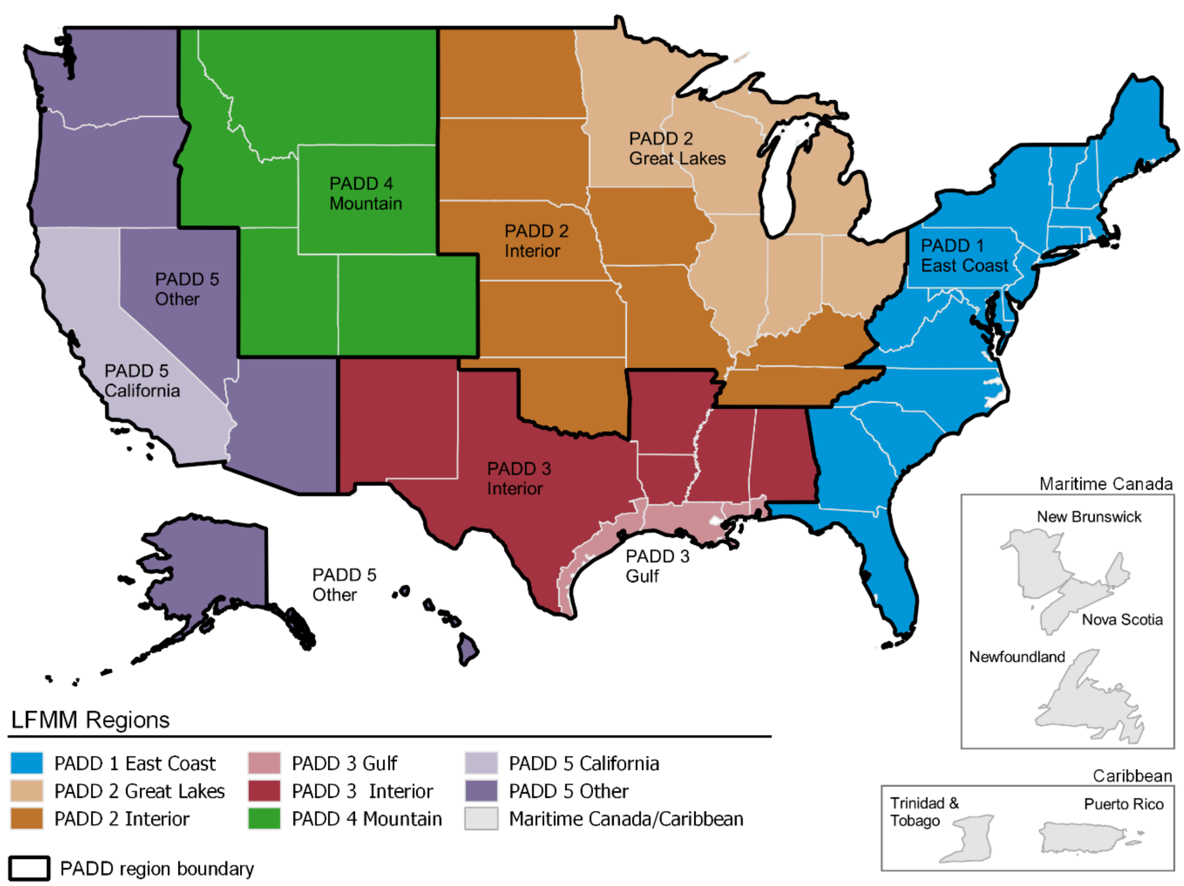
Liquid Fuels Market Module

The National Energy Modeling System (NEMS) Liquid Fuels Market Module (LFMM) projects petroleum product prices and sources of liquid fuels supply for meeting petroleum product demand. The sources of liquid fuels supply include petroleum-based fuels, such as domestic and imported crude oil, petroleum product imports, and unfinished oil imports. They also include non-petroleum-based inputs, such as alcohols, ethers, esters, corn, biomass, natural gas, and coal. In addition, liquid fuels supply includes natural gas plant liquids production and refinery processing gain. The LFMM also projects capacity expansion and fuel consumption at domestic refineries.

The LFMM contains a linear programming (LP) representation of U.S. petroleum refining activities, biofuels production activities, and other non-petroleum liquid fuels production activity in eight U.S. regions. It also represents refining activity in the non-U.S. Maritime Canada/Caribbean refining region, which predominantly serves U.S. markets. To better represent policy, import/export patterns, and biofuels production, the eight U.S. regions are created by subdividing three of the five Petroleum Administration for Defense Districts (PADDs) (Figure 1).

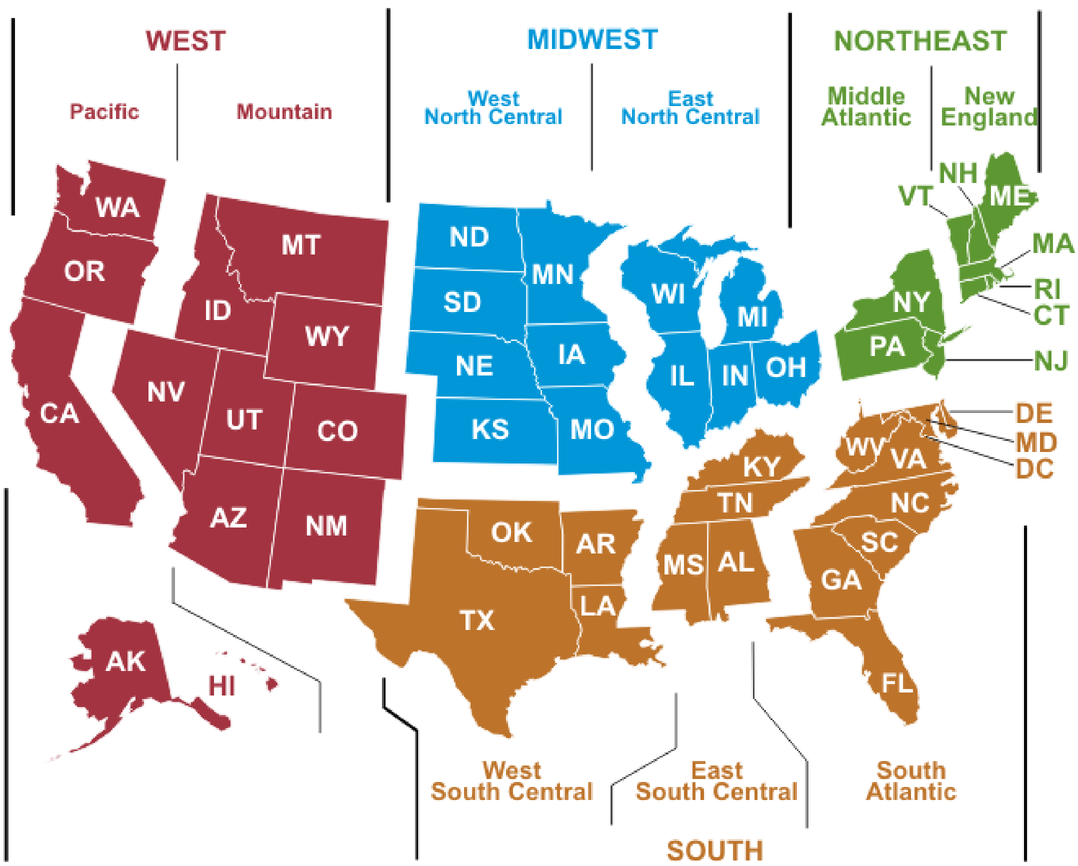
Figure 1. Liquid fuels market module regions



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

The LP model also represents supply curves for crude oil imports and exports, petroleum product imports and exports, biodiesel imports, and ethanol imports and exports. The nine LFMM regions and import/export curves are connected in the LP via crude oil and product transport links. To interact with other NEMS modules with different regional representations, certain LFMM inputs and outputs are converted from sub-PADD regions to other regional structures and vice versa. For example, the LP model converts end-use product prices from the LFMM regions (excluding the Maritime Canada/Caribbean region) into prices for the nine U.S. census divisions (Figure 2) using the assumptions and methods described below.

Figure 2. U.S. census divisions



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

Key assumptions

Product types and specifications

The LFMM models refinery production of the products shown in Table 1.

The LFMM assumes no change in the state and federal specifications for the products listed below. The costs of producing different formulations of gasoline and diesel fuel required under current regulations are determined within the LP representation of refineries.

Table 1. Petroleum product categories

Product category	Specific products
Motor gasoline	Conventional and reformulated (including CARB[1] gasoline)
Jet fuel	Kerosene-type
Distillates	Kerosene, heating oil, low sulfur diesel, ultra-low sulfur diesel, and CARB[1] diesel
Residual fuels	Low sulfur and high sulfur
Liquefied petroleum gases	Ethane, propane, propylene, normal-butane, and isobutane
Petrochemical feedstock	Petrochemical naphtha, petrochemical gas oil, and aromatics
Others	Lubricating products and waxes, asphalt/road oil, and still gas
	Petroleum coke, special naphthas, and aviation gasoline

[1]CARB (California Air Resources Board) establishes regulations for gasoline and diesel specifications in California.
Source: U.S. Energy Information Administration, Office of Energy Analysis

Motor gasoline specifications and market shares

The LFMM models the production and distribution of two types of gasoline: conventional and reformulated. The following specifications are included in the LFMM to differentiate between conventional and reformulated gasoline blends: Reid vapor pressure (RVP), benzene content, aromatic content, sulfur content, olefins content, and the percent evaporated at 200 degrees and 300 degrees Fahrenheit (E200 and E300) (Table 2). The LFMM incorporates the U.S. Environmental Protection Agency (EPA) Tier 3 program requirement that the sulfur content of delivered gasoline be no greater than 10 parts per million (ppm), effective January 1, 2017 [1]. Within the LFMM, refiners are assumed to produce 5 ppm gasoline because some sulfur content will increase during transportation to the end user. By producing 5 ppm gasoline, the refiner ensures that the gasoline will meet the 10 ppm requirement by the time it gets to the end user.

Table 2. Year-round gasoline specifications by Petroleum Administration for Defense District

PADD/Type	Reid vapor pressure (Max PSI)	Aromatics volume percent (Max)	Benzene volume percent (Max)	Sulfur[1] ppm (Max)	Olefin volume percent (Max)	Percent evaporated at 200°F (Min)	Percent evaporated at 300°F (Min)
Conventional							
PADD 1	10.11	24.23	0.62	22.48/5.0	10.8	45.9	81.7
PADD 2	10.11	24.23	0.62	22.48/5.0	10.8	45.9	81.7
PADD 3	10.11	24.23	0.62	22.48/5.0	10.8	45.9	81.7
PADD 4	10.11	24.23	0.62	22.48/5.0	10.8	45.9	81.7
PADD 5	10.11	24.23	0.62	22.48/5.0	10.8	45.9	81.7
Reformulated							
PADD 1	8.8	21.0	0.62	23.88/5.0	10.36	54.0	81.7
PADD 2	8.8	21.0	0.62	23.88/5.0	10.36	54.0	81.7
PADD 3	8.8	21.0	0.62	23.88/5.0	10.36	54.0	81.7
PADD 4	8.8	21.0	0.62	23.88/5.0	10.36	54.0	81.7
PADD 5							
Nonattainment	8.8	21.0	0.62	23.88/5.0	10.36	54.0	81.7
CARB[2] (attainment)	7.7	23.12	0.58	10/5.0	6.29	42.9	86.3

[1]Two values are reported to reflect sulfur levels before and after January 1, 2017, to meet EPA final ruling: "EPA Sets Tier 3 Motor Vehicle Emission and Fuel Standards." The LFMM uses 5 ppm at the refinery to ensure sulfur contamination does not cause the specification to exceed 10 ppm at the market point.

[2]CARB (California Air Resources Board) establishes regulations for gasoline and diesel specifications in California.

Max = maximum, Min = minimum, PADD = Petroleum Administration for Defense District, ppm = parts per million by weight, PSI = pounds per square inch.

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

Reformulated gasoline (RFG) has been required in many areas in the United States since January 1995 [2]. In 1998, EPA began certifying reformulated gasoline using the Complex Model, which required refiners to achieve emissions reductions compared with a baseline for four categories [3]. At present, requirements for air toxics, benzene, and nitrogen oxide emissions have been subsumed by other clean gasoline programs [4], leaving only a volatile organic compounds standard. As an estimate of compliance with this remaining standard, LFMM restricts Reid vapor pressure (RVP) to levels sufficient to achieve these reductions.

The *Annual Energy Outlook 2020* (AEO2020) assumes a minimum 10% blend of ethanol in domestically consumed motor gasoline. Federal reformulated and conventional gasoline can be blended with up to 15% ethanol (E15) in light-duty vehicles of model years 2001 and later and with up to 85% ethanol (E85) used in flex-fuel vehicles (LFMM assumes an average annual ethanol content of 74% for E85 fuel). Reformulated and conventional gasoline can also be blended with 16% biobutanol. Actual levels will depend on the ethanol and biobutanol blending value and relative cost-competitiveness with other gasoline blending components. In addition, current state regulations, along with marketplace constraints, limit the full penetration of E15 in the projection period. The Energy Independence and

Security Act of 2007 (EISA2007) defines a requirements schedule for blending renewable fuels into transportation fuels by 2022.

Although RVP limitations are in effect during summer months and, typically, are defined differently by consuming region, the LFMM is not designed to represent RVP at this level of detail. Instead, the LFMM assumes that these variations in RVP are captured in the annual average specifications, which are based on summertime RVP limits, wintertime estimates, and seasonal weights.

Within the LFMM, total gasoline demand is separated into demand for conventional gasoline and for reformulated gasoline by applying assumptions about the annual market shares for each type. In AEO2020, the annual market shares for each region reflect actual 2015 market shares and are held constant throughout the projection period (Table 3).

Table 3. Percentage in market shares for gasoline types by census division

Gasoline type	New England	Middle Atlantic	East North Central	West North Central	South Atlantic	East South Central	West South Central	Mountain	Pacific
Conventional gasoline	14	35	81	85	83	95	69	82	26
Reformulated gasoline	86	65	19	15	17	5	31	18	74

Note: Data derived from Form EIA-782C, *Monthly Report of Prime Supplier Sales of Petroleum Products Sold for Local Consumption*, January–December 2015.
Note: As of January 2007, oxygenated gasoline is included within *conventional gasoline*.
Source: U.S. Energy Information Administration, Office of Energy Analysis

Distillate, residual, and jet fuel specifications and market shares

Distillate fuel in the LFMM consists of low sulfur diesel, ultra-low sulfur diesel (ULSD), and heating oil. Residual fuel (resid) is represented as high and low sulfur resid. Jet fuel is kerosene-based jet fuel. The quality specifications required for each of these fuels (Table 4) include sulfur content, aromatics and/or cetane levels, American Petroleum Institute (API) gravity, and freeze point index.

Table 4. Year-round distillate and residual fuel specifications

Type	Freeze point index (max)	Sulfur ppm (max)	API[1] gravity (max)	Aromatics volume percent (max)	Cetane index (min)
CARB diesel	24.35	10[2]	37.0	10	53
Ultra-low sulfur diesel	24.35	15	37.0	35	40
Low sulfur diesel	24.35	500	37.0	40	40
Heating oil	24.35	3,000	37.0	100	--
Ultra-low sulfur heating oil	24.35	15	37.0	35	40
Jet fuel	28.77	3,000	51.1	30	--
Low sulfur residual fuel oil	--	5,000	12.39	--	--
High sulfur residual fuel oil	--	29,000	13.62	--	--

[1]American Petroleum Institute (API).
[2]The LFMM uses 10 ppm for CARB diesel at the refinery to ensure sulfur contamination does not cause the specification to exceed 15ppm at the market point.

In the LFMM, ULSD is differentiated from other distillates to account for ULSD (highway diesel) regulations related to the Clean Air Act Amendments of 1990 (CAAA90). This ruling currently limits sulfur in ULSD to 15 ppm. AEO2020 also incorporates the nonroad, locomotive, and marine (NRLM) diesel regulation finalized in May 2004 for large refiners and importers. The final NRLM rule established a new ULSD limit of 15 ppm for nonroad diesel by mid-2010. In addition, for locomotive and marine diesel, the rule established an ULSD limit of 15 ppm in mid-2012.

In NEMS, California's share of the Pacific Region (Census Division 9) is required to meet California Air Resources Board (CARB) standards for diesel. The CARB standards currently limit sulfur to 15 ppm. However, the LFMM sets the CARB diesel sulfur requirement to 10 ppm at the refinery to ensure sulfur contamination does not cause the specification to exceed 15 ppm when purchased.

In NEMS, diesel and heating oil demands are provided as an aggregate distillate demand for each end-use sector. The LFMM developed a methodology to parse the distillate demand into diesel and heating oil. Demand for ULSD in LFMM is assumed to be the sum of total transportation distillate demand, 78% of industrial distillate demand, and 67% of commercial distillate demand. LFMM also differentiates ultra-low sulfur heating oil demands as mandated in some states: Connecticut, Delaware, Maine, Massachusetts, New Hampshire, New Jersey, New York, Rhode Island, and Vermont.

Beginning in 2020, the International Maritime Organization's MARPOL Annex 6 rule requires marine vessels traveling in specified international waters to have reduced sulfur emissions, either through the addition of scrubbers to their high sulfur residual fuel-fired engines or through a combination of switching to a compliant lower sulfur fuel mix (low sulfur resid, ultra-low sulfur diesel, or a combination). Although the LFMM does not directly represent the export of fuel specific for use by international marine vessels to meet MARPOL requirements, it does model low sulfur resid and ultra-low sulfur diesel production and allows for exports of each to the global international market. In addition, the TDM provides the LFMM with demand for any fuel purchased at U.S. ports by marine vessels.

End-use product prices

End-use petroleum product prices are based on marginal costs of production plus production-related fixed costs, distribution costs, and taxes. The marginal costs of production are determined within the LP and represent variable costs of production, including additional costs for meeting reformulated fuels provisions of CAAA90. Environmental costs associated with controlling pollution at refineries are implicitly assumed in the annual update of the refinery investment costs for the processing units.

The costs of distributing and marketing petroleum products are represented by adding product-specific distribution costs to the marginal refinery production costs (product wholesale prices). The distribution costs (Table 5) are obtained from a set of base distribution markups.

Table 5. Petroleum product end-use markups by sector and census division

2019 dollars per gallon

			Census division						
Sector/product	New England	Middle Atlantic	East North Central	West North Central	South Atlantic	East South Central	West South Central	Mountain	Pacific
Residential sector									
Distillate fuel oil	1.01	1.15	0.00	0.00	1.10	1.05	0.89	0.73	1.13
Kerosene	0.00	0.92	1.00	1.01	0.86	1.51	0.93	1.08	0.00
Liquefied petroleum gases	1.48	1.45	1.01	0.95	1.32	1.46	1.21	0.91	1.12
Commercial sector									
Distillate fuel oil	0.69	0.39	0.00	0.00	0.40	0.39	0.34	0.52	0.56
Gasoline	0.57	0.46	0.40	0.42	0.42	0.40	0.36	0.41	0.59
Kerosene	0.00	0.95	1.00	1.02	0.85	1.41	0.74	1.04	0.00
Liquefied petroleum gases	0.50	0.54	0.51	0.51	0.00	0.53	0.54	0.40	0.30
Low-sulfur residual fuel oil[1]	0.00	-0.08	0.00	0.00	0.16	0.00	0.46	0.00	0.00
Utility sector									
Distillate fuel oil	0.20	0.72	0.00	0.00	0.50	0.18	0.20	0.61	0.53
Low-sulfur residual fuel oil[1]	0.00	0.10	0.00	0.00	0.04	-0.04	-0.51	0.00	0.62
Transportation sector									
Distillate fuel oil	0.45	0.55	0.45	0.35	0.41	0.40	0.37	0.43	0.79
E85[2]	0.44	0.37	0.36	0.32	0.34	0.31	0.29	0.33	0.40
Gasoline	0.28	0.30	0.29	0.24	0.24	0.18	0.19	0.29	0.45
High/low-sulfur residual fuel oil[1]	0.00	-0.04	0.07	-0.41	-0.17	-0.25	-0.42	0.00	1.24
Jet fuel	0.01	0.03	0.03	0.07	0.03	0.01	0.03	0.01	0.00
Liquefied petroleum gases	0.33	0.50	1.28	1.28	0.15	1.19	0.94	0.78	0.80
Industrial sector									
Asphalt and road oil	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Distillate fuel oil	0.58	0.41	0.00	0.00	0.58	0.50	0.49	0.60	0.62
Gasoline	0.57	0.46	0.45	0.43	0.43	0.40	0.36	0.43	0.51
Kerosene	0.00	0.24	0.20	0.15	0.15	0.70	0.09	0.52	0.00
Liquefied petroleum gases	0.99	1.07	0.56	0.57	0.83	0.49	-0.16	0.72	0.40
Low-sulfur residual fuel oil[1]	0.00	-0.09	0.00	0.00	0.21	0.31	0.40	0.04	0.00

[1]Negative values indicate that average end-use sales prices were less than wholesale prices. This difference often occurs with residual fuel, which is produced as a byproduct when crude oil is refined to make higher-value products such as gasoline and heating oil.

[2]E85 refers to a blend of 85% ethanol (renewable) and 15% motor gasoline (non-renewable). To address cold-starting issues, the percentage of ethanol varies seasonally. The annual average ethanol content of 74% is used.

Note: Data from markups are based on EIA Form EIA-782A, *Refiners'/Gas Plant Operators' Monthly Petroleum Product Sales Report;* EIA Form EIA-782B*, Resellers'/Retailers' Monthly Petroleum Report Product Sales Report;* Form FERC-423, *Monthly Report of Cost and Quality of Fuels for Electric Plants prior to 2008;* EIA Form EIA-923, *Power Plant Operations Report starting in 2008;* EIA Form EIA-759 *Monthly Power Plant Report;* EIA, *State Energy Data Report 2017, Consumption (January 2019);* EIA, *State Energy Data 2017: Prices and Expenditures* (January 2019).

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

State, local, and federal taxes (Tables 6 and 7) are also added to transportation fuels to determine final end-use prices. Tax trend analysis indicates that state taxes increase at the rate of inflation; therefore, state taxes are held constant in real terms throughout the projection period. This assumption is extended to local taxes, which are assumed to average 1% of motor gasoline prices [5]. Federal taxes are assumed to remain at current levels in line with the overall AEO2020 assumption of current laws and regulations. Federal taxes are not held constant in real terms but are deflated as follows:

$$\text{Federal Tax}_{\text{product, year}} = \text{Current Federal Tax}_{\text{product}} / \text{GDP Deflator}_{\text{year}}$$

Table 6. State and local taxes on petroleum transportation fuels by census division

2019 dollars per gallon

			Census division					
New England	Middle Atlantic	East North Central	West North Central	South Atlantic	East South Central	West South Central	Mountain	Pacific
0.32	0.46	0.35	0.24	0.33	0.23	0.20	0.25	0.52
0.33	0.57	0.37	0.24	0.32	0.23	0.20	0.27	0.71
0.15	0.15	0.21	0.23	0.22	0.21	0.16	0.17	0.07
0.24	0.26	0.20	0.19	0.16	0.17	0.17	0.18	0.30
0.00	0.08	0.04	0.07	0.05	0.06	0.17	0.03	0.03

[1]Tax also applies to gasoline consumed in the commercial and industrial sectors.
[2]E85 refers to a blend of 85% ethanol (renewable) and 15% motor gasoline (non-renewable). To address cold-starting issues, the percentage of ethanol varies seasonally. The annual average ethanol content of 74% is used.
Sources: American Petroleum Institute, *State Motor Fuel Taxes by State*, January 2018; The 2018 Sales Tax Handbook (a free public resource site) is used to define taxes for jet fuel.

Table 7. Federal taxes

nominal dollars per gallon

Product	Tax
Gasoline	0.184
Diesel	0.242
Jet fuel	0.043
E85[1]	0.195

[1]E85 refers to a blend of 85% ethanol (renewable) and 15% motor gasoline (non-renewable). To address cold-starting issues, the percentage of ethanol varies seasonally. The annual average ethanol content of 74% is used.
Note: IRS Internal Revenue Bulletin 2006-43.pdf is available on the web.
Sources: Omnibus Budget Reconciliation Act of 1993 (H.R. 2264); Tax Payer Relief Act of 1997 (PL 105-34), *Clean Fuels Report* (Washington, DC, April 1998), and Energy Policy Act of 2005 (PL 109-58)

Crude oil quality

In the LFMM, the quality of crude oil is characterized by average API gravity and sulfur levels. Both domestic and imported crude oil are divided into 11 categories, as defined by the ranges of gravity and sulfur shown in Table 8.

Table 8. Crude oil specifications

Crude oil categories	Crude designation	Sulfur (%)	Gravity (degrees API)
API 50+	Light sweet	<0.5	API≥50
API 40–50	Light sweet	<0.5	40≤API<50
API 35–40 sweet	Light sweet	<0.5	35≤API<40
API 35+ sour	Light sour	≥0.5	API≥35
API 27–35 med-sour	Medium med-sour	<1.1	27≤API<35
API 27–35 sour	Medium sour	≥1.1	27≤API<35
API<27 sweet	Heavy sweet	<1.1	API<27
API<27 sour	Heavy sour	≥1.1	API<27
California	California	1.1–2.6	API<27
Syncrude	Syncrude	<0.5	API≥35
DilBit/SynBit	DilBit/SynBit	>1.1	API<27

Note: Syncrude = synthetic crude oil from oil sands; Dilbit/Synbit = bitumen diluted with lighter petroleum products or synthetic crude oil.
Source: U.S. Energy Information Administration, *U.S. Crude Oil Production Forecast- Analysis of Crude Types*, May 28, 2015.

A composite crude oil with the appropriate yields and qualities is developed for each category by averaging the characteristics of specific crude oil streams in the category. Each category includes both domestic and foreign crude oil, which are used to determine category characteristics. For each category's domestic crude oil volumes, estimates of total regional production are made first. Each region's production is then divided among each of the 11 categories based on that region's distribution of average API gravity and sulfur content. For AEO2020, as required under the Consolidated Appropriations Act, 2016 [6], all crude oil types are permitted to be exported from the United States. For imported crude oil, a separate supply curve is provided (by the International Energy Module) for each category.

Under the Bipartisan Budget Act of 2015 and the FAST Act, AEO2020 models the required Strategic Petroleum Reserve (SPR) drawdown from 2016 to 2025 [7, 8]. The SPR projected sales volumes were converted from fiscal year accounting to calendar year levels using a 0.25/0.75 split between the previous calendar year and the current calendar year. In addition, the crude oil volumes were assumed to be 40% light sweet (API 35–40, sulfur < 0.5%) and 60% medium sour (API 27–35, sulfur ≥ 1.1%).

Capacity expansion

The LFMM allows for capacity expansion of all processing unit types. These processing unit types include distillation units such as the atmospheric distillation unit (ADU), vacuum distillation unit (VDU), and condensate splitters, as well as secondary processing units such as the hydrotreating, coking, fluid catalytic cracking, hydrocracking, and alkylation units. Capacity expansion occurs by processing unit, starting from regional capacities established using historical data.

Expansion occurs in the LFMM when the value received from the sale of products that could be produced with new processing capacity exceeds the investment and operating costs of adding this new capacity, plus the cost of purchasing additional feedstock. The investment costs assume a financing ratio of 60% equity and 40% debt and an after-tax return on investment ranging from 6% for building new refinery processing units to more than 13% for higher-risk projects, such as the construction of a coal-to-liquids plant.

The LFMM models capacity expansion using a three-period (period 1, 2, and 3) planning approach similar to that used in the NEMS Electricity Market Module (EMM). The first two periods contain a single model year (current year and next year, respectively), and the third period represents a net present value of the next 19 years in the projection period. The second and third planning periods are used to establish an economic plan for capacity expansion for the next NEMS model year. In period 2, product demands and legislative requirements must be met. Period 3 acts like a leverage in the capacity expansion decision for period 2, and it is controlled by the discount rate assumptions. Larger discount rates increase the net present value (NPV) of revenue and expenditures in earlier periods and decrease the NPV of revenue and expenditure in later periods. The LFMM uses multiple discount rates for the NPV calculation to represent various categories of risk. For AEO2020, the LFMM uses an 18% discount rate.

Capacity expansion is also modeled for the production of corn and cellulosic ethanol, biobutanol, biomass pyrolysis oil, biodiesel, renewable diesel, coal-to-liquids, gas-to-liquids, and biomass-to-liquids. All process unit capacity that is expected to begin operating in the future is added to existing capacities in their respective start years. The retirement and replacement of existing refining capacity is not explicitly represented in the LFMM.

Capacity utilization of a process unit is the ratio of the actual throughput for a unit to the total capacity for that unit. Throughput for an atmospheric distillation unit (ADU) is typically a blend of crude oils, but historically it has included unfinished oil imports at some refineries. Therefore, historical ADU capacity utilization at these refineries includes both crude oil and unfinished oil imports. Because the LFMM processes only unfinished oil imports in secondary units, downstream from the ADU, an assumed historical percentage of the unfinished oils imported to the refinery was included as part of the throughput when calculating the ADU capacity utilization reported in AEO2020.

Non-petroleum fuel technology characteristics

The LFMM explicitly models a number of liquid fuels technologies that do not require petroleum feedstock. These technologies produce both fuel-grade products for blending with traditional petroleum products and alternative feedstock for the traditional petroleum refinery (Table 9).

Table 9. Alternative fuel technology product type

Technology	Product type	Feedstock	Product yield (percent by volume)
Biochemical			
Corn ethanol	Fuel grade	Corn	100% ethanol
Advanced grain ethanol	Fuel grade	Grain	100% ethanol
Cellulosic ethanol	Fuel grade	Stover	100% ethanol
Biobutanol	Fuel grade	Sorn	biobutanol
Thermochemical catalytic			
Methyl ester biodiesel	Fuel grade	Yellow or white grease, or seed oil	98.5% biodiesel 1.5% glycerol
Non-ester renewable diesel	Fuel grade	Yellow or white grease, or seed oil	98% renewable diesel, 2% renewable naphtha
Pyrolysis	Fuel grade	Agriculture residue, forest residue, or urban wood waste	60% distillate, 40% naphtha
Thermochemical Fischer-Tropsch			
Gas-to-liquids (GTL)	Fuel grade/refinery feed	Natural gas	52% diesel, 23% kerosene, 24.5% naphtha, 0.5% liquid petroleum gas (LPG)
Coal-to-liquids (CTL)	Fuel grade/refinery feed	Coal	51% diesel, 21% kerosene, 28% naphtha
Biomass-to-liquids (BTL)	Fuel grade/refinery feed	Biomass	22% diesel, 46% kerosene, 32% naphtha

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

Estimates of capital and operating costs corresponding to specified nameplate capacities for these technologies are shown in Table 10. The cost data are defined assuming a 2020 base year and are deflated to 2019 dollars using the GDP (gross domestic product) deflator in NEMS.

Table 10. Non-petroleum fuel technology characteristics[1]

AEO2020 2020 basis (2019$)	Nameplate capacity[2] b/sd	Overnight capital cost[3] $/b/sd	Thermal efficiency[4] %	Utilization rate[5] %	Cost of capital[6] (WACC) %	Fixed O&M cost[7] $/d/b/sd	Non-feedstock variable O&M cost[7] $/b
Biochemical							
Corn ethanol	6,800	27,500	49%	100%	11%	7	7
Advanced grain ethanol	3,400	65,600	49%	100%	11%	20	3
Cellulosic ethanol	4,400	206,900	28%	85%	11%	42	1
Biobutanol (retrofit of corn ethanol plant)	6,500	14,300	62%	90%	11%	2	7
Thermochemical catalytic							
Methyl ester biodiesel (FAME)	1,200	29,800	21%	100%	11%	23	8
Non-ester renewable diesel (NERD)	2,100	42,300	21%	95%	11%	24	8
Pyrolysis	5,200	421,000	60%	90%	11%	73	7
Thermochemical Fischer-Tropsch							
Gas-to-liquids (GTL)[8]	24,000	209,600	55%	85%	11%	36	10
Coal-to-liquids (CTL)	24,000	260,900	49%	85%	14%	45	12
Biomass-to-liquids (BTL)	6,000	475,400	38%	85%	11%	78	8

[1]This table is based on the AEO2020 Reference case projections for year 2020.
[2]*Nameplate capacity* is the expected size of a unit based on historical builds and engineering estimations. Capacity amounts are provided on an output basis.
[3]*Overnight capital cost* is given in unit costs, relative to nameplate capacity, and it is defined as the cost of a project with no interest incurred or as the lump sum cost of a project as if it were completed overnight. It excludes additional costs from optimism on the first unit and cost reductions on the nth unit as a result of learning effects (e.g., new technology) (see Table 11).
[4]*Thermal efficiency* represents the ratio of the combustive energy of the products to the combustive energy of the feedstock used to produce the products.
[5]*Utilization rate* represents the expected annual production divided by the plant capacity divided by 365 days.
[6]*Cost of capital* is the weighted average cost of capital (WACC) during construction and lifetime operations. This term is used with the plant lifetime and overnight capital cost to compute an amortized unit capital cost ($/b/sd for a year).
[7]*Fixed operations and maintenance (O&M) cost* and *non-feedstock variable O&M cost* affect the annual costs ($/year) and units costs ($/b).
[8]These costs are for a Gulf Coast facility. The costs in other regions, particularly Alaska, are expected to be much higher.
b/sd = barrels per stream day
$/b/sd = dollars per barrel per stream day
Note 1: For all technologies listed, length of construction is assumed to be 4 years and plant lifetime is assumed to be 20 years. Length of construction affects the interest that accrues during construction and plant lifetime affects the amortized cost of capital.
Note 2: Values from this table come from analysis of reports and discussions with various sources from industry, government, and the U.S. Department of Energy Fuel Offices and National Laboratories. These values represent the cost and performance of typical plants under normal operating conditions for each technology.
Key sources reviewed are listed in Notes and Sources at the end of this section.
Source: U.S. Energy Information Administration

Overnight capital cost is the anticipated cost of completing a project from start to finish, including working capital but excluding time-related costs, such as accrued interest and depreciation of assets (i.e., the lump sum cost of a project as if it were completed overnight). Because some components of technologies have not yet been proven on a commercial scale, a technology optimism factor is applied to the assumed first-of-a-kind overnight capital cost. This factor is a multiplier that increases the first-of-a-kind plant cost (e.g., 1.2 for BTL). The multiplier is an estimate of the underestimated construction errors and underestimated costs in building the first full-scale commercial plant. As experience is gained (after building the first four units), the technology optimism factor is gradually reduced to 1.0, after which the overnight capital cost may be reduced as a result of learning (reflected through new technology).

The learning function has the nonlinear form:

$$OC(C) = a*C^{-b},$$

where C is the cumulative capacity (or number of standard-sized units) for each technology component and OC represents the overnight capital cost expected with cumulative capacity C of the technology.

The learning function in NEMS is determined at a component level. Each new technology is broken into its major components, and each component is identified as revolutionary, evolutionary, or mature. Different learning rates are assumed for each component, based on the level of construction experience with the component. In the case of the LFMM, the second and third phases of a technology will have only evolutionary/revolutionary (fast) and mature (slower) learning components, depending on the mix (percentage) of new and mature processes that comprise a particular technology.

The progress ratio (pr) is related to the speed of learning or learning rate (LR) (e.g., how much costs decline for every doubling of capacity). The reduction in capital cost for every doubling of cumulative capacity (i.e., LR) is an exogenous input parameter for each component. The progress ratio and LR are related by:

$$pr = 2^{-b} = (1 - LR).$$

The parameter *b* is calculated from the second half of the equality above:

$$b =-(\ln(1-LR)/\ln(2)).$$

The parameter *a* is computed from initial overnight cost and capacity conditions of the nonlinear learning curve:

$$a = OC (Co)/Co^{-b}.$$

Note that Co (or (k+1) in Table 11) is the assumed cumulative capacity, which is the number of units built as of the beginning of the current time period/year plus 1. In addition, OC(Co) is factored into two components: unadjusted overnight capital costs and the learning type fraction (*m* in Table 11).

In the LFMM, both parameters *a* and *b* are calculated offline for each advanced process unit, maturity phase, and learning speed (fast/slow), and they are read into the model as input values.

As a new technology matures, the capital cost is expected to decline, reflecting the principle *of learn by doing* and manufacturing experience. This principle is implemented in the LFMM much like the methodology used in the EMM. The learning occurs in three phases. The first phase is represented by the linear phase out of optimism (and some revolutionary learning) over the first four plants (such that the optimism factor for the fifth and later plants is 1.0). The non-linear learning function shown above is used for the second (up to 32 plants built) and third (beyond 32 plants) phases.

Each technology was assessed to determine the mix of technological maturity of each component (revolutionary, evolutionary, or mature). This assessment was used to define what percentage (m) of the cost would decline slowly (slow meaning mature) versus quickly (fast meaning evolutionary/revolutionary) as a result of learning. Next, for each learning category (fast and slow), a rate of learning (f) is assumed (i.e., a percentage reduction in overnight capital cost for every doubling of cumulative capacity).

The overall learning factor is the weighted combination of the fast and slow learning factors (OC), weighted by the percentage that each component represents of the technology. Model parameters for both optimism (first-of-a-kind) and learning (after the fourth unit is built) are shown in Table 11 for applicable technologies.

Table 11. Non-petroleum fuel technology learning parameters

Technology type	Cumulative plants (k)	Phase 1 1st-of-a-kind optimism	Phase 2 5th-of-a-kind fast[1]	Phase 2 5th-of-a-kind slow[1]	Phase 3 32nd-of-a-kind fast[1]	Phase 3 32nd-of-a-kind slow[1]
All technology types	Cumulative plants (k)	< 4	4	4	32	32
Cellulosic ethanol	Optimism factor and revolutionary learning	1.20	1.0	1.0	1.0	1.0
	Learning type fraction (m)	--	33%	67%	33%	67%
	Learning rate (f)	--	0.25	0.10	0.10	0.05
Pyrolysis	Optimism factor and revolutionary learning	1.20	1.0	1.0	1.0	1.0
	Learning type fraction (m)	--	33%	67%	33%	67%
	Learning rate (f)	--	0.25	0.10	0.10	0.05
Biomass-to-liquids (BTL)	Optimism factor and revolutionary learning	1.20	1.0	1.0	1.0	1.0
	Learning type fraction (m)	--	15%	85%	15%	85%
	Learning rate (f)	--	0.10	0.01	0.10	0.01
Coal-to-liquids (CTL)	Optimism factor and revolutionary learning	1.15	1.0	1.0	1.0	1.0
	Learning type fraction (m)	--	15%	85%	15%	85%
	Learning rate (f)	--	0.10	0.01	0.10	0.01
Gas-to-liquids (GTL)	Optimism factor and revolutionary learning	1.10	1.0	1.0	1.0	1.0
	Learning type fraction (m)	--	10%	90%	10%	90%
	Learning rate (f)	--	0.10	0.01	0.10	0.01

[1]Fast = evolutionary/revolutionary learning; slow = mature learning

Note: Parameters *a* and *b* (see text) are calculated offline where *b* = func(f) and *a* = func(k, m, f, *b*).

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

Biofuels supply

Supply functions for corn, non-corn grain, and cellulosic biomass feedstocks are provided on an annual basis through 2050 for ethanol production (blended into transportation fuel). Supply functions for soy oil, other seed-based oils, and grease are provided on an annual basis through 2050 for biodiesel and renewable diesel production. Available ethanol imports and potential ethanol exports are represented by supply and demand curves, respectively.

- Corn feedstock supplies and costs are represented in the LFMM as corn supply curves, defined using U.S. corn supply/cost data and corn-to-ethanol data provided by Polysys in the NEMS Renewable Fuels Module (RFM). Operating costs of corn ethanol plants are from the U.S.

Department of Agriculture (USDA) survey of ethanol plant costs [9]. Energy requirements come from a study about energy consumption by corn and ethanol producers [10].

- Biodiesel and renewable diesel feedstock supplies include seed oils, yellow grease, and white grease. Seed oils include soybean, cottonseed, sunflower, and canola oils. All seed oil supplies, except soybean oils, are provided externally to NEMS. The price and supply data for soybean oil supply are provided by Polysys in the RFM. Based on a 2017/2018 estimate by USDA [11], the LFMM assumes that 30% of the soybean oil supply is used for biodiesel. The soybean oil price is used as a proxy for defining the price in the seed oil supply curves. The supply data for yellow and white grease available for biodiesel production are a function of regional population, fat production, and an estimate of how much fat is available for biodiesel production. Corresponding costs are about 75% of soybean oil supply costs.
- Cellulosic (biomass) feedstock supply and costs are provided by the RFM in NEMS. Initial capital costs for biomass cellulosic ethanol are from a research project reviewing cost estimates from multiple sources. Operating costs and credits for excess electricity generated at biomass ethanol plants are from a survey of literature [12].
- Ethanol export demand curves allow corn ethanol to be exported to the world. The curve is an isoelastic demand curve built from an initial price, quantity, and elasticity (Po, Qo, eps=-0.4). For historical years, Po is estimated to be 50% higher than the historical domestic wholesale ethanol price, with a 1% growth each projection year. Qo is assumed to grow 2.5% from the previous year, beginning with historical 2019 levels. Po is in dollars per barrel ($/b), and Qo in thousand barrels per calendar day (Mb/cd).
- Ethanol import supply curves represent sugarcane ethanol available for import from Brazil. The curve is an isoelastic supply curve built from an initial price, quantity, and elasticity (Po, Qo, eps=0.4). For historical years, Po is estimated to be 2% higher than the historical domestic wholesale ethanol price, with a 2% growth each projection year. Qo is assumed to grow 1% from the previous year, beginning with historical 2019 levels. (Po in $/b, Qo in Mb/d)
- To model the Renewable Fuel Standard (RFS) in EISA2007, several assumptions were required:
    - The penetration of cellulosic ethanol into the market is limited before 2023 to several planned projects with aggregate nameplate capacity of about 18.2 million gallons per year. Planned capacity through 2021 for pyrolysis and biomass-to-liquids (BTL) processes is about 46 million gallons per year.
    - Methyl ester biodiesel (FAME) production contributes 1.50 credits toward the advanced mandate.
    - Renewable diesel fuel, cellulosic diesel fuel (including that from pyrolysis oil), and Fischer-Tropsch diesel contribute 1.70 credits toward the cellulosic mandate.
    - Cellulosic drop-in gasoline contributes 1.54 credits toward the cellulosic mandate.
    - Imported Brazilian sugarcane ethanol (contributes 1 credit) counts toward the advanced renewable mandate.
    - Separate biofuel waivers can be activated for each of the four RFS fuel categories.
    - Biodiesel and BTL diesel are assumed to be compatible with diesel engines without significant infrastructure modification (either in vehicles or delivery infrastructure).

- Ethanol is assumed to be consumed as E10, E15, or E85, with no intermediate blends. The cost of placing E85 pumps at the most economical stations is spread over diesel and gasoline pump costs.
- To accommodate the ethanol requirements, transportation modes are expanded or upgraded for E10, E15, and E85, and most ethanol is assumed to originate in the Midwest, with nominal transportation costs of a few cents per gallon.
- For E85 dispensing stations, the average cost to retrofit an existing station or to build a new station is assumed to be about $160,000 per station (2016 dollars). Interregional transportation is assumed to be by rail, ship, barge, and truck, and the associated costs are included in the LFMM.
- Potential RFS target reductions determined by EPA and/or reflecting RFS credits from fuels (such as biogas) that are not modeled by the LFMM are provided externally to NEMS.

Non-petroleum fossil fuel supply

Gas-to-liquids (GTL) facilities convert natural gas into distillates and are assumed to be built if the prices for lower sulfur distillates reach a sufficiently high level to make production of GTL distillates economical. The earliest start date for a GTL facility in the model is set at 2024.

Coal-to-liquids (CTL) facilities are assumed to be built when low-sulfur distillate prices are high enough to make them economical. A 48,000-barrel-per-day CTL facility is assumed to cost nearly $7.4 billion in initial capital investment (2016 dollars). These facilities could be built near existing refineries. For the East Coast, potential CTL facilities could be built near the Delaware River Basin; for the Central region, near the Illinois River Basin or near Billings, Montana; and for the West Coast, near Puget Sound in Washington. The earliest build date for CTL facilities is assumed to be 2027.

Combined heat and power (CHP)

Electricity consumption at refineries and other liquid fuels production facilities is a function of the throughput of each unit. Sources of electricity consist of refinery power generation, utility purchases, and CHP from other liquid fuels producers (including cellulosic/advanced ethanol and coal- and biomass-to-liquids). Power generators and CHP plants are modeled in the LFMM linear program as separate units, and they are allowed to compete with purchased electricity. Operating characteristics for these electricity producers are based on historical parameters and available data. Sales to the grid or own-use decisions are made on an economic basis within the LP solution. The price for electricity sales to the grid is set to the marginal energy price for baseload generation (provided by the EMM for each NEMS model year).

Short-term methodology

Petroleum balance and price information for 2019 and 2020 are projected at the U.S. level in EIA's *Short-Term Energy Outlook* (STEO), October 2019. The LFMM adopts STEO results for 2019 and 2020, using regional estimates taken from the national STEO projections.

Legislation and regulation

The Tax Payer Relief Act of 1997 reduced excise taxes on liquefied petroleum gases and methanol produced from natural gas. The reductions set taxes on these products equal to the federal gasoline tax, based on British thermal units.

Title II of CAAA90 established regulations for oxygenated and reformulated gasoline and on-highway diesel fuel. These regulations are explicitly modeled in the LFMM. Reformulated gasoline represented in the LFMM meets the requirements of Phase 2 of the Complex Model, except in the Pacific region where it meets CARB 3 specifications.

AEO2020 reflects EPA's Tier 3 Vehicle Emissions and Fuel Standards, which require the average annual sulfur content of federal gasoline to contain no more than 10 ppm after January 1, 2017. For years before 2017, AEO2020 reflects the Tier 2 Motor Vehicle Emissions Standards and Gasoline Sulfur Control Requirements, which require the average annual sulfur content of all gasoline used in the United States to be 30 ppm.

AEO2020 reflects Heavy-Duty Engine and Vehicle Standards and Highway Diesel Fuel Sulfur Control Requirements. All highway diesel must not contain more than 15 ppm sulfur at the pump.

AEO2020 reflects NRLM diesel requirements that nonroad diesel supplies contain no more than 15 ppm sulfur. For locomotive and marine diesel, the action establishes a NRLM limit of 15 ppm in mid-2012.

AEO2020 represents major provisions in the Energy Policy Act of 2005 (EPACT2005) for the petroleum industry, including removal of the oxygenate requirement in RFG.

AEO2020 includes provisions outlined in EISA2007 for the petroleum industry, including a Renewable Fuel Standard (RFS) that increases total U.S. consumption of renewable fuels. To account for the possibility that RFS targets might be unattainable at reasonable cost, LFMM includes a provision for purchasing waivers. The price of a cellulosic waiver is specified in EISA2007. The non-cellulosic LFMM RFS waivers function as maximum allowed Renewable Identification Number (RIN) prices. LFMM also assumes that EPA will reduce RFS targets as allowed by the EISA2007 statute.

AEO2020 includes the EPA Mobil Source Air Toxics (MSAT 2) rule, which includes the requirement that all gasoline products (including reformulated and conventional gasoline) produced at a refinery during a calendar year must contain no more than 0.62% benzene by volume. This requirement does not include gasoline produced or sold in California, which is already covered by the current California Phase 3 Reformulated Gasoline Program.

AEO2020 includes California's Low Carbon Fuel Standard, which aims to reduce the carbon intensity (CI) of gasoline and diesel fuels in that state by 20% from 2010 through 2030.

AEO2020 incorporates the cap-and-trade program within the California Assembly Bill (AB32), the Global Warming Solutions Act of 2006. The program started January 1, 2012, and enforceable compliance obligations began in 2013. Petroleum refineries are given allowances (calculated in the LFMM) in the cap-and-trade system based on the volumetric output of aviation gasoline, motor gasoline, kerosene-type jet fuel, distillate fuel oil, renewable liquid fuels, and asphalt. Suppliers of reformulated blend stock for oxygenate blending (RBOB) and Distillate Fuel Oil No. 1 and No. 2 were required to comply starting in 2015 if the emissions from full combustion of these products are greater than or equal to 25,000 metric tons of CO_2 equivalent ($mtCO_2e$) in any year from 2011 to 2014.

AEO2020 includes mandates passed by Connecticut, Delaware, Maine, Massachusetts, New Hampshire, New Jersey, New York, Rhode Island, and Vermont that aim to lower the sulfur content of all heating oil to ultra-low sulfur diesel over different time schedules. It also includes a transition to a 2% biodiesel content in Maine and Connecticut.

The International Maritime Organization's MARPOL Annex 6 rule that covers cleaner marine fuels and ocean ship engine emissions is not explicitly represented in LFMM, but it is reflected in the effects on transportation and petroleum product export demands, which are provided to the LFMM from the Transportation Demand Module (TDM) and International Energy Module (IEM), respectively, in NEMS. LFMM produces several fuels that can be used to meet marine fuel demands including: ULSD, low sulfur resid, and high sulfur resid (if marine vessel has a scrubber on board).

The AEO2020 Reference case does not extend the $1.00 per gallon biodiesel excise tax credit or the $1.01 per gallon cellulosic biofuels production tax credit during the projection period.

Notes and sources

[1] U.S. Environmental Protection Agency (EPA), "Final Rule for Control of Air Pollution from Motor Vehicles: Tier 3 Motor Vehicle Emission and Fuel Standards."

[2] Federal Register, U.S. Environmental Protection Agency, 40 CFR Part 80, Regulation of Fuels and Fuel Additives: Standards for Reformulated and Conventional Gasoline, Rules and Regulations, p. 7800 (Washington, DC, February 1994).

[3] U.S. Environmental Protection Agency (EPA), "Complex Model used to Analyze RFG and Anti-dumping Emissions Performance Standards."

[4] Electronic Code of Federal Regulations, "Title 40: Protection of Environment, PART 80—REGULATIONS OF FUELS AND FUEL ADDITIVES, Subpart D—Reformulated Gasoline," Standards and Requirements for compliance: §80.41(f)(2) and §80.41(f)(3).

[5] American Petroleum Institute, How Much We Pay for Gasoline: 1996 Annual Review, May 1997.

[6] *Consolidated Appropriations Act, 2016*, H.R.2029, 114th Congress (2015-2016), *Division O – Other Matters, Title I – Oil Exports, Safety Valve, and Maritime Security*, became Public Law No: 114-113 on December 18, 2015.

[7] U.S. Congress, "H.R. 1314 – Bipartisan Budget Act of 2015," Title IV--Strategic Petroleum Reserve, Sec. 401-403, 114th Congress (2015-2016), became Public Law No: 114-74 on November 2, 2015.

[8] U.S. Congress, "H.R. 22 – FAST Act," Sec 32204. Strategic Petroleum Reserve drawdown and sale, 114th Congress (2015-2016), became Public Law No: 114-94 on December 4, 2015.

[9] Shapouri, Hosein and Gallagher, Paul, "USDA's 2002 Ethanol Cost-of-Production Survey," July 2005.

[10] U.S. Department of Agriculture, "2008 Energy Balance for the Corn-Ethanol Industry," June 2010.

[11] U.S. Department of Agriculture (USDA), "U.S. Bioenergy Statistics," data set: Feedstocks, Table 6—Soybean oil supply, disappearance and share of biodiesel use (Table06.xls).

[12] Marano, John, "Alternative Fuels Technology Profile: Cellulosic Ethanol," March 2008.