National Energy Modeling System (NEMS) Natural Gas Market Module

1. Introduction

The Natural Gas Markets Module (NGMM) is the component of the NEMS that represents the North American natural gas transmission and distribution system. The module code is written in the AIMMS software package and is a quadratic program (see Section B) that maximizes consumer plus producer surplus minus transportation costs. The consumer surplus represents the amount of money saved by consumers who would buy natural gas at a given price, but are able to obtain it at a lower one. The producer surplus represents the added revenue of suppliers who could sell natural gas at a lower price, but are able to charge a higher one. Therefore, by maximizing this combined surplus, and subtracting transportation costs and subject to balance and capacity constraints, the model arrives at an equilibrium price for the market, as seen in Figure 1.
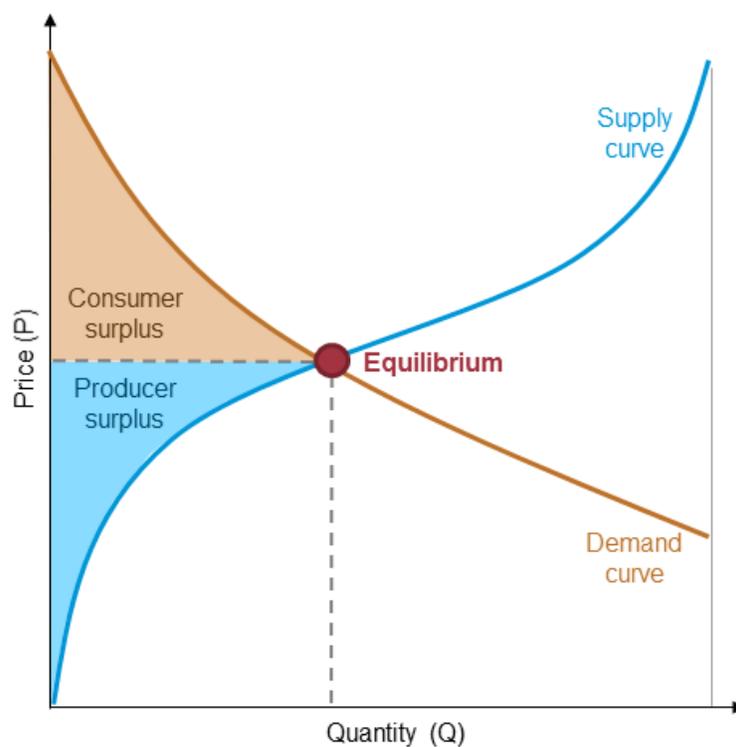

Figure 1 Schematic price-quantity graph illustrating maximized producer-consumer surplus

The NGMM projects monthly production, flows, and prices of natural gas within a state-level representation of the U.S. pipeline network[1] and a regional representation of the Canadian and Mexican pipeline network (Figure 1.1[2]), connecting domestic and foreign supply regions with demand regions.

End-use natural gas consumption by sector, storage, and liquefied natural gas (LNG) export terminals are all integrated into the network by *demand region*. The NGMM projects lease fuel, plant fuel, pipeline fuel, fuel used for liquefaction, LNG export capacity builds, and pipeline capacity expansions. It also projects distributor tariffs to arrive at the delivered price of natural gas to domestic consumers. Although the NGMM provides monthly projections, it generally passes annual totals or averages to the other NEMS modules, most of which operate on an annual basis.

2. Description of the Quadratic Program

2.1 Overview

Within the NEMS, the NGMM represents the transmission, distribution, and pricing of natural gas. Based on information received from other NEMS modules, the NGMM also develops representations of

Figure 2 NGMM natural gas pipeline network representation

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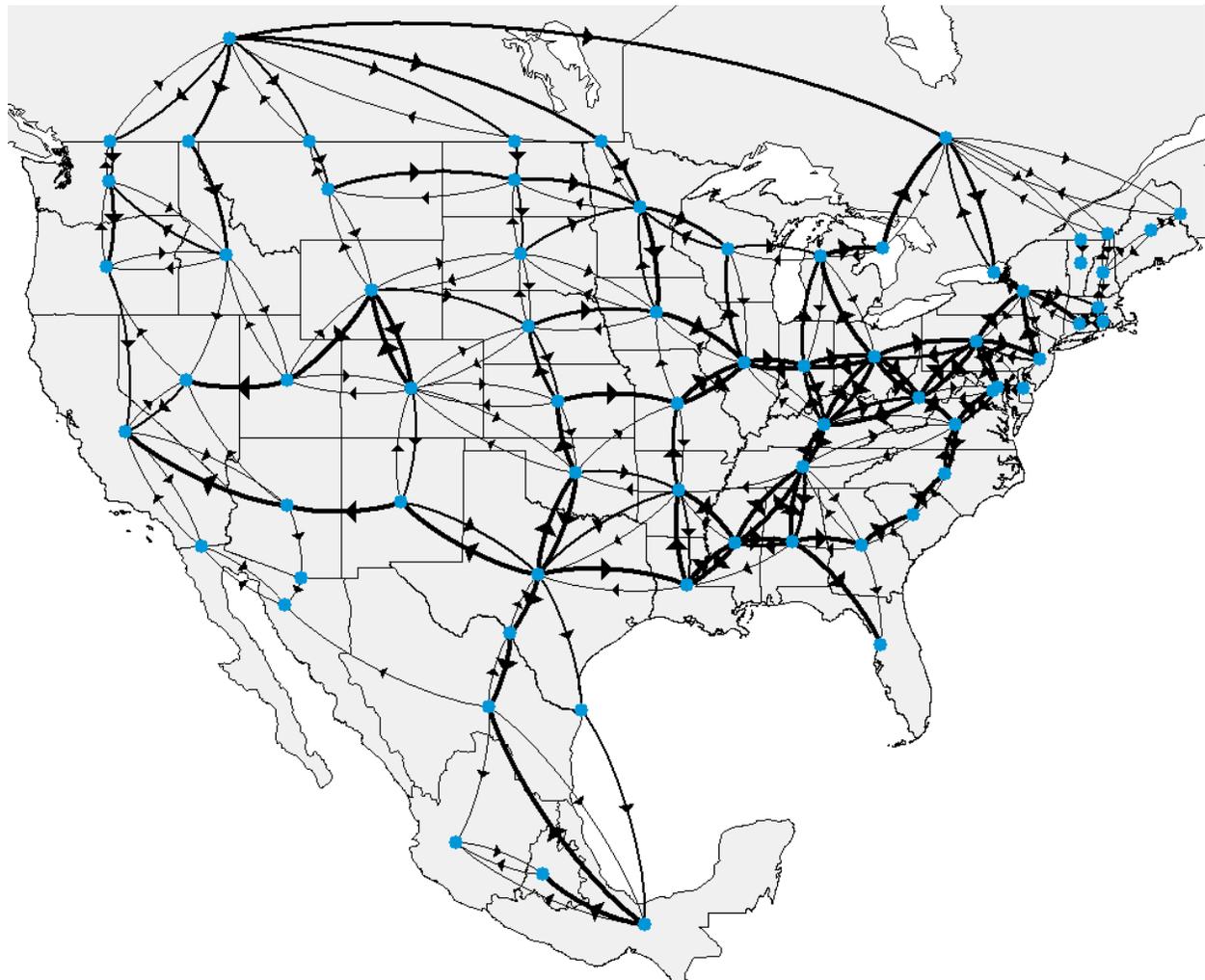
[1] The Alaskan natural gas market is modeled in the NGMM independent of the integrated network.
[2] Blue circles represent transshipment nodes. Arcs represent pipeline capacity existing between nodes in 2019.

the end-use demand for natural gas, the production of domestic natural gas, and the availability of natural gas traded on the international market. The NGMM represents links between natural gas suppliers (including importers) and consumers (including liquefied natural gas (LNG) export terminals) in the Lower 48 states and across the Mexican and Canadian borders through transmission between market hubs. The NGMM projects monthly production, flows, and market clearing prices of natural gas within a state-level representation of the U.S. pipeline network and a regional representation of the Canadian and Mexican pipeline networks.

The NGMM derives natural gas pricing and flow patterns by using a quadratic program (QP) to solve for a market equilibrium across the three main elements of the natural gas market: the supply element, the demand element, and the transmission and distribution network that links them. The methodology allows for the analysis of impacts of regional capacity constraints in the interstate natural gas pipeline network and the identification of primary pipeline capacity expansion requirements.

The Lower 48 states' demand regions are individual states. Canada is divided into eastern and western regions,[3] while Mexico is divided into five regions.[4] For all demand regions, the module projects consumption for five end-use sectors: residential, commercial, industrial, electric power, and transportation (or natural gas vehicles). The U.S. transportation sector is separated into compressed and liquefied natural gas for use in vehicles (retail and fleet), ships, and trains. The NGMM also projects natural gas consumed in lease and plant operations, consumed or lost during interstate transport of natural gas via pipeline, and used for liquefaction at LNG export facilities. Canadian and Mexican demand projections are not provided by other NEMS modules but by EIA's *International Energy Outlook* (IEO). The NGMM models Canadian consumption of natural gas in oil sands production.

One or more domestic supply regions are represented in each NGMM demand region. Both the Canadian and Mexican supply regions match the demand regions. While the NEMS Oil and Gas Supply Module (OGSM) projects U.S. and Canadian expected production of both associated-dissolved (AD) and nonassociated (NA) gas, the NGMM projects the realized, or actual, NA natural gas production required to meet demand at a given price. Mexican natural gas production is represented within the NGMM and is estimated as a function of both world oil price (for associated-dissolved gas) and the Henry Hub price (for nonassociated gas).

To determine import and export volumes, border crossing hubs are represented for each of the Lower 48 states where pipeline capacity to a Canadian or Mexican region exists. Imports of LNG into North America are set to historical levels in the United States and set for Canada and Mexico according to IEO results. U.S. LNG exports are modeled within the NGMM for each state where it is assumed that construction of future liquefaction facilities will be allowed. Any LNG facilities in existence or under construction are included in the model.

To summarize, the NGMM projects the following volumes and prices:

- Realized nonassociated natural gas production and supply prices by oil and gas district (84), annual
- Supplemental natural gas supply by state, annual
- Total dry gas production and supply prices by oil and gas region (13), annual

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[3] The eastern Canadian region includes the provinces of Ontario, Quebec, Newfoundland and Labrador, Nova Scotia, New Brunswick, and Prince Edward Island. The western Canadian region includes the provinces of Manitoba, Saskatchewan, Alberta, and British Columbia, as well as the three territories.

[4] The Mexican demand regions are consistent with the regionality used by the Secretaría de Energía de México (SENER) in reporting natural gas market statistics and modeling natural gas markets: Northeast, Northwest, Interior-West, Central, and South Southeast.

- Realized nonassociated natural gas production and supply prices by Canadian region, annual
- Henry Hub spot price, annual
- Delivered end use prices by sector and Census division, annual
- Delivered end use prices to the transportation sector by transportation mode and Census division, annual
- Delivered end use prices to the electric power sector by Natural Gas-Electricity Market Module (NGEMM) region (17) and season (3)
- Lease, plant, pipeline, and liquefaction fuel use by Census division, annual
- Natural gas pipeline and LNG import and export volumes for Canada and Mexico, annual
- LNG export capacity and volumes by Census division (plus western Canada and Alaska), annual
- Natural gas pipeline flows and capacities by Natural Gas market region (11) or Canada/Mexico region, annual

2.2 Natural gas production and supply

2.2.1. Realized nonassociated natural gas production

The NGMM represents variable, or price-responsive, natural gas supply as the area under a short-term supply curve. This short-term supply curve takes the form of a piecewise linear function based on a price/quantity pair that represents the expected or baseline level of production or supply with an associated price. In the NGMM, the price/quantity pair is represented by the previous projection year's supply price and the expected production from the OGSM. Segments are then built on that point by assuming a price elasticity of supply based on the percentage change from the expected production.

The expected production represents an economically viable level and mix of production that producers are planning to make available to the market without either stressing the system or needing to cut back because of over-supply. The supply curves are built around this expected production point with a shape that drives the solution towards that point while allowing some adjustment to balance the market. In modeling the market balance, the NGMM assumes that changes in production values will be less responsive to price change at volumes less the expected production (i.e., once drilled, wells will produce regardless of price) and more responsive at volumes greater than the expected production (i.e., it will be more costly to speed up the drilling of new wells).

2.2.2. Supplemental natural gas supply

We assume that the following existing sources for synthetically-produced pipeline-quality natural gas (SNG) and other supplemental supplies continue to produce at average historical levels throughout the projection period:

- Synthetic natural gas from coal: While the NGMM assumes that the Great Plains Coal Gasification Plant in North Dakota will operate throughout the projection period, it does not project the building of new coal-to-gas facilities.
- Synthetic natural gas from liquid hydrocarbons: SNG is no longer produced from liquid hydrocarbons in the continental United States, although small amounts were produced in Illinois in some historical years. The QP includes the small amounts produced in Hawaii in its supply/demand balancing constraints for California.
- Other supplemental supplies: EIA defines other supplemental fuels as propane-air, coke oven gas, refinery gas, or biomass gas that is British thermal unit (Btu)-stabilized with steam or oxygen to manufacture pipeline-quality gas that enters the distribution network.

2.2.3. Total natural gas supply

Because the NEMS produces annual projections, NGMM results are generally passed to other NEMS modules as annual totals or quantity-weighted annual averages. While the NGMM and the OGSM pass expected/realized NA production, AD production, and supply prices to each other by OGSM district (of which there are 84), these results are ultimately passed to the NEMS by "oil and gas supply region." There are 14 of these regions in *Annual Energy Outlook*: 7 onshore regions, 3 offshore regions, 3 Alaska regions, and a U.S. total. These regions, as well as their relationships to state boundaries and county-level tight oil and shale gas regions,[5] are shown in Figure 2.4.
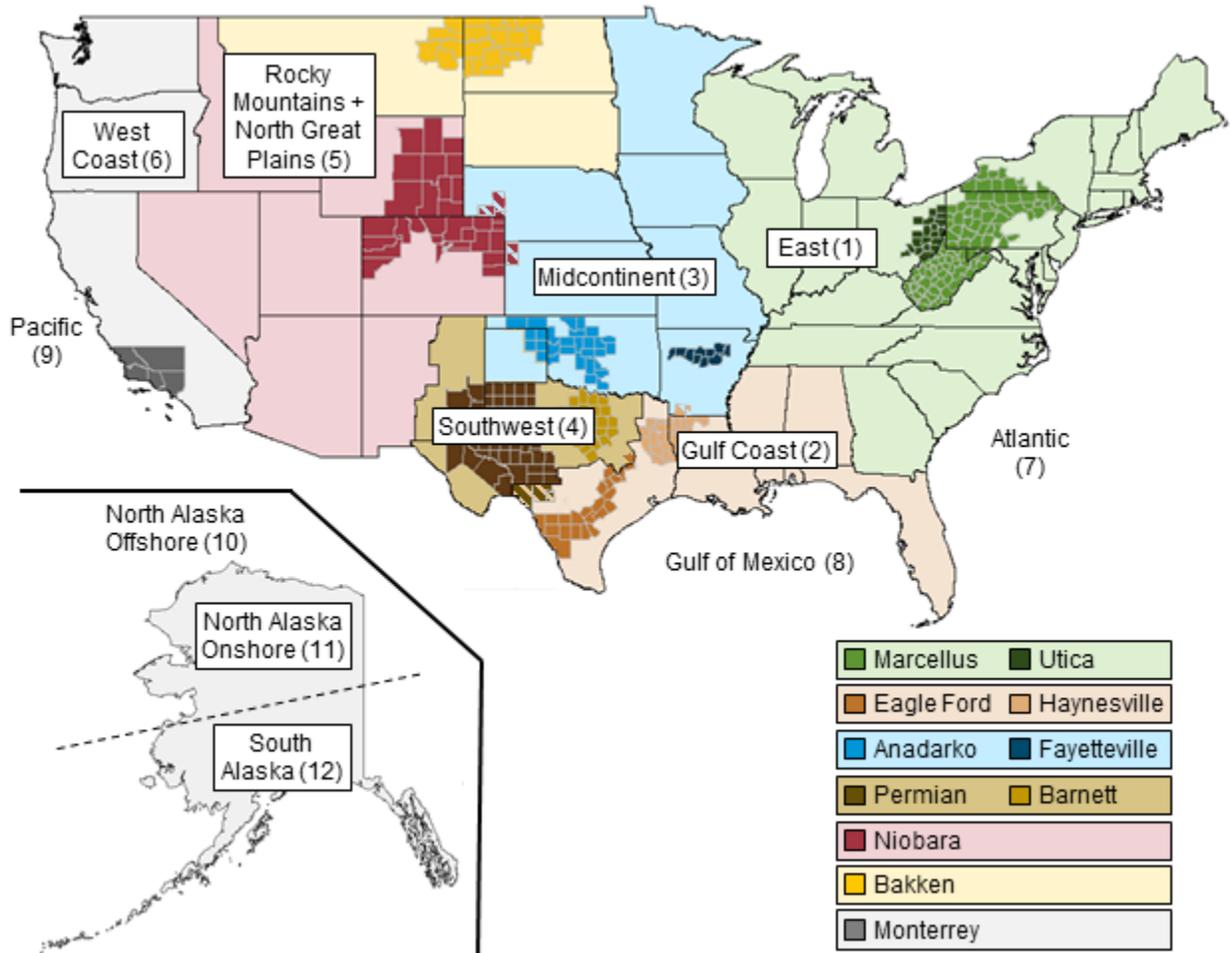
Figure 3. NEMS Oil and Gas Supply Regions and corresponding tight oil and shale gas regions

LNG imports

While LNG imports peaked at 770 Bcf in 2007, since 2013 they have remained relative flat and only averaged 84 Bcf per year through 2017. Cargoes have gone primarily to Everett, Massachusetts, where the LNG terminal operates in conjunction with the Mystic Generating Station power plant. During peak periods of natural gas demand, sporadic deliveries have also gone to Cove Point, Maryland; and Elba

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[5] Tight oil and shale gas regions are used by EIA's *Drilling Productivity Report* (DPR) to estimate changes in oil and natural gas production in selected key basins. Regions for additional plays are included in order to interpret which shale gas basins contribute to the total production for a given region. The DPR combines the Marcellus and Utica regions, projected Appalachia basin production.

Island, Georgia. Because recent historical LNG imports have remained relatively constant, the NGMM sets LNG imports for the projection period at the level of the most recent historical year.

Canada

Canadian natural gas production is modeled in the OGSM (both AD and NA). See Section A.? for a discussion of how Canadian natural gas production is projected in the NEMS. After solving the QP, the NGMM sends supply prices for eastern and western Canada back to the OGSM, which it uses as a basis for projecting natural gas production for the two regions in Canada.

Mexico

The NGMM accounts for three supply types for Mexico: NA gas production, AD gas production, and LNG imports. While it is expected that the production of AD gas, which is co-produced with crude oil, will depend on world oil price, NA gas production is expected to respond to natural gas prices. LNG imports, on the other hand, are needed to meet demand in regions that do not have sufficient access to pipeline gas. Therefore, each of the three supply types are represented independently, using different methodologies.

All Mexican AD gas is assumed to be produced in the South-Southeast region, where Gulf of Mexico reserves have historically been developed and drilled. The NGMM uses a linear time-series regression model (see Section B.1) to estimate AD gas production as a function of the two-year lagged world oil price, a one-year lagged dependent variable, and a constant term. The regression coefficents are assumed constant throughout the projection period.

The NGMM uses a linear time-series regression model to project Mexican NA gas production as a function of the one-year lagged Henry Hub natural gas spot price and a one-year lagged dependent variable. The Henry Hub price is included because the module assumes that gas from Mexican plays will be in direct competition with exports from the United States (i.e., not drilled for natural gas liquids). Therefore, lower-priced U.S. natural gas (represented by the Henry Hub price) will suppress Mexican NA gas production, while higher-priced U.S. natural gas will spur additional development. The model coefficients are estimated for two time periods: the start of the projection until the onset of shale gas production and the period over which shale gas production occurs. The first year of shale gas production is a judgment-based projection. The coefficients for the two time periods differ and are estimated using production projections from EIA's *IEO*.

All Mexican NA gas production during the projection period is assigned to the Northeast, because this region accounts for a majority of historical production and is the location of most of Mexico's shale gas resources, such as the Burgos basin. LNG imports into Mexico are projected in accordance with EIA's *IEO*. In general, LNG imports into Mexico are zero through much of the projection period, because intra-Mexico natural gas pipelines connect supply regions to interior demand regions.

Alaska

The NGMM projects both Alaskan production and consumption in NEMS. BecauseAlaska is not part of the North American natural gas transmission system, these are modeled outside of the QP. The NGMM uses historical data to project Alaskan natural gas demand by end-use sector. It then calculates Alaskan natural gas production by assuming it fulfills the projected demand. Alaskan natural gas demand for the residential and commercial sectors is projected as a function of the following:

- Projected Alaskan population
- National U.S. unemployment rate
- Alaska citygate natural gas price (based on world oil price)

Alaska natural gas consumption for the industrial sector is assumed to be a relatively small volume of natural gas, and it remains constant across the projection period. The use of natural gas in compressed or liquefied natural gas vehicles in Alaska is assumed to be negligible or nonexistent. The Electricity Market Module (EMM) provides a value for natural gas consumption in Alaska by electric generators.

The production of natural gas in Alaska is set equal to the sum of the volumes consumed in and transported out of Alaska plus what is consumed for lease, plant, and pipeline operations, and the balancing item. If a new LNG export facility is built (we assume Kenai will no longer export LNG), production also includes the volume of exported gas plus any related liquefaction fuel that is consumed. Lease and plant fuel is primarily consumed in north Alaska during crude oil extraction and is estimated based on crude oil production in Alaska and the previous year's lease and plant fuel volume. Pipeline fuel is projected as an assumed percentage of total consumption.

2.2.4. Lease and plant fuel

The NGMM projects the consumption of lease and plant fuel, defined as natural gas used in well, field, and lease operations (such as gas used in drilling operations, heaters, dehydrators, and field compressors) and fuel used in processing plants. To project lease fuel consumption, the NGMM calculates the average percentage of dry gas production that is consumed in lease operations for each OGSM region during several historical years, applying these region-specific percentages to the projected volumes of realized dry gas production in the QP's objective function. All of the subregions within a state or within the Gulf of Mexico are assigned the same average historical percentage. Offshore regions outside of the Gulf of Mexico (e.g., offshore California) are combined with onshore regions for the historical average calculations and are assigned the same factor as the rest of the state. The percentages of dry natural gas consumed as lease fuel are assumed constant throughout the projection period.

Similarly, the NGMM projects plant fuel, which is fuel used in natural gas processing plants, by estimating average historical plant fuel volumes as percentages of natural gas plant liquids (NGPL) processing volumes and assuming that the percentages are constant throughout the projection period. Within the NEMS, the OGSM provides historical and projected NGPL production for each OGSM region. The NGMM then determines average historical state shares for the fraction of production processed in each demand region. Using historical NGPL production and these state-level shares, the NGMM calculates the average plant fuel consumed per unit of total NGPL processed over a period of several historical years. The NGMM projects plant fuel volumes by assuming that the percentage of processed NGPL that is consumed as plant fuel is constant throughout the projection period. To control for some anomalies in the historical data, the estimated percentages are limited to a range[6] specified by EIA analysts. States that historically do not process NGPL are assigned a national average percentage. Within the QP, plant fuel is a fixed consumption level (i.e. it does not change with production levels as the NGPL production volume is assumed to be fixed).

2.3. Natural Gas Transmission

2.3.1. Natural gas pipeline flows

Natural gas pipeline flows are projected within the QP. For reporting natural gas regional flows and pipeline capacities, the NGMM uses Natural Gas (NG) regions (Figure 4). This regionality is consistent with the natural gas storage regions used by EIA in its *Weekly Natural Gas Storage Report* and other

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[6] In AEO 2018, the allowed range for plant fuel factors was between 0.005 and 1.7.

natural gas data publications, but it is further disaggregated to provide greater insight into projected flows from and to specific supply and demand regions in the United States.
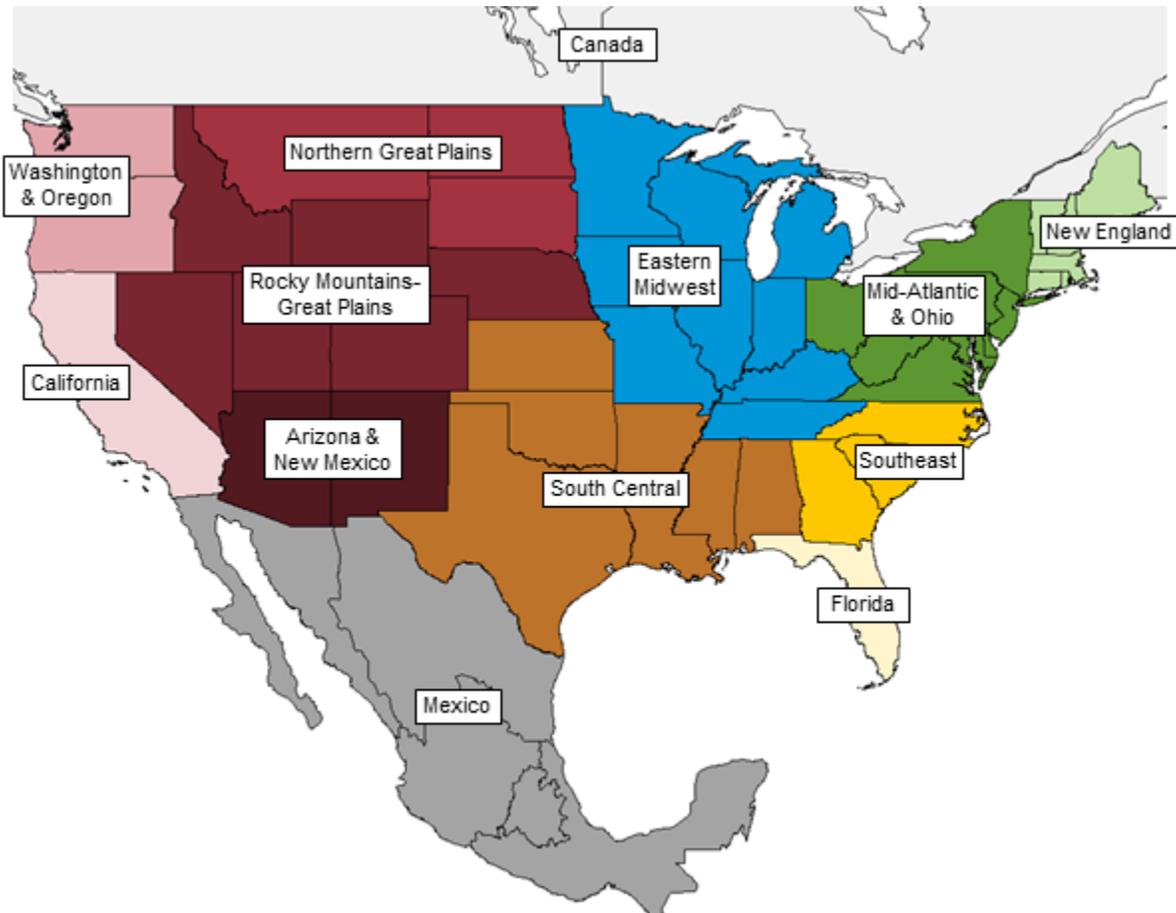

Figure 4 Natural Gas (NG) regions used to report regional flows and capacity

2.3.2. Natural gas pipeline capacities
For the early years of the projection, pipeline capacities between regions are set to historical levels plus planned pipeline capacity expansions. These are defined as pipelines either under construction, approved by the Federal Energy Regulatory Commission (FERC), or those deemed likely to move forward. To project pipeline capacity for the later projection years, EIA analysts run the QP for a peak summer and winter month to determine whether or not the market needs and supports additional pipeline capacity. If so, they add the needed capacity to the projected capacity. They perform this capacity adjustment before running the QP.

2.3.3. Pipeline fuel
The NGMM accounts for three components of natural gas consumed in the operation of pipelines:

- Natural gas used in the distribution pipeline network (i.e., local distribution companies, or LDCs)
- Natural gas used in injecting and withdrawing volumes from storage

- Natural gas used in interstate transmission

Because the NGMM represents the pipeline network at the state level, it only projects flows on interstate pipelines. To account for the other two components of pipeline fuel consumption, the NGMM uses assumed factors (see Appendix E) and projects their consumption by multiplying those factors by residential and commercial consumption (for distribution losses) and storage injections and withdrawals (for storage losses). To account for pipeline fuel used in the transportation of natural gas during transmission on the interstate pipeline system (as well as the associated cost), the module uses historical data to estimate a loss factor for each demand region in the network and then assumes that the loss factors are constant throughout the projection period.

Because data are available for pipeline fuel use at the state level, and flows are reported as one arc between states and measured at the border between them, the model breaks up the arc from state **x** to state **y** into two arcs (one arc from state **x** to the border between **x** and **y** and a second arc from the border to state **y**). This representation assumes that the percentage of natural gas lost, as a function of the starting flow (i.e. the volume prior to fuel loss), on each arc segment is constant within each state. So for the arcs flowing from a state's border into the state transshipment node, the associated interstate pipeline fuel use is a pipeline fuel loss factor multiplied by the flow entering at the border. For the arcs flowing from a state's transshipment node to the state's border, the associated interstate pipeline fuel use is the flow exiting at the border multiplied by a different loss factor (a function of the first loss factor) that corrects for the fuel lost prior to being measured at the border.

To estimate the constant loss factor for each state, we first write the equation for the total interstate pipeline fuel used for natural gas transportation in the state. The total natural gas used in natural gas transporation equals the sum of all losses over all flows coming into the state plus the sum of all losses over flows exiting the state, displayed mathematically as

$$\text{Total NG Lost=}[\text{Loss Factor} \times \text{NG Inflow}]+\left[\left(\frac{\text{Loss Factor}}{\text{1-Loss Factor}}\right)\times \text{NG Outflow}\right].$$

The state's net gain in natural gas supply is calculated as

$$\text{Net Gain in NG Supply=NG Inflow-NG Outflow-Total NG Lost.}$$

Rearranging variables in the two equations above gives the quadratic equation

$$[\text{NG Inflow} \times (\text{Loss Factor})^2] + [\text{Net Gain in NG Supply} \times \text{Loss Factor}] + \text{Total NG Lost} = 0,$$

which can be solved for the Loss Factor using the quadratic formula. These calculations allow the Loss Factor to be estimated based on historical data on natural gas flows into and out of the state.

Estimated pipeline fuel loss factors (after subtracting distribution, storage, and intrastate transportation losses) for several historical years are averaged to arrive at the loss factors used in the NGMM. These loss factors are applied in the QP to account for the quantity lost on the interstate arcs and to effectively account for the cost of the fuel used. The loss factors are applied to projected flow volumes during post-processing to arrive at the total pipeline fuel used in interstate transmission. The three components are then added together, giving the total pipeline fuel used. Because of a lack of historical data, the NGMM does not independently account for pipeline fuel loss in Canada or Mexico.

2.4. Natural gas prices

2.4.1. Supply and spot prices, including the Henry Hub spot price

At each hub or node in the simplified pipeline network represented in the NGMM, the hub balance constraint in the QP forces the flows of natural gas into and out of the node to balance. The shadow price[7] associated with this constraint represents the marginal price at the hub, which is the variable cost of supplying one more unit to the node. The assumption in the NGMM is that this price is indicative of the spot price at this representative node. This assumption is also supported by the construction of the variable tariff curves and the pipeline fuel loss factors, which together are intended to reflect historically-observed basis differentials between reported spot prices as functions of the pipeline utilization rates. The NGMM sets balancing constraints and projects spot prices for each state and month, as well as at each supply point and border crossing. At production nodes, these prices are assumed to reflect the wellhead or supply price. With the exception of the Henry Hub price, the NGMM does not report projected prices at state hubs, but it uses these prices to project citygate and delivered prices. The Henry Hub price is set at the wellhead price in South Louisiana plus an assumed gathering charge.

2.4.2. Delivered natural gas prices by end-use sector

For all end-use demand modules and sectors, consumption volumes and delivered end-use prices are passed within the NEMS at the Census division level.

The NGMM projects delivered natural gas prices by adding a markup to the projected average citygate or average spot price at the appropriate regional level. An annual quantity-weighted average citygate price is projected for each Census division by averaging monthly prices across all months and relevant states, using the residential plus commercial sector consumption levels as weights. Projected residential and commercial prices, as well as some of the vehicle fuel prices, are based on the projected average citygate prices plus a markup. Prices to the industrial and electric generator sectors are based on average spot prices, using the industrial and electric generator consumption levels, respectively, as weights.[8]

Citygate prices

Citygate prices are the prices local distribution companies (LDCs) or utilities pay for natural gas from the pipeline transmission system. They include the cost of the commodity (spot or contract price) as well as any additional costs of transporting natural gas in the pipeline system, applicable taxes, storage fees, and net losses from hedging. The NGMM uses linear regression models to estimate citygate prices for each projection year by state and month. With several exceptions (described below), the average monthly spot price is a reasonable approximation for a commodity cost at the citygate. Therefore, monthly natural gas citygate prices are estimated as a function of the following:

- The average monthly spot price
- A constant monthly fee per unit, estimated by dividing LDC deliveries by the sum of residential and commercial consumption (the bulk of LDC deliveries)
- A constant term, representing any other fixed fees (e.g., storage injection/withdrawals costs)

Historical monthly citygate prices, spot prices, and consumption in the residential and commercial sectors are used to estimate the parameters in the regression model. For most states, the estimated

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[7] See footnote (51).

[8] While the model is structured to allow the user to calculate delivered prices using different markups and different base prices, as relevant, the particular options used for AEO2018 are generally the only ones described in the documentation.

parameters do not vary by month or season. However, using coefficients fixed across months did not always produce reasonable projection results in test runs.

Due to regulations requiring utilities to be able to meet demand for natural gas for their customers during peak periods of consumption, natural gas volumes are typically contracted. Therefore, while citygate prices will rise during periods of high demand, they will often not see the same volatility as spot prices. This is particularly evident in places such as New England, where pipeline constraints limit flows into the area. For four states (Arizona, Oregon, Nevada, and New York) the regression model described above was estimated separately for the winter months (November through February) and the non-winter months to improve the estimation. For the states in New England, Utah, and Delaware, modeling the prices by season still did not provide a reasonable predictor, so prices for the winter months were estimated by setting the November and December price to October's value and setting the January and February price to the average of the year's March price and the previous year's October price.

Delivered end use natural gas prices to the residential sector
Prices charged to residential customers are projected annually for each Census division as the average regional citygate price plus an estimated residential distribution markup. The markup is estimated using a linear regression model with the following independent variables:

- A constant term
- Natural gas consumption per household (where the number of households using natural gas is projected by the Residential Demand Module), which is intended to capture variable charges
- A lagged dependent variable

The model coefficients were estimated using historical data on annual average residential and citygate prices, residential consumption, and the number of residential households using natural gas.

Delivered end use natural gas prices to the commercial sector
Average annual prices charged to commercial customers are projected similarly to the residential sector prices, using the same average citygate prices. However, the markup for the commercial sector is a function of consumption per unit floor space (output from the Commercial Demand Module), total commercial sector consumption, a constant term, and a lagged dependent variable.

Delivered end use natural gas prices to the industrial sector
The NGMM projects average annual prices charged to the industrial sector based on the quantity-weighted average spot price in each Census division, averaged from state/monthly spot prices using industrial consumption as weights, plus a markup.

Average markups by Census division are set based on the historical difference between delivered prices to the industrial sector and this average spot price, and held constant through the projection period. Historical natural gas prices for the industrial sector are estimated rather than extracted directly from annual/state level published EIA prices. These prices only reflect revenues received from industrial customers who purchase gas from local distribution companies, or about 15% of the sector's consumption. However, price data from EIA's Manufacturing Energy Consumption Survey (MECS) are assumed to better approximate prices paid by the whole sector, even though they do not include nonmanufacturing industries.

Since the MECS only provides prices every four years and by the four Census regions, a regression model was used to fill in the industrial prices for the missing years and the regional detail. The historical MECS prices for each census region and year were fit to a linear regression model with the following independent variables:

- Average regional supply price
- Industrial price published in the Natural Gas Annual
- A constant term

The estimated regression model parameters were used to create an estimated historical data series and, by extension, an average historical markup representing the difference between the spot price and the price paid by industrial consumers.

Delivered end use natural gas prices to the transportation sector by transportation mode
End-use, or delivered, natural gas prices to the transportation sector (i.e., for natural gas fueled vehicles) are calculated for two fuel types (compressed natural gas-CNG, liquefied natural gas-LNG) and 4 different modes of transportation: personal vehicles (cars and trucks), fleet vehicles (cars, trucks, and buses), rail, and marine. These prices, 8 in total, have 4 different components:

a) Base price of natural gas delivered to the dispensing station or a LNG facility
b) For LNG, the cost of liquefying and transporting fuel to the dispensing station[9]
c) Retail markup or the cost, above the base price, of delivered CNG or LNG at the dispensing station (including per-unit cost of dispensing fuel)
d) Federal and state motor fuels taxes

For the transportation sector, the module provide three options for the base price (a) of natural gas: citygate prices, industrial sector prices, and electric power sector prices. Using the citygate price as the basis for fuel prices to vehicles implies that dispensing stations buy from a local distribution company (LDC) and have the additional cost of reserving firm capacity on pipelines as part of the end use price. Personal and fleet vehicles fueled by CNG use the citygate price as their base price. When the citygate price is used as a base price, the historical markup is calculated based on the historical difference between the price of CNG from either public stations (i.e. personal vehicles) or private stations (i.e. fleet vehicles) reported in the Office of Energy Efficiency and Renewable Energy's quarterly *Clean Cities Alternative Fuels Price Report[10]* and the historical citygate price.

Using the industrial or electric power sector prices[11] as a base price for the transportation sector indicates that stations or LNG facilities buy natural gas and reserve pipeline space similarly to these other sectors (i.e. on an interruptible basis and in large volumes).

The fuel cost (b) associated with liquefying and transporting LNG to the dispensing station, represented as a loss factor, is assumed to be the same as that projected for LNG export facilities plus an additional loss factor similar to that for CNG.

Retail markups at dispensing stations (c) for the eight categories of natural gas vehicle fuel were calculated based on assumed sizes and costs of generic dispensing facilities, short of motor fuel taxes.[12] These retail markups represent costs that must be added to the retail price in order to recover all capital and operational costs of a dispensing station, and are calculated from the following parameters:

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[9] For AEO2018, the cost associated with the fuel used to liquefy and transport LNG to a dispensing station was captured in the NGMM via a loss factor (LOSS); however, additional charges associated with providing this service (e.g., capital cost recovery) were inadvertently excluded. This will be corrected in the future.

[10] U.S. Office of Energy Efficiency & Renewable Energy, *Clean Cities Alternative Fuel Price Report*.

[11] For AEO2018, all but CNG vehicles are assumed to see prices based on the industrial price.

[12] *Assumptions to the Annual Energy Outlook 2018: Natural Gas Market Module*

- Weighted average cost of capital for a the construction of a dispensing station, representing the discount rate for calculating net present value (%); represents the minimum rate of return required to satisfy investors
- Number of years over which the total capital expenditures are expected to be fully recovered for the dispensing station
- Total capital expenditure required to construct a dispensing station (1987$)
- Daily capacity of a dispensing station, or total volume of fuel that a station can dispense (Mcf/d)
- Expected percentage utilization of a dispensing station
- Cost required to operate a dispensing station per unit of fuel dispensed (1987$/Mcf)

Finally, appropriate federal and state motor fuels taxes (d), net of credits, are added to the price. Federal taxes are held constant in nominal dollars throughout the projection period, consistent with the federal tax code. While the laws for adjusting state taxes vary, a simplifying assumption was applied in the NGMM that state taxes are constant in real dollars of the first projection year. The module therefore assumes that only federal taxes rise with inflation while state taxes do not.

Delivered end use natural gas prices to the electric power sector
In the case of the electric power sector, natural gas consumption and prices are transferred between the NGMM and the EMM by Natural Gas-EMM (NGEMM) regions (Figure 2.7). These regions approximate the relationship between the North American Electric Reliability Corporation (NERC) regions at which the EMM operates and the demand regions used in the the NGMM. For the regions in the Lower 48 states, natural gas prices for the electric power sector are based on the average regional/seasonal spot price, calculated by averaging over state/month spot prices, with state/month electric generator natural gas consumption levels as weights. The base year markup (or the one-year lagged markup for the first projection year) is set to an historical average difference between the delivered price and the spot price in each region/season.
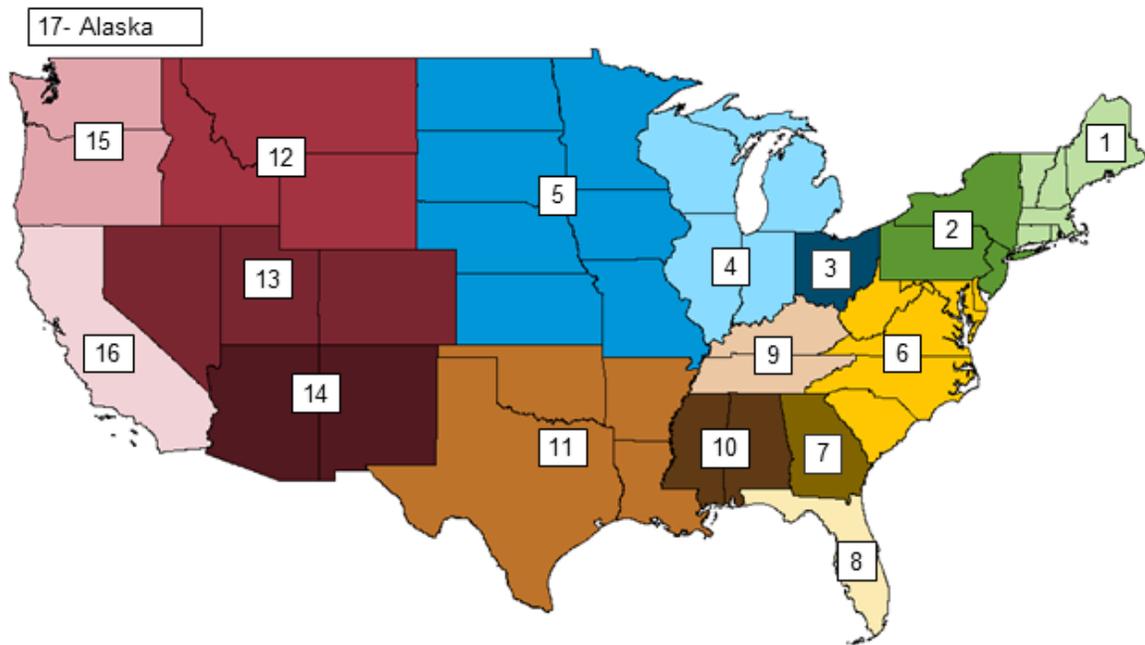
Figure 1 Natural Gas-Electricity Market Module (NGEMM) regions

The projected markup in each year is allowed to increase/decrease from the historical markup depending on how much the projected electric generator consumption increases/decreases compared to consumption in the other sectors.[13] This is intended to reflect that electric generators will likely need to reserve more space on the pipeline system as their market share increases. The module projects a markup for each NGMM region, seasonal period, and projection year. Because these markups can theoretically be negative, the spot price is added to the markup to ensure it is positive and then subtracted after the scaling is applied. The equation describing this markup is below.

$$
\begin{aligned}
\text{This Year's Markup} =\ & \Big[(\text{This Year's NG Spot Price + Last Year's Markup}) \\
& \times \left(\frac{1 + \text{Proportionate Change in Electric Power Sector NG Consumption}}{1 + \text{Proportionate Change in Total NG Consumption}}\right)^{\text{Factor}}\Big] \\
& - \text{This Year's NG Spot Price.}
\end{aligned}
$$

The Factor in the exponent represents the sensitivity of the price markup to changes in the electric power sector's share of total natural gas consumption. The proportionate changes in consumption are computed relative to the current projection year's consumption:

$$
\text{Proportionate Change in Consumption} = \frac{\text{This Year's Consumption} - \text{Last Year's Consumption}}{\text{This Year's Consumption}}.
$$

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[13] This ratio is represented in parentheses in the equation shown and is limited to fall between 0.5 and 2.0.

Alaska is not part of the natural gas transmission and distribution system represented in the NGMM. The delivered price to electric generators in Alaska is assumed constant across seasons and is projected by adding a markup, estimated from historical data, to the projected citygate price for Alaska.

2.5. Natural gas imports and exports

2.5.1. Natural gas pipeline import and export volumes for Canada and Mexico

Pipeline import and export volumes are projected using the flow volumes at border crossings, for which the QP solves through constrained optimization. Rather than projecting volumes sent between state market hubs, the NGMM treats the border crossings between individual states and Canadian or Mexican regions as hubs and only projects flows to and from the state and Canadian or Mexican region into or out of the border crossing hubs.

2.5.2. LNG export capacity

The NGMM QP projects LNG exports of domestically-sourced natural gas. Before running the QP, the module projects liquefaction capacity additions beyond existing capacity and capacity under construction. The QP also projects the utilization of this capacity. To project capacity additions, the module evaluates the long-term economic viability, in each projection year, of adding (or expanding) a generic LNG liquefaction facility consisting of up to three large *trains* of a specified capacity. An LNG *train* is an LNG plant's purification and liquefaction facility. The module performs this evaluation independently for each of the coastal regions of the United States that EIA analysts have identified as possible locations for added LNG export capacity. It then selects the most economically profitable region for any projected construction. It accounts for all assumed restrictions, such as earliest start year or maximum allowable expansion. An underlying assumption is that facilities will be built if consumers are interested in signing long-term contracts at a price that allows cost recovery, so the economic viability is evaluated from the perspective of potential consumers. Once built,[14] the liquefaction facility is assumed to be able to operate at full capacity (accounting for some operational down-time) throughout the rest of the projection period.

To effectively assess the economic viability to consumers in representative world destinations of signing a contract with a new U.S. liquefaction facility versus an assumed alternative, the NGMM calculates a net present value over the assumed lifetime of a contract with the LNG liquefaction facility. This net present value corresponds to the cost of purchasing from the United States versus another global supplier. The module compares the alternative supplier's LNG price, or the world price of LNG at a given destination, over the lifetime of the contract, to the price of U.S. LNG at the consuming destinations. The U.S. LNG price includes a sunk cost to recover the initial investment required to build the facility, the operational costs (including regasification), and the costs of shipping a cargo to the destination.

World LNG price
Fuel prices change in response to supply and demand pressures and the prices of competing fuels. For each world destination represented, the module projects a representative price of LNG based on projected world oil prices and supply and demand variables from EIA's most recent *International Energy*

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[14] The number of years between the decision to build new LNG export capacity and the beginning of its operations is a model assumption. In AEO 2019, new liquefaction facility builds were assumed to have a completion date four years after the year of the decision to build.

Outlook. Projections may be updated to account for recent market events as well as additional nonpublished information and analyses based on EIA's International Natural Gas Model (INGM) results.

World natural gas prices are assumed to start at their recent historical ratio to the world oil price. Over time, the price of LNG becomes less tied to the world oil price (WOP) as the ratio of flexibly-priced LNG to the representative regional net natural gas demand increases relative to its base year level, according to the following basic equation:

$$\text{Projected LNG Price} = (\text{Projected WOP})^{\alpha}$$
$$\times \left(\frac{\text{Projected Supply/Demand Ratio}}{\text{Historical Supply/Demand Ratio}}\right)^{\beta}.$$

The β parameter represents the sensitivity of the LNG price to changes in supply and demand pressures, while the α parameter represents the sensitivity of the LNG price to changes in the WOP. The historical supply/demand ratio is based on data for the most recent historical year for which data are available.

The concept is that the proportionate change in the supply/demand ratio reflects the tightness or looseness of the world LNG market pushing or pulling, respectively, the LNG price toward or away from the world oil price.

The (historical and projected) LNG supply volume used in the supply/demand ratios is the sum of the following volumes:

- Volume of flexibly priced LNG on the world market, excluding volumes from the United States
- LNG exports from the United States
- LNG exports from U.S. liquefaction facilties under consideration for construction

U.S. LNG prices
In order to assess whether the next incremental amount of U.S. LNG exports from an additional LNG train will be competitive in global markets over the look-ahead period, the NGMM first estimates a U.S. LNG price for each relevant domestic region. It then add costs for liquefaction (including fixed charges), regasification, and transport overseas to arrive at a potential price for this U.S. LNG in global markets.

The projected natural gas supply price for each potential U.S. export region is used for the current projection year; for all future projection years, the supply price for that year from the last NEMS cycle is used and adjusted to account for the difference between the natural gas production in the last NEMS cycle and the estimated production in that year in the current cycle. This difference equals the difference, between the two cycles, in existing and potential LNG export capacity for the future year, as well as any domestic changes to demand. For years that extend beyond the last projection year, the price is set by applying a growth rate to the regional supply price in the last year in which growth is consistent with the growth trend in the later projection years.

Net present value of LNG export capacity
When the NGMM projects the addition of a new LNG export facility, it finds the region where the new facility's net present economic value will be maximized. After the NEMS projects LNG prices for Europe and Asia over the assumed lifespan of a liquefaction plant, the NGMM compares these prices to the projected prices for LNG exports from the United States to these destinations. The price difference represents the added value to the consumer (or to whoever is able to capture the economic return) of purchasing LNG from the United States over other potential supply options. The module accumulates

the projected price differences over the assumed lifetime of the plant and applies an assumed discount rate (to reflect the time value of money) to compute the net present value of the LNG export facility for each projection year.

The region with the resulting highest net present economic value is assumed to be the location of the next liquefaction train, subject to the following other conditions:

- The earliest potential start year in the selected region is sufficiently early.
- The maximum allowed export volume in the selected region is not exceeded.
- The maximum number of trains built in a year in the United States is not exceeded (reflecting practical limits on the necessary resources/manpower for such specialized construction).
- No existing LNG export facility in the region is high-risk, which is defined as having a net present value lower than the risk threshold.

The module assumes that the construction will take a number of years specified by EIA analysts, and it phases in the additional LNG volumes over time.

2.5.3. LNG export volumes and liquefaction fuel use

The decision to build additional LNG export capacity in a given demand region is projected as described above, outside of the QP. The QP projects capacity utilization, including that of new capacity built, and LNG export volumes. Because the QP decision variable for export volumes also includes the natural gas consumed during liquefaction, the module disaggregates the two volumes. It first computes the area under the LNG demand curve, then multiplies this total volume by the assumed percentage of the export volume required to liquefy the natural gas.

The utilization of existing LNG export capacity is projected using a linear demand curve as shown in Figure 6. The world LNG price is projected as discussed in Section 2.5.2 above. If the U.S. LNG export price in a demand region, minus sunk costs, is at or below the world LNG price, then the LNG export capacity in that region will be fully utilized. If the U.S. LNG export price in the demand region is greater than the world price, however, capacity will be underutilized. At or above a certain price, which we assume is approximately 150% of the world LNG price, LNG exports reach zero (a consequence of the demand curve structure).
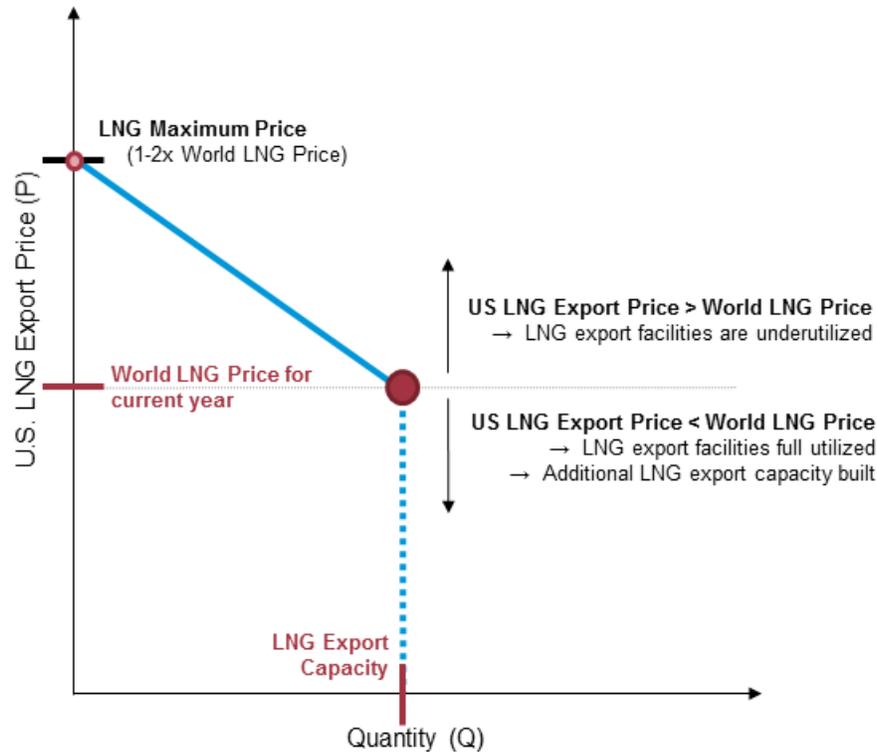
Figure 6 Schematic representation of LNG export demand curve used in NGMM

For Alaska and western Canada, the two regions where LNG exports are not considered part of the QP, the NGMM assumes that the LNG export capacity is fully utilized. In both of these cases, it is not the supply price of natural gas that determines market competitiveness; rather, it is the comparatively high capital cost of the liquefaction projects, including the new pipeline infrastructure required, that would make building new LNG export capacity uneconomic. Their locations on the Pacific coast also mean that shipping costs to Asia are much less than the shipping costs for LNG exports from the Gulf Coast. Therefore, once LNG export facilities are built, LNG from Alaska or western Canada would be expected to out-compete all other global LNG supplies on a variable cost basis. The corresponding fuel used for liquefaction in Alaska is included in the U.S. total; fuel used for liquefaction is not explicitly calculated for western Canada.

3. Objective function

The QP's solution maximizes consumer plus producer surplus, minus variable transport costs. The objective function represents consumer demand as the sum of the areas below the LNG export demand curves for all LNG export regions. It represents production and transportation costs as the sum of the following:

- The area below the supply curves for all supply types and supply regions
- Variable transport costs, which include the gathering charges applied to all flows from a supply region to a hub, as well as tariffs, represented by the sum of the areas beneath the pipeline tariff curves for all flows between hubs (i.e. along transportation links)

All volumes are in billion cubic feet (Bcf), and all prices are in 1987 real dollars.

The decision variables for the NGMM QP objective function are the following:

- The volume of each supply type taken from each step defining the supply curve for all supply regions
- The total volume of supply of each supply type taken from each supply region
- The total volume of LNG export demand that is met from each step of the LNG demand curve for each LNG demand region, as well as the fuel used for liquefaction of these volumes
- The volume under each tariff curve step for each flow arc
- The total volume of natural gas that flows from one hub to another hub
- The total volume of natural gas that flows from all supply regions to a hub
- The total volume of natural gas that flows from all hubs to all demand regions
- The total volume of natural gas that flows from all hubs to all LNG export regions
- The total volume of natural gas that flows from all storage region to a hub
- The total volume of natural gas that flows from all hubs to a storage region

4. Description of constraints

Supply Accounting and Supply Mass Balance. The supply mass balance constraint says that for all supply types and all supply regions, in each month of the projection period, the total production of natural gas of each supply type in a supply region equals the sum of the areas under all supply steps in the supply curve (including the step representing the minimum production allowed). The supply accounting constraint states that for all supply types and all supply regions, in each month, total production (or supply) of all supply types must equal the total flow from the supply region to a hub.

The NGMM accounts for 6 types of natural gas supply: nonassociated (NA) gas, associated-dissolved (AD) gas, liquefied natural gas (LNG) imports, synthetic natural gas (SNG) from coal, synthetic natural gas from liquids, and other synthetic natural gas. All supply regions, including those in Canada and Mexico, can have any number of these supply types. Only NA gas supply is considered a variable supply (i.e., it is solved for in the QP and allowed to change dynamically in response to the supply price in each region). The supply levels for the remaining categories are projected for each projection year before market clearing prices are projected.

Demand Mass Balance. For each demand region and projection month, the flow from a hub to its demand region must equal the sum of all sources of demand.

The NGMM receives projections of U.S. natural gas consumption (interpreted as demand) in the five primary consuming sectors—residential, commercial, industrial, electricity generators, and transportation—from the NEMS demand modules. The NGMM peforms some additional calculations to convert the consumption estimates to the monthly, regional levels used in the QP. For all but the electric power sector, the NGMM disaggregates annual Census division consumption levels into the state and monthly representation that the NGMM requires. The regional representation for the electric power sector differs from the other NEMS sectors, because the Electricity Market Module (EMM) solves internally by North American Electric Reliability Corporation (NERC)-based regions for three seasons in each year, enabling a more disaggregated representation of consumption within the NGMM. The EMM converts the NERC-based regions, which do not always align with state borders and generally do not share common borders with the Census divisions, to 17 regions that do. The conversion is based on the relative geographic location (and natural gas-fired generation capacity) of the current and proposed

electricity generation plants within each region. Within the NGMM, electricity consumption by these 17 regions (one of which is Alaska) and 3 seasons (peak, offpeak, and shoulder) is disaggregated to the state and monthly representation that the NGMM requires.

The NGMM disaggregates regional demands annually/seasonally using historical state and monthly shares, which it assumes remain constant throughout the projection period. For the Pacific Division, in all sectors except electric power generation, natural gas consumption estimates for Alaska are first subtracted to establish a consumption level for just the contiguous Pacific Division before the historical share is applied. The consumption of gas in Hawaii is not handled separately, because it is considered negligible.

Flow Balance at Hubs. For each hub and projection month, total flow into the hub is equal to total flow out of the hub.

Flow Balance at Border Crossings for Pipeline Imports into the United States. For each border crossing and projection month, total flow into the United States at the border crossing is equal to the total flow out of a Canadian or Mexican region into the border crossing.

Flow Balance at Border Crossings for Pipeline Exports out of the United States. For each border crossing and projection month, total flow out of the United States to the border crossing is equal to the total flow from the border crossing into a Canadian or Mexican region.

LNG Export Demand Mass Balance. For each region having LNG export capacity and for each projection month, the total demand for LNG exports, including the fuel used for liquefaction, equals the sum of flows from all hubs to their corresponding LNG export regions.

Tariff Curve Quantity Balance. For all natural gas flow arcs, the flow on the arc equals the total volume of natural gas implied by the utilization of the arc's capacity (i.e. the flow from hub to hub equals the volume implied by the tariff curve quantity on that arc).

For each arc between two different hubs, a tariff curve was created to represent the variable cost of transportation per unit of flow as a function of capacity utilization (minus cost due to pipeline fuel used during transport). These curves (see the representative curve in Figure 7) are based on historical basis differentials between the spot prices at the two hubs.[15] They are specified so that the tariff increases rapidly as the flow approaches the pipeline capacity, or nears complete utilization; the final step is extended by a set percentage above the existing capacity.[16] For most arcs, this difference between the last two steps represents the maximum capacity build in a projection year. Exceptions for larger capacity builds in a projection year are allowed on arcs in two cases:

- For arcs where capacity is greater in the opposite direction, the model can simulate a decision to build additional capacity up to that level, representing pipeline reversals on large pipelines.
- For arcs with capacity below a level[17] specified by EIA analysts, projected capacity is allowed to double in a year, allowing small markets to grow at a faster rate.

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[15] Monthly average spot price history begins in 2009; data are used through latest available month and provided by Natural Gas Intelligence.

[16] For AEO 2018, additional capacity of up to 40% of the existing capacity can be added in a given year.

[17] For AEO 2018, this capacity was defined as 30 Bcf, or approximately 1 Bcf/d.
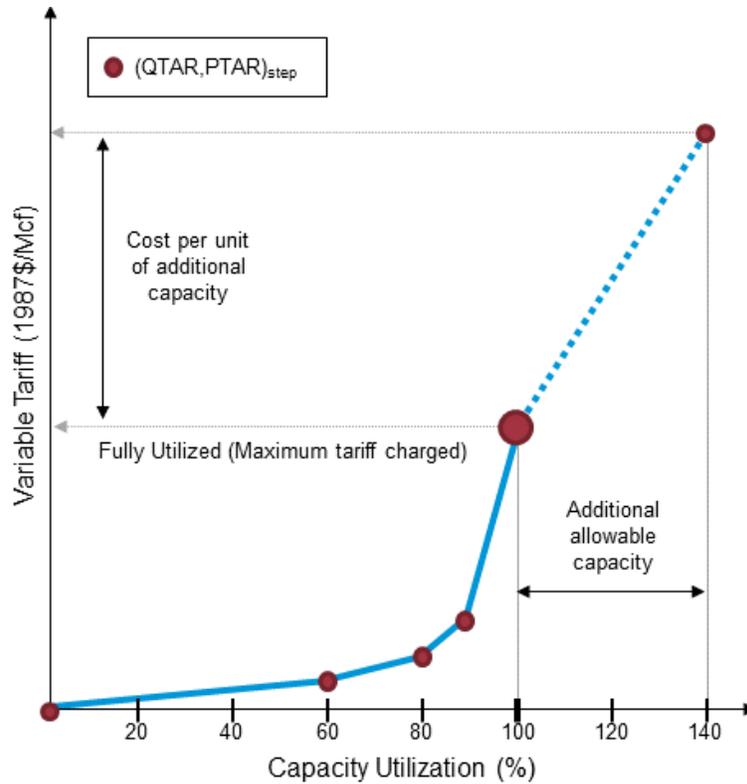
Figure 7 Schematic representation of tariff curve structure used in NGMM

The formulation of the tariff curve is designed to provide a hurdle rate. When representative peak day consumption levels are projected to flow through the network at or above this rate, the model projects an addition to pipeline capacity. If pipeline capacity is added in one projection year, it indicates that either consumption has exceeded existing pipeline capacity or the cost of adding capacity along the arc is less than the cost of transporting natural gas via another existing route. The additional cost is assumed to be recovered by charging the same variable tariff rate for larger volumes of flow over time.

Storage Withdrawal Balance and Storage Injection Balance. For all storage regions, in each month, the flow out storage equals the total withdrawals from storage, and the flow into storage equals the total injections into storage. Storage is represented in the NGMM for all Lower 48 states and Canada. While storage is an integral part of balancing natural gas markets in the short term to mitigate price increases during periods of peak demand, over the long term it is not expected to play a role in setting prices. The NGMM assumes that net storage withdrawals over a projection year equal zero, i.e., storage injections equal storage withdrawals at each hub.

The NGMM assumes that recent historical storage injection and withdrawal patterns will continue throughout the projection period. The current formulation of the QP requires preset storage activity levels and cannot dynamically solve for storage injections and withdrawals.

To estimate historical storage injections and withdrawals by month and storage region (state and Canada region), the NGMM starts by calculating the average injections and withdrawals over a a period of several historcal years for each month and region, then normalizing these monthly/regional averages to insure that net storage withdrawals over the year equal zero for each storage region. The resulting

storage withdrawals and injections by month and storage region are assumed constant throughout the projection period.

Supply Curve Range. For all supply curve steps for all supply types in all regions and projection months, the quantity under the step must be between its defined minimum and maximum volumes.

Tariff Curve Range. For all tariff curve steps for each flow arc and each projection month, the quantity under the step must be less than or equal to its maximum volume.

LNG Export Demand Curve Range. For all LNG export demand curve steps in all regions and projection months, the quantity under the step must be between its defined minimum and maximum volumes

Flow capacity. For all flows along an arc and for each projection month, the flow cannot exceed the arc's capacity.

Non-negativity. There are also constraints that ensure that all natural gas volumes and flows, as solved by the QP, are either zero or positive. Non-negative constraints exist for the following outputs:

- Natural gas production
- Flows from hub to hub
- Flows from hub to demand region
- Flows from hub to LNG export region
- Flows to and from hubs and storage regions
- Natural gas volumes under all steps of the variable tariff curve

5. Input data and sources

5.1. DOE Input Sources
- Energy Information Administration, Natural Gas Annual/Natural Gas Monthly
  - Natural gas consumption and delivered prices by month, state, and sector
  - Natural gas pipeline import and export volumes and prices by month, state, and border crossing
  - Natural gas storage injections and withdrawals by month and state
  - Balancing item by state and year
  - Interstate flows of natural gas by state and year
  - Citygate prices by state and month
  - Number of residential customers for natural gas by state and eyar
  - Supplemental supply volumes by state and year
  - Pipeline fuel consumption, lease fuel consumption, and plant fuel consumption by state and year
  - Natural gas plant liquid volumes processed, extraction losses, and total condensate by state and year
- Energy Information Administration, natural gas pipeline data
  - Historical U.S. state-to-state natural gas pipeline capacity by year and state
  - Planned natural gas pipeline projects by year and state
  - a) Energy Information Administration, Electric Power Monthly
  - Natural gas consumption and prices to electric generators by state and month
- Energy Information Administration, EIA-846, Manufacturing Energy Consumption Survey

- o Base year core and non-core industrial end use prices by Census region
- Energy Information Administration, Short-Term Energy Outlook
  - o Natural gas delivered end use price forecasts by Census division for the the first 2 years beyond history
  - o National natural gas market forecast for the first two years beyond history
- Energy Information Administration, International Energy Outlook
  - o Natural gas consumption projections for Canada and Mexico by sector and year
  - o Natural gas production projection for Mexico by year
  - o Projected flexible liquefied natural gas supplies (i.e. liquefied natural gas volumes not sold under contracts) available to the global market by year
  - o Liquefied natural gas imports into Europe and Asia by year
- Office of Fossil Energy
  - o Liquefied natural gas export capacity planned and under construction by facility
  - o Import and export volumes and prices by border crossing
- Office of Energy Efficiecy and Renewable Energy, Clean Cities Alternative Fuel Price Report
  - o Delivered compressed natural gas prices to the transportation sector at public and private dispensing stations
- Office of Energy Efficiecy and Renewable Energy, Alternative Fuels Data Center
  - o State natural gas vehicle taxes by fuel type

5.2. Non-DOE Input Sources

- Natural Gas Intelligence
  - o Historical spot prices
- Secretaría de Energía de México/Sistema de Información Energética
  - o Historical annual Mexico natural gas production by supply type and field
  - o Historical Mexico consumption by month, sector, and region
  - o Historical annual LNG imports to Mexico by terminal
  - o Historical natural gas spot prices by month for Northeast and South-Southeast Mexican regions
  - o Historical annual natural gas pipeline capacities
- Statistics Canada
  - o Historical Canadian consumption by month, sector, and province
  - o Historical Canadian storage injections and withdrawals by month and province
- National Energy Board of Canada
  - o Historical annual natural gas pipeline capacities and flows within Canada by region
- Alberta Energy Regulator
  - o Historical annual bitumen production from oil sands in Alberta by mining type
  - o Historical annual natural gas produced, consumed, and purchased for oil sands production by mining type
- Internal Revenue Service
  - o Federal natural gas vehicle taxes by fuel type
- State of Alaska, Department of Labor and Workforce Development
  - o Alaska population projections by year

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