# 8. Natural Gas

This chapter discusses the representation of and assumptions for natural gas. The chapter starts with a brief synopsis of ICF's Gas Market Model (GMM), the primary tool used for generating the natural gas supply curves. This is followed by discussion of the approach taken to translate GMM results to IPM inputs for the EPA's Platform v6 Summer 2021 Reference Case (EPA Platform v6). Lastly, brief descriptions of modeling methodologies and data used in GMM are presented.

Natural gas supply curves and seasonal basis differentials are key inputs to IPM and are developed using GMM. GMM and IPM are iterated in tandem to develop a forecast of Henry Hub gas price and total power sector gas demand that informs the derivation of the supply curves. The approach is described as follows:

- IPM takes the natural gas supply curves, which are developed based on GMM outputs and specified as a function of Henry Hub prices.
- For each year, delivered price adders and three sets of seasonal natural gas transportation differentials (summer, winter, and winter shoulder) are added to the supply curves to generate the final delivered curves by IPM region.
- IPM projects the power sector's demand for natural gas. The projected demand is then matched with the supply curve to find the market-clearing price.
- IPM's linear programming formulation takes into consideration the gas supply curves, as well as competing fuels such as coal, and detailed power plant modeling in determining electric market equilibrium conditions.

Like IPM, GMM is a large-scale linear programming model that incorporates a detailed representation of gas supply characteristics, demand characteristics, and an integrating pipeline transportation model to develop forecasts of gas supply, demand, prices, and flows. GMM is a full supply/demand equilibrium model of the North American gas market. The model solves for monthly natural gas prices throughout North America, given different supply/demand conditions, the assumptions for which are specified by each scenario.

On the supply side, prices from GMM are determined by production and storage price curves that reflect prices as a function of production and storage utilization. Prices are also influenced by "pipeline discount" curves, which reflect the change in basis or the marginal value of gas transmission as a function of load factor. On the demand side, prices are represented by a curve that captures the fuel-switching behavior of end-users at different price levels. The model balances supply and demand at all nodes in the model at the market clearing prices. Figure 8-1 shows the supply side of the calculation in GMM, and Figure 8-2 shows the interaction of IPM and GMM.

**Figure 8-1 GMM Gas Quantity and Price Response**

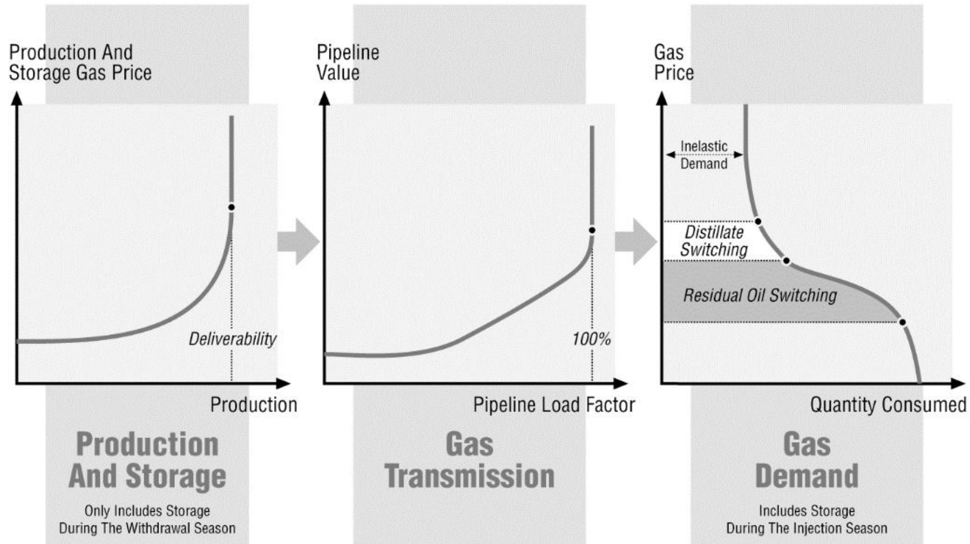
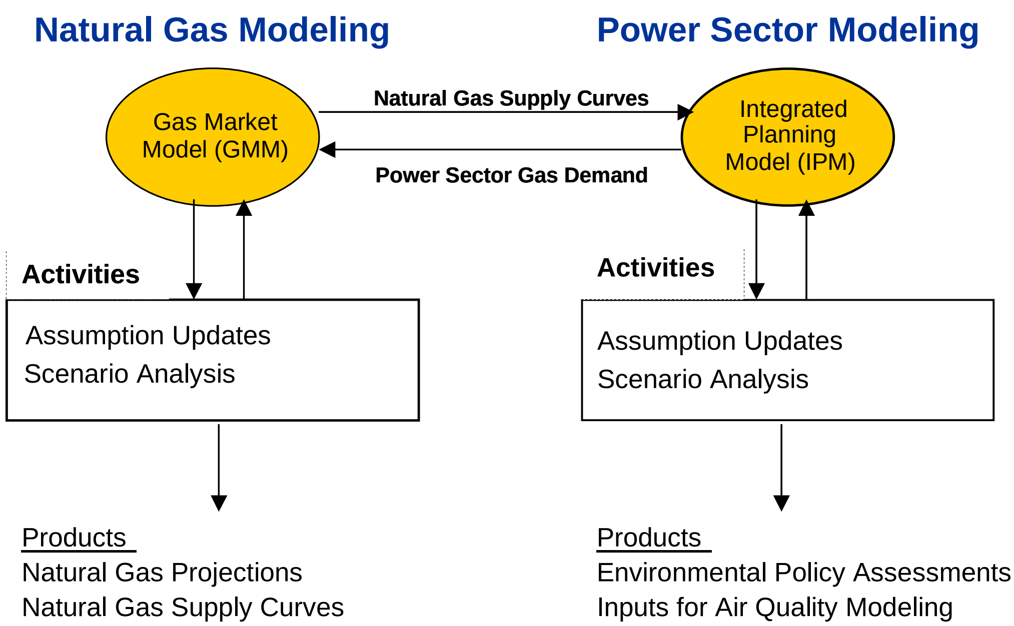


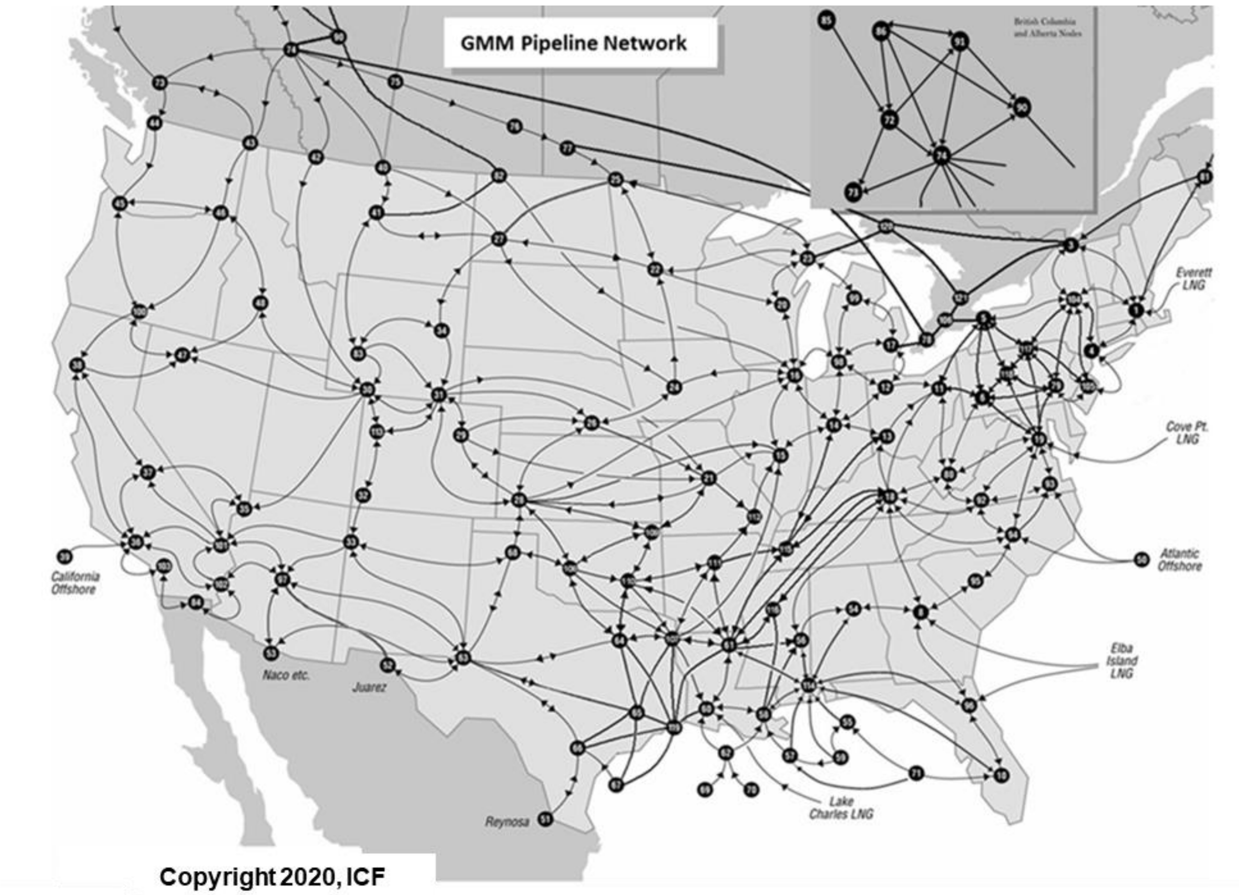

**Figure 8-2 IPM/GMM Interaction**



## 8.1 GMM

GMM is designed to perform comprehensive assessments of the entire North American gas flow pattern. It is a large-scale, dynamic linear program that models economic decision-making to minimize the overall cost of meeting natural gas demand. GMM is reliable and efficient in analyzing the broad range of natural gas market issues. Figure 8-3 presents the geographic coverage of GMM.

**Figure 8-3 Geographic Coverage of GMM**




Important features of GMM are described below.

**Natural Gas Market Prices** in GMM are determined by the marginal (or incremental) value of natural gas at 121 regional market centers. The regional market centers are also referred to as nodes. Prices are “at the margin”, not “average.” Marginal prices do not translate directly into pipeline or utility revenues. Prices represent “market center” prices as opposed to delivered prices. Gas prices are determined by the balance of supply and demand in a regional marketplace. Supply is determined considering both availability of natural gas deliverability at the wellhead, the transportation capacity and cost to deliver gas to market centers.

Natural gas prices are determined from spot gas price curves that yield price as a function of deliverability utilization: Curves reflect price for gas delivered into the transmission system (including gathering cost). Gas storage withdrawal price curves are added to the production price curves during the withdrawal season. Pipeline value curves are then added to yield a total supply curve for a node. The intersection of the supply curve and the demand curve (including net storage injections) yields the marginal price at a node. Price is set by the demand curve when all available supply is utilized.

**Demand** is modeled for residential, commercial, industrial, and power sectors for each of the 121 nodes. GMM solves for gas demand across different sectors, given economic growth, weather, and the level of price competition between gas and oil. Econometric equations define demand by sector. The industrial and power sectors incorporate fuel competition, dispatch decisions, new power plant builds, economic growth, and weather. GMM solves the power generation dispatch on a regional basis to determine the amount of gas used in power generation, which is allocated along with end-use gas demand to model nodes. GMM iterates with IPM to better capture electric sector demand for natural gas.

**Transportation** is modeled by over 427 transportation links between the nodes, balancing seasonal, sectoral, and regional demand and prices, including pipeline tariffs and capacity allocation. Node structure was developed to reflect points of change or influence on the pipeline system. These points include major demand and supply centers, pipeline hubs and market centers, and points of divergence in pipeline corridors.

Pipeline capacity expansions address the physical constraints of transporting gas from supply regions to demand regions. They therefore contribute to determining the supply curves and seasonal basis. For the near–term, pipeline capacity expansions are input to GMM based on identifiable, near-term development plans and ICF's market assessment. For the longer term, new "generic" pipeline capacity is added in GMM when the market value of the added capacity exceeds its cost. Generic pipeline capacity in the model can be added starting 2024 and is deployed in response to expected growth in natural gas markets.

ICF includes projects that satisfy certain criteria in its analysis. The criteria are listed below.

- First Criteria: The project is already under construction; OR…
- Second Criteria: The project has the necessary approvals to proceed from FERC and other relevant regulatory proceedings; OR…
- Third Criteria: The project has been filed with FERC and has the necessary firm shipper commitments; OR…
- Fourth Criteria: The project has been filed with FERC and does not have the necessary shipper commitments, but does appear to have sufficient market support; OR…
- Fifth Criteria: The project has NOT yet been filed with FERC but appears to have sufficient market support.

For the fourth and fifth criteria, ICF typically considers supply growth directly upstream of the project, market growth for markets that are relevant to the project's delivery point/s, and basis differentials that exceed the per unit cost of pipeline expansion as indicators of market support. If the indicators are all positive, ICF will add the project as a "generic" project and size it based on the level of market support. In the case in which there are multiple generic projects for a single GMM link, the generic projects will be sized in aggregate based on the total level of market support for expansion of the link. Generic projects are classified as such until one of the first three criteria are satisfied.

For certain markets like New York, New Jersey, and New England, ICF looks closely at regulatory support for the project which could override the criteria above in determining the pipeline additions in GMM. For example, if a project like Northeast Supply Enhancement Project (NESE) has been denied water permits even though it has broad market support, ICF does not include it in its base case.

Pipeline cost assumptions used in GMM have been derived by considering data from Oil and Gas Journal (OGJ) surveys of pipeline projects. Using regression analysis of the OGJ data across years, we estimated an average U.S. pipeline cost of $228,000 per inch-mile for 2019 (in 2019 dollars) for large gas transmission pipelines. The pipeline cost for future years is kept flat in real terms post 2019. Regional cost multipliers have also been derived from OGJ data as the pipeline costs vary by region. Cost multipliers can be different across regions; for example, costs are relatively high in the Northeast where projects have been very difficult and time consuming to construct.

**Supply** is modeled by using node-level natural gas deliverability or supply capability, including import and export levels while accounting for gas storage injections and withdrawals at different gas prices. Total supply in the United States comes from three sources: production from natural gas fields located in the lower 48 states, Canadian imports, Alaska, and LNG imports/exports. Natural gas production activity is represented in 82 of the 121 model nodes where historical production has occurred, or where future production appears likely.

**Natural Gas Storage** activity is represented for 24 United States and two Canadian storage regions, with activity allocated to individual nodes based on historical field level storage capacity. Regional differences in the physical and market characteristics of storage are captured in the storage injection and withdrawal relationships separately estimated for each region.

Net monthly withdrawals are calculated from a "storage supply curve" that reflects the level of withdrawals relative to gas prices. The curve has been fit to actual historical data. Net monthly injections are calculated from econometrically fit relationships that consider working gas levels, gas prices, and weather (i.e., cooling degree days). The level of gas storage withdrawals and injections are calculated within the supply and demand balance algorithm based on working gas levels, gas prices, and extraction/injection rates and costs.

Storage levels have an impact on GMM's seasonal basis differentials, which are an important component in constructing the gas supply curves and/or basis differentials that are then input into IPM. The arbitrage value of storage is driven by the seasonal difference in the supply-area gas prices plus the seasonal difference in pipeline transportation value. Storage expansions (or increased utilization of existing storage) decreases seasonal basis differentials in the region surrounding the storage facilities.

## 8.2 Translating GMM Results to IPM Natural Gas Supply Curves[82]

In this section, we describe GMM results underlying the natural gas supply curves for EPA Platform v6. A typical GMM run generates the following outputs:

- Natural gas prices
- Natural gas production by region
- Natural gas consumption by region and sector

Table 8-1 summarizes the supply/demand balance and Henry Hub price for a GMM run underlying the natural gas supply curves. The regional breakout in the demand/supply data is by census region and the mapping to the state and GMM nodes is provided in Figure 8-4 and Figure 8-5. Table 8-8 provides additional results.

[82] The GMM results presented in this section are illustrative and consistent with a draft version of the EPA Platform v6. GMM was not rerun for a final calibration with EPA Platform v6 using IPM.

**Table 8-1 Supply/Demand Balance and Henry Hub Price for a GMM Run Underlying the Natural Gas Supply Curves in v6**

| **Demand (Bcf per year)** | **2023** | **2025** | **2028** | **2030** | **2035** | **2040** | **2045** | **2050** |
|---|---|---|---|---|---|---|---|---|
| New England | 926 | 880 | 880 | 877 | 867 | 866 | 863 | 833 |
| Mid-Atlantic | 4,443 | 4,586 | 4,505 | 4,539 | 4,344 | 4,174 | 4,155 | 4,560 |
| East North Central | 5,022 | 5,105 | 5,090 | 5,070 | 5,135 | 5,278 | 5,566 | 5,246 |
| West North Central | 1,948 | 1,986 | 1,948 | 1,945 | 1,934 | 1,907 | 1,883 | 1,848 |
| South Atlantic | 4,662 | 4,900 | 4,873 | 4,943 | 5,217 | 5,314 | 5,473 | 5,681 |
| East South Central | 2,098 | 2,150 | 2,104 | 2,112 | 2,274 | 2,219 | 2,348 | 2,399 |
| West South Central | 7,187 | 7,517 | 7,427 | 7,526 | 7,739 | 7,882 | 7,805 | 7,671 |
| Mountain | 2,128 | 2,165 | 2,126 | 2,238 | 2,185 | 2,256 | 2,152 | 2,060 |
| Pacific (contiguous) | 2,991 | 2,947 | 3,006 | 2,894 | 2,786 | 2,577 | 2,622 | 2,537 |
| Alaska | 323 | 319 | 313 | 310 | 303 | 303 | 303 | 303 |
| **Total L-48** | **31,407** | **32,236** | **31,959** | **32,145** | **32,481** | **32,473** | **32,868** | **32,834** |
| **Total United States** | **31,730** | **32,556** | **32,272** | **32,454** | **32,784** | **32,776** | **33,171** | **33,136** |
| **Exports/Imports (Bcf per year)** | | | | | | | | |
| Net LNG Exports from US | 4,010 | 4,248 | 5,255 | 5,648 | 5,889 | 5,900 | 5,906 | 5,906 |
| Net Pipeline Exports to Mexico | 2,454 | 2,710 | 2,769 | 2,795 | 2,773 | 2,723 | 2,723 | 2,730 |
| Net Pipeline Imports from Canada | 1,362 | 1,165 | 1,175 | 1,187 | 1,416 | 1,616 | 2,142 | 2,357 |
| **Supply (Bcf per year)** | | | | | | | | |
| New England | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Mid-Atlantic | 7,786 | 8,126 | 8,121 | 8,207 | 7,818 | 7,668 | 7,613 | 7,556 |
| East North Central | 2,576 | 2,734 | 2,847 | 2,912 | 2,977 | 3,060 | 3,112 | 3,125 |
| West North Central | 1,089 | 1,088 | 1,075 | 1,068 | 1,051 | 1,041 | 1,042 | 1,050 |
| South Atlantic | 2,213 | 2,349 | 2,434 | 2,470 | 2,473 | 2,507 | 2,531 | 2,534 |
| East South Central | 541 | 493 | 475 | 511 | 459 | 434 | 450 | 731 |
| West South Central | 18,344 | 19,039 | 19,864 | 20,480 | 21,041 | 20,810 | 20,692 | 20,579 |
| Mountain | 4,245 | 4,142 | 4,057 | 4,046 | 3,868 | 3,687 | 3,570 | 3,452 |
| Pacific (contiguous) | 168 | 154 | 157 | 158 | 159 | 153 | 145 | 140 |
| Alaska | 319 | 314 | 304 | 306 | 315 | 317 | 317 | 317 |
| **Total L-48** | **36,961** | **38,125** | **39,030** | **39,852** | **39,846** | **39,361** | **39,157** | **39,168** |
| **Total United States** | **37,280** | **38,440** | **39,334** | **40,158** | **40,161** | **39,677** | **39,474** | **39,485** |
| | **2023** | **2025** | **2028** | **2030** | **2035** | **2040** | **2045** | **2050** |
| **Henry Hub, 2019$/MMBtu** | 2.68 | 2.39 | 2.81 | 3.13 | 3.17 | 3.33 | 3.40 | 3.41 |

**Figure 8-4 Demand Region Definition**

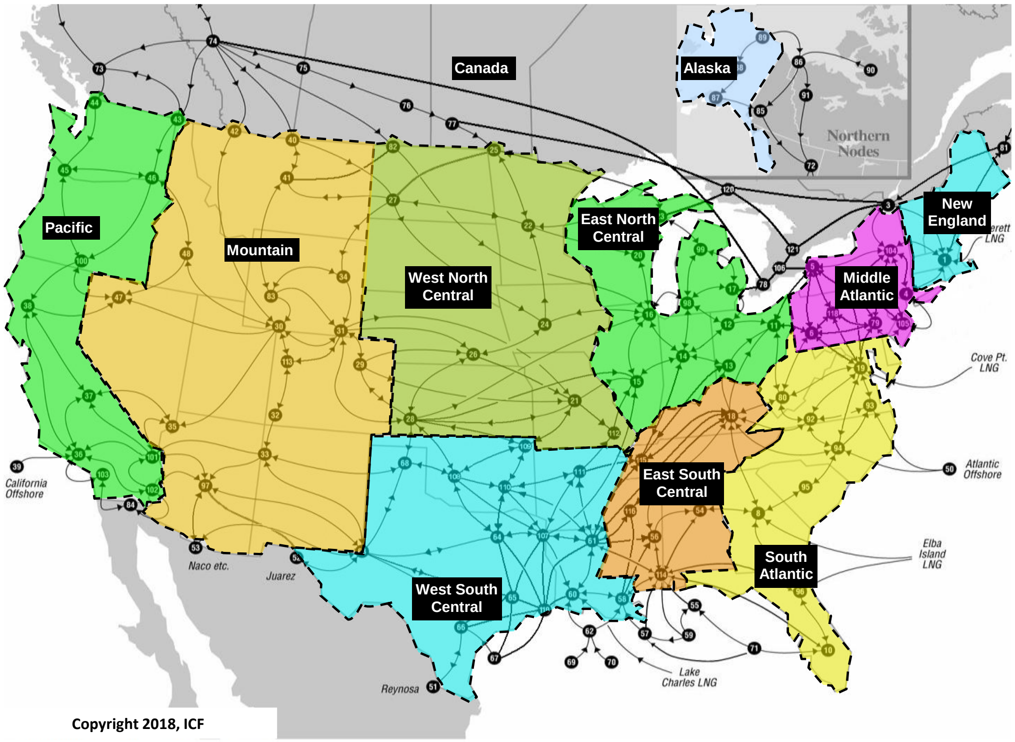
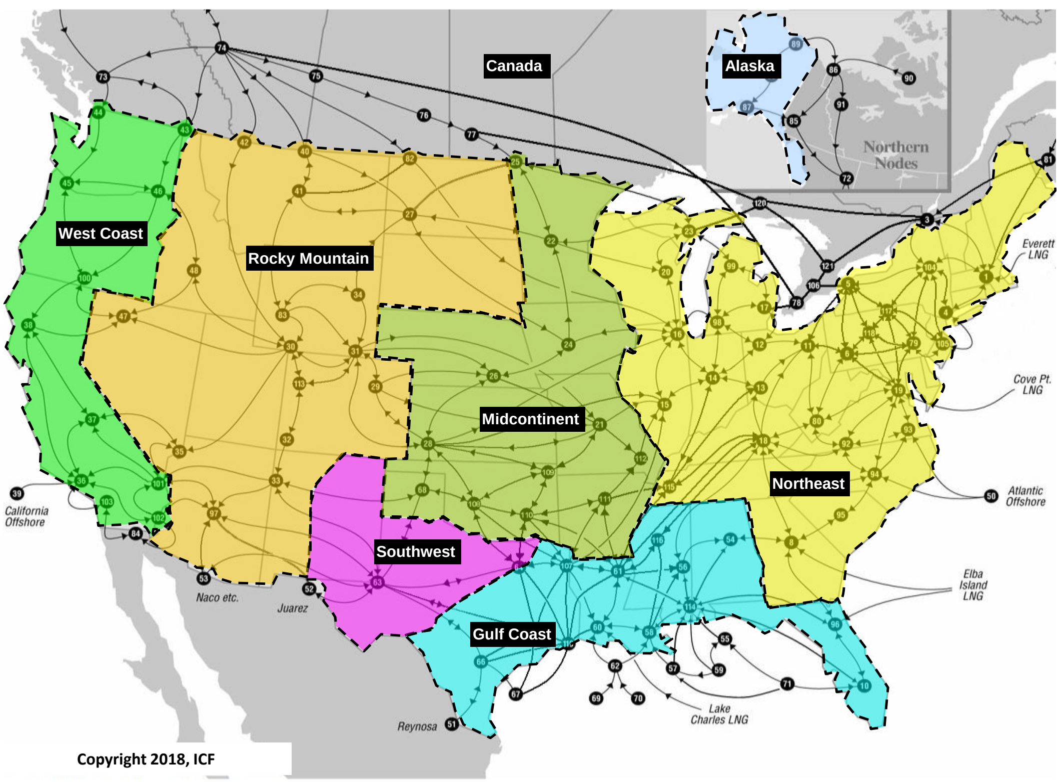



**Figure 8-5 Supply Region Definition**



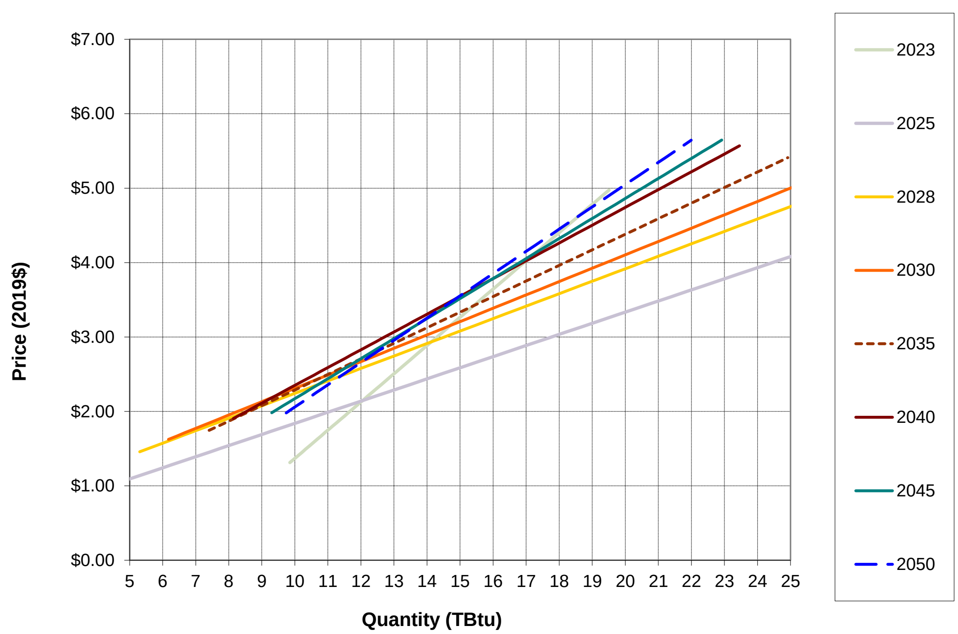
### 8.2.1 Supply Curves for EPA Platform v6

Henry Hub is a pipeline interchange hub in Louisiana Gulf Coast near Erath, LA, where eight interstate and three intrastate pipelines interconnect. Liquidity at this point is very high and it serves as the primary point of exchange for the New York Mercantile Exchange (NYMEX) active natural gas futures markets. Henry Hub prices are considered as a proxy for U.S. natural gas prices. Natural gas from the Gulf moves through the Henry Hub onto long-haul interstate pipelines serving demand centers. Due to the importance and significance of Henry Hub, GMM generated supply curves are specified at Henry Hub prices.

For IPM modeling, GMM generates a price forecast over a time horizon and a set of time dependent price/supply curves based on that price path for each year in the forecast. For each year, the mid-point price of the supply curve is set equal to the solved Henry Hub price from GMM and the mid-point volume is set equal to the solved gas consumption for the power sector from GMM. Each supply curve's elasticity is set equal to the effective price-elasticity for gas supply in that year. In this manner, even while GMM has itself projected particular levels of gas supply and consumption (and corresponding market-clearing prices) over time, the information included in those projections is input into IPM in the form of gas supply curves that enable IPM to solve for levels of power sector gas consumption and resulting gas prices that respect a least-cost power production future. The power generation gas use by model region from IPM run outputs are used as inputs in GMM to generate a new set of supply curves and basis which are used by IPM as inputs for the next iteration. This iteration process is repeated until the power generation gas use from IPM and GMM converge.

The final resulting supply curves developed for years 2023, 2025, 2028, 2030, 2035, 2040, 2045, and 2050 are shown in Figure 8-6 and Table 8-10. In the very short-term, gas supply is price inelastic because there are few years to respond to the market changes. Over time, gas supply becomes more price elastic because producers have more time to respond to the market changes. Thus, the supply curves are much more price elastic by 2028. In the longer term, resource depletion tends to offset elasticity making the curves slightly less elastic than they are between 2028 and 2030.

**Figure 8-6 Supply Curves for 2023, 2025, 2028, 2030, 2035, 2040, 2045, and 2050**



The static national supply curves used for EPA Platform v6 are robust for typical scenario analysis, although EPA reevaluates price dynamics in scenarios to ensure that IPM and GMM are iterated in cases where the regional natural gas demand in the power sector is expected to be significantly different from the reference case.

### 8.2.2 Basis

Basis is the difference in gas price in a given market from the widely used Henry Hub reference price. Basis reflects the price in a given market based on demand, available supply, and the cost of transporting gas to that location. A negative basis value represents that the gas price in that area is lower than the Henry Hub price. Basis between two nodes in GMM is the difference in prices between the two nodes. The GMM utilizes its network of 121 nodes that comprises 423 gas pipeline corridors to assess the basis between two desired nodes. The pipeline corridors between nodes are represented by pipeline links and can be characterized by their maximum capacity. Each of the links has an associated discount curve (derived from GMM natural gas transportation module), which represents the marginal value of gas transmission on that pipeline segment as a function of the pipeline's load factor. The basis value is calculated by using the supply/demand balance in two nodes along with the resulting prices in each node and the cost of transporting gas between the two nodes as determined by the discount curve on that link. The discount curve is a function of the pipeline tariffs and the load factor. The discount curves are continuously calibrated to accurately reflect historical basis values. Their parameters can be adjusted to account for regulatory changes that can affect pipeline values.

The GMM solves for basis monthly. Basis pressure (i.e., spiking basis) will generally occur when average monthly load factors rise to above 80%. Since many U.S. markets are winter peaking, the higher basis typically occurs in the winter months when gas use and pipeline utilization are highest. The IPM relies on seasonal basis that reflects averages of the monthly basis values solved for in the GMM for three seasons. IPM uses the gas supply curves and regional price relationships (differentials) on a seasonal basis over time as inputs, based on GMM-projected future of gas supply/demand. While EPA Platform v6 has the flexibility to re-determine the relationship of power sector gas demand to supply and to accordingly find different gas price futures, EPA Platform v6 will maintain the future (basis differential) price relationship between Henry Hub and each regional location in a national supply picture as originally determined by these GMM projections. Table 8-9 provides the full set of seasonal basis differentials at the IPM region level.

### 8.2.3 Delivered Price Adders

As stated in Section 8.1, GMM prices are market center prices and not delivered prices. To estimate delivered prices at a power plant, an adder is applied to the seasonal basis from GMM. The delivered price adder is calculated for each state by comparing the GMM historical prices with historical delivered gas prices to electric power plants based on EIA-176 data. The delivered price adders implemented in EPA Platform v6 are shown in Table 8-2.

**Table 8-2 Delivered Price Adders**

| State | Adder (2019$/MMBtu) | State | Adder (2019$/MMBtu) |
|---|---|---|---|
| Alabama | 0.01 | Nebraska | 0.54 |
| Arizona | 0.03 | Nevada | 0.15 |
| Arkansas | 0.14 | New Hampshire | - |
| California | 0.22 | New Jersey | 0.20 |
| Colorado | 0.19 | New Mexico | 0.03 |
| Connecticut | 0.05 | New York | 0.20 |
| Delaware | 0.01 | North Carolina | 0.31 |
| Florida | 0.02 | North Dakota | 0.04 |
| Georgia | 0.00 | Ohio | 0.04 |
| Idaho | 0.06 | Oklahoma | 0.02 |
| Illinois | 0.15 | Oregon | 0.01 |
| Indiana | 0.13 | Pennsylvania | 0.04 |
| Iowa | 0.14 | Rhode Island | 0.00 |
| Kansas | 0.15 | South Carolina | 0.15 |
| Kentucky | 0.17 | South Dakota | 0.01 |
| Louisiana | 0.04 | Tennessee | 0.03 |
| Maine | 0.03 | Texas | 0.22 |
| Maryland | 0.16 | Utah | 0.12 |
| Massachusetts | 0.03 | Virginia | 0.07 |
| Michigan | 0.16 | Washington | 0.11 |
| Minnesota | 0.40 | West Virginia | 0.14 |
| Mississippi | 0.03 | Wisconsin | 0.17 |
| Missouri | 0.12 | Wyoming | 0.11 |
| Montana | 0.45 | Canada | 0.15 |

## 8.3 GMM Assumptions

This section describes the key GMM assumptions and data used for EPA Platform v6.

### 8.3.1 GMM Resources Data and Reservoir Description

This section describes the approach used in GMM and documents the changes to the resource data and reservoir characterization work conducted for EPA Platform v6.

**U.S. Resources and Reserves**

This section describes the U.S. resource data sources and methodology used in GMM for EPA Platform v6.

Current U.S. and Canada gas production is from about 500 trillion cubic feet (Tcf) of proven gas reserves. ICF assumes that the U.S. and Canada natural gas resource base totals roughly 4,000 Tcf of unproved plus discovered but undeveloped gas resource. This can supply the U.S. and Canada gas markets for over 100 years (at current consumption levels). Shale gas accounts for over 50 percent of remaining recoverable gas resources. No significant restrictions on well permitting and fracturing are assumed beyond restrictions that are currently in place.

Data sources: Conventional resource base assessment is based on data from the U.S. Geological Survey (USGS), Minerals Management Service (MMS), and Canadian Gas Potential Committee (CGPC) using ICF's Hydrocarbon Supply Model (HSM).

In the area of unconventional gas, ICF has worked for many years with the Gas Research Institute (GRI)/Gas Technology Institute (GTI) to develop a database of tight gas, coalbed methane, and Devonian Shale reservoirs in the U.S. and Canada. Along with USGS assessments of continuous plays, the database was used to help develop the HSM's "cells", which represent resources in a specific geographic area, characterizing the unconventional resource in each basin, historical unconventional reserves estimates and typical decline curves. ICF has built up a database on gas compositions in the United States and has merged that data with production data to allow the analysis of net versus raw gas production.

Resources are divided into three general categories: new fields/new pools, field appreciation, and unconventional gas. The methodology for resource characterization and economic evaluation differs for each.

<u>New Fields</u>

Conventional new discoveries are characterized by size class. For the United States, the number of fields within a size class is broken down into oil fields, high permeability gas fields, and low permeability gas fields based on the expected occurrence of each type of field within the region and interval being modeled. The fields are characterized further as having a hydrocarbon make-up containing a certain percent each of crude oil, dry natural gas, and natural gas liquids. In Canada, fields are oil, sweet non-associated gas, or sour non-associated gas.

The methodology uses a modified "Arps-Roberts" equation to estimate the rate at which new fields are discovered. The fundamental theory behind the find-rate methodology is that the probability of finding a field is proportional to the field's size as measured by its areal extent, which is highly correlated to the field's level of reserves. For this reason, larger fields tend to be found earlier in the discovery process than smaller fields. The new equation developed by ICF accurately tracks discovery rates for mid- to small-size fields. Since these are the only fields left to be discovered in many mature areas, the more accurate find-rate representation is an important component in analyzing the economics of exploration activity in these areas.

An economic evaluation is made in the model each year for potential new field exploration programs using a standard discounted after-tax discounted cash flow (DCF) analysis. This DCF analysis takes into account how many fields of each type are expected to be found and economics of developing each. The economic decision to develop a field is made using "sunk cost" economics where the discovery cost is ignored, and only time-forward development costs and production revenues are considered. However, the model's decision to begin an exploration program includes all exploration and development costs.

<u>Field Appreciation</u>

Field appreciation refers to potential resources that can be proved from already discovered fields. These inventories are referred to as appreciation, growth-to-known or "probables." The inventories of probables are increased due to expected future appreciation due to many factors that include higher recovery percentages of the gas in-place resulting from infill drilling and application of improved technology and experience gained in the course of developing and operating the field.

<u>Unconventional Gas</u>

The ICF assessment method for shale gas is a "bottom-up" approach that first generates estimates of unrisked and risked gas-in-place (GIP) from maps of depth, thickness, organic content, and thermal maturity. Then, ICF uses a different model to estimate well recoveries and production profiles. Unrisked GIP is the amount of original gas-in-place determined to be present based upon geological factors—without risk reductions. "Risked GIP" includes a factor to reduce the total gas volume based on proximity to existing production and geologic factors such as net thickness (e.g., remote areas, thinner areas, and areas of high thermal maturity have higher risk). ICF calibrates expected well recoveries with specific geological settings to actual well recoveries by using a rigorous method of analysis of historical well data.

To estimate the contributions of changing technologies ICF employs the "learning curve" concept used in several industries. The "learning curve" describes the aggregate influence of learning and new technologies as having a certain percent effect on a key productivity measure (for example cost per unit of output or feet drilled per rig per day) for each doubling of cumulative output volume or other measure of industry/technology maturity. The learning curve shows that advances are rapid (measured as percent improvement per period of time) in the early stages when industries or technologies are immature and that those advances decline through time as the industry or technology matures. We find the learning curve effect is roughly 20 percent per doubling of cumulative wells.

**Major Unconventional Natural Gas Categories**

**Definition of Unconventional Gas:** Quantities of natural gas that occur in continuous, widespread accumulations in low quality reservoir rocks (including low permeability or tight gas, coalbed methane, and shale gas), that are produced through wellbores but require advanced technologies or procedures for economic production.

**Tight Gas** is defined as natural gas from gas-bearing sandstones or carbonates with an *in situ* permeability (flow rate capability) to gas of less than 0.1 millidarcy. Many tight gas sands have *in situ* permeability as low as 0.001 millidarcy. Wells are typically vertical or directional and require artificial stimulation.

**Coalbed Methane** is defined as natural gas produced from coal seams. The coal acts as both the source and reservoir for the methane. Wells are typically vertical but can be horizontal. Some coals are wet and require water removal to produce the gas, while others are dry.

**Shale Gas** is defined as natural gas from shale formations. The shale acts as both the source and reservoir for the methane. Older shale gas wells were vertical while more recent wells are primarily horizontal with artificial stimulation. Only shale formations with certain characteristics will produce gas.

**Shale Oil with Associated Gas** is defined as associated gas from oil shale in horizontal drilling plays such as the Bakken in the Williston Basin. The gas is produced through boreholes along with the oil.

## Upstream Cost and Technology Factors

In ICF's methodology, supply technology advancements effects are represented in three categories:

- Improved exploratory success rates
- Cost reductions of platform, drilling, and other components
- Improved recovery per well

These factors are included in the model by region and type of gas and represent several dozen actual model parameters. ICF's database contains base year cost for wells, platforms, operations and maintenance, and other relevant cost items.

### 8.3.2 Oil Prices

Natural gas prices and LNG export levels are forecasted by taking oil prices into account. ICF uses the Refiner Acquisition Cost of Crude Oil (RACC) price as an oil price input to GMM. The RACC price is a term commonly used in discussing crude oil. It is the cost of crude oil to the refiner, including transportation and fees. ICF's crude oil price forecast uses futures prices for 2020 and a blend of futures and our fundamental forecast for 2021-2024. ICF expects a slow recovery in oil prices to an equilibrium marginal production cost of $60/bbl (in 2019$) by 2035 and stays flat beyond 2035 in real terms. The residual oil price averages between 70 and 100 percent of the RACC price on a dollar per Btu basis. This is the price used to determine switching in the industrial sector. Table 8-3 shows the ICF's RACC price assumption for EPA Platform v6.

**Table 8-3 Refiners' Acquisition Cost of Crude (RACC)**

| Year | Annual Average Price in 2019$/bbl |
|---|---|
| **2023** | 44.9 |
| **2025** | 46.6 |
| **2028** | 51.0 |
| **2030** | 55.0 |
| **2035** | 59.9 |
| **2040** | 60.0 |
| **2045** | 60.0 |
| **2050** | 60.0 |

### 8.3.3 Gas Production

Current United States and Canada gas production is from about 500 trillion cubic feet (Tcf) of proven gas reserves. ICF assumes that the United States and Canada natural gas resource base totals roughly 4,000 Tcf of unproved plus discovered but undeveloped gas resource. This can supply the U.S. and Canada gas markets for over 100 years (at current consumption levels). Shale gas accounts for over 50 percent of remaining recoverable gas resources. No significant restrictions on well permitting and fracturing are assumed beyond restrictions that are currently in place.

To estimate the contributions of changing technologies ICF employs the "learning curve" concept used in several industries. The "learning curve" describes the aggregate influence of learning and new technologies as having a certain percent effect on a key productivity measure (for example cost per unit of output or feet drilled per rig per day) for each doubling of cumulative output volume or other measure of industry/technology maturity. The learning curve shows that advances are rapid (measured as percent improvement per period of time) in the early stages when industries or technologies are immature and that those advances decline through time as the industry or technology matures. The learning curve effect is roughly 20 percent per doubling of cumulative wells.

In ICF's methodology, supply technology advancements effects are represented in three categories:

- Improved exploratory success rates
- Cost reductions of platform, drilling, and other components
- Improved recovery per well

These factors are included in the model by region and type of gas and represent several dozen actual model parameters. ICF's database contains base year cost for wells, platforms, operations and maintenance, and other relevant cost items. Table 8-4 shows the ICF's United States and Canada dry gas production by source and run year for EPA Platform v6.

**Table 8-4 United States and Canada Projected Dry Gas Production by Source (Bcfd)**

| Year | Conventional Onshore | Coalbed Methane | Tight | Offshore | Shale | Total |
|---|---|---|---|---|---|---|
| **2023** | 14.9 | 2.8 | 7.9 | 2.1 | 91.0 | 118.6 |
| **2025** | 13.5 | 2.6 | 7.3 | 1.9 | 98.2 | 123.5 |
| **2028** | 12.1 | 2.3 | 6.6 | 1.9 | 103.5 | 126.4 |
| **2030** | 11.5 | 2.2 | 6.5 | 2.1 | 108.9 | 131.2 |
| **2035** | 10.3 | 1.8 | 5.7 | 2.0 | 112.0 | 131.9 |
| **2040** | 9.6 | 1.5 | 5.1 | 2.1 | 112.7 | 131.0 |
| **2045** | 9.3 | 1.3 | 4.8 | 2.3 | 114.4 | 132.1 |
| **2050** | 9.2 | 1.2 | 4.6 | 3.0 | 114.7 | 132.7 |

### 8.3.4 Demand Assumptions

Gas demand is calculated by sets of algorithms and equations for each sector and region. Recent data from DOE/EIA and Statistics Canada have been considered in the calibration of the model. ICF performs market reconnaissance and data analysis each month to support the GMM calibration. GMM models natural gas demand in four end-use sectors: residential, commercial, industrial, and power generation.

**Residential/Commercial** gas demand calculated from regional equations fit econometrically to weather, economic growth, and price elasticity.

**Industrial** gas demand is based on a detailed breakout of industrial activity by census region and includes ten industry sectors, focusing on gas-intensive industries.

**Power generation** demand in the GMM is modeled for 13 dispatch regions as shown in Figure 8-7 for the contiguous United States. All the power sector inputs in GMM are changed to be consistent with IPM results over time. Most importantly, the total gas use regionally is benchmarked against IPM's gas use.

**Pipeline fuel** consumption is a function of the fuel rate and the volume of gas moved on each pipeline corridor. Pipeline gas use is estimated as a percent of natural gas throughput for each link in the pipeline network.

**Lease & Plant** gas use is forecasted based on historical percentages of the dry gas produced at each node. Regional factors determine the share of lease & plant gas use for each supply region.

There are four key drivers for natural gas demand in GMM. They are:

**i)** **Macroeconomic parameters:** From 2023 forward, ICF assumes U.S. GDP grows at 2.1% per year, and Canada GDP grows at 2.0% per year.[83]
**ii)** **Electric Demand Growth:** Electric demand growth rate is assumed to be 0.94% per year consistent with EPA Platform v6.
**iii)** **Demographics:** Projected demographic trends are consistent with trends over the past 20 years. U.S. population growth averages about 1% per year throughout our projection.
**iv)** **Weather:** Future weather is assumed consistent with regional and monthly average heating and cooling degree days (HDD/CDD) over the past 20 years (2000 through 2019).

[83] The U.S. Congressional Budget Office assumes an average annual GDP growth rate of 2.2% between 2021 and 2031 in their February 2021 release, while the 2021 U.S. Energy Information Administration Annual Energy Outlook used an average annual GDP growth rate of 2.1% between 2020 and 2050.

**Figure 8-7 GMM Power Generation Gas Demand Regions**

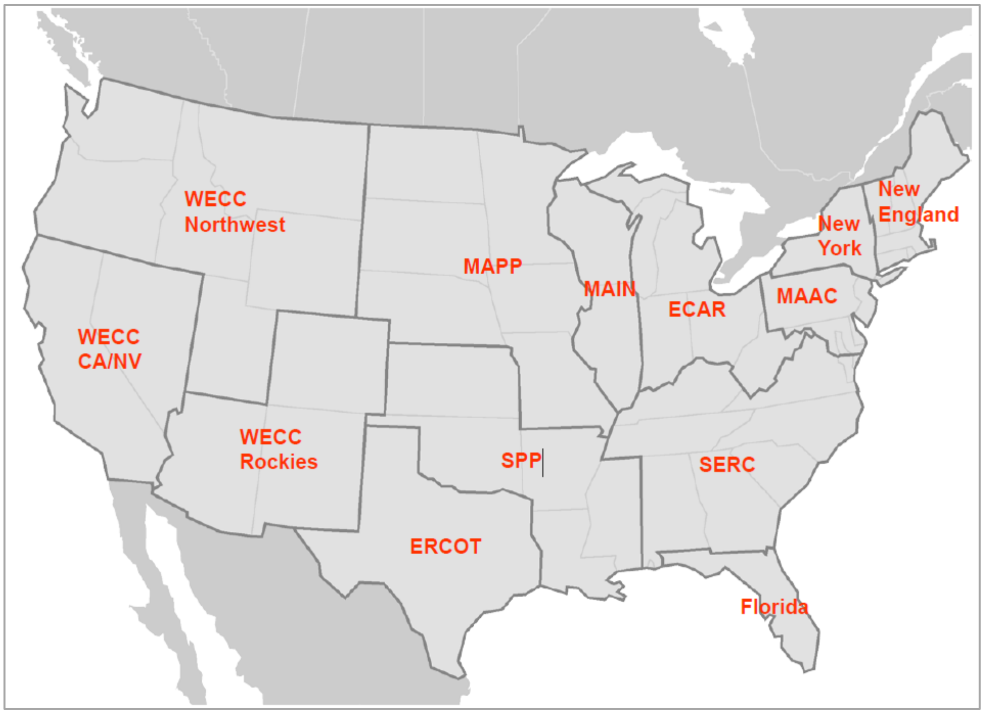



Table 8-5 shows the ICF's United States and Canada natural gas demand by sector and run year for EPA Platform v6.

**Table 8-5 GMM United States and Canada Gas Demand Projection (Bcfd)**

| Year | Residential | Commercial | Industrial | Other | Non-Power | Power |
|---|---|---|---|---|---|---|
| **2023** | 16.0 | 10.8 | 27.1 | 9.3 | 63.3 | 36.4 |
| **2025** | 16.2 | 10.8 | 28.7 | 9.7 | 65.5 | 37.0 |
| **2028** | 16.4 | 10.8 | 28.9 | 10.0 | 66.0 | 35.8 |
| **2030** | 16.3 | 10.6 | 28.8 | 10.3 | 66.0 | 37.0 |
| **2035** | 16.2 | 10.4 | 29.5 | 10.5 | 66.5 | 37.6 |
| **2040** | 16.2 | 10.3 | 29.5 | 10.4 | 66.5 | 37.7 |
| **2045** | 16.4 | 10.3 | 28.9 | 10.6 | 66.3 | 39.0 |
| **2050** | 16.6 | 10.4 | 28.9 | 10.6 | 66.5 | 38.7 |

Note: "Other" includes pipeline fuel and lease & plant.

### 8.3.5 LNG Exports and Pipeline Exports to Mexico

Existing and Potential Liquefied Natural Gas (LNG) Terminals

Based on current global LNG market conditions, ICF assumes that the nine U.S. LNG terminals currently under construction are completed and expanded in future. Those terminals are Sabine Pass, Freeport, Cove Point, Cameron, Corpus Christi, Elba Island, Golden Pass, Port Arthur and Calcasieu Pass. By 2021, ICF projects U.S. LNG export capacity will be 11.3 billion cubic feet per day (Bcfd). ICF assumes an additional 10.1 Bcfd of export capacity will come online in the U.S. between 2021 and 2045. The U.S. and Canadian LNG export terminal capacity utilization is projected to average about 81% through 2045. ICF assumes that two LNG export facilities will be built in British Columbia: Woodfibre LNG and LNG Canada.

**Table 8-6 LNG Export Volumes and Capacity (Bcfd)**

| Year | US Gulf Coast | US East Coast | US West Coast | British Columbia | Capacity Online (Annual Average) |
|---|---|---|---|---|---|
| **2023** | 9.1 | 1.0 | 0.0 | 0.0 | 13.2 |
| **2025** | 9.7 | 1.0 | 0.0 | 1.6 | 17.4 |
| **2028** | 12.1 | 1.0 | 0.0 | 1.9 | 19.2 |
| **2030** | 13.1 | 1.0 | 0.0 | 3.3 | 20.9 |
| **2035** | 13.7 | 1.0 | 0.0 | 3.3 | 20.9 |
| **2040** | 13.7 | 1.0 | 0.0 | 3.3 | 20.9 |
| **2045** | 13.8 | 1.0 | 0.0 | 3.3 | 20.9 |
| **2050** | 13.8 | 1.0 | 0.0 | 3.3 | 20.9 |

Pipeline Exports to Mexico

Mexico's demand for natural gas will continue to increase between 2020 and 2030 due to Mexico's expansion of its domestic pipeline infrastructure, increased power generation gas demand, and lower domestic production. Since 2015, Mexico's imports of U.S. gas have undergone a ~84.4% increase, reaching 5.3 Bcfd in 2020. ICF projects that exports will reach 7.6 Bcfd by 2030. ICF assumes the first phase of the Costa Azul LNG export facility will be built in Mexico, further increasing pipeline exports to Mexico from the United States.

**Table 8-7 U.S. Pipeline Exports to Mexico (Bcfd)**

| Year | California | West Texas/ New Mexico | Arizona | South Texas |
|---|---|---|---|---|
| **2023** | 0.4 | 1.1 | 0.4 | 4.8 |
| **2025** | 0.4 | 1.4 | 0.5 | 5.1 |
| **2028** | 0.4 | 1.7 | 0.5 | 4.9 |
| **2030** | 0.4 | 1.9 | 0.5 | 4.7 |
| **2035** | 0.4 | 2.2 | 0.6 | 4.4 |
| **2040** | 0.4 | 2.1 | 0.6 | 4.3 |
| **2045** | 0.4 | 2.1 | 0.6 | 4.3 |
| **2050** | 0.4 | 2.1 | 0.6 | 4.3 |

**List of tables that are uploaded directly to the web:**

Table 8-8 EIA Style Gas Report for EPA Platform v6 Summer 2021 Reference Case

Table 8-9 Natural Gas Basis for EPA Platform v6 Summer 2021 Reference Case

Table 8-10 Natural Gas Supply Curves for EPA Platform v6 Summer 2021 Reference Case