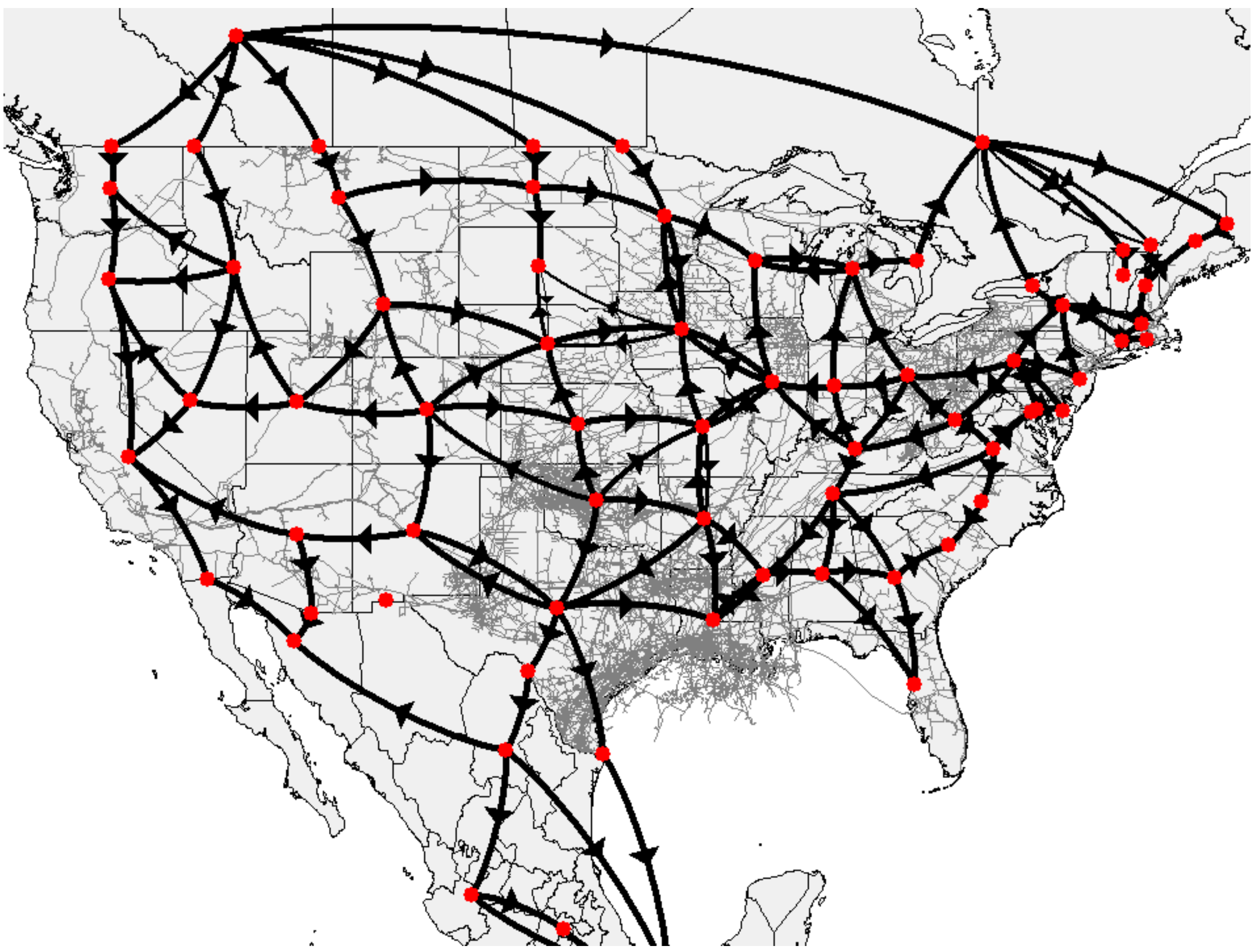
Natural Gas Market Module

The Natural Gas Market Module (NGMM) of the National Energy Modeling System (NEMS) projects wellhead, border, spot, citygate, and delivered prices that balance monthly natural gas supply and demand through a simplified North American pipeline network (Figure 1). These projections are generated using a quadratic program (QP) that maximizes consumer plus producer surplus minus variable transportation costs (with a nonlinear representation). The program is subject to linear constraints: mass balance requirements, pipeline capacity limits, and assumed storage withdrawals/injections. The NGMM model code solves for

- Nonassociated dry natural gas production
- State-to-state flows
- Imports and exports
- Pipeline fuel
- Lease and plant fuel

Figure 1. Natural Gas Market Module network representation



Note: The figure represents the flows (black arrows) from hub to hub (red circles) as determined by the NGMM in a given year. Bidirectional flows indicate the monthly (i.e., seasonal) variability in the direction of natural gas flow. The existing pipeline infrastructure (grey lines) was aggregated to estimate state-level capacity.
Source: U.S. Energy Information Administration, Natural Gas Market Module

Interstate pipeline capacity additions are projected using a similar but modified QP. The NGMM includes a representation of natural gas markets in Canada (two regions) and Mexico (five regions), as well as domestic consumption and production at state and state/substate levels. A complete list of NGMM assumptions and an in-depth description of the methodology is presented in the *Natural Gas Market Module of the National Energy Modeling System: Model Documentation 2018*.

Because other modules in NEMS provide natural gas consumption data to the NGMM at a more aggregate level (generally annually by census division), the NGMM disaggregates these volumes for the Lower 48 states at a monthly level based on historical average shares for the past five years, after subtracting econometrically estimated consumption levels for Alaska. The Oil and Gas Supply Module (OGSM) provides state/substate dry associated-dissolved natural gas production and expected dry nonassociated production as a basis for establishing annual, short-term natural gas supply curves at a state/substate level for the United States and for eastern and western Canada. The NGMM uses these curves in the QP to project realized production levels and their associated wellhead prices.

Liquefied natural gas (LNG) export capacities are projected separately in the module and are used to develop LNG export demand curves for the QP. The module also has fixed additional assumptions about supplemental natural gas supplies, LNG imports, consumption in Canada and Mexico, and supply in Mexico. We use the following NGMM outputs as benchmarks to align with the U.S. Energy Information Administration's (EIA) *Short-Term Energy Outlook* (October 2019) for 2019 and 2020:

National

- Production
- Supplemental supplies
- Lease and plant fuel
- Pipeline fuel[1]
- Storage withdrawals
- Pipeline imports/exports
- LNG imports/exports
- Henry Hub price
- Delivered natural gas price to electric generators

Regional

- Delivered prices to residential and commercial customers

STEO benchmark factors calculated for this alignment in 2020 will be phased out during the next five years except in cases where no phase-out is applied—LNG exports, pipeline imports/exports, and the Henry Hub price.

[1] The STEO forecast for pipeline fuel includes fuel used for liquefaction at LNG export facilities. This total is calculated separately in the NGMM; therefore, the NGMM benchmarks to pipeline fuel after subtracting this volume from STEO. Fuel used for liquefaction is assumed to be 10% of the LNG export volume.

Key assumptions

Supply curves for natural gas production in North America

EIA assumes that projections of associated-dissolved natural gas production do not change in response to current year natural gas prices in the supply/demand balancing process in the NGMM's QP. Nonassociated natural gas is represented in each state/substate (or region for Canada and Mexico) using a short-term supply curve. Each curve is based on a price/quantity pair, where the quantity is the expected production level and the price is assumed to be equal to the price from the previous projection year. For each state/substate, a piecewise linear supply curve with five segments is defined by this price/quantity pair using assumed slopes or elasticities. This curve has four options; the quantities that define the endpoints of these lines and the slopes of each segment (the percentage change in production divided by the percentage change in price) for all four options are in Table 1. Most supply regions are defined by Option 2; Option 1 corresponds to fixed supply that cannot vary with price.

Table 1. Piecewise linear supply curve options and associated parameters

Months after initial in-service month	Option 1	Option 2	Option 3	Option 4
Segment quantities	± 0%, ± 0%	± 3%, ± 9%	± 6%, ± 18%	± 1%, ± 3%
Slope-Segment 1	—	0.8	1.25	0.7
Slope-Segment 2	—	0.7	1.0	0.5
Slope-Segment 3	—	0.5	1.0	0.1
Slope-Segment 4	—	0.3	0.8	0.05
Slope-Segment 5	—	0.2	0.5	0.05

Source: U.S. Energy Information Administration

International representation

Imports and exports of liquefied natural gas to and from Canada and Mexico are set externally in the NGMM, based on projections from the *International Energy Outlook 2019* (IEO2019)(Table 2). Mexico's natural gas consumption in the residential, commercial, transportation, and electric power sectors are assumed to equal the IEO2019 consumption volumes.[2] Mexico's natural gas consumption in the industrial sector is calculated endogenously, and it is assumed to have an *other industrial* component and a component related to oil production. The *other industrial* component is a function of the Henry Hub price, and the oil-related component is related to oil production. The coefficients defining this relationship are estimated using historical data. Consumption of natural gas in Canada is assumed to equal the projections published by the Canada Energy Regulator in *Canada's Energy Future 2018*.

Production in eastern and western Canada is represented in the NGMM just as it is for U.S. states by using values computed by OGSM. Mexico is similarly represented but from production levels set from within the NGMM. Associated-dissolved production is set using a historically estimated equation as a

[2] Although the published natural gas consumption volumes in IEO2019 combine Mexico and Chile, Chile contributes to only the industrial and electric power sectors. The industrial consumption is not used in the NGMM, and electric power sector consumption in 2018 is for Mexico alone when including private electric power producers. Growth in natural gas consumption in Chile's electric power sector is assumed to be negligible.

function of oil production,[3] world oil price, and the previous year's production volumes. In contrast, expected nonassociated production is assumed to be related to the previous year's nonassociated natural gas production and the Henry Hub price. Nonassociated natural gas production from Mexico's shale gas resources is assumed to be undeveloped.

Table 2. Exogenously specified oil production and LNG trade for Canada and Mexico

thousand barrels per year, billion cubic feet per year

	Mexico oil production	Mexico LNG imports	Canada LNG exports
2019	636	630	—
2020	607	450	—
2025	450	100	526
2030	—	—	730
2035	—	—	1,221
2040	—	—	1,879
2045	—	—	1,879
2050	—	—	1,879

LNG=liquefied natural gas.
Source: U.S. Energy Information Administration, *International Energy Outlook 2019*.

U.S. LNG export capacity representation

The capacity to export LNG from the United States beyond existing infrastructure and new projects already under construction through 2025 is set endogenously in the NGMM outside of the QP. The actual level of exports out of each region is determined in the QP using

- A demand curve based on the projected available capacity
- The estimated competing price in Asia or Europe in the given year
- A liquefaction and pipeline transport fee equal to the variable cost component (i.e., excluding assumed capacity reservation or sunk charges for liquefaction)

Exports fall lower than the operating capacity if the regional spot price plus liquefaction, shipping, and regasification costs exceed the price in Asia or Europe. The projects under construction when AEO2020 was developed are assumed to come online or to have come online within the timeframes in Table 3. [4]

For all projects, trains are assumed to ramp up their utilization rates according to Table 4.

[3] Mexico oil production is based on initial assumptions used in IEO2019 from the upstream component of the Global Hydrocarbon Supply Model and the world oil price path in the Reference case. Assumed values are used through 2025, after which oil production is a function of world oil price.
[4] The dates and base capacities for LNG export facilities were consistent with EIA's reported U.S. liquefaction capacity as of October 2019.

Table 3. In-service dates of known LNG export facilities

Project		In-service date
Cameron LNG, Louisiana		
	Train 1	September 2019
	Train 2	March 2020
	Train 3	June 2020
Corpus Christi LNG, Texas		
	Train 2	September 2019
	Train 3	December 2021
Freeport LNG, Texas		
	Train 1	October 2019
	Train 2	March 2020
	Train 3	November 2020
Elba Liquefaction Project, Georgia		December 2019–May 2020
Sabine Pass LNG Terminal, Louisiana		
	Train 6	November 2023
Calcasieu Pass, Louisiana		
	Train 1	November 2023
	Train 2	November 2024
Golden Pass LNG, Louisiana		
	Train 1	November 2024
	Train 2	April 2025
	Train 3	November 2025

LNG=liquefied natural gas.
Source: U.S. Energy Information Administration

Table 4. Percentage of utilization by LNG train number and months after initial in-service date

Months after initial in-service month	Train 1	Train 2	Train 3
In-service month	10	10	50
1	25	25	85
2	50	50	—
3	50	85	—
4	85	—	—

LNG=liquefied natural gas.
Source: U.S. Energy Information Administration

In each projection year, the module assesses the relative economics of constructing and operating one to three generic trains, which each produce 200 billion cubic feet per year, for the next 20 years in four representative Lower 48 states or in a four-train Alaska LNG terminal. This assessment compares a model-generated estimate of the expected market price in Europe and Asia during the period with the expected price of domestic natural gas (assuming the increased exports) in each state, in addition to the assumed charges for liquefaction, shipping, and regasification (shown in Table 5). A present value of the differential is set with a discount rate of 10%. The first train will come online with a positive present value, but the next two trains require a progressively higher present value to reflect additional risk. Once the module determines that a train is economically viable, its LNG export capacity is added for three years in the state showing the greatest positive economic potential. The decision to build a liquefaction facility is assumed to be made four years before the facility first comes online.

Other constraining assumptions are considered, such as the earliest start year and maximum export capacity in each state. The projected market prices of LNG in Europe (National Balancing Point) and Asia (Japan) are based on the assumed volumes shown in Table 6, projected Brent oil prices, and North American LNG exports. The flexible LNG volumes and regional natural gas consumption are consistent with growth rates in IEO2019.

LNG import volumes are based on historical levels and are assumed to total 78 billion cubic feet per year in the projection period after benchmarking to STEO values.

Table 5. Selected charges related to LNG exports

2019 dollars per million British thermal units

	Maryland	Georgia	Louisiana	Texas	Alaska
Liquefaction and pipe fee	3.30	3.30	3.00	3.00	6.12
Reservation charge	3.00	3.00	3.00	3.00	0.00
Shipping to Europe	0.70	0.70	0.86	0.86	2.00
Shipping to Asia	1.92	1.92	1.87	1.87	0.65
Regasification	0.10	0.10	0.10	0.10	0.10
Fuel charge (percent)*	15	15	15	15	15

*Percentage increase in market price of natural gas charged by liquefaction facility to cover fuel-related expenses, largely fuel used in the liquefaction process.
LNG=liquefied natural gas.
Source: U.S. Energy Information Administration

Table 6. International LNG volume drivers for world LNG Europe and Asia market price projections

billion cubic feet

	Flexible LNG[a]	Natural gas consumption: OECD Europe	Natural gas consumption: Asia[c]
2019	4,127	19,710	29,014
2020	3,722	20,130	30,342
2025	5,032	20,587	33,830
2030	7,293	21,054	37,719
2035	9,429	21,532	42,054
2040	11,305	22,021	46,888
2045	16,098	21,521	52,278
2050	16,889	23,303	58,287
2055	17,679	23,555	64,987
2060	18,470	24,090	72,457
2065	19,260	24,637	80,786
2070	20,051	25,197	90,072

[a]Flexible LNG is a baseline projection of the volumes of LNG sold in the spot market or effectively available for sale at flexible destinations.
[b]OECD Europe and non-OECD Europe and Eurasia includes all countries in Europe except Turkey and all former Soviet Union countries except Kazakhstan and Russia.
[c]The following IEO regions are included: China, India, South Korea, and other Asian countries. These regions are defined in the *International Energy Outlook 2019*.
LNG=liquefied natural gas.
OECD= Organization for Economic Cooperation and Development.
Source: U.S. Energy Information Administration (EIA), *International Energy Outlook 2019*.

Other miscellaneous volumes

Although the NGMM receives primary production and consumption volumes from other NEMS modules, other miscellaneous volumes are set within the NGMM, including storage withdrawals and injections, supplemental supplies, and lease and plant fuel:

- Month/state storage withdrawals and injections are held constant during the projection period at the average historical level for the previous five years, after being scaled to ensure that the net withdrawals during the year sum to zero for each state.
- The relatively small supplemental natural gas supply projections, which include synthetically produced natural gas and other gaseous substances mixed with the natural gas stream (such as propane), are held constant at the average historical level for the previous five years and assumed constant throughout the projection period.
- Natural gas plant liquids production, as set in OGSM by state/substate on an annual basis, is moved to an assumed state for processing based on where each state's volumes were moved historically in recent years. The amount of natural gas used in processing facilities in each state is established using the ratio of natural gas plant liquids processed to the natural gas fuel needed to process it in the most recent historical year. Volumes are assumed constant throughout the projection period.

- Similarly, lease fuel consumption is calculated by state/substate using historically based ratios, averaged for the previous five years, of natural gas produced to lease fuel consumed.
- Pipeline fuel use includes fuel used for distribution and storage services, as well as inter/intrastate pipelines. Fuel used for storage and distribution are set using exogenous, historically based ratios of the fuel used. Storage fuel use is assumed to be 0.4% of gross storage injections and withdrawals, and distribution fuel use is assumed to be a state-specific percentage of delivered natural gas volumes (0.3%–6.2%). The remaining volumes are assumed to reflect fuel used on interstate pipelines and are represented as a percentage of state-to-state flows that are lost.[5] In the historical years, these fuel volumes are allocated to state-to-state arcs proportionately to the historical flows in and out of the region to calculate a historically based loss factor for use in the projection period.
- Natural gas used at facilities that liquefy natural gas for export is assumed to equal 10% of the exported volumes.

Pipeline capacity expansion

Currently known pipeline capacity additions, such as projects under construction or projects approved by the Federal Energy Regulatory Commission (FERC), are assumed to be completed in the NGMM and to come online in November of the expected in-service year.[6] After 2021 and before the regular QP is solved in each NEMS iteration, unplanned pipeline capacity additions are determined by running a structurally identical QP but with two changes in primary model inputs: the weather assumption driving consumption levels and the limits on pipeline flows. For the regular QP, consumption levels, provided by NEMS, reflect normal weather, and flows between states/nodes are limited by projected capacity levels.

For the capacity expansion QP, consumption levels are multiplied by a sector- or state-specific factor to reflect the most extreme weather potential. For AEO2020, the weather factors applied to the residential and commercial sectors in winter months are based on historical differences between the most extreme January consumption level and average January consumption in recent years. The other months are based on similar differences in August. The factors for the industrial and electric generation sectors are assumed to be 10% higher than normal in all months. These sectors are not always the driving force behind pipeline additions because they can frequently employ other options in extreme weather. In addition, in the capacity expansion, QP pipeline capacity additions are limited to 40% of the existing capacity. Accordingly, each variable tariff curve is extended from its price point at full utilization to a price point at a utilization rate 40% higher than existing capacity; this price is generally twice as high as the price at 100% utilization. This method is used to reflect the reality that pipeline capacity will only be added if enough users are willing to pay an additional reservation fee.

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[5] Although in AEO2020 all remaining pipeline fuel is assumed to be used by compressor stations on interstate pipelines, the NGMM does structurally allow for pipeline fuel use or losses on arcs coming from supply nodes (i.e., intrastate pipeline transport primarily serves to bring natural gas from processing plants to the interstate pipeline system).

[6] Historically, many projects are planned for the in-service date to coincide with the start of the peak demand (winter) season. See EIA's natural gas Pipeline Projects spreadsheet to view the in-service dates for recently completed and historical natural gas pipeline projects.

Pricing

Spot prices are effectively set within the QP based on the marginal price (shadow price on each balancing constraint in the QP) at each node in the transportation network. Each state has a node where the monthly flows into and out of the state are balanced, including the internal state supply and consumption. The marginal prices at these nodes are used as a proxy for representative state-level spot prices. The price at each supply node (wellhead price) is set equal to the spot price minus the assumed transport or gathering charge ($2019 $0.30/thousand cubic feet). Most of the other arcs in the QP, usually representing state-to-state flows, are assigned a variable tariff in the QP via a curve, which allows the tariff to vary as a function of the pipeline utilization. These curves vary by arc and were informed by historical spot price differentials, historical state-to-state total pipeline capacities, and monthly historical state-to-state flows. All curves have the same general shape: a generally constant or flat tariff at low utilization rates and a sharply increasing rate as utilization approaches 100%. The difference in the price from one node to the next (or basis differential) will also reflect the pipeline fuel loss on the arc, and it can be even higher if pipeline flow constraints on the arc are binding in the QP.

State-level/monthly citygate prices are set using econometrically estimated equations as a function of the spot price and the volume of natural gas consumed by residential and commercial customers in a state during a specific month. Annual/census division delivered prices to residential and commercial customers are set by adding a sector-specific econometrically estimated distributor tariff to the average annual citygate price in the census division, which is calculated by using residential plus commercial consumption in each state/month as a quantity weight. Distributor tariffs are a function of residential consumption per household and commercial consumption per unit of commercial floorspace for the residential and commercial sectors, respectively. Markups to annual/census division delivered prices to industrial customers are set at the historical average from the previous five years of the industrial price minus the average annual spot price in the region, calculated using industrial consumption in each state/month as a quantity weight. Historical industrial prices are estimated based on prices published in EIA's *Manufacturing Energy Consumption Survey*.

For the electric power sector, the NEMS transfers consumption volumes and prices between the NGMM and the Electricity Market Module (EMM) for 16 regions in the Lower 48 states for each of the three seasons. Delivered prices to electric power generators are set by adding a markup to the average spot price in the region/season, which was generated using electric consumption as a quantity-weight. These markups are initially set at the historical average from the previous five years, and they increase/decrease during the projection period as the ratio of electric consumption to other consumption in a given region or season increases or decreases. This method reflects the need for electric generators to purchase more firm pipeline service as their market shares increase. The price in Alaska is set by adding a historically based markup to an econometrically estimated citygate price.

The natural gas used in the transportation sector, excluding pipeline fuel use, is distinguished by

- Fuel type
    - Compressed natural gas (CNG)
    - LNG

- Customer category
    - Personal vehicle (purchased fuel at public station)
    - Fleet vehicle (purchased fuel at private station)
    - Train
    - Ship

All transport modes for a fuel type are assumed to see the same price with five adjustments:

- Vehicles are assumed to pay the state and federal motor fuels taxes for either CNG or LNG.
- Ships are assumed to pay the same price as vehicles minus the state motor fuels tax.
- Trains are assumed to pay the same price as vehicles minus both the state and federal motor fuels tax.
- Retail markups are higher for personal vehicles because of smaller volumes of fuel being sold.
- Retail markups are lower for rail and ship use because of lower infrastructure costs.

The rail and ship prices are further disaggregated in the NEMS Transportation Demand Module, but the prices assigned in the NGMM are not distinguished further.

For delivered prices to the transportation sector for vehicles using LNG, the price for delivered dry natural gas to a liquefaction plant is estimated by using the price for delivered natural gas to industrial customers. The retail price for LNG into a vehicle, train, or ship is equal to

- The sum of the price to industrial customers
- The assumed price to liquefy and transport the LNG to a station
- The retail price markup at the station and the excise taxes

Table 7 shows the national average state excise tax, and in the model these taxes vary by region.

For delivered prices to the transportation sector to vehicles using CNG, the markup from the regional citygate price is based on posted rates in the U.S. Department of Energy, Office of Energy, Efficiency, & Renewable Energy's publications of the *Clean Cities Alternative Fuel Price Report*. These markups are adjusted for any historical changes in the state and federal excise taxes against what is assumed in the projection period. Prices at public and private stations are reported separately. The NGMM assumes that the public prices are for personal vehicles and private stations are for fleet vehicles. These reported prices are assumed to include the retail markup. Therefore, only CNG fleet assumptions are used to calculate a retail markup for rail and shipping transport using CNG's industrial price. The values used throughout the projection period for these components and the primary assumptions behind them are shown in Table 7.

Table 7. Assumptions for setting CNG and LNG fuel prices

Year	CNG private	LNG private	LNG public
Retail markup after dry gas pipeline delivery, with no excise tax (2019$/dge)	0.93	0.74	0.96
Capacity (dge/day)	1,600	4,000	4,000
Usage (percentage of capacity)	80	80	60
Capital cost (million 2019$)	0.93	1.17	1.17
Capital recovery (years)	5	5	10
Weighted average cost of capital (rate)	0.10	0.10	0.15
Operating cost (2019$/dge)	0.40	0.48	0.69
Federal excise tax (nominal$/dge)[1]	0.21	0.25	0.25
State excise tax (nominal$/dge)[2]	0.17	0.15	0.15
Fuel loss for liquefying and delivering LNG (percentage of input volumes)	--	10	10
Fuel loss at station (percentage of input volumes)	0.5	1.0	2.0

dge=diesel gallon equivalent.
CNG= compressed natural gas.
LNG=liquefied natural gas.
Sources: U.S. Energy Information Administration, Office of Petroleum, Natural Gas, and Biofuels Analysis; U.S. Tax Code [1] and state tax codes [2].

Legislation and regulations

Current federal and state motor fuels taxes are applied to both CNG and LNG used in vehicles.

Notes and sources

[1] Source: H.R. 3236 (Public Law number 114-41) and 26 U.S. Code 4041 and 4081 (Internal Revenue Service). Propane and compressed natural gas (CNG) are subject to a federal excise tax of $0.183 per gasoline gallon equivalent (GGE).

[2] Source: U.S. Department of Energy Office of Energy Efficiency and Renewable Energy's Alternative Fuels Data Center. When state motor vehicle fuel tax information was unavailable for alternative fuels, the following state government sources were used:

State of Connecticut Department of Revenue Services, PS 92 (10.1)
Illinois Department of Revenue, Tax Rate Database, Motor Fuel Tax Rates and Fees
Massachusetts Department of Revenue, DOR Motor Fuel Excise
Comptroller of Maryland, Motor Fuel Tax Rates
Montana Legislature, Montana Code Annotated 2019, Chapter 70. Gasoline and Vehicle Fuels Taxes
New Hampshire Department of Safety, Road Toll Bureau
Ohio Department of Taxation, Motor Fuel Tax
State of Rhode Island, Division of Taxation, Taxability of Special Fuels
State of Wisconsin, Department of Revenue, Alternate Fuel Tax
Wyoming Department of Transportation, Fuel Tax Administration, Tax Rates