUMYR,2)	$87/bbl,Mbbl/cd	Imported low sulfur distillate (P,Q)
RFCRDOTH(MNUMPR,MNUMYR	MMbbl/cd	Other crude imports by PAD District
BLDIMP(MNUMPR,MNUMYR)	MMbbl/cd	Blending component imports
RFMTBI(MNUMPR,MNUMYR)	MMbbl/cd	Imported MTBE
RFMTBD(MNUMPR,MNUMYR)	MMbbl/cd	Domestic MTBE production.
RFMETI(MNUMPR,MNUMYR)	MMbbl/cd	Imported methanol
RFETHE85(MNUMPR,MNUMYR)	MMbbl/cd	Ethanol for E85 production
RFMETM85(MNUMPR,MNUMYR)	MMbbl/cd	Methonal for M85 production

PRICE VARIABLES

NAME	UNITS	DEFINITION
PMGCM(MNUMCR,MNUMYR)	$87/MMBtu	Motor Gasoline, Commercial
PMGTR(MNUMCR,MNUMYR)	$87/MMBtu	Motor Gasoline, Transportation
PMGIN(MNUMCR,MNUMYR)	$87/MMBtu	Motor Gasoline, Industrial
PMGAS(MNUMCR,MNUMYR)	$87/MMBtu	Motor Gasoline, All Sectors
PJFTR(MNUMCR,MNUMYR)	$87/MMBtu	Jet Fuel, Transportation
PDSRS(MNUMCR,MNUMYR)	$87/MMBtu	Distillate, Residential
PDSCM(MNUMCR,MNUMYR)	$87/MMBtu	Distillate, Commercial
PDSTR(MNUMCR,MNUMYR)	$87/MMBtu	Distillate, Transportation
PDSIN(MNUMCR,MNUMYR)	$87/MMBtu	Distillate, Industrial
PDSEL(MNUMCR,MNUMYR)	$87/MMBtu	Distillate, Electricity (+petroleum coke)
PDSAS(MNUMCR,MNUMYR)	$87/MMBtu	Distillate, All Sectors
PKSRS(MNUMCR,MNUMYR)	$87/MMBtu	Kerosene, Residential
PKSCM(MNUMCR,MNUMYR)	$87/MMBtu	Kerosene, Commercial
PKSIN(MNUMCR,MNUMYR)	$87/MMBtu	Kerosene, Industrial
PKSAS(MNUMCR,MNUMYR)	$87/MMBtu	Kerosene, All Sectors
PLGRS(MNUMCR,MNUMYR)	$87/MMBtu	Liquid Petroleum Gases, Residential
PLGCM(MNUMCR,MNUMYR)	$87/MMBtu	Liquid Petroleum Gases, Commercial
PLGTR(MNUMCR,MNUMYR)	$87/MMBtu	Liquid Petroleum Gases, Transportation
PLGIN(MNUMCR,MNUMYR)	$87/MMBtu	Liquid Petroleum Gases, Industrial
PLGAS(MNUMCR,MNUMYR)	$87/MMBtu	Liquid Petroleum Gases, All Sectors
PRLCM(MNUMCR,MNUMYR)	$87/MMBtu	Residual Fuel, Low Sulfur, Commercial
PRLTR(MNUMCR,MNUMYR)	$87/MMBtu	Resid. Fuel, Low Sulfur, Transportation
PRLIN(MNUMCR,MNUMYR)	$87/MMBtu	Residual Fuel, Low Sulfur, Industrial
PRLEL(MNUMCR,MNUMYR)	$87/MMBtu	Residual Fuel, Low Sulfur, Electricity
PRLAS(MNUMCR,MNUMYR)	$87/MMBtu	Residual Fuel, Low Sulfur, All Sectors
PRHTR(MNUMCR,MNUMYR)	$87/MMBtu	Residual Fuel, High Sulfur, Transp.
PRHEL(MNUMCR,MNUMYR)	$87/MMBtu	Residual Fuel, High Sulfur, Electricity
PRHAS(MNUMCR,MNUMYR)	$87/MMBtu	Residual Fuel, High Sulfur, All Sectors
PRSCM(MNUMCR,MNUMYR)	$87/MMBtu	Residual Fuel, Commercial
PRSTR(MNUMCR,MNUMYR)	$87/MMBtu	Residual Fuel, Transportation
PRSIN(MNUMCR,MNUMYR)	$87/MMBtu	Residual Fuel, Industrial
PRSEL(MNUMCR,MNUMYR)	$87/MMBtu	Residual Fuel, Electricity
PRSAS(MNUMCR,MNUMYR)	$87/MMBtu	Residual Fuel, All Sectors
PPFIN(MNUMCR,MNUMYR)	$87/MMBtu	Petrochemical Feedstocks, Industrial

NAME	UNITS	DEFINITION
PASIN(MNUMCR,MNUMYR)	$87/MMBtu	Asphalt, Road Oil, Industrial
POTTR(MNUMCR,MNUMYR)	$87/MMBtu	Other Petroleum, Transportation
POTIN(MNUMCR,MNUMYR)	$87/MMBtu	Other Petroleum, Industrial
POTAS(MNUMCR,MNUMYR)	$87/MMBtu	Other Petroleum, Industrial
PTPRS(MNUMCR,MNUMYR)	$87/MMBtu	Total Petroleum, Residential
PTPCM(MNUMCR,MNUMYR)	$87/MMBtu	Total Petroleum, Commercial
PTPTR(MNUMCR,MNUMYR)	$87/MMBtu	Total Petroleum, Transportation
PTPIN(MNUMCR,MNUMYR)	$87/MMBtu	Total Petroleum, Industrial
PTPRF(MNUMCR,MNUMYR)	$87/MMBtu	Total Petroleum, Refinery
PTPEL(MNUMCR,MNUMYR)	$87/MMBtu	Total Petroleum, Electricity
PTPAS(MNUMCR,MNUMYR)	$87/MMBtu	Total Petroleum, All Sectors
PMETR(MNUMCR,MNUMYR)	$87/MMBtu	Methanol, Transportation
PETTR(MNUMCR,MNUMYR)	$87/MMBtu	Ethanol, Transportation

COGEN VARIABLES

NAME	UNITS	DEFINITION
CGREQ(MNUMCR,MNUMYR,4,2)	tBtu	Refinery Fuel Consumption
CGRECAP(MNUMCR,MNUMYR,4,2,2)	mW	Refinery Cogen Capacity
CGREGEN(MNUMCR,MNUMYR,4,2)	gWh	Refinery Cogen Generation

A.1.2.1 PMM Input Variables

QUANTITY VARIABLES

NAME	UNITS	DEFINITION
QMGCM(MNUMCR,MNUMYR)	MMBtu/Yr	Motor Gasoline, Commercial
QMGTR(MNUMCR,MNUMYR)	MMBtu/Yr	Motor Gasoline, Transportation
QMGIN(MNUMCR,MNUMYR)	MMBtu/Yr	Motor Gasoline, Industrial
QMGAS(MNUMCR,MNUMYR)	MMBtu/Yr	Motor Gasoline, All Sectors
QJETR(MNUMCR,MNUMYR)	MMBtu/Yr	Jet Fuel, Transportation
QDSRS(MNUMCR,MNUMYR)	MMBtu/Yr	Distillate, Residential
QDSCM(MNUMCR,MNUMYR)	MMBtu/Yr	Distillate, Commercial
QDSTR(MNUMCR,MNUMYR)	MMBtu/Yr	Distillate, Transportation
QDSIN(MNUMCR,MNUMYR)	MMBtu/Yr	Distillate, Industrial
QDSRF(MNUMCR,MNUMYR)	MMBtu/Yr	Distillate, Refinery
QDSEL(MNUMCR,MNUMYR)	MMBtu/Yr	Distillate, Electricity (+petroleum coke)
QDSAS(MNUMCR,MNUMYR)	MMBtu/Yr	Distillate, All Sectors
QKSRS(MNUMCR,MNUMYR)	MMBtu/Yr	Kerosene, Residential
QKSCM(MNUMCR,MNUMYR)	MMBtu/Yr	Kerosene, Commercial
QKSIN(MNUMCR,MNUMYR)	MMBtu/Yr	Kerosene, Industrial
QKSAS(MNUMCR,MNUMYR)	MMBtu/Yr	Kerosene, All Sectors
QLGRS(MNUMCR,MNUMYR)	MMBtu/Yr	Liquid Petroleum Gases, Residential
QLGCM(MNUMCR,MNUMYR)	MMBtu/Yr	Liquid Petroleum Gases, Commercial
QLGTR(MNUMCR,MNUMYR)	MMBtu/Yr	Liquid Petroleum Gases, Transportation
QLGIN(MNUMCR,MNUMYR)	MMBtu/Yr	Liquid Petroleum Gases, Industrial
QLGRF(MNUMCR,MNUMYR)	MMBtu/Yr	Liquid Petroleum Gases, Refinery
QLGAS(MNUMCR,MNUMYR)	MMBtu/Yr	Liquid Petroleum Gases, All Sectors
QRLCM(MNUMCR,MNUMYR)	MMBtu/Yr	Residual Fuel, Low Sulfur, Commercial
QRLTR(MNUMCR,MNUMYR)	MMBtu/Yr	Residual Fuel, Low Sulfur, Transp.
QRLIN(MNUMCR,MNUMYR)	MMBtu/Yr	Residual Fuel, Low Sulfur, Industrial
QRLRF(MNUMCR,MNUMYR)	MMBtu/Yr	Residual Fuel, Low Sulfur, Refinery
QRLEL(MNUMCR,MNUMYR)	MMBtu/Yr	Residual Fuel, Low Sulfur, Electricity
QRLAS(MNUMCR,MNUMYR)	MMBtu/Yr	Residual Fuel, Low Sulfur, All Sectors
QRHTR(MNUMCR,MNUMYR)	MMBtu/Yr	Residual Fuel, High Sulfur, Transp.
QRHEL(MNUMCR,MNUMYR)	MMBtu/Yr	Residual Fuel, High Sulfur, Electricity
QRHAS(MNUMCR,MNUMYR)	MMBtu/Yr	Residual Fuel, High Sulfur, All Sectors
QRSCM(MNUMCR,MNUMYR)	MMBtu/Yr	Residual Fuel, Commercial
QRSTR(MNUMCR,MNUMYR)	MMBtu/Yr	Residual Fuel, Transportation
QRSIN(MNUMCR,MNUMYR)	MMBtu/Yr	Residual Fuel, Industrial

NAME	UNITS	DEFINITION
QRSRF(MNUMCR,MNUMYR)	MMBtu/Yr	Residual Fuel, Refinery
QRSEL(MNUMCR,MNUMYR)	MMBtu/Yr	Residual Fuel, Electricity
QRSAS(MNUMCR,MNUMYR)	MMBtu/Yr	Residual Fuel, All Sectors
QPFIN(MNUMCR,MNUMYR)	MMBtu/Yr	Petrochemical Feedstocks, Industrial
QSGIN(MNUMCR,MNUMYR)	MMBtu/Yr	Still Gas, Industrial
QSGRF(MNUMCR,MNUMYR)	MMBtu/Yr	Still Gas, Refinery
QPCIN(MNUMCR,MNUMYR)	MMBtu/Yr	Petroleum Coke, Industrial
QPCRF(MNUMCR,MNUMYR)	MMBtu/Yr	Petroleum Coke, Refinery
QPCEL(MNUMCR,MNUMYR)	MMBtu/Yr	Petroleum Coke, Electricity
QPCAS(MNUMCR,MNUMYR)	MMBtu/Yr	Petroleum Coke, All Sectors
QASIN(MNUMCR,MNUMYR)	MMBtu/Yr	Asphalt and Road Oil, Industrial
QOTTR(MNUMCR,MNUMYR)	MMBtu/Yr	Other Petr. Transp, (lubes, aviation gas)
QOTIN(MNUMCR,MNUMYR)	MMBtu/Yr	Other Petroleum, Industrial
QOTRF(MNUMCR,MNUMYR)	MMBtu/Yr	Other Petroleum, Refinery
QOTAS(MNUMCR,MNUMYR)	MMBtu/Yr	Other Petroleum, All Sectors
QTPRS(MNUMCR,MNUMYR)	MMBtu/Yr	Total Petroleum, Residential
QTPCM(MNUMCR,MNUMYR)	MMBtu/Yr	Total Petroleum, Commercial
QTPTR(MNUMCR,MNUMYR)	MMBtu/Yr	Total Petroleum, Transportation
QTPIN(MNUMCR,MNUMYR)	MMBtu/Yr	Total Petroleum, Industrial
QTPRF(MNUMCR,MNUMYR)	MMBtu/Yr	Total Petroleum, Refinery
QTPEL(MNUMCR,MNUMYR)	MMBtu/Yr	Total Petroleum, Electricity
QTPAS(MNUMCR,MNUMYR)	MMBtu/Yr	Total Petroleum, All Sectors
QMETR(MNUMCR,MNUMYR)	MMBtu/Yr	Methanol Transportation
QETTR(MNUMCR,MNUMYR)	MMBtu/Yr	Ethanol Transportation
QELRF(MNUMCR,MNUMYR)	MMBtu/Yr	Purchased Elec., Refinery
QNGRF(MNUMCR,MNUMYR)	MMBtu/Yr	Natural Gas, Refinery
QCLRF(MNUMCR,MNUMYR)	MMBtu/Yr	Coal, Refinery
QBMRF(MNUMCR,MNUMYR)	MMBtu/Yr	Biomass, Refinery

INTERNATIONAL MARKET MODEL VARIABLES

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

OIL AND GAS SUPPLY MODEL VARIABLES

NAME	UNITS	DEFINITION
OGELSCO(MNUMOR,MNUMYR)	Dimensionless	Oil elasticity
OGPRRCO(MNUMOR,MNUMYR)	MMbbl/MMbbl/yr	Oil PR ratio
OGRESCO(MNUMOR,MNUMYR)	MMbbl/Yr	Oil reserves

NATURAL GAS TRANSMISSION AND DISTRIBUTION SUPPLY MODEL VARIABLES

NAME	UNITS	DEFINITION
OGPRDNG(MNUMOR,MNUMYR)	Bcf/Yr	Domestic dry NG production
OGWPRNG(MNUMOR,MNUMYR)	$87/Mcf	Ng wellhead price
PRNG_PADD(MNUMPR,MNUMYR)	Bcf/Yr	Total dry gas production (W/L&P)

NAME	UNITS	DEFINITION
PELIN(MNUMCR,MNUMYR)	$87/MMBTU	Purch. Elec. Industrial
PNGIN(MNUMCR,MNUMYR)	$87/MMBTU	Natural Gas. Industrial

RENEWABLE VARIABLES

NAME	UNITS	DEFINITION
WPETOH(MNCROP,MNUMCR,MNUMYR,MNETOH)	$87/bbl	Ethanol price/step
WQETOH(MNCROP,MNUMCR,MNUMYR,MNETOH)	Mbbl/cd	Ethanol quan/step

A.1.2.2 Other PMM Variables

VARIABLES USED INTERNALLY IN PMM

NAME	UNITS	DEFINITION
		Refinery products prices
PALMG(MNUMCR,MNUMYR)	$87/bbl	Motor gasoline all combined
PMGTRG(MNUMCR,MNUMYR)	$87/bbl	Traditional mogas
PMGRFG(MNUMCR,MNUMYR)	$87/bbl	RFG mogas
PMGTRH(MNUMCR,MNUMYR)	$87/bbl	TRH mogas
PMGRFH(MNUMCR,MNUMYR)	$87/bbl	RFH mogas
PMG2TR(MNUMCR,MNUMYR)	$87/bbl	TRG mogas with markup
PMG3TR(MNUMCR,MNUMYR)	$87/bbl	RFG mogas with markup
PMG4TR(MNUMCR,MNUMYR)	$87/bbl	TRH mogas with markup
PMG5TR(MNUMCR,MNUMYR)	$87/bbl	RFH mogas with mu
PDS(MNUMCR,MNUMYR)	$87/bbl	Distillate fuel oil
PDSL(MNUMCR,MNUMYR)	$87/bbl	Low sulfur diesel
PJF(MNUMCR,MNUMYR)	$87/bbl	Jet fuel
PRL(MNUMCR,MNUMYR)	$87/bbl	Residual fuel oil low sulfur
PRLUT(MNUMCR,MNUMYR)	$87/bbl	Low sulfur utility resid.
PRH(MNUMCR,MNUMYR)	$87/bbl	High sulfur resid.
PRHUT(MNUMCR,MNUMYR)	$87/bbl	High sulfur utiltiy resid.
PLG(MNUMCR,MNUMYR)	$87/bbl	LPG
PPF(MNUMCR,MNUMYR)	$87/bbl	Petrochemical feedstocks
PPC(MNUMCR,MNUMYR)	$87/bbl	Petroleum coke
PKS(MNUMCR,MNUMYR)	$87/bbl	Kerosene
POTH(MNUMCR,MNUMYR)	$87/bbl	Other
PAS(MNUMCR,MNUMYR)	$87/bbl	Asphalt and road oil
PE85(MNUMCR,MNUMYR)	$87/bbl	E85
PM85(MNUMCR,MNUMYR)	$87/bbl	M85
QCDUPD(MNUMYR)	$87/bbl	Crude used as product
OLEOYRS(MNUMOR,MNUMYR)	MMbbl	End of year reserves for oil
OLEXTRT(MNUMOR,MNUMYR)	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,MNUMYR,5,3)	$87/bbl	Price of crude, refinery gate
QCRDRF(MNUMPR,MNUMYR,5,3)	Mbbl/cd	Quantity of crude, refinery gate
QPRDRF(MNUMPR,MNUMYR,18)	Mbbl/cd	Refinery production volume by product
QPRDRFT(MNUMYR)	Mbbl/cd	Total refinery production volumes
QGPLTRF(MNUMPR,MNUMYR,10)	BCF	Refinery gas plant production volumes
QPRDEX(MNUMPR,18)	Mbbl/cd	Refinery production export by product
QPRDEXD(MNUMPR,18,MNUMYR)	Mbbl/cd	Production distress export by product
RFMETM85(MNUMYR)	MMbbl/cd	Methanol for M85
RFCRDDCR(MNUMYR)	Mbbl/cd	Domestic crude production
RFCRDAKA(MNUMYR)	Mbbl/cd	Alaskan crude production
RFCRDL48(MNUMYR)	Mbbl/cd	Lower 48 crude production
RFCRDTOT(MNUMYR)	MMbbl/cd	Total crude production
RFNGFTOT(MNUMYR)	Mbbl/cd	Total natural gas production

NAME	UNITS	DEFINITION
QPRDIMD(MNUMYR)	Mbbl/cd	Total distress imports
PRDTOT(MNUMYR)	Mbbl/cd	Total product demand for report 4
PRPFU(5)	MFOEbbl/day	RHS value for resid. by PAD District
PRPFF(5)	MFOEbbl/day	RHS value for resid. by PAD District
PQUFC1(MNUMPR,MNUMYR,2)	$87/bbl,Mbbl/cd	Unfinished crude 1
PQUFC2(MNUMPR,MNUMYR,2)	$87/bbl,Mbbl/cd	Unfinished crude 2
PQUFC3(MNUMPR,MNUMYR,2)	$87/bbl,Mbbl/cd	Unfinished crude 3
PQUFC4(MNUMPR,MNUMYR,2)	$87/bbl,Mbbl/cd	Unfinished crude 4
PQUFC5(MNUMPR,MNUMYR,2)	$87/bbl,Mbbl/cd	Unfinished crude 5
PQUFC6(MNUMPR,MNUMYR,2)	$87/bbl,Mbbl/cd	Unfinished crude 6
PQUFC7(MNUMPR,MNUMYR,2)	$87/bbl,Mbbl/cd	Unfinished crude 7
PQUFC8(MNUMPR,MNUMYR,2)	$87/bbl,Mbbl/cd	Unfinished crude 8
PQUFC9(MNUMPR,MNUMYR,2)	$87/bbl,Mbbl/cd	Unfinished crude 9
PQUFC10(MNUMPR,MNUMYR,2)	$87/bbl,Mbbl/cd	Unfinished crude 10
		Refinery fuel use
QDISFU(MNUMPR,MNUMYR)	TBtu/Yr	Distillate
QRESFU(MNUMPR,MNUMYR)	TBtu/Yr	Resid.
QCOLFU(MNUMPR,MNUMYR)	TBtu/Yr	Coal
QLPGFU(MNUMPR,MNUMYR)	TBtu/Yr	LPG
QSTGFU(MNUMPR,MNUMYR)	TBtu/Yr	Still gas
QNTGFU(MNUMPR,MNUMYR)	TBtu/Yr	Natural gas
QCOKFU(MNUMPR,MNUMYR)	TBtu/Yr	Petroleum coke
QOTHFU(MNUMPR,MNUMYR)	TBtu/Yr	Other
		End use markups by sector
MGMUAS(MNUMCR,MNUMYR,2)	$87/MMBtu	Motor gasoline mark ups All Sectors
MGMUTR(MNUMCR,MNUMYR,2)	$87/MMBtu	Transportation
MGMUIN(MNUMCR,MNUMYR,2)	$87/MMBtu	Industrial
MGMUCM(MNUMCR,MNUMYR,2)	$87/MMBtu	Commercial
MEMUTR(MNUMCR,MNUMYR,2)	$87/MMBtu	M85
ETMUTR(MNUMCR,MNUMYR,2)	$87/MMBtu	E85
		Fuel oil
DSMUAS(MNUMCR,MNUMYR,2)	$87/MMBtu	Distillate
DSMURS(MNUMCR,MNUMYR,2)	$87/MMBtu	
DSMUCM(MNUMCR,MNUMYR,2)	$87/MMBtu	
DSMUTR(MNUMCR,MNUMYR,2)	$87/MMBtu	
DSMUIN(MNUMCR,MNUMYR,2)	$87/MMBtu	
DSMUEL(MNUMCR,MNUMYR,2)	$87/MMBtu	
JFMUTR(MNUMCR,MNUMYR,2)	$87/MMBtu	Jet fuel transportation
RLMUAS(MNUMCR,MNUMYR,2)	$87/MMBtu	Low sulfur Resid.
RLMUCM(MNUMCR,MNUMYR,2)	$87/MMBtu	
RLMUTR(MNUMCR,MNUMYR,2)	$87/MMBtu	
RLMUEL(MNUMCR,MNUMYR,2)	$87/MMBtu	
RLMUIN(MNUMCR,MNUMYR,2)	$87/MMBtu	
RHMUAS(MNUMCR,MNUMYR,2)	$87/MMBtu	High Sulfur Resid.
RHMUTR(MNUMCR,MNUMYR,2)	$87/MMBtu	
RHMUEL(MNUMCR,MNUMYR,2)	$87/MMBtu	
LGMUAS(MNUMCR,MNUMYR,2)	$87/MMBtu	LPG
LGMURS(MNUMCR,MNUMYR,2)	$87/MMBtu	
LGMUCM(MNUMCR,MNUMYR,2)	$87/MMBtu	
LGMUTR(MNUMCR,MNUMYR,2)	$87/MMBtu	
LGMUIN(MNUMCR,MNUMYR,2)	$87/MMBtu	
PFMUIN(MNUMCR,MNUMYR,2)	$87/MMBtu	Petrochemical feedstocks
ASMUIN(MNUMCR,MNUMYR,2)	$87/MMBtu	Asphalt and road oil
KSMUAS(MNUMCR,MNUMYR,2)	$87/MMBtu	Kerosene
KSMURS(MNUMCR,MNUMYR,2)	$87/MMBtu	
KSMUCM(MNUMCR,MNUMYR,2)	$87/MMBtu	
KSMUIN(MNUMCR,MNUMYR,2)	$87/MMBtu	
OTMUAS(MNUMCR,MNUMYR,2)	$87/MMBtu	Other
OTMURS(MNUMCR,MNUMYR,2)	$87/MMBtu	
OTMUCM(MNUMCR,MNUMYR,2)	$87/MMBtu	
OTMUEL(MNUMCR,MNUMYR,2)	$87/MMBtu	
OTMUTR(MNUMCR,MNUMYR,2)	$87/MMBtu	Other markups transportation sector
OTMUIN(MNUMCR,MNUMYR,2)	$87/MMBtu	Other markups industrial sector

NAME	UNITS	DEFINITION
NLV(9)	Text	Census division character identifers
NLV2(9)	Text	Domestic crude supply regn identifers
QNT(9)	Text	Quantity character identifiers
PRD(20)	Text	Product character identifiers
IPRD(12)	Text	Imported product chrctr identifers
PADD(5)	Text	PAD District character identifiers
CRDTYP(5)	Text	Crude type character identifiers
MGSCHAR(65)	Text	Mogas share character identifiers
BNDS(2)	Text	Bounds character identifiers
RFCESWTC	Text	Capacity expansion switch
MPSSWTC	Text	MPS matrix load switch
RFADVBAS	Text	Advance basis load switch
RPT1SWTC	Text	Report 1 switch
RPT7SWTC	Text	Report 7 switch
RFETSWTC	Text	Ethanol supply curve switch
PRCUNIT(40)	Text	Process unit character identifier
RFHIST	Text	History switch
RFOTHFU(19)	Text	Other fuel use character identifier
MGSPCS(65,MNUMYR)	Many	Motor gasoline specifications
MGSHR(MNUMYR,6,MNUMCR)	Percent	Motor gasoline market shares
PRDDMD(MNUMCR,MNUMYR,20)	Mbbl/cd	Product demand
PRDDMDME(MNUMYR)	Mbbl/cd	Chemical methanol demand
LOWBND	None	Variable for passing data to OML
UPBND	None	Variable for passing data to OML
PRICLP	None	Variable for passing data to OML
PCOKL	None	Variable for passing data to OML
PCOKH	None	Variable for passing data to OML
PUCUM(MNUMPR,40,MNUMYR)	Mbbl/cd	Process unit cumulative builds
PUINV(MNUMPR,40,MNUMYR)	Mbbl/cd	Process unit investment builds
FO1PMM	None	Variable for file unit identifier
FO2PMM	None	Variable for file unit identifier
PMMINF	None	Infeasible solution 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
PUBASE(MNUMPR,40,MNUMYR)	Mbbl/cd	Processing units base capacity
PUBASEUT(MNUMPR,40,MNUMYR)	Pecent	Processing units base utilization
RFMETI(MNUMYR)	MMbbl/cd	Imported methanol
RFMTBD(MNUMYR)	MMbbl/cd	Domestic MTBE
RFMTBI(MNUMYR)	MMbbl/cd	Imported MTBE
RFEMISST(MNUMPR,MNUMYR,12)	Many	Total refinery emissions
RFFMT(MNUMPR,MNUMYR,30)	Percent	Refinery fuel mix
RFCGSTEAM(MNUMPR,MNUMYR	Percent	Steam, PAD District percent adjustment
RFSTEAM(MNUMPR,MNUMYR)	MMlb/day	Steam by PAD District
RFCGCONS(MNUMPR,MNUMYR)	tBtu	Refinery cogeneration PAD District
RFCGREC(MNUMPR,MNUMYR)	kWh	Receipts of electricity
RFCGGENPD(MNUMPR,MNUMYR)	TBtu	Refinery cogeneation by PAD Ditrict
RFCGGRIDPD(MNUMPR,MNUMYR)	TBtu	Refinery cogen. to grid by PAD District
RFCGSELFPD(MNUMPR,MNUMYR)	TBtu	Refinery cogen. Self
RFCGFUELPD(MNUMPR,MNUMYR)	TBtu	Refinery cogen. Fuel
RFCGGENCD(MNUMCR,MNUMYR)	TBtu	Refinery cogen. Generation
RFCGGRIDCD(MNUMCR,MNUMYR)	TBtu	Refinery cogen. To grid by cenus division
RFCGSELFCD(MNUMCR,MNUMYR)	TBtu	Refinery cogen. Self by cenus division
RFCGFUELCD(MNUMCR,MNUMYR)	TBtu	Refinery cogen. Fuel by cenus division
FLOWCRD(MNUMYR,14)	Mbbl/cd	Crude pipeline flow
CAPCRD(MNUMYR,14)	Percent	Crude pipeline utilization
FLOWPRD(MNUMYR,21)	Mbbl/cd	Product pipeline flow
CAPPRD(MNUMYR,21)	Pecerent	Product pipeline utilization
FLOWLPG(MNUMYR,10)	Mbbl/cd	LPG pipeline flow
CAPLPG(MNUMYR,10)	Percent	LPG pipeline utilization

NAME	UNITS	DEFINITION
RFPRDFX(MNUMCR,MNUMYR,20)	$87/bbl	Refinery capital cost by product
RFQNGLRF(MNUMPR,MNUMYR)	MMbbl/cd	Quantity of ngl inputs to refinery
FHLADD(MNUMPR)	Mbbl/cd	Additonal supply imports of HL crude
N6XQNT(9)	Fraction	Supply step adjustment for N6I/B
N6XPRC(9)	Fraction	Price step adjustment for N6I/B
IRACN	$87/bbl	Refiner acquisition cost min. tolerance
IRACX	$87/bbl	Refiner acquisition cost max. tolerance
QPRDIMD(MNUMCR,23,MNUMYR)	MMbbl/cd	Quantity of distress product import
RFNGFTOT(MNUMYR)	MCF/cd	Domestic natural to refineries
QSUBFU(MNUMPR,MNUMYR)	MMbbl/cd	Subtotal refinery fuel use w/o nat. gas
QTOTFU(MNUMPR,MNUMYR)	MMbbl/cd	Total refinery fuel use with natural gas
RFIPQSB(MNUMPR,MNUMYR,2)	MMbbl/cd,$87/bbl	Subtotal imported product w/o Methanol
RFIPQTL(MNUMPR,MNUMYR,2)	MMbbl/cd,$87/bbl	total imported product with Methanol
MUFTAX(15)	$87/MMBtu	Federal motorgasoline tax
RWOP(MNUMYR)	$87/bbl	PMM local expected WOP
FRSTIT	Text	Write basis on first/last iteration switch
PRDEXPTOT(MNUMYR)	MMbbl/cd	Total allowable product exports
LHCDIST(2,MNUMY,7,30)	Percent	Model testing variable
LHCRUN	Integer	Model testing switch
DSLSPLT	Percent	Low sulfur diesel and distillate split
WOPMTPLY	Percent	Distress import price multiplier
WOPZ9EXP	Percent	Distress export price multiplier
Z9EXPRD	Text	Distress export index list
SUBNM	Text	Subroutine name index
SUBNMX	Text	Passing subroutine name index
PMMRGNS	Integer	PMM refining regions index
DMDRGNS	Integer	PMM demand regions index
RFETHMGS(MNUMPR,MNUMYR)	MMbbl/cd	Ethanol for motor gasoline
RFETHETB(MNUMPR,MNUMYR)	MMbbl/cd	Ethanol for ETBE
RFFUELU(MNUMYR)	MMbbl/cd	Total refinery fuel use w/o nat. gas
CRDOTHOT(MNUMPR,MNUMYR)	MMbbl/cd	Total other crude suplied
CRDUNACC(MNUNPR,MNUMYR)	MMbbl/cd	Unnaccouted crude
CRDSTWDR(MNUMPR,MNUMYR)	MMbbl/cd	Crude stock withdrawals
NGLMK(MNUMPR,MNUMYR,6,2)	MMbbl/cd	NGL to market
NGLRF(MNUMPR,MNUMYR,6,2)	MMbbl/cd	NGL from refinery
RFMETETH(MNUMPR,MNUMYR)	MMbbl/cd	Methanol for ether
PRDSTKWDR(MNUMPR,MNUMYR)	MMbbl/cd	Product stocks withdrawals
MISCINP(MNUMPR,MNUMYR)	MMbbl/cd	Miscellaneous inputs
BLDPRD(MNUMPR,MNUMYR)	MMbbl/cd	Product blending component
OTHOXY(MNUMPR,MNUMYR)	MMbbl/cd	Other oxgenates
XRFWOP(MNUMYR,2)	MMbbl/cd	Local expected WOP
XRFELP(MNUMPR,MNUMYR)	MMbbl/cd	Local expected electricity price
XRFNGP(MNUMPR,MNUMYR)	MMbbl/cd	Local expected natural gas price
RFETBD(MNUMPR,MNUMYR)	MMbbl/cd	ETBE oxygenate quantity
RFTAED(MNUMPR,MNUMYR)	MMbbl/cd	TAE oxygenate quantity
RFTAMD(MNUMPR,MNUMYR)	MMbbl/cd	TAME oxygenate quantity
RFTHED(MNUMPR,MNUMYR)	MMbbl/cd	THE oxygenate quantity
RFTHMD(MNUMPR,MNUMYR)	MMbbl/cd	THM oxygenate quantity
NGRFUPIT(MNUMPR,MNUMYR)	MMbbl/cd	Natural gas fuel use previous iteration

Legend for Codes

MNUMYR = NEMS year index, 1 through 21
MNUMCR = census region index, 1 through 11
MNUMPR = PAD District index, 1 through 6
MNUMOR = Oil and Gas Region Index, 1 through 15
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 by EIA and others since DOE received the first model database from Turner, Mason Associates during 1975-76. These data were used extensively during 1983-1986 during the development of 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. In 1985, EIA provided the updated RYM/NPC data and OMNI matrix and report generator programs to Oak Ridge National Laboratories (ORNL), and its consultant ENSYS, to support a study for the U.S. Navy.[1] The most recent vintage was provided by ENSYS to EIA in September 1992 and is based on some ENSYS in-house data sources as well as review and commentary received from major oil companies. Much of the data has been updated from 1985 to 1992. The 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 and Purvin & Gertz.

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

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[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).

in industry journals, papers from industry conferences and surveys (such as NPRA), engineering and licensing contractor data, and published consultant studies.

A.2.2 Refinery Capacity Construction and Utilization Data

The base capacity for refinery process units, as published by EIA, provide the base year values. The planned construction of refinery process units, as published annually by the *Oil & Gas Journal (OGJ)*, together with published articles on national, company, or individual refinery activities are used to supplement and cross-check the base data from EIA. These data require annual updating and careful cross-checking for error, omissions, and operating status.

Construction project data are gathered principally from annual surveys published in the *Oil & Gas Journal* and in *Hydrocarbon Processing*, again supplemented, cross-checked and updated by individual announcements or published studies. 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.

It is also necessary to track installed and projected capacity for MTBE and 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 and the PMM writes them to the file

CN6005.PRJ.@.PMM.IMPCURV.%SCN.DMMDDYRn

where %scn is the scenario name and MM is month, DD is the day, YR is the year, and n is the case number. Each year of a NEMS run contains quantities and import prices for crude oil in three step supply increments for each importing PAD District.

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	> 24	0.5 MAX	< 15%
Medium Sulfur - Heavy	MH	> 24	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	> 0.7	> 15%

Natural Gas Liquids (NGL's)

The NGL's are produced by the gas plant model matrix that is a part of PMM. See Appendix F.

Other Hydrocarbons and Alcohols

Other hydrocarbons such as propane and butanes are supplied by the output of the gas plant model. Ethanol is supplied by the Renewable Fuels Model of NEMS in Census Divisions 3 and 4. The supply of ethanol is represented as a step function with each increment of supply available at a higher price.

Some methanol is imported with the balance required by PMM supplied by the methanol plant in each refining region. Methyl Tertiary Butyl Ether (MTBE) is produced by MTBE plants in each refining region; additional supplies are imported.

Product demands are downloaded from the NEMS restart file 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 data for the United States on capacities and rates have been developed from the OSPR NACOD Model and updated for environmental costs reflecting the Oil Pollution Control Act. The transportation costs were obtained from a recent National Petroleum Council study in 1993.

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 day, prices or costs are in dollars per barrel and quantities of money are, therefore, in thousands of dollars per 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	HH2	.008190	23,077
Hydrogen sulfide	H2S	.001040	10,145
Methane/natural gas	NGS	.003414	6,917
Ethane	CC2	.003245	3,861
Process gas	PGS	.003245	3,861
Ethylene	C2E	.003219	4,180

One barrel FOE is 6.3 million Btu.

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

Stream	Code	MMBtu/bblFOE
Gasoline	TRG	5.253
Jet Fuel	JTA	5.670
No. 2 Heating Oil	N2H	5.825
Residual Oil	N6I,N6B	6.287
LPG	LPG	3.625
Methanol/gasoline	M85	2.820
Ethanol/gasoline	E85	3.500

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.

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, C24, ALK, CPL, DIP, DIM, ARP, C4I, H2P, and SUL. Note also that unit activity level of H2P, and SUL activities represents the production of 0.1 thousand fuel oil equivalent barrels of hydrogen and 0.1 thousand short tons of sulfur per day, and uses 0.1 units 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 .00493 fuel oil equivalent bbl per day to raise 1 lb/hr of steam is equivalent to 1225 Btu per lb steam.

8. Electricity consumption is in kWh/bbl. Generation is in MkWh/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 Mbbl/cd for volume and $/bbl for costs, unless otherwise noted. All data tables are located in a partitioned data set (PDS) named:

CN6007.PRJ.AEO95.PMM.TABLES.DATA

The reference (:NAME) in the following pages refers to the individual member name which contains the tables described. The symbols (R) and (D) used in the table names represent a refining region (R) or Census division (D) where:

(R)	Refining Region	(D)	Census Division
E	PAD District I	1	New England
C	PAD District II	2	Mid Atlantic
G	PAD District III	3	East North Central
M	PAD District IV	4	West North Central
W	PAD District V	5	South Atlantic
		6	East South Central
		7	West South Central
		8	Mountain
		9	Pacific, including California

A.3.1 Matrix Control

This section describes the tables used to control the number of constraints (rows) and column variables in the matrix as well as the stipulations for the limits on constraints and variables.

(:CONTAB)

BNDDEM   DEMAND BOUND RANGES

Column names   One column for each Census division

Row names   First three characters finished product codes.

Entries   Fraction of demand as a lower bound. A value of 1.0 means the lower bound is 100 percent of the upper bound, i.e. fixed at the upper bound. A value of 0.50 means that the product demand is bounded between 50 percent and 100 percent of the demand.

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.

SADELPX FRACTION OF PRICES FOR EACH QUANTITY SHIFT

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

Row names   One character Census division codes.

Entries   Percentage (as a fraction) of price of import step R3 for imported products.

SELCGN COGENERATION SALES BY PADD

Column names   One column, SOLD

Row names   PADD Codes, E,C,G,M,W.

Entries   Fraction sold in each PADD.

NGP CONTROL TABLE FOR SCALAR FACTORS

Column names   One column, BAU92

Row names   Scalar factor names used for matrix generation control. F8791 converts 1991 values to constant 1987 dollars, NGP is proxy natural gas price, WOPTOL is range of tolerance in $/bbl for average refiner acquisition cost of crude oil, MXPRIM is 0.0 if product imports are open, 1.0 if a maximum is imposed, PSX represents fraction of step 1 import price used for export price, PZ9 represents fraction of step 1 import price used for distress export prices.

Entries   Scalar factors.

CREXP VOLUME OF CRUDE EXPORTS FROM U.S.

Column names   Two columns, CRDEXP represents crude oil exports, CRDSPR represents the SPR fill rate.

Row names   One row, VOL.

Entries   Export volume in Mbbl/cd

FUMCTRL CONTROLS REFINERY FUEL BURNING OF GAS AND RESIDUAL OIL

Column names   Five columns, one for each refining region.

Row names   First three characters are product codes for fuel burned. The fourth character is either X for maximum or N for minimum.

Entries   Fractions of total refinery fuel burned by each fuel.

SPNGF   SUPPLY STEP PRICES FOR NATURAL GAS TO REFINERY

Column names   Five columns, one for each refining region.

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 well head price.

SQNGF   SUPPLY STEP QUANTITIES FOR NATURAL GAS TO REFINERY

Column names   Five columns, one for each refining region.

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   Volume increments in Bcf from reference quantity supplied.

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 in increments of 2 percent.

Row names   R2 through R9. Step name increments.

Entries   R1B is fraction of step 1 import level. R1PR is price level over step 1 price.

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

EXPLIM   LIMIT ON U.S. PRODUCT EXPORTS

Column names   One column FIX

Row names   One row, @ implies all regions.

Entries   Fixed limit on product exports in Mbbl/cd

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 unfinished oil imports to crude input.

UNFIMP   UNFINISHED OIL IMPORT SHARES

Column names   Three columns, E, G, and Z. E and G represent import refining regions. Z represents multiplier of World Oil Price (WOP) for import prices.

Row names   Row UNF represents total unfinished oils. Rows NPP, HGM, and ARB are unfinished oil streams imported to U.S..

Entries   Coefficients under refining regions represent volume fractions. Column Z values are multipliers of WOP applied to import price.

UNFBND   LIMITS ON UNFINISHED OIL IMPORTS

Column names   Two columns, E and G, represent import refining regions.

Row names   Rows NPP, HGM, and ARB are unfinished oil streams imported to United States.

Entries   Volume limits on individual import streams.

INVLIM   INVESTMENT LIMIT BY REFINING REGION (R)

Column names   One column, MAX.

Row names   One character refining region code.

Entries   Limit of investment in millions of dollars.

INVUSA   INVESTMENT LIMIT FOR U.S.

Column names   One column, MAX.

Row names   One row, @ implies all regions.

Entries   Limit of investment in millions of dollars.

EMUNS   EMISSIONS FROM PROCESS UNITS

Column names   Five columns, representing type of emission - VOC, CO1, NOX, SOX, and CAR (Carbon).

Row names   First three characters process unit codes.

Entries   Emissions in Mlb/Mbbl for VOC, NOX, SOX. Units of MM lbs/Mbbl for CO1, CO2, CAR.

EMFUM   EMISSIONS FROM FUEL BURNING

Column names   Five columns, representing type of emission - VOC, CO1, NOX, SOX, and CAR (Carbon).

Row names   First three characters 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.

TABLE CONTROL   INVESTMENT AND SPECIFICATION CONTROL FLAGS

Column names   One column, SET.

Row names   Three rows, INV, SPC, SSN.

Entries   A non-blank entry in row INV causes investment activities to be
                  generated. A non-blank entry in row SPC activates **Table EXSPEC**
                  (see below) and only those specifications indicated there will be
                  generated.

                  An entry in row **SSN** must be present and must be either 1, 2, or
                  3 where:
                  1.   causes generation of year-round average specifications
                  2.   causes generation of winter specifications
                  3.   causes generation of summer specifications

TABLE EXCAP   STREAMS EXCLUDED IF UNIT NOT IN TABLE CAP

Column names   Process unit codes.

Row names   Intermediate stream codes

Entries   A non-blank entry indicates that, if the unit is absent from **Table
                  CAP**, the corresponding intermediate stream cannot exist and
                  that part of the matrix structure which applies to that stream is
                  not to be generated.

TABLE EXSPEC   **GASOLINE AND DISTILLATE SPECS REDUCTION**

Column names   Quality codes

Row names   Three-character product code followed by a single character N or X signifying a miNimum or a maXimum constraint.

Entries   A non-blank entry signifies that the corresponding quality constraint is to be generated. Conversely, a blank prevents the constraint from being generated. *Table EXSPEC* only takes effect if the correct flag is set in *Table CONTROL*. These three EX tables constitute a system which optionally limits the size of the generated model.

TABLE VECBNDS   **BOUNDS ON SPECIFIC ACTIVITIES**

Column names   Three columns, MIN, MAX and FIX

Row names   Matrix column names

Entries   Any entry will appear in the generated model as a bound of appropriate type on the matrix column.
Table VECBNDS can be used to impose any desired limit on any vector in the model. It is most often used for limiting movements -e.g. on intermediate streams (unfinished oils) into the United States - or for forcing minimum volumes of regional crudes to be refined in local refineries.

(:FIXVEC)

(R)DJBND   LIST OF VARIABLES TO BE EXCLUDED FOR REGION (R)

Column names   Two columns, DJ and FIX

Row names   Matrix column names

Entries   Penalty cost (DJ) in $/bbl and volume flow in Mbbl/cd.

A solution to PMM is processed offline to select those variables belonging to refining and blending activities whose penalty cost is higher than a user-specified value, currently $5.01. The variables found are then fixed at a level of 0.0. This strategy comprises a Level 1 compact matrix.

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.

(:DCRYNN)

TABLE DCRSUP   **DOMESTIC CRUDE OIL IMPORTS BY OGSM REGION**

Column names   One column for each OGSM region

Row names   One row, VOL

Entries   Production volume in each OGSM region

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

(:ACUTAB94)

TABLE DCRSHR   **SHARE BY LOWER 48 CRUDE GROUP**

Column names   One column for each OGSM region except Alaska

Row names   Five domestic aggregate crude groups.

Entries   Fractional share of production volume in each OGSM region

TABLE ALASHR   **SHARE BY ALASKA CRUDE GROUP**

Column names   One column for Alaskan OGSM region

Row names   Two Alaskan groups ALL and AMH

Entries   Fractional share of production volume in Alaska OGSM region

(:BAUICR)

TABLE ICR(crt)(R) **CRUDE OIL IMPORTS BY CRUDE GROUP**

Column names   Six columns, C1,Q1,C2,Q2,C3,Q3

Row names   NEMS year code

Entries   Columns Q(n) represent the availability in Mbbl/cd of each crude. Columns C(n) show the landed price in $/bbl at each refining region.

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

(:CRDAV)

TABLE CRDAV   **CRUDE OIL QUALITIES**

Column names   Six columns, QTY, P, API, SUL, GR and S

Row names   Crude codes

Entries   Column QTY contains the projected availability in Mbbl/cd of each crude. These volumes are only used for determining the relative volumes of each crude oil.

For reporting purposes, the table also includes data on the gravity, sulfur content, and 'grade' of each crude. The grade consists of two letters indicating the group LL, MH, HL, HH, HV, the first indicative of the sulfur content and the second, of API gravity.

Column S contains a code letter indicating the source of the crude where: A = Alaska, D = Domestic (i.e. lower 48 States), F = Foreign, S = U.S. strategic reserve

A.3.3 Other Raw Materials Availability

(:ETOH)

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

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

Row names   NEMS Year code

Entries   Columns R(n) represent the availability in Mbbl/cd of Ethanol. Columns C(n) show the supply price in $/bbl in each Census division.

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

(:CAP)

TABLES (R)NCP AVAILABILITIES OF NON-CRUDE INPUTS REGION R

Column names Four columns, CST, MIN, MAX and FIX

Row names   Non-crude input codes

Entries   Either the cost (in $/bbl) or a minimum, maximum, or fixed quantity (Mbbl/cd) will be specified.[2]

---

[2] In general, inputs of all NCP non-crudes are fixed except for methanol and natural gas.

TABLES (R)UAP   **UTILITY PURCHASES - REFINERY R**

Column names   CST, MIN, MAX, FIX, FCT.

Row names   Codes for purchased utilities.

Entries   Column CST contains the purchase price of the utility in dollars per unit.
Columns MIN, MAX, and FIX permit the application of limits to the amount purchased. In the current model, fuel (FUL) is not purchased and is excluded from the table[3]. Electricity is purchased in kWh and the process tables express power consumption in kWh per barrel. Purchase of steam (STM) may also be activated in this table, although general practice is to omit it or fix it at zero on the basis that refineries normally generate steam internally.

---

[3]   Purchased fuel may take the form of purchased natural gas input via *Tables (R)NCP*.

A.3.4 Product Imports

(:BAUIPR)

TABLE IPR(PRD)(R)   PRODUCT IMPORTS TO REGION (R)

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

Row names   NEMS Year code

Entries   Column R(n) represent the availability in Mbbl/cd of each product (PRD) imported. Columns C(n) show the landed price in $/bbl at each refining region.

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

A.3.5 Product Demands

(:BAUDEM)

TABLES DMNDYyy   PRODUCT DEMAND FOR Year yy

Column names   One column for each Census division, Total U.S = B

Row names   Three character finished product codes.

Entries   Demand in Mbbl/cd

These demands are downloaded from the NEMS restart file for a given scenario.

(:PREXP)

(D)PRDEXP PRODUCT EXPORTS

Column names   One column SX for volume exported

Row names   First three characters of export finished product codes.

Entries   Export volume in Mbbl/cd

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 as the first two characters to represent the mode - TP for tanker movements, PL for pipeline and BV for Barge/Truck. Characters 3 and 4 are CR for crude oil, PR for products, and LG for LPG. Shipping costs are in $/bbl 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.

(:TRANS)

TABLES TPCR(S)   **DOMESTIC CRUDE MOVEMENTS (TANKER) EX OGSM REGION (S)**

Column names   Crude group domestic, three characters.

Row names   First character is mode code; second character, code for destination refining region.

Entries   Shipping cost in $/bbl to destination region.

TABLES PLCR(S)   **DOMESTIC CRUDE MOVEMENTS (PIPELINE) EX OGSM REGION (S)**

Column names   Crude group domestic, three characters.

Row names   First character is mode code; second character, code for destination refining region.

Entries   Shipping cost in $/bbl to destination region.

TABLES PLCR(R) **ALL CRUDE MOVEMENTS (PIPELINE) EX REGION (R)**

Column names Crude group domestic and foreign, three characters.

Row names First character is mode code; second character, code for destination region.

Entries Shipping cost in $/bbl to destination region.

TABLES TPPR(R) **PRODUCT SHIPPING COSTS (TANKER) EX REFINERY 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 $/bbl.

TABLES PLPR(R) **PRODUCT SHIPPING COSTS (PIPELINE) EX REFINERY R**

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) EX REFINERY 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 EX REFINERY 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 EX 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.

TABLES PLLG(R)   ***LPG & PCF SHIPPING COSTS (PIPELINE) EX REFINERY 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) CAPACITY***

Column names   MAX for maximum capacity

Row names   TVC followed by transportation mode (one character) and CP

Entries   Capacity in thousands of dead weight tons (DWT)

TABLE PLCCAP   *PIPELINE (CRUDE) CAPACITY*

Column names   MAX for maximum capacity

Row names   TPC followed by source region code (one character), transportation mode (one character) and destination region code (one character)

Entries   Capacity in Mbbl/cd

TABLE MVPCAP   *MARINE VESSEL (PRODUCTS) CAPACITY*

Column names   MAX for maximum capacity

Row names   TVP followed by transportation mode (one character) and CP

Entries   Capacity in thousands of dead weight tons (DWT)

TABLE BVPCAP   *MARINE BARGE (PRODUCTS) CAPACITY*

Column names   MAX for maximum capacity

Row names   TVP followed by transportation mode (one character) and CP

Entries   Capacity in thousands of dead weight tons (DWT)

TABLE PLPCAP   *PIPELINE (PRODUCTS) CAPACITY*

Column names   MAX for maximum capacity

Row names   TPC followed by source region code (one character), transportation mode (one character) and destination region code (one character)

Entries   Capacity in Mbbl/cd

TABLE PLLCAP   *PIPELINE (LPG PRODUCTS) CAPACITY*

Column names   MAX for maximum capacity

Row names   TPL followed by source region code (one character), transportation mode (one character) and destination region code (one character)

Entries   Capacity in Mbbl/cd

(:CAP)

TABLES CAP(R) REFINING CAPACITIES - REFINERY R

Column names   CDCAP, PUL, AND BLD.

Row names   Process unit codes.

Entries   Column CDCAP 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 a 0.0 means no capacity expansion for that unit.

Column names   OBJ, MIN, MAX, FIX and PCT.

Row names   There are two classes of row names, those which are necessary to the generation of essential parts of the matrix and those which generate additional processing constraints. The former class is relatively fixed; the latter may change with changing circumstances. The fixed rows are: OBJ, LOS, COK, OVC, APF and FRL.

The remaining rows correspond to processing constraints and are discussed below.

Entries   A non-blank entry in column OBJ in any of the first class of rows causes generation of a non-constraining row used for accounting and reporting purposes. This is used in table rows OBJ, LOS and COK.

The other accounting rows form totals of refinery loss and FCC catalyst coke, respectively.

In the same class of rows, a non-blank entry in one of the other columns causes generation of a row of corresponding type. Thus, the row OVC sums other refining variable costs, APF sums losses of light ends to fuel and FRL sums evaporation losses.

It is recommended that this portion of the (R)POL tables not be altered.

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, PFL, PFU, PFF limit H$_2$S, 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 capacities,

---

[4]   PFL, 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.

MSL, MSR, FCR, MSD, MSZ, FCU 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
- FCU: maximum ultra-low sulfur feed operations

MXU, L00, L05, H00, H05, C05, RCU control reformer operations:
- MXU: maximum use of R62 high octane catalyst
- 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
- RCU: maximum ultra-low pressure and low benzene operations on the RFC unit

DKU and DDU limit deep desulfurization of kerosene/heavy kerosene and of diesel/light cycle oil in the distillate desulfurizer. NME limits non-MTBE operations on the in-refinery oxygenate production unit, ETH.

The process table entries in the process constraint rows are of two types:

for severity constraints (SVR, SVH, SVL, SVC) they represent the severity of the given activity (as percentages) and the (R)POL entries represent maximum average severities. The generator program treats any nonzero entry in these rows as percentages.

For the other constraints the process table entries are 0/1. The *(R)POL* entries may be in terms of throughput, each appropriate vector having a +1 in the row and the (R)POL entry is taken as a RHS chosen to limit the sum of those vectors, or they may be percentages (understood as percentage of total throughput).

The generator program will construct percentage controls, provided a non-blank entry appears in column PCT of *table (R)POL*.

Note that the entries in tables (R)POL, which represent throughput, will appear as entries in the RHS column. In the case of percentage controls, no RHS element is generated.

TABLE INVREF   INVESTMENT PARAMETERS REFINERY UNITS

Column names   INV, CAPREC, FXOC, TOTEXP

Row names   Process unit codes.

Entries   Column INV contains investment in $/bbl, CAPREC has the daily annualized investment cost, FXOC has the fixed operating cost in $/bbl, and TOTEXP is the sum of CAPREC and FXOC.

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.

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 INVMOH   INVESTMENT PARAMETERS METHANOL PLANT

Column names   INV, CAPREC, FXOC, TOTEXP

Row names   Process unit MOH.

Entries   Column INV contains investment in $/bbl, CAPREC has the daily annualized investment cost, FXOC has the fixed operating cost in $/bbl, and TOTEXP is the sum of CAPREC and FXOC.

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 INVFACT   **INVESTMENT LOCATION AND ENVIRONMENTAL FACTORS**

Column names   LOC, ENV

Row names   One character refining region code.

Entries   Column LOC contains the investment location factor multiplier, refining region III, U.S. Gulf coast is assumed to be 1.0. Column ENV contains the environmental investment cost multiplier, currently set at 1.0 for all regions.

(:UNSNRF)

GASPLT93   **GAS LIQUIDS PROCESSING PLANT**

Column names   Five columns, (R)01 for each refining region.

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 in Bcf/day, yields in Mbbl/Bcf.

GASSHFT   ALLOW SHIFT OF ETHANE AND PROPANE TO NATURAL GAS

Column names   Two columns, SC2 for shift of ethane to natural gas, SC3 for shift of propane to natural gas.

Row names   CC1, (natural gas), LOS processing loss, and OBJ.

Entries   Amount shifted from gas plant yield to natural gas in Mbbl/Bcf. OBJ represents credit for gas plant operating costs.

GASCAP93   CAPACITY OF GAS PLANT

Column names   Five columns, (R)01 for each refining region.

Row names   CC1, dry gas supply limit, FAC, gas residue factor, CAP, gas plant capacity, LIM, limit on propane shift.

Entries   Gas plant feed and CAP in Bcf/day, FAC is volume fraction, LIM in Mbbl/cd.

MOHPLT93 METHANOL PLANT

Column names   Five columns, (R)01 for each refining region.

Row names   CC1, (natural gas feed), MET methanol output, OVC operating cost.

Entries   Natural gas plant feed in MMcf/day, yields in Mbbl/cd of methanol.

MOHCAP93 CAPACITY OF METHANOL PLANT

Column names   Five columns, (R)01 for each refining region.

Row names   One row, CAP.

Entries   Plant capacity in Mbbl/cd.

A.3.8 Product Blending and Specifications

(:BLEND)

TABLES GCC, DCC — GASOLINE AND DISTILLATE 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.

TABLES GCB, DCB — GASOLINE AND DISTILLATE QUALITIES (EX OCTANE)

Column names   Quality codes

Row names   Intermediate product codes

Entries   Blending values

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   Research and motor octane blending numbers for each component at four levels of lead.

TABLE OCTWT — OCTANE WEIGHTINGS

Simply defines combined or road octane (CON) as a combination of research and motor methods. A fifty-fifty weighting yields the familiar (R+M)/2 octane rating.

The following tables are contained in the member (:BLEND)

TABLE REGBV	*LEADED REGULAR GASOLINE COMPONENT BONUSES*
TABLE UNLBV	*UNLEADED GASOLINE COMPONENT BONUSES*
TABLE RFGBV	*REFORMULATED GASOLINE COMPONENT BONUSES*

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. Non-zero entries are added to the base octanes from *Table MCO* and used in the relevant gasoline blend.

(:SPEC)

TABLES MGSP	*MASTER GASOLINE SPECIFICATIONS.*
Column names	Columns A, KWH plus quality codes
Row names	Finished gasoline codes, followed in the second part of the table by X (maximum) or N (minimum)
Entries	A non-blank entry in column A controls the generation of the corresponding specification control row.

Column KWH contains power requirements for blending.

Remaining columns contain specification levels for the corresponding qualities. (Note that *Table EXSPEC* provides a way of generating only SOME of the quality controls).

Note that, to obtain correct weight blending of sulfur content, the quality code SPM (for gasolines) or SPC (for distillates) must be used, since this code is explicitly used by the generator program. The reason for two different codes is to permit different scaling to be applied to each.

Entries under column API comprise estimated product gravities and are used solely to compute delta sulfur coefficients where regional sulfur specifications differ. For gasoline, a sulfur specification only applies to reformulated gasoline.

TABLE MDSP   **MASTER DISTILLATE/FUEL OIL SPECIFICATIONS**

Column names   A, CST, KWH, STM, plus quality codes.

Row names   In the first part of the table, three-character product codes; in the second part, three-character product code followed by a single character N or X signifying a miNimum or a maXimum constraint.

Entries   Column A needs a non-blank entry in a row with <u>a three-character row name</u> if the quality constraints on the corresponding product are to be generated. Conversely, a blank prevents generation of any quality controls on that product. (Note that **Table EXSPEC** provides a way of generating only SOME of the quality controls.)

Columns CST, KWH, and STM contain any costs (e.g. additive costs), power or steam consumptions encountered in blending the corresponding products. The second part of the table contains specification values for the quality control equations.

Entries under column API comprise estimated product gravities and are used solely to compute delta sulfur coefficients where regional sulfur specifications differ.

(:SPECYnn and SPECD9Ynn)

Specification tables for both gasoline and distllate products are contained in member(s) (:SPECYnn) and (:SPECD9Ynn) where nn is last two digits of NEMS year and D9 contains California specifications.

TABLES W(R)DSP/GSP CHANGED SPECS - REGION R - WINTER
TABLES S(R)DSP/GSP CHANGED SPECS - REGION R - SUMMER

Column names   Any subset of the column names of **Table MDSP/MGSP**.

Row names   Any subset of the row names of **Table MDSP/MGSP**

Entries   These tables are demand region specific and are used to enter in differences from the standard specification values in the master MDSP and MGSP tables. The generator program first creates a set of region-specific **Tables (R)DSP**, which are initially identical copies of **Table MDSP**. Then, according to the entry in **Table**

CONTROL, row SSN, any values given in **Tables W(R)DSP or S(R)DSP** will overwrite the corresponding values in the corresponding (R)DSP tables; similarly for the GSP tables.

In general, blank values in the change spec tables have no effect.

Note that for <u>any</u> specification to be active in the generated matrix, its activation must be anticipated by an appropriate entry in **Table EXSPEC.**

GSPETH   MINIMUM OXYGEN FRACTION IN·RFG

Column names   One column, RE

Row names   One row, RFGN

Entries   Minimum fraction of oxygen in reformulated gasoline.   EPA regulation requires 15% in 1995 and 30% thereafter.

Q(R)DFO   DISTILLATE FUEL OIL SPECIFICATIONS

Column names   Distillates JTA, N2H, DSL and residual fuel oils N6I,N6B

Row names   Product qualities codes using three characters; the first two are quality codes, the last is either X for maximum or N for minimum.

Entries ,   Product quality specifications.

(R)SSR   SUBSPEC RFG QUALITY SPECIFICATIONS

Column names   ETH, RFG, SSR, and RFH

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.

Entries   Product quality specifications. The quality coefficients of SSR reflect a reformulated gasoline that is to be blended with 7.8% Ethanol and therefore has a lower octane and other qualities to accommodate the quality barrels delivered by Ethanol.

(R)SST   *SUBSPEC TRG QUALITY SPECIFICATIONS*

Column names   ETH, TRG, SST, and TRH

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.

Entries   Product quality specifications. The quality coefficients of SST reflect a traditional gasoline that is to be blended with 7.8% Ethanol and therefore has a lower octane and other qualities to accommodate the quality barrels delivered by Ethanol.

(:L2BLNTAB)

When a compact Level 2 formulation is invoked, the Distillate Desulfurization (DDS) and Deep hydrotreating (DHT) process units column activities are deleted and the distillate fuel oil blending submatrices are supplemented with blending activities that reflect the untreated streams, utilities and other inputs needed to produce a barrel of hydrogen treated stream. The following tables are used to supply the appropriate coefficients. The letters (DFO) represent the five distillate fuel oil products (JTA= Jet Fuel, N2H = No. 2 Heating Oil, DSL = Low Sulfur Diesel fuel, N6I = Low Sulfur Residual Oil, N6B = High Sulfur Residual Oil).

FN(DFO)   *UNTREATED STREAM QUALITIES FOR (DFO) FUEL BLENDING*

Column names   Three character untreated intermediate stream codes.

Row names   Product qualities codes using three characters; the first two are quality codes, the last is either X for maximum or N for minimum.

Entries   Product quality specifications. The Sulfur coefficients are the difference between the product specification and the component sulfur content on a weight basis.

BX(DFO)   DDS TREATED STREAM QUALITIES AND INPUTS FOR (DFO) FUEL BLENDING.

Column names Three character pseudo codes for the combination of the untreated/treated stream combination JTA = J01 to J20, N2H = Q01 to Q67, DSL = L01 to L65, N6I = R01 to R60, N6B = S01 to S59.

Row names Product qualities codes using three characters; the first two are quality codes, the last is either X for maximum or N for minimum. Other rows represent the utilities, operating cost, capacity of the DDS unit and untreated intermediate stream inputs required.

Entries Product quality specifications. The Sulfur coefficients are the difference between the product specification and the component sulfur content on a weight basis.

BHDSL   DHT TREATED STREAM QUALITIES AND INPUTS FOR DSL FUEL BLENDING

Column names Three character pseudo codes for the combination of the untreated/treated stream combination from the DHT unit = H01 to H24.

Row names Product qualities codes using three characters; the first two are quality codes, the last is either X for maximum or N for minimum. Other rows represent the utilities, operating cost, capacity of the DHT unit and untreated intermediate stream inputs required.

Entries Product quality specifications. The Sulfur coefficients are the difference between the product specification and the component sulfur content on a weight basis.

TABLE RCP RECIPE BLEND CONTROL

Column names	Two columns, A and CST, 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 making up the blend.

TABLE TRSPMM   PIPING NETWORK AND MISCELLANEOUS TRANSFERS

This unit 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 TRSPMM**, 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 TRSPMM 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.

CKSMIX   SALABLE COKE RECIPES

Column names   Two columns, representing low sulfur coke and high sulfur coke.

Row names   Coke stream codes and Product coke, COK. OBJ is scaled selling price for coke.

Entries   Price for coke in 1987 dollars divided by WOP. Conversion from tons to barrels of salable coke.

BLNSP(D)   RECIPE BLENDING FOR KEROSENE AND RESIDUAL OIL TO UTILITIES

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. A table exists for each Census division.

BLOX(D)YXX   RECIPE BLENDS FOR HIGH OXYGEN GASOLINES IN CENSUS (D)

Column names   Four columns, E85, M85, TRH, and RFH.

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.

A.3.9 Refining Technology

The tables described in this section are essential to the representation of refining technology. The table entries are in volume fractions (bbl Output/bbl Input) except for costs ($/bbl) and utilities for electricity (kWh) or steam (lb/bbl).

(:ACUTAB94)

TABLE ACU ATMOSPHERIC CRUDE UNIT FOR CRUDE GROUPS

Column names	CR followed by three character aggregate crude 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 plus utilities, variable operating cost, capacity and policy constraint rows.
Entries	Volume fractions (bbl Output/bbl Input) except for costs ($/bbl) and utilities for electricity (kWh) or steam (lb/bbl).

This table is a product of the crude oil aggregation groups combined with the yields from the Table AVC, described in a later section.

TABLE AVC CRUDE ATMOSPHERIC DISTILLATION UNIT

Atmospheric distillation refinery process unit. This unit characterizes the 66 assayed 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
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
ATMOS RED CRUDE	(A-M)	Type A through M	ARA-M

Table AVC also specifies the vacuum residua cut points which are used in *Table VCU*, the most common being 1050 degrees Fahrenheit.

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.

Table AVC 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 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.

All the following tables described in this section are located in member name (:UNSREF). The table entries are in volume fractions (bbl Output/bbl Input) except for costs ($/bbl) and utilities for electricity (kWh) or steam (lb/bbl).

(:UNSREF)

TABLE MATBAL MATERIAL BALANCE STREAMS

Column names   One column, A

Row names   Codes for purchased and intermediate streams

Entries   A non-blank entry in column A ensures that the generated model will contain a material balance row for that stream. Material balance rows for crude oils and for finished recipe and blended products are controlled elsewhere.

TABLE CRC CRUDES REPRESENTED BY ASSAYED CRUDES

This table estimates the properties of minor crude oils by specifying a composite using proportions of the relevant assayed crude oils contained in *Table AVC*. The crude oils represented in *Table CRC* extend coverage to include all appreciable production in foreign countries. Countries with multiple grades are represented either by the individual grade or by a single composite grade. All of the current crude mixtures stored in the SPR caverns are also represented.

Since there are 66 assayed crude oils, condensates and synthetic crudes in *Table AVC* to select from, good accuracy may be obtained if the proper proportions are used for estimating the *Table CRC* crudes.

TABLE KRD DELAYED COKER

Delayed coking of vacuum residua and FCC decant oil streams to 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 and 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, LGM, and LGH: paraffinic, low, medium, and high sulfur light gas oils, 690 to 800 degrees Fahrenheit.

HGP, HGL, HGM, and HGH: paraffinic, low, medium, and high sulfur heavy gas oils, 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 TRSPMM* 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 TRSPMM*:

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 of 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 widespread use. However, the advent of reformulated gasoline has renewed interest because the naphtha hydrocracker 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 DHT DISTILLATE DEEP HYDROTREATER

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 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 TRSPMM** 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

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

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 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 TRSPMM* 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
med.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
med.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
med.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
med.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 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 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

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

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 CPL CATALYTIC POLYMERIZATION

A process using 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

A process using 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
LSR GASO(C5-175)ION	SRI
LSR GASO(C5-158)	GLI
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 in 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

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 CGN COGENERATION

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.

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 AVC* 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 *Tables*

(R)POL. Each crude processing vector in *Table AVC* has a 1 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.

APPENDIX B

Mathematical Description of Model

APPENDIX B. Mathematical Description of Model

Each refiner is trying to minimize the cost of meeting demands. Therefore, the market moves toward lower-cost refiners who have access to crude oil and markets. A key premise is that the selection of crude oils, refinery process utilization, and logistics will adjust to minimize the overall cost of supplying the market with petroleum products.

In order to generate refined product prices, the PMM contains a static linear program model of the U.S. petroleum refining and marketing system that meets demand for refined products while minimizing costs. The PMM, like the other NEMS models, is written in FORTRAN. The mainframe software includes the Optimization Modeling Library or OML, a set of FORTRAN callable subroutines. The LP portion of the PMM is a complete problem matrix prepared offline (prior to NEMS processing). The LP remains in fast memory throughout the NEMS run, thereby avoiding many disk I/O operations.

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

Offline processing of the PMM matrix is performed using OMNI[1], a data-driven mathematical programming language. The control program, MPS III[2], and the optimizer, WHIZARD[3], are compatible with the MPS matrix format. Later, it may be convenient and economic to convert to completely FORTRAN callable subroutines for data table manipulation, matrix generation, and solution retrieval programs for report writing.

B.1 Mathematical Formulation

The table of column activity definitions and row constraints defined in the PMM matrix incorporate certain premises which are described in Appendix A. The general structure of the matrix is shown in Table B1.

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[1] Haverly Systems, Inc., *OMNI Linear Programming System, User Reference Manual,*(January 1987).

[2] Ketron Management Science, Inc., *MPS III Mathematical Programming System, User Manual,* (August 1988).

[3] Ibid.

Table B1. PMM Linear Program Structure

PMM Linear Program Overview

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

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

B.2 Matrix Indices

Several indices are used in the column and row definitions presented below. The definition of these indices are shown in Table B2.

Table B2. Index Definitions

Index Symbol	Description
(b)	Domestic crude oil production region
(c)	Crude oil type
(d)	Marketing region
(h)	Product recipe
(i)	Intermediate stream
(m)	Processing mode or shipping mode
(s)	Refinery stream
(p)	Refined product
(q)	Pricing level
(r)	Refinery region
(s)	Refinery stream
(u)	Processing unit type
(v)	Crude oil source
(y)	Product specification quality

B.3 Column Definitions

Table B3. Column Definitions

Column Notation	Description
$B_{a,d,q}$	Volume of alcohol (a) purchased in demand region (d) at price level (q). At present, this column exists only for ethanol.
$D_{p,d}$	Sales volume of product (p) in demand region (d).
$Dn_{p,d,q}$	Increment of sales volume decrease from the base of $D_{d,p}$ for product (p) in demand region (d) at price level (q).
$Dp_{p,d,q}$	Increment of sales volume increase from the base of $D_{d,p}$ for product (p) in demand region (d) at price level (q).
$E_{u,r}$	Stream day capacity added during this simulated period for processing unit type (u) in refinery region (r).
$G_{i,p,r}$	Volume of intermediate stream (i) blended into spec blended product (p) at refinery region (r).
$H_{p,h,r}$	Volume of product (p) manufactured in refinery region (r) using recipe (h).
$H_{p,h,d}$	Volume of product (p) made by recipe (h) in demand region (d) by splash blending.
$I_{p,d}$	Volume of distress import of product (p) into demand region (d) where d = 2,3,7,8,9.
$I_{p,r,q}$	Volume of refined product (p) imported into refinery region (r) at price level (q).
$K_{u,r}$	Base processing capacity in processing unit (u) at refinery region (r) in Mbbl/cd. This column is upper bounded.
$L_{u,r}$	Cumulative stream day capacity added for processing unit (u) at refinery region (r) during the previous simulated periods. This column is fixed.
M_r	Volume of methanol consumed by the chemical industry in refinery region (r).

Column Notation	Description
Mt	Total volume of U.S. methanol consumption by the chemical industry, an input.
$O_{c,v,b}$	Export volume of crude oil (c) with source code (v) produced in domestic region (b).
P_b	Volume of domestic crude oil produced at producing region (b).
$Pi_{c,r,q}$	Volume of imported crude oil type (c) imported by refinery region (r) at price level (q).
$Q_{p,r}$	Volume of spec product (p) manufactured in refinery region (r).
$Ra_{c,v,r}$	Crude oil volume distilled in refinery region (r) from source (v) of crude oil type (c).
$R_{u,r,m}$	Manufacturing activity level in mode (m) operation in processing unit (u) at refinery region (r).
Tu	Total volume of imported unfinished oil over all refinery regions.
$T_{i,r}$	Volume of unfinished oil component (i) processed in refinery region (r).
$Tx_{s,p,r}$	Volume of stream (s) transferred into product (p) in refinery region (r).
$Tx_{p,p',r}$	Volume of product (p) transferred into product (p') storage in refinery region (r).
$Tx_{s,s',r}$	Volume of stream (s) transferred to stream (s') at refinery region (r).
$U_{l,r}$	Quantity of utility (l) that is purchased in refinery region (r): (l) = KWH, STM, and NGF (power, steam, and natural gas fuel) with units in thousands of kWh, Mlbs., and MMcf respectively.
Vcj	Total dead weight ton capacity of Jones Act crude oil tankers. This column is constrained to some maximum.

Column Notation	Description
V_{pc}	Total dead weight tons of Jones Act product tanker of shipping class (pc). This column is constrained to some maximum.
V_{cts}	Total crude oil transhipped from PAD District III to PAD District II. This column is constrained to some maximum.
$V_{cp_{b,r}}$	Total crude oil shipped by pipeline from domestic producing region (b) to refinery region (r). This column is constrained to some maximum.
$V_{pp_{r,d,m}}$	Total volume of light products (p) shipped via pipeline mode (m) from refining region (r) to demand region (d). This column is constrained to some maximum.
$V_{tpl_{r,d,m}}$	Total volume of LPG products (p) shipped via pipeline mode (m) from refining region (r) to demand region (d). This column is constrained to some maximum.
$W_{a,d,r,m}$	Volume of alcohol (a) shipped from demand region (d) to refinery region (r) via mode (m).
$W_{p,r,d,m}$	Volume of product (p) shipped from refinery region (r) to demand region (d) via mode (m).
$W_{p,d,d',m}$	Volume of product (p) transhipped from demand region (d) to demand region (d') via mode (m).
$X_{p,d}$	Volume of product (p) exported from demand region (d).
$Y_{c,v,b,r,m}$	Volume of crude oil type (c) with source code (v) shipped from domestic region (b) to refinery region (r) via mode (m).
$Y_{c,v,r,r',m}$	Volume of domestic crude oil type (c) with source code (v) transhipped from refinery region (r) to refinery region (r') via mode (m).
Z_t	Total volume of crude oil processed over all refinery regions.
ZET_d	Total volume of ethanol supplied from region (d).
ZOX_r	Total quantity of percent oxygen-barrels in reformulated gasoline produced in region (r).

B.4 Objective Function

The objective function has been established based on the premise that costs associated with product imports, non-crude oil inputs, and crude oil supplies are based on a given world oil price. With this in mind, the following objective function has been defined for PMM.

Given:

$PR_{p,d}$ is the unit price of product (p) sold in demand region (d). It is the price associated with the demand volume for that product in the specified demand region, i.e. it is associated with $D_{p,d}$. Similarly, each of the other 'PR' coefficients represents the unit price of the activity it is associated with.

$C_{u,r,m}$ is the variable cost per unit of column $R_{u,r,m}$, i.e. the cost of one unit of manufacturing activity in mode (m) operation in processing unit (u) at refinery region (r). Similarly, each of the other 'C' coefficients represents the unit cost of the activity it is associated with in the objective function as stated below.

TE_d is the sum of federal and state tax credits for use of ethanol in gasoline.

Maximize the difference between the following sum of product revenues and costs. Thus the objective function is represented as the maximization of a quantity defined by the following revenue terms:

$$\Sigma_d\Sigma_p\ D_{d,p}{}^*PR_{d,p} + \Sigma_p\Sigma_d\Sigma_q\ Dp_{p,d,q}{}^*PR_{p,d,q} + \Sigma_p\Sigma_h\Sigma_r\ H_{p,h,r}{}^*PR_{p,h,r} + \Sigma_p\Sigma_h\Sigma_d H_{p,h,d}{}^*PR_{p,h,d}$$

$$+ \Sigma_p\Sigma_d\ X_{p,d}{}^*PR_{p,d} + \Sigma_c\Sigma_v\Sigma_b O_{c,v,b}{}^*PR_{c,v,b} + \Sigma_d\ ZET_d * TE_d$$

minus the following cost terms:

$$\Sigma_p\Sigma_d\Sigma_q\ Dn_{p,d,q}{}^*C_{p,d,q} + \Sigma_a\Sigma_d\Sigma_q\ B_{a,d,q}{}^*C_{a,d,q} + \Sigma_p\Sigma_r\ I_{p,r}{}^*C_{p,r} + \Sigma_p\Sigma_d\ I_{p,d}{}^*C_{p,d}$$

$$+ \Sigma_b\ P_b{}^*C_b + \Sigma_c\Sigma_r\Sigma_q\ Pi_{c,r,q}{}^*C_{c,r,q} + \Sigma_i\Sigma_r\ T_{i,r}{}^*C_{i,r} + \Sigma_l\Sigma_r\ U_{l,r}{}^*C_{l,r}$$

$$+ \Sigma_u\Sigma_r\Sigma_m\ R_{u,r,m}{}^*C_{u,r,m} + \Sigma_u\Sigma_r\ E_{u,r}{}^*C_{u,r} + \Sigma_u\Sigma_r\ L_{u,r}{}^*C_{u,r} +$$

$$+ \Sigma_a\ \Sigma_i\ \Sigma_r\ \Sigma_l\ W_{a,d,r,m}{}^*C_{a,d,r,m} + \Sigma_p\Sigma_r\Sigma_d\Sigma_m\ W_{p,r,d,m}{}^*C_{p,r,d,m} + \Sigma_p\Sigma_d\Sigma_{d'}\Sigma_m\ W_{p,d,d',m}{}^*C_{p,d,d',m}$$

$$+ \Sigma_c\Sigma_v\Sigma_b\Sigma_r\Sigma_m\ Y_{c,v,b,r,m}{}^*C_{c,v,b,r,m} + \Sigma_c\Sigma_v\Sigma_r\Sigma_{r'}\Sigma_m\ Y_{c,v,r,r',m}{}^*C_{c,v,r,r',m}$$

B.5 Row Constraints

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

$$\Sigma_b\ P_b * C_b + \Sigma_c \Sigma_r \Sigma_q\ Pi_{c,r,q} * C_{c,r,q} - WOP * Nwop * Zt\ \geq\ 0$$

where:

P_b	the volume of domestic crude oil produced in production region (b).
C_b	the crude oil cost applicable to P_b. \$/bbl
$Pi_{c,r,q}$	the volume of imported crude oil acquired by refinery region (r) of crude type (c) at price level (q). The volume of each crude type (c) is upper bounded by each step of the supply curve.
$C_{c,r,q}$	is crude oil cost applicable to $Pi_{c,r,q}$. \$/bbl
WOP	is the premised World Oil Price. \$/bbl
Nwop	is minimum fraction of the WOP by which refiners must acquire crude oils by volume weighted average; of course Nwop ≤ 1.
Zt	is total processed crude oil over all refinery regions.

I.e., the average refiner acquisition cost of crude oil will be at least some input fraction of WOP.

Note: The index (v) denoting crude oil source is always "F" for imported crude. Therefore, no summation on (v) occurs for $Pi_{c,r,q}$.

2. The implicit world oil price, WOP (the refiner's acquisition cost of imported crude oil), must not be greater than some fraction of premised WOP:

$$\Sigma_b\ P_b * C_b + \Sigma_c \Sigma_r \Sigma_q\ Pi_{c,r,q} * C_{c,r,q} - WOP * Nwop * Zt\ \leq\ 0$$

where:

Xwop	is the maximum fraction of the WOP by which refiners must acquire crude oils by volume weighted average, of course Xwop ≥ 1.

I.e., the average refinery acquisition cost of crude oil must not exceed some input fraction of WOP.

Note: This constraint in conjuction with the previous constraint confine the imported crude oil volumes so that their composite unit cost is close to the WOP. Since the costs of the 5 types of imported crude oil bracket the WOP, there is a continuum of import possibilities. Of course the crude oils vary in cost according to crude quality and transportation cost. However, to avoid infeasibilities due to an overly restrictive constraint, it is presently the practice to allow a variation of 50 cents per barrel. This is also made necessary when maximum import restrictions are placed on all but a "swing" crude oil. Clearly, if the tolerance is sufficiently relaxed, a single crude type could be imported rather than a reasonably balanced mix.

3. Calculate total crude oil processed by summing all crude oil volumes processed over all refinery regions:

$$\sum_c \sum_v \sum_r Ra_{c,v,r} - Zt = 0$$

where:

$Ra_{c,v,r}$ is the crude oil volume distilled in refinery region (r) from source (v) of crude oil type (c).

i.e. the total U.S. refined crude oil volume equals the sum of all crude oils refined over all regions.

4. Place an upper bound on product import volume:

$$\sum_p \sum_r \sum_q I_{p,r,q} \leq IPmax$$

where:

$I_{p,r,q}$ is the volume of product (p) imported into refinery region (r) at cost level (q).

IPmax is the maximum assumed volume of imported products allowed into the U.S., an input value.

I.e., the sum of product volumes imported at all price levels over all refinery regions must not exceed some maximum.

5. Assure that the volumes of methanol consumed in each refinery region sum to the assumed total volume.

$$\Sigma_r \, M_r - Mt = 0$$

where:

M_r is methanol consumed by the chemical industry in refinery region (r).

Mt is total U.S. methanol consumption by the chemical industry, an input.

I.e., methanol consumed by the chemical industry in each refinery region must sum to the projected chemical industry total.

Note: The PMM models domestic methanol production aggregated to the refinery region level as though the plants were processing units integral to the refinery. The methanol production is allocated to two demands: chemical industry demand and transportation sector demand.

6. Limit capital investment for refinery expansion in each refinery region:

$$\Sigma_u \, E_{r,u} * A_{r,u} \leq Emax_r \qquad \forall \, r$$

where:

$E_{r,u}$ is a capacity addition for this operating year for processing unit type (u) in refinery region (r).

$A_{r,u}$ is the capital investment required per unit of capacity for processing unit type (u) in refinery region (r), million dollars per Mbbl/d.

$Emax_r$ is the upper limit on capital expenditures in refinery region (r), an input. $MM

I.e., total capital expenditures are limited for each refinery region. This limit allows the user to place limits on expansion for a given scenario. The default values are large such that they are not constraining, except in PADD I where a limit of $500 million dollars is the default. This value is based on analyst judgement to reflect the low expectation of refinery expansion on the East Coast.

Note: For NEMS production runs, this constraint has not been operative except for PAD District I. The assumption has been that environmental waivers and permits will preclude capacity additions in this region.

7. Limit total U.S. refinery capital investment:

$$\Sigma_r \Sigma_u \ E_{r,u} * A_{r,u} \ \leq \ Emax$$

where:

Emax   is the upper limit on capital investment over all refinery regions, an input. $MM

I.e., total capital expenditures are constrained to some maximum. This limit allows the user to place limits on expansion for all regions in the United States. The default value is $50 billion and is not constraining.

Note: This constraint has been used to determine maximum product import needs by setting Emax to zero. It has not been operative in any production runs thus far. However, like the previous row, it is a potential policy exploration handle. For instance, one could hypothesize that in a capital-short domestic environment, total industry investment is limited.

8. Limit the volume of unfinished oil processed in U.S. refineries:

$$\Sigma_c \Sigma_v \Sigma_r \ Ra_{c,v,r} \ - \ B1 * Tu \ \geq \ B0$$

where:

$Ra_{c,v,r}$ is the crude oil volume distilled in refinery region (r) from source (v) of crude oil type (c).

Tu   is total processed unfinished oil over all refinery regions.

B0,B1   are regression equation coefficients (see Appendix A). B0 = 11,674.3, B1 = 4.087.

I.e., the maximum allowable unfinished oil processed is a linear function of total crude oil processed.

9. Limit the volume of each unfinished oil component processed in each refinery region:

$$A_{i,r} * Tu - T_{i,r} \geq 0 \quad \forall \; r, i$$

where:

$T_{i,r}$ is the volume of unfinished oil component (i) processed in refinery region (r).

$A_{i,r}$ is the fraction of component (i) of total unfinished oil that is processed in refinery region (r), an input.

I.e., the volume distribution of each type of unfinished oil processed at each refinery region is constrained to the historical pattern.

10. Balance by volume, at the demand regions, each alcohol purchased by the petroleum industry and domestic methanol shipped in from the refinery regions against alcohol blended by recipe in the demand region and alcohol shipped out of the demand region:

$$\Sigma_q \, B_{a,d,q} + \Sigma_r\Sigma_m \, W_{a,r,d,m} - \Sigma_p\Sigma_h \, H_{p,h,d}*A_{h,a} - \Sigma_r\Sigma_m \, W_{a,d,r,m} \;\; = \; 0 \quad \forall \; a, d$$

where:

$B_{a,d,q}$ is the volume of alcohol (a) purchased in demand region (d) at price level (q). At present, this column exists only for ethanol.

$W_{a,r,d,m}$ is the volume of alcohol (a) received in demand region (d) from refinery region (r) via shipping mode (m). This column exists only for methanol.

$H_{p,h,d}$ is the volume of recipe product (p) containing alcohol (a) consumed in demand region (d).

$A_{h,a}$ is the recipe fraction, by volume, of alcohol (a) in product (p), an input.

$W_{a,d,r,m}$ is the volume of alcohol (a) shipped from demand region (d) to refinery region (r) via mode (m). This column is valid only for ethanol. It is assumed that all ethanol purchases are made in the demand regions. Thus, ethanol needed by the refinery for processing or blending must be shipped from the demand regions.

I.e., in each demand region, all alcohol that is purchased or produced and shipped in from the refinery regions must be either splash blended into or shipped to a refining center.

11. For those products which are not blended by recipe at the demand regions, each demand region, and for each product, imports plus what is received via domestic shipment must equal the volume blended into recipes plus regular sales volume:

$$I_{p,d} + \Sigma_r \Sigma_m W_{p,r,d,m} - X_{p,d} - \Sigma_p \Sigma_h H_{p',h,d} * A_{p,h} - D_{p,d} + \Sigma_q Dn_{p,d,q} - \Sigma_q Dp_{p,d,q} = 0$$
$$\forall \ d, p$$

where:

$I_{p,d}$ is volume of product (p) imported into demand region (d).

$W_{p,r,d,m}$ is product (p) received in region (d) from refinery region (r) via mode (m).

$X_{p,d}$ is volume of product (p) exported from demand region (d).

$H_{p',h,d}$ is volume of product (p') manufactured by recipe (h) at demand region (d). This column exists only when product (p) is consumed to produce product (p) by a recipe blended at the demand region, i.e. splash blended at the terminals.

$A_{p,h}$ is the volume fraction of product (p) consumed by recipe (h), an input.

$D_{p,d}$ is a base sales volume of product (p) in demand region (d), this activity is fixed at the last NEMS iterative demand value; i.e., it does not impact the solution.

$Dn_{p,d,q}$ is an increment of sales volume decrease from the base of $D_{d,p}$ for product (p) in demand region (d) at price level (q).

$Dp_{p,d,q}$ is an increment of sales volume increase from the base of $D_{d,p}$ for product (p) in demand region (d) at price level (q).

I.e., in each demand region, for each product, a balance is made whereby the volume imported and the volume shipped in from the refinery regions must equal the volume splash blended at the terminal plus straight sales volume.

Note: The columns $Dn_{p,d,q}$ and $Dp_{p,d,q}$ represent and allow incremental increases and decreases around the base demand

value, $D_{p,d}$. An increase in volume around this base is activated with an average input price determined by the demand elasticity of the product. The situation for incremental volume decreases is similar, except the price is given a negative value since the increment is essentially being backed out of the base volume. The purpose of this structure, as opposed to having a single fixed $D_{p,d}$, is to reduce wide swings in demand between NEMS iterations and thus make the marginal price more stable. This is called the "avoids" structure.

12. Balance, at each demand region, the volumes for each of the recipe products M85 and E85 - the products which are blended at the demand terminals - so that manufactured volume plus imports equals the recipe sales volume for these terminal splash blended recipes:

$$\Sigma_h \, H_{p',h,d} + I_{p',d} - D_{p',d} = 0 \quad \forall \ p', d$$

where:

$p' \in p$ so that p' is a subset of all products and in fact, p' = E85 and M85.

$H_{p',h,d}$ is volume of product (p') made by recipe (h), produced at demand region (d) by splash blending.

$I_{p',d}$ is volume of product (p') imported into demand region (d).

$D_{p',d}$ is the sales volume of product (p') in demand region (d).

I.e., for each demand region, all M85 and E85 blended at the terminals plus M85 and E85 imported into the demand region must equal sales of the corresponding products.

13. For Census Divisions (demand regions) 5 and 6, balance the volume of each product that is shipped into the demand region with volume shipped out of the demand region:

$$\Sigma_m \, W_{p,r,d',m} + \Sigma_d \Sigma_m \, W_{p,d,d',m} - \Sigma_d \Sigma_m \, W_{p,d',d,m} = 0 \quad \forall \ d', p$$

where:

$d' \in d$ and in fact, d' = Census Divisions 5 (South Atlantic) and 6 (South Central).

$W_{p,r,d',m}$ is volume of product (p) received by demand region (d') from refinery region (r) via pipeline (P/L) mode (m). These columns are generated only for the pipeline shipping mode when (d') is CD 6.

$W_{p,d,d',m}$ is volume of product (p) received in demand region (d') via transhipment from demand region (d) by mode (m), e.g. from 6 to 5 or from 5 to 2. For these columns, d' = d is not allowed.

$W_{p,d',d,m}$ is volume of product (p) transhipped from demand region (d') to demand region (d) by mode (m). However, for these columns, d' = d is allowed; in this case the activity represents P/L sales

I.e., pipeline product received in CD 5 or CD 6 must balance P/L product sales and transhipments.

Note: CD 5 and CD 2 (Mid Atlantic) receive much of their product volumes via pipeline (P/L) originating in PAD District III. Thus PAD District II production which is transported via P/L is split into one activity representing P/L product which is sold in CD 6 and another activity which is product transhipped through CD 6 into CD 5. Similarly, this latter component is split into two column activities, one which represents P/L product sales in CD 5, and another which represents product transhipped through CD 5 to CD 2.

14. Balance the domestic production of each crude type at each producing region against exports and shipments to domestic refineries:

$$P_b * A_{c,v,b} - O_{c,v,b} - \sum_r \sum_m Y_{c,v,b,r,m} = 0 \quad \forall \ b, c, v$$

where:

P_b is total volume of domestic crude oil produced at producing region (b).

$A_{c,v,b}$ is the fraction by volume of P_b that is crude type (c) with source code (v), an input.

$O_{c,v,b}$ is the export volume of crude oil (c) with source code (v) produced in domestic region (b).

$Y_{c,v,b,r,m}$ is volume of crude oil type (c) with source code (v) produced in domestic region (b) that is shipped to refinery region (r) via mode (m).

I.e, for each production region and crude oil type, domestic production must be balanced against exports and shipments to refinery regions.

15. Limit shipments of crude oil on Jones Act marine tankers:

$$\Sigma_c \Sigma_v \Sigma_b \Sigma_r \Sigma_{m'} \ Y_{c,v,b,r,m'} * A_c - Vcj \ = \ 0$$

where:

$m' \in m$ m' is the set of shipping modes that correspond to Jones Act crude oil tankers.

$Y_{c,v,b,r,m'}$ is volume of crude oil type (c) with source code (v) produced in domestic region (b) that is shipped to refinery region (r) via mode (m').

A_c is dead weight tons per barrel of crude oil of type (c), about 0.1344.

Vcj is total dead weight tons of Jones Act crude oil. This column is constrained to some maximum.

I.e., total Jones act crude oil shipments are limited by the existing fleet.

Note: This constraint is stated in the form 'X - MAX = 0' with bounds on MAX rather than in the form 'X ≤ MAX' (which is more straight forward from a mathematical standpoint) because this allows the analyst to add a minimum constraint or change over to a fixed constraint within the fortran code without a regeneration of the MPS file. Thus it is an artifice of convenience.

16. Limit shipments of refined product on Jones Act marine tankers by product class (clean, dirty...):

$$\Sigma_p \Sigma_r \Sigma_d \Sigma_{m'} \ W_{p',r,d,m'} * A_{p'} - V_{pc} \ = \ 0 \qquad \forall \ \text{product class (pc)}$$

where:

$m' \in m$ m' is the set of shipping modes that correspond to Jones Act product tankers carrying product class (pc).

$p' \in p$ p' is the set of products which correspond to the product class (pc) of the particular constraint row.

$W_{p',r,d,m'}$ is volume of product (p') shipped from refinery region (r) to demand region (d) via mode (m').

A_c is dead weight tons per barrel of product (p), an input.

V_{pc} is total dead weight tons of Jones Act product of a shipping class (pc). This column is constrained to some maximum.

I.e., Jones Act product shipment volume is limited by tanker availability.

17. Allow and limit transhipments of crude oil from the Gulf Coast to the PAD District II refining region:

$$\Sigma_v \Sigma_c \, Y_{c,v,G,C,m} - Vcts = 0$$

where:

$Y_{c,v,G,C,m}$ is volume of crude oil type (c) with source code (v) that is transhipped from the PAD District III (code=G) refinery region to the PAD District II (code=C) refinery region.

$Vcts$ is total crude oil transhipped from PAD District III to PAD District II. This column is constrained to some maximum

I.e., the volume of crude oil shipped from the Gulf Coast to PAD District II refineries is limited.

18. For each domestic crude oil producing region and refinery region (r) allowable combination, allow and limit pipeline shipments of crude oil:

$$\Sigma_c \Sigma_v \Sigma_m \, Y_{c,v,b,r,m} - Vcp_{b,r} = 0 \qquad \forall \ b, r$$

where:

$Y_{c,v,b,r,m}$ is volume of Crude oil type (c) that is shipped from domestic producing region (b) to refinery region (r) via pipeline mode (m).

$Vcp_{b,r}$ is total crude oil shipped by pipeline from domestic producing region (b) to refinery region (r). This column is constrained to some maximum.

I.e., limit the crude oil volume shipped by pipeline from each applicable producing region//refinery region pair.

19. For each refinery/demand region applicable combination, limit pipeline shipments of light products to available capacity:

$$\Sigma_{p'}\Sigma_{r}\Sigma_{d}\Sigma_{m} \; W_{p',r,d,m} - Vpp_{r,d,m} \; = \; 0 \qquad \forall \quad r, d, m$$

where:

$p' \in p$ p' is the set of light products which can be shipped from refinery region (r) to demand region (d) via pipeline mode (m).

$W_{p',r,d,m}$ is volume of product (p') shipped from refinery region (r) to demand region (d) via pipeline mode (m).

$Vpp_{r,d,m}$ is total volume of light products (p') shipped via pipeline mode (m) from refining region (r) to demand region (d). This column is constrained to some maximum.

I.e., the volume of light products that can be shipped by pipeline from each refinery region to each demand region is limited by the available pipeline capacity.

20. For each refinery/demand region applicable combination, limit pipeline shipments of liquid petroleum gas volumes to available LPG pipeline capacity:

$$\Sigma_{p'}\Sigma_{r}\Sigma_{d}\Sigma_{m} \; W_{p',r,d,m} - Vtpl_{r,d,m} \; = \; 0 \qquad \forall \quad r, d, m$$

where:

$p' \in p$ p' is the set of LPG products which can be shipped from refinery region (r) to demand region (d) via pipeline mode (m).

$W_{p',r,d,m}$ is volume of LPG product (p') shipped from refinery region (r) to demand region (d) via pipeline mode (m).

$Vtpl_{r,d,m}$ is total volume of LPG products (p') shipped via pipeline mode (m) from refining region (r) to demand region (d). This column is constrained to some maximum.

I.e., the volume of LPG products that can be shipped by pipeline from each refinery region to each demand region is limited by the available pipeline capacity.

21. Refinery 'policy' table entries are adhered to:

$$\Sigma_u \Sigma_m \, R_{u,r,m} \, * \, A_{e,u,r,m} \quad \leq,\geq,= \quad A_{e,r} \qquad \forall \quad e, r$$

where:

$R_{u,r,m}$ is the manufacturing activity level in mode (m) operation in processing unit (u) at refinery region (r).

$A_{e,u,r,m}$ is the coefficient entered into the processing unit (u) table for refinery region (r) in the operating mode (m) column at policy row (e), an input.

$A_{e,r}$ is the value entered in the policy table in row (e) for refinery region (r), an input.

I.e., constraints may be introduced by the analyst via the "policy" rows.

Note: The type of row ($\leq,\geq,=$) is determined by the column heading in the policy table in which the right hand side value (RHS), $A_{e,r}$, appears; MAX, MIN, or FIX. It may also be a non-constraining row, in which case there is no RHS and the row is free.

22. For each applicable combination of domestic crude oil and refinery region, balance shipments received directly from the producing region plus transhipments received from other refinery regions against crude oil consumed at the refinery and crude that is transhipped to other refinery regions:

$$\Sigma_b \Sigma_m \, Y_{c,v,b,r,m} \; + \; \Sigma_r \Sigma_m \, Y_{c,v,r',r,m} \; - \; \Sigma_r \Sigma_m \, Y_{c,v,r,r',m} \; - \; Ra_{c,v,r} \quad = \quad 0 \qquad \forall \quad c, v, r$$

where:

$Y_{c,v,b,r,m}$ is volume of crude oil type (c) with source code (v) produced in domestic region (b) that is shipped to refinery region (r) via mode (m).

$Y_{c,v,r',r,m}$ is volume of domestic crude oil type (c) with source code (v) that is received at refinery region (r) by transhipment through refinery region (r') via mode (m).

$Y_{c,v,r,r',m}$ is volume of domestic crude oil type (c) with source code (v) that is transhipped through refinery region (r) to refinery region (r') via mode (m).

$Ra_{c,v,r}$ is volume of domestic crude oil type (c) with source code (v) that is processed through the atmospheric tower at refinery region (r).

I.e., for each domestic crude oil at each refinery region, the volume consumed at the refinery plus what is shipped out of the refinery region must equal what is shipped into the refinery region.

23. For each applicable combination of imported crude oil and refinery region, balance imports received directly plus imports transhipments received from other refinery regions against crude oil consumed at the refinery and crude that is transhipped to other refinery regions:

$$\Sigma_q \, Pi_{c,r,q} + \Sigma_{r'}\Sigma_m \, Y_{c,F,r',r,m} - \Sigma_{r'}\Sigma_m \, Y_{c,F,r,r',m} - Ra_{c,F,r} = 0 \quad \forall \; c, r$$

where:

$Pi_{c,r,q}$ is the quantity of imported crude oil acquired by refinery region (r) of crude type (c) at price level (q).

$Y_{c,F,r',r,m}$ is volume of imported crude oil type (c) that is received at refinery region (r) by transhipment from refinery region (r') via mode (m).

$Y_{c,F,r,r',m}$ is volume of imported crude oil type (c) that is transhipped from refinery region (r) to refinery region (r') via mode (m).

$Ra_{c,F,r}$ is volume of imported crude oil type (c) that is processed through the atmospheric tower at refinery region (r).

I.e., each imported crude oil must be balanced at each refinery by matching imports and what is received through transhipment against refinery consumption and what is transhipped to other refineries.

24. Balance each product at each refinery region:

$$Q_{p,r} + \Sigma_h H_{p,h,r} + \Sigma_q I_{p,r,q} + \Sigma_{p'} \, Tx_{s,p,r} - \Sigma_{p'} \, Tx_{p,p',r} - \Sigma_p\Sigma_h \, H_{p',h,r}*A_{p,h}$$

$$- \Sigma_m\Sigma_d \, W_{p,r,d,m} = 0 \quad \forall \; p, r$$

where:

$Q_{p,r}$ is volume of spec product (p) manufactured in refinery region (r). When product (p) is a spec product, column $H_{p,h,r}$ does not exist.

$H_{p,h,r}$ is volume of product (p) manufactured in refinery region (r) using recipe (h). When this column is active for product (p), column $Q_{p,r}$ does not exist.

$I_{p,r,q}$ is volume of refined product (p) imported into refinery region (r) at price level (q).

$Tx_{s,p,r}$ is the volume of stream (s) transferred into product (p) in refinery region (r).

$Tx_{p,p',r}$ is the volume of product (p) transferred into product (p') storage in refinery region (r).

$H_{p',h,r}$ is the volume of product made by recipe (h) at refinery region (r) in which product (p') is an ingredient.

$A_{p,h}$ is the volume of product (p) consumed per unit of recipe (h), an input.

$W_{p,r,d,m}$ is the volume of product (p) shipped from refinery region (r) to demand region (d) via mode (m).

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

25. Balance each utility at each refinery region:

$$U_{l,r} + \Sigma_u \Sigma_m R_{u,r,m} * A_{l,u,r,m} - \Sigma_p Q_{p,r} * A_{l,p,r} - \Sigma_p \Sigma_h H_{p,h,r} * A_{l,h,r} = 0 \quad \forall \ r, l$$

where:

$U_{l,r}$ is the quantity of utility (l) that is purchased in refinery region (r). Of course (l) = KWH, STM, and NGF (power, steam, and natural gas fuel) with units in thousands of kWh, lbs., and Mcf respectively.

$R_{u,r,m}$ is the manufacturing activity level in mode (m) operation in processing unit (u) at refinery region (r).

$A_{l,u,r,m}$ is the quantity of utility (l) consumed (-) or manufactured (+) per unit of operation of processing unit (u) in mode (m) in refinery region (r). The (u) index includes the utility manufacturing units.

$Q_{p,r}$ is the volume of spec product (p) manufactured at refinery region (r). This column exists only when product (p) is a spec blend.

$A_{l,p,r}$ is the quantity of utility (l) consumed per unit of spec product (p) manufactured at refinery region (r).

$H_{p,h,r}$ is the volume of product (p) manufactured by recipe blend (h) at refinery region (r). This column exists only when product (p) is a spec blend.

$A_{l,h,r}$ is the quantity of utility (l) consumed per unit of recipe product (h) manufactured at refinery region (r).

     I.e., for each utility at each refinery region, the quantity purchased plus the amount manufactured must equal the consumption.

26. Constrain each processing unit throughput to maximum capacity at each refinery region:

$$\sum_m R_{u,r,m} - K_{u,r} - A_{u,r} * (L_{u,r} + E_{u,r}) = 0 \qquad \forall \ r, u$$

where:

$R_{u,r,m}$ is the manufacturing activity level in mode (m) operation in processing unit (u) at refinery region (r).

$K_{u,r}$ is the base processing capacity in processing unit (u) at refinery region (r) in Mbbl/cd. This column is upper bounded rather than fixed. See note below.

$A_{u,r}$ is the stream factor for processing unit (u) at refinery region (r) defined as the ratio of calendar day capacity to stream day capacity.

$L_{u,r}$ is the cumulative stream day capacity added for processing unit (u) at refinery region (r) during the previous simulated periods. This column is, of course, fixed.

$E_{u,r}$ is the stream day capacity added during this simulated period for processing unit (u) at refinery region (r). This column is generally upper bounded.

     I.e., the activity of a particular processing unit must be limited to the maximum operating capacity.

Note: By making this row fixed with the base capacity upper bounded, the processing throughput is calculated as $K_{u,r}$ + $A_{u,r}*(L_{u,r} + E_{u,r})$. Of course, in a model lacking capacity expansion capability, the capacity constraint row is commonly constructed as throughput and is equal to or less than a right-hand-side capacity value so that the throughput is merely the row activity.

27. Balance each intermediate refinery stream at each refinery region:

$$\Sigma_u \Sigma_m R_{u,r,m} * A_{i,u,r,m} + \Sigma_s (Tx_{s,i,r} - Tx_{i,s,r}) - \Sigma_p G_{i,p,r} - \Sigma_p \Sigma_h H_{p,h,r} * A_{i,h} = 0 \qquad \forall \ i, r$$

where:

$i \in s$ i.e., the intermediate streams are a subset of all refinery streams.

$R_{u,r,m}$ is the manufacturing activity level in mode (m) operation in processing unit (u) at refinery region (r).

$A_{i,u,r,m}$ is the volume fraction of intermediate stream (i) created (or consumed if the sign is negative) per unit of manufacturing activity level in mode (m) operation in processing unit (u) at refinery region (r) for processing unit (u) at refinery region (r).

$Tx_{s,i,r}$ is the volume of stream (s) transferred to intermediate stream (i) at refinery region (r).

$Tx_{i,s,r}$ is the volume of intermediate stream (i) transferred to stream (s) at refinery region (r).

$G_{i,p,r}$ is the volume of intermediate stream (i) blended into spec blended product (p) at refinery region (r).

$H_{p,h,r}$ is the volume of product (p) manufactured according to recipe (h) at refinery region (r).

$A_{i,h}$ is the volume fraction of intermediate stream (i) consumed per unit volume of product manufactured according to recipe (h) at refinery region (r).

I.e., at each refinery region, each intermediate stream must be volume balanced so that the amount manufactured plus the amount transferred from higher quality streams must equal the volumes consumed by manufacturing processes, the amount that may be transferred to other lower quality streams plus the volumes blended into spec and recipe products.

28. Constrain qualities of spec blended products:

$$\sum_i G_{i,p,r} * A_{y,i,p} - Q_{i,r} * A_{y,p,r} \quad \leq, \geq, = \quad 0 \qquad \forall \quad y, p, r$$

where:

$G_{i,p,r}$ is the volume of intermediate stream (i) blended into spec-blended product (p) at refinery region (r).

$A_{y,i,p}$ is the blend value of property (y) for spec product (p) of stream (i).

$Q_{p,r}$ is the total volume of spec-blended product (p) manufactured at refinery region (r).

$A_{y,p,r}$ is the constraining value of property (y) that spec product (p) must adhere to; e.g., an octane number, at refinery region (r).

Note: The row type varies depending upon whether the blend specification quality is a maximum, minimum, or fixed value.

i.e., for each spec for each product at each refinery region, the aggregate spec value of the product determined by volume weighting the spec properties of the consumed blending stocks must not violate the specification limit.

29. Sum oxygen percentage contribution by oxygenates blended to reformulated gasoline

$$\sum_{OX} G_{OX,RFG,r} * PO_{OX} + H_{ETH,RFG,r} * PO_{ETH} * F_{ETHRFG} + H_{ETH,RFH,r} * PO_{ETH} * F_{ETHRFH} = ZOX_r$$

where:

$G_{OX,RFG,r}$ is the volume of oxygenate stream (OX) blended to RFG in region (r).

PO_{OX} is the percentage oxygen in oxygenate stream (OX). This group includes MTBE, TAM, and THM from methanol and ETB, TAE, and THE from ethanol. Also included is the ethanol splash blended.

$H_{ETH,RFG,r}$ is the volume of RFG splash blended with ethanol in region r.

PO_{ETH} is the percentage oxygen in ethanol

F_{ETHRFG} is the fraction of ethanol in RFG for 2.0% min oxygen (= 5.8%).

$H_{ETH,RFH,r}$ is the volume of RFH splash blended with ethanol in region r.

F_{ETHRFH} is the fraction of ethanol in RFH for 2.7% min oxygen (= 7.8%).

ZOX_r is the total volume in units of percent oxygen-barrels of RFG.

30. Sum oxygen percentage contribution by renewable oxygenates blended to RFG.

$$\Sigma_{OE}\; G_{OE,RFG,r}\; *PO_{OE} + H_{ETH,RFG,r}\; *PO_{ETH}\; *F_{ETHRFG} + H_{ETH,RFH,r}\; *PO_{ETH}\; *F_{ETHRFH} \geq L*ZOX_r$$

where, in addition to the terms defined in equation 29:

$G_{OE,RFG,r}$ is the volume of renewable oxygenate stream (OE) blended to RFG in region (r).

PO_{OE} is the percentage oxygen in oxygenate stream (OE). This group includes ETB, TAE, and THE from ethanol. Also included is the ethanol splash blended.

L is the volume fraction of the oxygen that must come from renewable oxygenates, i.e., ethanol, ethylbenzene (ETB) and ethyl ethers (TAE and THE).

31. In addition to the above, several non-constraining rows exist merely as a convenience to sum over certain columns via the row activity parameter.

B.6 Row and Column Cross References

The PMM LP matrix is generated from a program written in the OMNI language. The correspondence between the rows and the column symbols in the preceding matrix description and the OMNI generated names of PMM are shown in Table B4.

Table B4. Column Cross References

Column Notation	OMNI Name
$B_{a,d,q}$	C(d)(a)R(q)
$D_{p,d}$	D(d)(p)S1
$Dn_{p,d,q}$	D(d)(p)N(q)
$Dp_{p,d,q}$	D(d)(p)P(q)
$E_{u,r}$	E(r)(u)INV
$G_{i,p,r}$	B(r)(p)(i) & F(r)(p(i)
$H_{p,h,r}$	X(r)(h)(p)
$H_{p,h,d}$	X(d)(h)(p)
$I_{p,d}$	I(d)(p)Z9
$I_{p,r,q}$	I(r)(p)R(q)
$K_{u,r}$	K(r)(u)CAP
$L_{u,r}$	L(r)(u)BLD
M_r	G(r)METDEM
Mt	D@METS1
$O_{c,v,b}$	O@CRDEXP
P_b	P(b)DCRQ1
$Pi_{c,r,q}$	P(r)F(c)Q(q)

Column Notation	OMNI Name
$Q_{p,r}$	Q(r)(p)
$Ra_{c,v,r}$	R(r)ACU(v)(c)
$R_{u,r,m}$	R(r)(u)(m)
Tu	T@TOTUNF
$T_{i,r}$	T(r)UNF(i)
$Tx_{s,p,r}$	T(r)(s)(p)
$Tx_{p,p',r}$	T(r)(p)(p')
$Tx_{s,s',r}$	T(r)(s)(s')
$U_{l,r}$	U(r)(l)
Vcj	VTVC(m)CP
V_{pc}	VTVP(m)CP
$Vcts$	VTPCGAC
$Vcp_{b,r}$	VTPC(b)(m)(r)
$Vpp_{r,d,m}$	VPP(r)(d)(m)
$Vtpl_{r,d,m}$	VTPL(r)(m)(d)
$W_{a,r,d,m}$	W(r)(a)(m)(d)
$W_{a,d,r,m}$	W(d)(a)(m)(r)
$W_{p,r,d,m}$	W(r)(p)(m)(d)
$W_{p,d,d',m}$	W((d)(p)(m)(d')
$X_{p,d}$	D(d)(p)Z9
$Y_{c,v,b,r,m}$	Y(b)(v)(c)(m)(r)
$Y_{c,v,r,r',m}$	Y(r)(v)(c)(m)(r')

Column Notation	OMNI Name
Zt	Z@TOTCRD
ZET_d	Z(d)ETHTAX
ZOX_r	Z(r)RFGOXY

Table B5. Row Cross References

Row Number	OMNI Name
1	Z@IRACN
2	Z@IRACX
3	Z@CRDTOT
4	A@PRDIMP
5	D@MET
6	A@INVST
7	A(r)INVST
8	F@TOTCRD
9	F(r)UNF(i)
10	D(d)(a)
11	D(d)(p)
12	D(d)(p')
13	M(d)(p)
14	C(b)(v)
15	TVC(m)CP
16	TVP(m)CP
17	TPCGAC
18	TPC(b)(m)(r)
19	TPP(r)(m)(d)
20	TPL(r)(m)(d)
21	P(r)(e)
22	C(r)(v)(c)
23	C(r)F(c)
24	M(r)(p)
25	U(r)(l)
26	L(r)(u)CAP
27	B(r)(i)
28	Q(r)(p)(y)
29	S(r)RFGOXY
30	Q(r)RFGREN

APPENDIX C

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APPENDIX C Bibliography

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APPENDIX D

Model Abstract

APPENDIX D   Model Abstract

D.1   Model Name:

Petroleum Market Model

D.2   Model Acronym:

PMM

D.3   Description:

The Petroleum Market Model is a simulation of the U.S. petroleum industry. It includes 12 domestic crude oil production regions, 5 refining centers with full processing representations and capacity expansion capability and gas plant liquid production, and 9 marketing regions. The heart of the model is a linear program optimization which ensures a rational economic simulation of decisions of petroleum sourcing, resource allocations, and the calculation of marginal price basis for the products. Eighteen refined products are manufactured, imported, and marketed. Seven of these products are specification blended, while the remaining 11 are recipe blended. Capacitated transportation systems are included to represent existing intra-U.S. crude oil and product shipments (LPG, clean, dirty) via pipeline, marine tanker, barge, and truck/rail tankers. The export and import of crude oil and refined products is also simulated. All imports are purchased in accordance with import supply curves. Domestic manufacture of methanol is represented as though the processing plants were a part of the refinery complexes whereas ethanol sources are treated as merchant. Transportation is allowed for ethanol shipments to the demand region terminals for splash blending.

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

D.4 Purpose of the Model:

The PMM models domestic petroleum refining activities, the marketing of petroleum products to consumption regions, the production of natural gas liquids in gas processing plants, and domestic methanol production. 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 model contains adequate structure and is sufficiently flexible to examine the impact of a wide variety of petroleum-related issues and policy options, in order to foster understanding of the petroleum refining and marketing industry as well as determine the effects of certain policies and regulations.

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

D.5 Most Recent Model Update:

November 1994

D.6 Part of Another Model?

National Energy Modeling System (NEMS)

D.7 Model Interfaces:

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

D.8 Official Model Representative:

Bruce Bawks
Office of Integrated Analysis and Forecasting
Oil and Gas Analysis Branch
(202) 586-6579

D.9 Documentation:

EIA Model Documentation: Petroleum Market Model of the National Energy Modeling System (NEMS), December 1994. (DOE/EIA-M059).

D.10 Archive Media and Installation Manual

Archived as part of the NEMS production runs.

D.11 Energy System Described:

Petroleum refining industry and refined products market.

D.12 Coverage:

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

Time Unit/Frequency: Annual, 1990 through 2010

Products: LPG, traditional motor gasoline, traditional high oxygen motor gasoline, reformulated motor gasoline, reformulated high oxygen motor gasoline, M85, E85, jet fuel, distillate fuel oil, highway diesel, low-sulfur residual fuel oil, high-sulfur residual fuel oil, petrochemical feedstocks, asphalt/road oil, marketable coke, still gas, other.

Refinery Processes: crude distillation, vacuum distillation, delayed coker, fluid coker, visbreaker, fluid catalytic cracker, hydrocracker-dist, hydrocracker-resid, solvent deasphalter, resid desulfurizer, FCC feed hydrofiner, distillate HDS, naphtha hydrotreater, catalytic reformer-450 psi, catalytic reformer-200 psi, alkylation plant, catalytic polymerization, pen/hex isomerization, butane isomerization, MTBE (etherol), butanes splitter, dimersol, butylene isomerization, naphtha splitter, C2-C5 dehydrogenator, hydrogen plant, sulfur plant, aromatics recovery plant, lube + wax plants, FCC gasoline splitter, gas/H2 splitter, stream transfers, fuel system, steam production, power generation

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

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

D.13 Modeling Features:

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

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

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

D.14 Non-DOE Input Sources:

Information Resources Inc. (IRI), WORLD model data, National Petroleum Council, ICF Resources

D.15 DOE Input Sources:

Forms:/

EIA-14	Refiners' Monthly Cost Report
EIA-182	Domestic Crude Oil First Purchase
EIA-782A	Monthly Petroleum Product Sales
EIA-782B	Reseller/Retailer's Monthly Petroleum Product Sales
EIA-782C	Monthly Petroleum Products Sold into States for Consumption
EIA-810	Monthly Refinery Report
EIA-811	Monthly Bulk Terminal Report
EIA-812	Monthly Product Pipeline Report
EIA-813	Monthly Crude Oil Report
EIA-814	Monthly Imports
EIA-817	Monthly Tanker and Barge Movement
EIA-820	Annual Refinery Report
EIA-826	Monthly Electric Utility Sales
EIA-856	Monthly Foreign Crude Oil Acquisition
EIA-867	Annual Nonutility Power Producer Report

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

D.16 Computing Environment:

Hardware:	IBM 3090
Operating System:	MVS
Software:	VS FORTRAN ver. 2.05
Memory Requirement:	4,000K
Storage Requirement:	550 tracks on an IBM 3080 disk pack (26.4 MB)
Estimated Run Time:	5,000 seconds in a full NEMS run (26 years)
Special Features:	None.

D.17 Independent Expert Reviews Conducted:

Independent reviews of the Component Design Report of the PMM were conducted by:

A.S. Manne, ASM Consulting Services, July 1992
A.S. Manne, ASM Consulting Services, September 1992

D.18 Status of Evaluation Efforts by Sponsor:

None.

APPENDIX E

Data Quality

APPENDIX E. Data Quality

E.1 Quality of Distribution Cost Data

Costs related to distributing petroleum products to end-users are incorporated by adding fixed transportation markups to the wholesale prices which include the variable and fixed refinery costs. Transportation markups for petroleum products are estimated as the average annual difference between retail and wholesale prices over the years 1984 through 1992[1]. The differences are based on **wholesale prices** in the producing Census division and **end-use prices** (which do not include taxes) in the consuming Census division. See Appendix F for a discussion of programs and input files used in estimating these markups.

Annual **wholesale prices** for all petroleum products are aggregated from state-level prices from the EIA-782A. The estimation and reliability of the EIA-782A data is discussed in the *Petroleum Marketing Annual 1992* (DOE/EIA-0492). See Table E1 for inputs and sources.

With the exception of gasoline, non-utility distillate fuel, and jet fuel, **sectoral end-user prices** through 1990 are aggregated from prices from the State Energy Price and Expenditures Report 1990 (SEPER). The methodology behind these state-level sectoral prices are discussed in the *State Energy Price and Expenditures Report 1990* (DOE/EIA-0376(90)). One area of concern is the SEPER methodology for residual fuel transportation prices where the vessel bunkering prices are tied to State electric utility prices. This methodology is questionable because most utility residual fuel use is on the East Coast whereas vessel bunkering is concentrated on the Gulf and West Coasts.

Gasoline, jet fuel, and non-utility distillate prices are estimated as weighted averages using end-user prices from EIA-782A and sectoral consumption from the *State Energy Data Report* (DOE/EIA-0214(91) (SEDS).

Due to a two-year lag in the publication of the SEPER data, end-use price estimates for 1991 and 1992 are calculated using the same data series and methodology described in SEPER. The SEPER methodology uses prices from EIA-782A, FERC-

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

423, EIA-759, and weights them with consumption volumes from SEDS. Refer to SEDS for a discussion of the reliability of consumption data and to Electric Power Annual 1992 (DOE/EIA-0348(92)) for a discussion or the reliability of electric utilities data from FERC-423 and EIA-759. Table E1 shows the data series used in the estimation of end-use prices.

Table E1. Sources of Markup Inputs

Products	Sectors	Data Series Inputs
Distillate	CM, IN, RS, TR	EIA-782A, SEDS
Jet Fuel	TR	EIA-782A, SEDS
Motor Gasoline	CM, IN, TR	EIA-782A, SEDS
Asphalt and Road Oil	IN	SEPER, EIA-782A, SEDS
Kerosene	CM, IN, RS	SEPER, EIA-782A,

documentation, titled *Documentation of the Petroleum Market Model, Appendix: Model Developer's Report*. In an earlier effort, a detailed calibration was made, using the same refinery model technology database as in PMM, compared against the EIA Petroleum Supply Annual (PSA) for 1989.[2] This comparison indicated that the validation was quite good with total crude volumes from the model only 0.48 percent above actual PSA values and total production just 0.28 percent higher. A more complete comparison, including assumptions, can be found in the cited reference.

APPENDIX F

Estimation Methodologies

APPENDIX F. Estimation Methodologies

F.1 Refinery Investment Recovery Thresholds

The calculation methodology for the capital investment recovery threshold values have been taken from a standard refinery industry reference.[1] The inside battery limits (ISBL) investment cost and labor costs for most of the processing unit types were obtained from a study by Bonner and Moore Associates.[2] The data for typical unit sizes and stream factors as well as supplementary investment and labor was obtained from the World Oil Refining, Logistics, and Distribution (WORLD) model.[3] A basic premise used in the PMM application is that the investment recovery value at the end of project life (PL) will equal site decommissioning cost, an expectation that seems to be widely shared in the petroleum industry.

The inside battery limits cost per barrel investment cost at the Gulf Coast (P) for each refinery process modeled was obtained from the cited data sources. The total investment cost (INV) was then calculated using the referenced methodology. Finally, the capital recovery threshold for each process was calculated.

Given that a Gulf Coast plant and equipment battery limits cost for an expansion of processing plant type i is P_i dollars per barrel per day of stream day capacity (This is assumed to include required storage facilities but not necessarily all mandated environmental systems.), then the nominal total plant and equipment cost at some arbitrary location would be

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[1] J.H. Gary and G.E. Handwerk, *Petroleum Refining: Technology and Economics* (New York: Marcel Dekker, 1975), Chapters 13 and 14.

[2] Bonner & Moore Associates, Inc., *A Capital Expansion Methodology Review of the Department of Energy's Petroleum Market Model*, prepared for the United States Department of Energy, Contract No. EI-94-25066 (Houston, TX, July 1994).

[3] Ensys Energy & Systems, Inc., *WORLD Reference Manual*, a reference for use by the analyst and management prepared for the United States Department of Energy, Contract No. DE-AC-01-87FE-61299 (Washington, D.C., September 1992).

$$NTPE_i = P_i(1+U)(1+O)$$ (1)

where   U = Utilities cost multiplier

     O = Offsites multiplier

With construction occurring over a 3-year period at a constant rate, the present value of the nominal total plant and equipment is

$$PVNTPE_i = \frac{NTPE_i}{3} \Sigma_{j=1}^3 (1+DEF_i)^j$$ (2)

where DEF = inflation rate during construction

The final land, plant, and equipment cost is

$$FLPE_i = PVNTPE_i(1+S)(1+C)$$ (3)

where   S = Special costs multiplier (includes land)

     C = Contingency cost multiplier

The total investment is

$$INV_i = (1+W)*FLPE_i$$ (4)

where   W = Working capital multiplier

A multiplier called the plant depreciation factor or PDF, is used in the investment recovery calculations. It is merely the ratio of depreciable investment to total investment. More specifically, the numerator of the PDF is total investment less land, working capital, and supplies. The total Gulf Coast investment cost and depreciable investment fraction (PDF) as well as the fixed costs are presented in Table F4. The location factors, taken from working papers developed for the 1993 NPC refinery study, are presented in Table F2. In order to do this, several premises have been set in accordance with Table F1. The multipliers in Table F1 were obtained from the Gary and Handwerk reference. The variability of these factors is unknown. The INV values were pre-calculated in a worksheet so the recovery factors could be placed in the FORTRAN code while maintaining flexibility in changing the key volatile parameters such as required return on investment. The investment data are used for two different purposes in PMM: (1) the negative of the sum of the recovery factor and the fixed cost are entered into the objective row of the unit expansion vectors of the PMM LP to provide an investment decision criteria; i.e., the investment will occur to the extent that it is economic and (2) the basic investment cost (INV) multiplied by the location factor (L) and any appropriate environment factor is what must be multiplied by the LP expansion vector activity with the resulting products summed to provide entries for the CAPEXP matrix, i.e. the capital expenditure table, of the NEMS FORTRAN common block.

Table F1. Investment Multiplier Values

Multiplier	Value
U	0.075
O	0.15
DEF	0.03
C	0.15
S	0.04
W	0.10

The capital recovery threshold is calculated from:

$$CRT_{i,j} = \frac{INV_i \times (L_j + E) \times \left(U_{R,PL} - PDF_i \times \dfrac{TR_j}{PL \times 365} \right)}{(1 - TR_j)} \tag{5}$$

where,

$CRT_{i,j}$ = The daily investment recovery required for processing unit type i at location j, $/bbl

INV_i = The investment required for processing unit type i on the Gulf Coast, $/bbl

L_j = Location factor for PAD District j

E = Investment factor for environmental capital expenditure

PDF_i = Plant depreciation factor (fraction of investment that may be depreciated) for processing unit type i

TR_j = Effective combined income tax rate in PAD District j

R = Investment return rate, fraction

PL = Plant life, years

Table F2. Location Index (J) and Location Factors

PAD District	Location Factor
I	1.2
II	1.2
III	1.0
IV	1.2
V	1.2

when R > 0, then

$$U_{R,PL} = \frac{R}{365 \times (1 - (1 + \frac{R}{365})^{-PL \times 365})} \qquad (6)$$

otherwise,

$$U_{R,PL} = \frac{1}{PL \times 365} \qquad (7)$$

Also,

$$TR_j = TRF + TRS_j - TRF x TRS_j$$

where

TRF = Federal income tax rate

TRS_j = Average state income tax rate for PAD District j, weighted by crude oil charge

Note that an investment tax credit can be added to this investment model by decreasing the INV by the applicable fraction.

The reader may verify his understanding of the investment equations from a simple example. Calculating the capital recovery required to expand the crude oil distillation tower capacity in PAD District III by one barrel per day for a 15 percent return over a 15-year plant life with a combined income tax rate of 44.2 percent with no allowance for collateral environmental cost,

$$CRT_{ACU,I} = \$0.48/day.$$

Refinery Unit Fixed Cost Factor

The fixed cost which, in conjunction with the capital recovery threshold forms the threshold for expansion investment decisions, for processing unit type i is calculated from:

$$FC_i = \frac{1}{365}[B_i + PVNTPE_i \sum_{j=1}^{6} F_j] \qquad (8)$$

where

B = Operations labor, $/year/BBL/day
the 6 "F" multipliers are shown in Table F3.

Table F3. Fixed Cost Multiplier Values

Multiplier	Value
1, Insurance	0.005
2, Local tax rate	0.01
3, Maintenance	0.04
4, Supplies	0.002
5, Overhead	0.015
6, Environment	0.02

The labor charge, B, and the overhead multiplier is taken from the WORLD model. The first 4 multipliers was obtained from the Gary and Handwerk reference. The environment base multiplier results from analyst judgement. The 1993 NPC study estimates the new environmental refinery operation and maintenance cost as about one third of base operations and maintenance over the 1991-1995 time period. Gary and Handwerk estimate the maintenance factor to vary between 3% and 8%, 4% was used because the trend is for refineries to increase operating efficiency over time. Variability of the other factors is unknown.

Table F4. Refinery Investment Recovery Data ($1991)

Processing Unit	Unit Index	INV (Dollars per bbl/d)	PDF	Fixed Cost ($/bbl)
Crude oil tower	ACU	$673	0.760	$0.14
Vacuum unit	VCU	$1,067	0.760	$0.21
Solvent deasphalting	SDA	$2,275	0.760	$0.46
Delayed coker	KRD	$5,135	0.760	$0.99
Fluid/flexicoker	KRF	$6,559	0.760	$1.28
Visbreaker/TCC	VBR	$1,657	0.760	$0.34
Naphtha hydrotreater	NDS	$1,312	0.760	$0.28
Distillate desulfurizer	DDS	$1,933	0.760	$0.41
FCC feed hydrofiner	FDS	$2,349	0.760	$0.47
Residuum desulfurizer	RDS	$5,394	0.760	$1.11
Gas oil hydrocracker	HCR	$6,512	0.760	$1.33
Residuum hydrocracker	HCV	$8,702	0.760	$1.74

Processing Unit	Unit Index	INV (Dollars per bbl/d)	PDF	Fixed Cost ($/bbl)
Naphtha hydrotreater	HCN	$3,990	0.760	$0.81
Lube and wax units	LUB	$16,109	0.760	$3.21
Gas oil dewaxer	DEW	$1,613	0.760	$0.34
Prefrac hi density ATF	JFP	$2,584	0.760	$0.88
Hi density ATF HD unit	HDN	$17,819	0.760	$3.63
HP Semi regen REFORMER	RFH	$2,157	0.760	$0.49
LP Cyclic reformer	RFL	$2,661	0.760	$0.59
LP Continuous reformer	RFC	$3,164	0.760	$0.68
Naphtha splitter	SPL	$863	0.760	$0.17
C3/C4 dehydrogenation	OLE	$13,232	0.760	$2.73
Fluid cat cracker	FCC	$4,358	0.760	$0.88
FCC fractionation	FGS	$690	0.760	$0.13
Alkylation unit	ALK	$7,150	0.760	$1.54
Polymerization unit	CPL	$2,244	0.760	$0.49
Dimersol unit	DIM	$3,107	0.760	$0.65
Aromatics recovery	ARP	$3,625	0.760	$0.78
Pen/Hex Isomerization	PHI	$4,315	0.760	$1.14
Butane isomerization	C4I	$6,213	0.760	$1.68
Total recycle isom	TRI	$6,725	0.760	$1.37
Cyclar unit	CYC	$12,797	0.760	$2.49
Etherol unit	ETH	$8,054	0.760	$1.78
H2 Steam ref bfoe/d	H2P	$32,779	0.760	$6.56
H2 Partial Ox bfoe/d	H2X	$32,634	0.760	$6.31
Sulfur, S tons/day	SUL	$200	0.760	$0.04
Steam gener, lbs/hr	STG	$72	0.760	$0.01
Power generation, MKW	KWG	$9	0.760	$0.00
M Dist Furfural trting	FEX	$2,053	0.760	$0.41
M Dist deep hydrotrt	DHT	$2,851	0.760	$0.56
Methanol unit	MOH	$30,611	0.760	$3.41

F.2 Gas Plant Models

The gas plant models for each PAD District is maintained on the spreadsheet 'NGL.WK1' maintained within EIA by the Oil and Gas Analysis Branch. These models require gas plant residual gas as an input in order to accommodate the information available and permit gas plant activity to be driven by dry natural gas demand. The gas plant models have been structured to accommodate this requirement. The residue gas is summed over all model operating modes to equal the residue gas demand. The PMM models only the California gas plants in PAD District V. Although Alaska produces and processes a considerable volume of natural gas, it is nearly all used for reinjection or dumped into the crude pipeline with the exception of modest volumes of southern Alaska production which does have a local NGL market with much of the dry gas shipped out as LNG. In any case, the PAD District V refinery industry is virtually unaffected by Alaska NGL production. Thus, the PMM aggregate gas plant includes California only. Actually, gas residue volumes are not available to the PMM but total dry gas volumes by PAD District are. This information is in the NEMS common block region. Specifically, the total dry gas volumes are available in:

Common block:	NGTDMOUT
Variable matrix:	PRNG_PADD(PADD,YEAR), BCF
Description:	Total dry gas produced including plant fuel and lease fuel (P&L) for PAD District 'PADD' in year 'YEAR' excluding Alaska.

Each of the five values must be multiplied by a factor to obtain an estimate of the corresponding gas plant residue gas; i.e., multiplied by the ratio of gas plant residual gas to total dry gas production. Whereas the gas plant models are based upon 6

years of history, the five gas plant ratios are based only upon 1991 data[4] so that data variability is unknown. There simply has not been sufficient time to consider a lengthier set of data. The five multipliers are shown in Table F5.

Table F5. Total Dry Gas Multiplier

PAD District	Multiplier
I	0.3273
II	0.6899
III	0.7581
IV	0.9769
CA	0.6185

The multiplier for PAD District I is low because relatively little of the modest PAD District I gas production is processed beyond field decontamination.

The residue gas is converted, in the model, into wet gas. The extraction is allowed to occur at a minimum, maximum, or average level. Complete ethane rejection is allowed with a processing credit for each barrel rejected. Propane rejection occurs in U.S. gas plants but to an unknown extent. The model allows propane rejection up to one fourth of the propane volume. The basic model structure is devised from the Pace Consultants annual petrochemical report[5]. The liquids extraction data have been calculated by averaging actual liquid extraction volumes from the 6-year period 1986 - 1991[6] as well as obtaining minimum and maximum values. The coefficients were then normalized. The minimum and maximum values seem to suggest the variability of the data but the reader is cautioned that statistically based models, as opposed to engineering models, may understate processing flexibility. The model for

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[4] Energy Information Administration, *Natural Gas Annual 1991,* DOE/EIA-0131(91), (Washington, DC, October 1992).

[5] Pace Petrochemical Service, *Annual Issue,* (Houston, TX, September 1989).

[6] Energy Information Administration, *Natural Gas Annual 1991*, DOE/EIA-0131(91), (Washington, DC, October 1992) and similarly, the Natural Gas Annuals for 1986-1990.

PAD District III is shown in the following table. Models for the other PAD Districts are similar except the extraction coefficients differ.

Table F6. Gas Plant Model for PAD District III

	MIN	MAX	AVG	NGL	ETH	PRO	Row Type	RHS
Wet Nat. Gas (MMcf)	1.058	1.068	1.064	-1.000			=	0
Dry Gas (MMcf)	-1.000	-1.000	-1.000		0.001	0.001	=	+
Ethane (bbl)				14.39	-1.00			
Propane (bbl)				11.71		-1.000		
I-Butane (bbl)				4.52				
N-Butane (bbl)				2.691				
Nat. Gasoline (bbl)				7.36				
Volume Loss (MMcf)	-0.058	-0.068	-0.064	-39.69	0.998	0.998		
Oper. Cost ($)	-124.74	-133.35	-128.86					
Oper. Cost ($/bbl)					6.74	3.37		
Capacity limit (bbl/d)						1.000	<=	+

The above table differs from the implemented model in three respects. Propane rejection is controlled via column limit in the LP rather than as a row limit and the operating costs are merely entered into the objective function row rather than occupying two rows as the above depiction suggests. Of course these things are shown in the above form for the sake of clarity. The major difference is that the dry gas balance row is an equal zero row in the LP representation. There is a column representing pseudo purchases of dry gas with a plus one in the dry gas balance row and minus the forecasted gas price in the objective function row. Of course, this column is fixed at the determined level of gas plant gas residue.

F.3 Chemical Industry Demand for Methanol

Since the PMM includes methanol plant models in each PAD District representing all U.S. methanol capacity, U.S. chemical industry demand (demand other than for MTBE/TAME feedstock and neat fuel) is a required input. The Pace Consultants make long range forecasts of the chemical industry demand[7]. Their forecast is:

Table F7. Chemical Industry Demand for Methanol

Year	Demand (Mbbl/d)	Year	Demand (Mbbl/d)
1990	66.7	2003	97.4
1991	67.3	2004	100.3
1992	66.0	2005	103.4
1993	76.3	2006	106.5
1994	79.1	2007	109.7
1995	80.5	2008	112.9
1996	82.3	2009	116.3
1997	84.3	2010	119.8
1998	85.9	2011	123.4
1999	87.9	2012	127.1
2000	90.3	2013	130.9
2001	92.4	2014	134.9
2002	94.6	2015	138.9

The methanol plant model in each PAD District is represented by a single column activity that consumes natural gas and produces methanol. Two additional transportation activities allow the methanol produced to be transported to the refining region for production of MTBE/TAME and/or splash blending in gasoline or sent to meet the national demand for methanol by chemical plants. The model also allows capacity expansion of the methanol plant.

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[7] Pace Petrochemical Service, *Annual Issue*, (Houston, TX, October 1992).

F.4 Estimation of Refinery Fixed Costs

The marginal prices computed in the PMM by the use of the Simplex algorithm cannot be used directly to determine the wholesale (refinery gate) price because they do not include the fixed costs of operating the refinery. The marginal prices do include the raw material and variable unit operating costs and will reflect the relative costs of producing each product.

A methodology was developed to allocate fixed refinery costs to the marginal prices of light products (LPG, gasoline, kerosine, jet fuel, No. 2 heating oil, and low sulfur highway diesel) thus including fixed costs in the prices reported at the refinery gate. The heavy products (residual oil, petrochemical feedstocks, asphalt, and other) are priced at their marginal cost due to competition from other fuels. Fixed refinery costs in each PAD District are estimated as the sum of fixed operating costs, return on assets, and environmental costs associated with controlling pollution at refineries (Table F8). The average annual cost is applied to all years and is recovered in the prices of light products only. These costs do not vary in the present model, but further analysis will be performed to determine the variability of these costs.

Table F8. Refinery Fixed Costs, by PAD District
(1987 $/bbl)

	PAD District I	PAD District II	PAD District III	PAD District IV	PAD District V
Operating Costs	2.64	1.70	2.01	1.66	2.53
Return On Assets	0.24	0.14	0.21	0.18	0.23
Annual Environmental Cost	1.16	1.17	0.92	1.69	1.28
Total	4.04	3.01	3.14	3.53	4.04

The methodology for allocating costs among light products is based on the concept of marginal cost and was developed from a similar approach used by the Gas Research Institute (GRI).[8] The steps used are as follows:

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[8]   Gas Research Institute, "U.S. Refining Model Methodology", (May 1991).

(1) Determine the fixed costs for each PAD District which include payroll, maintenance, depreciation, and other fixed operating expenses.

(2) Determine a fair return (profit) on assets.

(3) Determine the environmental investment and operating costs.

(4) The total costs to be recovered are the sum of (1), (2), and (3).

(5) Determine the marginal revenue from the LP solution that will recover the marginal cost (the product of the marginal price of each product times the production volume).

(6) Calculate ratios that will apportion the fixed costs to the light products marginal prices.

(7) Use the ratios from (6) to scale the marginal prices to refinery gate wholesale prices.

Equations: First, marginal revenue is determined for each refining region R:

$$REVLP(LP)_R = VALUE(LP)_R * VOLUME(LP)_R$$
$$REVHP(HP)_R = VALUE(HP)_R * VOLUME(HP)_R$$

where:

VALUE(LP)   is the marginal price for each light product (LP) that <u>will</u> bear the fixed cost

VALUE(HP)   is the marginal price for each heavy product (HP) that <u>will not</u> bear the fixed cost

VOLUME(LP)   is the production volume for each light product

VOLUME(HP)   is the production volume for each heavy product

$$TOTREV_R = REVLP(LP)_R + REVHP(HP)_R$$

Second, the total revenue required, including the fixed costs, FIXCOST is determined:

$$NTOTREV_R = REVLP(LP)_R + REVHP(HP)_R +(FIXCOST_R*VOLUME)$$
$$NLTREV_R = NTOTREV_R - REVHP(HP)_R$$

The last step is to calculate the refinery gate price for each light product

$$GATEPR(LP)_R = (NLTREV_R/REVLP(LP)_R) * VALUE(LP)_R$$

Refinery Fixed Operating Costs

The fixed operating cost values were developed from information published by the National Petroleum Council based on a 1984 survey of U.S. refineries [9] and are summarized in Table F9. The published values were adjusted to 1987 dollars based on the Nelson Investment Index. The original NPC data included refineries of different complexities from simple to deep conversion in each PAD District. Volume weighted costs were developed based on capacities in each PAD District.

Table F9. Fixed Operating Costs by PAD District
(1987 $/bbl except where noted)

Operating Cost Items	PAD District I	PAD District II	PAD District III	PAD District IV	PAD District V
Payroll, etc.	1.03	0.70	0.70	0.68	0.77
Contract Maintenance	0.28	0.14	0.15	0.12	0.22
Maintenance Materials	0.32	0.19	0.21	0.17	0.19
Depreciation	0.45	0.29	0.42	0.22	0.43
Other Operating Expenses	0.56	0.39	0.53	0.48	0.91
Subtotal, $/bbl	**2.64**	**1.70**	**2.01**	**1.66**	**2.53**
Nelson Complexity Factor	9.62	8.97	10.19	6.77	8.61
Crude Oil Charge (Mbbl/cd)	1594	3198	7168	456	2897
Number of Refineries	23	36	64	14	44

Refinery Return on Assets

The use of a return on assets (ROA) is an attempt to include a fair return on investment as part of the refinery cost structure. Estimates of gross fixed assets by refinery type and PAD District were obtained from the NPC study previously cited.

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[9] National Petroleum Council, *U.S. Petroleum Refining*, (October 1986).

The level of return on assets was set at 4 percent. This return is based on a simple average of the net income to total assets for major energy producers for the years 1989, 1990, and 1991 reported by EIA in 1992.[10] By comparison, the Standard & Poor's 400 ROA is 3.9 percent. In Table F10, the Gross Fixed Assets are expressed in $/bbl/d of distillation capacity and the resulting per barrel cost at a rate of 4 percent are shown for each PAD District.

Table F10. Return on Assets, by PAD District

	PAD District I	PAD District II	PAD District III	PAD District IV	PAD District V
Gross Fixed Assets (1987 $/bbl/d)	2183	1280	1925	1687	2091
ROA at 4 Percent (1987 $/bbl)	0.24	0.14	0.21	0.18	0.23

Refinery Environmental Costs

Refinery source costs are expenditures incurred to satisfy regulations related to air and water pollutants, solid waste management, and health and safety controls at refineries. Related costs are based on estimates of capital investment, one-time, and operation and maintenance expenses provided in the 1993 National Petroleum Council Study.[11]

The NPC Study provides PAD District level estimates of capital, one-time, and operating and maintanence expenses over three time periods: 1991-1995, 1996-2000, and 2000-2010. The NPC estimates were converted to an annual average cost per barrel of distillation capacity for inclusion as a refinery fixed cost (Table F8).

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[10] Energy Information Administration, *Performance Profiles of Major Energy Producers, 1991*, DOE/EIA-0206(91), (Washington, D.C., December 1992).

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

The underlying NPC analysis reflects the actions described below:

Air related costs include attainment of ambient air quality standards (Title I of the Clean Air Act Amendments), hazardous air pollutants (Title III, MACT standards), and permits (Title V)[12].

Water related costs include technology required to satisfy toxicity requirements of the National Pollution Discharge Elimination System (NPDES) authorized by the Clean Water Act. Costs for additional measures to protect groundwater are also assumed[13].

Solid waste related costs include remediation of contaminated soil at refineries sites, recovery and monitoring wells, the listing of additional refinery wastes as hazardous, the closing of unlined impoundments, and an assumed phased replacement of half the tanks over 40 years of age[14].

Safety and health related costs includes an assumed phase-out of hydrofluoric alkylation (hf) plants due to the classification of hf as a highly hazardous material. Small costs associated with implementing process hazards analysis are also contained in the NPC estimates[15].

For comparative purposes NPC's estimated capital and OTE costs aggregated over 1991-2010 results in total environmental investments of $43.5 billion. The NPC sum can be compared to estimated investments published by the API[16], by adding the API estimates for individual legislation that are consistent with NPC. The NPC total falls in the middle of the range of API investments of $19.4 to $60.0 billion.

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12   Ibid, Section V-9-12.

13   Ibid, Section V-13.

14   Ibid, Section V-16.

15   Ibid, Section V-19.

16   The sum of the initial cost estimates in *Costs to the Petroleum Industry of Major New and Future Federal Government Environmental Requirements*, American Petroleum Institute, Discussion Paper #070, (Washington, D.C., October 1991), Tables ES-1 and ES-2. Aggregate estimates exclude product specification and off-site costs, and utilized minimum RCRA reauthorization.

F.5   Estimation of Distribution Costs

Costs related to distributing petroleum products to end-users are incorporated by adding fixed transportation markups to the wholesale prices which include the variable and fixed refinery costs. Transportation markups for petroleum products are estimated as the average annual difference between retail and wholesale prices over the years 1984 through 1992. The differences are based on wholesale prices in the producing Census division and end-use prices (which do not include taxes) in the consuming Census division. Wholesale prices are aggregated from State-level prices from the EIA-782A. Sectoral end-user prices are aggregated from State-level prices from the State Energy Price and Expenditures Report (SEPER) 1990. End-use prices after 1990 are estimated according to the SEPER's methodology. Computer programs and data files used to estimate transportation markups are discussed below.

Data-Reading Programs

The following programs access EIA survey data and should be updated each year. Member names of SAS data sets are given in parenthesis.

Program: CN6007.PRJ.NEMS.MARKUP.WHOLSALE

Files Read: CN6007.BBM.A.SASDB.STATE
                       (IMPSTATA)
                 CN6007.PRJ.NEMS.MARKUP.SASDB
                       (REGIONS)
                       (WHOLSALE)

This program reads a database containing State-level wholesale prices from the EIA-782A. Wholesale prices for asphalt and road oil, distillate fuel, gasoline, jet fuel, kerosene, liquefied petroleum gases, and residual fuel oil are aggregated into Census division prices (cents/gallon) and output to the NEMS database for other markup programs to access.

Program: **CN6007.PRJ.NEMS.MARKUP.EIA782.READ**

Files Read: CN6849.PRJ.ANNUAL.IMPUTE.AB.F9201
                      CN6849.PRJ.ANNUAL.IMPUTE.AB.F9202
                      CN6849.PRJ.ANNUAL.IMPUTE.AB.F9203
                      CN6849.PRJ.ANNUAL.IMPUTE.AB.F9204
                      CN6849.PRJ.ANNUAL.IMPUTE.AB.F9205
                      CN6849.PRJ.ANNUAL.IMPUTE.AB.F9206
                      CN6849.PRJ.ANNUAL.IMPUTE.AB.F9207
                      CN6849.PRJ.ANNUAL.IMPUTE.AB.F9208
                      CN6849.PRJ.ANNUAL.IMPUTE.AB.F9209
                      CN6849.PRJ.ANNUAL.IMPUTE.AB.F9210
                      CN6849.PRJ.ANNUAL.IMPUTE.AB.F9211
                      CN6849.PRJ.ANNUAL.IMPUTE.AB.F9212
                      CN6007.PRJ.NEMS.MARKUP.SASDB
                              (REGIONS)
                              (PRODE)

This program updates retail prices on the NEMS database using the most recent data from the EIA-782A. The State-level prices for gasoline, distillate, kerosene, jet fuel, high and low sulfur residual fuel, and liquefied petroleum gases for the most recent 2 years, 1991 and 1992, are aggregated into regional prices and added to data for previous years (using PRODE). The program is updated by revising files and incrementing YEAR in line 82. Contact the Petroleum Marketing Division of the Office of Oil and Gas concerning the EIA-782 data.

Program: **CN6007.PRJ.NEMS.MARKUP.GDP87**

Files Read: CN6007.PRJ.NEMS.MARKUP.SASDB
                    (GDP87)

This program updates the GDP deflators in the NEMS database. Program should be rerun after adding most recent year's deflator.

Program: CN6007.PRJ.NEMS.MARKUP.CONFAC

Files Read: CN6007.PRJ.NEMS.MARKUP.SASDB
(CONVER84 through CONVER91)

This program provides annual conversion factors for each product. Factors for the most recent year of the SEPER's should be added to the data. These conversion factors are accessed by the SEPER.READ programs.

Program: CN6007.PRJ.NEMS.MARKUP.SEPER.READ90

Files Read: CN6356.PRJ.SEPER90.SAS.DATA
CN6007.PRJ.NEMS.MARKUP.SASDB
(CONVER84 through CONVER91)
(STATE84 through STATE90)

This program reads State-level prices by sector from SEPER-1990 and puts them into the NEMS database. Prices are accessed for the following products:

gasoline (mg)
distillate (df)
kerosene (ks)
residual fuel (rf)
liquefied petroleum gases (lg)
jet fuel (jf)
pentanes plus (pp)
asphalt and road oil (ar)
petrochemical feedstocks (fs)
naphtha feedstocks (fn)
other feedstocks (fo)

The program is set up to read only one year of data at a time. The program should be rerun for historical years back to 1984 since historical data are sometimes revised in SEPER's. Each year's data can be updated by uncommenting the appropriate line between 15 and 21. The price series is read from the SEPER's database with 1984 prices at location 211 and consecutive years at intervals at 14 (1985 at 225, and so

on). The appropriate lines should also be uncommented between 38 and 44 and between 61 and 67.

Program: **CN6007.PRJ.NEMS.MARKUP.F759.READ**

Files Read: CN6007.PRJ.NEMS.MARKUP.SASDB
(REGIONS)
(E759Y85 through E759Y92)
CN6944.PRJ.F759.MASTER92

This program reads monthly volumes of distillate, low and high sulfur residual fuel consumed by electric utilities from EIA-759. The volumes are by State and are in gallons. The program annualizes the volumes and assigns them to Census divisions.

Program: **CN6007.PRJ.NEMS.MARKUP.F423.READ**

Files Read: CN6501.PRJ.F423.EXTR1984.REVGAS
CN6501.PRJ.F423.EXTR1985.REVGAS
CN6501.PRJ.F423.EXTR1986.REVGAS
CN6501.PRJ.F423.EXTR1987.REVGAS
CN6501.PRJ.F423.EXTR1988.DATA
CN6501.PRJ.F423.EXTR1989.DATA
CN6501.PRJ.F423.EXTR1990.DATA
CN6501.PRJ.F423.EXTR1991.FINAL
CN6501.PRJ.F423.EXTR1992.FINAL
CN6007.PRJ.NEMS.MARKUP.SASDB
(EUSTATE)
(UTDIV)

This program reads State-level quantities and costs of distillate, and high and low sulfur residual fuel consumed by electric utilities from FERC Form 423. The quantities and costs are converted to a trillion Btu basis and assigned to Census divisions.

Program: **CN6007.PRJ.NEMS.MARKUP.ARVOL**

Files Read: CN6356.PRJ.SEDS.PUBLIC91.DATA
                CN6007.PRJ.NEMS.MARKUP.SASDB
                   (ARVOL84 through ARVOL91)

This program reads industrial asphalt and road oil volumes from SEDS. The program is updated by accessing the most recent SEDS file and adding another output file similar to ARVOL91. The location of the volume should be incremented by 14 (@329+14).

Program: **CN6007.PRJ.NEMS.MARKUP.KEROVOL**

Files Read: CN6356.PRJ.SEDS.PUBLIC91.DATA
                CN6007.PRJ.NEMS.MARKUP.SASDB
                   (KERVOL84 through KERVOL91)

This program reads kerosene consumption in the residential, commercial, and industrial sectors from SEDS. To update - access the most recent SEDS file and add another output file similar to KERVOL91. The location of the volume should be incremented by 14 (@329+14).

Program: **CN6007.PRJ.NEMS.MARKUP.GASVOL**

Files Read: CN6356.PRJ.SEDS.PUBLIC91.DATA
                CN6007.PRJ.NEMS.MARKUP.SASDB
                   (GASVOL84 through GASVOL91)

This program reads gasoline consumption in the transportation, commercial, and industrial sectors from SEDS. To update - access the most recent SEDS file and add another output file similar to GASVOL91. The location of the volume should be incremented by 14 (@329+14).

Program: **CN6007.PRJ.NEMS.MARKUP.LPGVOL**

Files Read: CN6356.PRJ.SEDS.PUBLIC91.DATA
             CN6007.PRJ.NEMS.MARKUP.SASDB
                (LPGVOL84 through LPGVOL91)

This program reads gasoline consumption in the transportation, residential, and commercial sectors from SEDS. To update - access the most recent SEDS file and add another output file similar to LPGVOL91. The location of the volume should be incremented by 14 (@329+14).

Program: **CN6007.PRJ.NEMS.MARKUP.RSVOL**

Files Read: CN6356.PRJ.SEDS.PUBLIC91.DATA
             CN6007.PRJ.NEMS.MARKUP.SASDB
                (RSVOL84 through RSVOL91)

This program reads gasoline consumption in the commercial, industrial, and transportation sectors from SEDS. To update - access the most recent SEDS file and add another output file similar to RSVOL91. The location of the volume should be incremented by 14 (@329+14).

Markup Estimating Programs

All "CALC" programs calculate markups as the difference between a products retail and wholesale price in each Census division and sector. The estimated markups are output to CN6007.PRJ.NEMS.MARKUP.SASDB in 1987 dollars per trillion Btu. The output file from each program contains the variables PRODPMM, SECTOR, CENDIV, MEAN, AND STDERR.

Census Division "99" represents national data and Sector "ZZ" represents all sectors. The following table describes the source programs for petroleum product markups:

Table F11. Markups Output

Products	Sectors	Markup Program	File Name on MARKUP.SASDB
DS	CM, IN, RS, TR, ZZ	PMM.CALC	MARKPMM
JF	TR, ZZ	PMM.CALC	MARKPMM
MG	CM, IN, TR, ZZ	PMM.CALC	MARKPMM
AR	IN, ZZ	ASRO.CALC	MARKAR
KS	CM, IN, RS, ZZ	KERO.CALC	MARKOTH1
LG	CM, IN, RS, TR, ZZ	LPG.CALC	MARKLPG
RL	CM, IN	RESID.CALC	MARKRL
RH	TR	RHTR.CALC	MARKRH
DS	EU	ELECUTIL.CALC	MARKELEC
RL	EU	ELECUTIL.CALC	MARKELEC
RH	EU	ELECUTIL.CALC	MARKELEC

Program: **CN6007.PRJ.NEMS.MARKUP.PMM.CALC**

Files Read: CN6007.PRJ.NEMS.MARKUP.SASDB
        (PRODE)
        (WHOLSALE)
        (GDP87)
        (GASVOL84 through GASVOL91)
        (CONVER84 through CONVER91)
        (RGAL82)
        (MGBTU)
        (MARKPMM)

This program uses retail gasoline, distillate, and jet fuel prices and volumes

originating from the EIA-782A. Commercial and industrial gasoline prices are estimated by weighting the EIA-782 end-user (transportation) prices with SEDS volumes for these two sectors. Commercial and industrial gasoline volumes for 1991 are used to represent 1992, since SEDS stops with 1991 data. Distillate and gasoline markups are estimated as the average annual difference between end-use and wholesale prices for the years 1984 forward. Due to a break in the data trend, jet fuel markups are based on data starting in 1986.

To update: After updating "data" programs, revise this program to utilize more recent SEDS volumes by adding another data set that reads GASVOL92. Use CONVER92 and increment all year dependent formulas by first changing "92's" to "93's", "91's" to "92's", and "90's" to "91's".

Program: CN6007.PRJ.NEMS.MARKUP.ASRO.CALC

Files Read: CN6007.PRJ.NEMS.MARKUP.SASDB
                (PRODE)
                (WHOLSALE)
                (STATE84 through STATE90)
                (PRODE)
                (ARVOL91)
                (GDP87)
                (CONVER84 through CONVER91)
                (RGAL82)
                (ARBTU)
                (MARKAR)

This program uses State-level asphalt and road oil prices to the industrial sector from SEPER's through 1990. End-use prices for 1991 and 1992 are estimated using the 1991 and 1992 changes in the EIA-782 high sulfur residual fuel prices. Prices for each Census division are calculated using 1991 volumes from the SEDS. Estimates for 1992 are weighted using 1991 volumes. Markups are estimated as the average annual difference between end-use and wholesale prices for the years 1984 forward.

To update: After updating "data" programs, revise this program to utilize more recent data. Add a data set STATE91, use ARVOL92 and CONVER92,

and increment all year dependent formulas by first changing "92's" to "93's", "91's" to "92's", and "90's" to "91's".

Program: **CN6007.PRJ.NEMS.MARKUP.KERO.CALC**

Files Read: CN6007.PRJ.NEMS.MARKUP.SASDB
                    (PRODE)
                    (WHOLSALE)
                    (STATE84 through STATE90)
                    (PRODE)
                    (KEROVOL91)
                    (GDP87)
                    (CONVER91)
                    (KEROGAL)
                    (KEROBTU)
                    (MARKOTH1)

This program uses State-level kerosene prices to the residential, commercial, and industrial sectors from SEPER's through 1990. End-use prices for 1991 and 1992 are estimated using the 1991 and 1992 changes in the EIA-782 distillate prices. Prices for each Census division are calculated using 1991 volumes from the SEDS. End-use price estimates for 1992 are weighted using 1991 volumes. Markups are estimated as the average annual difference between kerosene end-use and distillate wholesale prices for the years 1984 forward.

To update: After updating "data" programs, revise this program to utilize more recent data. Add a data set STATE91, use KERVOL92 and CONVER92, and increment all year dependent formulas by first changing "92's" to "93's", "91's" to "92's", and "90's" to "91's".

Program: **CN6007.PRJ.NEMS.MARKUP.RESID.CALC**

Files Read: CN6007.PRJ.NEMS.MARKUP.SASDB
                    (PRODE)
                    (WHOLSALE)
                    (STATE84 through STATE90)

(RSVOL91)
        (GDP87)
        (CONVER84 through CONVER91)
        (RSGAL)
        (RSBTU)
        (MARKRL)

This program uses State-level residual fuel prices to the commercial, and industrial sectors from SEPERS through 1990. End-use prices for 1991 and 1992 are estimated using the 1991 and 1992 changes in the EIA-782 low sulfur residual fuel prices. Commercial and industrial prices for each Census division are calculated using 1991 volumes from SEDS. Price estimates for 1992 are weighted using 1991 volumes. Residential prices are estimated using 1991 and 1992 EIA-782 consumption volumes. Markups are estimated as the average annual difference between low sulfur end-use prices and aggregate residual fuel wholesale prices for the years 1984 forward.

To update: After updating "data" programs, revise this program to utilize more recent data. Add a data set STATE91, use RSVOL92 and CONVER92, and increment all year dependent formulas by first changing "92's" to "93's", "91's" to "92's", and "90's" to "91's".

Program: **CN6007.PRJ.NEMS.MARKUP.RHTR.CALC**

Files Read: CN6007.PRJ.NEMS.MARKUP.SASDB
                (PRODE)
                (WHOLSALE)
                (STATE84 through STATE90)
                (PRODE)
                (REGIONS)
                (EUSTATE)
                (RSVOL91)
                (GDP87)
                (CONVER91)
                (RSTRGAL)
                (RSTRBTU)
                (MARKRHTR)

This program uses State-level residual fuel prices to the transportation sector from SEPERS through 1990. End-use prices for 1991 and 1992 are estimated using average residual fuel prices to electric utilities according to SEPER's methodology. The average Census division prices to utilities are multiplied by the ratio of national high sulfur price from the EIA-782 to the national residual fuel price to utilities. Prices for each Census division are calculated using 1991 volumes from SEDS. End-use price estimates for 1992 are weighted using 1991 volumes. Markups are estimated as the average annual difference between high sulfur end-use prices and aggregate residual fuel wholesale prices for the years 1987 forward.

To update: After updating "data" programs, revise this program to utilize more recent data. Add a data set STATE91, use RSVOL92 and CONVER92, and increment all year dependent formulas by first changing "92's" to "93's", "91's" to "92's", and "90's" to "91's".

Program: **CN6007.PRJ.NEMS.MARKUP.LPG.CALC**

Files Read: CN6007.PRJ.NEMS.MARKUP.SASDB
                     (PRODE)
                     (WHOLSALE)
                     (STATE84 through STATE90)
                     (PRODE)
                     (REGIONS)
                     (LPGVOL91)
                     (GDP87)
                     (CONVER91)
                     (LPGGAL)
                     (LPGBTU)
                     (MARKLG)

This program uses State-level SEPER's prices for liquefied petroleum gases to the commercial, industrial, transportation, and residential sectors through 1990. End-use prices for 1991 and 1992 are estimated using SEPER's methodology. State prices to the commercial, industrial, and transportation sectors are estimated by weighting the 1991-92 LPG end-user price from the EIA-782 with sectoral volumes from SEDS

1991. Residential prices are estimated by applying the rate of change in EIA-782 prices to each PAD District to the 1990 SEPER's prices. As with prices to other sectors, State-level residential prices are aggregated to Census division using SEDS 1991 consumption data. End-use price estimates for 1992 are weighted using 1991 volumes. Markups are estimated as the average annual difference between end-user lpg prices and wholesale prices for the years 1985 forward. The average residential markups exclude 1989 data because of the price spike related to a heating oil crisis that winter.

To update: After updating "data" programs, revise this program to utilize more recent data. Add a data set STATE91, use LPGVOL92 and CONVER92, and increment all year dependent formulas by first changing "92's" to "93's", "91's" to "92's", and "90's" to "91's".

Program: **CN6007.PRJ.NEMS.MARKUP.ELECUTIL.CALC**

Files Read: CN6007.PRJ.NEMS.MARKUP.SASDB
                            (PRODE)
                            (WHOLSALE)
                            (STATE84 through STATE90)
                            (PRODE)
                            (REGIONS)
                            (UTDIV)
                            (E759Y84 through E759Y92)
                            (GDP87)
                            (CONVER84 through CONVER91)
                            (EURFRGAL)
                            (EURFBTU)
                            (MARKELEC)

This program uses State-level SEPER's prices for distillate, high sulfur, and low sulfur residual fuel to electric utilities through 1990. End-use prices for 1991 and 1992 are estimated using SEPER's methodology. The program breaks residual fuel consumption from the EIA-759 into high and low sulfur using a high/low sulfur breakout estimated from the FERC Form 423. The estimated high and low sulfur

residual fuel volumes are used to estimate weighted average prices to the utility sector.

Markups are estimated as the average annual difference between prices to utilities and wholesale prices for the years 1984 forward. The average markup for high sulfur residual fuel in Census division 8 excludes all years but 1990 because of an anomalous trend.

To update: After updating "data" programs, revise this program to utilize more recent data. Add datasets CONVER92, and E759Y93.

Program: **CN6007.PRJ.NEMS.MARKUP.CREATE.FLATFILE**

Files Read: CN6007.PRJ.NEMS.MARKUP.SASDB
          (MARKPMM)
          (MARKLPG)
          (MARKRL)
          (MARKRHTR)
          (MARKOTH1)
          (MARKAR)
          (MARKELEC)
          (CN6005.PRJ.PMM.MU1PRDS.)BASE.D0707931

This program pulls together the markups for each product, transposes the data and outputs it to a file used by NEMS.

F.6 Estimation of Taxes

In the PMM, taxes are added to the prices of gasoline, transportation distillate fuel, transportation liquefied petroleum gas, and jet fuel. Taxes are also estimated for M85 (transportation methanol) and E85 (transportation ethanol). Weighted averages of the most recently-available State and Federal taxes are developed for each Census division. The State taxes are fixed in real terms; the Federal taxes decline at the rate of inflation (i.e., Federal taxes are fixed in nominal terms). Historical values are also calculated for gasoline and transportation distillate and added to historical end-use prices excluding taxes in order to develop a series with taxes included. The State taxes, by sector, product, and year, are contained in following file which is read into the PMM:

CN6005.PRJ.PMM.MU2PRDS.BASE.D0823941

The Federal taxes are read into the PMM from file

CN6005.PRJ.PMM.QDCRDCF.BASE.D0922941

and are updated each forecast year by deflating the current value by the rate of inflation for that forecast year.

The following section traces the development of the taxes and lists the files used to produce both historical and forecast values. The historical data are developed on a monthly basis by State, then aggregated to volume-weighted annual averages by Census division. The outputs specified are members of the following SAS database unless otherwise stated:

CN6007.BBM.NEMS.TAX.SASDB

Program: **CN6007.BBM.NEMS.TAX.Dyymm**

Inputs: semi-annual tax information from *Petroleum Marketing Monthly* and other sources

Outputs: STyymmS

STyymmM

where yymm refers to years 84 through 92, and months 01 and
07 (except for 1990 when the months are 01 and 08)

State-level taxes are obtained from the *Petroleum Marketing Monthly* on a semi-
annual basis (usually reflecting taxes as of January 1 and July 1), supplemented by
information from the Highway Users Federation and other sources. These data are
entered into the above program.

We assume that taxes remain at the same level for the 6 months following each
semi-annual report, unless information on effective dates of tax changes is provided.
Thus, the tax level reported for say, 9207, is kept at the same amount for 9208-9212.
The file STyymmS contains data for 1 month, while the file STyymmM reproduces
the results for the subsequent 6 months, taking into account tax changes to the
extent that they are known.

Program: **CN6007.BBM.NEMS.TAX.CALC**

Inputs: STyymmM for years 1984 to current
IMPSTATB, a file containing State-level refiner and marketer
prices for petroleum products
IMPSTATA, a file containing State-level sales of petroleum
products, which are used as weights in calculating weighted
averages
REGIONS, maps States to Census divisions
GDP87, GDP deflators for conversion to constant dollars

Outputs: STGAS_MO

STDES_MO

The CALC program pulls together the monthly tax information and calculates
Federal, State, and total taxes by month and State in cents per gallon and dollars per
million Btu for both nominal and constant 1987 dollars. Sales volumes and regional
designations are added to facilitate volume weighting across time and regions as

required. Gasoline and diesel files are calculated and output separately.

Program: **CN6007.BBM.NEMS.TAX.YRREG**

Inputs: STGAS_MO
                    STDES_MO

Outputs: STGAS_YR
                    STDES_YR
                    CDGAS_YR
                    CDDES_YR

The YRREG program takes the State monthly tax files created in the CALC program and develops weighted average annual taxes by State, then averages across Census divisions and outputs annual average taxes by Census division. The Census division annual averages are used to develop historical end-use prices including taxes by adding the calculated taxes to ex-tax prices from the *Petroleum Marketing Monthly*.

Program: **CN6007.BBM.NEMS.TAX.FORECAST**

Inputs: STGAS_MO
                    STDES_MO
                    STGAS_YR
                    STDES_YR

Outputs: GASCAST
                    DIESCAST

The FORECAST program uses the latest tax information, combined with the most recent year of sales data, and develops Census division weighted-average taxes which are used for the forecast. The latest tax information is in the file:

CN6007.BBM.NEMS.TAX.DCURR

The outputs include both nominal and constant 1987 dollar denominations for both cents per gallon and dollars per million Btu.

Program: **CN6007.BBM.NEMS.TAX.CREATE.FLATFILE**

Inputs: GASCAST
                      DIESCAST

Outputs: CN6005.PRJ.PMM.MU2PRDS.BASE.D0924932

This program takes the Census division taxes to be used in the forecast and creates an input file that the PMM reads.

F.7 Gasoline Specifications

The PMM models the production and distribution of four different types of gasoline: traditional, oxygenated, reformulated, and reformulated/high-oxygen. The following specifications are included in PMM to differentiate between traditional and reformulated gasoline blends: octane, oxygen content, Reid vapor pressure (Rvp), benzene content, aromatics content, sulfur content, olefin content, and percent distillate at three temperatures.

Starting in 1998 the specifications for traditional gasoline reflect the Environmental Protection Agency's (EPA) "1990 baseline". These specifications prevent the quality of traditional gasoline from eroding overtime which is the intent of the EPA's "antidumping" requirements.

Oxygenated gasoline which has been required during wintertime in many U.S. cities since October of 1992 requires a oxygen content of 2.7 percent by weight. There will be some overlap of areas that already require oxygenated gasoline and those that will require reformulated gasoline in the future. In those areas, reformulated-high oxygen gasoline containing 2.7 percent oxygen will be required. Oxygenated gasoline is assumed to have specifications identical to traditional gasoline with the exception of a higher oxygen requirement. Similarly, the oxygen requirement is assumed to be the only difference between the reformulated/high oxygen and reformulated gasoline blends.

Beginning in 1995, many areas of the country will require reformulated gasoline. Between 1995 and 1997 the Environmental Protection Agency (EPA) will certify reformulated gasoline according to either the "simple" or "complex" models. The PMM assumes that reformulated gasoline during this time period will meet the EPA's "simple model" definition which allows no lead content, limits benzene content to 1.0 percent and aromatics content to 25 percent by volume, requires an oxygen content of 2.0 percent by weight, and caps nitrogen oxide emissions at a baseline level. Beginning in 1998 the EPA will only certify reformulated gasoline using the "complex model" which allows refiners to specify reformulated gasoline based emissions reductions from their companies 1990 baseline, or the EPA's 1990 baseline. The PMM uses a set of specifications that meet the "complex model" requirements but does not attempt to determine the optimal specifications that meet the "complex

model" (Table 13). Specifications such as Rvp, aromatics, sulfur and olefin content change in the year 2000 , reflecting further emissions reductions required by CAAA90.

The CAAA90 provided for special treatment of California that would allow different specifications for oxygenated and reformulated gasoline in that State. In 1992, California requested a waiver from the wintertime oxygen requirements of 2.7 percent, reducing the requirement to a range of 1.8 to 2.2 percent. The PMM assumes that PAD District V refiners must meet the California specifications. Therefore, for 1993-1994, the specifications for oxygenated gasoline in PAD District V meet a 2.0-percent standard. Starting in 1996, the specifications for reformulated gasoline in PAD District V are the same as California standards.

Annual Average Rvp Methodology

The annual average Rvp limits are derived based on existing summertime requirements and estimated wintertime levels. The assumed summer and winter Rvp specifications are annualized in spreadsheet RVP.wk1 by using summer and winter weights provided by the EPA.[17] To reflect pipeline requirements which are tighter than EPA limits, the specifications used in PMM (Table F12.) are 0.3 psi below the weighted annual specifications. Since the cost of reducing Rvp may not be linear, the PMM could be used in the future to test for the appropriate Rvp to represent the annual average.

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[17]The summer weight of 0.396 and winter weight of 0.604 were provided by Dave Korrotney of EPA (313-668-5507).

Table F12. Estimated Annual Reid Vapor Pressure

Gasoline Market/Type	Weighted Annual	Annual Rvp in PMM
PADD I-IV		
Traditional/Oxygenated	10.5	10.2
1995-1997 Reformulated/Reformulated-High Oxygen	10.0	9.7
1998-1999 Reformulated/Reformulated-High Oxygen	9.8	9.5
2000-forward Reformulated/Reformulated-High Oxygen	9.4	9.1
PADD V		
Traditional	9.5	9.2
Reformulated (CARB)	9.0	8.7

The lower Rvp specifications in PAD District V reflect more stringent California limits which are imposed statewide.

Complex Model Standards for Motor Gasoline

The Environmental Protection Agency (EPA) has promulgated new regulations for reformulated motor gasoline that are designed to lower vehicle emission pollutants

as required by the amended Clean Air Act of 1990[18]. The reformulated gasolines are designed to reduce vehicle emissions of toxic and ozone-forming compounds. Reformulated gasoline must be sold in certain regions where there are summertime ozone problems as well as in areas which opt into the program. Traditional gasoline may be sold elsewhere but it must not be more polluting than it was in 1990. These areas are discussed elsewhere in the documentation. Although The EPA has established some conventionally treated specifications, namely minimum oxygen content and maximum benzene content, the new conceptual aspect of the emission standards is that the reformulated gasoline must be blended in such a way that it meets maximum allowable emissions of volatile organic compounds (VOCs), nitrous oxides (NO_x), and toxics. These new motor gasoline standards are calculated by complex formulae based upon key properties of the gasoline blend. The new regulations cover Phase I (1 January 1995 through 31 December 1999) and Phase II (1 January 2000 and indefinitely afterwards). During Phase I the refiner must certify his reformulated gasoline to meet the new standards but, at his option, he may use a simpler EPA model rather than the complex EPA model until 1 January 1998. The model assumes that the refiners will use the simple model for as long as possible. Thus, Phase I has, in effect, two subphases; Phase Ia applies to 1 January 1995 through 31 December 1997 while Phase Ib applies to 1 January 1998 through 31 December 1999. Also, the refiner may meet the requirements for VOCs and NO_x on either a per gallon basis or on an average basis although some per gallon constraints still apply. The average basis has been incorporated into the model.

The NO_x and toxics emission standards for reformulated gasoline apply year-round whereas the VOCs standards apply only in the summer. The NO_x standard varies depending upon whether the VOCs standards apply, i.e. depending upon whether it is summer or winter. The VOCs standard for the north[19] is different from the VOCs standard applying to the south, greater volatility is allowed in the north. The Complex Model Averaged Standards are shown below in Table F13.

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[18] Federal Register, Environmental Protection Agency, <u>Regulation of Fuels and Fuel Additives;Standards for Reformulated and Conventional Gasoline; Final Rule</u>, Part II, 40 CFR Part 80, (Washington, DC, 16 February 1994)

[19] For the sake of simplicity, we use the terms south and north to refer to EPA regions 1 and 2 respectively. Region 1 is covered by ASTM Class B while Region 2 is covered by Class C.

Table F13. Complex Model Standards

	Phase I 1995 - 1999	Phase II 2000+
VOC Reduction, %		
South	≥ 36.6	≥ 29.0
North	≥ 17.1	≥ 27.4
NO_x Reduction, %		
Summer	≥ 1.5	≥ 6.8
Winter	≥ 1.5	≥ 1.5
Toxics Reduction, %	≥ 16.5	≥ 21.5
Oxygen, wt%	≥ 2.1	≥ 2.1
Benzene, %	≤ 0.95	≤ 0.95

These standards were translated into traditionally configured specifications for blending motor gasoline. First, two winter specifications were developed, one for Phase I and one for Phase II. Of course, the VOCs standard was excluded from consideration. Then four summer specifications were created, a south set and a north set for Phase I and similarly for Phase II.

These sets were developed by use of a spreadsheet, developed by EPA, which calculates the VOCs, NO_x, and Toxics of a reformulated gasoline as a function of the 'conventional' properties of the gasoline, i.e. as a function of Rvp, sulfur content, oxygen content, aromatics content, olefins content, benzene content, percent evaporation at 200 degrees Fahrenheit (E200), and percent evaporated at 300 degrees Fahrenheit (E300). The approach was to start with 'best informed guess' properties and use trial and error to gradually expand the allowable property limits. The blend

properties cited as typical fuels in an EPA presentation[20] served as the starting values for both Phases I and II. The same starting point was used for both winter and summer. Table F14, following a chart developed by the EPA[21], indicates the directional sensitivities of the properties on the standards. Of course, a more rigorous approach is possible in establishing the specification sets. For instance, one might perform incremental changes over the reformulated gasoline properties followed by computer runs to establish minimum cost specifications. However, in the event, resources were constrained. The above procedure was used after some discussion.

Table F14. Directional Emission Effects of Gasoline Property Changes

Property	VOC	NO$_x$	Air Toxics
Rvp ↓	↓↓↓	–	↓
Sulfur ↓	↓	↓↓↓	↓↓
Aromatics ↓	↓	↓	↓↓
Olefins ↓	–	↓	–
E200 ↑	↓	↑	↓
E300 ↑	↓	–	–
Oxygen ↑	–	–	↓↓
Benzene ↓	–	–	↓↓↓

The PMM is an annual model, i.e. it does not have seasonality. A decision was made

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[20] C.L. Gray, "Reformulated Gasoline Final Rulemaking and Renewable Oxygenate Proposal," Proceedings of The World Conference on Refinery Processing and Reformulated Gasoline, March 22-24, 1994, Information Resources, Inc.

[21] ibid

to develop, for PADDs I-IV, a single reformulated gasoline specification for Phase I simulation and a single specification for Phase II. This required several actions. The two summer sets for Phase I were linearly blended by compositing the projected gasoline sales-weighted south specifications to the appropriately weighted specifications of the north. The resulting two sets of specifications for Phase I, one for summer and one for winter, were then composited after weighting them according to summer sales and winter sales respectively.. The Phase II specifications were collapsed to a single set in the same manner. The composites were calculated in a spreadsheet maintained by the Oil and Gas Analysis Branch. This specification was adapted from the presentation made by Charles L. Gray at the conference cited above. The resulting reformulated gasoline specifications are shown in Table F15. It is, of course, a simple matter to convert the PMM blending stock distillation temperature values as needed.

Table F15. PMM Reformulated Gasoline Specifications

	Phase I PADDs I-IV	Phase II PADDs I-IV
Max Rvp, psia	9.5	9.1
Max S, ppm	339	140
Max Aro, %	25.6	25.0
Max Ole, %	10.6	12.0
Min E200, %	43.4	49.0
Min E300, %	83.0	87.0
Min Oxy, wt%	2.1	2.1
Max Ben, %	0.95	0.95

F.8   Estimation of Gasoline Market Shares

Time series market shares for traditional (TRD), oxygenated (TRH), reformulated (RFG), and reformulated/high oxygen (RFH) gasoline were estimated using a Gasoline Market Share Spreadsheet (GMSS). The estimates are based on the population of control areas (nonattainment areas requiring or assumed to require new types of gasoline) relative to the population of each Census division. Control areas used are based on a list of nonattainment areas put out by the Environmental Protection Agency [22]. Population data are from the 1990 Census, U.S. Bureau of Census.

The ratio of the control area population to the Census division population are used by PMM to disaggregate gasoline demand in that region. The control areas included in each year reflect assumptions about the phase-in of CAAA and State legislation.

MGSHR   is the annual percent of total gasoline demand.

OXY   ratio of population in carbon monoxide nonattainment areas, requiring oxygenated gasoline.

RFH   ratio of population in areas that are both carbon monoxide and ozone nonattainment, requiring high oxygen reformulated gasoline.

WDEM   ratio of wintertime gasoline demand to annual demand in each region (see table). The ratio was estimated using monthly gasoline sales data from the Form EIA-782A for the years 1983 through 1991.

Census Division	1	2	3	4	5	6	7	8	9
WDEM	.22	.48	.09	.06	.13	.11	.22	.30	.46

COPOP   population of carbon monoxide nonattainment areas.

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[22] Environmental Protection Agency, Office of Air Quality Planning and Standards, *Ozone and Carbon Monoxide Areas Designated Nonattainment*, (October 1991, Research Triangle Park, NC).

COOZ   population of areas of overlap for carbon monoxide and severe ozone nonattainment areas.

COOZOPT   population of areas in carbon monoxide and less severe ozone nonattainment areas assumed to opt-in to the reformulated gasoline program.

OZ   population in nine severe ozone nonattainment areas where RFG is mandated.

OZOPT   population in less severe ozone nonattainment areas assumed to opt-in to the RFG program.

DIV   population of a given Census division.

SPILL   "spillover demand" or demand for reformulated fuels outside the boundaries of nonattainment areas. Spillover is assumed to be 5 percent.

Prior to the start of the oxygenated gasoline program in November 1992, EIA estimated that spillover demand for oxygenated gasoline could be as high as 22 percent of the mandated demand for oxygenated gasoline[23]. After the onset of the program, the spillover estimate was continually adjusted down as it became apparent that the distribution system was functioning more efficiently than anticipated. The estimated spillover for the first year of the program was negligible due to efficiency gains and the suspended participation in three non-attainment areas[24]. In the future the three nonparticipating areas will be required to participate..

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[23] Energy Information Administration, *Monthly Energy Review*, DOE/EIA-0035 (92/08) (Washington, D.C., August 1992), pp. 2-5.

[24] Energy Information Administration, *Petroleum Marketing Monthly*, DOE/EIA-0308 (93/08) (Washington, D.C., August 1993), pp. 13-26.

Traditional Gasoline Market Shares:

In every year the annual market share of traditional gasoline is calculated by:

$$MGSHR_{TRD,CD} = 1 - MGSHR_{TRH,CD} - MGSHR_{RFG,CD} - MGSHR_{RFH,CD}$$

where

CD   represents a Census division.

Oxygenated Gasoline Market Shares:

In every year the annual market share of oxygenated gasoline is calculated as a percentage of total annual gasoline demand:

$$MGSHR_{TRH,CD} = OXY_{CD} * WDEM_{CD}$$

In **1993 and 1994** the annual market share for oxygenated gasoline is calculated as follows:

$$OXY_{CD} = (\Sigma COPOP_{CD})/DIV_{CD} * (1 + SPILL)$$

In most Census divisions the annual market share for oxygenated gasoline from **1995 forward** is calculated as follows:

$$OXY_{CD} = (\Sigma(COPOP_{CD} - COOZ_{CD} - C00Z0PT_{CD}))/DIV_{CD} * (1 + SPILL)$$

Beginning in 1996, a different estimation for oxygenated gasoline is required in **Census Division 9** due to a statewide mandate of 2.2 percent oxygen in gasoline used in California:

$$OXY_{CD9} = (\Sigma(COPOP_{CD9} - COOZ_{CD9} - C00Z0PT_{CD9} - COPOP_{CA} - COOZ_{CA} - C00Z0PT_{CA}))/DIV_{CD9}$$

Beginning in 1997, a different estimation for oxygenated gasoline is required in **Census Division 4** due to a statewide mandate of 2.7 percent oxygen in gasoline used in Minnesota:

$$OXY_{CD4} = (MNPOP/DIV_{CD4}) * (1 + SPILL)$$

where

MNPOP   is the population of Minnesota

Reformulated Gasoline (2.0 percent oxygen) Market Shares:

The reformulated gasoline program **begins in 1995**, therefore the market share for reformulated gasoline are estimated as follows:

$$MGSHR_{RFG,CD} = ((\Sigma(OZ_{CD} + OZOPT_{CD}))/DIV_{CD} * (1 + SPILL)) - MGSHR_{RFH,CD}$$

Beginning in 1996, the reformulated market share in **Census Division 9** has a unique calculation reflecting a statewide requirement for reformulated gasoline in California:

$$MGSHR_{RFG,CD9} = CAPOP/DIV_9 + (\Sigma(COOZ_{CD9} + COOZOPT_{CD9}-COOZ_{CA} + COOZOPT_{CA}))/DIV_{CD9} * (1 + SPILL))$$

Reformulated/High Oxygen Gasoline (2.7 percent oxygen) Market Shares:

Requirements for gasoline that is both reformulated and oxygenated occur during the wintertime in areas that fail to meet both carbon monoxide and ozone standards. **Beginning in 1995**, the market shares are estimated as:

$$MGSHR_{RFH,CD} = RFH_{CD} * WDEM_{CD}$$

where

$$RFH_{CD} = (((\Sigma(COOZ_{CD} + COOZOPT_{CD}))/DIV_{CD}) * (1 + SPILL))$$

Beginning in 1996, the estimation for the high oxygen/reformulated market share in **Census Division 9** must exclude sales in California because of State legislation:

$$MGSHR_{RFH,CD9} = (\Sigma(COOZ_{CD9} + COOZOPT_{CD9}\text{-}COOZ_{CA} - COOZOPT_{CA}))/DIV_{CD9} * (1 + SPILL))$$

F.9   Estimation of Low-Sulfur Diesel Market Shares

The CAAA90 mandates the use of low sulfur diesel for on-highway use. Market shares for low-sulfur diesel relative to distillate fuel are estimated based on data from EIA's *Annual Fuel Oil and Kerosene Sales 1992*(DOE/EIA-0535(92)). Since 20 percent of current demand in the transportation sector is off-highway, 80 percent of transportation demand for distillate fuel is assumed to be low-sulfur.

F.10 Low-Sulfur Diesel Specifications

In order to account for diesel desulfurization regulations, low-sulfur diesel is differentiated from other distillates. Specifications for sulfur, aromatics content, and API gravity are included in the PMM. Diesel fuel in Census Divisions 1 through 9 have a maximum sulfur content of 0.05 percent by weight, and a maximum aromatics content of 35 percent, reflecting Federal specifications. The specifications for diesel fuel supplied to Census Division 9 will be updated to reflect the more severe California Air Resources Board requirements.

F.11 Estimation of Regional Conversion Coefficients

Differing regional definitions necessitate the conversions of certain variables from one regional structure to another. Regional conversions are not extensive in the PMM, but are needed for three refinery input prices, refinery fuel consumption, and cogeneration information.

Conversions for Prices of Refinery Inputs

PMM receives prices for refinery inputs of natural gas in other regional configurations and must convert these into PAD District level prices. Due to the proximity of refineries in PAD Districts 2, 3, and 4 to the sources of natural gas supply, prices in these PAD Districts reflect wellhead natural gas prices in the corresponding Oil and Gas Production Regions. PAD Districts 1 and 5 use industrial prices in the corresponding Census divisions in order to capture the additional costs of moving the natural gas to the refineries. Table F16. shows the source of PAD District level natural gas prices:

Table F16. Source of PMM Natural Gas Prices

Correlation of Prices	
PAD District	Input Price
1	Census Division 2 industrial price (PGIIN)
2	Oil and Gas Production Region 3 wellhead price (OGWPRNG)
3	quantity weighted average of Oil and Gas Production Regions 2,4, & 8 wellhead price (OGWPRNG)
4	Oil and Gas Production Region 5 wellhead price (OGWPRNG)
5.	Census Division 9 industrial price (PGIIN)

PMM receives prices for refinery inputs of electricity by Census division. PAD

District level prices are derived by assuming prices in intersecting Census divisions. Table F17. shows the correlation between PAD District and Census division electricity input prices:

Table F17. Source of PMM Electricity Prices

Correlation of Prices	
PAD District	Input Price
1	Census Division 2 industrial prices (PELIN)
2	Census Division 3 industrial prices (PELIN)
3	Census Division 7 industrial prices (PELIN)
4	Census Division 8 industrial prices (PELIN)
5	Census Division 9 industrial prices (PELIN)

Conversions for Refinery Fuel Consumption

Refinery fuel consumption must be converted from the PAD District to the Census division level. Each Census division consumption number will equal the consumption in the overlapping PAD Districts times a factor. The factors were developed using State-level refinery operating capacity and are shown in Table F18. The factors are interpreted as follows: The 0.8434 at the intersection of Census Division 2 and PAD District I indicates that 84.3 percent of the PAD District I refinery fuel consumption is estimated (using refinery operating capacity as estimator) to occur in Census Division 2. These values will change by small amounts as refinery capacities change, but the impact on model results will be small.

Example: Census Division 7 fuel consumption =
(PAD District II consumption * .12) + (PAD District III consumption * .93)

Table F18. PAD District to Census Division Conversion Factors

| | Census Division | | | | | | | | | |
	1	2	3	4	5	6	7	8	9	SUM
PAD District 1		0.84			0.16					1.00
PAD District 2			0.60	0.19		0.09	0.12			1.00
PAD District 3						0.07	0.93			1.00
PAD District 4								1.00		1.00
PAD District 5									1.00	1.00

Conversions for Cogeneration

Information including cogeneration levels (RFCGGEN(CD)), cogeneration capacity (RFCGCAP(CD)), refinery fuel consumption (RFCGFUEL(CD)), self-generation (RFCGSELF(CD)), and generation for grid (RFCGGRID(CD)) must also be converted from PAD District level to Census divisions. The same factors and methodology developed for refinery fuel consumption (Table F18) are used to convert the cogeneration data.

Conversion coefficients for refinery fuel consumption and cogeneration information are estimated using &6007PRJ.PMM.CAPACITY.READ. An input file named &6007PSD.CAPACITY.DATA contains refinery capacity data from the 1991 Petroleum Supply Annual (PSA) which was provided by Sam Nealey of the Petroleum Supply Division. To update the program, operating capacity data can be pulled from IPS. (Manual updates to the data file can be made using data from Table 36 of the PSA and making some minor adjustments to the program that reads the data.)

F.12 Estimation of Sulfur Dioxide Allowance Equations

Between Oct. 1, 1993, and Dec. 31, 1999, small refineries that produce low sulfur diesel fuel will be eligible to receive allowances for sulfur dioxide emissions through the year 1999[25]. Refiners are not covered under the Acid Rain program but can trade the allowances with electric utilities and other units that must meet Title VI compliance. Allowance trading under the Acid Rain program will begin in 1995.

In order to be eligible for allowances, small refiners must desulfurize both on- and off-road diesel. A "small refinery" is defined as a refinery or portion of a refinery that has a crude throughput less than 18.25 million barrels (MMbbl) and that is owned by a refiner with a combined throughput less than 50.19 MMbbl. The annual throughput will be measured as of November 15, 1990, according to Form EIA-810[26].

Analysis of the 1990 EIA-810 data indicates distillate production from eligible small refiners represented 12.8 percent of domestic distillate production in 1990. Identification of eligible small refiners and production of distillate was done in program CN6007.SSE.DIESEL.READ, which reads company level data from the EIA-810 data contained in CN6007.SSE.PSD.DIESEL.DATA.

AEO95 assumes that all small refiners desulfurize and produce low sulfur diesel at the national diesel (transportation and off-highway) to normal distillate ratio of 59 percent which correlates with 86,337 allowance requests. The actual number of small refiners that will choose to invest in desulfurization and the amount of the distillate yield at these refineries eligible for allowances (used as motor fuel) is very uncertain. The EPA awards allowances based on the EIA-810 which began differentiating between low sulfur and regular distillate in January 1993 but does not report end-uses. The maximum requests for allowances based on 1990 data and assuming all eligible refiners will produce only low sulfur distillate is 93,930.

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[25] Proposed Rules,_Federal Register_, Vol. 57, No. 130, July 7, 1992, pp. 29960-29961.

[26] Ibid.

Small refiner distillate volumes eligible for allowances can be estimated as:

Possible Allowance Volume (PAV) = total distillate $* .128 * .59$

(MMbbl)

The EPA will award allowances based on their estimates of sulfur dioxide reduction resulting from desulfurization. Each unit of low-sulfur diesel produced by eligible refiners will be equated to a .224 percent reduction in sulfur by weight[27]. Reflecting molecular weights, the reduction in sulfur is converted to a reduction in sulfur dioxide by multiplying by 2. One allowance request will be allowed for every ton of reduction in sulfur dioxide. Eligible volumes are converted to weight to estimate sulfur dioxide reduction/allowances as follows:

Possible Allowance Weight (PAW) = PAV $*$ (302/2000 tons/bbl)

(MMtons)

and

Requested Allowances = PAW $*$ (0.00224 % wt) $* 2$

Allowances for each refinery will be based on diesel yield as reported on the EIA-810. A maximum total of 35,000 allowances per year will be available for small refineries. An individual refinery may receive up to 1500 allowances per year. Therefore, sulfur allowances are estimated as the minimum of requested allowances estimated above or 35,000.

Future Methodology:

In January of 1993 the EIA-810 started to differentiate between low sulfur diesel and other distillate. Annual data can be used to calculate the percent of low sulfur diesel produced at small refineries. This percent should replace the 59-percent assumption discussed above.

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[27] The percent weight .224 represents the difference in sulfur content between high-sulfur(.274 percent weight) and low-sulfur (.05 percent weight) distillates.

F.13 Unfinished Oil Imports Methodology

PAD Districts I and III are the primary recipients of unfinished oil imports into the United States. Of the four categories that EIA publishes, light gas oils are practically nil and will not be modeled in PMM.

The Oil Market Module used the most recent known values for imports of unfinished oils, which remained fixed throughout the forecast period. While simplistic, this methodology was difficult to improve on.

In the methodology described below, unfinished oil imports are estimated as a function of crude oil input to refineries. Only six observations were available for this equation (1989 was an outlier and was not used), so this methodology should be reviewed later, possibly re-estimating the equation using quarterly data. Total U.S. unfinished oil imports are estimated from the equation, then the PAD District I and III values are shared out.

$$\text{U.S. Unfinished Oil Imports} = -2856.7 + (0.2447 * \text{Crude Inputs})$$

t-stats: (-157.5)   (8.97)

R-squared: .95

PAD District III Unfinished Oil Imports = U.S. Unfinished Oil Imports * 0.65
     PAD District III Naphthas = PAD District III Total * 0.24
     PAD District III Heavy Gas Oils = PAD District III Total * 0.27
     PAD District III Residuum = PAD District III Total * 0.49

PAD District I Unfinished Oil Imports = U.S. Unfinished Oil Imports * 0.35
     PAD District I Naphthas = PAD District I Total * 0.09
     PAD District I Heavy Gas Oils = PAD District I Total * 0.73
     PAD District I Residuum = PAD District I Total * 0.18

F.14 Product Pipeline Capacities and Tariffs

Two sources were used to obtain the product pipeline data; (1) The NPC study [28] and (2) The North American Crude Oil Distribution (NACOD) model prepared by ICF for the Office of Strategic Petroleum Reserves (OSPR) during 1990-91. The NACOD data was received in LOTUS.WK3 spreadsheet format from Don Buck of OSPR.

NACOD data for the year 2000 were used for the petroleum product pipeline capacities and tariffs (1991$). The NPC study was used for LPG and NGL pipeline capacity data. The NACOD model defines 15 crude oil demand regions (including Canada and Puerto Rico/Virgin Islands) and the NPC study uses PAD District regions. The links needed for PMM, as shown in Table F19, are based on PAD Districts for refining regions and Census divisions for demands.

Many of the arcs shown in Table F20 and Table F21 represent more than one pipeline. In some cases, we have retained more than one arc from a source to a destination in order to have a better representation of product movements.

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

Table F19. NACOD Regions and NEMS/PMM Census Regions

NACOD Regions		NEMS/PMM Regions	
Code	Locations	Code	Locations
1	New England	1	NE, New england
2	Includes MD,DE	2	MA, excludes MD,DE
3	WV to FL	5	SA, includes MD,DE
4	KS, OK	7	WSC, includes OK,KS
5	PAD District II	3, 4	WNC,ENC, and KY, TN from 6
6	Texas Gulf Coast	7	WSC
7	LA Gulf Coast	7	WSC
8	West Texas, NM	7	WSC, excludes NM
9	AR, No. LA, No. MS, AL	6, 7	ESC,AR,LA,MS,AL
10	PAD District IV, North-ID, MT	8	MNT
11	PAD District IV, South-WY,UT,CO	8	MNT
12	Alaska		
13	Hawaii		
14	PAD District V,	9	PAC, excludes NV,AZ

The product pipeline capacities, excluding LPG/NGL service, are shown in Table F21. The matrix formulation used in PMM allows for separate arcs for product movements. For example, to deliver a barrel of gasoline to Dorsey MD (In Census Region 2) from PAD District III, (Census Region 7), requires flow on the arc from Region 7 to Region 6 (capacity of 2280 Mbbl/cd) at a cost of $0.31/bbl, flow on the arc from Region 6 to Region 5 (capacity of 2526 Mbbl/cd) at a cost of $0.74/bbl, and flow on the arc from Region 5 to Region 2 (capacity of 1392 Mbbl/cd) at a cost of $0.16/bbl. The total tariff is $1.21/bbl or 2.88 cents/gallon.

Table F20. Petroleum Product Pipeline Capacities and Tariffs[29]

Census region			
From	To	Capacity (Mbbl/cd)	Rate (Wt. avg $/bbl)
ENC, 3	MA, 2	157	1.32
ENC, 3	SA, 5	20	1.40
SA, 5	MA, 2	1392	0.16
ESC, 6	SA, 5	2526	0.74
WSC, 7	ENC, 3	328	0.56
WSC, 7	WNC, 4	280	0.86
WSC, 7	WNC, 4	717	0.80
WSC, 7	ESC, 6	2280	0.31
WSC, 7	MNT, 8	81	0.74
WSC, 7	MNT, 8	58	0.73
MNT, 8	WNC, 4	44	0.99
MNT, 8	PAC, 9	73	0.99

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[29] Capacities and tariffs from NACOD model.

The LPG/NGL pipelines are shown in Table F21.

Table F21. LPG/NGL Pipelines Capacities and Tariffs[30]

Census Region			
From	To	Capacity (Mbbl/cd)	Rate (Wt. avg $/bbl)
ENC, 3	MA, 2	61	2.18
WNC, 4	ENC, 3	56	0.99 (estimated)
WNC, 4	SA, 5	57	0.99 (estimated)
ESC, 6	SA, 5	109	0.65
WSC, 7	ESC, 6	120	0.28
WSC, 7	WNC, 4	225	0.65
WSC, 7	WNC, 4	65	1.14
WSC, 7	MNT, 8	47	0.84
MNT, 8	WNC, 4	12	1.15

F.15 Cogeneration Methodology

Electricity consumption in the refinery is a function of the throughput of each unit. Sources of electricity consist of refinery power generation, utility purchases, and refinery cogeneration. Power generation and utility purchases have always been modeled as part of the PMM Linear Program (LP), while cogeneration was calculated post process. Electricity generated from refinery cogeneration has now been incorporated into the PMM LP. Cogeneration activity for each refinery was aggregated to the PADD level and modeled using historical data. Cogeneration capacity, fuel consumption, and percent sales to the utility grid were estimated from the EIA-867, Annual Nonutility Power Producer Report for 1992. The data covers all

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[30] Capacities from NPC study, tariffs from NACOD model data

of SIC 29, not just SIC 2911. Cogeneration investment and operating costs were derived from the 1980 Office of Technology Assessment (OTA) report "Industrial Cogeneration".

Cogeneration capacity for each refining region was derived from the EIA-867 historical data base. It should be noted that the capacity provided in the data base is summertime capability and not nameplate capacity. The LP limits utilization to 90 percent of the summertime capability. Cogeneration capacity is allowed to expand when the value received from the additional product exceeds the investment and operating costs of the new unit. The value of adding capacity includes revenues from sales to the utility grid and the displacement of purchases of electricity. Investment costs are derived from the OTA report. The capacity expansion methodology is described in detail in Chapter 4.

Cogeneration fuel consumption was also calculated using the 1992 EIA-867 historical data base. It was found that consumption of 3.567 barrels of fuel oil would produce approximately 1000 kwh of electricity and 6530 lbs of steam. The shares of individual fuels were also determined from the historical data and are computed post process. The shares are allocated as follows:

Petroleum Products 54.4%
Natural Gas   45.0%
Other   0.6%.

In general, refineries will sell portions of the cogenerated electricity back to the utility grid. However, because of the "all or nothing" nature of an LP, sales to the grid could not be projected. If it is cost effective to sell cogeneration electricity, the LP will sell all of it. Likewise if it is not profitable, it will sell none of it. To model the situation more realistically, sales to the grid were modeled using percentages derived from the historical data base. The percentage of sales to the grid for each refining region (PADD) was calculated from the 1992 data as follows:

REGION	PERCENT SOLD TO GRID
PADD 1	83.68
PADD 2	0.09

PADD 3	30.90
PADD 4	71.70
PADD 5	60.25

The LP is then forced to sell electricity back to the grid in these percentages at a price equal to the average price of electricity.

Fixed operating costs are calculated in the model as a function of cogeneration capacity while variable operating costs are determined as a function of electricity generated. The following rates were determined from the OTA report.

Annual Fixed Cost	$7.32/kw
Variable Cost	$0.00565/kwh

Data from the EIA-867 report was reconfigured using the following SAS programs to extract information necessary to the LP.

CN6007.JDI.COGEN.MBTU.FIXIT manipulates the EIA-867 raw data so that all pertinent information for each refinery is contained in one line (SAS observation). This program also corrects some minor errors observed in the original data set. The results are stored in the SAS data base
CN6007.JDI.COGEN.F867.SASDB.D0629941.

CN6007.JDI.COGEN.LP.DATA reads from the newly created SAS data base and calculates fuel consumption in BFOE/LBSTM and BFOE/KWH. Installation and operating costs are also stored in this program.

CN6007.JDI.COGEN.HISTRY.DATA performs several functions. The EIA-867 refinery data is aggregated by PADD and census division (CD) for input into the PMM history file. The PMM LP requires data to be sorted by PADD whereas the NEMS model requires cogeneration data be aggregated by CD. The program corrects minor errors in the original data base, calculates fuel allocation shares, and percentage of sales to the utility grid.

F.16 Natural Gas Plant Fuel Consumption

The consumption of natural gas by natural gas processing plants is modeled as a function of dry gas production. Natural gas consumed at gas processing plants is calculated as a percentage of dry gas production using data from the *Natural Gas Annual 1992*. The ratios are calculated by PAD District, except for PAD District V where Alaska is computed separately from the rest of PAD District V.

PAD District I	1.36
PAD District II	2.50
PAD District III	2.43
PAD District IV	2.61
PAD District V	2.25
ALASKA	8.93