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Liquid Fuels Market Model of the National Energy Modeling System: Model Documentation 2013

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Update Information

This edition of the Liquid Fuels Market Model (LFMM) of the National Energy Modeling System—Model Documentation 2013 reflects changes made to the model over the past year for the Annual Energy Outlook 2013. These changes include:

- Replaced Petroleum Market Model (PMM)
- Updated most associated data files

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Acronyms and Abbreviations

AEO	EIA Annual Energy Outlook
API	American Petroleum Institute
ASTM	American Society of Testing Materials
bbl	Barrel
bbl/cd	Barrels Per Calendar Day
Btu	British thermal unit
CARB	California Air Resources Board
CBTL	Coal-Biomass-To-Liquids (converting coal-biomass mix to diesel-grade blending streams)
CD	Census Division
CHP	Combined Heat and Power
Cn	Represents a hydrocarbon stream containing n atoms of carbon, i.e., C1 is methane, C2 is ethane, C3 is propane, C4 is butane, etc.
CTL	Coal-To-Liquids (converting coal to diesel-grade blending streams)
DOE	U.S. Department of Energy
E85	Gasoline blend of 85 percent ethanol and 15 percent conventional gasoline (annual average of ethanol content in E85 is lower when factoring in cold start need in winter)
EIA	U.S. Energy Information Administration
EISA2007	Energy Independence and Security Act of 2007
EPA	U.S. Environmental Protection Agency
FOE	Fuel Oil Equivalent
GTL	Gas-To-Liquids (converting natural gas to diesel-grade blending streams)
IEO	EIA International Energy Outlook
IEM	International Energy Model
ISBL	Inside the battery limit
KWh	Kilowatt-hour
LCFS	Low Carbon Fuel Standard
LFMM	Liquid Fuels Market Model
LP	Linear Programming
LPG	Liquefied Petroleum Gas
Mbbl/cd	Thousand Barrels Per Calendar Day
Mbtu	Thousand British Thermal Units
MMbbl/cd	Million Barrels Per Calendar Day
MMbtu	Million British Thermal Units
MTBE	Methyl Tertiary Butyl Ether
MW	Megawatts, electric generation capacity
MWh	Megawatt-hour
NACOD	North American Crude Oil Distribution
NEMS	National Energy Modeling System
NETL	National Energy Technology Laboratory
NGL	Natural Gas Liquid
NPC	National Petroleum Council
NPRA	National Petrochemical and Refiners Association
OGSM	Oil and Gas Supply Module
ORNL	Oak Ridge National Laboratory
OVC	Other Variable Costs
PADD	Petroleum Administration for Defense District

PCF	Petrochemical Feed
PMM	Petroleum Market Model
ppm	Parts per million
PSA	Petroleum Supply Annual
RFG	Reformulated Gasoline
RFS	Renewable Fuels Standard
RVP	Reid Vapor Pressure
RYM	Refinery Yield Model (EIA)
SCF	Standard Cubic Feet
SPR	Strategic Petroleum Reserve
STEO	Short Term Energy Outlook
TRG	Conventional gasoline (replacing old nomenclature for traditional gasoline)
ULSD	Ultra-Low Sulfur Diesel

Introduction

Purpose of this report

The purpose of this report is to define the objectives of the Liquid Fuels Market Model (LFMM), describe its basic approach, and provide details on how it works. This report is intended as a reference document for model analysts and users. It is also intended as a tool for model evaluation and improvement. Documentation of the model is in accordance with EIA's legal obligation to provide adequate documentation in support of its models (Public Law 94-385, section 57.b.2). An overview of the LFMM and its major assumptions can also be found in two related documents: The National Energy Modeling System: An Overview 2010, DOE/EIA-0581(2010) and Assumptions to the Annual Energy Outlook of 2013, DOE/EIA-0554(2013). This volume documents the version of the LFMM used for the Annual Energy Outlook 2013 (AEO2013) and thus supersedes all previous versions of the documentation.

Model summary

The LFMM models petroleum refining activities, the marketing of petroleum products to consumption regions, the production and fractionation of natural gas liquids in natural gas processing plants, and the production of renewable fuels (including ethanol, biodiesel, and cellulosic biofuels), and non-pretroleum fossil fuels (including coal- and gas-to-liquids). The LFMM projects domestic petroleum product prices and input supply quantities for meeting petroleum product demands by supply source, fuel, and region. These input supplies include domestic and imported crude oil; alcohols, biodiesel, and other biofuels; domestic natural gas plant liquids production; petroleum product imports; and, unfinished oil imports. In addition, the LFMM estimates domestic refinery capacity expansion and fuel consumption. Product prices are estimated at the Census Division (CD) level; much of the liquid fuels production activity information is at the level of Petroleum Administration for Defense Districts (PADDs) and sub-PADDs.

Model archival citation

The LFMM is archived as part of the National Energy Modeling System (NEMS) for AEO2013. The model contact is:

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Organization of this report

The remainder of this report is organized in the following chapters: Model Purpose; Model Rationale; Model Structure; Appendix A, Data and Outputs; Appendix B, Mathematical Description of Model; Appendix C, Bibliography; Appendix D, Model Abstract; Appendix E, Data Quality; Appendix F, Estimation Methodologies; Appendix G, Historical Data Processing; Appendix H, Changing Structure of the Refining Industry.

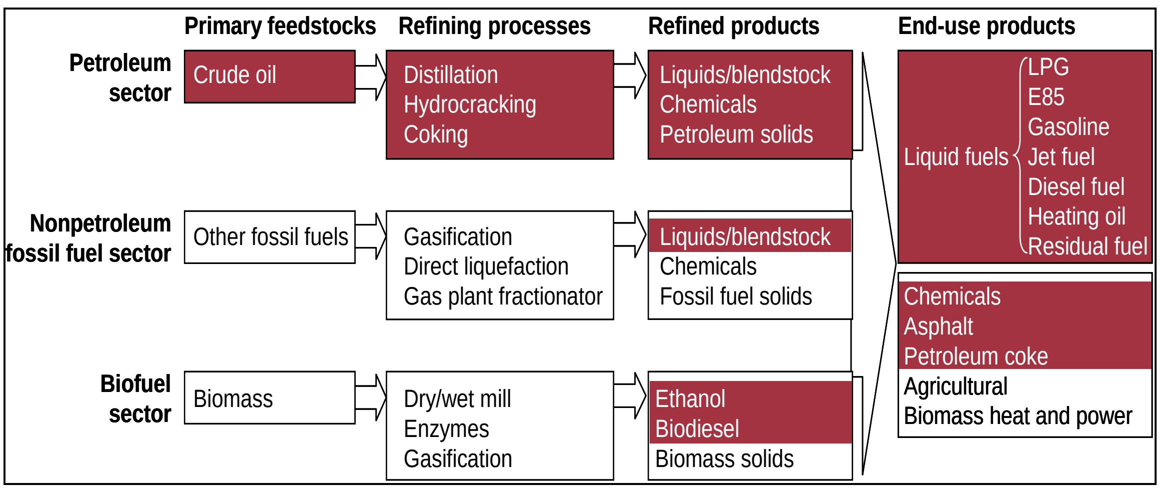
Model Purpose

Model objectives

The Liquid Fuels Market Model (LFMM) models production and marketing of liquid fuels, including petroleum products and non-petroleum liquid fuels (see Appendix H for a discussion of this evolving industry). The purpose of the LFMM is to project liquid fuel prices, production activities, and movements of petroleum into the United States and among domestic regions. In addition, the LFMM estimates capacity expansion and fuel consumption in the liquid fuels production industry. The LFMM is also used to analyze a wide variety of issues and policies related to petroleum fuels and non-petroleum liquid fuels in order to foster a better understanding of the liquid fuels industry, and the effects of certain policies and regulations.

The production processes and physical flows represented in LFMM are shown in red in the figure below.

Figure 1. Liquid fuels production industry, with LFMM highlighted in red



The LFMM simulates the operation of petroleum refineries and non-petroleum liquid fuels production plants in the United States, with a simple representation of the international refinery market used to provide competing crude oil[1] and product import prices and quantities. The U.S. component includes the supply and transportation of crude oil to refineries, regional processing of these raw materials into petroleum products, and the distribution of petroleum products to meet regional demands. The U.S. component also represents the fractionation of natural gas liquids from natural gas processing plants, the production of distillate and naptha blending streams from natural gas (gas-to-liquids, GTL), coal (coal-to-liquids, CTL), and biomass (biomass-to-liquids, BTL), the processing of renewable fuel feedstock (corn, biomass, seed oils, fats and greases) into alcohol and biomass-based diesel liquid blends, and the production of combined heat and power (CHP) from petroleum coke (petcoke) gasification technologies. The essential outputs of this model are domestic product prices, a petroleum supply/demand balance, demands for refinery fuel use, and capacity expansion decisions.

[1] The International Energy Model (IEM) contains price and quantity representation for foreign crude supplies.

- domestic and international petroleum product demands
- domestic crude oil production levels
- international crude oil supply curves and import/export links
- costs of production inputs such as natural gas and electricity
- costs and available quantities of feedstocks used to produce blending components such as ethanol and biodiesel
- yield coefficients for crude oil distillation and other processing units
- existing processing unit capacities
- investment costs for capacity additions
- capacities and costs for pipeline and other transportation modes
- product specifications
- policy requirements

From these inputs, the LFMM produces:

- a slate of domestic prices for petroleum products
- the quantity of domestic crude oil processed
- imports of crude oil and petroleum products
- estimates of other refinery inputs and processing gain
- domestic refinery capacity expansion
- refinery fuel consumption.

The LFMM is used to represent the liquid fuels production and marketing sector in projections published in the Annual Energy Outlook. The model is also used for analysis of a wide variety of related issues. The LFMM is able to project the impact on refinery operations and on the marginal costs of refined products associated with changes in any demands for various kinds of petroleum products; crude oil prices; refinery processing unit capacities; changes in certain petroleum product specifications; energy policies and regulations; and taxes, tariffs, and subsidies.

Relationship to other models

The LFMM represents the liquid fuels production and marketing sector within the National Energy Modeling System (NEMS). The LFMM projects petroleum product prices and supply sources. These projections are generated as part of a NEMS supply/demand/price equilibrium solution. The LFMM does not examine inventories or inventory changes between projection years.

Several other models in NEMS provide inputs to the LFMM. These inputs are listed below.

- Demands for petroleum products are provided by the Residential, Commercial, Industrial, Transportation, and Electricity Market Models. The demands include motor gasoline, jet fuel, kerosene, heating oil, ultra-low sulfur diesel, CARB diesel, low- and high-sulfur residual fuel, liquefied petroleum gases (LPG), petrochemical feedstocks, petroleum coke, and other petroleum products.
- Benchmark crude price is provided by the International Energy Model (IEM). A benchmark crude oil supply curve is provided for Brent crude. Prices for the eight other types of crude are computed in the model by adjusting from the benchmark by the quality and delivery point basis.

- Domestic crude oil production levels are provided by the Oil and Gas Supply Module (OGSM). The crude oil is categorized into the same nine types incorporated into the import supply curves.
- Natural gas liquids, which are among the non-crude inputs to refineries, are also estimated using domestic natural gas production from OGSM.
- Coal supply information (prices and quantities on supply curve, coal type, transportation network, emissions, and consumption for electricity generation) used for feedstock to produce CTL and CBTL are provided by the Coal Market Module (CMM).
- Natural gas and electricity prices are provided by the Natural Gas Transmission and Distribution Module (NGTDM) and the Electricity Market Module (EMM), respectively. The LFMM estimates the refinery consumption of these energy sources.
- Certain macroeconomic parameters from the Macroeconomic Activity Model (MAM). The Baa average corporate bond rate is used for the cost of debt calculation, and the 10-year Treasury note rate is used for the cost of equity calculation. Both rates are used in estimating the capital-related financial charges for refinery investments. Discount rates are also provided by the MAM.
- Cellulosic feedstock prices and quantities are provided by the Renewable Fuels Module (RFM).
- The logit function and other parameters used to estimate the ratio of E85 to motor gasoline usage for flex fuel vehicles (FFV) are provided by the Transportation and Distribution Module (TDM).

The LFMM also provides information to other NEMS modules, including:

- Prices of petroleum products are passed to the Residential, Commercial, Industrial, Transportation, Electricity Market, and Natural Gas Transmission and Distribution Modules. The prices are used to estimate end-use demands for the various fuels.
- Supply balance quantities, including crude oil production, non-crude refinery inputs, and processing gain, are provided for reporting purposes.
- Capacity expansion and utilization rates at production plants (mainly for reporting purposes).
- Fuel consumption from refineries. This information is passed to the Industrial Demand Module for inclusion in the industrial sector totals. In addition, refinery combined heat and power (CHP) capacity and generation levels are also sent to the Industrial Demand Module.
- Cellulosic biomass consumption to the Renewables module

Model Rationale

Theoretical approach

The National Energy Modeling System (NEMS) is a general energy-economy equilibrium model that solves for quantities and prices of fuels delivered regionally to end-use sectors. The solution algorithm (Gauss-Seidel) is an iterative procedure used to achieve convergence between prices and quantities for each fuel in each region. For example, the various demand modules use the petroleum product prices from the LFMM to estimate product demands. The LFMM then takes the petroleum product demands as given, and estimates petroleum product prices. When successive solutions of energy quantities demanded and delivered prices are within a pre-specified percentage (convergence tolerance), the NEMS solution is declared converged. If the computed prices have not converged, new demand quantities are computed, passed to LFMM, and the cycle is repeated. This process continues until a converged solution is found. See the description of theNEMS integrating module for a more complete description of the iterative process and convergence tests.

Within the LFMM, a linear program (LP) is used to represent domestic liquid fuels production, distribution, and marketing operations. The model includes eight U.S. regions based on PADDs (Petroleum Administration for Defense Districts) and sub-PADDs, and one international region representing petroleum refining activity in eastern Canada and the Caribbean. A transportation network model represents transport of crude oils to the refining regions and products from the refining regions to the end-use Census Division demand regions. Changes in one refining region can affect operations in other refining regions because each demand region can be supplied by more than one refining region (if the transportation connections exist). Similarly, a transportation structure is defined for international crude supply and product demand, with additional links between the U.S. and international markets to allow modeling of crude and product imports and exports.

An optimal solution is found by minimizing net total cost while simultaneously meeting the demands in all regions. The model estimates revenues from prices and product sales in the previous NEMS iteration, and projects costsincurred from the purchase and processing of raw materials and the transportation of finished products to the market. The liquid fuels production activities are constrained by material balance requirements on feedstocks and intermediate streams, product specifications, processing and transportation capacities, demand, and policy requirements. Economic forces also govern the decision to import crude oil or refined products into the U.S. regions.

Fundamental assumptions

The LFMM assumes the liquid fuels production 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, renewable fuel blends, and logistics will adjust to minimize the overall cost of supplying the market with petroleum products. If petroleum product demand is unusually high in one region, the price will increase, driving down demand and providing economic incentives for bringing supplies in from other regions, thus restoring the supply/demand balance. Because the LFMM is an annual model, it cannot be used to analyze short-term petroleum market issues related to supplies, demands, or prices.

Model Structure

During each NEMS iterative solution, product demand quantities and other variables provided by the other NEMS demand and supply modules are used to update the LFMM linear program (LP). Once an optimal solution is obtained from the updated LP, 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 LFMM LP matrix are accomplished by a GAMS program and the Xpress solver. Appendix B describes the formulation of the linear programming representation in the LFMM.

The REFINE Fortran subroutine (called by NEMS) is the main controlling subroutine for the LFMM. Through subroutine calls and a call to the main GAMS program lfshell.gms, it initializes variables, reads in data, updates and solves the LP matrix, retrieves and processes results, and generates reports.

Main subroutines (refine.f, lfshell.gms)

LFMM includes Fortran subroutines and GAMS programs. The Fortran subroutines are in file refine.f: REFINE, RFHIST1, PMM_NEXTDATA, WRITE_INIT_GDX, WRITE_GDX, READ_GDX, and E85_Demand_Curve. Fortran subroutine REFINE calls the GAMS program lfshell.gms.

Subroutine REFINE

REFINE is the main entry point into LFMM from the rest of NEMS. It calls subroutines RFHIST1 (which in turn calls subroutine PMM_NEXTDATA), Write_INIT_GDX, WriteGDX, E85_Demand_Curve, lfshell.gms, and Read_GDX.

Subroutines RFHIST1 and PMM_NEXTDATA

RFHIST1 reads the text file rfhist.txt, which contains historical and STEO-year data on crude imports, production capacity of petroleum refineries and non-petroleum liquid fuels plants, capacity utilization, product imports and exports, product demands, refinery gain, NGPL production, etc.

RFHIST1 calls PMM_NEXTDATA to iterate through the rfhist.txt file.

Subroutine WRITE_INIT_GDX

Writes relevant NEMS variables (available the first model year the LFMM is called) to a GAMS GDX data file: NEMS_TO_LFMM_INIT.gdx. This GDX file is used for debugging purposes

Subroutine WRITE_GDX

Writes relevant NEMS variables (every model year and iteration, beginning with the LFMM start year, 2010) to NEM_TO_LFMM1.gdx, a GAMS GDX file which is later read by lf_nem.gms.

Subroutine READ_GDX

Reads LFMM LP results from LFMM_to_NEMS.gdx, a GAMS GDX file created by lfreport.gms that includes LFMM model results for other NEMS models and NEMS reports.

Subroutine E85_Demand_Curve
Sets up an E85 demand curve to speed up convergence between LFMM and TRAN. The curve is written to E85.gdx, a GAMS GDX file which is later read by lfprep.gms.

Lfshell.gms
Lfshell.gms is the main entry point to the GAMS portion of LFMM.

- Call lf_nem.gms to read NEM_TO_LFMM1.gdx
- Call lfprep.gms to read input data files lfminput.gdx, lfminset.gdx.
- Call lfmodel.gms to set up the LP model (decision variables, objective function, constraints)
- Set capacity expansion parameters (fixed costs, learning, etc.)
- NPV (net present value) calculations to put all data on a consistent (nominal) year basis.
- LCFS: create LCFS carbon factors ready to be incorporated into the LP
- RFS: read expected demand for motor fuels, which is an input to the calculated RVO used to implement RFS requirements for each year.
- Set up supply curves for crude, imported sugarcane ethanol, various feedstcock (corn, soyoil, etc.)
- Restrict alternative fuel builds (celluloisic ethanol, etc.) before 2016 to planned builds
- Solve LP
- Call lfreport.gms to write LP results to LFMM_TO_NEMS.gdx

LP Preprocessing (lf_nem.gms, lfprep.gms)

lf_nem.gms
Reads NEM_TO_LFMM1.gdx (created in refine.f), contains all the data defined by other NEMS models, including product demands, feedstock costs and supply curve data, energy conversion factors, etc.

lfprep.gms
- Read lfminset.gdx, which defines many of the sets used by the LFMM GAMS code
- Read lfminput.gdx, a GDX data file created by reading in various Excel (xls) data files
- Create mapping sets that mediate between NEMS regions and LFMM regions
- Initialize LP parameters based on NEMS variables read from NEM_TO_LFMM1.gdx
- Set up supply curves for corn, soyoil, and other non-crude feedstocks
- Define “waiver costs” for RFS and LCFS to ensure that the LP does become infeasible

LP (lfmodel.gms)
Lfmodel.gms specifies the LP decision variables, the constraints, and the objective function. The LP finds the minimum cost means of satisfying the set of liquid fuel demands given by the NEMS demand modules, subject to build/operate constraints (e.g., processing capacity, volume balance, feedstock purchases) and policy constraints (e.g., RFS, LCFS, AB32). The outputs of the LP include build/operate decisions and wholesale product prices.

LP Post-Processing (lfreport.gms)

Lfreport.gms writes the file LFMM_TO_NEMS.gdx, which includes the following:

- Build/operate decisions for each liquid fuels production technology represented in LFMM;
- Wholesale product prices, based on shadow prices (duals) of selected LP constraints;
- Retail product product prices, based on wholesale prices and markeups for taxes and distribution;
- Items useful for debugging

Appendix A. Data and Outputs

This appendix is divided in three parts: Section A.1 lists variables passed between LFMM and the NEMS Integrating Module, Section A.2 lists data sources, and Section A.3 lists the data files used to create LFMM's GDX data files that are loaded into the NEMS environment. The data files described in A.3 constitute the major portion of the LFMM data as they represent the liquid fuels process unit technologies and capacities, quality characteristics, and specifications.

Variables and definitions

NEMS variables are passed to LFMM via file NEM_TO_LFMM1.gdx. LFMM results (including product prices) are passed to the NEMS Integrating module via file LFMM_TO_NEMS.gdx.

Data sources

Data for LFMM were developed by OnLocation, Inc./Energy Systems Consulting and their subcontractors. These data were based on (1) new analysis, and (2) existing analysis used in LFMM's predecessor model, the Petroleum Market Module (PMM). For details on the new analysis, see the LFMM Component Design Report (http://www.eia.gov/oiaf/emdworkshop/pdf/LFMM%20CDR.pdf).

Data for PMM, the predecessor to LFMM, were developed and updated by EIA and others since the first model database was provided by Turner, Mason Associates during 1975-76. The original data were used extensively during 1983-1986 in the EIA Refinery Yield Model (RYM). The RYM database underwent substantial review and update by oil industry experts when the National Petroleum Council (NPC) used the RYM during the development of their 1986 study on U.S. refining flexibility. To support a study for the U.S. Navy in 1985, EIA provided Oak Ridge National Laboratories (ORNL) and its consultant EnSys with the updated RYM/NPC data and OMNI matrix and report generator programs.[2] Most of the data used for this version of the PMM was provided by EnSys to EIA in June 2003 and is based on some EnSys in house data sources. Other data were provided by DOE's National Energy Technology Lab (NETL) and its consultant John J. Marano (LLC). The various data sources include:

- The original Refinery Yield Model (RYM) Data Base provided by EIA in about 1981 to ORNL. This data was then combined with the 1985 RYM/NPC updates and used by their consultant, EnSys.
- Oil & Gas Journal, Hydrocarbon Processing, NPRA papers, API papers, ASTM specs and correlation methods, Chemical Engineering, Gary & Handwerk (mainly correlations), AIChE papers, Petroleum Review.
- An extensive review of foreign journals obtained with the aid of ORNL for the high-density jet fuel study.
- Contractor reports and data M.W. Kellogg, UOP, IFP, Snam Projetti and Foster and Wheeler.
- Consultant reports and data as published Bonner & Moore, A.D. Little, Chem Systems, Purvin & Gertz, and National Energy Technology Laboratory.

[2] 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).

- Updated data tables for the alkylation units (HFA, SFA, and others), isooctane units (IOT, IOX), and petroleum coke gasifier (GSF, GSH, CHP), were all provided by DOE's National Energy Technology Laboratory and its consultant John J. Marano (LLC).
- John J. Marano (LLC) also provided new hydrogen stream data (associated with relevant processing units) such that a single hydrogen stream (HH2) was disaggregated into three hydrogen streams (HYL, HYM, HYH) that were distinguished by quality (low, medium, and high).

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

Refinery capacity construction and utilization data
The base capacity for refinery process units are derived principally from EIA data (see section D.15)and annual surveys published in the Oil & Gas Journal. The approach used is to review all announced projects, but to only include as active those that have reached the engineering, construction, or start-up stage. (Unit capacity is measured in volume per calendar day.) Historical process unit utilization is derived from the EIA Petroleum Supply Annual.

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 international crude and petroleum product demands that are used by the LFMM to determine crude and product imports to the U.S. Individual crude oil streams for both domestic and imported crude oils are grouped in nine categories differentiated by API gravity, sulfur content, and yield characteristics. These categories are detailed in Assumptions to the Annual Energy Outlook 2013.

Non-petroleum feedstocks
The following non-petroleum feedstocks are discussed in Appendix F:

- natural gas plant liquids (Oil and Gas Supply module)
- coal (Coal module)
- natural gas (Natural Gas Transmission and Distribution module)
- cellulosic biomass (Renewables module)
- corn, seed oils, and bio-greases (LFMM)

Products
Product demands are available from the NEMS restart file (determined by NEMS demand models and the electricity model) for a given scenario by year. The product list for the liquid fuels market includes: motor gasoline, Carb motor gasoline, E85, diesel, Carb diesel, jet fuel, heating oil, distillate oil, residual oil, LPG, naphthas (petrochemical feedstocks), petroleum coke, ethane, propane, iso- and n-butane,

natural gasoline, propylene, and others (lubes, aviation gasoline, asphalt, benzene, toluene, xylene). Some coproducts are also represented.

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.

Transportation data

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

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: Gary & Handwerk, p.175.

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

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 reflective of base gasoline sensitivity have been drawn from many sources and averaged.

Units of measurement

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

Exceptions to the above rule are:

- The LP itself uses nominal year-dollars for each NEMS iteration.
- Gases lighter than propane are measured in thousands of barrels fuel oil equivalent (FOE) per day. These are based on the following conversion factors:

Table A-1. Btu/bbl for gases lighter than propane

Gas stream	Code	bblFOE/lb	cf/bblFOE
Hydrogen	H2,H2U	.009620	19,646
Hydrogen sulfide	H2S	.001040	10,145
Methane/natural gas	NGS,CC1	.003414	6,917
Gas stream	Code	bblFOE/lb	cf/bblFOE
Ethane	CC2	.003245	3,861
Process gas	PGS	.003245	3,861

- One barrel FOE (fuel oil equivalent) is 6.287 million Btu.

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

Table A-2. Btu/bbl for other streams

Stream	Code	MMBtu/bbl
Gasoline	--=	5.202
Jet Fuel	JTA	5.355
Diesel (ULSD)	DSU	5.755
No. 2 Heating Oil	N2H	5.825
Residual Oil	N6I,N6B	6.287
LPG	LPG, CC3	3.603
Ethanol	ETH	3.563

- Yields of coke are measured in short tons per barrel and demands are in short tons per day. A factor of 5.0 crude oil equivalent (COE) barrels per short ton is used. Heat content is 6.024 MMBtu/bbl.
- 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.
- Process unit capacities are generally measured in terms of feedstock volume. Exceptions are process units, principally those with gaseous feeds and liquid products, whose capacities are measured in terms of product volume.
- Process unit activity levels for H2P, H2R, and SUL represent the production of fuel oil equivalent barrels of hydrogen and short tons of sulfur per day.
- Quality and specification units are those specified in each ASTM test method or are dimensionless (as in the case of blending indices). Sulfur specs are defined in parts per million for both gasoline and diesel blend streams, but are converted to volume percent (using specific gravity) for use in the LP.
- Steam consumption is in pounds per barrel (lb/bbl). Thus an activity in Mbbl/cd consumes steam in thousands of pounds per day (M lb/day). Steam generation capacity is in millions of pounds per day (MM lb/day). The consumption of 0.00668 fuel oil equivalent barrels per day to raise 1 pound per hour of steam is equivalent to 1225 Btu per pound steam (assuming 70 percent energy conversion efficiency).
- Electricity consumption is in KWh/bbl. Generation is in MWh/cd (megawatt-hrs/calendar day).

Data tables

LFMinset.gdx defines sets used by LFMM but not by other NEMS modules. For example,

- Process, ProcessMode: set of all production processes and their operating modes
- Stream: set of all physical and non-physical streams
- RecipeProd: set of products produced according to a specific recipe
- SpecProd: set of products blended to meet various specifications rather than according to a recipe (diesel, jet, #2 heating oil, California BOB, conventional BOB, reformulated BOB, residual fuel oil)
- EndProduct, EndProductNGL: set of products which are demanded by the various NEMS demand modules. Approximately equal to the union of sets SpecProd and RecipeProd.
- CoProduct: set of co-products manufactured incidentally to the production of end products

LFMinput.gdx defines parameters used by LFMM. For example,

- ProcessTableCrude: input/out matrix for each LFMM process
- RecipeBlending: recipe definitions for RecipeProd products
- StreamProp: stream properties (API, etc.) for blending of SpecProd products

LFMinput.gdx is based on data from a group of Excel 2003 data files, each comprising multiple worksheets.

Table A- 3. Excel files used to make LFMINPUT.GDX

Excel File (.xls)	Worksheets
lfblending	Properties, RCP, StreamSpecProd, DieselFrac
lfcapacity	ForImport, OJG Data, Notes, AltFuels, Calibrate, Calibrate PSA-O&GJ
lfcontrol	CoalDReg-to-RefReg, Census-to-RefReg, StateMaps, mappings, Streams, Processes, StreamFactors
lfdistconstr	RefReg-to-RefReg Cap, RefReg-to-RefReg Cost, RefReg-to-Census Cap, RefReg-to-Census Cost, Census-to-Census Cap, Census-to-Census Cost, RefReg-to-RefReg Cap Import, RefReg-to-RefReg Cost Import, RefReg-to-Census Cap Import, RefReg-to-Census Cost Import, Census-to-Census Cap Import, Census-to-Census Cost Import, E15MaxPen
lfdistcosts	ProductMarkups, StateFuelTax, FedFuelTax, EnvMarkups, lffeedstock.xls, Crude_Transportation, Allowed_Crude_Use, CornPriceExp, CornTranCost, SeedOilQnty, GrainQnty
lfimportpurch	ForImport, BrzAdvEthProd, BrzEthDmd, NonUSEthDmd, FBDImpQuant, FBDImpCoef
lfinvestment	CapCostImp, NFImport, StateTax, FedTax, RegionalData, InvestmentFactors, Capital Costs, N-F Indicies, Learning, AFGrowthRates, AFBldSteps
lfnonpetroleum	data, ForImport, EDH, EDM, SEW, NCE, AET, CLE, BPU, BTL, CBL, CBLCCS, FBD, GDT, CTL, CTLCCS, GTL
lfpetcrackers	FCC, RGN, HCD
lfpetenviro	SUL, ARP, DDA
lfpetother	LUB, SGP, UGP
lfpetseparation	LNS, FGS, DC5, DC4
lfpetupgraders	DDS, SDA, KRD, KRD_orig, ALK, BSA, RCR, RSR, NDS, C4I, CPL, FDS, GDS, PHI, TRI
lfpolicy	RFSMandates, RFSScores, RFSCategory, RFSWaiver, LCFS_AltVehicles, LCFS_Penalty_Cost, LCFS_Target, LCFS_BioStreams, LCFS_PetStreams, LCFS_BioImports, AB32_CapAdjFactor, AB32_AssistFactor, AB32_BenchFactor, AB32_Control
lfproducts	LPGPricing, CoproductPricing, Gas_Spec_UB, Gas_Spec_LB, Dist_Spec_LB, Dist_Spec_UB, Resid_Spec_UB, Resid_Spec_LB
lfrefpurch	1_RefReg -- 9_RefReg
lftransfers	TRS, old
lfutilities	FUM, KWG, STG, CGN, H2R

Appendix B. Mathematical Description of Model

The LFMM LP is programmed in lfmodel.gms, which defines the objective function, decision variables, and constraints, and in lf_nem.gms and lfprep.gms, which define relevant sets and parameters. Bounds on LP variables are set in lfshell.gms.

Objective function

The objective function minimizes total amortized cost, in nominal dollars, for purchasing feedstock and other inputs, production operations, transportation, and capital expansion. The LP has three periods over which costs are considered: the current NEMS year (for operating decisions), the next NEMS year (for capacity expansion decisions), and a 19-year lookahead period that enables capital expansion to meet upcoming demands while avoiding stranding capital assets.

In words, the objective function seeks to minimize the sum of the following terms:

- Operating variable cost
- Cost of crude oil
- Cost to transport crude oil
- Cost of ethanol imported from Brazil
- Cost to transport ethanol exports to Brazil
- Cost to transport ethanol imports from Brazil
- Cost of natural gas and electricity utilities
- Cost of non-crude refinery feedstocks
- Cost of cellulosic biomass
- Cost of coal
- Cost to transport materials between production regions
- Cost to transport products to demand regions
- Cost of distress (safety valve) imports
- Fixed operating cost
- Build costs
- -1 * revenue from coproducts
- Cost of RFS waivers (safety valves)
- Cost of LCFS waivers (safety valves)
- Cost to transport coal
- SO_2 costs
- Mercury costs
- Cost of imported gasoline
- -1 * revenue from fixed exports
- Cost of AB32 allowances
- Cost of biodiesel imports
- Cost of NGL imports
- Cost of carbon taxes

Decision variables

Table B-1. LP decision variables

Decision Variable	Units	Description
BIODEMAND	varies	Amount (units vary) of biomoass in demand by other NEMS modules
BIODIMP	M bbl/d	Biodiesel imported at each supply step in each period
BIODIMPref	MB/CD	Total biodiesel imports by refining region
BIOPURCH	MMbtu/d	Amount(units vary) of biomass purchased at each supply step in each period
BIOXFER	MMbtu/d	Amount of biomass transferred from each coal demand region
BOBPURCH	M bbl/d	Amount of RBOB-CBOB purchased
BrzEthExpNonUs	M bbl/d	M BBLs per day of ethanol exported from Brazil to satisfy non-US demand
BUILDS	M bbl/d	M BBLs per day capacity added to processes in each period, except period 1
CDSUPPLY	M bbl/d	M BBLs per day domestically-produced end product available by census division
CenCenTRAN	M bbl/d	M BBLs transferred per day by transp mode from census division CenDiv to CenDivA
COALDEMAND	MMbtu/d	Amount of coal in demand by other NEMS modules
COALPURCH	MMbtu/d	Amount of coal purchased at each supply step in each period
COALTRANSP	MMbtu/d	Amount of coal transported from coal suppy to coal demand region
COALXFER	MMbtu/d	Amount of coal transferred from coal demand region to refinery region
COPRODUCTS	varies	Amount (units vary) of co-products produced from refinery processes
CRUDENONUS	M bbl/d	M BBLs per day Non-US crude demand at each demand step in each period
CRUDEPURCH	M bbl/d	M BBLs per day of each crude purchased at each supply step in each period
CRUDETOTAL	M bbl/d	M BBLs per day total world crude at each supply step in each period
CRUDETRANS	M bbl/d	M BBLs per day of each crude transported from source to sup-region in each period
DISTRESSIMPORT	M bbl/d	M BBLs per day of global import
E85STP	M bbl/d	M BBLs per day E85 production on each pricing step
ETH_BRAZIL	M bbl/d	M BBLs per day of TOTAL ethanol produced in Brazil
ETHEXP	M bbl/d	M BBLs per day of corn ethanol exported at each supply step in each period
ETHIMP	M bbl/d	M BBLs per day of ethanol imported at each supply step in each period
ETHNonUS	M bbl/d	M BBLs per day of ethanol Non-US demand
ExpFromSPECBLEND	M bbl/d	Amount BOB transferred from Spec Blending
EXPORTS	M bbl/d	Amount of product exports
HGCREDITS	Scalar	Mercury credits purchased
IMPORTS	M bbl/d	Amount of product imports
ImpToSPECBLEND	M bbl/d	Amount BOB transferred to Spec Blending
LCFS_AltVehicles	Ttil btu	LCFS Alternate Vehicle Demand
LCFS_Bio_Sub	$/mMTC	LCFS Subsidy For Bio-Liquid Relief in Price Period only
LCFS_Pet_Cst	$/mMTC	LCFS Cost For Petroleum Deficit in Price Period only
LCFS_Pet_to_Bio	mMTC/d	LCFS Transfer Petroleum Deficit to Bio-Liquid Relief
LCFSSafety	mMTC/d	LCFS credits that exceed the maximum credit price

Table B-1. LP decision variables (cont.)

Decision Variable	Units	Description
MCCDEMAND	M bbl/d	Discretionary demand from Maritime Canada and the Carribean (RefReg1 Only)
NGLEXPORTS	M bbl/d	Volume of NGL imports
NGLIMPORTS	M bbl/d	Volume of NGL exports
OPERATECAP	M bbl/d	M BBLs per day EXISTING capacity operated in each period
PROCMODE	M bbl/d	M BBLs per day for each process and mode in each period
PRODTOCENSUS	M bbl/d	M BBLs transferred per day from supply regions to census divisions
QE85	M bbl/d	M BBLs per day total of all E85 used to satisfy flex-fuel BTU constraint
QMG	M bbl/d	M BBLs per day total of all gasoline used to satisfy flex-fuel BTU constraint
QMG10	M bbl/d	M BBLs per day total E10 gasoline used to satisfy demand
QMG15	M bbl/d	M BBLs per day total E15 gasoline used to satisfy demand
RECIPEMODE	M bbl/d	M BBLs per day on recipe in each period
RECIPESUPPLY	M bbl/d	M BBLs per day total end product available by census division including imports
RECIPETOPROD	M bbl/d	M BBLs per day transferred of recipes to end products
RefCenTRAN	M bbl/d	M BBLs transferred per day by transp mode between supply region and census division
REFPURCH	Varies	Amount (units vary) of refinery input purchased at each supply step in each period
REFPURused	Varies	Amount (units vary) of purchased refinery input used by each refinery type
RefRefTRAN	M bbl/d	M BBLs transferred per day from supply region RefRegA to RefReg
RFS_PRD_to_RQM	M bbl/d	RFS Transfer Production to Requirement Constraints
RFS_PRD_VAL	M bbl/d	RFS Subsidy for Biofuel Production by RFS Category for Price Period Only
RFS_RQM_CST	M bbl/d	RFS Cost for Purchasing RFS Credits by RFS Category for Price Period Only
RFSESCAPE	M bbl/d	RFS escape valves
SO2CREDITS	Scalar	SO2 credits purchased
ToRECIPEBLEND	M bbl/d	Volume of stream going to recipe product recipies
ToSPECBLEND	M bbl/d	Volume of stream going to specification blending pool
TotalCost	M $	Objective function value
TOTPROD	M bbl/d	Total production of each product by supply region
UTILPURCH	various	Amount(units vary) of each utility purchased in each period

Table B-2. LP constraints

Constraint	Description
BioBalance	Biomass balance
BioBalance	Biomass balance at coal demand regions
BiodieselBalance	Balance biodiesel imports over refinery types
BiodieselBalance	Balance biodiesel imports over refinery types
BioRefRegBal	Biomass balance at refining regions
BOBBalance	RBOB-CBOB balance
BOBBalance	RBOB-CBOB balance

Table B-2. LP constraints (cont.)

Constraint	Description
BrzEthProdBal	Satisfy non-US ethanol demand
BrzEthProdBal	Satisfy non-US ethanol demand
BrzMaxExportsToUS	Maximum exports from Brazil to U.S.
CapacityBalance	Balance of overall process capacities with the activity on their modes
CaRBOBBalance	Balance CaRBOB transferred to each census division with amount used towards BTU constraint
CDSupplyTot	Recipe product supply balance for each census
CDtoCDTran	Enforce census to census transport bounds
CFG15Balance	Balance CFG15 transferred to each census with amount used towards BTU constraint
CFGBalance	Balance CFG transferred to each census with amount used towards BTU constraint
CoalDemBalance	Coal balance by coal demand region
CoalRefRegBal	Coal balance by refinery supply region
CoalSupBalance	Coal balance by coal supply region
CombineSupply	Sum regional production over refinery types
CrudeBalance	Crude-ACU balance equations
CrudeSupCurve	Enforce balance between crude supply and crude transport
CrudeTransLimit	Enforce Crude Transport Limits between Source ans RefReg
DistSpecBalance	Specification blending volume balance for distillate products
DistSpecQualMax	Specification blending constraints for distillate products
DistSpecQualMin	Specification blending constraints for distillate products
E15Max	Enforce E15 maximum penetration factors
E85Balance	Balance E85 transferred to each census with amount used on supply steps by census
E85Total	E85 used to satisfy flex-fuel BTU constraint into combined vector
EthBalance	Ethanol stream balance equations
EthTranLimit	Limits on ethanol transportation capacity
EthWorldBal	Brazil ethanol production balance
FlexBTUDmd	Must satisfy total gasoline blend demand in BTUs in each census
GasSpecBalance	Specification blending volume balance for gasoline products
GasSpecQualMax	Specification blending constraints for gasoline products
GasSpecQualMin	Specification blending constraints for gasoline products
HGEmisBal	Mercury Emissions balance
LCFS_BioFuel	LCFS Constrain - BioFuel Relieve
LCFS_Petroleum	LCFS Constraint - Petroleum Deficit
MaxCornRFS	Limit activity on corn modes that count towards the RFS to 15 bil gal per year
MGTotal	Total gasoline used to satisfy flex-fuel BTU constraint into combined vector
NGLDmd	Must at least satisfy NGPL demands

Table B-2. LP constraints (cont.)

Constraint	Description
NGLEndBal	Total all NGPL available by census over domestic and imports
OBJ	Objective function
RecipeBalance	Recipe volume balance between input streams and recipes
RecipeBPTransfer	Transfer co-products into products for sales
RecipeDemands	Must satisfy demand non-gasoline recipe-blended end products in all census divisions
RecipeEndBal	Total all product available by census over domestic and imports
RecipeTransfer	Transfer recipes that satisfy demands into products for consumption
RefInpBalance	Stream balance for refinery input streams
RefPurchBal	Balance refinery purchase variables
REFtoCDCap	Enforce bounds on non-marine transportation capacity
REFtoCDTran	PADD-to-Census transportation balance
REFtoREFCapMB	Enforce bounds on marine transportation capacity
REFtoREFTran	Balance RefReg to RefReg transfers for a given Reftype
ResidSpecBalance	Specification blending volume balance for resid products
ResidSpecQualMax	Specification blending constraints for resid products
ResidSpecQualMin	Specification blending constraints for resid products
RestrictGrowth	Capacity expansion growth restrictions
RFG15Balance	Balance RFG15 transferred to each census with amount used towards BTU constraint
RFGBalance	Balance RFG transferred to each census with amount used towards BTU constraint
RFSConstraintsPRD	PRD RFS Constraints - Production
RFSConstraintsRQM	RQM RFS Constraints - Requirement
RFSConstraintsRQM2	RQM RFS Constraints – Limit purchase of cellulosic waivers
SO2EmisBal	SO2 Emissions balance
StreamBalance	Intermediate steam balance equations
TotPRODTran	Transfer end products between supply regions and census divisions
UtilBalance	Utility stream balance equations
WorldCrudeSup	Enforce balance between total world crude supply and total crude demand

Sets and parameters

LFMM-specific sets and parameters are defined in the input files LFMinset.gdx and LFMinput.gdx, respectively, and in the GAMS source code files. LFMinset defines over one hundred sets, including sets for regions, crude types, product types, and process units. LFMinput.gdx defines over one hundred parameters, including process unit characteristics, recipe blending tables, product specifications, operating and capital costs, tax rates, biofuel feedstock supply curves, and policy requirements.

Appendix C. Bibliography

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Also see citations in Appendix A, the AEO2013 Assumptions Document, and the LFMM Component Design Report.

Appendix D. Model Abstract

Model name

Liquid Fuels Market Model

Model acronym

LFMM

Description

The Liquid Fuels Market Model is a simulation of the U.S. liquid fuels industry. The heart of the model is a linear programming optimization that ensures a rational economic simulation of decisions of feedstock sourcing, resource allocation, and the calculation of a marginal price basis for the products. The model accounts for over twenty refined products that are manufactured, imported, and marketed. These include specification-blended and recipe-blended products, as well as co-products, unfinished products, and by-products. The LFMM models domestic liquid fuels production activities, the marketing of petroleum products to consumption regions, and the production of natural gas plant liquids in gas processing plants.

Capacity-limited transportation systems are included to represent existing intra-U.S. crude oil and product shipments (LPG, clean, dirty) via pipeline, marine tanker, barge, and truck/rail tankers. The export and import of crude oil and refined products is also simulated. All crude imports and some gasoline blend component imports are purchased in accordance with import supply curves.

The majority of LFMM is written in GAMS, but some parts are in Fortran.

Purpose of the model

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

The LFMM 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 and renewable feedstocks; natural gas plant liquids production; petroleum product imports; and refinery processing gain. In addition, the LFMM estimates domestic refinery capacity expansion and fuel consumption. Product prices are estimated at the Census Division (CD) level and much of the refining activity information is at the PADD (Petroleum Administration for Defense District) and sub-PADD level.

Most recent model update

This documentation describes the October 2012 version used to develop projections for AEO2013.

Part of another model?

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

Model interfaces

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

Official model representative

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Documentation

EIA Model Documentation: Liquid Fuels Market Model of the National Energy Modeling System (NEMS), December 2013. (DOE/EIA-M059 (2013)).

Archive media and installation manual

Archived as part of the NEMS AEO2013 production runs.

Energy system described

Petroleum refining industry, non-petroleum liquid fuels industry, and refined products market.

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); eight domestic refining regions; 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), one international refining region comprising eastern Canada and the Caribbean, and one Rest of World crude and product supply region.

Time unit/frequency: annual, 2013 through 2040.

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

Production Processes:

ACU	"Atmospheric Distillation Unit"
AET	"Advanced Ethanol (non-cellulosic)"
ALK	"Alkylation"
ARP	"Aromatics Plant"
BPU	"Pyrolysis"
BSA	"Benzene Saturation"
BTL	"Biomass-to-Liquids"
C4I	"Butane Isomerization"
CBL	"Coal-and-Biomass-to-Liquids"
CBLCCS	"Coal-and-Biomass-to-Liquids with CCS"
CGN	"Power Generation & Co-Generation"
CLE	"Cellulosic Ethanol"
CPL	"Catalytic Polymerization"
CTL	"Coal-to-Liquids"
CTLCCS	"Coal-to-Liquids with CCS"
DC4	"Debutanization"
DC5	"FCC Naphtha Depentanizer"
DDA	"Distillate Dearomatizer"
DDS	"ULSD Hydrotreater"
EDH	"Corn Ethanol - Dry Mill, High Efficiency"
EDM	"Corn Ethanol - Dry Mill"
FBD	"FAME Biodiesel"
FCC	"Fluid Catalytic Cracker"
FDS	"FCC Feed Hydrotreater"
FGS	"FCC Naphtha Fractionator"
FUM	"Fuel Psuedo-Unit"
GDS	"FCC Naphtha Hydrotreater"
GDT	"Green Diesel"
GTL	"Gas-to-Liquids"
H2P	"Hydrogen Production"
H2R	"Hydrogen Recovery"
HCD	"Hydrocracker"
KRD	"Delayed Coker"
KWG	"Electricity Generation"
LNS	"Light Naphtha Splitter"
LUB	"Lubricant Production"
NCE	"Non-corn Starch Ethanol"
NDS	"Naphtha Hydrotreater"

PHI	"Once-Thru Isomerization"
RCR	"Continuous Cyclic Reformer"
RGN	"FCC Catalyst Regenerator"
RSR	"Semi-Regenerative Reformer"
SDA	"Solvent Deasphalter"
SEW	"Corn Ethanol - Wet Mill"
SGP	"Saturated Gas Plant"
STG	"Steam Production"
SUL	"Sulfur Plant"
TRI	"Total Recycle Isomerization"
TRS	"Stream Transfer Pseudo-Unit"
UGP	"Unsaturated Gas Plant"
VCU	"Vacuum Distillation Unit"

Crude Oil: nine crude oils that vary by API gravity and sulfur content.

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

Modeling features

Model Structure: GAMS and Fortran

Model Technique: Optimization of linear programming representation of refinery processing and non-petroleum liquid fuels production and transportation that 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, environmental, and policy-related costs.

Non-DOE input sources

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

DOE input sources

Forms:

EIA-14	Refiners' Monthly Cost Report
EIA-182	Domestic Crude Oil First Purchase
EIA-782A	Monthly Petroleum Product Sales
EIA-782B	Reseller/Retailer's Monthly Petroleum Product Sales
EIA-782C	Monthly Petroleum Products Sold into States for Consumption

EIA-759	Monthly Power Plant Report
EIA-810	Monthly Refinery Report
EIA-811	Monthly Bulk Terminal Report
EIA-812	Monthly Product Pipeline Report
EIA-813	Monthly Crude Oil Report
EIA-814	Monthly Imports
EIA-817	Monthly Tanker and Barge Movement
EIA-820	Annual Refinery Report
EIA-826	Monthly Electric Utility Sales
EIA-856	Monthly Foreign Crude Oil Acquisition
EIA-920	Combined Heat and Power Plant Report (and predecessor forms)
FERC-423	Monthly Report of Cost and Quality of Fuels for Electric Plants

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

Independent expert reviews conducted

None.

Independent reviews of the predecessor to LFMM, PMM, were conducted by:

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

Status of evaluation efforts by sponsor

None.

Appendix E. Data Quality

Quality of distribution cost data

Costs relating to distributing petroleum products to end-users are incorporated by adding fixed transportation markups to the wholesale prices which include the variable and fixed refinery costs. Transportation markups for petroleum products are estimated as the average annual difference between retail and wholesale prices over the years 1990 through 2008.[4] 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 2009. See Explanatory Notes for inputs and sources.
http://www.eia.doe.gov/oil_gas/petroleum/data_publications/petroleum_marketing_annual/pma.html

With the exception of gasoline, non-utility distillate fuel, and jet fuel, sectoral end-user prices through 2008 are aggregated from prices from State Energy Data 2008: Prices (SEDP) (http://www.eia.doe.gov/emeu/states/_seds.html). The methodology behind these state-level sectoral prices is discussed in the Technical notes section (http://www.eia.doe.gov/emeu/states/sep_prices/notes/pr_petrol.pdf).

Gasoline, jet fuel, and non-utility distillate prices are estimated as weighted averages using end-user prices from EIA-782A and sectoral consumption from the State Energy Data 2008: Consumption (SEDC) (http://www.eia.doe.gov/emeu/states/_seds.html).

Due to a lag in the publication of the SEDP data, end-use price estimates for 2009 & 2010 are calculated using the same data series and methodology described in SEDP. The SEDP methodology uses prices from EIA-782A, FERC-423, EIA-759, and weights them with most recent consumption volumes from SEDC. Refer to SEDC for a discussion of the reliability of consumption data (http://eia.doe.gov/pub/state.data/pdf/petrol.pdf, May 2001). Year 2010 is estimated by applying the percent change of national product prices as reported in the September 2010 Short Term Energy Outlook (STEO) to each 2005 sector price.

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

Table E-1. Sources of markup inputs

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

Quality of tax data

In the LFMM, State and Federal taxes are added to the prices of gasoline, distillate fuel, liquefied petroleum gas (LPG), jet fuel, ethanol, and methanol in the transportation sector. State taxes are assumed to keep pace with inflation (held constant in real terms) while Federal taxes are held at current nominal levels (deflated in each forecast year).[5] The Federal tax assumption reflects the overall forecast assumption of current laws and legislation. The assumption that State taxes will increase at the rate of inflation reflects an implied need for additional highway revenues as driving increases. An additional 1 percent per gallon of gasoline price is added to the State gasoline taxes to approximate local taxes.

The State taxes are added as Census Division weighted averages which are based on the most recently-available State taxes. State taxes for jet fuel are derived from unpublished data collected by EIA. State and Federal taxes for gasoline, transportation distillate, and LPG are based on data from the Federal Highway Administration, but are modified to include other known changes to State taxes. The quality of the State level tax data is unknown but deemed reliable. The local tax estimate of 1 percent per gallon of gasoline price is reasonable given that a comparison of two EIA data series, one including local taxes and one not, revealed a gasoline price difference of 1.6 cents-per-gallon. Federal taxes, which were adjusted in January of 2001, are widely published and deemed highly reliable.

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

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

Critical variables

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

World oil price
Product demands
Imported crude supply curves
Imported product supply curves
Domestic crude production
Prices and available supplies of renewable liquid fuels and their feedstocks
Investment cost for capacity expansion
Market shares for gasoline and distillate types
NGPL supply volumes

Most of these variables are provided by other models in the NEMS system. The investment cost and market share data are developed offline and read in to the LFMM.

Appendix F. Estimation Methodologies

Refinery investment recovery thresholds

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

$$PCF = \sum_i (CFC_i + FOC_i + OVC_i), \tag{1}$$

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

In the LFMM, the variable operating costs (OVC) are defined directly from input data (so will not be addressed in this section), while the capital-related financial charges (CFC) and the fixed operating costs (FOC) are derived using a series of process investment cost equations. The methodologies used to calculate these cost components are presented below.

Capital-Related Financial Charges (CFC)

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

$$CFC_i = ACR_i - DTC_i. \tag{2}$$

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

Since the LFMM and other energy forecasting models employ “notional” representations of U.S. petroleum refineries involving aggregation of data for many individual refineries, the cost estimating algorithm has been simplified while still capturing all the factors and costs refiners must consider when adding a new processing unit. The methodology draws upon the National Petroleum Council (NPC) study[6] and other sources.[7] Some of the steps for the cost estimate are conducted exogenous to the

[6] National Petroleum Council, U.S. Petroleum refining – Meeting Requirements for Cleaner Fuels and Refineries, Washington, D.C., August 1993.

[7] J.H. Gary and G.E. Handwerk, Petroleum Refining: Technology and Economics, 4th edition (New York: Marcel Dekker, 2001), Chapters 17 and 18.

NEMS (Step 1 below), either by the analyst in preparing the input data or during input data preprocessing. The individual steps in the plant capital cost estimation algorithm are:

1. Estimation of the inside battery limits (ISBL) field cost (done exogenous to NEMS)
2. Estimation of the ISBL field cost for different refinery locations (location factor)
3. Estimation of the outside battery limits (OSBL) field cost (added to ISBL to define total field cost)
4. Estimation of total project cost
5. Estimation of capital-related financial charges
6. Conversion of capital-related charges to a "per-day," "per-capacity" basis

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

Step 1 - Estimation of ISBL field cost

The inside battery limits (ISBL) field costs include the direct cost such as major equipment, bulk materials, direct labor costs for installation, construction subcontracts, and indirect costs. The ISBL investment cost and labor costs for most of the refinery processing unit types modeled were initially obtained from a study by Bonner and Moore Associates (BMA),[8] and updated annually with revised estimates from EnSys Energy and Systems, Inc. (EnSys). The data for typical unit sizes and stream factors, as well as supplementary investment and labor, were obtained from the World Oil Refining, Logistics, and Distribution (WORLD) model.[9] The data used by the LFMM currently represent process plants sited at a generic U.S. Gulf Coast (PADD III) location, and are in year 1993 dollars.

Step 2 - Year-dollar and location adjustment to ISBL field costs

The ISBL investment cost data must be adjusted to include location factors and correct year-dollars.:

a. Adjust the ISBL field costs and labor costs for each processing unit (*j*) from 1993 dollars, first to the year-dollar (rptyr) reported by NEMS (e.g.,2011 dollars for *AEO2013*), using the Nelson-Farrar refining-industry cost-inflation indices. Then the GDP chain-type price indices provided by the NEMS Macroeconomic Activity Model are used to convert from report-year dollars to 1987 year dollars used internally by the NEMS.
b. Convert the ISBL field costs in 1987 dollars for each processing unit from a PADD III (Gulf Coast) basis ($BM\_ISBL\__i$) to costs of the same processing unit for other PADD regions ($ISBL\__j$) via location multipliers ($INVLOC\__l$. The location multipliers represent differences in material costs between the various PADD regions.

$$ISBL_j = \frac{BM\_ISBL_i * INVLOC_l}{1000} \tag{3}$$

[8] 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).
[9] 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).

where

i	= process unit in PADD III
l	= refining region
j	= process unit *i* in refining region *l*
$ISBL_j$	= ISBL costs for processing unit *i* in refining region (PADD) *l (j)*, in million 1987 dollars
BM_ISBL_i	= ISBL costs for processing unit*i* in PADD III, in thousand 1987 dollars
$INVLOC_l$	= Location multiplier for refining region *l*

Location multipliers for refinery construction were developed on a PADD-basis using the most recent data available from the U.S. Bureau of Labor Statistics (BLS)[10] and the EIA.[11] The development of these multipliers and assumed values for other factors is described elsewhere. [12] The recommended location multipliers for refinery construction are given below:

Table F-1. Location multipliers for refinery construction

Location	Location Construction Multiplier
PADD I – U.S. East Coast	1.16
PADD II – U.S. Midwest- inland	1.00
PADD II – U.S. Midwest- lakes	1.00
PADD III – U.S. Gulf Coast- gulf	1.00
PADD III – U.S. Gulf Coast- inland	1.00
PADD IV – U.S. Rocky Mountain	1.08
PADD V – U.S. West Coast- California	1.15
PADD V – U.S. West Coast- Other	1.15

Step 3 - Estimation of OSBL cost and total field cost

The outside battery-limit (OSBL) costs include the cost of cooling water, steam and electric power generation and distribution, fuel oil and fuel gas facilities, water supply, etc. The total field cost (FDC) is

[10] Wages Data, U.S. Department of Labor, Bureau of Labor Statistics, available on the web at www.bls.gov/bls/blswage.htm.
[11] Refinery Capacity Data, U.S. Department of Energy, U.S. Energy Information Administration, available on the web at www.eia.doe.gov/oil_gas/petroleum/data_publications/refinery_capacity_data/refcapacity.html.
[12] *A General Cost Estimating Methodology for New Petroleum Refinery Process Capacity,* Appendix D, prepared for the U.S. Department of Energy, National Energy Technology Laboratory, and U.S. Energy Information Administration by John Marano, Ph.D., September 2004.

the sum of the ISBL and OSBL field costs. The OSBL field cost is estimated as a fraction (OSBLFAC) of the ISBL costs. Thus, the resulting FDC equation is:

$$FDC_j = (1 + OSBLFAC) * ISBL_j \tag{4}$$

j	= process unit *i* in refining region *l*
FDC_j	= Total field costs for processing unit in refining region *(j)*, in million 1987 dollars
$ISBL_j$	= ISBL costs for processing unit in refining region *(j)*, in million 1987 dollars
OSBLFAC	= OSBL fraction of ISBL costs (assumed to be 0.45 in LFMM)

Step 4 – Estimation of total project investment

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

$$TPI_j = FDC_j - OTC_j \tag{5}$$

j	= process unit *i* in refining region *l*
TPI_j	= Total project investment for processing unit in refining region *(j)*, in million 1987 dollars
FDC_j	= Total field costs for processing unit in refining region *(j)*, in million 1987 dollars
OTC_j	= Other one-time costs for processing unit in refining region *(j)*, in million 1987 dollars

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

$$OTCFAC = PCTENV + PCTCNTG + PCTLND + PCTSPECL + PCTWC \tag{6}$$

where

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

PCTWC = *0.10* Working capital

thus,

OTCFAC = *0.30*

and

$$OTC_j = OTCFAC * FDC_j \tag{7}$$

The TPI given above represents the total project investment (cost) for "overnight construction." The TPI at project completion and startup will be discussed in Step 5 below.

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

$$WRKCAP_j = PCTWC * FDC_j \tag{8}$$

and,

$$FCI_j = TPI_j - WC_j \tag{9}$$

where,

j = process unit *i* in refining region *l*

WC_j = Total working capital for processing unit in refining region *(j),* in million 1987 dollars

FDC_j = Total field costs for processing unit in refining region *(j)*, in million 1987 dollars

PCTWC = Working capital as percent of FDC_j

FCI_j = Fixed capital investment for processing unit in refining region *(j)*, in million 1987 dollars

TPI_j = Total project investment for processing unit in refining region *(j)*, in million 1987 dollars

The total depreciable investment is equal to the total project investment less the cost of land, interest during construction and working capital (as discussed in Step 4 below). For construction at an existing refinery site through expansion, as most likely the case in the United States, the cost of land can be assumed to be zero, and interests during construction are considered implicitly in the calculation of the capital charge factor (Step 5); thus, total depreciable investment is assumed to be approximately equal to fixed capital investment:

$$TDI_j = FCI_j \tag{10}$$

where,

j = process unit i in refining region l

TDI_j = Total depreciable investment for processing unit in refining region *(j)*, in million 1987 dollars

FCI_j = Fixed capital investment for processing unit in refining region *(j)*, in million 1987 dollars

Step 5 - Estimation of capital-related financial charges

For the purpose of determining the economic viability of expanding refinery processing capacity, capital-related financial charges (CFC), which consist of an annual capital recovery charge (ACR) and a depreciation tax credit (DTC), must be estimated from the total project investment (TPI). The ACR is based on the cost of capital (COC) for the corporation that owns the refinery where the project is located.

It is assumed that projects will be financed by both debt and equity and will return the expected interest payments to creditors and the expected dividends to shareholders. Therefore, the after-tax weighted average cost of capital is an appropriate discount rate for evaluating investment opportunities.

Cost of capital

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

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

and

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

Where:

X_{eq}, X_{debt} = Fractions of equity and debt financing, respectively ($X_{debt} = 1 - X_{eq}$)

$T_{eff,l}$ = Effective corporate income tax rate; "l" is for refining region index where all state taxes in that region are averaged to represent a single value *at, bt* = Indices for after-taxes and before-taxes, respectively

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

Also, the effective tax rate (T_{eff}) is related to the federal tax rate T_{fed} and state tax rate $T_{state,l}$ as follows:

$$Teff,l = Tstate,l + Tfed \times (1 - Tstate,l) \quad (13)$$

Average state and federal income tax rates were developed on a PADD basis using the most recent tax information available as of Jan. 1, 2004.[13] PADD averages were weighted based on the crude oil processing capacity within the states making up each PADD. The resulting state and federal tax rates used in the model are:

Table F-2. State and Federal corporate income tax rates

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

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

The expected opportunity cost, or cost of equity (COE), for stockholders should be comparable to what could be realized from alternative investments of similar risk. The Capital Asset Pricing Model (CAPM) is used to compute a cost of equity,[14] which is an implied investor's opportunity cost or the required rate of return of any risky investment. The model is:

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

The COE is computed as a function of three variables: *RFR*, a "risk-free" rate; EMRP, an expected market risk premium; and β, a systematic risk coefficient relative to the stock market (referred to as the "equity beta"). In the model, the risk-free rate is based on 10-year Treasury note rates (MC_RMTCM10Y, provided by the NEMS Macroeconomic Activity Model). The EMRP and β are assumed to be constant. Thus, the EMRP is assumed at 6.75 percent (7.5% for high risk) based on the expected return on market

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

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

over the rate of a 10-year Treasury note (risk-free rate); and, the β is set based on the risk level of the processing unit investment (for average risk, β = 0.8; for high risk, β = 1.8).

Annual Capital Recovery

The annual capital recovery (ACR) is the difference between the total project investment (TPI) and the recoverable investment (RCI), all in terms of present value (e.g., at startup). The TPI estimated in Step 4 is for overnight construction (ONC). In reality, the TPI is spread out through the construction period. Land costs (LC) will occur as a lump-sum payment at the beginning of the project, construction expenses (TPI – WC – LC) will be distributed during construction, and working capital (WC) expenses will occur as a lump-sum payment at startup. Thus, the TPI at startup (present value) is determined by discounting the construction expenses (assumed as discrete annual disbursements), adding land costs (as lump payment at beginning of project), and adding working capital (WC):

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

where

TPI(startup)	= Total project investment at *startup*, in million 1987 dollars
TPI(ONC)	= Total project investment (overnight construction), in million 1987 dollars
WC	= Total working capital, in million 1987 dollars
LC	= Total land costs, in million 1987 dollars
F_v	= Future-value compounding factor for an instantaneous payment made *n* years before the *startup* year
$F_{v,n}$	= Future-value compounding factor for discrete uniform payments made at the beginning of each year starting *n* years before the *startup* year
N_{con}	= Construction time in years before *startup* year
COC	= Cost of capital

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

$$F_v(COC,N_{con}) = (1 + COC)^{Ncon} \qquad (16)$$

$$F_{v,n}(COC,N_{con}) = \left(\sum_{k=1,\,N_{con}} \left((1+COC)^k \right) \right) / N_{con} \qquad (17)$$

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

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

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

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

where

PVI(startup) = Present value of project investment at *startup*, in million 1987 dollars

RCI = Recoverable investment, in million 1987 dollars

TPI(startup) = Total project investment at *startup*, in million 1987 dollars

P_v = Present-value discounting factor for an instantaneous payment made n years (project life) in the future

N_{asset} = Asset's economic life in years after *startup* year

COC = Cost of capital

The present-value factor is a function of the number of discounting periods (*n*), and the interest rate used for discounting. In this case, *n* equals the asset's economic life in years N_{asset}, and the discounting rate is the cost of capital *COC*:

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

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

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

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

$$ACR(at) = Av\ (COC,Nasset) * PVI(startup) \qquad (MM87\$/yr) \qquad (22)$$

where

ACR(at) = Annual capital recovery, where (*at*) signifies that this is on an after-tax basis

PVI(startup) = Present value of project investment at *startup*, in million 1987 dollars

A_v = Uniform-value leveling factor for a periodic payment (annuity) made at the end of each year for (*n*) years in the future

N_{asset} = Asset's economic life in years after *startup* year

COC = Cost of capital

The uniform-value factor is a function of the number of periods (*n*) and the interest rate used for discounting, where *n* equals the asset's economic life in years N_{asset}, and the discounting rate is the cost of capital *COC*, as defined by:

$$A_v\,(COC,N_{asset}) \quad = (COC *((1.+COC)^{Nasset})) \;\; / \;\; (((1.+ COC)^{Nasset}) -1.) \qquad (23)$$

A construction period of 2 years and asset life of 20 years are assumed for construction of a new process unit within an existing refinery.

Depreciation tax credit & capital-related financial charges

The depreciation tax credit (DTC) is based on the depreciation schedule for the investment and the total depreciable investment (TDI) (defined in step 4 above). The simplest method (DPM) used for depreciation calculations (and used in the LFMM) is the straight-line method, where the total depreciable investment is depreciated by a uniform annual amount over the tax life of the investment. The following generic equations represent the present value of the TDI (PVDDPM) and the levelized value of the annual depreciation charge (DTC(at)), on an after-tax basis.

$$PVD_{DPM}(startup) = P_{v,DPM}(COC,N_{tax}) * TDI \qquad (MM87\$) \qquad (24)$$

$$DTC(at) = A_v\,(COC,N_{asset}) * T_{eff} * PVD_{DPM}(startup) \qquad (MM87\$/yr) \qquad (25)$$

where

$PVD_{DPM}(startup)$ = Present value of total depreciable investment, at startup, where *DPM*=straight line depreciation method, in million 1987 dollars

DTC(at) = Annualized depreciation tax credit, where *at*=after tax basis, in million 1987 dollars

TDI = Total depreciable investment, in million 1987 dollars

T_{eff} = Effective combined income tax rate

$P_{v,DPM}$ = Present-value discounting factor for depreciation, which is a function of the number of discounting periods (tax life), and the cost of capital

A_v = Uniform-value leveling factor for a periodic payment (annuity) made at the end of each year for *n* years in the future and an interest rate *r*, where *n* is the asset life and *r* is the cost of capital (*COC*)

at = Signifies the depreciation tax credit on an after-tax basis

N_{asset}	= Asset's economic life, in years after *startup* year
N_{tax}	= Tax life, in years after *startup* year
COC	= Cost of capital
N_{asset}	= Asset's economic life, in years after *startup* year
N_{tax}	= Tax life, in years after *startup* year
COC	= Cost of capital

If the tax life N_{tax} is assumed to be equal to the asset life N_{asset}, then the leveled depreciation tax credit (DTC) can be represented as follows:

$$DTC(at) = T_{eff} \times TDI \ / \ N_{asset} \quad (MM87\$/yr,\ DPM = SRL,\ Ntax = Nasset) \tag{26}$$

Finally, the capital-related financial charges (CFC) are set equal to the annual capital recovery (ACR) less the DTC, after taxes (at) and before taxes (bt):

$$CFC(at) = ACR(at) - DTC(at) \quad (MM87\$/yr) \tag{27}$$

and,

$$CFC(bt) = CFC(at) \ / \ (1 - T_{eff}) \quad (MM87\$/yr) \tag{28}$$

Step 6 - Convert fixed operating costs to a "per-day," "per-capacity" basis

The annualized capital-related financial charge is converted to a daily charge, and then converted to a "per-capacity" basis by dividing the result by the operating capacity of the unit being evaluated. The result is a fixed operation cost on a per-barrel basis. It is the after-tax CFC that is included in the process plant cost function (PCF) presented in equation (1) above.

Refinery unit fixed operating costs

Fixed operating costs (FOC), a component of total product cost, are costs incurred at the plant that do not vary with plant throughput, and any other costs that cannot be controlled at the plant level. These include such items as wages, salaries and benefits; the cost of maintenance, supplies and repairs; laboratory charges; insurance, property taxes and rent; and other refinery overhead. These components can be factored from either the operating labor requirement or the capital cost. The accuracy of this type of estimate should be within ±50 percent.

Like capital cost estimations, operating cost estimations, involve a number of distinct steps. Some of the steps associated with the FOC estimate are conducted exogenous to NEMS (Step 1 below), either by the analyst in preparing the input data or during input data preprocessing. The individual steps in the plant fixed operating cost estimation algorithm are:

1. Estimation of the annual cost of direct operating labor
2. Year-dollar and location adjustment for operating labor costs (OLC)
3. Estimation of total labor-related operating costs (LRC)

4. Estimation of capital-related operating costs (CRC)
5. Conversion of fixed operating costs to a “per-barrel” basis

Step 1 involves several adjustments which must be made prior to input into the LFMM; steps 2-5 are performed within the LFMM.

Step 1 – Estimation of direct labor costs

Direct labor costs are inputs to the LFMM and are reported based on a given processing unit size. The operating labor cost data for most of the processing unit types modeled in the LMM were initially obtained from a study by Bonner and Moore Associates (BMA), and updated annually with revised estimates from EnSys. The actual data were obtained from the World Oil Refining, Logistics, and Distribution (WORLD) model. [15] The data used by the LFMM currently represent processing plants sited at a generic U.S. Gulf Coast (PADD III) location, and are in year 1993 dollars.

Step 2 – Year-dollar and location adjustment for operating labor costs

Operating labor cost (OLC) data must be adjusted for location and correct year-dollars:

a. The labor costs for each processing unit (i) are adjusted from 1993 dollars, first to the year-dollar (rptyr) reported by NEMS for *AEO2013*, which is in 2011 dollars, using the Nelson-Farrar refining-industry cost-inflation indices. Then the GDP chain-type price indices provided by the NEMS Macroeconomic Activity Model are used to convert from report-year dollars to 1987 dollars used internally by the NEMS. This defines the interim operating labor cost (BM_LABOR).
b. The 1987 operating labor costs for each processing unit (i) are converted from a PADD III (Gulf Coast) basis into regional (other U.S. PADDs) costs using regional (l) location factors. The location multiplier (LABORLOC) represents differences between labor costs in the various locations and includes adjustments for construction labor productivity.

$$OLC_j = BM\_LABOR_i * LABORLOC_l \tag{29}$$

where*i*	= process unit in PADD III
l	= refining region
j	= process unit *i* in refining region *l*
cd	= calendar day
OLC_j	= Operating labor costs for processing unit *i* in refining region (PADD) *l (j)*, in 1987 dollars/cd
BM_LABOR_i	= Operating labor costs for processing unit *i* in PADD III, in 1987 dollars/cd
$LABORLOC_l$	= Location multiplier for refining region *l*

[15] 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).

Location multipliers for process ujnit operating labor were developed on a PADD basis using data available from the U.S. Bureau of Labor Statistics (BLS)[16] and the EIA.[17] The recommended location multipliers for process unit construction are given below:

Table F-3. Location multipliers for refinery operating labor

Location	Operating Labor Multiplier
PADD I – U.S. East coast	1.11
PADD II – U.S. Midwest- inland	0.98
PADD II – U.S. Midwest- lakes	0.98
PADD III – U.S. Gulf Coast- gulf	1.00
PADD III – U.S. Gulf Coast- inland	1.00
PADD IV – U.S. Rocky Mountain	1.07
PADD V – U.S. West Coast- California	1.06
PADD V – U.S. West Coast- Other	1.06

Step 3 - Estimation of labor-related fixed operating costs

Fixed operating costs related to the cost of labor for a processing unit include the salaries and wages of supervisory and other staffing, charges for laboratory services, and payroll benefits and other plant overhead. These labor-related fixed operating costs (LRC) consist of:

$$LRC = OLC + FXOC\_STAFF + FXOC\_OH \qquad (30)$$

where

LRC = labor-related fixed operating cost, in 1987$/cd

OLC = direct operating labor costs, in 1987$/cd

FXOC_STAFF = supervisory/staff fixed operating costs, in 1987$/cd

FXOC_OH = benefits/overhead fixed operating costs, in 1987$/cd

These component FXOC cost terms can be defined as a function of the direct operating labor costs (OLC), with the following relationships: FXOC_STAFF = 0.55*OLC, and FXOC_OH = 0.39*(OLC+FXOC_STAFF). The LRC equation is simplified to the following relationship.

$$LRC = 2.15 * OLC \qquad (87\$/cd) \qquad (31)$$

[16] Wages Data, U.S. Department of Labor, Bureau of Labor Statistics, available on the web at www.bls.gov/bls/blswage.htm.
[17] Refinery Capacity Data, U.S. Department of Energy, U.S. Energy Information Administration, available on the web at www.eia.doe.gov/oil_gas/petroleum/data_publications/refinery_capacity_data/refcapacity.html.

Step 4 - Estimation of capital-related fixed operating costs

Capital–related fixed operating costs (CRC) include insurance, local taxes, maintenance, supplies, non-labor related plant overhead, and environmental operating costs. These costs can be defined as a function of the fixed capital investment (FCI) (defined in equation 9 above). This relationship is expressed by:

$$CRC = M_{CRC} * FCI \quad (87\$/cd) \qquad (32)$$

where

M_{CRC} = Sum of CRC cost multipliers (defined in Table F-4)

Table F-4. Capital-related fixed operating cost multipliers

Yearly Insurance	0.005
Local Tax Rate	0.01
Yearly Maintenance	0.03
Yearly Supplies; Overhead, Etc.	0.005

Step 5 - Convert fixed operating costs to a "per-capacity" basis

On a "per-capacity" basis, the total fixed operating costs (FOC) is the sum of the capital-related operating costs (CRC) and the labor-related operating costs (LRC), divided by the operating capacity of the unit being evaluated.

Natural gas plant model

The natural gas plant component of LFMM estimates the production of each natural gas liquid (ethane, propane, iso-butane, normal butane, and natural gasoline) based on the production of unfractionated natural gas plant liquids, provided by the OGSM module of NEMS. The fractionation percentages for each individual NGPL stream are recorded in parameter NGLFracNGPL in lfminput.gdx. These fractionation percentages were calculated by averaging actual NGL extraction volumes for recent years through 2009 and estimated for each OGSM district from assay data for various gas reservoirs (Nehring Associates, www.nehringdatabase.com). [18]

[18] U.S. Energy Information Administration, *Petroleum Supply Annual*, DOE/EIA, and similarly, the *Natural Gas Annual*.

Table F-5. NGPL fractionation fractions

OGSM District	LFMM Prod'n Region	Ethane	Propane	Iso-Butane	Butane	Natural Gasoline
01_NGPLRG	4_RefReg	44.0	28.1	7.4	9.1	11.4
02_NGPLRG	8_RefReg	0.0	19.7	7.0	27.4	45.9
03_NGPLRG	8_RefReg	0.0	19.7	7.0	27.4	45.9
04_NGPLRG	5_RefReg	43.1	28.4	5.8	10.2	12.6
05_NGPLRG	7_RefReg	0.0	19.7	7.0	27.4	45.9
06_NGPLRG	6_RefReg	45.5	26.3	4.0	10.8	13.4
07_NGPLRG	1_RefReg	63.0	20.6	4.9	4.9	6.6
08_NGPLRG	1_RefReg	63.0	20.6	4.9	4.9	6.6
09_NGPLRG	1_RefReg	63.0	20.6	4.9	4.9	6.6
10_NGPLRG	1_RefReg	63.0	20.6	4.9	4.9	6.6
11_NGPLRG	1_RefReg	63.0	20.6	4.9	4.9	6.6
12_NGPLRG	6_RefReg	45.5	26.3	4.0	10.8	13.4
13_NGPLRG	3_RefReg	44.7	35.3	7.1	7.1	5.9
14_NGPLRG	3_RefReg	44.7	35.3	7.1	7.1	5.9
15_NGPLRG	2_RefReg	34.6	34.6	5.0	13.4	12.4
16_NGPLRG	2_RefReg	34.6	34.6	5.0	13.4	12.4
17_NGPLRG	2_RefReg	34.6	34.6	5.0	13.4	12.4
18_NGPLRG	4_RefReg	44.0	28.1	7.4	9.1	11.4
19_NGPLRG	1_RefReg	63.0	20.6	4.9	4.9	6.6
20_NGPLRG	3_RefReg	44.7	35.3	7.1	7.1	5.9
21_NGPLRG	3_RefReg	44.7	35.3	7.1	7.1	5.9
22_NGPLRG	4_RefReg	44.0	28.1	7.4	9.1	11.4
23_NGPLRG	2_RefReg	34.6	34.6	5.0	13.4	12.4
24_NGPLRG	6_RefReg	45.5	26.3	4.0	10.8	13.4
25_NGPLRG	2_RefReg	34.6	34.6	5.0	13.4	12.4
26_NGPLRG	8_RefReg	0.0	19.7	7.0	27.4	45.9
27_NGPLRG	1_RefReg	63.0	20.6	4.9	4.9	6.6
28_NGPLRG	5_RefReg	43.1	28.4	5.8	10.2	12.6
29_NGPLRG	5_RefReg	43.1	28.4	5.8	10.2	12.6
30_NGPLRG	1_RefReg	63.0	20.6	4.9	4.9	6.6
31_NGPLRG	1_RefReg	63.0	20.6	4.9	4.9	6.6
32_NGPLRG	2_RefReg	34.6	34.6	5.0	13.4	12.4
33_NGPLRG	3_RefReg	44.7	35.3	7.1	7.1	5.9
34_NGPLRG	2_RefReg	34.6	34.6	5.0	13.4	12.4
35_NGPLRG	8_RefReg	0.0	19.7	7.0	27.4	45.9
36_NGPLRG	1_RefReg	63.0	20.6	4.9	4.9	6.6

Table F-5. NGPL fractionation fractions (cont.)

OGSM District	LFMM Prod'n Region	Ethane	Propane	Iso-Butane	Butane	Natural Gasoline
37_NGPLRG	1_RefReg	63.0	20.6	4.9	4.9	6.6
38_NGPLRG	2_RefReg	34.6	34.6	5.0	13.4	12.4
39_NGPLRG	2_RefReg	34.6	34.6	5.0	13.4	12.4
40_NGPLRG	4_RefReg	44.0	28.1	7.4	9.1	11.4
41_NGPLRG	4_RefReg	44.0	28.1	7.4	9.1	11.4
42_NGPLRG	4_RefReg	44.0	28.1	7.4	9.1	11.4
43_NGPLRG	4_RefReg	44.0	28.1	7.4	9.1	11.4
44_NGPLRG	4_RefReg	44.0	28.1	7.4	9.1	11.4
45_NGPLRG	4_RefReg	44.0	28.1	7.4	9.1	11.4
46_NGPLRG	4_RefReg	44.0	28.1	7.4	9.1	11.4
47_NGPLRG	4_RefReg	44.0	28.1	7.4	9.1	11.4
48_NGPLRG	4_RefReg	44.0	28.1	7.4	9.1	11.4
49_NGPLRG	4_RefReg	44.0	28.1	7.4	9.1	11.4
50_NGPLRG	4_RefReg	44.0	28.1	7.4	9.1	11.4
51_NGPLRG	4_RefReg	44.0	28.1	7.4	9.1	11.4
52_NGPLRG	6_RefReg	45.5	26.3	4.0	10.8	13.4
53_NGPLRG	1_RefReg	63.0	20.6	4.9	4.9	6.6
54_NGPLRG	8_RefReg	0.0	19.7	7.0	27.4	45.9
55_NGPLRG	1_RefReg	63.0	20.6	4.9	4.9	6.6
56_NGPLRG	3_RefReg	44.7	35.3	7.1	7.1	5.9
57_NGPLRG	6_RefReg	45.5	26.3	4.0	10.8	13.4
58_NGPLRG	4_RefReg	44.0	28.1	7.4	9.1	11.4
59_NGPLRG	4_RefReg	44.0	28.1	7.4	9.1	11.4
60_NGPLRG	7_RefReg	0.0	19.7	7.0	27.4	45.9
61_NGPLRG	7_RefReg	0.0	19.7	7.0	27.4	45.9
62_NGPLRG	1_RefReg	63.0	20.6	4.9	4.9	6.6
63_NGPLRG	1_RefReg	63.0	20.6	4.9	4.9	6.6

Estimation of distribution costs

Costs related to distributing petroleum products to end-users are incorporated by adding fixed transportation markups to the wholesale prices that include the variable and fixed refinery costs. Transportation markups for petroleum products except gasoline are estimated as the average annual difference between retail and wholesale prices. These markups are held constant throughout the projection period.

Historically, these values were obtained by transforming a variety of files from different data sources into files that could be read and manipulated by mainframe SAS. EIA is transitioning away from mainframe data storage to storing and manipulating data within Oracle and MS SQL Server repositories via the Refinery Markups Database (RMD). When direct database links are available, the RMD uses connections to these servers to automatically retrieve data that are necessary to compute sector markups and generate input flat files. When direct database links are not available (as is the case with State price and consumption data), import routines have been coded so that data for a specifically designed input format can be efficiently shared in NEMS.

Sector level prices provided by EIA's State Energy Data System (SEDS) typically lag behind current average prices to all sectors by more than two years. The RMD uses various calculations from available Oil and Gas Information Research System (OGIRS) data to compute suitable proxies for Sector level prices during this time. These include algorithms filling in missing data by way of OGIRS state level and sectoral price data when available, calculated volume weighted regional averages, or in some cases manually entered and calculated price data that is overwritten when data is missing. Computer programs and data files used to estimate transportation markups are discussed below.

Data-Reading Programs

Database: RefineryMarkups.mdb

Input Files:

1. pr_pet_all_price.csv: This is imported from a file generated by the Combined State Energy Data System (CSEDS). It contains retail prices in comma-delimited format.
2. use_pet_all_btu.csv: This is imported from a file generated by CSEDS, at the direction of EMEU staff. It contains petroleum volumes in comma-delimited format.
3. taxfile.csv: This file is manually developed. It contains petroleum tax information, listed by State, in comma-delimited format. It includes dollar amounts and percentages, where applicable.
4. OGIRS_data: This includes the wholesale price data that are imported from the Oil and Gas Information Research System (OGIRS); data are imported via a direct read-only connection to OGIRS.

From the Data Import dialog box, you may select the desired file to import from a drop-down list. Each file to be imported must be copied to the same directory in which the RefineryMarkup.MDB file resides. Select the desired option and click the Import Data button. Data import is then performed and the various forms and tables within the MSAccess database are automatically updated and populated.

Updating to the current year

The last year of markups database output that is generated is based on the HeatContent_Year table when the data is imported and created. Also, for missing values to be populated, the "IRAC" Table (IRAC stands for International Refiner's Acquisition Cost) needs to have the most current IRAC value, which are used to calculate some missing prices.

The "qRetailPrice_KSRAFN_2002" query is updated to include the year of the most recent SEDS retail prices (increasing the year by 1 from the last AEO cycle). This allows the IRAC proxy variable calculations to only calculate for those years after which we already have retail prices for these fuels. This same year should be applied and updated in the "qRetailPriceList_CDBasedPrice_KSARFN" query for the IRAC calculation (the > [year] criteria) to only occur after the last CSEDS year.

Also, the Federal Tax Table (CSeds_Fedtax) is manually updated to include tax rates for the most recent year of markup calculations.

The 3 SEDS *.csv input files include the following data series from 1960-the most recent SEDS year:

Table F-6. Data series from federal tax table (CSeds_Fedtax)

ARICB	ARICD	ARICV	AVACB	AVACD
AVACV	DFACB	DFACD	DFACV	DFCCB
DFCCD	DFCCV	DFEUB	DFEUD	DFEUV
DFICD	DFICV	DFISB	DFRCB	DFRCD
DFRCV	FNICB	FNICD	FNICV	FOICB
FOICD	FOICV	FSICB	FSICD	FSICV
JFACB	JFACD	JFACV	JFEUB	JFEUD
JFEUV	KSCCB	KSCCD	KSCCD	KSICB
KSICD	KSICV	KSRCB	KSRCD	KSRCV
LGACB	LGACD	LGACV	LGCCB	LGCCD
LGCCV	LGICD	LGICV	LGISB	LGRCB
LGRCD	LGRCV	LUACB	LUACD	LUACV
LUICB	LUICD	LUICV	MGACB	MGACD
MGACV	MGCCB	MGCCD	MGCCV	MGICB
MGICD	MGICV	MSICB	MSICD	MSICV
PCEUB	PCEUD	PCEUV	PCICD	PCICV
PCISB	RFACB	RFACD	RFACV	RFCCB
RFCCD	RFCCV	RFEUB	RFEUD	RFEUV
RFICD	RFICV	RFISB	SNICB	SNICD
SNICV	WXICB	WXICD	WXICV	

The five letter code corresponds to the following information.

Table F-7. Data identification codes

Data Identification Codes	
Characters	**Identity**
1 and 2	Represent an Energy Source (Fuel)
3 and 4	Represent an Energy Consumption End-Use Sector (Sector)
5	Represent a Type of Data (Type)

Energy Source (Characters 1 and 2)	
Code	Name
AR	Asphalt and road oil
AV	Aviation gasoline
DF	Distillate fuel
FN	Petrochemical feedstocks naphtha less than 401 degrees F
FO	Petrochemical feedstocks other oils equal to or greater than 401 degrees F
JF	Jet fuel
KS	Kerosene
LG	Liquefied petroleum gases
LU	Lubricants
MG	Motor gasoline
MS	Miscellaneous petroleum products
PC	Petroleum coke
RF	Residual fuel
WX	Waxes

Energy End-Use Sectors (Characters 3 and 4)	
Code	Name
AC	Transportation sector estimates
CC	Commercial sector estimates
EI	Electric power sector estimates
EU	Electric utility sector estimates
IC	Industrial sector estimates
RC	Residential sector estimates
TC	Total energy sector estimates

Type of Data (Character 5)	
Code	Name
B	Consumption in Btu. Data are in billion Btu.
D	Current price per Btu. Data are in dollars per million Btu.
P	Consumption in various physical units.
V	Expenditures in current dollars. Data are in millions of dollars.

Other ther tables that might require updating include BTU to Barrels (conversion factors) and GDP87 (Macroeconomic inflators).

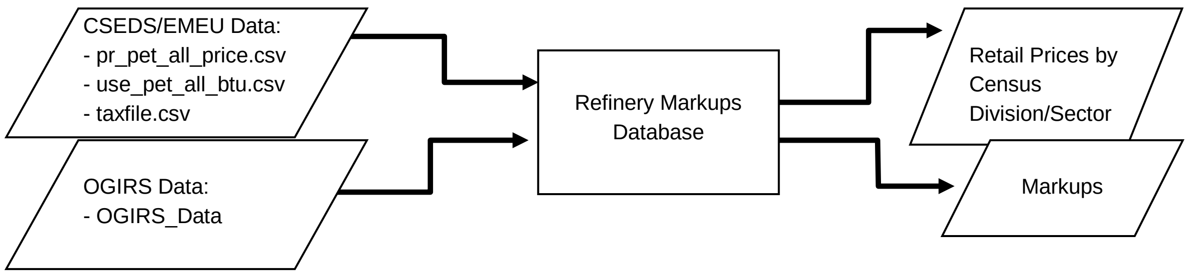
The Refinery Markups Database (RMD) contains state and sector-level retail prices that are used to estimate sector-level retail prices by Census District.

Markup estimating program

The Refinery Markups Database (RMD) is built into a single Microsoft Access database (.MDB) file, called RefineryMarkups.mdb and is used in estimating the differences between wholesale and retail product prices. It includes 1 Form, 2 Macros, 53 Tables, 2 Reports, and over 100 Queries. In order to be able to import data from the Oil and Gas Information Resource System (OGIRS), the user must have "read data" permission, provided by Office of Energy Statistics, Survey Support and Application Management (SSAM), on the OGIRS database.

System Flow

A basic flow chart, showing the flow of data into and out of the RMD, is shown below:



Data files are generated by the Combined State Energy Data System (CSEDS) and imported from OGIRS into the RMD, and the desired Retail, Wholesale and Markup Prices are calculated and presented in various pre-defined reports and text files created by MSAccess.

NOTE: Users of the RMD are granted read-only access to OGIRS, for importing purposes only. Therefore, the RMD can never be used to make any changes within OGIRS, e.g., alter any Sourcekeys. More detailed instructions can be found through the Refinery Markups Documentation provided by ABACUS Technology Corporation.

Estimation of taxes

In the LFMM, taxes are added to the prices of gasoline, transportation distillate fuel (diesel), transportation liquefied petroleum gases (LPG), and jet fuel. Taxes are also estimated for E85 (transportation ethanol). Weighted averages of the most recently available State and Federal taxes are developed for each Census Division (CD) using periodic State survey data collected by the Defense Energy Support Center (DESC).[19] The DESC data is then aggregated to the CD level in an analyst's spreadsheet using State annual product volumes obtained from the Petroleum Marketing Annual to calculate a volume-weighted CD average.

The State taxes are fixed in real terms; the real value of Federal taxes decline at the rate of inflation (i.e., Federal taxes are fixed in nominal terms). An additional 1 percent of the retail product CD value is added to the gasoline and diesel taxes to approximate local taxes. Historical tax values are also calculated for

[19] Defense Energy Support Center, "Compilation of United States Fuel Taxes, Inspection Fees and Environmental Taxes and Fees," June 5, 2010.

gasoline, transportation distillate, jet fuel and LPG, which are then added to historical end-use prices excluding taxes in order to develop a series with taxes included.

The Federal taxes are updated each projection year by deflating the current value by the rate of inflation for that projection year.

Gasoline specifications

The LFMM models the production and distribution of three different types of gasoline: conventional, reformulated, and CARB (California) gasoline. The following specifications are included in LFMM to differentiate between conventional and reformulated gasoline blends, according to EPA and California regulations: octane (CON), oxygen content, Reid vapor pressure (RVP), benzene content (BNZ), aromatic content (ARO), sulfur content (Sulfur), olefin content (OLE), and the percent evaporated at 200 and 300 degrees Fahrenheit (E200 and E300).

Table F-8. Gasoline specification

	ARO (max)	BNZ (max)	OLE (max)	RVP (max)	Sulfur (max)	CON (min)	E200 (min)	E300 (min)
Conventional	24.23	0.62	10.80	10.11	22.48	84.9	45.9	81.7
Reformulated	21.00	0.62	10.36	8.80	23.88	84.9	54.0	81.7
California Reformulated	23.12	0.58	6.29	7.70	10.00	86.3	42.9	86.3

Estimation of gasoline market shares

Within the LFMM, total gasoline demand is disaggregated into demand for conventional, reformulated and CARB gasolines by applying assumptions about the annual market shares for each type. Annual assumptions for each region account for the seasonal and city-by-city nature of the regulations. The market shares are assumed to remain constant over the projection period.

Diesel specifications

LFMM models three types of distillate fuel oil: heating oil (N2H), low-sulfur diesel (DSL), and ultra-low-sulfur-diesel (DSU). The two types of diesel fuel differ in their specifications for sulfur, cetane index, aromatics content, and API gravity. DSL reflects a higher sulfur allowance, while DSU reflects the tighter "ultra-low-sulfur-diesel" (ULSD) requirement which began phasing-in in 2006. ULSD also covers growing volumes of nonroad, locomotive and marine (NRLM) applications beginning after 2010. DSL is assumed to meet Federal specifications including a maximum sulfur content of 500 parts per million (ppm), a cetane index of 40, and a maximum aromatic content of 40% by volume.

Table F-9. EPA diesel fuel sulfur Limits

Refiner Class	6/1/2006	6/1/2007	6/1/2010	6/1/2012	6/1/2014 +
		HIGHWAY DIESEL			
ON-“SMALL” REFINERIES		>80% 15 ppm		15 ppm	
“Small” refineries (<155,000 bbl/day; <1,500 employees)		-		15 ppm	
		NONROAD AND LOCOMOTIVE/MARINE (NRLM) DIESEL			
Non-“small” refineries nonroad (NR) diesel	-	500 ppm		15 ppm	
Non-“small” refineries locomotive/marine (LM) diesel	-	500 ppm		15 ppm	
“Small” refineries (< 155,000 bbl/day; < 1,500 employees)	-	-[a]		500 ppm	15 ppm[b]

[a]Northeast/Mid-Atlantic requires 500 ppm for all NRLM diesel starting mid-2007.
[b]LM diesel downgrade to 500 ppm is allowed indefinitely. Fifteen ppm sulfur is required at refinery gate only.

According to the “ultra-low-sulfur diesel” (ULSD) regulation finalized in December 2000, ULSD is highway diesel that contains no more than 15 ppm sulfur at the pump, is limited to a cetane index of 40, and has an aromatics content of 35 percent by volume. ULSD in California is assumed to meet California Air Resources Board (CARB) standards that limit sulfur content to 10 ppm, a cetane index of 53, and maximum aromatics to 21 percent by volume.[20]

During mid-2004, the U. S. Environmental Protection Agency (EPA) finalized its new nonroad diesel rules which effectively parallel the highway standards but lag by several years in implementation. The specifications and timing of each quality type by refiner class are summarized in Table F-9.

Estimation of diesel market shares

When the 2000 ULSD Federal regulations and the 2004 nonroad diesel rules are fully implemented after 2014, there will be three (3) distillate fuels in the marketplace: (a) 15 ppm highway, (b) Nonroad Locomotive & Marine (NRLM) diesel; (c) high-sulfur heating oil. The LFMM reflects this rule and at the same time has been calibrated regarding market shares of highway and NRLM diesels, as well as other distillate (including heating oil but excluding jet fuel and kerosene).

[20] http://www.arb.ca.gov/enf/fuels/dieselspecs.pdf.

Historically, volumes of highway-grade diesel supplied have nearly matched total volumes of transportation distillate sold, although some highway-grade diesel has gone to non-transportation uses such as agriculture and construction. An analysis was performed to aggregate diesel fuel by sector and by quality to reflect individual uses for the LFMM. Year 2007 historical percentages were computed from sector level data available from the EIA report “Fuel Oil and Kerosene Sales, 2007”.[21] The following table provides an overview of how the categories were grouped.

Table F-10. Screenshot of spreadsheet for estimation of diesel market shares

Distillate Consumption

Fuel Oil & Kerosene Sales Total Distillate Consumption by Sector (Thousands of gallons per year; adjusted sales)

NEMS (SEDS) Sectors	FO & Kero Sectors					In MMBCD						
						1998	1999	2000	2001	2002	2007	
U.S. Total						3.461	3.572	3.732	3.847	3.776	4.197	
Residential						0.367	0.381	0.399	0.409	0.384	0.328	
Commercial						0.199	0.196	0.217	0.229	0.199	0.180	
Industrial						0.147	0.142	0.138	0.152	0.145	0.167	
	Oil Company					0.037	0.038	0.044	0.054	0.054	0.057	
	Farm					0.198	0.189	0.204	0.224	0.206	0.229	
	0.35	road				0.069	0.066	0.071	0.078	0.072	0.080	<- "Road" diesel
	0.65	off-hwy				0.129	0.123	0.132	0.146	0.134	0.149	<- "Off-highway" diesel
	Off-Highway Diesel					0.142	0.140	0.150	0.164	0.144	0.174	
	Total Industrial					0.524	0.508	0.535	0.594	0.549	0.627	
Transportation												
	On-Highway Diesel					1.967	2.091	2.161	2.167	2.238	2.596	
	Railroad					0.185	0.182	0.197	0.193	0.200	0.257	
	Vessel Bunkering					0.139	0.135	0.133	0.137	0.134	0.141	
	Military					0.018	0.019	0.015	0.023	0.021	0.024	
	Total Transportation					2.308	2.427	2.507	2.519	2.593	3.018	
Electric Power						0.063	0.060	0.074	0.095	0.052	0.043	
Diesel used for highway diesel engines		& Military				1.985	2.110	2.176	2.189	2.259	2.621	<- tracked separately fr
Rail (locomotive) & Vessel (marine)						0.323	0.317	0.331	0.330	0.334	0.397	<- tracked separately fr
Industrial	(2007 data)	60%	(1998-2002,2007 avg)	63%	off-highway	0.335	0.320	0.340	0.378	0.348	0.374	<- Nonroad Farm + Off
		27%		23%	highway	0.106	0.108	0.124	0.134	0.123	0.168	<- Industrial Low-Sulfur
		14%		14%	heating oil	0.083	0.080	0.073	0.082	0.078	0.085	<- Industrial: No.1dist +
Residential & Electric	HO					0.430	0.441	0.474	0.504	0.435	0.371	<- Residential and Elec
Commercial	(2007 data)	38%	(1998-2002,2007 avg)	33%	highway	0.063	0.060	0.069	0.079	0.066	0.068	<- Commerical Low-Sul
		11%		14%	off-highway	0.032	0.031	0.031	0.032	0.031	0.019	<- Commerical High-Su
		52%		52%	heating oil	0.104	0.104	0.120	0.118	0.102	0.093	<- Commercial: No.2FC
Highway (Road) Diesel						2.155	2.278	2.369	2.402	2.448	2.856	
Non-Road (Off-Highway) Diesel						0.366	0.351	0.371	0.409	0.379	0.393	
Heating Oil (HO)						0.617	0.626	0.667	0.705	0.615	0.550	
Locomotive/Marine (LM)						0.323	0.317	0.331	0.330	0.334	0.397	

Data Sources:
Fuel Oil and Kerosene Sales with Data for 2007,
http://www.eia.gov/petroleum/fueloilkerosene/archive/2007/pdf/foksall.pdf

The ULSD regulation includes a phase-in period under the “80/20” rule that requires the production of 80 percent ULSD and 20 percent 500 ppm highway diesel between June 2006 and June 2010, and a 100 percent requirement for ULSD thereafter. The phase-in path for ULSD is available in the input file lfblending.xls (and listed in the table below).

[21] Department of Energy/ Energy Information Administration, “Fuel Oil and Kerosene Sales, 2007,” December, 2008, DOE/EIA-0535(07).

Heating oil is not subject to ULSD rules. Over two-thirds of all high sulfur distillate use after 2010 will be concentrated in the Northeast.

Table F-11. Distillate consumption distribution

		2006	2007	2008	2009	2010	2011	2012	2013
DSU	HWY	0.443	0.76	0.76	0.76	0.9	1	1	1
DSL	HWY	0.557	0.24	0.24	0.24	0.1	0	0	0
N2H	HWY	0	0	0	0	0	0	0	0
DSU	ONR	0	0	0	0	0.443	1	1	1
DSL	ONR	0	0.443	1	1	0.557	0	0	0
N2H	ONR	1	0.557	0	0	0	0	0	0
DSU	OLM	0	0	0	0	0	0	0.443	1
DSL	OLM	0	0.443	1	1	1	1	0.557	0
N2H	OLM	1	0.557	0	0	0	0	0	0

HWY = on-highway, ONR = off-highway (non-road) OLM = off-highway, locomotive, marine

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 LFMM, but are needed for some refinery input prices, refinery fuel consumption, and cogeneration information. The factors are used to convert prices consumption, or cogeneration from census districts to the regional level used by LFMM.

Product pipeline capacities and tariffs

The distribution network in LFMM is based on the distribution network used by its predecessor model PMM for *AEO2012*.

Five sources were used to obtain the product pipeline data: (1) The 1989 NPC study,[22] (2) The North American Crude Oil Distribution (NACOD) model prepared by ICF for the Office of Strategic Petroleum Reserves (OSPR) during 1990-91, (3) Updates to these sources prepared by ICF in July 2003, (4) The North American Supply Distribution (NASDM) model prepared by INTEK for the Office of Strategic Petroleum Reserves (OSPR) during 2008, and (5) Updates to these sources prepared by EIA in July 2008.

NACOD data for the year 2000 were used for the petroleum product pipeline capacities and tariffs (1991$). The NPC study was used for LPG and NGL pipeline capacity data. The NACOD model defines 15 crude oil demand regions (including Canada and Puerto Rico/Virgin Islands), and the NPC study uses PADD regions. Table F-12 illustrates how the NACOD regions are used to define transport links between PADDs and Census Divisions, as represented in the LFMM.

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

Table F-12. North American Crude Oil Distribution (NACOD) regions and NEMS Census Divisions

NACOD Region		NEMS Census Divisions	
Code	**Locations**	**Code**	**Locations**
1	PADD I, New England	1	NE, New England
2	PADD I, Includes MD, DE	2	MA, excludes MD, DE
3	PADD I, WV to FL	5	SA, includes MD, DE
4	PADD II, KS, OK	7	WSC, includes OK, KS
5	PADD II	3,4	WNC, ENC, and KY, TN from 6
6	PADD III, Texas Gulf Coast	7	WSC
7	PADD III, LA Gulf Coast	7	WSC
8	PADD III, West Texas, NM	7	WSC, excludes NM
9	PADD III, AR, No. LA, No. MS, AL	6,7	ESC, AR, LA, MS, AL
10	PADD IV, North ID, MT	8	MNT
11	PADD IV, South WY, UT, CO	8	MNT
12	PADD V, Alaska	9	PAC
13	PADD V, Hawaii	9	PAC
14	PADD V	9	PAC, excludes NV, AZ

Many of the regional links shown above represent more than one pipeline. In some cases, we have retained more than one link from a source to a destination in order to have a better representation of product movements.

Product pipeline capacities, excluding LPG/NGL service, are shown in Table F-13. These links (presented as PADD to CD, originally for PMM use) were used as the basis for defining the pipeline capacities and tariffs for the LFMM network, and allow for separate arcs for product movements. (These will be updated for the next AEO cycle.) Products produced in an LFMM region (PADD subregion) are transported from one LFMM region to another until they reach the region that will distribute the product to the demand region. Product demands are defined by Census Divisions (CD), which are linked specifically to one (maybe more) LFMM region that represents the same geographic location as the CD. The tariffs are added for each link between the source and the destination point.

Table F-13. Petroleum product pipeline capacities and tariffs

From PADD*	To Census Division (CD)	Capacity (Mbbl/cd)	Rate (Wt. avg $2007/bbl)
PAD District II	2	167	1.23
PAD District II	6	120	3.42
PAD District II	7	124	1.43
PAD District II	8	60	1.02
PAD District III	3	1,100	1.51
PAD District III	4	170	1.18
PAD District III	8	180	1.24
PAD District III	6	3100	0.89
PAD District IV	4	130	1.11
PAD District IV	9	73	1.04
CD 5	2	2000	0.82
CD 6	5	2,600	1.19

* Some census division source areas are included to represent pipelines that have terminals in more than one CD
Source: July 2008 INTEK/EIA update.

The LPG/NGL pipelines are shown in the following table. Likewise, these were defined for the predicesor model (PMM), and were used as a basis for use in the LFMM. (These will be updated for the next AEO cycle.)

Table F-14. LPG/NGL pipeline capacities and tariffs

From PADD*	To Census Division (CD)	Capacity (Mbbl/cd)	Rate)Wt/avg $2002/bbl)
PAD District I	CD 6	5	2.00
PAD District III	CD 4	50	1.34
PAD District III	CD 3	290	1.17
PAD District III	CD 6	109	0.24
PAD District II	CD 2	56	0.45
PAD District II	CD 7	165	2.48
PAD District II	CD 5	5	0.53
PAD District II	CD 8	5	0.53
PAD District IV	CD 7	160	1.15
PAD District IV	CD 4	60	1.15

* Some census district source areas are included to represent pipelines that have terminals in more than one CD
Source: July 2008 INTEK/EIA update.

Cogeneration methodology

Electricity consumption in the refinery is a function of the throughput of each unit. Sources of electricity consist of refinery power generation, utility purchases, refinery cogeneration, and merchant cogeneration. Power generators and cogenerators are modeled in the LFMM as separate units which are allowed to compete along with purchased electricity.

Refinery cogeneration

The refinery cogeneration unit in the LFMM was modeled using historical data as a guideline. Cogeneration activity for each refinery was aggregated to the LFMM regional level. Cogeneration capacity was estimated from the 2012 version of EIA-920 Combined Heat and Power Plant Report. Cogeneration investment and operating costs were derived from the 1980 Office of Technology Assessment (OTA) report "Industrial Cogeneration."

Cogeneration capacity (including planned capacity) for each LFMM region was also derived from the EIA-920. The LP limits utilization to 90 percent of capacity. Cogeneration capacity is allowed to expand when the value received from the additional product exceeds the investment and operating costs of the new unit. The value of adding capacity includes revenues from sales to the utility grid and the displacement of purchases of electricity. Investment costs are derived from the OTA report.

LFMM has the capability of modeling cogeneration of electricity and steam at the petroleum refinery by burning still gas and natural gas. In general, refinery cogeneration units tend to be small, designed to supply the refinery's steam and electricity needs, with a small amount of leftover capacity sold to the grid. However, if it is profitable to sell cogeneration electricity, the LP constraints will reflect the assumption that all of it is sold. Likewise if it is not profitable, the model will reflect the assumption that none of it is sold.

Non-petroleum feedstock supplies

Coal

The LFMM models a Coal-To-Liquid (CTL) production process. The coal feedstock is represented as a coal supply curve provided by the Coal Market Module (CMM) of NEMS.

Natural gas

The LFMM models a Gas-To-Liquid (GTL) production process. The natural gas feedstock prices are provided by the Natural Gas Transmission and Distribution Module (NGTDM) of NEMS.

Cellulosic biomass

The LFMM models cellulosic ethanol and Biomass-To-Liquids (BTL – Fischer-Tropsch, BTL - Pyrolsis) production processes. The feedstock consists of four cellulosic biomass supply curves (agricultural residue, foresest residue, energy crops, urban wood waste) which are provided by the Renewables module of NEMS.

Corn

The LFMM also models ethanol production from corn. The corn feedstock supply curve is defined within the LFMM by a price/quantity (P/Q) relationship, and is represented in the linear program (LP) as five segmented P/Q steps. The first three steps represent the quantity of corn consumed in the previous year (CRNCD), with the first step defined as 80 percent of CRNCD, and subsequent steps based on 95%, 100%, 105%, and 130% of CRNCD, set as incremental quantities. The EIA corn price model is approximated by a two-part function in LFMM. The parameters used below are defined in more detail in Section I.4.

For corn use at or below 4.7 billion bushels, the farm price of corn (FC, in 1987 dollars per bushel) is given by:

$$FC_{t,e} = b + m * X + 0.15 \qquad (33)$$

For corn use greater than 4.7 billion bushels, the farm price of corn (FC) is given by:

$$FC_{t,e} = \beta * EXP(\alpha * X) + 0.15$$

where

X = National total corn use for ethanol production (billion bushels per year), adjusted regionally to shift curve upward (3.03 for CD=3, 1.515 for CD=4)

b = intercept in part 1 of the corn price function

m = slope in part 1 of the corn price function

α = exponential coefficient in part 2 of the corn price function

β = base in equation in part 2 of the corn price function

0.15 = Charge added to the farm price of corn to represent the cost of delivering corn to ethanol plants (1987 dollars per bushel)

Seed oils, fats, and greases

The production of biodiesel and renewable diesel from virgin vegetable oil, yellow grease, white grease, and imported palm oil are represented in LFMM. Virgin oil supplies to biodiesel producers consist of regional quantities of soybean, cottonseed, canola, and sunflower oils. Yellow grease consists primarily of used cooking oil from restaurants. As such, its availability is nationwide and is assumed to grow at the same rate that population grows. White grease consists of fats from rendering. Biodiesel production capacity by feedstock is allocated among Census Divisions according to the National Biodiesel Board's map of existing and potential producers and according to potential feedstock supplies.[23]

The biodiesel feedstock supply data used in AEO2013 were based on data used by LFMM's predecessor model PMM. The data are presented in Table F.15, by refining region and feedstock type.

[23] http://www.biodiesel.org/production/plants

Table F-15. Available virgin feedstock (soybean oil, cotton seed oil, sunflower oil, canola oil)

LFMM region	Soybean oil	Cottonseed oil	Sunflower oil	Canola oil
PADD I	1.37749	1.16938	0.00000	0.28739
PADD II-Inland	18.59116	0.23784	4.65770	35.56699
PADD II-Lakes	5.64870	2.61624	0.88199	5.74780
PADD III- Gulf	1.48650	1.12974	0.00000	0.00000
PADD III- Inland	1.61533	3.72616	3.86490	5.82708
PADD IV	0.00000	0.13874	1.17929	10.40550
PADD V- Calif	0.00000	0.23502	0.15162	3.60105
PADD V- other	0.00000	0.07219	0.04658	1.10620
Eastern Canada, Caribbean	0.00000	0.00000	0.00000	0.00000

The biodiesel feedstock price curve used in *AEO2013* is also based on the curve used in LFMM's predecessor model PMM. The price curve, developed within EIA, is an exponential curve based on (1) the price and quantity of feedstock if biodiesel consumed the entire soybean oil supply and (2) the price and quantity of feedstock if biodiesel consumed the entire virgin oil supply (soybean, cottonseed, sunflower, and canola). This exponential curve is then divided into 50 linear steps.

For *AEO2013*, soybean oil prices (SOY) were econometrically linked with corn prices (C) via the following relation:

$$Soy_{rk} = \sum_{k} f_k * Corn_{rk}$$

Where

r = refining region
k = lag year index {1,2,4,6}
f_k = lag year factor
$Corn_{rk}$ = price of corn in refining region *r* in year *k* preceding the current NEMS year

Table F-16. Lag year factors for relating soyoil price to corn price

Lag year *k*	Factor f_k
1	7.29
2	-3.23
4	2.29
6	-1.08

Costs for other virgin oils (cotton seed, sunflower, and canola) are defined as a function of the soybean oil price. These relationships are based on historical comparisons between these other virgin oils (cotton seed, sunflower, and canola) with respect to soybean oil. Associated with these costs for each of the possible virgin oil biodiesel feedstocks is a supply step on the incremental "supply curve" for virgin feedstocks.

$$Cottonseed_{rk} = Soy_{rk} + 3.68$$

$$Sunflower_{rk} = Soy_{rk} + 9.09$$

$$Canola_{rk} = Soy_{rk} + 11.25$$

E85 Infrastructure representation

The large renewable fuel volumes mandated by EISA2007 effectively anticipates increased E85 use in vehicles. By existing rules and regulations, ethanol can only enter the transportation fuel supply as E10, E15, or E85. Once the E10 market is projected to be saturated, any ethanol used to meet the mandate would have to come into the market as E15 or E85. The E85 market requires the building of additional station infrastructure.

E85 infrastructure costs for modifying the retailer equipment to dispense E85 fuel were estimated and amortized over the lifetime of the equipment. Demand for E85 is represented by a logit function describing the interaction between E85 availability (i.e., percentage of retail stations that provide E85 within a given region), the price differential between motor gasoline and E85, and the share of flex-fuel vehicle demand that is E85 rather than E10/E15.

Renewable Fuels Standard (EISA 2007) Representation

Energy Independence and Security Act of 2007 (EISA 2007)

The LFMM includes provisions outlined in Section 202 of the Energy Independence and Security Act of 2007 (EISA2007) concerning the Renewable Fuels Standard (RFS), which require increases in the total U.S. consumption of renewable fuels. The total renewable fuels requirement is expanded over the requirement specified in the Energy Policy Act of 2005 to include four categories of renewable fuels: Total, Advanced Biofuels, Cellulosic Biofuels, and Biomass-derived Diesel (Biodiesel). Advanced biofuels are defined to be any renewable fuel, other than ethanol derived from corn starch, that has lifecycle greenhouse gas emissions that are at least 50 percent less than baseline lifecycle greenhouse gas emissions (gasoline or diesel fuel, EISA07 Sec 201(1)(C)). Cellulosic biofuel is defined as a renewable fuel derived from any cellulose, hemicellulose, or lignin that is derived from renewable biomass and that has lifecycle greenhouse gas emissions that are at least 60 percent less than the baseline lifecycle greenhouse gas emissions. Biomass-based diesel is defined as a renewable fuel that is biodiesel as defined in section 312(f) of the Energy Policy Act of 1992 (42 U.S.C. 13220(f)) and that has lifecycle greenhouse gas emissions that are at least 50 percent less than the baseline lifecycle greenhouse gas emissions. Cellulosic biofuels and biomass-derived diesel both count toward the advanced biofuels subtotal. The EPA is authorized to reduce mandate levels per specific authority in the statute. As implemented in LFMM for *AEO2013*, the RFS target volumes are as follows:

Table F-17. EISA2007 RFS schedule

billion ethanol-equivalent gallons/year

Year	Renewable Fuels	Advanced Biofuels	Cellulosic Biofuels	Biomass-based Diesel
2006	4	0	0	0
2007	4.7	0	0	0
2008	9	0	0	0
2009	11.1	0.6	0	0.75
2010	12.95	0.95	0.1	0.975
2011	13.95	1.35	0.25	1.2
2012	15.2	2	0.5	1.5
2013	16.55	2.75	1	1.92
2014	18.15	3.75	1.75	1.92
2015	20.5	5.5	3	1.92
2016	22.25	7.25	4.25	1.92
2017	24	9	5.5	1.92
2018	26	11	7	1.92
2019	28	13	8.5	1.92
2020	30	15	10.5	1.92
2021	33	18	13.5	1.92
2022	36	21	16	1.92

Starting in calendar year 2005, EIA is required to project the use of all transportation fuel, biomass-based diesel, and cellulosic biofuel for the following calendar year no later than October 31 (Clean Air Act 42 U.S.C 7545(o)(3)(A)). The existing waiver authority is retained, but specific procedures are established for waivers of the cellulosic biofuels requirement and for the biomass-based diesel requirement. By Nov. 30 of each calendar year, the EPA Administrator is required to adjust the cellulosic biofuels requirement for up to one year using EIA's projected quantity as a guideline if the projected available quantity is lower than the requirement. The legislation also directs the EPA Administrator to make credits for cellulosic biofuels available at at price equal to ($3.00 per gallon – wholesale gasoline price) or $0.25 per gallon, whichever is greater. The number of cellulosic biofuels credits is limited "…to the minimum applicable volume (as reduced under this subparagraph) of cellulosic biofuel for that year." (EISA07 Section 202(e)(2)(D)(i))

The EPA Administrator also is required to reduce the applicable volumes in succeeding years after issuing wavers that pass a certain size threshold, stated as follows. If either 20 percent or more of any requirement is waived in two consecutive years, or if 50 percent or more of any requirement is waived in one year, then the applicable volume requirement must be modified in all years following the final year of the waiver. However, applicable volumes for years prior to 2016 may not be modified under this subparagraph (EISA07 Section 202(e)(3)(F)). The LFMM LP implicitly accounts for this EPA authority by including escape valve variables in the relevant LP constraints.

EISA2007 also allows the EPA administrator to waive the biomass-based diesel requirement if a determination is made that the market circumstances will cause the price of biomass-based diesel to increase substantially. The waiver is limited to 15 percent of the annual requirement for a maximum of 60 days but can be renewed thereafter, every 60 days. No credits are required in the event of a waiver of the biomass-based diesel requirement. The Administrator may also reduce the applicable volume of renewable fuel and advanced biofuels requirements by the same or a lesser volume (EISA2007 Section 202(e)(3)(E)(ii)).

California Low Carbon Fuel Standard (LCFS) representation

The Low Carbon Fuel Standard (LCFS), which will be administered by the California Air Resources Board (CARB)[24] , was signed into law on January 12, 2010. The regulated parties under this legislation are generally the fuel producers or importers who sell motor gasoline or diesel fuel in California. This legislation is designed to reduce the Carbon Intensity (CI) of motor gasoline and diesel fuels sold in California by 10 percent between 2012 and 2020 through the increased sale of alternative "low-carbon" fuels. Each alternative low carbon fuel has its own CI based on a life cycle analyses conducted under the guidance of CARB for a number of approved fuel pathways. The CIs are calculated on an energy equivalent basis and measured in grams of CO2 equivalent emissions per megajoule (gCO2e/MJ).

The *AEO2013* Reference case uses the CARB mandated CIs and approved fuel pathways included in the LCFS[25]. Non-compliance penalties have not been officially quantified by the CARB to date. To represent non-compliance, EIA computed a monetary penalty to encourage compliance within the Reference case based on relevant provisions in the California Health and Safety Code[26] .

The CIs are a measure of the complete well-to-wheels or lifecycle emissions of each fuel pathway and include indirect land use change (ILUC) penalties for applicable fuels . The ILUC penalty is a controversial additional CI value that attempts to account for potential land use changes due to increased biofuels production. The science behind the ILUC penalty is relatively new, so potential revisions and updates to these numbers are expected as the LCFS evolves. These fuel pathways include existing technologies such as Midwestern corn ethanol, imported sugarcane ethanol, and soy based biodiesel, as well as a number of "next-generation" technologies like cellulosic ethanol and biomass-to-liquid diesel fuels. There are also provisions in the legislation that allow non-regulated parties such as electricity and hydrogen producers to contribute to the carbon reduction.

The following two tables show Carbon Intensity targets and carbon intensity factors used for AEO2012. The *AEO2013* data are similar, with minor updates.

[24] LCFS Final Regulation Order: http://www.arb.ca.gov/regact/2009/lcfs09/finalfro.pdf
[25] LCFS Fuel Pathway Lookup Tables: http://www.arb.ca.gov/fuels/lcfs/121409lcfs_lutables.pdf
[26] California Health and Safety Code, Section 43025 through 43029.

Table F-18. California LCFS carbon intensity targets

	Carbon Intensity (g CO2e / MJ)	
Year	**Diesel**	**Motor Gasoline**
2011	94.47	95.61
2012	94.24	95.37
2013	93.76	94.89
2014	93.29	94.41
2015	92.34	93.45
2016	91.40	92.50
2017	89.97	91.06
2018	88.55	89.62
2019	87.13	88.18
2020-2040	85.24	86.27

Table F-19. Sample carbon intensities

Fuel	Description & Notes	g CO2e / MJ	Note
DSU	petroleum diesel (ULSD)	**94.71**	**(1)**
BTL_NOCCS	Liquids from Biomass with no Carbon Sequestration	**-3.00**	**(2)**
CTL_NOCCS	Liquids from Coals Low Efficiency with no Carbon Sequestration	**233.93**	**(3)**
CBTL_NOCCS	Liquids from 80-20 Coal/Biomass Mix with no Carbon Sequestration	**186.54**	**(4)**
FAME_SBO	biodiesel: soybean (Midwest soybean oil transesterification)	**83.25**	**(5)**
FAME_PLM	biodiesel: palm oil	**83.25**	**(6)**
FAME_YGR	biodiesel: waste yellow grease	**13.80**	**(7)**
FAME_WGR	biodiesel: white grease (calculated)	**39.85**	**(8)**
NERD_SBO	renewable diesel: Midwest soybean oil hydrogenation	**82.16**	**(9)**
NERD_PLM	renewable diesel: palm oil (calculated)	**82.16**	**(10)**
NERD_YGR	renewable diesel: yellow grease (calculated)	**13.62**	**(11)**
NERD_WGR	renewable diesel: tallow (white grease)	**39.33**	**(12)**
MG	CA E10 baseline gasoline	**95.86**	**(13)**
ETA	ethanol: Brazilian sugarcane	**58.40**	**(14)**
ETC	ethanol: cellulosic	**21.30**	**(15)**
ETH	ethanol: CA average corn (80% dry mill, 20% wet mill)	**81.66**	**(16)**
GN_SBO	green naptha: same as NERD (calculated)	**82.16**	**(17)**
GN_PLM	green naptha: same as NERD (calculated)	**82.16**	**(18)**
GN_YGR	green naptha: same as NERD (calculated)	**13.62**	**(19)**
GN_WGR	green naptha: same as NERD (calculated)	**39.33**	**(20)**
CNG	natural gas (non-renewable) (for CNG vehicles)	**67.70**	**(21)**
EV	electricity (average CA mix)	**41.37**	**(22)**
LPG	LPG from refinery	**78.00**	**(23)**
PYO	Product refined from pyrolysis oil	**31.00**	**(24)**

(1) Table 7 of http://www.arb.ca.gov/fuels/lcfs/121409lcfs_lutables.pdf

(2) Table 2-3 (GREET analysis) of "A Low Carbon Fuel Standard for California Part 1: Technical Analysis (Farrel and Sperling August 2007); see also page 4 Table 1-1 NETL's "Affordable, Low Carbon Diesel Fuel from Domestic Coal and Biomass" (January 14, 2009) which shows a over 100% reduction in CO2 for BTL

(3) http://www.clf.org/uploadedFiles/CLF/Programs/Clean_Energy_&_Climate_Change /Climate_Protection/Regional_Greenhouse_Gas_Initiative/Exhibit%20A.pdf also see Table 1-1 on page 4 of NETL's "Affordable, Low Carbon Diesel Fuel from Domestic Coal and Biomass" (January 14, 2009)

(4) 20% BTL (2) and 80% CTL (3)

(5) Table 7 of http://www.arb.ca.gov/fuels/lcfs/121409lcfs_lutables.pdf

(6) Same as soy biodiesel since palm oil feedstock is lumped with other seed oil feedstock within LFMM. Note that neither CARB nor the EPA considers palm-oil based biodiesel to be a fuel worth considering in any significant supply. See EPA's discussion of palm oil biodiesel on pp. 60-63 in the "Draft Regulatory Impact Analysis: Changes to Renewable Fuel Standard Program" published May 2009.

(7) Average of yellow grease values from Table 7 of http://www.arb.ca.gov/fuels/lcfs/121409lcfs_lutables.pdf

(8) Calculated based on Renewable Diesel values in lieu of ARB value

(9) Table 7 of http://www.arb.ca.gov/fuels/lcfs/121409lcfs_lutables.pdf

(10) Assumed value of Midwest Soy Renewable Diesel value in lieu of ARB value.

(11) Calculated based on FAME Biodiesel values in lieu of ARB value

(12) Table 7 of http://www.arb.ca.gov/fuels/lcfs/121409lcfs_lutables.pdf

(13) http://www.arb.ca.gov/fuels/lcfs/022709lcfs_carbob.pdf

(14) Table 8 of http://www.arb.ca.gov/fuels/lcfs/100609lcfs_updated_es.pdf assumes latest CARB instinct to count all Brazilian ethanol as cofired with bagasse.

(15) Although according to the October 2009 CARB update on the LCFS program the cellulosic materials à ethanol conversion process is still a fuel pathway under development in terms of defining a CI (see Table 6 of http://www.arb.ca.gov/fuels/lcfs/100609lcfs_updated_es.pdf), an average of the two values from earlier analyses published by CARB on ethanol from farmed trees (http://www.arb.ca.gov/fuels/lcfs/022709lcfs_trees.pdf) and ethanol from forest waste (http://www.arb.ca.gov/fuels/lcfs/022709lcfs_forestw.pdf) provide the CI shown here.

(16) Table C of http://www.arb.ca.gov/fuels/lcfs/022709lcfs_cornetoh.pdf with assumed reduced ILUC penalty

(17) Assumed same values as same feedstock Renewable Diesel pathways

(18) Assumed same values as same feedstock Renewable Diesel pathways

(19) Assumed same values as same feedstock Renewable Diesel pathways

(20) Assumed same values as same feedstock Renewable Diesel pathways

(21) Table 6 of http://www.arb.ca.gov/regact/2009/lcfs09/lcfsfsor.pdf

(22) Takes into account EER for better electric car use of energy over conventional vehicle...Table ES-8 of "Proposed Regulation to Implement the Low Carbon Fuel Standard vol. 1" from CARB (Table ES-8 of http://www.arb.ca.gov/fuels/lcfs/030409lcfs_isor_vol1.pdf)

(23) Table 2-3 (GREET analysis) of "A Low Carbon Fuel Standard for California Part 1: Technical Analysis (Farrel and Sperling August 2007)

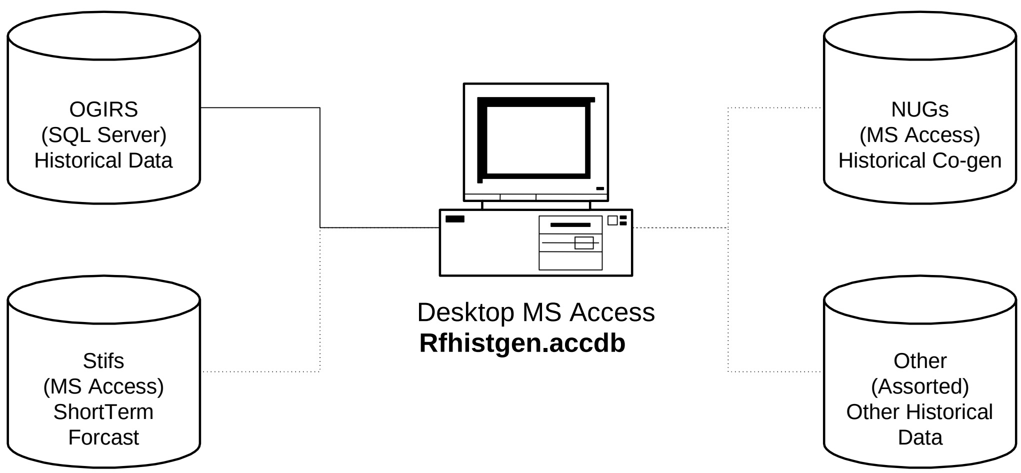
(24) memo from Steve Umnasch 4/29/10

Appendix G. Historical Data Processing

Processing data for LFMM history file

The LFMM uses historical data from a variety of sources. The Microsoft Access database "rfhistgen.accdb" collects and aggregates this data to prepare the LFMMinput file Elcgpur.txt. The three principle databases it collects from are the Oil and Gas Information Reporting System (OGIRS) which contains most historical wholesale price and volume information, the Non-Utility Generators (NUGs) database which contains refinery co-generation information, and the Short-Term Integrated Forecasting System (STIFS) database which contains data from the end of the historical period to the first NEMS projection year. Additional individual data elements are added as tables to the rhistgen.accdb database, as described below.

Figure G-1. Database linkages for historical data processing



Accessing data

The file "rfhistgen.accdb" currently resides in the set of defaults within the NEMS revision control system. The following explains how to connect to the component databases that are used in processing the historical input file.

- OGIRS: The OGIRS database is called via a short Visual Basic Application (VBA) script called "modOgirsFunction." This script searches the table "tblParkList" for the OGIRS keys and frequency of the data required to form a request to the main OGIRS server. Executing this function creates the local table "dbo_Ogidata" (Ogidata) with all data for the requested keys and frequency. For example, to pull annual data for kerosene-based jet fuel production for all the U.S. PAD Districts, enter the OGIRS Sourcekeys for the data series in the Sourcekey column and an "A" (for annual) in the "FrqncName" column as shown in the accompanying table. While it is unnecessary to complete the "SERIES" field, having a local reference to the Sourcekey definition is advisable.

Table G-1. Park list sample

SOURCEKEY	SERIES	FrqncName
MKJRPP12	PADD I Jet Fuel Kero Refinery Production (Mbbl/d)	A
MKJRPP22	PADD II Jet Fuel Kero Refinery Production (Mbbl/d)	A
MKJRPP32	PADD III Jet Fuel Kero Refinery Production (Mbbl/d)	A
MKJRPP42	PADD IV Jet Fuel Kero Refinery Production (Mbbl/d)	A
MKJRPP52	PADD V Jet Fuel Kero Refinery Production (Mbbl/d)	A
MKJRPUS2	US Jet Fuel Kero Refinery Production (Mbbl/d)	A

Most of data used by LFMM is pulled from OGIRS as an annual number. The only time monthly data are used is for the computation of Refinery Operable Capacity or for year-to-date 2012 data for refinery input/output variables that aren't provided by the Short Term Energy Outlook (STEO). For Refinery Operable Capacity, the January data values are the previous year's capacity.

The OGIRS database is mostly complete; however, there are a few missing fields in the database. To prevent errors from occurring when the queries are executed, the short list of missing values can be appended to Ogidata by running the query "Add Missing Keys to data." This query pulls known missing dataH-1 from the table "Missing Keys." For instance he last version of OGIRS is missing some of the elements of refinery production: nfrpp1-p5 (naphtha feedstocks), otrpp1-p5 (other oils for feedstock), msrpp1-us (miscellaneous products for non-fuel use), and pfrp-us (total petrochemical feedstocks). An even rarer occurrence is when data are incorrect in OGIRS. Should this be discovered, the correct values can be placed in the table "Data Errors" which will update Ogidata when the query "Update data" is executed. All new missing or incorrect data should be reported to the OGIRS database administrator (currently Jaime Chan 202-586-1515). Assuming correct entries in the tables "Missing Keys" and "Data Errors," the entire download process can be accomplished automatically by running the "Update From OGIRS and add missing Keys" Macro.

STIFS: The Current Month's Stifs database is created using a series of Excel spreadsheets. The original data set is located on the EIA LAN at: \\fs-f1\L6489\PRJ\EVIEWS\MonthYYYY\a15bbb.xls, with MonthYYYY representing the Month and year of the corresponding STEO release. Assistance in obtaining access to this file can be arranged with Tancred Lidderdale (202-586-7321). This file is then saved in the same directory as the Table_PA_creator.xls (saved on the EIA LAN at M:/ogs/amz) file, and after opening both spreadsheets, automatically organizes the data into the proper format for input into the rfhistgen.accdb MSAccess database. After completing these steps, open "rfhistgen.accdb" and from the "Database Tools" ribbon select "Linked Table Manager". Check the tables "Dates," "Table_PA,"

"Table_PA1" and the box "Always prompt for new location." Click OK and Browse to the location of Table_PA_creator.xls. This enables the database to extract the latest STEO database.

COGEN DATA: Annual cogeneration data updates are distributed in a spreadsheet from the NEMS Industrial team (previously by Mark Schipper). The new annual data is filtered by Industry to show only "Oil Refining" and then the most recent year is pasted into the "Cogen Update" Access table. This table is the source of a number of queries that re-organize the data for the rfhist.txt flat file, eventually creating the following updates tables in “rfhistgen.mdb.”

- Cogen Gen Cap
- Cogen Gen Cap
- Cogen Gen Fuel Use
- Cogen Gen Grid
- Cogen Gen Own

Other Data: Additional sources are used for creation of the LFMM history data file.

- Fuel consumption data in Table 47 of the Petroleum Supply Annual must be manually updated to table “PSA Table 47.”
- Global Database Variables: STEOYEAR, HISOYEAR, and STEOYEARS must be reset each year the History file generator is used. Running the Macro “STEO-HISTO” will prompt the user to enter the last Historical information year and the remaining keys will be updated automatically.
- Index for GDP Price deflators for the forecast period is stored in table “GDP87.” These are generally updated each year by the Macro team and can be found in Table 101 of the Ftab report.
- Historical Petroleum Product Prices are from the State Energy Data 2010: Prices (SEDP) and stored in the “Product price data” Table. For AEO2013, aggregated Census District level data from the previous year was used through 2010. For years 2011 through 2013 these prices were scaled by the change in the equivalent national numbers reported in the September 2012 Short Term Energy Outlook.

Data processing queries

After all the data from the different sources have been input (or linked) to the database, several queries are executed to manipulate the data into LFMMvariables. The numbers correspond with the position of the variable being generated in the Elcgpur.txt file. This code should not need to be changed absent a change in the definition of LFMM variable it represents. Should this occur, the individual variable query can be examined and edited.

LFMM variables are linked to variables in input databases (primarily OGIRS and STIFS) by table “Map PMM to OGIRS.” A complete list of mappings for both historical and STEO years is available in the following table. Multiple entries for a LFMM variable indicate that more than one OGIRS or STEO variable is needed to calculate the value for these variables. The multiple entries are summed to obtain the LFMM variable. For example the OGIRS keys for RFPRDOTH are the sum of the keys in that row (Aviation Fuel, Lubes, Naphtha, and Waxes). In the case where a (-) appears before a variable, the key is multiplied by -1 before summation.

RFQEXCRD	CRUDE EXPORTS IN MBD	OGIRS- MCREXPx2 (Where x is PADD#)	PADD x Averages/Totals Crude Oil Exports (Mbbl/d)	Assume last historical year
RFQICRD	CRUDE IMPORTS IN MMBD	OGIRS- MCRIMPx2 (Where x is PADD#)	PADD x Averages/Totals Crude Oil Imports (Mbbl/d)	CONXPUS use last historical year % to parse to PADDs
RFPQNGL	NGL PRODUCTION IN MMBD	OGIRS- MNGFPx1 (Where x is PADD#)	PADD x Averages/Totals Natural Gas Liquids and LRGs Totals Field Production (Mbbl/d)	NLPRPUS use last historical year % to parse to PADDs
RFBDSTCAP	BASE DISTILLATION CAPACITY MBCD	OGIRS- MOCLEPx1 (Where x is PADD#)	PADD x Averages/Totals Refinery Operable Capacity (Mbbl/d) - January Value	Not available use most recent historical year -proxy: CODIPUS
RFDSTUTL	DIST UTILIZATION RATE IN MBD	OGIRS- MOPUEPx2 (Where x is PADD#)	PADD x Averages/Totals Other Petroleum Products % Utilization Ref	CODIPUS/Last historical years Capacity
RFQEXPRDT	PRODUCT EXPORTS IN MMBD	OGIRS- MTPEXPx2 (Where x is PADD#)	PADD x Averages/Totals Total Crude Oil and Petroleum Products Exports (Mbbl/d)	Last years exports of Petroleum Products
RFPQIPRDT	PRODUCT IMPORTS IN MMBD	OGIRS- MNGEXPx2 (Where x is PADD#)	PADD x Finished Petroleum Products Imports (Mbbl/d)	PANIPUS
		OGIRS- MTPIMPx2 (Where x is PADD#)	PADD x Averages/Totals Natural Gas Liquids and LRGs Totals Imports (Mbbl/d)	Last years exports of Petroleum Products
RFDPRDAST (AST)	Asphalt Refinery Production (Mbbl/d)	OGIRS- MAPRPPx2 (Where x is PADD#)	PADD x Asphalt Refinery Production (Mbbl/d)	Use 10 year average growth
RFDPRDCOK (COK)	Pet Coke Refinery Production (Mbbl/d)	OGIRS- MCKRPPx2 (Where x is PADD#)	PADD x Petroleum Coke Refinery Production (Mbbl/d)	Use 10 year average growth
RFDPRDJTA (JTA)	Jet Fuel Kero Refinery Production (Mbbl/d)	OGIRS- MKJRPPx2 (Where x is PADD#)	PADD x Jet Fuel Kero Refinery Production (Mbbl/d)	JFROPUS* Last Histo Year PADD Splits
RFDPRDKER (KER)	Kerosene Refinery Production (Mbbl/d)	OGIRS- MKERPx2 (Where x is PADD#)	PADD x Kerosene Refinery Production (Mbbl/d)	Use 10 year average growth
RFDPRDLPG (LPG	Refinery production; LPG	OGIRS- MLPRPPx2 (Where x is PADD#)	PADD x Liquefied Petroleum Gases Refinery Production (Mbbl/d)	LGROPUS* Last Histo Year PADD Splits
RFDPRDN2H (N2H)	Refinery prd; no. 2 distillate	OGIRS- MDIRPPx2 (Where x is PADD#)	PADD x Total Distillate Refinery Production (Mbbl/d)	DFROPUS* Last Histo Year PADD Splits
RFDPRDN6B (N6B)	Refinery prd; high sulfur oil	OGIRS- MRGNPPx2 (Where x is PADD#)	PADD x Averages/Totals Residual Fuel Oil Sulfur > 1.0 Net Production (Mbbl)	RFROPUS*Histo year Sulfur Split and PADD
RFDPRDN6I (N6I)	Refinery prd; low sulfur resid oil	OGIRS- MRLNPPx2 (Where x is PADD#)	PADD x Averages/Totals Residual Fuel Oil Sulfur 0-0.3 Net Production (Mbbl/d)	RFROPUS*Histo year Sulfur Split and PADD
		OGIRS- MRMNPPx2 (Where x is PADD#)	PADD x Averages/Totals Residual Fuel Oil Sulfur .31-100 Net Production (Mbbl/d)	

RFQEXCRD	CRUDE EXPORTS IN MBD	OGIRS- MCREXPx2 (Where x is PADD#)	PADD x Averages/Totals Crude Oil Exports (Mbbl/d)	Assume last historical year
RFDPRDOTH (OTH)	Refinery prd; other petroleum	OGIRS- MGARPPx2 (Where x is PADD#)	PADD x Averages/Totals Aviation Gasoline Refinery Production (Mbbl/d)	Use 10 year average growth
		OGIRS- MLURPPx2 (Where x is PADD#)	PADD x Averages/Totals Lubes Refinery Production (Mbbl/d)	
		OGIRS- MNSRPPx2 (Where x is PADD#)	PADD x Averages/Totals Naphtha Special Refinery Production (Mbbl/d)	
		OGIRS- MWXRPPx2 (Where x is PADD#)	PADD x Averages/Totals Waxes Refinery Production (Mbbl/d)	
RFDPRDPCF (PCF)	Refinery prd; petrochemical feeds	OGIRS- MPFRPPx2 (Where x is PADD#)	PADD x Averages/Totals Petroleum Products Refinery Production (Mbbl/d)	Use 10 year average growth
RFDPRDSTG (STG)	Refinery prd; still gas	OGIRS- MSGRPPx2 (Where x is PADD#)	PADD x Still Gas Refinery Production (Mbbl/d)	Use 10 year average growth
RFDPRDTRG (TRG)	Refinery prd; motor gasoline	OGIRS- MGFRPPx2 (Where x is PADD#)	PADD x Finished Gasoline Refinery Production (Mbbl/d)	MGROPUS* Last Histo Year PADD Splits
CRDUNACC	Unaccounted crude	OGIRS - MCRAUPx2 (Where x is PADD #)	PADD x Averages/Totals Crude Oil Unaccounted for (Mbbl/d)	COUNPUS
CRDSTWDR	Crude stock withdrawals	OGIRS- MCRSCPx2 (Where x is PADD#)	PADD x Averages/Totals Crude Oil Stock Change (Mbbl/d)	COSQ_DRAW
				COSX_DRAW
TOTCRDIN	Crude Oil: refinery inputs	OGIRS- MCRRIUS2	US Crude Oil Input into Refineries (Mbbl/d)	CORIPUS
RFQPRCG	PROCESSING GAIN IN MMBD	OGIRS- MPGRPUS1/365	US Processing Gain Net Production (Mbbl)	PAGLPUS
BLDIMP	Blending component imports	OGIRS- MBCIMUS2	US Blending Components Gasoline Imports (Mbbl/d)	MBNIPUS
BLDPRD	Product blending component	OGIRS- MBCUA_NUS_2	US Blending Components Gasoline Field Production (Mbbl/d)	MBFPPUS
BLDREF_BIN	Net Product blending component used at refinery/blenders	MBCRIUS2	US Blending Components Gasoline Input into Refineries (Mbbl/d)	
		MBARIUS2	US Blending Components Av-Gas Input into Refineries (Mbbl/d)	
NGLRF(2)	NGL input to refinery and blenders	OGIRS- MNGRIUS2	U.S. Refinery and Blender Net Inputs of Natural Gas Liquids and Liquefied Refinery Gases (Thousand Barrels)	
BLDREFINC	Conv Product blending component used at refinery	OGIRS - mo5ro_nus_1	U.S. Conventional Gasoline Blending Components Refinery Net Input (M Barrels)	
BLDREFINR	Reformulated Product blending component used at refinery	OGIRS - mo1ro_nus_1	U.S. Reformulated Gasoline Blending Components Refinery Net Input (Thousand Barrels)	
BLDRFGPRD		OGIRS - mgrrz_nus_2	U.S. Reformulated Gasoline Blenders Net Production (MMbbl/day)	
BLDTRGPRD		OGIRS - mg4rz_nus_2	U.S. Conventional Gasoline Blenders Net Production (MMbbl/day)	

RFQEXCRD	CRUDE EXPORTS IN MBD	OGIRS- MCREXPx2 (Where x is PADD#)	PADD x Averages/Totals Crude Oil Exports (Mbbl/d)	Assume last historical year
BLDREFIN	Product blending component used at refinery	OGIRS - mbcro_nus_1		
RFGPRD	Refinery Net Production of RFG	OGIRS - mgrrx_nus_2	U.S. Refinery net Production Reformulated Gasoline (Mbbl/d)	
TRGPRD	Refinery Net Production of TRG	OGIRS - mg4rx_nus_2	U.S. Refinery net Production Conventional Gasoline (Mbbl/d)	
NGLIMP		OGIRS - MNGIMUS2	NGL Imports	
NGLRF(1)	NGL input to refinery	OGIRS- M_EPL0_YIY_NUS_2	US Natural Gas Liquids and LRGs Totals Input into Refineries (Mbbl/d)	LGRIPUS
		OGIRS - MNGEXUS2		PPRIPUS
NGLEXP	NGL Exports	STEO: MBRIPUS, OXRIPUS, UORIPUS	NGL Exports	
OTHLIQIN	Other liquids used at the refinery	OGIRS- m_epoo_yiy_nus_2		
OTHOXY	Other oxygenates	OGIRS - MOLUA_NUS_2	US Other Hydrocarbons/Oxygenates Field Production (Mbbl/d)	OHRIPUS
OTHOXYFP	Other oxygenates (Field production)	OGIRS - MOHIMUS2		
OTHOXYIMP	Imported oxygenates	OGIRS- MOYRIUS2		
RFHCXH2IN	Merchant Hydrogen	OGIRS - MOORIUS2		
RFOHOXYIN	Oxygenates Other Inputs into Refineries	OGIRS - moxro_nus_1		
RFOXYIN	Oxygenates Net Input into Refineries	OGIRS - MOLUPUS2		
OTHPRDSP	Other Liquids Product Supplied	OGIRS -molro_nus_1		
REFOTHLIQIN	Other Liquids into Refinery	OGIRS- M_EPL0_YIY_NUS_2	US Other Liquids Input into Refineries (Mbbl/d)	
PRDSTKWDR	Product stocks withdrawals	OGIRS- MTTSCUS2	United States Total Crude Oil and Petroleum Products Stock Change (Mbbl/d)	Assume Zero
		OGIRS- MCRSCPx2 (Where x is PADD#)	PADD x Averages/Totals Crude Oil Stock Change (Mbbl/d)	
RFETHETB	Zeros			
RFETHE85	Ethanol for E85 production		Oxy Fuel News Data	Oxy Fuel News Data
RFETHMGS	Ethanol for motor gasoline	OGIRS- OFETPUS2	US Oxygenates Fuel Ethanol Production (Mbbl/d)	EOFPPUS
RFMETETH	Methanol for ether		Zeros	Assume Zero
RFMTBI	Imported MTBE		US Oxygenates MTBE Imports (Mbbl/d)	Assume Zero
RFETHIN	Total Ethanol into Refinery	OGIRS - mfero_nus_1		
RFMTBEIN	MTBE Input into Refinery	OGIRS- mmtro_nus_1		
RFPQUFC	Total imports of unfinished crude	OGIRS- MUOIMUS2	US Unfinished Oils Imports (Mbbl/d)	UORIPUS
TOTUFOIN	Total Unfinished Oils into Refinery	OGIRS- m_eppu_yiy_nus_2		

RFQEXCRD	CRUDE EXPORTS IN MBD	OGIRS- MCREXPx2 (Where x is PADD#)	PADD x Averages/Totals Crude Oil Exports (Mbbl/d)	Assume last historical year
RFFPO	Other Liquids Field Production	OGIRS - MOLUA_NUS_1		
RFNETOLIMP	Other Liquids Net imports	OGIRS - MOLNTUS2		
RFSPRFR	SPR fill rate	OGIRS- -MCSSCUS1/365	US Crude Oil Stock Change SPR (Mbbl)	CONQPUS
ETHEXP	Ethanol Exports	OGIRS - M_EPOOXE_EEX_NUS-Z00_MBBLD		
RFQDINPOT	Other fuels input			
PALMG	US Wholesale Motor Gasoline Price	OGIRS - A103700002		
PDS11	US No. 2 Distillate Wholesale Price	OGIRS - A213700002		
PDSL11	US Diesel Fuel Wholesale Price	OGIRS - D230700002		
BIODIMP	US Biodiesel Imports	MER Table 10.4	Historic Biodiesel Impots in Static BIODIMP Table	BDNIPUS
BIODEXP	US Biodiesel Exports	MER Table 10.4	Historic Biodiesel Exports in Static BIODEXP Table	BDNIPUS
TDIESEL	Transportation Diesel Product Supplied	OGIRS - md1up_xxx_2 & md0up_xxx_2	STEO Years are calculated as prior years TDIESEL % of total distillate	
AST	Asphalt Product Supplied (Mbbl/d)	OGIRS- MAPUPPx2 (Where x is PADD#)	PADD x Averages/Totals Asphalt Product Supplied (Mbbl/d)	ARTCPUS
COK	Petroleum Coke Product Supplied (Mbbl/d)	OGIRS- MCKUPPx2 (Where x is PADD#)	PADD x Averages/Totals Petroleum Coke Product Supplied (Mbbl/d)	PCTCPUS
JTA	Jet Fuel Kero Product Supplied (Mbbl/d)	OGIRS- MKJUPPx2 (Where x is PADD#)	PADD x Averages/Totals Jet Fuel Kero Product Supplied (Mbbl/d)	JFTCPUS
KER	Kerosene Product Supplied (Mbbl/d)	OGIRS- MKEUPPx2 (Where x is PADD#)	PADD x Averages/Totals Kerosene Product Supplied (Mbbl/d)	KSTCPUS
LPG	Product Supplied; LPG	OGIRS- MLPUPPx2 (Where x is PADD#)	PADD x Averages/Totals Liquefied Petroleum Gases Product Supplied (Mbbl/d)	LGTCPUS
N2H	Product Supplied; no. 2 distillate	OGIRS- MDIUPPx2 (Where x is PADD#)	PADD x Averages/Totals Total Distillate Product Supplied (Mbbl/d)	DFTCPUS
N6B	Product Supplied; high sulfur oil	Computed- MRSUPHx2 (Where x is PADD#)	PADD x Averages/Totals Residual Fuel Oil Sulfur > 1.0 Product Supplied (Mbbl/d)	RFTCPUS * High%
N6I	Product Supplied; low sulfur residual oil	Computed- MRSUPLx2 (Where x is PADD#)	PADD x Averages/Totals Residual Fuel Oil Sulfur < 1.0 Product Supplied (Mbbl/d)	RFTCPUS* Low%
OTH	Product Supplied; other petroleum	OGIRS- MGAUPPx2 (Where x is PADD#)	PADD x Averages/Totals Aviation Gasoline Product Supplied (Mbbl/d)	AVTCPUS
		OGIRS- MLUUPPx2 (Where x is PADD#)	PADD x Averages/Totals Lubes Product Supplied (Mbbl/d)	LUTCPUS
		OGIRS- MNSUPPx2 (Where x is PADD#)	PADD x Averages/Totals Naphtha Special Product Supplied (Mbbl/d)	SNTCPUS
		OGIRS- MWXUPPx2 (Where x is PADD#)	PADD x Averages/Totals Waxes Product Supplied (Mbbl/d)	WXTCPUS
PCF	Product Supplied; petrochemical feeds	OGIRS- MPFUPPx2 (Where x is PADD#)	PADD x Averages/Totals Petroleum Products Product Supplied (Mbbl/d)	FETCPUS
STG	Product Supplied; still gas	OGIRS- MSGUPPx2 (Where x is PADD#)	PADD x Averages/Totals Still Gas Product Supplied (Mbbl/d)	SGTCPUS
RFQPRDT	Total product supplied	OGIRS- MTTUPPx2 (Where x is PADD#)	PADD x Averages/Totals Total Crude Oil and Pet Products Supplied (Mbbl/d)	Sum STEO Product Quantities
		OGIRS- MCRUPPx2 (Where x is PADD#)	PADD x Averages/Totals Crude Oil Product Supplied (Mbbl/d)	

RFQEXCRD	**CRUDE EXPORTS IN MBD**	**OGIRS- MCREXPx2 (Where x is PADD#)**	**PADD x Averages/Totals Crude Oil Exports (Mbbl/d)**	**Assume last historical year**
TRG	Product Supplied; motor gasoline	OGIRS- MGFUPPx2 (Where x is PADD#)	PADD x Averages/Totals Finished Gasoline Product Supplied (Mbbl/d)	MGTCPUS
QELETH	Historical Electricity use at Ethanol plants -	Multiply EOFPPUS ethanol production by Tony Radich's formulas for energy consumption		
QCLETH	Historical Coal use at Ethanol plants			
PETHM	Historical Ethanol price			
RFIPQCLL	STEO WTI Price			
ETHEXP	Historical Ethanol Exports	OGIRS - m_epooxe_eex_nus		
QCLRF	Refinery Fuel –Coal	Paste in from table 47 of PSA	Use In MMBTU	Assume last Historical Year ratio of fuel to production
QDSRF	Refinery Fuel -Distillate Fuel Oil	Paste in from table 47 of PSA	Use In MMBTU	Average refiner price of residual fuel oil
QELRF	Refinery Fuel -Purchased Elec.	Paste in from table 47 of PSA	Use In MMBTU	
QLGRF	Refinery Fuel –LPG	Paste in from table 47 of PSA	Use In MMBTU	
QNGRF	Refinery Fuel -Nat Gas	Paste in from table 47 of PSA	Use In MMBTU	
QOTRF	Refinery Fuel –Other	Paste in from table 47 of PSA	Use In MMBTU	
QPCRF	Refinery Fuel -Pet Coke	Paste in from table 47 of PSA	Use In MMBTU	
QRSRF	Refinery Fuel -Residual Fuel	Paste in from table 47 of PSA	Use In MMBTU	
QSGRF	Refinery Fuel -Still Gas	Paste in from table 47 of PSA	Use In MMBTU	
PASIN	Asphalt, Road Oil, Industrial	SEDS	PRODUCT PRICES IN 87$ PER MMBTU	RFTCUUS
PDSCM	Distillate, Commercial	SEDS	PRODUCT PRICES IN 87$ PER MMBTU	DSTCUUS
PDSEL	Distillate, Electricity (+petroleum coke)	SEDS	PRODUCT PRICES IN 87$ PER MMBTU	PRODUCT PRICES IN 87$ PER MMBTU
PDSIN	Distillate, Industrial	SEDS	PRODUCT PRICES IN 87$ PER MMBTU	DSTCUUS
PDSRS	Distillate, Residential	SEDS	PRODUCT PRICES IN 87$ PER MMBTU	DSTCUUS
PDSTR	Distillate, Transportation	SEDS	PRODUCT PRICES IN 87$ PER MMBTU	DSTCUUS
PJFTR	Jet Fuel, Transportation	SEDS	PRODUCT PRICES IN 87$ PER MMBTU	JKTCUUS
PKSCM	Kerosene, Commercial	SEDS	PRODUCT PRICES IN 87$ PER MMBTU	JKTCUUS
PKSIN	Kerosene, Industrial	SEDS	PRODUCT PRICES IN 87$ PER MMBTU	JKTCUUS
PKSRS	Kerosene, Residential	SEDS	PRODUCT PRICES IN 87$ PER MMBTU	JKTCUUS
RFQEXCRD	CRUDE EXPORTS IN MBD	OGIRS- MCREXPx2 (Where x is PADD#)	PADD x Averages/Totals Crude Oil Exports (Mbbl/d)	Assume last historical year
PLGCM	Liquid Petroleum Gases, Commercial		PRODUCT PRICES IN 87$ PER MMBTU	PRTCUUS

RFQEXCRD	CRUDE EXPORTS IN MBD	OGIRS- MCREXPx2 (Where x is PADD#)	PADD x Averages/Totals Crude Oil Exports (Mbbl/d)	Assume last historical year
PLGIN	Liquid Petroleum Gases, Industrial		PRODUCT PRICES IN 87$ PER MMBTU	PRTCUUS
PLGRS	Liquid Petroleum Gases, Residential		PRODUCT PRICES IN 87$ PER MMBTU	PRTCUUS
PLGTR	Liquid Petroleum Gases, Transportation		PRODUCT PRICES IN 87$ PER MMBTU	PRTCUUS
PMGCM	Motor Gasoline, Commercial		PRODUCT PRICES IN 87$ PER MMBTU	MGEIRUS
PMGIN	Motor Gasoline, Industrial		PRODUCT PRICES IN 87$ PER MMBTU	MGEIRUS
PMGTR	Motor Gasoline, Transportation		PRODUCT PRICES IN 87$ PER MMBTU	MGEIRUS
PPFIN	Petrochemical Feedstocks, Industrial		PRODUCT PRICES IN 87$ PER MMBTU	PRTCUUS
PRHEL	Residual Fuel, High Sulfur, Electricity		PRODUCT PRICES IN 87$ PER MMBTU	RFTCUUS
PRHTR	Residual Fuel, High Sulfur, Transp.		PRODUCT PRICES IN 87$ PER MMBTU	RFTCUUS
PRLCM	Residual Fuel, Low Sulfur, Commercial		PRODUCT PRICES IN 87$ PER MMBTU	RFTCUUS
PRLEL	Residual Fuel, Low Sulfur, Electricity		PRODUCT PRICES IN 87$ PER MMBTU	RFTCUUS
PRLIN	Residual Fuel, Low Sulfur, Industrial		PRODUCT PRICES IN 87$ PER MMBTU	RFTCUUS
PETTR	E85 Price	EERE: Alternative Fuel Report	PRODUCT PRICES IN 87$ PER MMBTU	
OG GEN GRID90	COGENERATION IN MBTU	EIA-923 Survey	Aggregates plant data to CD regions	Use Last Historical Year for STEO Years 1 & 2
PT GEN GRID90	COGENERATION IN MMBTU			
NG GEN GRID90	COGENERATION IN MMBTU			
OT GEN GRID90	COGENERATION IN MMBTU			
OG GEN OWN 90	COGENERATION IN MMBTU			
PT GEN OWN 90	COGENERATION IN MMBTU			
NG GEN OWN 90	COGENERATION IN MMBTU			
OT GEN OWN 90	COGENERATION IN MMBTU			
OG CAP	Capacity MW			
PT CAP	Capacity MW			
NG CAP	Capacity MW			
OT CAP	Capacity MW			
OG FUL	Cogen Fuel consumption			
PT FUL	Cogen Fuel consumption			
NG FUL	Cogen Fuel consumption			
OT FUL	Cogen Fuel consumption			

Creating LFMM flat-file

To create the final elcgpur.txt, file query results are called by the access report writer. For each variable or collection of variables, a report formats the results of the data queries into the exact Fortran fixed format position necessary to be read into the LFMM. The most often employed method for this is to have a report with the historical data include a sub-report which appends the STEO year data to it. These individual reports are all then included in the master report “zz- Generate Elcgpur” in the appropriate sequence. This file is then exported from the database as a text file.

Because MS Access formats reports to a specific printer (page size), additional lines appear where there are breaks in pages. To remove them a Short VBA script was written (eat space) that removes all of the blank lines from the file. All of the report generation and subsequent post-processing can be done automatically by first running the macro “Update Everything – Including STEO years – Final” and then “Make Elcgpur.” The resulting file will be placed in m:\ogs\amz. Formatting inconsistencies occur when using newer versions of MSAccess. The database has been modified to run in Access 2007.

Processing other historical data

In addition to developing an input history file, the LFMM utilizes other historical data to develop some inputs and to support analysis of the model results. This section describes the updating of these data, which is usually done on an annual basis.

Petroleum product price data

Data on petroleum product prices are obtained from the EIA-782 surveys. The EIA-782A survey contains only refiner data, and the EIA-782B survey includes petroleum marketers. Prices and volumes are produced monthly for the Petroleum Marketing Monthly and prior to 2010 were updated for annual publication in the Petroleum Marketing Annual. Post 2010 annual prices are calculated from monthly data published in the Petroleum Marketing Monthly. This information is also available as a series of OGIRS keys from which the state level data (by product) can be retrieved. By matching equivalent product volume and price information for each state, a weighted average for each Census District can be determined. Retail ethanol prices (E85) are collected from the Clean Cities Alternative Fuels Price Report published by the office of Energy Efficiency and Renewable Energy. This quarterly report is used to create an annual average by Census District.

Historical prices and margins

Historical wholesale and end-use prices from the EIA-782 are aggregated and presented in tabular form by product type and Census Division. The end-use transportation prices include State and Federal taxes, but for jet fuel and LPG the State taxes are not included prior to 1995.

Differentials with the world oil price (the refiner acquisition cost of imported oil from the EIA-14) are also calculated by product type and Census Division and presented in tabular form for analyzing similar margin calculations from the LFMM. The margins include the 1 percent local tax that is currently being added to gasoline price projections.

Appendix H – Changing Structure of the Refining Industry

(Note: This appendix is adapted from “Changing Structure of the Refining Industry” in the Issues in Focus chapter of AEO2012: http://www.eia.gov/forecasts/archive/aeo12/IF_all.cfm#refiningind)

Petroleum-based liquid fuels represent the largest source of U.S. energy consumption, accounting for about 37 percent of total energy consumption in 2010. The mix and composition of liquids, however, have changed in recent years in response to changes in regulations and other factors, and the structure of the liquid fuels production industry has changed in response [68]. The changes in the industry require that analytical tools used for market analysis of the liquid fuels produced by the industry also be reevaluated.

In recognition of the fundamental changes in the liquid fuels production industry, EIA developed a new Liquid Fuels Market Module (LFMM), used in place of the previous Petroleum Market Module (PMM) to produce the Annual Energy Outlook 2013. The LFMM will allow EIA to address more adequately the current and anticipated domestic and international market environments, to analyze the implications of emerging technologies and fuel alternatives, and to evaluate the impact of complex emerging energy-related policy, legislative, and regulatory issues

The landscape for both production and consumption of liquid fuels in the United States continues to evolve, leading to changes in the mix of liquid fuel feedstocks, with greater emphasis on renewable fuels and natural gas liquids. The liquid fuels markets are not homogeneous; regional differences have become more pronounced. Furthermore, U.S. policymakers are paying more attention to evolving markets for liquid fuels and the potential for improving the efficiency of liquid fuels consumption, reducing GHG emissions associated with the production and consumption of liquid fuels, and improving the Nation's energy security by reducing reliance on imports. Major industry changes and their implications are discussed below.

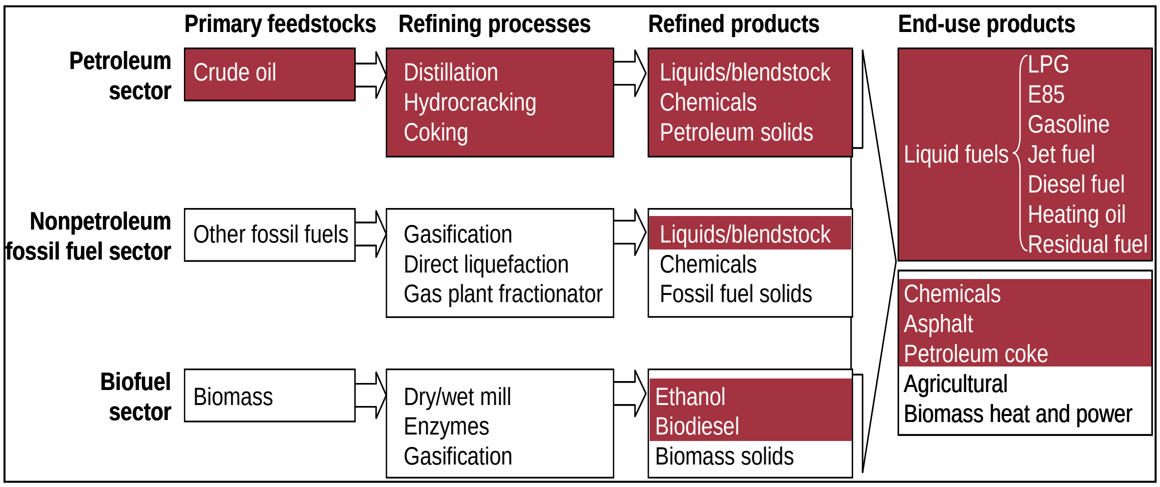
New feedstocks and technologies

Over the past 25 years, the U.S. liquid fuels production industry has changed from being based primarily on domestic petroleum to using a variety of feedstocks and finished products from sources around the world. Regulatory and policy changes have resulted in the use of feedstocks other than crude oil, such as natural gas and renewable biomass, and could lead to the use of other feedstocks (such as coal) in the coming years. These changes have resulted in a transition from a relatively straightforward supply chain relying on crude oil and finished products to an increasingly complex system, which must be reflected in models to produce valid projections.

The term "liquid fuels production industry" refers to all the participants in the production and delivery of liquid fuels, from production of feedstocks to delivery of both liquid and non-liquid end-use products to customers. It includes participants in the more traditional petroleum refining sector, relying on crude oil as a primary feedstock; in the nonpetroleum fossil fuel sector, using natural gas and coal to produce liquid fuels; and in the biofuel sector, using biomass to produce biofuels such as ethanol and biodiesel. The complexity of the industry supply chain is inadequately described by nomenclature predicated on specific feedstocks (e.g., crude oil), processes (e.g. refinery hydrotreating), or end-use products (e.g., diesel fuel and gasoline), which fail to capture the significant economic implications of non-liquid-fuel products for the industry.

The components of the U.S. liquid fuels production industry—including petroleum, nonpetroleum fossil fuel, and biofuel sectors—are shown in the following figure, along with examples illustrating processes and products.

Figure H-1. Liquid fuels production industry

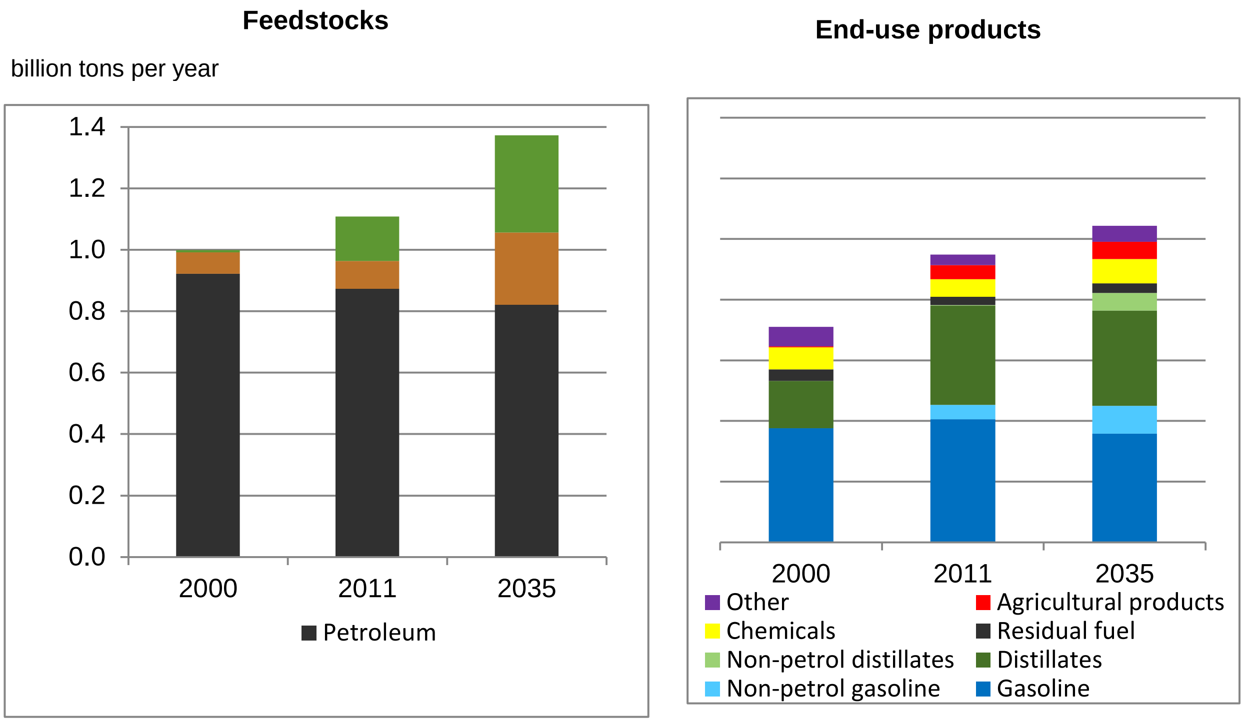


Nonpetroleum feedstocks are used in many new and emerging technologies, such as fermentation, enzymatic conversion, GTL, CTL, biomass-to-liquids, and algae-based biofuels. The new technologies provide valuable non-liquid-fuel co-products—such as chemical feedstocks, distiller's grains, and vegetable oils—that significantly affect the economics of liquid fuels production. The emergence of renewable biofuels has led to the introduction of midstream components such as ethanol and biodiesel, which are blended with petroleum products such as gasoline and diesel fuel during the final stages of the supply chain at refineries, blending sites, or retail pumps. The increase in biofuel production has led to new distribution channels and infrastructure investments and recognition of new production regions, such as the high concentration of ethanol producers in the Midwest. The LFMM includes the entire liquid fuels production industry, providing greater flexibility for integrating new technologies and their associated products into the liquid fuels supply chain, better reflecting the industry's evolution.

In *AEO2012*, the "petroleum and other liquids" category includes the petroleum sector and those non-petroleum-based liquid products shaded in red in Figure 41, such as ethanol and biodiesel, which are blended with petroleum products to make enduse liquid fuels. Because this approach treats nonpetroleum products as exogenously produced feedstocks, the petroleum and other liquids concept used in *AEO2012* does not explicitly link the industrial processes that yield nonpetroleum liquid fuels (nor their feedstocks, nonpetroleum fossil fuels and biomass) with liquids production. The more inclusive definition of the liquid fuels production industry illustrated in Figure H-1 is necessary to capture and model the full range of product flows and economic drivers of decisionmaking by firms involved in this complex industry.

Nonpetroleum feedstocks do not exist in traditional liquid form, and they require a different analytical approach for analysis of their conversion to liquid fuels. Traditional volumetric measures, such as process gain, are not applicable to an analysis of the liquids produced from nonpetroleum feedstocks. It is more appropriate to use the fundamental principles of mass and energy balance to evaluate process performance, market penetration, and supply/demand dynamics when the uses of nonpetroleum feedstocks are being examined. This approach allows for comparison among the different sectors of the liquid fuels production industry. The following provides an overview of the liquid fuels production industry on a mass basis (projections for year 2035 from *AEO2012*).

Figure H-2. Mass-based overview of the U.S. liquids fuels production industry, *AEO2012* LFMM case



The variety and changing dynamics of nonpetroleum feedstocks and the resulting end-use products also are illustrated in Figure H-2. In recent history, biomass has taken significant market share from petroleum feedstocks, correlated with shifts in product yields—a trend that is expected to continue in the future, along with further diversification into nonpetroleum fossil feedstocks. In 2000, nearly all liquid fuels were derived from petroleum. Since then, however, the share of petroleum has dropped while the shares of biomass and other fossil fuels have increased. In 2011, the combined biomass and other fossil fuels share of feedstocks was almost 18 percent, measured on a mass basis. In the AEO2012 LFMM case, the biomass share of feedstock consumption increases to 30 percent in 2035, and the petroleum share falls to about 57 percent. The biomass share of end-use products increases only to 10 percent in 2035, reflecting differences in conversion efficiencies between petroleum and nonpetroleum feedstocks, as highlighted by the growing but still small nonpetroleum content of gasoline and distillates.

Changes in crude oil types

Economic growth in the developing countries over the past decade has increased global demand for crude oil. Over the same period, new technologies for recovering crude oil, changes in the yields of existing crude oil fields, and a global increase in exploration have expanded the number and variety of crude oil types. The United States currently imports more than 100 different types of crude oil from around the world, including a growing number from Canada and Mexico, with a wide range of API gravities (between 10.4 and 64.6) and sulfur content (between 0.02 and 5.5 percent). Consequently, it is difficult to group them according to the categories used in the previous NEMS module PMM. A new and more comprehensive representation of the numerous crude types is required, as well as flexibility to add new sources.

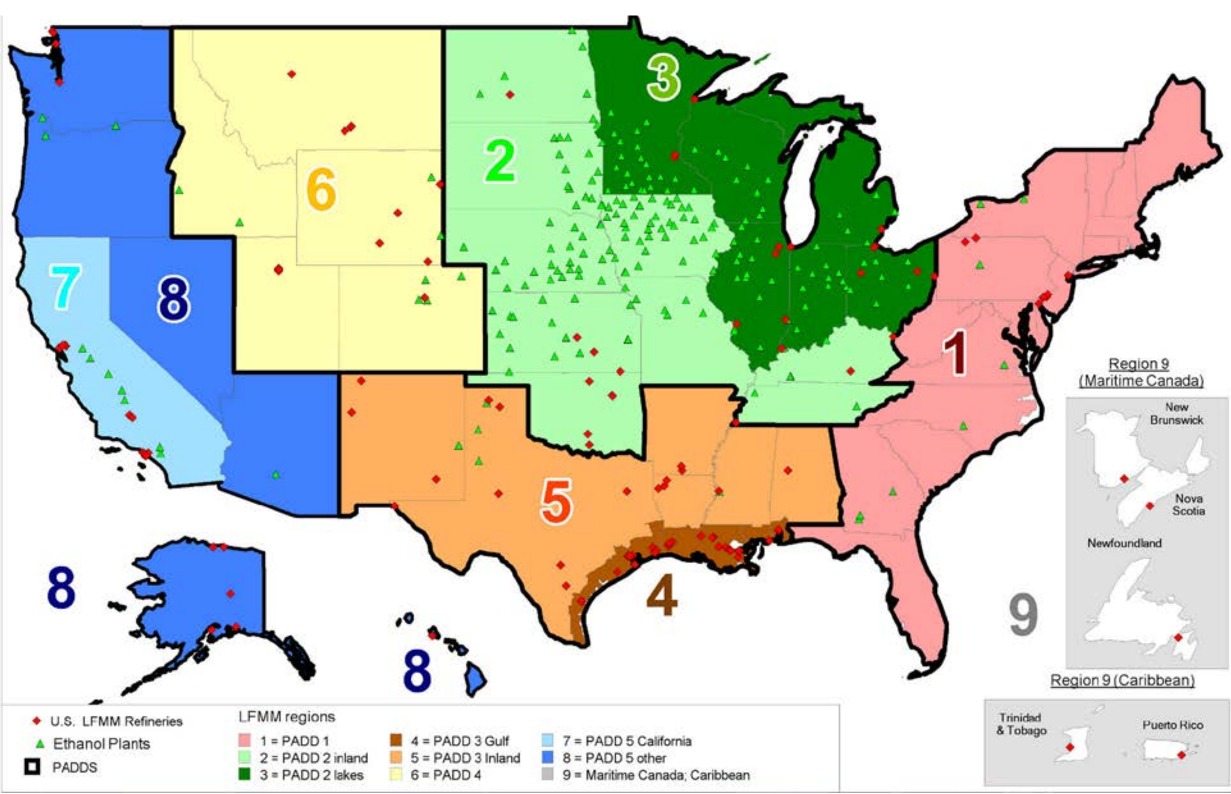
The United States increasingly is using crude oil extracted from oil sands and shale oil, as well as other nontraditional petroleum sources that require additional processing. The new sources have led to shifts in crude oil flows and changes in the distribution network. The increased variety and regional availability of certain crude types has created new market dynamics and pricing relationships that are difficult to capture using existing methods, especially considering the rapid emergence of "tight oil" production, which, to date, has been substantially different in quality from the crude oil previously expected to be available to U.S. refineries. For example, light sweet crude oil sourced from the Bakken shale formation in North Dakota has been sold to refiners on the Gulf Coast in recent years at a substantial discount relative to heavier imported crudes, because of limitations in the delivery infrastructure.

The growing number of sources, changes in characteristics of crudes, and shifting price relationships in crude oil markets require an updated representation of different crude types in NEMS. The model also needs an updated and more dynamic representation of the crude oil distribution network in order to provide better estimates of changes in crude oil flows and potential new regional sources in the future.

Regional updates

The Petroleum Administration for Defense Districts (PADD), which were developed by the Department of Defense during World War II, have been traditionally used as the regional framework for analyzing liquid fuels production. Because the topology and configuration of the liquid fuels market have changed significantly, and new feedstocks have emerged from regions that are subsets of PADDs, the regional definitions for processing liquid fuels need to be redefined. Toward this end, EIA has redefined the refining regions on the basis of market potential and availability of feedstocks. The redefined regions will be further divided as market conditions change. The regional configuration for the NEMS LFMM uses eight domestic regions and adds an international region.

Figure H-3. LFMM regions (PADDs and sub-PADDs)



Each refining region has unique characteristics. PADD 1 has been left unchanged from its original definition but can be further divided based on recent and possible future refinery closures and shifts in imports from Europe. PADD 2 is subdivided into the Great Lakes and Inland regions due to the concentrated production of biofuels and access to Canadian crudes. PADD 3 is divided into the Gulf Coast and Inland regions due to the inability of the interior refineries to handle heavy sour crude. PADD 4 is unchanged from its original definition. California is separated from the rest of PADD 5 due to the State's unique gasoline and diesel specifications and regulatory policies. The international region comprises Maritime Canada and the Caribbean.

The modified regional refinery format allows EIA's analyses to more accurately capture regional refinery trends and potential regional regulatory policies that affect the liquid fuels market. For example, California often enacts its own regulatory policies earlier than the rest of its PADD region, and its individual actions could not be represented accurately in the original PADD framework. As a further example, recent refinery closures and other developments on the East Coast evidence the need for a dynamic and flexible representation of the refinery regions that supply the U.S. market.

Changing product markets

Crude oil is still the most important and valuable feedstock for the liquid fuels production industry. More than 650 refineries, located in more than 116 countries, have the capacity to refine 86 million barrels of crude oil per day. In the past, most of the complex refineries that could transform a wide variety of crudes into numerous different products to meet demand were located in the United States. Now, however, complex refineries are becoming more common in Europe and the developing countries of

Asia and Latin America, and the products from export-focused merchant refineries in those countries have the potential to compete with U.S. products. An example is the regular export of surplus gasoline from refiners in Europe to the Northeast United States.

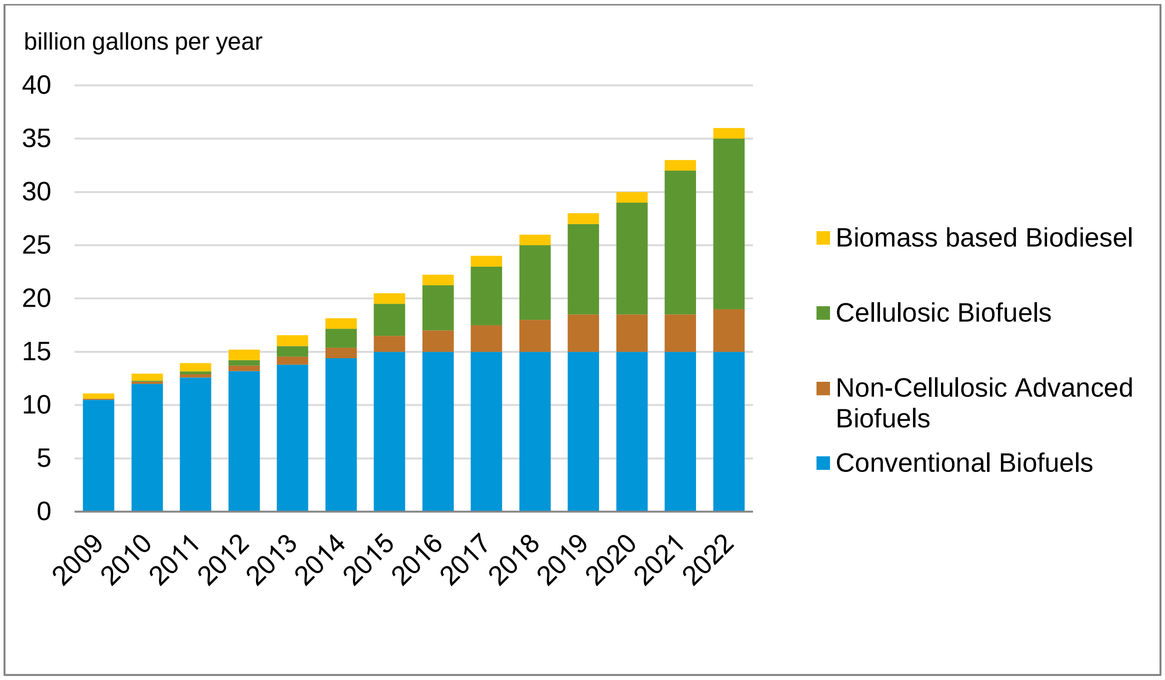
Traditional measures of profitability, such as the 3-2-1 crack spread, require modification in NEMS in view of the changing market for liquid fuels. The calculation of margins requires consideration of multiple feedstocks and multiple products produced in refineries, biorefineries, and production facilities for nonpetroleum fuels. Operators in the liquid fuels production industry are faced with a choice of investing in facilities and modifying their configurations to meet changing market demand, or exchanging domestic feedstocks and products with merchant refineries in a global market. For example, increased U.S. efficiency standards for light duty vehicles have reduced demand for gasoline and increased demand for diesel fuel, which has led to more gasoline exports and more investment to increase diesel output from domestic refineries.

EIA's new LFMM representation of the liquid fuels production industry accounts for global competition for both crude oil and end-use products. As refineries around the world become larger and more complex, smaller refineries may not be able to compete with imports produced at low margins. Therefore, it is necessary to have a more robust and dynamic representation of the liquid fuel producers, as well as additional flexibility to adjust inputs, refinery configurations, and crude and product demands as the industry evolves.

Regulations and policies

It is important for EIA's models to represent existing laws and regulations accurately, in addition to being flexible enough to model proposed laws and regulations. One of the most important regulations currently affecting the U.S. liquid fuels industry is the Renwable Fuel Standard (RFS), which not only has increased production and use of renewable fuels, but also has changed how fuels are distributed and consumed both here and abroad. The RFS mandates the use of biofuels that are consumed primarily as blends with traditional petroleum products, such as gasoline and diesel fuel. Because of their chemical properties, ethanol, biodiesel, and other first-generation biofuels generally require their own distribution networks or investments in new infrastructure. In addition, because they are produced outside traditional petroleum refineries, the new products are added at different points in the supply chain, either at blending terminals or at retail sites via blender pumps. Modeling those changes requires an update to the traditional PADD regional format used to represent the liquid fuels market, as well as an update to the representation of the transportation network that distributes the fuels.

Figure H-4. RFS-mandated consumption of renewable fuels, 2009-2022



he RFS also requires consideration of many new technologies and increases the complexity of decisionmaking in the liquid fuels production industry. Fuel volumes by product are mandated by the RFS. For each year, regulated parties must make the decision to either buy the available renewable fuels in proportion to their RFS requirements or purchase the necessary credits. For example, the cellulosic biofuel credit price is set as the greater of $0.25 cents per gallon or $3.00 per gallon minus the wholesale gasoline price, both based on 2008 real dollars. The RFS also contains a general waiver based on technical, economic, or environmental feasibility that the EPA Administrator has discretionary authority to act on to reduce the mandates for advanced and total biofuels.

In addition, use of biofuels has broader implications for the global market, in terms of both feedstocks and the fuels themselves. A good example is ethanol. Its primary feedstocks are corn and sugar, both of which are global commodities in high demand as food sources as well as biofuel feedstocks. U.S. ethanol producers compete globally in other countries, such as Brazil, that have their own renewable fuels mandates.

Finally, coproducts from biofuels production have a significant influence on their economics. For example, the value of the dried distillers grains coproduct from corn ethanol production, which can be sold to the agricultural sector, can offset up to one-third of the purchase cost for the corn feedstock. Thus, the economics of biofuels production are complex, and they require a model that accounts for numerous investment decisions, feedstock markets, and global interactions. The RFS adds to the liquids fuels market a number of fuel technologies, midstream products and coproducts, evolving regional production and distribution networks, and complex domestic and global market interactions.

The U.S. liquid fuels market has evolved substantially over the past 20 years in terms of available fuel types, production regions, global market dynamics, and regulations and policies. The transition has resulted in a liquid fuels market that uses both petroleum and nonpetroleum-based inputs, distributes them around the country by a variety of methods, and makes investment decisions based on both economic and regulatory factors. The changes are significant enough to make the framework and metrics used in traditional refinery models no longer adaptable or robust enough for proper modeling of the transformed liquid fuels market. EIA developed the LFMM to meet this new modeling need.