Independent Statistics & Analysis
U.S. Energy Information Administration

Liquid Fuels Market Module of the National Energy Modeling System: Model Documentation 2022

June 2022

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Update Information

This edition of the *Liquid Fuels Market Module (LFMM) of the National Energy Modeling System: Model Documentation 2022* reflects changes made to the module during the past two years and included in the *Annual Energy Outlook 2022*. These changes include:

- Modified penetration potential of E15 (motor gasoline blend containing up to 15% fuel ethanol) to be regionally defined as either low, medium, or high, where penetration begins slowly in 2019 and grows to a maximum of about 20%, 35%, and 55%, respectively, by 2050
- Intended to base the revised Renewable Fuel Standard (RFS) levels for historical and near-term years on the U.S. Environmental Protection Agency's (EPA) December 2020 final renewable volume obligation (RVO) (through 2021). However, EPA did not release a final RVO in 2019 or 2020, and its December 2021 release was too late to use for AEO2022. Therefore, AEO2022 used RVO estimates for years 2021 and 2022 that were defined for the September 2021 *Short-Term Energy Outlook* (STEO).
- Updated E85 infrastructure representation and availability curve, including new design for E85 availability curve
- Added renewable diesel imports representation
- Extended biomass-based diesel blender tax credits through 2022, per legislation
- Added revenue for sale of distillers dried grain
- Updated regional mapping of seed oil supply curve data from Polysys (National Energy Modeling System Renewable Fuels Module) as feedstock option for biodiesel and renewable diesel
- Updated refinery and non-refinery existing and planned capacity data as well as refinery cogeneration data
- Updated renewable diesel, biodiesel, and ethanol capacity data as well as growth rates
- Updated data defining crude oil and petroleum product transportation network, transport costs, and transport capacity for both domestic and import/export links
- Updated data used to estimate state mandated ultra-low sulfur heating oil
- Updated other historical data for prices and volumes
- Updated distribution markups and costs for gasoline, diesel, E85, and jet fuel
- Updated state and federal fuel taxes
- Updated fuel handling for refinery fuel units
- Updated mandated drawdown of U.S. Strategic Petroleum Reserve

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Acronyms and Abbreviations

AB32	California Assembly Bill 32, known as the Global Warming Solutions Act of 2006
ADU	atmospheric distillation unit
AEO	*Annual Energy Outlook*
AFPM	American Fuel and Petrochemical Manufacturers
API	American Petroleum Institute
ASTM	formerly known as the American Society for Testing and Materials
b	barrel
b/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, in other words, 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% ethanol and 15% conventional gasoline (The annual average of ethanol content in E85 is 74%, 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
FREC	U.S. Federal Energy Regulatory Commission
FOE	fuel oil equivalent
GTL	gas-to-liquids (converting natural gas to diesel-grade blending streams)
IEO	*International Energy Outlook*
IEM	International Energy Model
IMO	International Maritime Organization
ISBL	inside the battery limit
kWh	kilowatthour
LCFS	Low Carbon Fuel Standard
LFMM	Liquid Fuels Market Module
LP	linear programming
LPG	liquefied petroleum gas
Mb/cd	thousand barrels per calendar day
MBtu	thousand British thermal units
MMb/cd	million barrels per calendar day
MMBtu	million British thermal units
MTBE	methyl tertiary butyl ether
MW	megawatts, electric generation capacity
MWh	megawatthour
NACOD	North American Crude Oil Distribution
NEMS	National Energy Modeling System
NETL	National Energy Technology Laboratory
NGL	natural gas liquid
NGPL	natural gas plant liquid

NPC	National Petroleum Council
NPRA	National Petrochemical and Refiners Association, now known as the American Fuel and Petrochemical Manufacturers (AFPM)
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
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 Module (LFMM), describe its basic approach, and provide details on how it works. This report is a reference document for model analysts and users. It is also 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 is available in two related documents: *Annual Energy Outlook 2022 (Appendix E)* and *Assumptions to the Annual Energy Outlook 2022*. This volume documents the version of the LFMM used for the *Annual Energy Outlook 2022* (AEO2022) and supersedes all previous versions of the LFMM documentation.

Model summary

The LFMM models petroleum refining activities, the marketing of petroleum products to consumption regions, imports and exports of petroleum liquids, the distribution of natural gas liquids from natural gas processing plants, and the production of renewable fuels (including ethanol, biomass-based diesel, and cellulosic biofuels) and non-petroleum fossil fuels (including coal-to-liquids and gas-to-liquids). The LFMM projects domestic petroleum product prices and movement of liquid fuel quantities for meeting petroleum product demands by supply source, fuel, and region. These liquid fuels include:

- Domestic, imported, and exported crude oil
- Alcohols, biomass-based diesel, and other biofuels
- Domestic natural gas plant liquids
- Petroleum product imports and exports
- Unfinished oil imports and exports

In addition, the LFMM estimates domestic refinery capacity expansion and fuel consumption. Product prices are estimated at the census division (CD) level, while 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 AEO2022. 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; and Appendix G, Historical Data Processing.

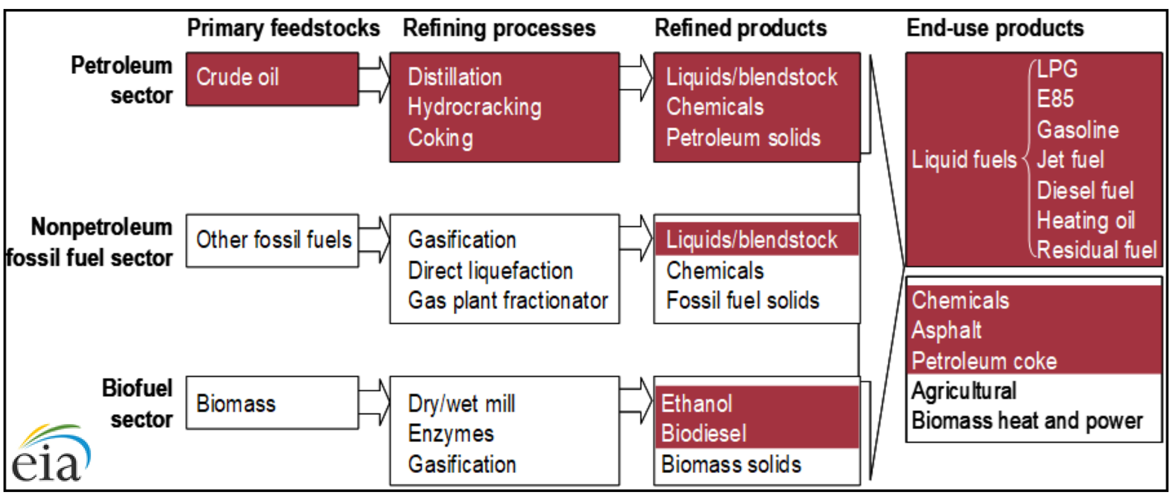
Model Purpose

Model objectives

The Liquid Fuels Market Module (LFMM) models production and marketing of liquid fuels, including petroleum products and non-petroleum liquid fuels. The purpose of the LFMM is to project liquid fuel prices, production activities, and movements of petroleum into and out of 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 the figure below.

Figure 1. Liquid fuels production industry, with the Liquid Fuels Market Module highlighted in red



Source: U.S. Energy Information Administration, Office of Energy Analysis
Note: LPG refers to liquefied petroleum gas; E85 refers to a blend of up to 85% ethanol and 15% motor gasoline.

The LFMM simulates the operation of petroleum refineries and non-petroleum liquid fuels production plants in the United States. The module also has a simple representation of the international refinery market used to provide competing crude oil and petroleum product[1] import and export 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 marketing and distribution of the

[1] The International Energy Module (IEM) in NEMS provides price and quantity representation for foreign crude and product supplies and demands.

fractionated natural gas liquids from natural gas processing plants, the production of distillate and naphtha blending streams from natural gas (gas-to-liquids, GTL), coal (coal-to-liquids, CTL), and biomass (biomass-to-liquids, BTL), and the processing and marketing of renewable fuel feedstock (corn, biomass, seed oils, fats, and greases) into alcohol and biomass-based diesel and naphtha liquid blends. The essential outputs of this model are domestic liquid fuels product prices, a petroleum supply and demand balance (including crude oil and petroleum product imports and exports), demands for refinery fuel use, and capacity expansion decisions.

Inputs to the LFMM:

- Domestic petroleum product demands
- International petroleum product import/export curves and import/export links to LFMM regions
- Domestic crude oil production levels for 9 crude oil types, including average California crude oil
- International crude oil supply curves for 10 crude oil types, excluding California and including Canadian syncrude and dilbit, and import/export links to LFMM regions
- Costs of energy inputs such as natural gas, electricity, and coal
- Costs and available quantities of feedstocks (such as biomass, corn, etc.) used to produce blending components (such as ethanol and biodiesel)
- Yield coefficients for crude oil distillation and other processing units
- Existing and planned process unit capacities
- Investment costs for capacity expansion
- Capacities and tariffs for pipeline and other transportation modes for crude oil and petroleum products
- Product specifications
- Policy requirements (including RFS, LCFS, AB32, etc.)

From these inputs, the LFMM produces:

- A slate of domestic prices for petroleum products
- Regional domestic crude oil prices
- The quantity of crude oil processed at domestic refineries
- Imports and exports of crude oil and petroleum products
- Estimates of other refinery inputs and processing gain
- Domestic capacity expansion for petroleum refineries and biorefineries
- Biofuels production levels
- Refinery fuel consumption, including electricity, natural gas, still gas, and catalyst coke

The LFMM represents the liquid fuels production and marketing sector in projections published in the *Annual Energy Outlook* (AEO). The model also analyzes a wide variety of related issues. The LFMM is able to project the impacts on refinery operations and on the marginal costs of refined products associated with changes in:

- Demands for various kinds of petroleum products
- Crude oil prices and domestic production levels
- Refinery processing unit capacities

- Petroleum product specifications
- Energy policies and regulations
- 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, crude oil and petroleum product import and export levels, and supplies and production of alternative fuels. 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:

- The Residential Demand Module (RDM), Commercial Demand Module (CDM), Industrial Demand Module (IDM), Transportation Demand Module (TDM), and Electricity Market Module (EMM) provide demands for petroleum products. The demands include motor gasoline, E85, jet fuel, kerosene, heating oil, ultra-low sulfur diesel, CARB gasoline and diesel, low- and high-sulfur residual fuel, liquefied petroleum gases (LPG), petrochemical feedstocks, petroleum coke, and other petroleum products (such as lubes and asphalt).
- The International Energy Module (IEM) provides the benchmark crude oil price. The IEM provides a benchmark crude oil supply curve for Brent (light-sweet) crude oil, as well as for nine other crude oil types. Regional prices for these crude oil types are computed in the LFMM based on the import and export decision levels for each crude oil type.
- The Oil and Gas Supply Module (OGSM) provides domestic crude oil production levels. The crude oil is categorized into the same types represented for the import supply curves (excluding Canadian dilbit and syncrude), plus an average California crude oil.
- Natural gas liquids, which are among the non-crude oil inputs to refineries, are also estimated by OGSM from domestic natural gas production levels and characteristics.
- Coal supply information (prices and quantities on supply curves, coal type, transportation network, emissions, and consumption for electricity generation and other needs) used for feedstock to produce CTL and CBTL, along with coal demands by other sectors (for example, an electric utility), are provided by the Coal Market Module (CMM).
- The Natural Gas Market Module (NGMM) provides natural gas prices, and the Electricity Market Module (EMM) provides electricity prices. The LFMM estimates the refinery consumption of these energy sources.
- The Macroeconomic Activity Module (MAM) provides certain macroeconomic parameters. The Baa average corporate bond rate (reflects a low-risk investment) 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 and liquid fuels process unit investments. Discount rates (GDP) are also provided by the MAM.
- The Renewable Fuels Module (RFM) provides corn, cellulosic, and soy bean oil feedstock prices and quantities.
- The Transportation Demand Module (TDM) provides logit function and other parameters used to estimate the ratio of E85 to motor gasoline usage for flex fuel vehicles (FFV).

The LFMM also provides information to other NEMS modules:

- Passes prices of petroleum products to the Residential Demand, Commercial Demand, Industrial Demand, Transportation Demand, and Electricity Market Modules. The prices are used to estimate end-use demands for the various fuels.
- Passes regional domestic crude oil prices to the Oil and Gas Supply Module.
- Provides supply balance quantities, including crude oil refinery inputs, non-crude oil refinery inputs, and processing gain, for reporting purposes.
- Determines capacity expansion and utilization rates at petroleum refinery and biorefinery plants mainly for reporting purposes.
- Passes fuel consumption at refineries to the Industrial Demand Module (IDM) for inclusion in the industrial sector totals. In addition, refinery combined-heat-and-power (CHP) capacity and generation levels are sent to the IDM and EMM.
- Sends cellulosic biomass consumption to the Renewable Fuels Module (RFM).

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 (U.S. census division). 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 and, combined with information from other modules, estimates petroleum product prices. When successive solutions of energy quantities demanded and delivered prices are within a pre-specified percentage difference (convergence tolerance), the NEMS solution is declared converged. If the computed prices have not converged, new demand quantities are computed, passed to the LFMM, and the cycle is repeated. This process continues until a converged solution is found. See the description of the NEMS integrating module for a more complete understanding of the iterative process and convergence tests.

The LFMM uses a linear program (LP) to represent domestic liquid fuels production, consumption, distribution, and marketing operations. The model includes eight U.S. refinery production regions based on PADDs (Petroleum Administration for Defense Districts) and sub-PADDs and based on one international region representing petroleum refining activity in eastern Canada and the Caribbean. A transportation network model represents transport of domestic crude oils to the refining regions and transport of petroleum products from the refining regions to the end-use census division (CD) 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). Additional supply and demand for crude oil and petroleum products from and to the international market are represented by import and export curves that connect the international markets to the domestic transportation network described above.

An optimal solution is to minimize net total cost while simultaneously meeting regional demands and various constraints. The model estimates revenues from prices and product sales in the previous NEMS iteration and projects costs incurred from the purchase and processing of raw materials and from 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 specification requirements, processing and transportation capacities, demand, and policy requirements. Economic forces also govern the decision to import or export crude oil or refined products into or out of U.S. regions.

Fundamental assumptions

The LFMM assumes that the liquid fuels production and marketing industry is competitive. The market will move toward lower-cost refiners (producers) who have access to crude oil (or non-petroleum feedstocks) and markets. The selection of feedstocks, process utilization, renewable fuel blends, and logistics will adjust to minimize the overall cost of supplying the market with petroleum products. If domestic 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 (or imports), thus restoring the supply and 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 Code Structure

During each NEMS iterative solution (each iteration, each model year), product demand quantities, crude oil and petroleum product import and export curve data, and other data provided by the other NEMS demand and supply modules are used to update the LFMM linear program (LP) matrix. Once the updated LP provides an optimal solution, marginal crude oil and petroleum product prices and other material balance information are extracted, followed by some post-processing needed to convert results into output required by other models and reports. For example, additional costs (such as, state and federal taxes and distribution costs) are added to the marginal product prices to define domestic petroleum product prices for each end-use sector in each CD. In addition, refinery input and output volumes are reallocated from LFMM regions to CD reporting regions. System variables are updated, and reports are produced. The modification and optimization of the LFMM LP matrix are accomplished within a GAMS program using the Xpress solver. Appendix B describes the formulation of the LP representation in the LFMM.

The LFMM program code is a mix of GAMS and Fortran. The model starts operating when NEMS calls the Fortran subroutine REFINE—the main controlling subroutine for the LFMM. Through subroutine calls and a call to the main GAMS program lfshell.gms, the LFMM code initializes variables, reads data, updates and solves the LP, retrieves and processes results, performs STEO benchmarking, and generates report variables. Each major routine and its function are described below.

Main subroutines (refine.f, lfshell.gms)

The LFMM includes Fortran subroutines and GAMS programs. The Fortran subroutines are in the file refine.f: REFINE, RFHIST1, PMM_NEXTDATA, WRITE_INIT_GDX, WRITE_GDX, READ_GDX, and E85_Demand_Curve. The Fortran subroutine REFINE calls the GAMS program lfshell.gms, which subsequently calls other GAMS programs to read and prepare data, set up and solve the LP, and extract results for reporting to other NEMS modules.

Subroutine REFINE
REFINE is the main entry point into the LFMM from the rest of NEMS. It calls subroutines RFHIST1, Write_INIT_GDX, Write_GDX, 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 oil imports, production capacity of petroleum refineries and non-petroleum liquid fuels plants, capacity utilization, product imports and exports, refinery product production, refinery gain, hydrocarbon gas liquids (HGL) imports and exports, etc. This routine also reads in the STEO benchmarking adjustment data used to transition between STEO results and near-term model projections of product prices.

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 database (GDX) file: NEM_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 database (GDX) file. This GDX file contains all information provided by other NEMS models that the LFMM needs, including projection year, GDP data, product demands, domestic crude oil supply, import and export curves, etc. Data from this GDX file are later accessed 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 modules and NEMS reports.

Subroutine E85_Demand_Curve
Sets up an E85 demand curve using the logit function LFMM_FFVSHR to speed up convergence between the LFMM and the Transportation Demand Module (TDM). The data used to help define the curve are read from the input file rfinvest.txt. The final E85 demand curve data are written to E85.gdx, a GAMS GDX file that is later read by lfprep.gms.

lfshell.gms
lfshell.gms is the main entry point to the GAMS portion of the LFMM, and it is called by the Fortran subroutine REFINE. lfshell.gms performs the following:

- Calls lf_nem.gms to read the NEMS data from NEM_TO_LFMM1.gdx
- Calls lfprep.gms to read GDX input data files LFMinput.gdx, lfminset.gdx, and lfinvest.gdx and to prepare data used to define the LP matrix
- Calls lfmodel.gms to set up the LP model (decision variables, objective function, constraints)
- Sets capacity expansion parameters (fixed costs, learning, etc.) and limits

- Performs NPV (net present value) calculations to put all data on a consistent (nominal) year basis
- Creates California Low Carbon Fuel Standard (LCFS) carbon factors ready to be incorporated into the LP
- Uses expected demand for motor fuels to help calculate the renewable volume obligation (RVO) used to implement EPA Renewable Fuel Standard (RFS) requirements for each year
- Sets bounds on supply curves for crude oil, imported sugarcane ethanol, various feedstocks (corn, soyoil, biomass, etc.)
- Restricts capacity expansion for alternative fuel processes (celluloisic ethanol, gas-to-liquids, etc.) before a specified year
- Solves LP
- Calls 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), which contains all the data defined by other NEMS models that are needed to build the LP matrix (includes product demands, feedstock costs and supply curve data, energy conversion factors, etc.).

lfprep.gms

- Reads lfminset.gdx, which defines many of the sets used by the LFMM GAMS code
- Reads LFMinput.gdx, a GDX data file containing LFMM-specific input data (such as existing refinery and biofuels capacity and production characteristics, policy requirements, transport network costs and capacity, etc.) that reside in numerous Excel (xlsx) data files
- Reads lfinvest.gdx, a GDX data file created from process unit investment and learning data stored in lfinvestment.xlsx
- Creates mapping sets that mediate between NEMS regions and LFMM regions
- Initializes LP parameters based on NEMS variables read from NEM_TO_LFMM1.gdx
- Sets up supply curves for corn, soyoil, and other non-crude oil feedstocks using data provided by the RFM (via NEM_TO_LFMM1.gdx data file)
- Defines *waiver costs* for RFS and LCFS to ensure that the LP remains feasible

LP Formulation (lfmodel.gms)

lfmodel.gms specifies the LP decision variables, the constraints, and the objective function that represents the operations of liquid fuels production facilities in the United States, transport of liquids between supply and demand regions, and imports and exports of liquid fuels in the United States. The LP finds the minimum net cost of satisfying the set of liquid fuel demands given by the NEMS demand modules, subject to build, operation, and transport constraints (for example, processing capacity, volume balance, feedstock purchases, pipeline and transport capacities) and policy constraints (for example, RFS, LCFS, AB32, fuel specifications). The outputs of the LP include build, operation, and transport decisions, import and export decisions, and, most importantly, domestic crude oil and wholesale product prices. Appendix B contains a mathematical description of the LP model.

LP Post-Processing (lfreport.gms)

lfreport.gms writes the file LFMM_TO_NEMS.gdx, which contains the following important information passed from the LFMM to other NEMS modules and reports:

- Build and operation decisions for each liquid fuels production technology represented in the LFMM
- Regional domestic crude oil prices
- Wholesale product prices, based on shadow prices (duals) of selected LP constraints
- Retail product prices, based on regional wholesale prices and sector mark-ups representing taxes and distribution costs
- Energy purchases and process fuel use requirements
- Crude oil and petroleum product import and export decisions
- Items useful for debugging

Appendix A. Data and Outputs

This appendix has three parts:

1. Section A.1 lists variables passed between the LFMM and the NEMS Integrating Module.
2. Section A.2 lists data sources.
3. Section A.3 lists the data files used to create the LFMM's GDX data files that are loaded into the NEMS environment. The data files described in A.3 account for the largest portion of the LFMM data because they represent the liquid fuels process unit technologies and capacities, policy requirements, and product quality characteristics and specifications.

A.1 Variables and definitions

NEMS variables are passed to the LFMM via file NEM_TO_LFMM1.gdx. LFMM results (including product prices) are passed to the NEMS Integrating Module via variables included in the file LFMM_TO_NEMS.gdx. The most recent version of the NEMS text file varlistL.txt lists the NEMS variables and their associated Fortran-based *include* files that are passed between NEMS Fortran code and LFMM GAMS code. These variables are defined in another NEMS text file dict.txt, which we update annually.

A.2 Data sources

Most of the data for the LFMM were developed by OnLocation, Inc./Energy Systems Consulting and their subcontractors. These data were based on both new analysis and existing analysis used in the LFMM's predecessor model, the Petroleum Market Module (PMM). For details on the new analysis, see the *LFMM Component Design Report*.

Process technology and cost data

Refining process technology and cost data need to be periodically reviewed and updated because environmental legislation, lighter product slates, and ever-changing crude oil slates have spurred new process technology developments that affect existing processes, new processes, new crude oil types, and costs. Sources for new developments include research and other papers in industry journals, papers from industry conferences and surveys (such as the American Fuel and Petrochemical Manufacturers, AFPM), engineering and licensing contractor data, and published consultant studies.

Refinery capacity construction and utilization data

The base capacities for refinery process units are derived principally from EIA's annual *Refinery Capacity Report* (see section D.15) and annual surveys published in the *Oil & Gas Journal*. To represent planned capacity expansion, all announced projects were reviewed but only those that had reached the engineering, construction, or start-up stage were accepted. (Unit capacity is measured in volume per calendar day.) Historical process unit utilization is derived from EIA's *Petroleum Supply Annual*.

Crude oil supply and product demand data

The crude oil supply data are provided by two of the NEMS modules: OGSM, which incorporates a production function to estimate domestic oil production (including for Alaska), and the International Energy Module (IEM), which provides volumes and prices of international crude oil (in the form of supply curves by crude oil type) and non-U.S. crude oil demands (by crude oil type). The IEM also provides corresponding volumes and prices of international petroleum product supply and demand curves that the LFMM uses to determine product imports and exports to and from the United States. Individual crude oil streams for both domestic and imported crude oils are grouped into 11 crude oil categories, differentiated by API gravity, sulfur content, and yield characteristics. These categories are detailed in *Assumptions to the Annual Energy Outlook 2022*.

Non-petroleum feedstocks

Data related to the following non-petroleum feedstocks are discussed in Appendix F:

- Natural gas plant liquids supply (Oil and Gas Supply Module)
- Coal supply curves (Coal Market Module)
- Natural gas prices (Natural Gas Market Module)
- Cellulosic biomass supply curves (Renewable Fuels Module)
- Corn supply and prices (Renewable Fuels Module and LFMM processing)
- Seed oils and bio-greases (Renewable Fuels Module and LFMM processing)

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 (resid)
- LPG
- Naphtha (petrochemical feedstock)
- Petroleum coke
- Ethane
- Propane
- Iso-butane and n-butane
- Natural gasoline
- Propylene
- 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 AFPM, API, and NPC, together with government sources such as U.S. 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.

Product yield and quality blending data

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

- 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).
- Weighted percentage hydrogen: ASTM Method D3343 (replacing D1018)
- Smoke point versus 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.
- Reid vapor pressure (RVP) blending indices have been gathered from several public and in-house sources and have been verified against Gary & Handwerk, p.166.

Research octane number (RON) and motor octane number (MON) blending deltas reflective of base gasoline sensitivity have been drawn from many sources and averaged.

Transportation data

LFMM transportation rates (dollars per volume or mass transported) and capacity data for the United States are represented for transport of crude oil and petroleum products by pipeline, rail, truck, vessel, and barge. Over the years, crude oil and petroleum product pipeline capacity and tariff data have been updated based on research through filings by the Federal Energy Regulatory Commission (FERC), as well as online searches and news releases related to pipeline companies.

Units of measurement

The general rule adopted for input data in the LFMM 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:

- The LP itself uses nominal-year dollars for each iteration of each NEMS year.
- Gases lighter than propane are measured in thousands of barrels of fuel oil equivalent (FOE) per calendar day. These measurements are based on the conversion factors in Table A-1.

Table A-1. British thermal units per barrel for gases lighter than propane

Gas stream	Code	Barrels of fuel oil equivalent per pound	Cubic feet per barrels of fuel oil equivalent
Hydrogen	H2,H2U	.009620	19,646
Hydrogen sulfide	H2S	.001040	10,145
Methane/natural gas	NGS,CC1	.003414	6,917
Ethane	CC2	.003245	3,861
Process gas	PGS	.003245	3,861

- One barrel FOE (fuel oil equivalent) is 6.287 million British thermal units (MMBtu).

The assumed Btu content for other major refinery streams is shown in Table A-2.

Table A-2. British thermal units per barrel for other streams

Stream	Code	Million British thermal units per barrel
Gasoline	(multiple)	5.057
Jet fuel	JTA	5.67
Diesel (ultra-low sulfur diesel)	DSU	5.77
No. 2 heating oil	N2H	5.825
Residual oil	N6I,N6B	6.287
Liquefied petroleum gas	LPG, CC3	3.532
Ethanol	ETH	3.558

- 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/b.
- 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 percentage (using specific gravity) for use in the LP.
- Steam consumption is in pounds per barrel (lb/b). Thus, an activity in Mb/cd consumes steam in thousands of pounds per day (Mlb/day). Steam generation capacity is in millions of pounds per day (MMlb/day). The consumption of 0.00668 fuel oil equivalent barrels per day to raise 1

pound per hour of steam is equivalent to 1225 Btu per pound steam (assuming 70% energy conversion efficiency).
- Electricity consumption is in kWh/b. Generation is in MWh/cd (megawatthours per calendar day).

A.3 Data tables

LFMinset.gdx contains names and content of sets used by the LFMM but not by other NEMS modules. Table A-3 presents the GAMS files and corresponding set names that are generated for the LFMinset.gdx file. Some example sets include:

- 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 formed from streams blended to meet various product-specific quality specifications rather than according to a recipe (diesel, jet, No. 2 heating oil, California BOB, conventional BOB, reformulated BOB, residual fuel oil)
- DistProp, GasProp, ResidProp: set of quality specifications that need to be met for selected distillates, motor gasolines, and residual fuel
- EndProduct, EndProductNGL (alias NGLProduct): set of products that are demanded by the various NEMS demand modules. About equal to the union of sets SpecProd and RecipeProd.
- CoProduct: set of coproducts manufactured incidentally to the production of end products

Table A-3. GAMS files used to make LFMinset.GDX

GAMS file (.gms)	Set names
SetBldStep	BldStep
SetIntStream	Crude, CrudeAll, CoalStr, BioStr, FCOType, NGLInputStr, MethanolInputStr, Purchase_Streams, AltPurchase_Streams, OtherPurchase_Streams, RefInputStr, Fueluse_Streams, EthStreamsRFS, EthStreamNoRFS, EthStream, Utility, LightGases, LightGasesExNaphtha, NaphthaLightBiofuels, NaphthaLightNPF, NaphthaLightPet, NaphthaMedium, NaphthaHeavyBiofuels, NaphthaHeavyNPF, NaphthaHeavyPet, ReformateBiofuels, ReformateNPF, ReformatePet, Alkylate, GasolineCat, GasolinePoly, IsomerateBiofuels, IsomerateNPF, IsomeratePet, PetNaphtha, KeroseneBiofuels, KeroseneNPF, KerosenePet, LightCycleOil, DieselBiofuels, DieselNPF, DieselPet, DieselHeavy, GasOilLight, GasOil, GasOilHeavy, PetDistillate, ResidualOil, Raffinate, PetResid, Solids, NaphthaAndLighter, Int_Misc, IntStream_Other, IntStream
SetInvParam	InvParam
SetLCFS	LCFS_BioImport_PetStream, LCFS_BioImports, LCFS_BioMode, LCFS_BioProcess
SetLrn	LearningProcess, LrnParam, LrnSpeed, LrnPhase, MoreLrnParam
SetMarkup	MarkupFuel, MarkupSector
SetMisc	Period, PrcPeriod, BldPeriod, t, tIdx, CapExpYr, ReportYr, Step
SetNFBaseYr	NFBaseYr
SetProcess	PetroleumProcess, CornProcess, NonCornProcess, EthanolProcess, AltFuel_Process, NPFProcess
SetProcessMode	ProcessMode
SetProcessRisk	BldRiskClass, ProcessRisk
SetProduct	EndProductGas (alias GasProduct), EndProductDist, EndProductResid, EndProductMisc, EndProduct, CoProduct, EthCoproduct, CoProductSales, endProductNGL (alias NGLProduct), RecipeProd, RecipeOut
SetProperty	Property
SetRcpMode	RcpMode
SetRefType	RefType
SetRegionality	Source, DomRefReg, NonDomRefReg, RefReg, ActiveDem, CenDiv, CoalDReg, CoalSReg, CoalDReg_2_Census, NGPL_2_RefRe, State
SetRFSCategory	RFSCategory (alias RFSCategoryA)
SetSector	DieselSector, LPGSector
SetSpecProd	DistSpecprod, GasSpecProd, ResidSpecProd, SpecProd
SetSpecProdProp	GasProp, DistProp, ResidProp
SetStream	StreamOVC, Stream, NoMat, NonCrudeUtil, RecipeInputs, RecipeEnd
SetTranMode	MrineMode, NonMarineMode, TranMode

LFMinput.gdx defines parameters used by the LFMM and created from input data originally stored in a group of Microsoft Excel data files. These Excel files are composed of multiple worksheets (highlighted in

Table A-4). The following are examples of a few parameters in the LFMinput.gdx file that originated in an Excel file.

- ProcessTableCrude: input streams, output yields, and fuel and utility requirements for each Process and ProcessMode represented in the LFMM
- RecipeBlending: a variety of recipe definitions available to produce the products listed in the set RecipeProd
- StreamProp: stream properties (API, sulfur (SPM), octane (CON), etc.) used to meet quality specifications (listed in DistProp, GasProp, and ResidProp) defined by DistSpecMax/Min, GasSpecMax/Min, and ResidSpecMax/Min for blending of products listed in the set SpecProd

Table A-4. Excel files used to make LFMINPUT.GDX

Excel file (.xlsx)	Worksheets
lfblending	Properties, RCP, StreamSpecProd, DieselFrac
lfcapacity	ForImport, OGJ 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, IntReg-to-RefReg Cap, IntReg-to-RefReg Cost, RefReg-to-IntReg Cap, RefReg-to-IntReg Cost, RefReg-to-RefReg Cap Import, RefReg-to-RefReg Cost Import, RefReg-to-Census Cap Import, RefReg-to-Census Cost Import, IntReg-to-RefReg Cap Import, IntReg-to-RefReg Cost Import, RefReg-to-IntReg Cap Import, RefReg-to-IntReg Cost Import, E15MaxPen
lfdistcosts	StateFuelTax, ProductMarkups, FedFuelTax, EnvMarkups
lffeedstock	SPR_Withdraw, Crude_Import_Cap, Crude_Import_Cost, Crude_Export_Cap, Crude_Export_Cost, Allowed_Crude_Use, Crude_Import_Region, Crude_Export_Region, CornPriceExp, CornTranCost, SeedOilQnty, GrainQnty
lfimportpurch	ForImport, BrzAdvEthProd, BrzEthDmd (obsolete as of AEO2020), NonUSEthDmd, FBDImpQuant, FBDImpCoef
lfnonpetroleum	data, ForImport, EDH, EDM, IBA, SEW, NCE, AET, CLE, BPU, BTL, CBL, CBLCCS, FBD, GDT, CTL, CTLCCS, GTL
lfpetcrackers	FCC, RGN, HCD
lfpetcrudeunits	ACU, LTE, VCU, CSU
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, RFSMandates_orig, RFSScores, RFSCategory, RFSWaiver, LCFS_AltVehicles, LCFS_Penalty_Cost, LCFS_Target, LCFS_BioStreams, LCFS_PetStreams, LCFS_BioImports, AB32_CapAdjFactor, AB32_AssistFactor, AB32_BenchFactor, AB32_Control, ULSD_N2H, State_Biodiesel, BiofuelSubsidy
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, H2P

A third file, LFinvest.gdx, contains investment information that we obtained from original data that reside in another set of worksheets in another Microsoft Excel file (lfinvestment.xlsx) listed in Table A-5. The following describes some of the data in the gdx file that originated in the Excel worksheets.

- CapExpSize, CapExpISBL, CapExpLabor: these represent the unit size, ISBL cost, and expected labor associated with building a specific process unit
- InvFactors, InvLoc: list of multipliers associated with added investment costs as a function of base capital cost
- FedTax, StateTax: tax rates used during investment calculations
- LearningData: data specifically used to adjust the calculated capital investment to represent cost improvement as a result of learning

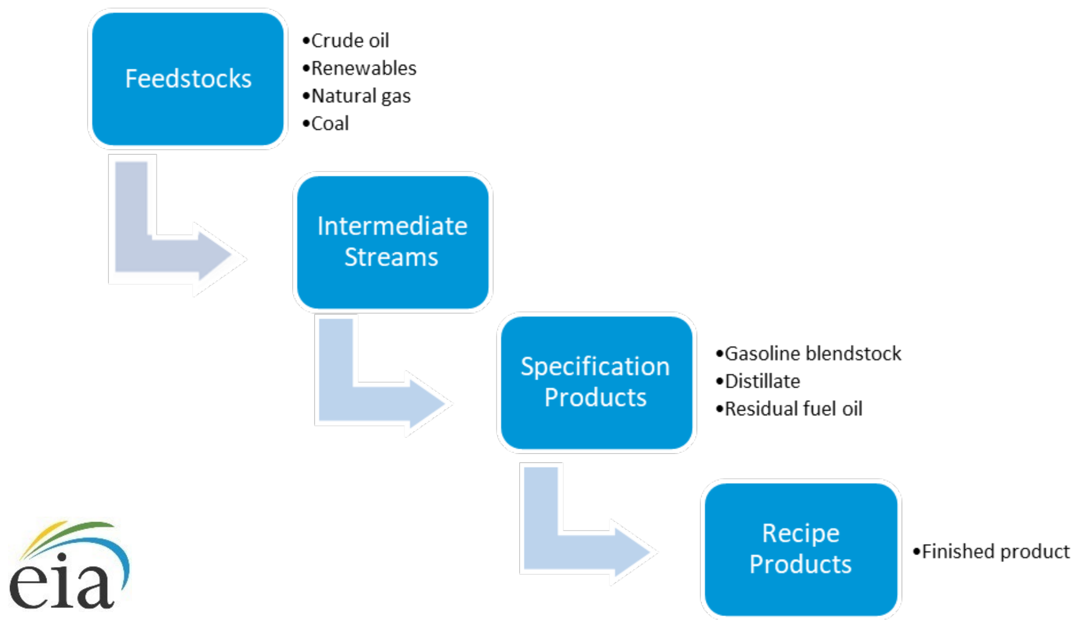
Table A-5. Excel files used to make LFinvest.GDX

Excel file (.xlsx)	Worksheets
lfinvestment	CapCostImp, NFImport, StateTax, FedTax, RegionalData, InvestmentFactors, Capital Costs, N-F Indices, Learning, Learning2, AFGrowthRates, AFBldSteps (and OptimismWorksheet)

Appendix B. Mathematical Description of Model

The LFMM models the transformation of feedstock into intermediate streams that are blended to create intermediate and finished products (Figure B-1). The LFMM models two types of blending: specification-blending and recipe-blending for intermediate and finished products. In specification-blending, intermediate streams are blended such that the resulting specification-product stream (Table B-1) meets certain quality restrictions (or specifications). For example, various petroleum streams are mixed in different proportions to make a gasoline blendstock that meets sulfur limits, RVP requirements, benzene restrictions, and other required specifications. In recipe-blending, intermediate streams (including specification-product streams) are blended in fixed proportions to make final products, such as E10 gasoline blended from 90% gasoline blendstock and 10% denatured ethanol.

Figure B-1. Flow chart of stream flows



Source: U.S. Energy Information Administration, Office of Energy Analysis

Table B-1. Specification-blended intermediate products

Specification-product	Description
Gasoline blendstock	
CaRBOB	California reformulated blendstock
CBOB	Conventional blendstock
RBOB	Reformulated blendstock
Distillate	
CarbDSU	California ultra-low sulfur diesel
DSL	Low-sulfur diesel
DSU	Ultra-low sulfur diesel
JTA	Jet fuel
N2H	No. 2 heating oil
Residual fuel oil	
N6B	No. 6 fuel oil, high sulfur
N6I	No. 6 fuel oil, intermediate sulfur

The LFMM models 79 recipes for blending recipe-products. Some recipes have single input streams, such as the recipes for the various hydrocarbon gas liquids. Other recipes comprise multiple input streams, such as RCP_RFG10a, which blends 90% RBOB gasoline blendstock and 10% denatured corn ethanol to make recipe-product RFGout (Table B-2).

Table B-2. Recipe-blended (finished) products

Recipe-product	Description
Distillate	
CarbDSUout	Diesel, ultra-low sulfur, California, and renewable diesel
DSLout	Diesel, low-sulfur, and renewable diesel
DSUout	Diesel, ultra-low sulfur, and renewable diesel
JTAout	Jet fuel
N2Hout	No. 2 heating oil
Gasoline-like	
CaRBOBout	E10 from CaRBOB blendstock and ethanol
CFG15out	E15 from CBOB blendstock and ethanol
CFGb16out	Bu16 from CBOB blendstock and biobutanol
CFGout	E10 from CBOB blendstock and ethanol
E85out	E85 from CBOB blendstock and ethanol
RFG15out	E15 from RBOB blendstock and ethanol
RFGb16out	Bu16 from RBOB blendstock and biobutanol
RFGout	E10 from RBOB blendstock and ethanol
Residual fuel oil	
N6Bout	No. 6 fuel oil, high-sulfur
N6Iout	No. 6 fuel oil, low-sulfur
Hydrocarbon gas liquids	
CC2out	Ethane
LPGout	LPG (propane)
UC3out	Propylene
NC4out	Normal butane
IC4out	Isobutane
NATout	Natural gasoline / pentanes+
Other	
ASPHout	Asphalt / road oil
AVGout	Aviation gasoline
BTXout	Benzene-toluene-xylene
COKout	Petroleum coke
LUBout	Lubricants
PCFout	Petrochemical feedstock

The LFMM is formulated as a linear program (LP) that is implemented in GAMS. The GAMS code has been structured based on functionality:

- lfshell.gms is the main GAMS program in LFMM that organizes the code structure (calls other GAMS code that prepares the LP to be solved and extracts results), sets bounds in the LP,

converts preprocessed data to the net present value (NPV) format required by the LP, and instructs the LP to solve.
- lf_nem.gms defines the data sets and parameters and reads the relevant NEMS data provided by other NEMS modules.
- lfprep.gms also defines data sets and parameters, reads in LFMM-specific data, and prepares the data needed to set up the LP.
- lfmodel.gms defines the objective function, decision variables, and constraints in the LP.
- lfreport.gms extracts solution results from the LP and writes results to be sent to other NEMS modules.

Three distinct time periods are represented in the LFMM LP: Period 1 (current NEMS year), Period 2 (next NEMS year), Period 3 (next 19 NEMS years after Period 2). Period 1 represents operations based on existing capacity, without the option to build additional capacity. Period 2 and Period 3 represent operations based on existing capacity along with the capability to add new capacity. The Period 1 LP is executed every NEMS iteration (in other words, multiple times each NEMS year); the LP representing Period 2 and Period 3 is executed in the last iteration (after NEMS sets FCRL=1) of each NEMS year. Period 2 capacity expansion decisions from the last iteration of a particular NEMS year are added to the Period 1 existing capacity for the following NEMS year. Period 3 capacity expansion decisions are discarded; however, Period 3 representation helps to inform the capacity expansion decision made in Period 2 by representing the economic impact over the life of the new expansion.

The following information serves as a glossary of terms and abbreviations used in this section to define the LFMM LP model.

Notation

Table B-3. Sets

Set name	Description
Biostr	= biomass feedstock types
Crude	= crude oil types (based on API gravity and sulfur content)
EthStream	= ethanol types (from corn, sugar cane, cellulosic, etc.)
EndProductGas	= gasoline products, a subset of RecipeProd
IntStream	= all intermediate streams (including streams blended into product) and feedstock streams (including crude oil and biofuel feedstocks), no product streams
IntStream_Other	= all intermediate streams, but not feedstock or products streams
RecipeProd	= recipe-blended products
RFSCategory	= Renewable Fuel Standard categories: total, advanced, biomass-based diesel, cellulosic
SpecProd	= specification-blended products

Table B-4. Indexes

Index	Description
b	= biomass feedstock type
c	= crude oil type
cp	= coproduct type
$\hat{e}$	= emission type (sulfur dioxide, mercury)
j	= general index for streams, which can take values for biodiesel *b*, crude oil *c*, ethanol *e*, product *p*, or stream type $\hat{s}$
m	= transportation mode
p	= product
$\hat{p}$	= process mode
q	= specification property type
r, r'	= region
$\hat{r}$	= recipe
s	= step on supply curve or demand curve
$\hat{s}$	= stream type, including *b*, *c*, *j*, *p*, *u*
u	= utility type

Table B-5. Parameters used in the objective function

Parameter	Description
Cbim_{rs}	= cost of FAME (fatty acid methyl ester) biodiesel (FBD) imports into region *r* purchased on step *s* of the supply curve (FBDImpPrice)
Crim_{rs}	= cost of renewable diesel (RDH) imports into region *r* purchased on step *s* of the supply curve (RDHImpPrice)
Cbr_{s}	= cost of sugarcane (advanced) ethanol on import supply step *s* (EthImpSupPrc)
Cbrex_{r}	= transport cost per unit export of material in stream $j \in \mathrm{E}$ from region *r* to the world (mostly Brazil) (TranCostToBrazil)
Cbrim_{r}	= transport cost per unit import of material in stream $j \in \mathrm{E}$ to region *r* from the world (mostly Brazil) (TranCostFromBrazil)
$\mathrm{Cbld}_{\hat{p}r}$	= net present value of capital costs and fixed operating cost of newly-added capacity of process mode $\hat{p}$ in region *r* (BuildCost)
$\mathrm{Ccr1}_{s}$	= base cost of crude oil at step *s* of the supply curve, dollars per barrel (CrudePriceTotal)
$\mathrm{Ccr2}_{cs}$	= incremental cost of crude oil type *c* at step *s* of the supply curve, dollars per barrel (CrudePriceIncremental)
Ccrex_{crs}	= cost to export crude oil type *c* from region *r* at step *s,* dollars per barrel (CrudeExportCost)
Ccrim_{crs}	= cost to import crude oil type *c* from region *r* at step *s,* dollars per barrel (CrudeImportCost)
Ccrint_{cs}	= cost of non-U.S. demand for crude oil type *c* at step *s,* dollars per barrel (NonUSCrudeDemandPrice)
$\mathrm{Cfxoc}_{\hat{p}r}$	= fixed operating cost of existing capacity of process mode $\hat{p}$ in region *r* (FXOCCost)
$\mathrm{Cm}_{\hat{s}r's}$	= cost of stream $\hat{s}$ purchased in region r' at step *s* of the supply curve (BiomassPrc, CoalPrc)
Cpex_{pr}	= cost of exports of product *p* from region *r,* dollars per barrel (ImportPrice, NGLImportCost, GlobalImpPrice)
Cpim_{pr}	= cost of imports of product *p* to region *r,* dollars per barrel (ExportPrice, NGLExportCost)
Cpim_{ps}	= cost to purchase imported product *p* at step *s,* dollars per barrel (ImportPrice)
$\mathrm{Cproc}_{\hat{p}r}$	= cost per unit of activity on process mode $\hat{p}$ in region *r*, typically in dollars per barrel of output (OpVarCost)
$\mathrm{Cpur}_{\hat{s}rs}$	= cost to purchase stream $\hat{s}$ in region *r* on step *s* of the supply curve (RefInpPrc)
$\mathrm{Crcp}_{\hat{r}}$	= cost per unit of activity on recipe $\hat{r}$ (RecipeOVC), typically in dollars per barrel of output.
$\mathrm{Ctran}_{jrr'}$	= cost to transport material in stream *j* from region *r* to region r' (REFtoREFTranCost, INTtoREFTranCost, REFtoINTTranCost, REFtoCDTranCost)
Cu_{ur}	= cost per unit of utility *u* used in region *r* (UtilityPrice). Units of measure vary.
Rpex_{ps}	= revenue per unit of product *p* on each step *s* of the product export demand curve, dollars per barrel (ExportPrice)
Rce_{s}	= revenue per unit of corn ethanol on each step *s* of the ethanol export demand curve, typically in dollars per barrel (EthExpDmdPrc)
Rcp_{pr}	= revenue per unit of coproduct *cp* in region *r*, typically in dollars per barrel (CoproductPrice)

Note: Unless otherwise indicated, objective function parameters are in nominal dollars per barrel (nom$/b).

Table B-6. Parameters used in constraints

Parameter	Description
$A_{\hat{p}j}$	= units of *j* produced or consumed per unit of activity of process mode $\hat{p}$ (ProcessTable)
$A_{\hat{p}u}$	= utility *u* used per unit of activity of process mode $\hat{p}$. Units of measure vary.
D_{pr}	= demand for product *p* in region *r*
$G_{\hat{s}r}$	= electricity market demand for stream $\hat{s}$ in region r. Units of measure = billion British thermal units per day
$H_{\hat{e}r\hat{s}}$	= emissions of stream type $\hat{e}$ per unit of coal stream $\hat{s}$ purchased in region *r*. Units of measure vary (for example, 1,000 tons of sulfur dioxide per MMBtu of coal; 0.001 tons mercury per MMBtu of coal).
$LCFSfactor_{p\hat{r}}$	= amount by which product *p* produced by recipe $\hat{r}$ exceeds the California Low Carbon Fuel Standard (LCFS) target carbon intensity
$LCFSfactor_{p,lg}$	= amount by which landfill gas exceeds the California Low Carbon Fuel Standard (LCFS) target carbon intensity
$MaxE15frac$	= maximum fraction of total motor gasoline demand that can be E15
N	= non-U.S. demand for ethanol
P_{cr}	= domestic production of crude oil type *c* in region *r*
$\hat{P}_{q\hat{s}}$	= level of property *q* in stream $\hat{s}$ (StreamProp)
$\hat{P}_{qp}^{max}$	= maximum level of property *q* in product *p.* Units of measure vary.
$\hat{P}_{qp}^{min}$	= minimum level of property *q* in product *p.* Units of measure vary.
$R_{\hat{s}\hat{r}}$	= volume of stream $\hat{s}$ in recipe $\hat{r}$
$RFSScore_{k\hat{s}}$	= credits (ethanol-equivalent volume) of stream $\hat{s}$ toward Renewable Fuel Standard (RFS) category *k*
$RFSTarget_k$	= target volume for RFS category *k*, in ethanol-equivalent volume
$T_{rr'}$	= maximum volume of ethanol that can be transported from region *r* to region *r'*
$T_{mrr'}$	= maximum (non-ethanol) volume that can be transported via mode *m* from region *r* to region *r'*
UE_{rs}	= upper limit on total exports of crude oil from region *r*
UI_{rs}	= upper limit on total imports of crude oil into region *r*
$UE_{rr'}$	= upper limit on product shipments (exports) from region *r* to international region r'
$UI_{r'r}$	= upper limits on product shipments (imports) from international region $r'$to region *r*

Note: Unless otherwise indicated, constraint parameters are in thousands of barrels per day (Mb/d). The corresponding GAMS parameter name is listed in parentheses following each parameter definition.

Table B-7. Decision variables

Variable	Description
a_{ur}	= amount of utility *u* used in region *r* (UTILPURCH)
$b_{\hat{s}r}$	= amount of stream $\hat{s}$ that is purchased and then used in region *r* (REFPURused)
cp_{pr}	= total coproduct *p* produced in region *r* (COPRODUCTS)
$d_{\hat{s}rs}$	= amount of stream $\hat{s}$ in region *r* that is purchased on step *s* of the supply curve (REFPURCH)
e_{pr}	= exports of product *p* from region *r* (EXPORTS)
e_{crs}	= exports of crude oil type *c* from region *r* at step *s* (CRUDEEXPORT)
e_{ps}	= total exports of product *p* to the world on step *s* of the demand curve (PRODEXP)
$E_{\hat{p}r}$	= usage of existing capacity of process mode $\hat{p}$ in region *r*. Upper-bounded by the existing capacity. (OPERATECAP)
$\hat{E}_{\hat{p}r}$	= newly added capacity of process mode $\hat{p}$ in region *r*. Set to zero for Period 1. (BUILDS)
$f_{\hat{e}r}$	= emissions of type $\hat{e}$ in region *r*
g_r	= volume of sugar cane (advanced) ethanol imported from the world into region *r* (ETHIMP)
$\hat{g}_r$	= volume of corn ethanol exported to the world from region *r* (ETHEXP)
h_{pr}	= recipe product *p* available in region *r* (TOTPROD)
lg_{pr}	= landfill gas available to recipe product *p* carbon intensity target in region *r* (LCFS_LandfillGas)
i_{rs}	= imports of biodiesel into region *r* purchased on step *s* of the supply curve (BIODIMP)
i_{pr}	= total imports of product *p* into region *r* (IMPORTS, BIODIMPref, RENEWDIMPref)
i_{crs}	= imports of crude oil type *c* into region *r* at step *s* (CRUDETRANS)
$\hat{\imath}_{ps}$	= total imports of product *p* from the world at step *s* (PRODIMP)
j_{rs}	= imports of renewable diesel into region r purchased on step s of the supply curve (RENEWDIMP)
ke_s	= total world demand for corn ethanol exported from the United States at step *s* (ETHEXPUSdmd)
ki_s	= total sugar cane (advanced) ethanol available for import to the United States at step *s* (ETHIMPUSsup)
$\widehat{m}_{\hat{s}r'r}$	= amount of stream type $\hat{s}$ purchased in region r' used for liquid fuels production in region *r* (BIOXFER, COALXFER)
$m_{\hat{s}r's}$	= amount of stream $\hat{s}$ purchased in region r' at step *s* of the supply curve (BIOPURCH, COALPURCH)
n_{cs}	= total non-U.S. demand for crude oil type *c* at step *s* (CRUDENONUS)
$t_{jrr'}$	= shipments of material in stream *j* from region *r* to region r' (RefRefTRAN, PRODImpTRAN, PRODExpTRAN)
w'_s	= total world consumption of all crude oil types at step *s* of the total supply curve (CRUDETOTAL)
w_{cs}	= total world purchases of crude oil type *c* at step *s* of the supply curve (CRUDEPURCH)
$x_{\hat{p}r}$	= activity on process mode $\hat{p}$ in region *r* (PROCMODE)
$\hat{x}_{r\hat{r}}$	= activity on recipe $\hat{r}$ in region *r* (RECIPEMODE)
$\check{x}_{rp}$	= volume of recipe-product *p* blended in region *r* (RECIPETOPROD)
$y_{jr\hat{r}}$	= volume of stream *j* recipe-blended into recipe-products in region *r* via recipe $\hat{r}$ (ToRECIPEBLEND)
$z_{\hat{s}pr}$	= volume of stream $\hat{s}$ specification-blended into specification-product *p* in region *r* (ToSPECBLEND)

Note: Unless otherwise indicated, decision variables are in thousands of barrels per day (Mb/d). Corresponding GAMS names are in parentheses after each variable description. Variables indexed by step *s* have upper bounds.

Objective function

The objective function represents net annual cost in thousands of nominal dollars per calendar day. In the formulation below, multiple summation indexes are suppressed. In actuality, each term is summed over all the indexes of the summand. The LP has three periods over which costs are considered: Period 1 represents the current NEMS year (for operating decisions), Period 2 represents the next NEMS year (for capacity expansion decisions), and Period 3 represents the subsequent 19 years as a look-ahead period that enables capital expansion to meet upcoming demands while avoiding stranding capital assets. The objective function minimizes net annual costs, as defined below.

Minimize total cost minus applicable revenue from exports and coproduct sales =

Fixed operating cost of processing units

$$\sum \mathrm{Cfxoc}_{\hat{p}r} E_{\hat{p}r}$$

Build cost of processing units

$$+\sum \mathrm{Cbld}_{\hat{p}r} \hat{E}_{\hat{p}r}$$

Variable operating cost of processing units

$$+\sum \mathrm{Cproc}_{\hat{p}r} x_{\hat{p}r}$$

Crude oil purchase cost

$$+\sum \mathrm{Ccr1}_{s} w_s' \ +\sum \mathrm{Ccr2}_{cs} w_{cs}$$

Transport cost to export crude oil and import crude oil

$$+\sum \mathrm{Ccrex}_{crs} e_{crs} \ +\sum \mathrm{Ccrim}_{crs} i_{crs}$$

Cost of crude oil to non-U.S. users

$$+\sum \mathrm{Ccrint}_{cs} n_{cs}$$

Cost to purchase imported sugar cane (advanced) ethanol from the world

$$+\sum \mathrm{Cbr}_s ki_s$$

Cost to transport sugar cane (advanced) ethanol imported from the world

$$+\sum \mathrm{Cbrim}_r g_r$$

Cost to transport corn ethanol exported to the world

$$+\sum \mathrm{Cbrex}_r \hat{g}_r$$

Utility costs

$$+\sum \mathrm{Cu}_{ur} a_{ur}$$

Cost of non-crude oil refinery input streams and interregional crude oil and petroleum product transport

$$+\sum \mathrm{Cpur}_{\hat{s}rs} d_{\hat{s}rs}$$

$$+\sum \mathrm{Cm}_{\hat{s}r's} m_{\hat{s}r's} + \sum \mathrm{Crcp}_{\hat{r}} \hat{x}_{r\hat{r}} + \sum \mathrm{Ctran}_{jrr'} t_{jrr'}$$

Cost of purchased petroleum products imported from the world supply curve

$$+\sum \mathrm{Cpim}_{ps} \hat{\imath}_{ps}$$

Transport cost of U.S. petroleum product imports and exports

$$+\sum \mathrm{Cpim}_{pr} i_{pr} + \sum \mathrm{Cpex}_{pr} e_{pr}$$

Cost of FBD biodiesel imports

$$+\sum \mathrm{Cbim}_{rs} i_{rs}$$

Cost of RDH renewable diesel imports

$$+\sum \mathrm{Crim}_{rs} j_{rs}$$

Revenue from coproduct sales

$$-\sum \mathrm{Rcp}_{pr} cp_{pr}$$

Revenue from product exports

$$-\sum \mathrm{Rpex}_{ps} e_{ps}$$

Revenue from corn ethanol exports

$$-\sum \mathrm{Rce}_{s} ke_{s}$$

Crude oil-related constraints

Table B-8. Crude oil-related constraints

Constraint description	GAMS cross reference
Crude oil balance	CrudeBalance
Crude oil import limit	CrudeImportLimit
Crude oil export limit	CrudeExportLimit
Crude oil export limit to Sarnia: 393,000 barrels per day	CrudeExportLimit3CAN
World crude oil supply	WorldCrudeSup
Foreign crude oil supply curve	CrudeSupCurveForeign
Limited re-exports of crude oil	ExportDomCrudeOnly

Crude oil balance

The volume of each crude oil type processed in a region is equal to domestic production plus net imports plus net shipments from other regions.

$$\sum_{\hat{p}} A_{\hat{p}c} x_{\hat{p}r} = P_{cr} + \sum_{s} i_{crs} - \sum_{s} e_{crs} + \sum_{r'} (t_{cr'r} - t_{crr'}) \qquad \text{for all } c, r$$

World crude oil supply

Total world supply of all crude oils equals non-U.S. supply plus U.S. production.

$$\sum_{s} w'_{s} = \sum_{c} \sum_{s} n_{cs} + \sum_{c} \sum_{r} P_{cr}$$

Foreign crude oil supply

Total world consumption of each crude oil type equals non-U.S. consumption plus net imports to the United States.

$$\sum_{s} w_{cs} = \sum_{s} n_{cs} + \sum_{r} \sum_{s} i_{crs} - \sum_{r} \sum_{s} e_{crs} \qquad \text{for all } c$$

Crude oil import limit

Total crude oil imports are limited on each step of the international crude oil supply curve.

$$\sum_{c} i_{crs} \leq UI_{rs} \qquad \text{for all } r, s$$

Crude oil export limit

Total crude oil exports are limited on each step of the international crude oil demand curve.

$$\sum_{c} e_{crs} \leq UE_{rs} \qquad \text{for all } r, s$$

Crude oil export limit to Sarnia

API>40 crude oil exports to Sarnia, Canada, from LFMM region 3 are limited to 393,000 b/d.

$$\sum_{c} e_{crs} \leq 393 \qquad \text{for all } r, s$$

Limit re-exports of crude oil

Any U.S. crude oil exports from a particular region must be from domestic production in that region or shipments from a different U.S. region, rather than immediate re-exports of imported crude oil.

$$P_{cr} + \sum_{r'} t_{cr'r} \leq \sum_{s} e_{crs} \qquad \text{for all } c, r$$

Product imports and exports

Table B-9. Product import and export constraints

Constraint description	GAMS cross reference
Product import balance	ProdImpBalance
Product import supply curve	ProdImpSupCurve
Product import transportation limit	ImpTranLimit
Product export balance	ProdExpBalance
Product export demand curve	ProdExpSupCurve
Product export transportation limit	ExpTranLimit

Product export balance

The total exports of a product to an international region equals the sum of exports from all domestic regions.

$$e_{pr} = \sum_{r'} t_{prr'} \qquad \text{for all } p, r$$

Product export demand curve

The total exports of a product to an international region equals the sum of exports over all steps of the demand curve.

$$\sum_{r} t_{prr'} = \sum_{s} \hat{e}_{pr's} \qquad \text{for all } p, r'$$

Product export transportation limit

$$\sum_{p} t_{prr'} \leq UE_{rr'} \qquad \text{for all } r, r'$$

Product import balance

The total imports of a product to a domestic region equals the sum of imports to the region from all international regions.

$$i_{pr} = \sum_{r'} t_{pr'r} \qquad \text{for all } p, r$$

Product import supply curve

The total imports of a product from an international region equals the sum of imports from the region over all steps of the supply curve.

$$\sum_{r} t_{pr'r} = \sum_{s} \hat{\imath}_{pr's} \qquad \text{for all } p, r'$$

Import transportation limit

$$\sum_{p} t_{pr'r} \leq UI_{r'r} \qquad \text{for all } r, r'$$

Ethanol trade flow

Table B-10. Ethanol trade constraints

Constraint description	GAMS cross reference
Balance on corn ethanol exports from United States	EthExpUSBal
Balance on advance ethanol imports to United States	EthImpUSBal

Balance on corn ethanol exports from the United States

The sum of corn ethanol exported from the United States is equal to total foreign demand for corn ethanol from the United States.

$$\sum_{r} e_{jr} = \sum_{s} ke_{s} \qquad where\ j = corn\ ethanol$$

Balance on advanced ethanol imports to the United States

Total foreign supply of sugar cane (advanced) ethanol on all steps of the supply curve is equal to the sum of sugar cane ethanol imported to the United States.

$$\sum_{s} ki_{s} = \sum_{r} i_{jr} \qquad \text{where } j = \text{sugar cane (advanced) ethanol}$$

Ethanol flows

Table B-11. Ethanol flow constraints

Constraint description	GAMS cross reference
Ethanol balance	EthBalance

Ethanol balance

The total volume of ethanol produced in a region plus net imports plus net shipments from other domestic regions is equal to the total amount blended into finished products (gasoline and E85).

$$\sum_{\hat{p}} A_{\hat{p}j} x_{\hat{p}r} + \left(i_{jr} - e_{jr}\right) + \sum_{r'} \left(t_{jr'r} - t_{jrr'}\right) = \sum_{\hat{r}} y_{jr\hat{r}} \qquad \text{for all } r, j \in E$$

Refinery input streams (non-crude oil)

Table B-12. Refinery input stream constraints

Constraint description	GAMS cross reference
Refinery input balance	RefInpBalance
Refinery purchase balance	RefPurchBal
Refinery balance of coal and bio streams	BioRefRegBal, CoalRefRegBal
Supply balance of coal and bio streams	BioBalance, CoalDemBalance, CoalSupBalance
FBD biodiesel balance	BiodieselBalance
RDH renewable diesel balance	RenewDieselBalance
Coal emissions (optional)	SO2EmisBal, HGEmisBal

Refinery input balance

Refinery input streams that are purchased in a region must be consumed by a refinery process or used in recipe-blending or specification-blending in that region.

$$b_{\hat{s}r} = \sum_{\hat{p}} A_{\hat{p}\hat{s}} x_{\hat{p}r} + \sum_{\hat{r}} y_{\hat{s}r\hat{r}} + \sum_{p} z_{\hat{s}pr} \qquad \text{for all } r, \hat{s} \in \text{InputStream}$$

Refinery purchase balance

The total amount of a purchased refinery input includes the amount purchased on all steps of a domestic supply curve plus net imports.

$$b_{\hat{s}r} = \sum_{s} d_{\hat{s}rs} + i_{\hat{s}r} - e_{\hat{s}r} \qquad \text{for all } r, \hat{s}$$

Refinery balance of coal and bio streams

$$\sum_{r'} \widehat{m}_{\hat{s}r'r} \geq \sum_{\hat{p}} A_{\hat{p}\hat{s}} x_{\hat{p}r} \qquad \text{for all } \hat{s}, r$$

Supply balance of coal and bio streams

$$\sum_{s} m_{\hat{s}r's} = G_{\hat{s}r'} + \sum_{r} \widehat{m}_{\hat{s}r'r} \qquad \text{for all } r', \hat{s}$$

FBD biodiesel balance

$$i_r = \sum_{s} i_{rs} \qquad \text{for all } r$$

RDH renewable diesel balance

$$j_r = \sum_{s} j_{rs} \qquad \text{for all } r$$

Coal emissions

$$f_{\hat{e}r} \geq \sum_{\hat{s}} \sum_{r'} H_{\hat{e}r\hat{s}} \widehat{m}_{\hat{s}rr'} \qquad \text{for all } \hat{e}, r$$

Miscellaneous constraints

Table B-13. Miscellaneous constraints

Constraint description	GAMS cross reference
Utility balance	UtilBalance
Stream balance	StreamBalance
Capacity balance	CapacityBalance
Limit regional growth in ADU condensers (LTE)	MaxLTE
Limit national growth in new technologies	RestrictGrowth
Limit national growth in CTL and CBTL (carbon capture)	RestrictGrowthCTL, RestrictGrowthCBL
Limit national growth in CTL and GTL, combined	RestrictGrowthCTLGTL
Specification-blend property—maximum	GasSpecQualMax, DistSpecQualMax, ResidSpecQualMax
Specification-blend property—minimum	GasSpecQualMin, DistSpecQualMin, ResideSpecQualMin
Specification-blend balance	GasSpecBalance, DistSpecBalance, ResidSpecBalance
Recipe balance	RecipeBalance
Recipe transfer	RecipeTransfer, RecipeBPTransfer
Interregional transport	REFtoREFTran
Combined recipe-product supply	CombineSupply
Demand satisfaction	RecipeDemands,RecipeEndBal, NGLDmd, NGLEndBal, TotProdTran,REFtoCDTran,REFtoCDCap, REFtoREFCapMB
Maximum E15	E15Max
OGSM CO_2 demand balance	OGSM_CO2_Demand
LFMM CO_2 carbon capture and sequestration (CCS) balance	CO2CCSBalance

Utility balance

$$a_{ur} = \sum_{\hat{p}} A_{\hat{p}u} x_{\hat{p}r} \qquad \text{for all } r, u$$

Stream balance

Intermediate streams that are produced in a region, plus net imports, and that are not otherwise consumed in a refinery process must be used in recipe-blending or specification-blending in that region.

$$\sum_{\hat{p}} A_{\hat{p}\hat{s}} x_{\hat{p}r} + i_{\hat{s}r} - e_{\hat{s}r} = \sum_{\hat{r}} y_{\hat{s}r\hat{r}} + \sum_{p} z_{\hat{s}pr} \qquad \text{for all r}, \hat{s} \in \text{IntStream}$$

Capacity balance

Period 1

$$x_{\hat{p}r} \leq E_{\hat{p}r} \qquad \text{for all } \hat{p}, r$$

Periods 2 and 3

$$x_{\hat{p}r} \leq E_{\hat{p}r} + \hat{E}_{\hat{p}r} \qquad \text{for all } \hat{p}, r$$

Limit regional growth in ADU condensers (LTE), Periods 2 and 3 only

For ADU condensers, regional expansion is limited to regional-specific $maxBld_r$ every model year.

$$\hat{E}_{\hat{p}r} \quad \leq maxBld_r \qquad \text{for all r}, \hat{p} = LTE$$

Limit national growth in new technologies, Periods 2 and 3 only

For each new technology, total U.S. expansion is limited to maxBld every model year.

$$\sum_{r} \hat{E}_{\hat{p}r} \quad \leq maxBld \qquad \text{for all } \hat{p} = new\ tech$$

Limit national growth in CTL and CBTL (carbon capture), Periods 2 and 3 only

For CTL and CBTL separately, total U.S. expansion is limited to maxBld every model year.

$$\sum_{r} \hat{E}_{\hat{p}r} \quad \leq maxBld \qquad \text{for all } \hat{p} = CTL, CTLCCS, CBL, CBLCCS$$

Limit national growth in CTL and GTL, Periods 2 and 3 only

For CTL and GTL combined, total U.S. expansion is limited to maxBld every model year.

$$\sum_{r} \hat{E}_{\hat{p}r} \quad \leq maxBld \qquad \text{for all } \hat{p} = CTL, CTLCCS, GTL$$

Specification-blend property—maximum

For every specification-product property subject to a maximum level, the volume-weighted property of all streams specification-blended into that specification-product may not exceed the maximum level.

$$\sum_{\hat{s}} \hat{P}_{q\hat{s}} z_{\hat{s}pr} \leq \sum_{\hat{s}} \hat{P}_{qp}^{max} z_{\hat{s}pr} \qquad \text{for all } q, r, \qquad p \in \text{SpecProd}$$

Specification-blend property—minimum

For every specification-product property subject to a minimum level, the volume-weighted property of all streams specification-blended into that specification-product may not be less than the minimum level.

$$\sum_{\hat{s}} \hat{P}_{q\hat{s}} z_{\hat{s}pr} \geq \sum_{\hat{s}} \hat{P}_{qp}^{min} z_{\hat{s}pr} \qquad \text{for all } q, r, \qquad p \in \text{SpecProd}$$

Specification-blend balance

All specification-blended products must eventually be used in recipe-blending.

$$\sum_{\hat{s}} z_{\hat{s}pr} = \sum_{\hat{r}} y_{pr\hat{r}} \qquad \text{for all } r, p \in \text{SpecProd}$$

Recipe balance

$$y_{\hat{s}r\hat{r}} = R_{\hat{s}\hat{r}} \hat{x}_{r\hat{r}} \qquad \text{for all } \hat{s}, r, \hat{r}$$

Recipe transfer

$$\breve{x}_{rp} = \sum_{\hat{r}} R_{\hat{s}\hat{r}} \hat{x}_{r\hat{r}} \qquad \text{for all } \ r, \hat{s} = p \in \text{RecipeProd}$$

Interregional transport

$$\sum_{\hat{s}} t_{\hat{s}rr'} \leq T_{mrr'} \qquad \text{for all } \ r, r'$$

Combine recipe-product supply

$$h_{pr} = \breve{x}_{rp} + i_{pr} - e_{pr} + \sum_{r'} \left(t_{pr'r} - t_{prr'} \right) \qquad \text{for all } r, p \in \text{RecipeProd}$$

Demand satisfaction

$$h_{pr} = D_{pr} \qquad \text{for all } r, \qquad p \in \text{RecipeProd}$$

Maximum E15

The fraction of the total motor gasoline market that can be E15 is subject to an exogenous maximum value. This value changes over time, but the year subscript is suppressed in the equation.

$$\sum_{r} h_{\text{E15},r} \leq MaxE15frac * \sum_{\substack{p \in \\ \text{Gasoline}}} \sum_{r} h_{pr}$$

LFMM CO_2 CCS balance

Carbon dioxide produced at CTL and CBTL facilities, captured, and compressed for sequestration in an LFMM region (r’) must be either sent to saline aquifers for storage or transferred to OGSM regions (r̂) to meet CO_2 demand for enhanced oil recovery.

$$\sum_{r'\hat{p}} A_{\hat{p}\hat{s}} x_{\hat{p}r'r} = \sum_{\hat{r}} xTLeor_{\hat{s}r\hat{r}} + CO2saline_r \quad \text{for all r}, \hat{s} = CO2, \hat{p} = CTLCCS, CBLCCS$$

OGSM CO_2 demand balance

Enhanced oil recovery demand for CO_2 in an OGSM region is satisfied from multiple sources: CO_2 produced at CTL and CBTL facilities (r) and transferred to OGSM regions (r̂) and CO_2 produced from a list of other sources (including ammonia plants, cement plants, power plants, etc.) in this (r̂) and other OGSM regions (r'). The LFMM LP includes a safety valve, not shown here, that allows purchase of CO_2 to ensure that the LP is feasible.

$$\sum_{r'} OTHeor_{\hat{s}r'\hat{r}} + \sum_{r} xTLeor_{\hat{s}r\hat{r}} = CO2eorDmd_{\hat{r}} \quad \text{for all } \hat{r}, \hat{s} = CO2$$

Policy constraints

Table B-14. Policy constraints

Constraint description	GAMS cross reference
RFS requirements	RFSConstraintsPRD, RFSConstraintsRQM
LCFS requirements	LCFS_Biofuel, LCFS_Petroleum, LCFS_LandfillGasConstr
AB32 requirements	AB32_Constraint

RFS requirements

The total amount of credits earned from production of RFS-compliant biofuels must be at least as great as the adjusted RFS target.

$$\sum_{r} \sum_{\hat{p}} \sum_{\hat{s}} RFSScore_{k\hat{s}} A_{\hat{p}\hat{s}} x_{\hat{p}r} \geq RFSTarget_k \quad \text{for all } k \in \text{RFSCategory}, A < 0$$

LCFS requirements

The total carbon intensity of motor fuels (gasoline and diesel) sold in California must be lower than the (adjusted) target carbon intensity. This factor is represented by two constraints, one for each recipe product (p): gasoline and diesel. The difference in carbon intensity of each recipe stream and its recipe product target must be less than or equal to zero. Landfill gas (lg) is counted toward either (not both) recipe product targets. Thus, a balance row for landfill gas prevents the total available from being exceeded. The LFMM LP includes a safety valve, not shown here, that allows purchase of carbon credits to ensure that the LP is feasible.

$$\sum_{\hat{r}} LCFSfactor_{p\hat{r}} \; h_{pr} + LCFSfactor_{p,lg} \; lg_{pr} \leq 0 \quad \text{for } r = \text{California}, p \in \text{RecipeProd}$$

$$\text{(gasoline and diesel)}$$

$$\sum_{p} lg_{pr} = Landfill\ gas\ total_r \quad \text{for } r = \text{California}$$

Appendix C. Bibliography

The LFMM mid-term model development web page includes a section on:

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- Needs Assessment and Model Development Process (May 10, 2009; November 24, 2009
- Technical Workshop (September 30, 2009)
- Component Design Report (October 16, 2010)

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Additional citations are in Appendix A, the AEO2022 Assumptions Document, and the LFMM Component Design Report.

Appendix D. Model Abstract

Model name

Liquid Fuels Market Module

Model acronym

LFMM

Description

The Liquid Fuels Market Module (LFMM) is a simulation of the U.S. liquid fuels industry. The core 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 petroleum products. The model accounts for more than 20 refined petroleum products that are manufactured, imported, and marketed. These products include specification-blended and recipe-blended petroleum products, as well as coproducts, unfinished products, and by-products. The LFMM models domestic liquid fuels production activities and the marketing of petroleum products to consumption regions.

Capacity-limited transportation systems are included to represent existing intra-U.S. crude oil and petroleum product shipments (LPG, clean, dirty) by pipeline, marine tanker, barge, and truck/rail tankers. The export and import of crude oil and refined products is also simulated. All crude oil and petroleum product imports are purchased in accordance with import supply curves. Crude oil exports are allowed and are connected to the world crude oil supply curves. Product exports are valued by individual export demand curves.

Most of the LFMM is written in GAMS, but some data processing is done in Fortran.

Purpose of the model

The purpose of the LFMM is to project petroleum product prices, refining activities, and movements of petroleum across U.S. 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 determining 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; HGL imports and exports; 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 January 2022 version used to develop projections for AEO2022.

Main model

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

Model interfaces

The LFMM receives information from the International Energy Module, Natural Gas Market Module, Oil and Gas Supply Module, Renewable Fuels Module, and Electricity Market Module, as well as the Residential, Commercial, Industrial, and Transportation Demand Modules. The LFMM also delivers information to each of the modules listed above plus the Macroeconomic Module within NEMS.

Official model representative

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Documentation

U.S. Energy Information Administration, *Liquid Fuels Market Module of the National Energy Modeling System: Model Documentation 2022*, March 2022. (DOE/EIA-M059 (2022)).

Archive media and installation manual

Archived as part of the NEMS AEO2022 production runs.

Energy system described

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

Coverage

Geographic:

- 13 domestic crude oil production regions
  - East
  - Gulf Coast
  - Mid-Continent
  - Southwest
  - Rocky Mountain
  - Northern Great Plains
  - West Coast
  - Atlantic Offshore
  - Gulf Offshore
  - Pacific Offshore
  - Alaska South
  - Alaska North
  - Alaska Offshore
- 8 domestic refining regions
  - PADD I
  - PADD II Inland
  - PADD II Lakes

- PADD III Gulf Coast
- PADD III Inland
- PADD IV
- PADD V California
- PADD V Other

- 9 market regions
- 9 census divisions
  - New England
  - Middle Atlantic
  - East North Central
  - West North Central
  - South Atlantic
  - East South Central
  - West South Central
  - Mountain
  - Pacific
- 1 international refining region comprising eastern Canada and the Caribbean
- 1 *rest of world* crude oil and petroleum product supply region

Time unit and frequency: annual, 2023 through 2050.

Products:

Asphalt/road oil	Low-sulfur diesel
Biomass-based diesel	Low-sulfur residual fuel oil
Catalyst coke (burned)	LPG
Conventional high oxygen motor gasoline	Marketable coke
Conventional motor gasoline	Other petroleum products
Distillate fuel oil	Petrochemical feedstocks
E85	Reformulated high oxygen motor gasoline
Ethanol	Reformulated motor gasoline
High-sulfur residual fuel oil	Still gas
Jet fuel	Ultra-low sulfur diesel

Production processes:

ACU	Atmospheric crude 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 and cogeneration
CLE	Cellulosic ethanol
CPL	Catalytic polymerization
CSU	Condensate splitter
CTL	Coal-to-liquids
CTLCCS	Coal-to-liquids with CCS
DC4	Debutanization
DC5	Fluid catalytic cracking (FCC) naphtha dependanizer
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
IBA	Isobutanol pseudo-unit
KRD	Delayed coker
KWG	Electricity generation
LNS	Light naphtha splitter
LTE	Light ends condenser on ADU
LUB	Lubricant production
NCE	Non-corn starch ethanol
NDS	Naphtha hydrotreater
PHI	Once-through 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: 11 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 pipeline, dirty pipeline, rail/truck tankers. These modes 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, exports, or domestic production of products is modeled; capacity expansion of conversion units 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 Report*
EIA-782A	*Refiners'/Gas Plant Operators' Monthly Petroleum Product Sales Report*
EIA-782B	*Resellers'/Retailers' Monthly Petroleum Product Sales Report*
EIA-782C	*Monthly Report of Prime Supplier Sales of Petroleum Products Sold for Local Consumption*
EIA-759	*Monthly Power Plant Report*
EIA-810	*Monthly Refinery Report*
EIA-811	*Monthly Bulk Terminal Report* (information obtained from EIA-815 after 2009)
EIA-812	*Monthly Product Pipeline Report*
EIA-813	*Monthly Crude Oil Report*
EIA-814	*Monthly Imports Report*
EIA-815	*Monthly Bulk Terminal and Blender Report*
EIA-817	*Monthly Tanker and Barge Movements Report*

EIA-819	*Monthly Report of Biofuels, Fuels from Non-Biogenic Wastes, Fuel Oxygenates, Isooctane, and Isooctene*
EIA-820	*Annual Refinery Report*
EIA-826	*Monthly Electric Sales and Revenue with State Distributions Report*
EIA-856	*Monthly Foreign Crude Oil Acquisition Report*
EIA-914	*Monthly Crude Oil and Lease Condensate, and Natural Gas Production Report*
EIA-920	*Combined Heat and Power Plant Report* (and predecessor forms)
EIA-923	*Power Plant Operations Report*
FERC-423	*Monthly Report of Cost and Quality of Fuels for Electric Plants* (information obtained from EIA-923 after 2009)

In addition to the above, EIA uses information from several of its 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 (prior to 2012)
- Monthly Energy Review
- State Energy Data Report
- State Energy Price and Expenditure Report

Independent expert reviews conducted

None.

Independent reviews of the predecessor to the LFMM, the Petroleum Market Module (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

EIA survey forms

Form EIA-14, Refiners' Monthly Cost Report

Form EIA-14, *Refiners' Monthly Cost Report*, is used to collect summary data that permit EIA to provide the government and the public certain cost and price statistics on the U.S. petroleum industry. The data appear on EIA's website and in the EIA publications, *Petroleum Marketing Monthly*, *Monthly Energy Review*, and *Annual Energy Review*.

Form EIA-182, Domestic Crude Oil First Purchase Report

Form EIA-182, *Domestic Crude Oil First Purchase Report*, is designed to collect data on both the average cost and volume associated with the physical and financial transfer of domestic crude oil off the property on which it was produced. The monthly reported data represent the initial market value and volume of domestic crude oil production. The primary statistic is the weighted average wellhead price for selected domestic crude oil streams aggregated by state. First purchase volumes are also used in generating estimates of domestic crude oil production. Because this report is statistical, definitions vary unavoidably from those of some state agencies whose purpose is strictly fiscal or regulatory (see Definitions). The U.S. Department of Energy (DOE) uses the data in reviewing the supply, demand, quality, and price changes of crude oil. We publish the average wellhead prices in the *Petroleum Marketing Monthly*, the *Monthly Energy Review*, the *Annual Energy Review*, and the *Oil and Gas Lease Equipment and Operating Costs 1994–2009*.

Form EIA-782A, Refiners'/Gas Plant Operators' Monthly Petroleum Product Sales Report

Form EIA-782A, *Refiners'/Gas Plant Operators' Monthly Petroleum Product Sales Report*, is used to collect data on the sales of selected petroleum products (volumes and prices) to various categories of end users and resellers at the state level. DOE uses the data to analyze and report on petroleum product supply, demand, and price changes. In addition, state and federal agencies (such as the Bureau of Economic Analysis and the Defense Logistics Agency (DLA) Energy), Congress, industry analysts, trade publications, academia, and the public use the data to analyze, model, and forecast petroleum product prices and sales by state and end-use category.

Form EIA-782B, Resellers'/Retailers' Monthly Petroleum Product Sales Report

Form EIA-782B, *Resellers'/Retailers' Monthly Petroleum Product Sales Report*, is used to collect data on the sales of selected petroleum products (volumes and prices) to various categories of end users and resellers at the state level. DOE uses the data to analyze and report on petroleum product supply, demand, and price changes. In addition, state and federal agencies (such as the Bureau of Economic Analysis and DLA Energy), Congress, industry analysts, trade publications, academia, and the public use the data to analyze, model, and forecast petroleum product prices and sales by state and end-use category. This report was suspended in 2011.

Form EIA-782C, Monthly Report of Prime Supplier Sales of Petroleum Products Sold for Local Consumption

Form EIA-782C, *Monthly Report of Prime Supplier Sales of Petroleum Products Sold for Local Consumption*, is used to collect data on the sales of selected petroleum products by prime suppliers delivered into states for local consumption. DOE uses the data to analyze and report on petroleum product demand. In addition, state and federal agencies (such as the Bureau of Economic Analysis), Congress, industry analysts, trade publications, academia, and the public use the data to analyze, model, and forecast petroleum product consumption by state.

Form EIA-810, Monthly Refinery Report

Form EIA-810, *Monthly Refinery Report*, is used to collect data on the operations of all petroleum refineries located in the 50 states, District of Columbia, Puerto Rico, the Virgin Islands, Guam, and other U.S. possessions. A summary of the data appears on EIA's website and in numerous government publications.

Form EIA-811, Monthly Bulk Terminal Report (terminated after 2009; now using Form EIA-815)

Form EIA-811, *Monthly Bulk Terminal Report*, is used to collect data on end-of-month stocks of petroleum products. The data appear on EIA's website and in numerous government publications.

Form EIA-812, Monthly Product Pipeline Report

Form EIA-812, *Monthly Product Pipeline Report*, is used to collect data on end-of-month stocks and movements of petroleum products transported by pipeline. A summary of the data appears on EIA's website and in numerous government publications.

Form EIA-813, Monthly Crude Oil Report

Form EIA-813, *Monthly Crude Oil Report*, is used to collect data on end-of-month stocks of crude oil and movements of crude oil by pipeline. A summary of the data appears on EIA's website and in numerous government publications.

Form EIA-814, Monthly Imports Report

Form EIA-814, *Monthly Imports Report*, is used to collect data on imports of crude oil and petroleum products. A summary of the data appears on EIA's website and in numerous government publications.

Form EIA-815, Monthly Bulk Terminal and Blender Report

Form EIA-815, *Monthly Bulk Terminal and Blender Report*, is used to collect data on end-of-month stocks of petroleum products. A summary of the data appears on EIA's website and in numerous government publications.

Form EIA-817, Monthly Tanker and Barge Movements Report

Form EIA-817, *Monthly Tanker and Barge Movements Report*, is used to collect data on the movement of crude oil and petroleum products. A summary of the data appears on EIA's website and in numerous government publications.

Form EIA-819, Monthly Report of Biofuels, Fuels from Non-Biogenic Wastes, Fuel Oxygenates, Isooctane, and Isooctene

Form EIA-819, *Monthly Report of Biofuels, Fuels from Non-Biogenic Wastes, Fuel Oxygenates, Isooctane, and Isooctene*, is used to collect data on the production capacity of fuel alcohol, biodiesel, renewable diesel, heating oil, jet fuel naphtha, other renewable fuels, isooctane, isooctane, and fuel oxygenates. Data collected include information regarding the balance between the supply (beginning stocks, receipts, and production) and disposition (inputs, shipments, plant use and losses, and ending stocks) of biofuels and oxygenates at the plant during the report month. The data appear on EIA's website and in numerous government publications.

Form EIA-820, Annual Refinery Report

Form EIA-820, *Annual Refinery Report*, is used to collect data on current and projected capacities of all operable petroleum refineries. The data appear on EIA's website and in numerous government publications.

Form EIA-826, Monthly Electric Utility Sales and Revenue Report with State Distributions

Form EIA-826, *Monthly Electric Utility Sales and Revenue Report with State Distributions*, collects information from electric utilities, energy service providers, and distribution companies that sell or deliver electric power to end users. Data collected on this form include sales and revenue for all end-use sectors (residential, commercial, industrial, and transportation). The data from this form appear in *Electric Power Monthly*, *Monthly Energy Review*, and *Annual Energy Review*. We use the data collected on this form to monitor the status and trends of the electric power industry and to inform our projections of the future of the industry.

Form EIA-856, Monthly Foreign Crude Oil Acquisition Report

Form EIA-856*, Monthly Foreign Crude Oil Acquisition Report*, is used to collect data on the cost and quantities of foreign crude oil (by country of origin) acquired for importation into the United States, including U.S. territories and possessions. DOE, the International Energy Agency (IEA), other federal agencies, and industry analysts use the data for forecasting and analytical purposes.

Form EIA-914, Monthly Crude Oil and Lease Condensate, and Natural Gas Production Report

Form EIA-914*, Monthly Crude Oil and Lease Condensate, and Natural Gas Production Report*, collects data directly from crude oil and natural gas producers in 15 states, the Federal Offshore Gulf of Mexico (GOM), and other states. The survey uses the reported data to estimate total production for those areas and the United States. A summary of the data appears on EIA's website and in numerous government publications.

Form EIA-923, Power Plant Operations Report

Form EIA-923, *Power Plant Operations Report*, collects information from electric power plants and combined-heat-and-power (CHP) plants in the United States. Data collected on this form include electric power generation, fuel consumption, fossil fuel stocks, delivered fossil fuel cost, combustion by-products, operational cooling water data, and operational data for nitrogen oxides, sulfur dioxide, and particulate matter control equipment. We use these data to monitor the status and trends of the electric power industry, and these data appear in many EIA publications, including:

- Electric Power Monthly
- Electric Power Annual
- Monthly Energy Review
- Annual Energy Review
- Natural Gas Monthly
- Natural Gas Annual
- Cost and Quality of Fuels
- Quarterly Coal Report
- Renewable Energy Annual

In addition to the above, we use information from several of our publications:

- Petroleum Supply Annual
- Petroleum Supply Monthly

- Petroleum Marketing Annual
- Petroleum Marketing Monthly
- Fuel Oil and Kerosene Sales
- Natural Gas Annual
- Natural Gas Monthly
- Annual Energy Review
- Monthly Energy Review
- State Energy Data Report
- State Energy Price and Expenditure Report

Quality of distribution cost data

We incorporate costs relating to distributing petroleum products to end users by adding fixed transportation markups to the wholesale prices, which include the variable and fixed refinery costs. We estimate transportation markups for petroleum products as the average annual difference between retail and wholesale prices from 1990 through 2017.[2] 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.

We aggregate annual wholesale prices for all petroleum products from state-level prices from Form EIA-782A. The estimation and reliability of Form EIA-782A data are discussed in the Petroleum Marketing Monthly. See Explanatory Notes in that report for inputs and sources.

We aggregate sectoral end-user prices through 2017 from prices from the State Energy Data System (SEDS) 2018 (select State, then Prices), except for gasoline, non-utility distillate fuel, and jet fuel. The methodology behind these state-level sectoral prices is discussed in the Technical Notes and Documentation section.

We estimate gasoline, jet fuel, and non-utility distillate prices as weighted averages using end-user prices from Form EIA-782A and sectoral consumption from the State Energy Data System (SEDS) 2018 (select State, then Consumption & Expenditures).

Because of a lag in the publication of the SEDS data, we calculated end-use price estimates for 2018 using the same data series and methodology described in SEDS. The SEDS methodology uses prices from Form EIA-782A, Form EIA-923, and Form EIA-906 (Table E-1) and weights them with the most recent consumption volumes from SEDS. Refer to SEDS for a discussion of the reliability of consumption data. We estimated 2019 and 2020 data by applying the percentage change of national product prices as reported in the October 2019 *Short-Term Energy Outlook* (STEO) to the sectoral volume weighted average price estimates in 2018.

[2] Transportation markups for kerosene are based on the difference between end-user kerosene prices and wholesale distillate prices. Markups are estimated based on the most recent available price data.

Table E-1. Sources of markup inputs

Products	Sectors	Data series inputs
Distillate	Commercial, industrial, residential	Form EIA-782A, SEDC
Jet fuel	Transportation	Form EIA-782A, SEDC
Low-sulfur diesel fuel	Transportation	Form EIA-782A, SEDC
Motor gasoline	Commercial, industrial, transportation	Form EIA-782A, SEDC
Asphalt and road oil	Industrial	SEDP, Form EIA-782A, SEDC
Kerosene	Commercial, industrial, residential	SEDP, Form EIA-782A, SEDC
Liquefied petroleum gases	Commercial, industrial, residential, transportation	SEDP, Form EIA-782A, SEDC
Low-sulfur residual fuel	Commercial, industrial	SEDP, Form EIA-782A, SEDC
High-sulfur residual fuel	Transportation	SEDP, Form EIA-782A, SEDC
Distillate	Electric utility	SEDP, Form EIA-906, Form EIA-923
Low-sulfur residual fuel	Electric utility	SEDP, Form EIA-906, Form EIA-923
High-sulfur residual fuel	Electric utility	SEDP, Form EIA-906, Form EIA-923

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), and federal taxes are held at current nominal levels (deflated in each projection year).[3] The federal tax assumption reflects the overall projection 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. We add an additional 1% per gallon of the gasoline price to the state gasoline taxes to estimate local taxes.

State taxes are added as census division weighted averages, which are based on tax data available as of 2020. We derive state taxes for jet fuel from unpublished data we collect. State and federal taxes for gasoline, transportation distillate, and LPG are based on data from the Federal Highway Administration, but they 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% 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 G for a description of programs and input files used to calculate historical taxes and estimate taxes used in the price projections.

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

Critical variables

The LFMM contains numerous variables and parameters. Some variables affect model results more than others do. The following is a list of variables that we believe have a high degree of influence on LFMM results. We provide it to help users understand the critical factors affecting the LFMM.

- World oil price
- Product demands
- Import crude oil supply curves
- Import and export product supply and demand curves
- Domestic crude oil 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

Other modules provide most of these variables 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 process plant cost function (PCF) represents the threshold for expansion investment decisions. 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):

$$PCF = \sum_i (CFC_i + FOC_i + OVC_i), \quad (1)$$

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

In the LFMM, the OVC are defined directly from input data (so these costs will not be addressed in this section), while the CFC and the 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):

$$CFC_i = ACR_i - DTC_i. \quad (2)$$

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 to determine the depreciation tax credit (DTC). Both the ACR and DTC are estimated on an after-tax basis.

Because the LFMM and other energy projection 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 on the National Petroleum Council (NPC) study[4] and other sources.[5] Some of the steps for the cost 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 capital cost estimation algorithm:

[4] National Petroleum Council, *U.S. Petroleum refining – Meeting Requirements for Cleaner Fuels and Refineries*, Washington, DC, August 1993.

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

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 that we must make before we input the ISBL field cost 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),[6] and we updated these costs annually with revised estimates from EnSys Energy and Systems, Inc. (EnSys). We obtained the data for typical unit sizes and stream factors, as well as supplementary investment and labor, from the World Oil Refining, Logistics, and Distribution (WORLD) model.[7] 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

We must adjust the ISBL investment cost data to include location factors and correct year-dollars:

- Adjust the ISBL field costs and labor costs for each processing unit (*j*) from 1993 dollars, first to the year-dollar (rptyr) reported by NEMS (for example, 2012 dollars for AEO2014), using the Nelson-Farrar refining-industry cost-inflation indices. Next, use the GDP chain-type price indices provided by the NEMS Macroeconomic Activity Model to convert from report-year dollars to 1987-year dollars used internally by NEMS.

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

[7] EnSys Energy & Systems, Inc., *WORLD Reference Manual*, a reference for use by the analyst and management, prepared for the U.S. Department of Energy, Contract No. DE-AC-01-87FE-61299 (Washington, DC, September 1992).

- Convert the ISBL field costs in 1987 dollars for each processing unit from a PADD III (Gulf Coast) basis (*BM_ISBL*) to costs of the same processing unit for other regions (*ISBL*) by using location multipliers (*INVLOC).* The location multipliers represent differences in material costs between the various PADD regions.

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

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; and

$INVLOC_l$ = 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)[8] and EIA.[9] The development of these multipliers and assumed values for other factors is described elsewhere.[10] 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

[8] Wages Data, U.S. Department of Labor, Bureau of Labor Statistics, available on the web at www.bls.gov/bls/blswage.htm.
[9] 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.
[10] *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.

Step 3 - Estimation of OSBL cost and total field cost

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

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

where

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; and

OSBLFAC = OSBL fraction of ISBL costs (assumed to be 0.45 in the 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):

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

where

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; and

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 OTCs are estimated as a function of total field costs (FDC), using cost factors (OTCFAC). The corresponding equations are presented below.

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

where

PCTENV = 0.10, home, office, contractor fee;

PCTCNTG = 0.05, contractor and owner contingency;

PCTLND = 0.00, land (assuming expansion only at existing refinery);

PCTSPECL = 0.05, prepaid royalties, license, start-up costs; and

PCTWC = 0.10, working capital.

thus,

OTCFAC *= 0.30*

and

$$OTC_j = OTCFAC * FDC_j \qquad (7)$$

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 FCI is equal to the TPI minus 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):

$$WRKCAP_j = PCTWC * FDC_j \qquad (8)$$

and

$$FCI_j = TPI_j - WC_j \qquad (9)$$

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; and

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

The TDI is equal to the TPI minus 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 would most likely be 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, TDI is assumed to be about equal to FCI:

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

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; and

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

Step 5 - Estimation of capital-related financial charges

To determine 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) because the holders of common stock (equity investors) accept all the risks involved in business ownership. The COC is related to COE and COD as follows:

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

and

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

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; and

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 January 1, 2004.[11] PADD averages were weighted based on the crude oil processing capacity within the states in each PADD. The resulting state and federal tax rates used in the model are in Table F-2:

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

[11] 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.

used to compute a cost of equity,[12] 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% (7.5% for high-risk and non-petroleum based technologies) based on the expected return on market over the rate of a 10-year Treasury note (risk-free rate); and, the β is set based on the risk level of the processing unit investment (for average risk, β = 0.8; for high-risk and non-petroleum based technologies, 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 minus WC minus 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):

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

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;

[12] 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 .

$F_{v,n}$ = 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; and

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:

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

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

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:

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

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

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

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; and

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*:

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

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:

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

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

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

where

ACR(at) = annual capital recovery, where (*at*) signifies 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; and

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 and 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.

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

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

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; and

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) minus 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 it is 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. The after-tax CFC 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 as well as any other costs that cannot be controlled at the plant level. These costs include 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%.

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 that must be made before 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. We initially obtained the operating labor cost data for most of the processing unit types modeled in the LFMM from a study by Bonner and Moore Associates (BMA), and we updated this data annually with revised estimates from EnSys. Ensys obtains the data from the World Oil Refining, Logistics, and Distribution (WORLD) model.[13] The data used by the LFMM currently represent processing plants sited at a generic U.S. Gulf Coast (PADD III) location and are in 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 AEO2014, which is in 2012 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 NEMS. This step 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.

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

[13] EnSys Energy & Systems, Inc., *WORLD Reference Manual*, a reference for use by the analyst and management prepared for the U.S. Department of Energy, Contract No. DE-AC-01-87FE-61299 (Washington, DC, September 1992).

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; and

$LABORLOC_l$ = location multiplier for refining region l.

Location multipliers for process unit operating labor were developed on a PADD basis using data available from the U.S. Bureau of Labor Statistics (BLS)[14] and EIA.[15] The recommended location multipliers for process unit construction are in Table F-3.

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:

$$LRC = OLC + FXOC\_STAFF + FXOC\_OH \tag{30}$$

where

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

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

[14] Wages Data, U.S. Department of Labor, Bureau of Labor Statistics, www.bls.gov/bls/blswage.htm.
[15] Refinery Capacity Data, U.S. Department of Energy, U.S. Energy Information Administration, www.eia.doe.gov/oil_gas/petroleum/data_publications/refinery_capacity_data/refcapacity.html.

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

FXOC_OH = benefits and 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.

$$LRC = 2.15 * OLC \quad (1987\$/cd) \quad (31)$$

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:

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

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 liquids

Beginning with AEO2016, the natural gas plant liquids supply to the LFMM is provided by the Oil and Gas Supply Module (OGSM) through the NEMS common variables OGNGPLET (ethane), OGNGPLPR (propane), OGNGPLIS (isobutane), OGNGPLBU (n-butane), OGNGPLPP (pentanes plus). All variables are dimensioned by OGSM production districts and model year. See the OGSM documentation for more details.

Estimation of distribution costs

We incorporate costs related to distributing petroleum products to end users by adding fixed transportation markups to the wholesale prices (model results) that include the variable and fixed refinery costs. We estimate transportation markups for petroleum products (except gasoline) as the average annual difference between retail and wholesale prices. We hold these markups constant throughout the projection period.

Distribution costs and markups are calculated and estimated on a planned four-year cycle. Every four years, we estimate distribution costs and markups by using State Energy Data System (SEDS) data and available EIA price data by census division, and we assume those results for the projection period.

Sector-level prices provided by EIA's SEDS database typically lag behind current average prices to all sectors by more than two years. Along with algorithms and methods derived from the now retired Refinery Markups Database, we use various calculations from available Oil and Gas Information Resource System (OGIRS) data and EIA API key data to compute suitable proxies for sector-level prices during this time. These derived methods include algorithms filling in missing data by way of OGIRS/API state-level and sectoral price data when available, calculated volume-weighted regional averages, or in some cases (when data are missing completely) price data that are estimated offline and entered manually. Computer programs and data files used to estimate transportation markups are discussed below.

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. We also estimate taxes for E85 (transportation ethanol). We develop weighted averages of the most recent available state and federal taxes for each census division (CD) using periodic state survey data collected by the American Petroleum Institute (API).[16] We then aggregate the API Energy data 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 declines at the rate of inflation (in other words, federal taxes are fixed in nominal terms). We add an additional 1% of the retail product CD value to the gasoline and diesel taxes to approximate local taxes. Historical tax values are also calculated for gasoline, transportation distillate, jet fuel, and LPG, which we then add to historical end-use prices excluding taxes in order to develop a series with taxes included.

We update federal taxes 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 the LFMM to differentiate between conventional and reformulated gasoline blends, according to EPA and California regulations.

- Octane (CON)
- Oxygen content

[16] American Petroleum Institute, "State Motor Fuel Taxes," August 2019.

- Reid vapor pressure (RVP)
- Benzene content (BNZ)
- Aromatic content (ARO)
- Sulfur content (Sulfur)
- Olefin content (OLE)
- The percentage evaporated at 200°F and 300°F (E200 and E300)

In accordance with the EPA Tier-3 regulatory announcement, refiners are required to reduce their average sulfur spec to a maximum of 10ppm beginning in 2017. Beginning in model year 2017, the LFMM reduces the average sulfur spec to 5ppm at the refinery gate to allow for potential contamination during transport. In addition, as a result of a trend in higher octane gasoline, the average octane (CON) increases linearly from 84.9 in 2017 to 87 by 2050 for conventional and from 86.3 to 88.3 for reformulated CARB gasoline.

Table F-5. 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[a]	84.9	45.9	81.7
Reformulated	21.00	0.62	10.36	8.80	23.88[a]	84.9	54.0	81.7
California reformulated	23.12	0.58	6.29	7.70	10.00[a]	86.3	42.9	86.3

Source: "EPA Sets Tier 3 Motor Vehicle Emission and Fuel Standards," https://www.epa.gov/fuels-registration-reporting-and-compliance-help/epa-webinar-slides-tier-3-gasoline-sulfur
Note: To account for potential contamination during transport, sulfur spec is set to 5pmm at the refinery gate in the LFMM beginning 2017.
[a] Maximum sulfur spec is reduced to 10ppm beginning in 2017 to meet EPA final ruling.

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. We assume the market shares remain constant during the projection period.

Diesel specifications

The 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 that followed a scheduled phase-in between 2006 and 2014. Currently, all diesel demand in the United States is classified as DSU in the LFMM projection years, and some small amounts of DSL are produced for export.

Table F-6. EPA diesel fuel sulfur limits

Refiner class	June 1, 2006	June 1, 2007	June 1, 2010	June 1, 2012	June 1, 2014 and beyond
Highway diesel					
Non-small refineries		More than 80% 15 parts per million (ppm)		15 ppm	
Small refineries (less than 155,000 barrels per day [b/d]; less than 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 (less than 155,000 b/d; less than 1,500 employees)		[a]		500 ppm	15 ppm[b]

[a]Northeast and mid-Atlantic requires 500 ppm for all NRLM diesel starting mid-2007.
[b]LM diesel downgrade to 500 ppm is allowed indefinitely, and 15 ppm sulfur is required at refinery gate only.
Source: https://www.epa.gov/diesel-fuel-standards/diesel-fuel-standards-and-rulemakings

According to the ultra-low sulfur diesel (ULSD) regulation finalized in December 2000, ULSD is highway diesel that contains no more than 15 ppm of sulfur at the pump, is limited to a minimum cetane index of 40, and has an aromatics content of 35% by volume. We assume ULSD in California meets California Air Resources Board (CARB) standards that limit maximum sulfur content to 15 ppm (modeled as 10 ppm at the refinery gate to account for potential contamination during transport), minimum cetane index of 53, and maximum aromatics to 10% by volume.[17]

During mid-2004, the U. S. Environmental Protection Agency (EPA) finalized its 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-7.

Estimation of diesel market shares

The 2000 ULSD federal regulations and the 2004 nonroad diesel rules were fully implemented after 2014, resulting in three distillate fuels in the marketplace: (a) 15 ppm highway, (b) nonroad locomotive and marine (NRLM) diesel, and (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).

[17] 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. We aggregate diesel fuel by sector and by quality to reflect individual uses for the LFMM. We computed 2007 historical percentages from sector-level data available from the EIA report *Fuel Oil and Kerosene Sales, 2007*.[18] Table F-7 provides an overview of how the categories were grouped.

Table F-7. 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	

Source: 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% ULSD and 20% 500 ppm highway diesel between June 2006 and June 2010 and a 100% requirement for ULSD thereafter. The phase-in path for ULSD is available in the input file lfblending.xlsx (and listed in Table F-8 below).

[18] U.S. Department of Energy, U.S. Energy Information Administration, "Fuel Oil and Kerosene Sales, 2007," December 2008, DOE/EIA-0535(07).

Table F-8. 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
DSU = ultra-low sulfur diesel, DSL = low-sulfur diesel, N2H = heating oil
Source: U.S. Energy Information Administration, Office of Energy Analysis

Heating oil is not subject to ULSD rules; however, many states in the northeast and mid-Atlantic have passed mandates requiring ultra-low sulfur heating oil by a certain date (Table F-9).

Table F-9. States and start years for ultra-low sulfur heating oil

State	Census division	Start year
Connecticut	CD 1	2018
Maine	CD 1	2018
Massachusetts	CD 1	2018
New Hampshire	CD 1	2018
Rhode Island	CD 1	2018
Vermont	CD 1	2018
New Jersey	CD 2	2016
New York	CD 2	2012
Delaware	CD 5	2016
District of Columbia	CD 5	2018

Source: "SULFUR & BIOHEAT REQUIREMENTS FOR No. 2 HEATING OIL IN THE NORTHEAST & MID-ATLANTIC STATES", Chart 1. Summary, updated 6-29-2017, http://oilandenergyonline.com/wp-content/uploads/2017/07/NEMARegion_HOspecs_2017.pdf

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 they are needed for some refinery input prices, refinery fuel consumption, and cogeneration information. The factors are used to convert prices, consumption, or cogeneration from the regional level used by the LFMM to census divisions. We generate these factors based on state-level ADU capacity, each mapped and aggregated into LFMM regions, and then mapped into census divisions, as a percentage of capacity in each LFMM region.

Other data, such as corn feedstock to ethanol plants, are mapped from 16 coal demand regions to the 8 domestic LFMM regions by determining the states that overlap the two regional representations.

Product pipeline capacities and tariffs

Products in the LFMM are produced domestically, imported, or exported based on domestic demand levels and relative market economics. Within the LFMM, products are transported between refining (LFMM) regions mainly by pipeline, but they can move by more expensive modes (such as rail, truck, tanker, or barge), usually if pipeline flows exceed available capacity.

Originally, we based the pipeline distribution network in the LFMM on the distribution network used by its predecessor model PMM (last used for AEO2012). We later updated the network for AEO2014 based on a proposal from OnLocation Inc, and we generated corresponding capacity and tariff data from online news releases, pipeline company sites, and detailed research of FERC filings. Only a few minor updates were made for AEO2018, but we made major changes in AEO2019 and AEO2020. Current data used for AEO2022 are listed in Tables F-10. Note that these data represent an aggregate of multiple product pipelines connecting the regions.

Table F-10. Product pipeline capacity and tariff data in the Liquid Fuels Market Module represented in the *Annual Energy Outlook 2022*

RefReg code	Source region	RefReg code	Destination region	Capacity (1,000 barrels per day)	Tariff range (2021 dollars per barrel)
1	PADD I	3	PADD II, lakes	240	$1.55 – $2.60
2	PADD II, inland	3	PADD II, lakes	2,492	$1.60 – $2.00
3	PADD II, lakes	1	PADD I	250	$2.15 – $3.60
4	PADD III, gulf	3	PADD II, lakes	330	$1.60 – $2.65
4	PADD III, gulf	5	PADD III, inland	4,434	$0.90 – $1.50
5	PADD III, inland	1	PADD I	3,000	$1.75 – $2.95
5	PADD III, inland	2	PADD II, inland	2,450	$1.40 – $2.30
5	PADD III, inland	6	PADD IV	84.7	$1.35 – $2.30
5	PADD III, inland	8	PADD V, other	200	$1.90 – $1.95
6	PADD IV	2	PADD II, inland	40	$1.80 – $2.25
6	PADD IV	8	PADD V, other	66	$2.10 – $3.50
7	PADD V, California	8	PADD V, other	128	$1.20 – $2.00

Source: U.S. Energy Information Administration, Office of Energy Analysis

Cogeneration methodology

Electricity consumption in the refinery is a function of the throughput of each unit. Sources of electricity consist of refinery power generation, utility purchases, and refinery cogeneration. We model power generators and cogenerators in the LFMM as separate units that 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. We aggregate cogeneration activity for each refinery to the LFMM regional level. We estimated cogeneration capacity from the 2018 version of Form EIA-923, *Power Plant Operations Report*. We derived cogeneration operating costs from the 1980 Office of Technology Assessment (OTA) report *Industrial Cogeneration*. We also derived cogeneration capacity (including planned capacity) for each LFMM region from Form EIA-923. The LP limits utilization to 90% of capacity. No unplanned builds for refinery cogeneration are allowed.

The LFMM can model cogeneration of electricity and steam at the petroleum refinery by burning still gas and natural gas (assumed to be 33% and 67%, respectively). In general, refinery cogeneration units tend to be small, designed to supply the refinery's steam and electricity needs and to sell a small amount of leftover capacity 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-liquids (CTL) production process. The coal feedstock is represented as a coal supply curve in each coal demand region, by coal type, and is provided by the Coal Market Module (CMM) of NEMS.

Natural gas

The LFMM models a gas-to-liquids (GTL) production process. The natural gas feedstock prices are provided by the Natural Gas Market Module (NGMM) of NEMS.

Cellulosic biomass

The LFMM models cellulosic ethanol and biomass-to-liquids (BTL—Fischer-Tropsch, BTL—Pyrolsis) production processes. The feedstock consists of three cellulosic biomass supply curves (agricultural residue, forest residue, and urban wood waste) that are generated from data provided by the Renewable Fuels Module (RFM) of NEMS.

Corn

The LFMM also models ethanol production from corn. Price/quantity (P/Q) corn-to-ethanol data from the RFM (NEMS) is used to develop the corn feedstock supply curve for the domestic LFMM regions. We use the initial P/Q pair to represent step five on the 29-step iso-elastic supply curve. Thus, the first five steps represent the starting production level projected by RFM, and the remaining steps represent the additional supply available (not to exceed a maximum of 10 times the initial production level (step 5) if the LFMM determines it economical to demand more. The RFM data are translated into LFMM corn supply curves by:

1. Defining corn supply and price by coal demand regions from total corn supply curves provided by Polysys (in RFM):
- Regional corn supply-for-ethanol = total U.S. corn supply-for-ethanol * ratio of regional total corn supply to U.S. total corn supply [use step 3 from all supply curves]
- National (U.S.) corn supply prices = step 3 from national (U.S.) total corn supply curves
- For years 2030 and beyond, set regional corn supply prices = prices in 2029 * growth rate set as a function of the change in world oil price (WOP)

2. Defining corn supply and price by LFMM regions from coal demand region price/supply information and LFMM region adjustments:
- Use mapping shares (CoalDReg2RefRegMap) to redistribute regional corn supply-for-ethanol from coal demand regions to LFMM regions. A small adjustment factor applies (CornTranSupMove)
- Apply cost differential data to the national (U.S.) corn supply price to set prices by LFMM regions

These initial P/Q pair (Po and Qo) are set as step 5 on a 29-step supply curve, and a maximum quantity on the curve is set to 10 times the initial Qo. The regional curves are set as iso-elastic supply curves, using regional elasticities, as described below.

$$P_s/P_o = (Q_s/Q_o)^{elas}$$

$$P_s = P_o * (Q_s/Q_o)^{elas}$$

where

P_s = price of corn on step s, 2008 dollars per bushel;

Q_s = quantity of corn supply on step s, 1,000 bushels per day;

Po, Qo = initial price and quantity of corn supply provided by RFM, 2008 dollars per bushel, 1,000 bushels per day; and

elas = price elasticity for each LFMM region; 0.50 for LFMM regions 2 and 3 (Midwestern region) and 0.75 for all other LFMM regions.

Seed oils, fats, and greases

The production of biodiesel and renewable diesel (in this section, both referred to as biodiesel) from virgin vegetable oil, yellow grease, and white grease are represented in the 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, it is available nationwide and is assumed to grow at the same rate that population grows. White grease consists of fats from rendering. We assume total fat production is 5.51 gallons per person per year, of which 1.84 gallons per person per year is available for biodiesel production. As of AEO2020, yellow grease and white grease production are combined into a single, iso-elastic supply curve in the LFMM, and we assume initial regional supply (Qo) to be 67% of total regional fat production available for biodiesel. We assume the initial regional price (Po) for the grease supply curve is 67% of the soybean oil price, defined further below. The regional supply curves are then generated using the same iso-elastic algorithm defined for generating the corn supply curve but using a 0.50 supply elasticity for all regions.

The approach to defining biodiesel feedstock supply data representing virgin oil supply (soybean and seed oils) in the LFMM was updated for AEO2021. The soybean oil available for biodiesel production is determined from soybean supply, soy oil production, and cost data from Polysys (in the RFM). The soybean oil production data are reallocated from coal demand regions into LFMM regions, and we assume the quantity available for biodiesel production is 34.3%. We estimate the other seed oil production from other data sources. The total of these two production levels define the initial quantity (Qo) of virgin oil (FCO) supplies for biodiesel production for each LFMM region. We estimate the corresponding price (Po) to be the average U.S. price for soybean oil provided by Polysys. The regional FCO supply curves are generated using the same iso-elastic algorithm defined for generating the corn supply curve but using a 1.2 supply elasticity for all regions.

We allocate biodiesel production capacity by feedstock among census divisions according to the National Biodiesel Board's map of existing and potential producers and according to potential feedstock supplies.[19]

E85 infrastructure representation and availability curve

The large renewable fuel volumes mandated by EISA2007 (and modified by EPA each year) can be met by a number of biofuels options represented in LFMM, including ethanol fuel 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 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, which in turn is used to build an E85 availability curve. We use this curve in the LFMM to project E85 availability, and corresponding gasoline and E85 prices. These prices are then passed to the Transportation Demand Module (TDM) in NEMS.

Prior to AEO2021, 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 (in other words, the 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 or E15. This interaction is still an option in the LFMM.

Beginning with AEO2021, we added a second optional (more simplistic) approach to establish the E85 availability curve used in LFMM. It assumes a starting E85 to gasoline price ratio, E85 availability and estimated growth, and price elasticities. As with the original approach, a step-wise linear supply curve is created with each step representing a price differential for E85 and a corresponding E85 availability and

[19] https://www.biodiesel.org/production/member-plants/member-plant-map.

demand (determined using the logit function mentioned above) for the LFMM to incorporate as a decision variable.

Renewable Fuels Standard (EISA 2007) representation

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-based diesel (biodiesel and renewable diesel). 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% less than baseline lifecycle greenhouse gas emissions (gasoline or diesel fuel, EISA07 Sec 201(1)(C)). Cellulosic biofuel is 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% 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% 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. The original RFS target volumes are as follows:

Table F-11. Energy Independence and Security Act of 2007 Renewable Fuels Standard schedule

billion ethanol-equivalent gallons per 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

Source: Energy Independence and Security Act of 2007

Since calendar year 2005, we have been 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 November 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 a 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 must reduce the applicable volumes in succeeding years after issuing wavers that pass a certain size threshold, stated as follows. If either 20% or more of any requirement is waived in two consecutive years, or if 50% 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 before 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 the market circumstances are determined to cause the price of biomass-based diesel to increase substantially. The waiver is limited to 15% 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 EPA 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)).

For AEO2022, the LFMM used RFS targets exogenously set by EIA analysts, using estimates for years 2021 and 2022 that were defined for the September 2021 *Short-Term Energy Outlook* (STEO). The exogenously revised targets included adjustments to remove components that are not modeled in the LFMM (such as biogas, banked credits, and small refinery exemptions). The LFMM was able to achieve these revised levels during the projection period.

Table F-12. Renewable Fuels Standard schedule implemented in AEO2022

billion ethanol-equivalent gallons per 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	0.975
2011	13.95	1.35	0	1.2
2012	15.03	2.00	0	1.5
2013	15.56	2.75	0.001	1.92
2014	15.85	2.64	0.001	2.445
2015	16.64	2.76	0.002	2.595
2016	16.98	3.25	0.023	2.73
2017	17.28	3.58	0.013	2.72
2018	17.90	3.70	0.020	2.92
2019	18.50	4.23	0.020	2.94
2020	17.61	4.02	0	3.27
2021	19.47	4.51	0.018	3.65
2022	19.99	4.62	0.009	3.74
2023	19.99	4.62	0.009	3.74
2024	19.99	4.62	0.009	3.74
2025	19.99	4.62	0.009	3.74
2026	19.99	4.62	0.009	3.74
2027	19.99	4.62	0.009	3.74
2028	19.99	4.62	0.009	3.74
2029	19.99	4.62	0.009	3.74
2030	19.99	4.62	0.009	3.74

California Low Carbon Fuel Standard (LCFS) representation

The Low Carbon Fuel Standard (LCFS), which is administered by the California Air Resources Board (CARB),[20] was signed into law on January 12, 2010, and was followed by several amendments over the years. 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 20% from 2010 through 2030 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

[20] LCFS Final Regulation Order. http://www.arb.ca.gov/regact/2009/lcfs09/finalfro.pdf.

CIs are calculated on an energy equivalent basis and measured in grams of CO_2 equivalent emissions per megajoule (gCO_2e/MJ).

The AEO2022 Reference case uses the CARB mandated CIs and approved fuel pathways included in the LCFS.[21] To represent non-compliance, we computed a monetary penalty to encourage compliance within the Reference case based on relevant provisions in the California Health and Safety Code.[22]

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 an additional CI value that attempts to account for potential land use changes as a result of increased biofuels production. The science behind the ILUC penalty is relatively new, so we expect potential revisions and updates to these numbers 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 such as cellulosic ethanol and biomass-to-liquid diesel fuels. The legislation also has provisions 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 factors used for AEO2022. The LFMM converts these data from g CO_2e/MJ into 1,000 metric ton C/trillion Btu using the conversion factor (cf) 3.475332 (for example, g CO_2e/MJ / cf = 1,000 metric ton C/trillion Btu).

[21] LCFS Fuel Pathway Lookup Tables. https://ww3.arb.ca.gov/fuels/lcfs/fuelpathways/pathwaytable.htm.
[22] California Health and Safety Code, Section 43025 through 43029.

Table F-13. California Low Carbon Fuel Standard carbon intensity targets

	Carbon intensity (grams of CO_2 equivalent emissions per megajoule)	
Year	**Diesel**	**Motor gasoline**
2011	94.41	95.55
2012	94.18	95.31
2013	96.99	97.90
2014	96.50	97.41
2015	95.52	96.42
2016	94.54	95.43
2017	93.07	93.94
2018	91.60	92.46
2019	94.17	93.23
2020	92.92	91.98
2021	91.66	90.74
2022	90.41	89.50
2023	89.15	88.25
2024	87.89	87.01
2025	86.64	85.77
2026	85.38	84.52
2027	84.13	83.28
2028	82.87	82.04
2029	81.62	80.80
2030−2050	80.36	79.55

Source: California Low Carbon Fuel Standard

Table F-14. Sample carbon intensities

Fuel	Description and notes	Grams of CO_2 equivalent emissions per megajoule	Note
DSU	Petroleum diesel (ULSD)	100.45	(1)
BTL_NOCCS	Liquids from biomass with no carbon sequestration	-3.00	(2)
CTL_NOCCS	Liquids from coal 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)	54.79	(5)
FAME_PLM	Biodiesel: palm oil	83.25	(6)
FAME_YGR	Biodiesel: waste yellow grease	20.43	(7)
FAME_WGR	Biodiesel: white grease (calculated)	35.01	(8)
NERD_SBO	Renewable diesel: Midwest soybean oil hydrogenation	44.01	(9)
NERD_PLM	Renewable diesel: palm oil (calculated)	82.16	(10)
NERD_YGR	Renewable diesel: yellow grease (calculated)	6.049	(11)
NERD_WGR	Renewable diesel: tallow (white grease)	34.31	(12)
MG	California E10 baseline gasoline	100.82	(13)
ETA	Ethanol (advanced): Brazilian sugarcane	46.82	(14)
ETC	Ethanol: cellulosic (average)	28.61	(15)
ETH	Ethanol: California average corn (80% dry mill, 20% wet mill)	70.06	(16)
GN_SBO	Green naphtha: same as NERD	39.75	(17)
GN_PLM	Green naphtha: same as NERD (calculated)	44.01	(18)
GN_YGR	Green naphtha: same as NERD	39.75	(19)
GN_WGR	Green naphtha: same as NERD	39.75	(20)
CNG	Natural gas (nonrenewable) (for CNG vehicles)	79.21	(21)
EV	Electricity (average California mix)	23.97	(22)
LPG	LPG from refinery	83.19	(23)
PYO	Distillate refined from pyrolysis oil	27.33	(24)
PYO	Naphtha refined from pyrolysis oil	23.63	(25)

(1) Search for *Diesel* under "Fuel Type" and *Lookup Table* under "Class" within "current-pathways_al.xlsx" file accessed through "Current Pathways" link at https://ww3.arb.ca.gov/fuels/lcfs/fuelpathways/pathwaytable.htm .

(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 over 100% reduction in CO_2 for BTL.

(3) http://www.clf.org/our-work/clean-energy-climate-change/reducing-greenhouse-gas-emissions/regional-greenhouse-gas-initiative/. 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) Look on California's Air Resource Board website https://ww3.arb.ca.gov/fuels/lcfs/fuelpathways/pathwaytable.htm .

(6) Same as soy biodiesel because palm oil feedstock is lumped with other seed oil feedstock within the 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) Search for *Biodiesel* under “Fuel Category” and *UCO* under “Feedstock” within “current-pathways_all.xlsx” file accessed through “Current Fuel Pathways” link at https://ww3.arb.ca.gov/fuels/lcfs/fuelpathways/pathwaytable.htm.

(8) Search for *Biodiesel* under “Fuel Category” and *Tallow and/or Fat* under “Feedstock” within “current-pathways_all.xlsx” file accessed through “Current Fuel Pathways” link at https://ww3.arb.ca.gov/fuels/lcfs/fuelpathways/pathwaytable.htm.

(9) August 2019 memo from Sean Hill (DOE/EIA/OEA/PNGBA).

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

(11) Search for *Renewable diesel* under “Fuel Category” and *Used Cooking Oil* under “Feedstock” within “current-pathways_all.xlsx” file accessed through “Current Fuel Pathways” link at https://ww3.arb.ca.gov/fuels/lcfs/fuelpathways/pathwaytable.htm.

(12) Search for *Renewable diesel* under “Fuel Category” and *Tallow* under “Feedstock” within “current-pathways_all.xlsx” file accessed through “Current Pathways” link at https://ww3.arb.ca.gov/fuels/lcfs/fuelpathways/pathwaytable.htm.

(13) Search for *CARBOB* under “Fuel Type” and *Lookup Table* under “Class” within “current-pathways_all.xlsx” file accessed through “Current Fuel Pathways” link at https://ww3.arb.ca.gov/fuels/lcfs/fuelpathways/pathwaytable.htm .

(14) Search for *Ethanol* under “Fuel Category” and *Sugarcane* under “Feedstock” and *Brazil* under “Facility Location” within “current-pathways_all.xlsx” file accessed through “Current Fuel Pathways” link at https://ww3.arb.ca.gov/fuels/lcfs/fuelpathways/pathwaytable.htm.

(15) Search for *Ethanol-Cellulosic* under “Fuel Category” within “current-pathways_all.xlsx” file accessed through “Current Fuel Pathways” link at https://ww3.arb.ca.gov/fuels/lcfs/fuelpathways/pathwaytable.htm.

(16) Substitute pathways table for 2019 on California’s Air Resource Board website https://ww3.arb.ca.gov/fuels/lcfs/fuelpathways/subpathwaytable.htm.

(17) Search for *Renewable Naphtha* under “Fuel Type” and *Tier 2* under “Class” within “current-pathways_all.xlsx” file accessed through “Current Fuel Pathways” link at https://ww3.arb.ca.gov/fuels/lcfs/fuelpathways/pathwaytable.htm.

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

(19) Assumed same values as same feedstock Renewable Naphtha SBO pathway.

(20) Assumed same values as same feedstock Renewable Naphtha SBO pathway.

(21) Search for *Compressed Natural Gas* under “Fuel Type” and *Lookup Table* under “Class” within “current-pathways_all.xlsx” file accessed through “Current Fuel Pathways” link at https://ww3.arb.ca.gov/fuels/lcfs/fuelpathways/pathwaytable.htm.

(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) Search for *LPG* under “Fuel Type” and *Lookup Table* under “Class” within “current-pathways_all.xlsx” file accessed through “Current Fuel Pathways” link at https://ww3.arb.ca.gov/fuels/lcfs/fuelpathways/pathwaytable.htm.

(24) Search for *Renewable Diesel* under “Fuel Type” and *from Forest REsidue* under “Feedstock” within “current-pathways_all.xlsx” file accessed through “Current Fuel Pathways” link at https://ww3.arb.ca.gov/fuels/lcfs/fuelpathways/pathwaytable.htm.

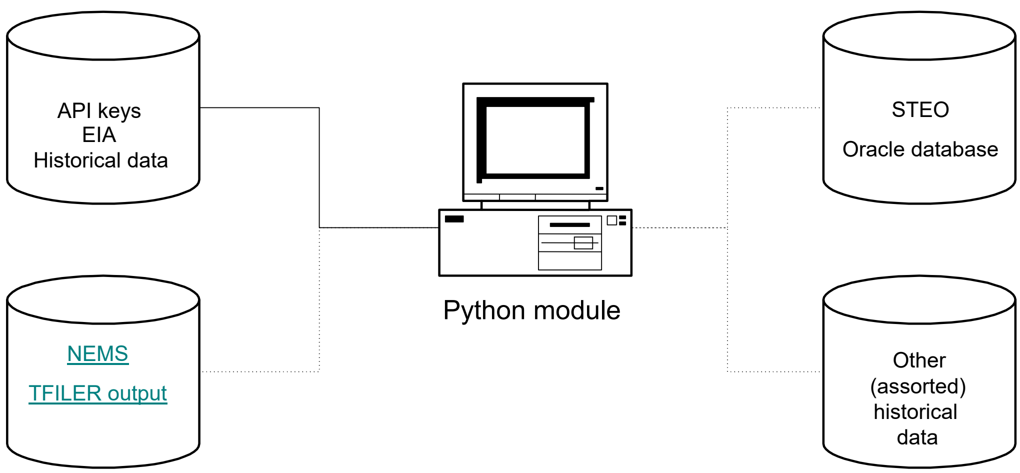
(25) Search for *Renewable Gasoline* under “Fuel Type” and *from Forest Residue* under “Feedstock” within “current-pathways_all.xlsx” file accessed through “Current Fuel Pathways” link at https://ww3.arb.ca.gov/fuels/lcfs/fuelpathways/pathwaytable.htm.

Appendix G. Historical Data Processing

Processing data for LFMM history file

The LFMM uses historical data from a variety of sources. A series of Python modules and scripts collects and aggregates these data to prepare the LFMM input file rfhist.txt. It primarily collects from the Oil and Gas Information Resource System (OGIRS), by way of Application Programming Interface (API) keys, which contains most historical wholesale price and volume information. It also primarily collects from the *Short-Term Energy Outlook* (STEO) Oracle database, which contains data from the STEO forecast that begins at the end of the historical period to the first NEMS projection year. We add a few additional individual historical data elements as inputs or exogenous calculations to the Python module, as well as historical NEMS results from TFILER output, as described below.

Figure G-1. Database linkages for historical data processing



Accessing data

The following provides some background on the component databases that are used in processing the historical input file.

- API Keys: The Python module collects most of its historical data through the use of API keys, which allow access to historical EIA survey data. The Python module includes two tables, one for annual data and one for monthly data. The tables list API source keys, which are used to query and pull the historical dataset from the API Open Database each time the Python module is run and updated.

Table G-1. API source key list sample

LFMM variable	Definition	API keys
RFQEXCRD	Crude oil exports in thousands of barrels per day	PET.MCREXUS2.M
RFQICRD	Crude oil imports in millions of barrels per day	PET.MCRIMUS2.M
RFBDSTCAP	Base distillation capacity in millions of barrels per calendar day	PET.MOCLEUS2.M
RFDSTUTL	Distillation rate as a percentage	PET.MOPUEUS2.M
RFQEXPRDT	Product exports in millions of barrels per day	PET.MBCEXUS2.M

Most of data used by the LFMM are pulled from the API as annual numbers. The only time monthly data are used is for the computation of refinery operable capacity or for year-to-date current year 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 EIA historical survey database is mostly complete; however, the database has a few missing fields. To prevent errors when the queries are executed, the short list of missing values has zeroes appended to them in the Python script that creates the rfhist.txt file.

- STEO Oracle database: The current month's STEO output database is created using a series of Excel spreadsheets generated from the STEO Oracle database. The Python module uses STEO output files to read in the STEO values used for the current STEO years used in the AEO benchmarking cycle.
- NEMS TFILER DATA: Additional historical data is pulled from previous NEMS runs to populate historical data that is either no longer available in EIA API source keys or comes from historical NEMS/LFMM model results. The data are from the NEMS program TFILER, which pulls NEMS run data from existing AEO restart files.

Additional sources are used to create the LFMM history data file.

- Refinery fuel consumption data in Table 47 of the *Petroleum Supply Annual*.
- Global Database Variables: The user defines the AEO year manually in the Python module code. The STEO_year variable does not need to be updated manually because it is automated from STEO release information.
- Historical E85 Prices: Historical E85 Retail Prices are manually updated using the *Clean Cities Alternative Fuel Price Report* provided by DOE's Office of Energy Efficiency and Renewable Energy.

Data processing queries

After all the data from the different sources have been input (or linked) to the Python module, several queries are executed to manipulate the data into LFMM variables. The numbers correspond with the position of the variable being generated in the rfhist.txt file. This code should not need to be changed if the definition of the LFMM variable it represents is not changed. If the definition changes, the individual variable query can be examined and edited.

LFMM variables are linked to variables in input databases (primarily API and STEO) in the Python module by matching up sector and fuel type. A complete list of mappings for both historical and STEO years is available in the following table. Multiple entries for an LFMM variable indicate that more than one API or STEO variable is needed to calculate the value for these variables. The multiple entries are summed to obtain the LFMM variable.

LFMM variable	Definition	API keys	STEO years
RFQEXCRD	Crude oil exports in thousands of barrels per day (Mb/d)	http://api.eia.gov/series/?api_key=YOUR_API_KEY_HERE&series_id=PET.MCREXUS2.M	Assume last historical year
RFQICRD	Crude oil imports in millions of barrels per day (MMb/d)	http://api.eia.gov/series/?api_key=YOUR_API_KEY_HERE&series_id=PET.MCRIMUS2.M	CONXPUS use last historical year percentage to parse to PADDs
RFBDSTCAP	Base distillation capacity (MMb/cd)	http://api.eia.gov/series/?api_key=YOUR_API_KEY_HERE&series_id=PET.MOCLEUS2.M	Not available; use most recent historical year proxy: CODIPUS
RFDSTUTL	Distillation utilization rate as a percentage	http://api.eia.gov/series/?api_key=YOUR_API_KEY_HERE&series_id=PET.MOPUEUS2.M	CODIPUS/last historical year's capacity
RFQEXPRDT	Product exports (MMb/d)	http://api.eia.gov/series/?api_key=YOUR_API_KEY_HERE&series_id=PET.MBCEXUS2.M http://api.eia.gov/series/?api_key=YOUR_API_KEY_HERE&series_id=PET.MTPEXUS2.M http://api.eia.gov/series/?api_key=YOUR_API_KEY_HERE&series_id=PET.MNGEXUS2.M http://api.eia.gov/series/?api_key=YOUR_API_KEY_HERE&series_id=PET.MUOEXUS2.M http://api.eia.gov/series/?api_key=YOUR_API_KEY_HERE&series_id=PET.M_EPOOR_EEX_NUS-Z00_MBBLD.M http://api.eia.gov/series/?api_key=YOUR_API_KEY_HERE&series_id=PET.M_EPOOXXFE_EEX_NUS-Z00_MBBLD.M	Last year's exports of petroleum products
RFPQIPRDT	Product imports (MMb/d)	http://api.eia.gov/series/?api_key=YOUR_API_KEY_HERE&series_id=PET.MNGIMUS2.M	PANIPUS
		http://api.eia.gov/series/?api_key=YOUR_API_KEY_HERE&series_id=PET.MTPIMUS2.M	Last year's exports of petroleum products
CRDUNACC	Unaccounted crude oil		COUNPUS
CRDSTWDR	Crude oil stock withdrawals	http://api.eia.gov/series/?api_key=YOUR_API_KEY_HERE&series_id=PET.MCRSCUS2.M	COSQ_DRAW COSX_DRAW

RFQPRCG	Refinery and blender processing gain	http://api.eia.gov/series/?api_key=YOUR_API_KEY_HERE&series_id=PET.MPGRPUS1.M	PAGLPUS
BLDIMP	Blending component imports	http://api.eia.gov/series/?api_key=YOUR_API_KEY_HERE&series_id=PET.MBCIMUS2.M	MBNIPUS
RFHCXH2IN	Hydrogen input to refineries	http://api.eia.gov/series/?api_key=YOUR_API_KEY_HERE&series_id=PET.M_EPOOOH_YIR_NUS_MBBLD.M	
RFQNGPF	Natural gas used as feedstock for hydrogen production (thousand cubic feet)	http://api.eia.gov/series/?api_key=YOUR_API_KEY_HERE&series_id=PET.8_NA_8NGFSHY_NUS_MMCF.M	
OTHPRDSP	Other liquids product supplied	http://api.eia.gov/series/?api_key=YOUR_API_KEY_HERE&series_id=PET.MOLUPUS2.M	
PRDSTKWDR	Product stocks withdrawals	http://api.eia.gov/series/?api_key=YOUR_API_KEY_HERE&series_id=PET.MTTSCUS2.M	Assume zero
OTHETHCD	Ethanol produced from other feedstock		
RFETHE85	Ethanol for E85 production		Assume zero
RFMTBI	Imported MTBE	http://api.eia.gov/series/?api_key=YOUR_API_KEY_HERE&series_id=PET.MMTIMUS2.M	Assume zero
RFETHIN	Total ethanol into refinery (MMb/d)	http://api.eia.gov/series/?api_key=YOUR_API_KEY_HERE&series_id=PET.MFERO_NUS_1.M	
RFPQUFC	Total imports of unfinished crude oil	http://api.eia.gov/series/?api_key=YOUR_API_KEY_HERE&series_id=PET.MUOIMUS2.M	UORIPUS
RFSPRFR	Rf spr fill rate	http://api.eia.gov/series/?api_key=YOUR_API_KEY_HERE&series_id=PET.MCSSCUS1.M	CONQPUS

AST	Asphalt product supplied (Mb/d)	http://api.eia.gov/series/?api_key=YOUR_API_KEY_HERE&series_id=PET.MAPUPUS2.M	ARTCPUS
COK	Petroleum coke product supplied (Mb/d)	http://api.eia.gov/series/?api_key=YOUR_API_KEY_HERE&series_id=PET.MCKUPUS2.M	PCTCPUS
JTA	Jet fuel kerosene product supplied (Mb/d)	http://api.eia.gov/series/?api_key=YOUR_API_KEY_HERE&series_id=PET.MKJUPUS2.M	JFTCPUS
BIODIMP	U.S. imports of biodiesel supplied (Mb/d)	http://api.eia.gov/series/?api_key=YOUR_API_KEY_HERE&series_id=PET.M_EPOORXFE_IM0_NUS-Z00_MBBLD.M	BDNIPUS
BIODEXP	U.S. exports of biodiesel (Mb/d)	http://api.eia.gov/series/?api_key=YOUR_API_KEY_HERE&series_id=PET.M_EPOORDB_EEX_NUS-Z00_MBBLD.M	BDNIPUS
RENEWDIMP	U.S. imports of renewable diesel (Mb/d)	http://api.eia.gov/series/?api_key=YOUR_API_KEY_HERE&series_id=PET.M_EPOORDO_IM0_NUS-Z00_MBBLD.M	
TDIESEL	Product supplied; distillate fuel oil, 0 ppm−15 ppm sulfur	http://api.eia.gov/series/?api_key=YOUR_API_KEY_HERE&series_id=PET.MD0UP_NUS_2.M	
N2H	Product supplied; no. 2 distillate	http://api.eia.gov/series/?api_key=YOUR_API_KEY_HERE&series_id=PET.MGAUPUS2.M	DFTCPUS
KER	Product supplied; kerosene	http://api.eia.gov/series/?api_key=YOUR_API_KEY_HERE&series_id=PET.MKEUPUS2.M	KSTCPUS
LPG	Product supplied; LPG	http://api.eia.gov/series/?api_key=YOUR_API_KEY_HERE&series_id=PET.MLPUPUS2.M	LGTCPUS
N6B	U.S. ending stocks of residual fuel oil, less than 0.31% sulfur, annual	http://api.eia.gov/series/?api_key=YOUR_API_KEY_HERE&series_id=PET.M_EPPRH_VPP_NUS_MBBLD.M	RFTCPUS * High%

N6I	U.S. ending stocks of residual fuel oil, greater than 1% sulfur, annual	http://api.eia.gov/series/?api_key=YOUR_API_KEY_HERE&series_id=PET.M_EPPRX_VPP_NUS_MBBLD.M	RFTCPUS* Low%
OTH	Product supplied, other petroleum	http://api.eia.gov/series/?api_key=YOUR_API_KEY_HERE&series_id=PET.MGAUPUS2.M	AVTCPUS
		http://api.eia.gov/series/?api_key=YOUR_API_KEY_HERE&series_id=PET.MLUUPUS2.M	LUTCPUS
		http://api.eia.gov/series/?api_key=YOUR_API_KEY_HERE&series_id=PET.MNSUPUS2.M	SNTCPUS
PCF	Product supplied, petrochemical feeds	http://api.eia.gov/series/?api_key=YOUR_API_KEY_HERE&series_id=PET.MPCUP_NUS_2.M	
STG	Product supplied, still gas	http://api.eia.gov/series/?api_key=YOUR_API_KEY_HERE&series_id=PET.MSGUPUS2.M	SGTCPUS
RFQPRDT	Total product supplied	http://api.eia.gov/series/?api_key=YOUR_API_KEY_HERE&series_id=PET.MTTUPUS2.M	Sum STEO product quantities
		http://api.eia.gov/series/?api_key=YOUR_API_KEY_HERE&series_id=PET.MCRUPUS2.M	
TRG	Product supplied; motor gasoline	http://api.eia.gov/series/?api_key=YOUR_API_KEY_HERE&series_id=PET.MGFUPUS2.M	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	OGIRS - m_epooxe_eex_nus	
PETHM (87$bbl)	Historical ethanol price		
ETHEXP	Historical ethanol exports		
QCLRF	Refinery fuel—coal	Paste in from Table 47 of PSA	Assume last historical year ratio of fuel to
QDSRF	Refinery fuel—distillate fuel oil	Paste in from Table 47 of PSA	

QELRF	Refinery fuel—purchased electricity	Paste in from Table 47 of PSA	production Average refiner price of residual fuel oil
QLGRF	Refinery fuel—LPG	Paste in from Table 47 of PSA	
QNGRF	Refinery fuel—natural gas	Paste in from Table 47 of PSA	
QOTRF	Refinery fuel—other	Paste in from Table 47 of PSA	
QPCRF	Refinery fuel—petroleum coke	Paste in from Table 47 of PSA	
QRSRF	Refinery fuel—residual fuel	Paste in from Table 47 of PSA	
QSGRF	Refinery fuel—still gas	Paste in from Table 47 of PSA	
PASIN	Asphalt, road oil, industrial		RFTCUUS
PDSCM	Distillate, commercial		DSTCUUS
PDSEL	Distillate, electricity (plus petroleum coke)		Product prices in 1987 dollars per million British thermal units
PDSIN	Distillate, industrial	SEDS	DSTCUUS
PDSRS	Distillate, residential	SEDS	DSTCUUS
PDSTR	Distillate, transportation	SEDS	DSTCUUS
PJFTR	Jet fuel, transportation	SEDS	JKTCUUS

PKSCM	Kerosene, commercial	SEDS	JKTCUUS
PKSIN	Kerosene, industrial	SEDS	JKTCUUS
PKSRS	Kerosene, residential	SEDS	JKTCUUS
RFQEXCRD	Crude oil exports in thousands of barrels per day	OGIRS - MCREXPx2 (Where x is PADD#)	Assume last historical year
PLGCM	Liquid petroleum gases, commercial		PRTCUUS

LFMM variable	Definition	OGIRS keys	STEO years
PLGIN	Liquid petroleum gases, industrial		PRTCUUS
PLGRS	Liquid petroleum gases, residential		PRTCUUS
PLGTR	Liquid petroleum gases, transportation		PRTCUUS
PMGCM	Motor gasoline, commercial		MGEIRUS
PMGIN	Motor gasoline, industrial		MGEIRUS
PMGTR	Motor gasoline, transportation		MGEIRUS
PPFIN	Petrochemical feedstocks, industrial		PRTCUUS
PRHEL	Residual fuel, high-sulfur, electricity		RFTCUUS
PRHTR	Residual fuel, high-sulfur, transportation		RFTCUUS
PRLCM	Residual fuel, low-sulfur, commercial		RFTCUUS
PRLEL	Residual fuel, low-sulfur, electricity		RFTCUUS
PRLIN	Residual fuel, low-sulfur, industrial		RFTCUUS
PETTR	E85 price	EERE: *Alternative Fuel Report*	

OG GEN GRID90	Cogeneration in thousands of British thermal units (MBtu)	Form EIA-923 Survey	Use last historical year for STEO years 1 and 2
PT GEN GRID90	Cogeneration in millions of British thermal units (MMBtu)	Form EIA-923 Survey	
NG GEN GRID90	Cogeneration in MMBtu	Form EIA-923 Survey	
OT GEN GRID90	Cogeneration in MMBtu	Form EIA-923 Survey	
OG GEN OWN 90	Cogeneration in MMBtu	Form EIA-923 Survey	
PT GEN OWN 90	Cogeneration in MMBtu	Form EIA-923 Survey	
NG GEN OWN 90	Cogeneration in MMBtu	Form EIA-923 Survey	
OT GEN OWN 90	Cogeneration in MMBtu	Form EIA-923 Survey	
OG CAP	Capacity in megawatts (MW)	Form EIA-923 Survey	
PT CAP	Capacity MW	Form EIA-923 Survey	
NG CAP	Capacity MW	Form EIA-923 Survey	
OT CAP	Capacity MW	Form EIA-923 Survey	
OG FUL	Cogeneration fuel consumption	Form EIA-923 Survey	
PT FUL	Cogeneration fuel consumption	Form EIA-923 Survey	

NG FUL	Cogeneration fuel consumption	Form EIA-923 Survey
OT FUL	Cogeneration fuel consumption	Form EIA-923 Survey

Creating LFMM flat-file

To create the final rfhist.txt, we first aggregate file query results and organize them into Python dataframe tables before exporting them to Excel output spreadsheets. The three output tables are **GAMS_US_RFHIST**, **Product_price_data**, and **Refinery_fuel_consumption**.

The final step once the output Excel spreadsheets are saved is to run the Python script that generates the final rfhist.txt file. We convert the three spreadsheets into the necessary rfhist.txt file using the create_RFHIST.py script, which is run from within a Korn shell or a Cygwin window using Python. The create_RFHIST.py Python script also manipulates some data from within the script, so any data or values not found in the Excel spreadsheets may be updated from within create_RFHIST.py.

Processing other historical data

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

Petroleum product price data

We obtain data on petroleum product prices from the Form EIA-782 surveys. Form EIA-782A contains only refiner data, and Form EIA-782B includes petroleum marketers. We did not use Form EIA-782B after 2011 because the survey was suspended. Prices and volumes are produced monthly for the *Petroleum Marketing Monthly* and before 2010 were updated for annual publication in the *Petroleum Marketing Annual*. After 2010, we calculated annual prices from monthly data published in the *Petroleum Marketing Monthly*. This information is also available as a series of API 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 division 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 division.

Historical prices and margins

Historical wholesale and end-use prices from Form EIA-782 are aggregated and presented in a table by product type and census division. The end-use transportation prices include state and federal taxes, but for jet fuel and LPG state taxes are not included before 1995.

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