

Natural Gas Market 2019-2020 Winter Outlook

Prepared for:



Natural Gas Supply Association

Prepared by:



Energy Ventures Analysis

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Overview

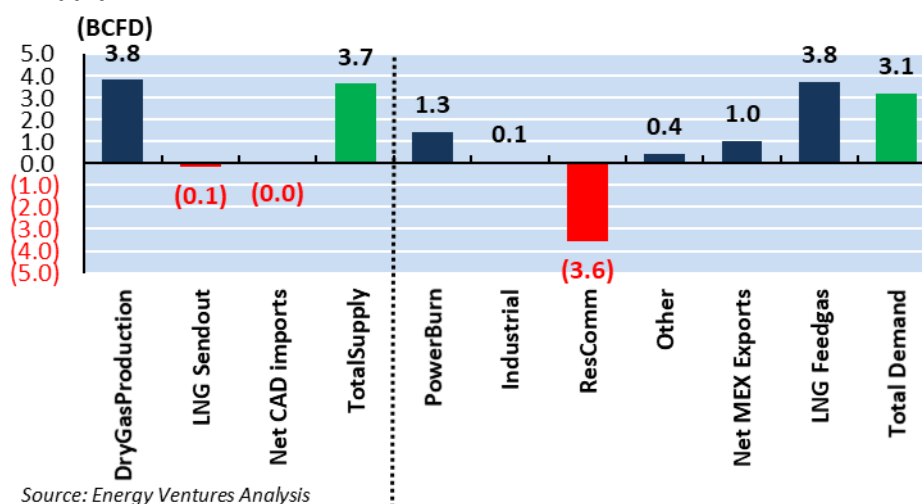
U.S. natural gas supply and demand for 2019-2020 winter¹ are both forecasted to experience substantial growth winter-over-winter. Total gas production is expected to grow 3.8 BCFD winter-over-winter, while demand components combined will grow 3.1 BCFD (See **Exhibit 1**)². Winter 2019-2020 storage inventories of natural gas are forecasted to start the winter heating season at 3,712 BCF, near the five-year average level. Assuming a 10-year normal weather for the 2019-2020 winter, gas withdrawals are forecasted to total 1,879 BCF, which is slightly lower than the five-year average. The lower-than-average withdrawal is due to record-high production outpacing demand growth (**Exhibit 2**).

Exhibit 2 presents a sector-by-sector look at changes expected this winter compared to last winter. The decline in the Residential and Commercial sector is the result of expected milder winter weather compared to last winter.

Exhibit 1: Summary of Winter Natural Gas Supply and Demand

Winter Natural Gas Supply and Demand Summary			
BCFD	Winter 2019-2020	Winter 2018-2019	Difference
Supply			
Dry Production	92.0	88.2	3.8
Net Canadian Imports	4.7	4.7	(0.0)
LNG Imports	0.2	0.3	(0.1)
Total Supply	96.9	93.3	3.7
Demand			
Power Burn	27.0	25.7	1.3
Industrial	24.8	24.7	0.1
Residential and Commercial	36.1	39.6	(3.6)
Net Mexico Exports	5.8	4.8	1.0
LNG Exports	8.3	4.5	3.8
Other	7.3	6.9	0.4
Total Demand	109.3	106.2	3.1
Implied Withdrawals	12.3	12.9	(0.6)
HDDs	3,469	3,620	(151)

Exhibit 2: Natural Gas Supply and Demand, 2019-2020 Winter vs 2018-2019 Winter



¹ For the purpose of this report, winter refers to November to March which is, in general, the gas withdrawal season.

² "Gas" is often used as a short form of natural gas in this report.

The highlights of the 2019-2020 winter outlook include the following:

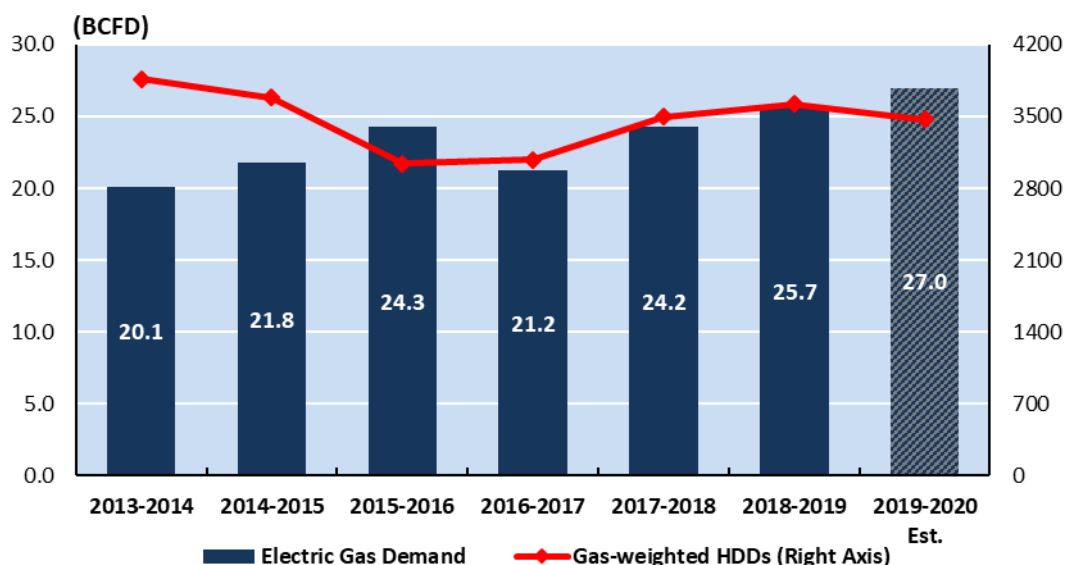
- **Lower-48 production is expected to grow further for the 2019-2020 winter.** Dry gas production is forecasted to average 92 BCFD this winter, which will represent 3.8 BCFD (~4%) of growth winter-over-winter. This winter, associated gas production from the Permian will contribute to the largest gain since production is likely to ramp up quickly as the 2-BCFD Gulf Coast Express pipeline and cross-border Mexico export pipelines are currently commissioning or recently entered service. Elsewhere, production from the Marcellus, Utica, Haynesville shales will grow further to meet regional demand and fill takeaway capacity. The strong growth from these areas will more than offset declines from conventional plays.
- **Power demand will maintain its growth momentum.** The strong growth in power demand is the result of low-natural gas prices, which encourages the dispatch of gas-fired generation units, as well as structural growth due to the addition of new and highly efficient combined cycle gas turbines (CCGTs). Structural growth due to these new CCGT additions has increased steadily over time, creating a strong base for power burn growth. On a national level, a 20 cent/MMBTU decline in natural gas prices would increase power burn by 1.2 BCFD while a 20 cent/MMBTU increase would reduce power burn by only 0.6 BCFD. Thus, there is more potential upside to power burn for this coming winter because of the market price sensitivity of demand.
- **Total natural gas exports—Gas exports via pipeline to Mexico and LNG exports—will lead the demand growth this winter.** Total natural gas exports are expected to grow by 4.8 BCFD winter-over-winter. The anticipated increase in gas flow via the Mexico Sur de Texas-Tuxpan pipeline is expected to increase gas demand in South Texas since late September. In terms of LNG, three new trains—Elba Island Phase 2 (0.1 BCFD), Freeport Train 2 (0.7 BCFD), and Cameron Train 2 (0.7 BCFD)—are expected to start up this winter, bringing total LNG export capacity to 8.5 BCFD by March 2020.
- **Based on the near-term supply and demand dynamics, natural gas storage levels are expected to finish the 2019-2020 winter withdrawal season at 1,833 BCF, slightly above the five-year average.** Production growth is expected to respond quickly to demand gains, resulting in lower-than-average storage withdrawals for the coming winter. Winter weather plays an important role in Residential and Commercial gas demand. A cold winter scenario can result in a below-average end-of-March storage level; however, winter weather is forecasted to be milder this winter compared to last.

Demand Outlook

Power

Power burn demand has been very strong so far this year, with year-to-date power burn averaging about 1.4 BCFD stronger year-over-year. The robust power burn is largely driven by new CCGT additions over the past few years, providing a solid base for power burn growth in a relatively low natural gas price environment. As a result, EVA's electricity dispatch model shows that, based on the current resource mix and dispatch economics, power burn is expected to average 27 BCFD for the 2019-2020 winter, about 1.3 BCFD higher winter-over-winter (See **Exhibit 3**).

Exhibit 3: Historical and Forecasted Winter Power Burn Demand

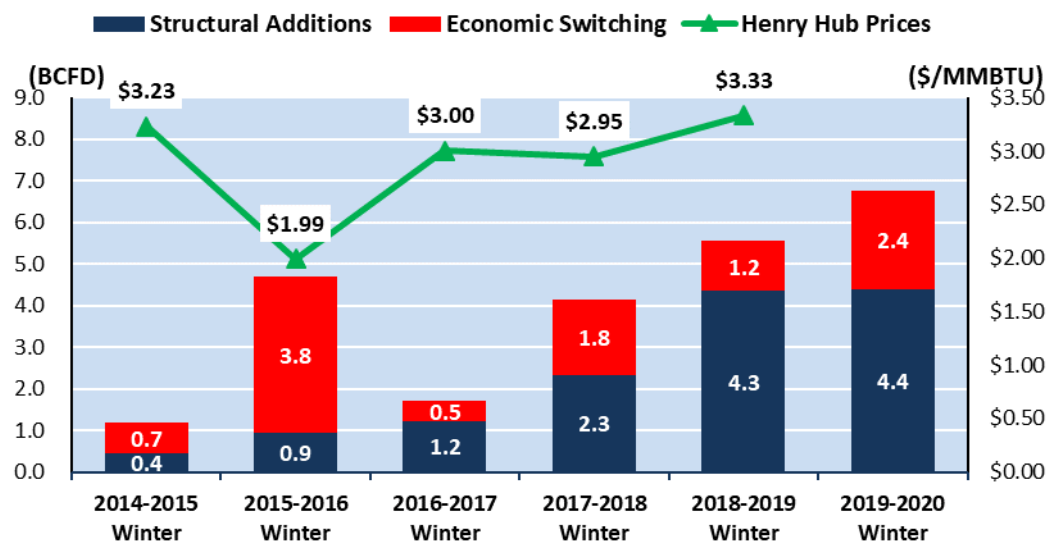


Source: U.S. EIA, NOAA, Energy Ventures Analysis

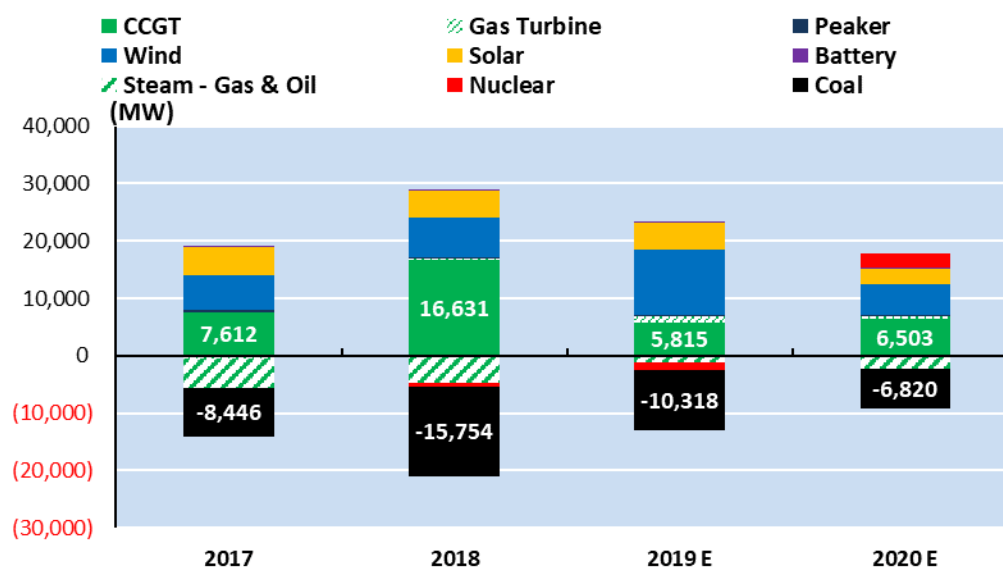
Exhibit 4 quantifies the increase in power burn from 2013-2014 winter due to either structural growth or economic fuel switching. Adjusted for weather, winter power burns have increased since the 2013-2014 winter, primarily due to natural gas-fired power generation additions that replaced retiring coal-fired power plants. An analysis of historical data shows that the growth from economic switching is sensitive to natural gas prices. In the 2015-2016 winter, Henry Hub gas prices averaged just below \$2.00/MMBTU, which enabled gas-fired units to dispatch ahead of other fossil fuel-burning units. Conversely, when natural gas prices increased during the 2016-2017 winter, power generation partially switched back to coal. As winter forward gas prices are expected to average below the last three-year levels³, economic switching from coal to natural gas is expected to be robust for the 2019-2020 winter.

Structural growth due to new CCGT additions has increased steadily over time, establishing a strong base for power burn growth. In 2019-2020 winter, incremental growth from structural additions is expected to be modest due to a slower pace of CCGT additions (See **Exhibit 5**). Historically, retiring coal capacity has been almost entirely replaced by new CCGT capacity. In 2019, another 10.3 GW of coal-fired capacity is scheduled to be retired by year end, but only 5.8 GW of new CCGT capacity is scheduled to enter service. Wind capacity additions in 2019 will top 11.3 GW and exceed CCGT additions for the first time due to investment driven primarily by the upcoming expiration of the Production Tax Credit (PTC) for wind.

³ Here, the last three-year levels refer to actual Henry Hub cash settlements.

Exhibit 4: Power Burn Increase from 2013-2014 Winter: Structural Growth vs Economic Switching


Source: Energy Ventures Analysis

Exhibit 5: Electricity Generation Capacity Net Change, 2017-2020


Source: U.S. EIA, Energy Ventures Analysis

Annual Net Change in Electricity Generation Capacity (MW)									
	Coal	CCGT	Gas Turbine	Steam - Gas & Oil	Nuclear	Peak & Other	Wind	Solar	Battery
2017	(8,446)	7,612	(530)	(5,055)	0	316	6,017	4,952	108
2018	(15,754)	16,631	211	(4,692)	(610)	352	6,847	4,826	156
2019 E	(10,318)	5,815	1,150	(1,111)	(1,483)	239	11,323	4,656	143
2020 E	(6,820)	6,503	463	(2,299)	2,474	172	5,280	2,773	250

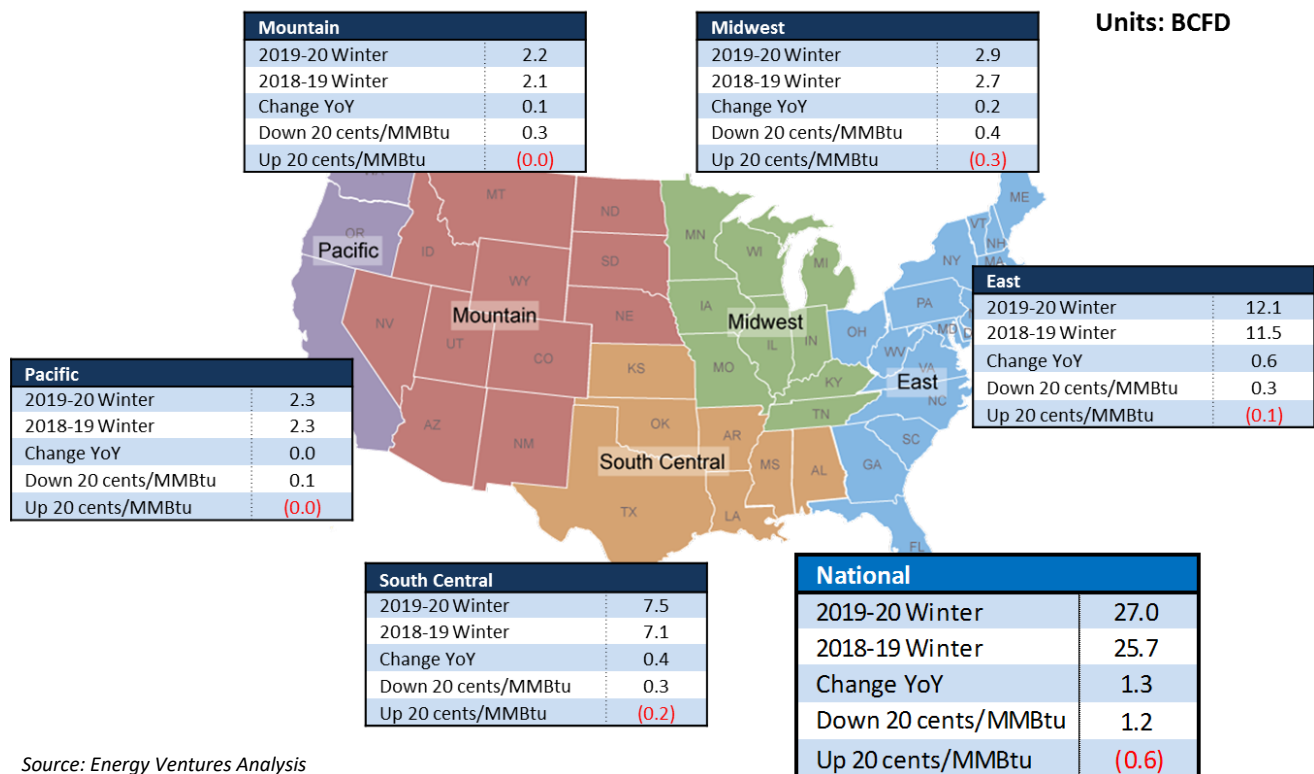
Source: U.S. EIA, Energy Ventures Analysis

Note: Negative numbers mean net retirement

On a regional level, the East region, which accounts for nearly 45% of the country's power burn, will continue to take the lead (See **Exhibit 6**). Power burn in the East region is expected to grow another 0.6 BCFD winter-over-winter to average 12.1 BCFD. The South Central and Midwest regions are also expected to see strong growth, with power burn forecasted to increase by 0.4 BCFD and 0.2 BCFD winter-over-winter, respectively. The strong growth in those regions is attributed to the proximity to abundant low-cost natural gas resources and natural gas-fired unit additions over the last few years. In contrast, Pacific power burn is forecasted to stay flat winter-over-winter as gas-fired capacity additions have been limited while the region has become more reliant on electricity from renewable sources.

Exhibit 6 shows the power burn sensitivity relative to gas price changes. More specifically, the analysis measures changes in regional power burn if natural gas prices vary by 20 cents/MMBTU higher or lower from the base case, which shows the potential of coal-to-gas economic switching. On a national level, a 20 cent/MMBTU lower natural gas price would increase power burn by 1.2 BCFD while a 20 cent/MMBTU higher gas price would reduce power burn by just 0.6 BCFD, indicating that there will be more upside potential for power burn during this coming winter. If natural gas prices were to increase, there is less potential variation in power burn demand due to the recent retirement of coal units, which have left limited room for coal switching back to gas. On the other hand, a lower natural gas price environment will further reduce the dispatch cost for gas-fired units, allowing them to compete against low-cost coal-fired units, like those that burn coal from the Powder River Basin (PRB). Regionally, the East, South Central and Midwest regions are all estimated to have the most potential in economically-driven fuel switching.

Exhibit 6: 2019-2020 Power Burn Forecast by Region and Gas Price Sensitivity



Between 2010 to 2019, annual average heat rates for CCGT units decreased by 9.5%. Heat rates are calculated based on the amount of energy (in Btu or MMBTU) used to generate a unit of electricity (in kWh or MWh). Lower heat rates indicate more efficient generation—in other words, generating the same amount of electricity requires less fuel. One main factor in the improvement of the CCGT fleet's heat rate is the growing installation of newer and larger advanced CCGT units, which led to efficiency gains. According to an Energy Information Administration (EIA) survey, better performance and

lower construction costs are likely to substantially increase the share of these advanced CCGT units in future years⁴. In addition, changes in usage patterns of CCGT plants could also affect their heat rates. Plants that are being operated more continuously—as opposed to being cycled on and off frequently—may consume less fuel to produce electricity⁵. With natural gas being more accessible and cheaper as well as generating fewer emissions compared to other fossil fuels, CCGT units have been operated at higher utilization rates and in many cases, as baseload capacity. This change in usage pattern will further improve the CCGT fleet's efficiency.

In recent years, higher renewable penetration has brought challenges to the power grid especially during high-demand peak hours when some renewable resources are less available, and may need to be supplemented by natural gas-fired generators or battery storage. For example, a June 2019 heat wave highlighted the potential for the California Independent System Operator (CAISO) to face struggles meeting the extreme peak loads that it had more effectively managed in previous years. On June 11, the grid operator issued a flex alert—a voluntary call for consumers to conserve electricity when extreme heat increases energy demand and CAISO's available capacity has a hard time meeting peak demand. The challenge came as solar generation dropped sharply in the evening hours even as demand remained high. Not long after, in September 2019, the California Public Utilities Commission proposed delaying the retirement of several gas-fired power plants, in order to address potential power capacity shortages beginning in 2021⁶.

Another example occurred in August 2019, when real-time power prices in the Electric Reliability Council of Texas (ERCOT) grid spiked to their administrative price cap of \$9,000/MWh amid a record-breaking heat wave. During the high-priced hours, the region's massive wind fleet performed below average and contributed to extremely tight reserve margins. In fact, market participants such as Calpine and NRG have long recognized this issue and asked ERCOT to revise its shortage pricing formula, or Operating Reserve Demand Curve (ORDC), to provide high enough price incentives to encourage the development of dispatchable generation⁷. Going forward, ERCOT provides a unique lens to observe how new power market designs and the integration of renewable and gas-fired generation will drive future resource mix and new investments.

⁴ More new natural gas combined-cycle power plants are using advanced designs:

<https://www.eia.gov/todayinenergy/detail.php?id=39912>

⁵ Natural gas-fired electricity conversion efficiency grows as coal remains stable:

<https://www.eia.gov/todayinenergy/detail.php?id=32572>

⁶ California Public Utilities Commission: Decision Requiring Electric System Reliability Procurement For 2021-2023

<http://docs.cpuc.ca.gov/SearchRes.aspx?docformat=ALL&docid=312522263>

⁷ NRG, Calpine proposes market fixes to avoid 'subversion' of ERCOT model

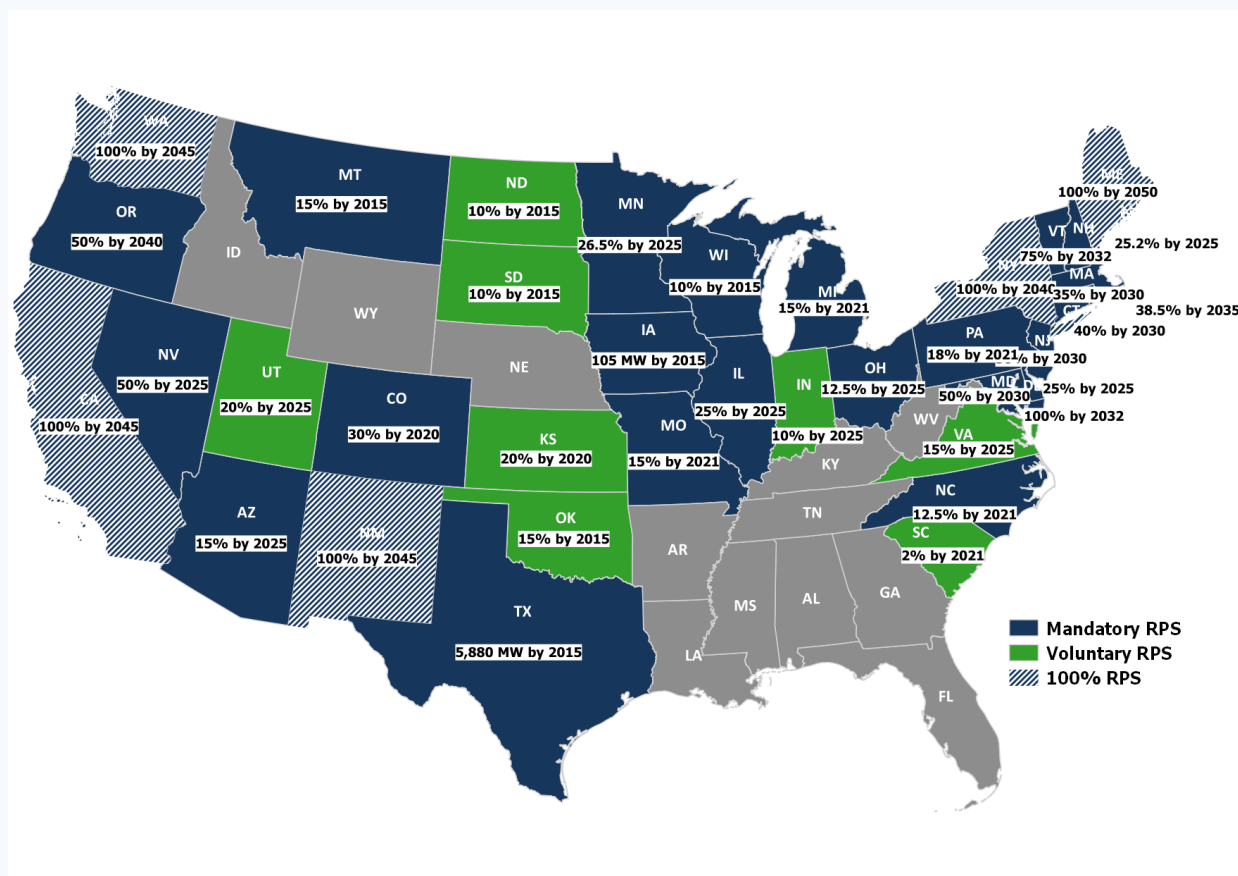
<https://www.utilitydive.com/news/nrg-calpine-propose-market-fixes-to-avoid-subversion-of-ercot-model/442530/>

The Development of State Renewable Portfolio Standard (RPS)

States have been very active in recent months revising and expanding their Renewable Portfolio Standards (RPS), which require a certain percentage of electricity that utilities sell to be generated through renewable, nuclear, or hydro resources. As of August 2019, 39 states (including Washington D.C.) have established mandatory or voluntary RPS programs (See **Exhibit 7**) that include time-bound mandates for procurement of renewable electricity and some states also include “set-asides” or “carve-outs” for solar PV as well as technology-specific buildout requirement for offshore wind and/or battery storage.

State-level RPS development in the Northeast, Mid-Atlantic, and West regions has experienced the most active development. RPS policies are expected to be the key driver for renewable energy development, especially in regions like the Northeast and Mid-Atlantic where renewable resources are relatively limited and investors will rely upon an additional revenue stream from selling renewable energy credits (RECs). For regions like Texas and the Midwest, actual renewable growth far outpaced RPS needs, given favorable wind energy capacity factors⁸. The southeastern states, apart from the Carolinas, have minimal RPS development.

Exhibit 7: State RPS as of August 2019



A few states have also advanced and moved towards 100% RPS. Among the lower-48 states, Maine, New York, Washington D.C., New Mexico, California, and Washington have passed legislation to achieve 100% clean energy. In June 2019, New York passed the country’s most ambitious climate targets—its own version of the “Green New Deal”—that will not only require 100% carbon free from the electricity sector by 2040 but also economy-wide, net-zero carbon emission by 2050 (the state allows up to 15% of economy-wide emission being offset or captured). This legislation will

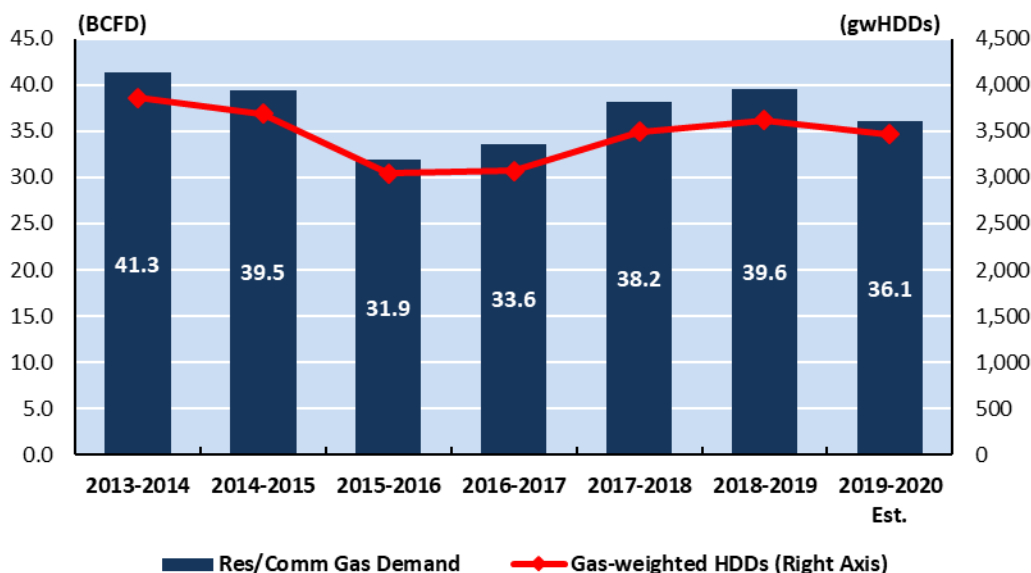
⁸ U.S. Renewable Portfolio Standards: 2017 Annual Status Report:
<https://emp.lbl.gov/sites/default/files/2017-annual-rps-summary-report.pdf>

have a long-term impact on New York State's natural gas demand as it lays out a plan and incentives to phase out carbon-emitting fuel from not just the electric sector but also from home and building heating systems. The anticipated reduction in natural gas demand will also affect future investment in gas infrastructure such as gas-fired power plants and pipelines. Regulatory uncertainty will likely grow over gas infrastructure such as the Northeast Supply Enhancement Project and Constitution Pipeline.

Residential and Commercial

Natural gas use in the residential and commercial sector includes space heating, water heating, and cooking. Residential and commercial consumption for natural gas is therefore strongly correlated with weather during the wintertime. We are assuming a 10-year normal weather for the 2019-2020 winter. The assumption of normal weather yields 3,469 gas-weighted heating degree days (gwhDDs)⁹. Residential and commercial demand is estimated to average 36.1 BCFD for the winter, about 3.5 BCFD lower winter-over-winter. Note that weather conditions can have a significant impact on residential and commercial sector demand—historically, winter residential and commercial gas demand has swung from 31.9 BCFD to 41.3 BCFD depending on the weather conditions (See **Exhibit 8**).

Exhibit 8: Historical and Forecasted Winter Weather and Residential/Commercial Gas Demand



Source: U.S. EIA, NOAA, Energy Ventures Analysis

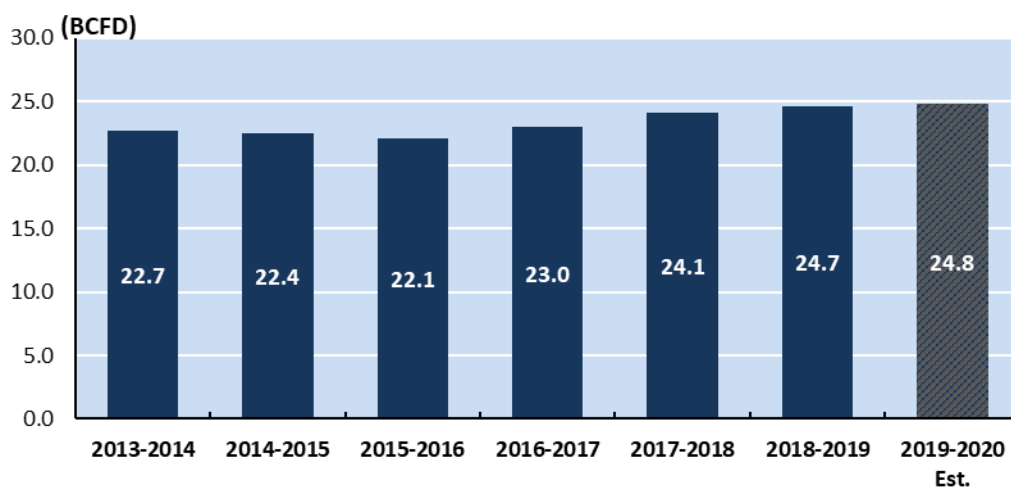
Natural gas demand in the residential sector has remained largely flat over the past few years mainly due to population shifts and efficiency gains that counterbalance population size and housing growth. According to the EIA's Residential Energy Consumption Survey (RECS) data, natural gas furnaces are most commonly used in areas with cold winter temperatures, while electric heat pumps are gaining popularity in the Southeast, where winters typically are milder. The U.S. population continued to shift to the South and the West from the Northeast and Midwest, resulting in a shift from natural gas to electric heating and hence slightly less natural gas heating need during wintertime. Gas use in the commercial sector is mostly driven by economic growth as well as energy efficiency improvements of heating and building components. Much of the growth in commercial use is due to business expansion and is mostly offset by continuing improvements in energy efficiency.

⁹ Gas-weighted heating degree days (gwhDDs) are HDDs that are weighted to reflect a combination of population in each area and the percent of the population in that area that uses natural gas for home heating.

Industrial

Industrial natural gas demand has grown substantially over the past few years, thanks to continuing economic growth and the availability of low-cost natural gas (**Exhibit 9**). Similar to the residential and commercial sectors, some of the industrial gas demand is also closely correlated to weather during wintertime¹⁰. Industrial end users consume natural gas as fuel to generate heat and power or as feedstock. Assuming a 10-year normal weather for 2019-2020 winter, industrial demand is projected to remain flat compared to last year at 24.8 BCFD.

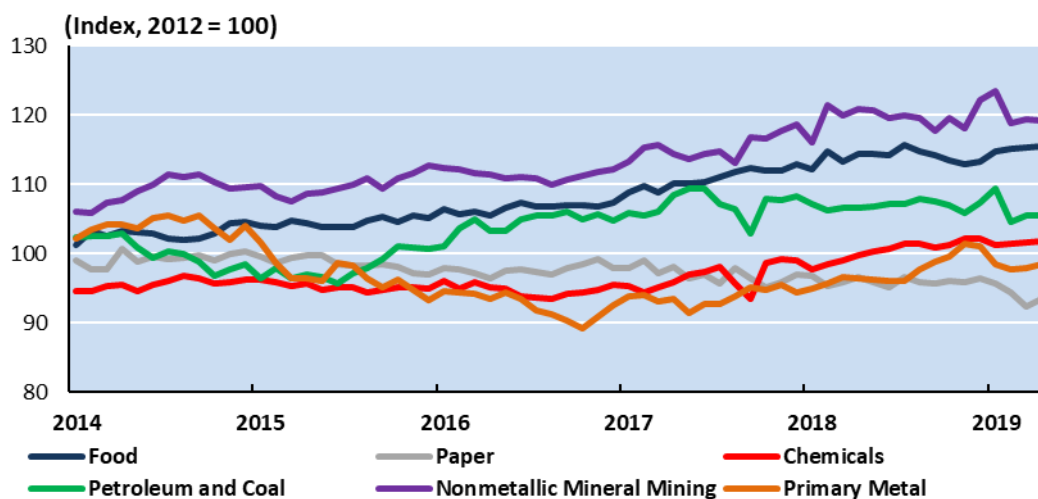
Exhibit 9: Historical and Forecasted Industrial Gas Demand



Source: U.S. EIA, Energy Ventures Analysis

Strong growth in energy-intensive industries has contributed to higher industrial gas demand in the last decade. As shown in **Exhibit 10**, the industrial sectors' performance index measured by the U.S. Federal Reserve has increased steadily since 2014. Among the six energy-intensive industries, production indices of nonmetallic mineral mining, food, petroleum and coal, as well as chemicals have experienced the largest growth over the last five years, contributing to higher gas demand in the industrial sector.

Exhibit 10: Performance of the Six Energy-Intensive Industries



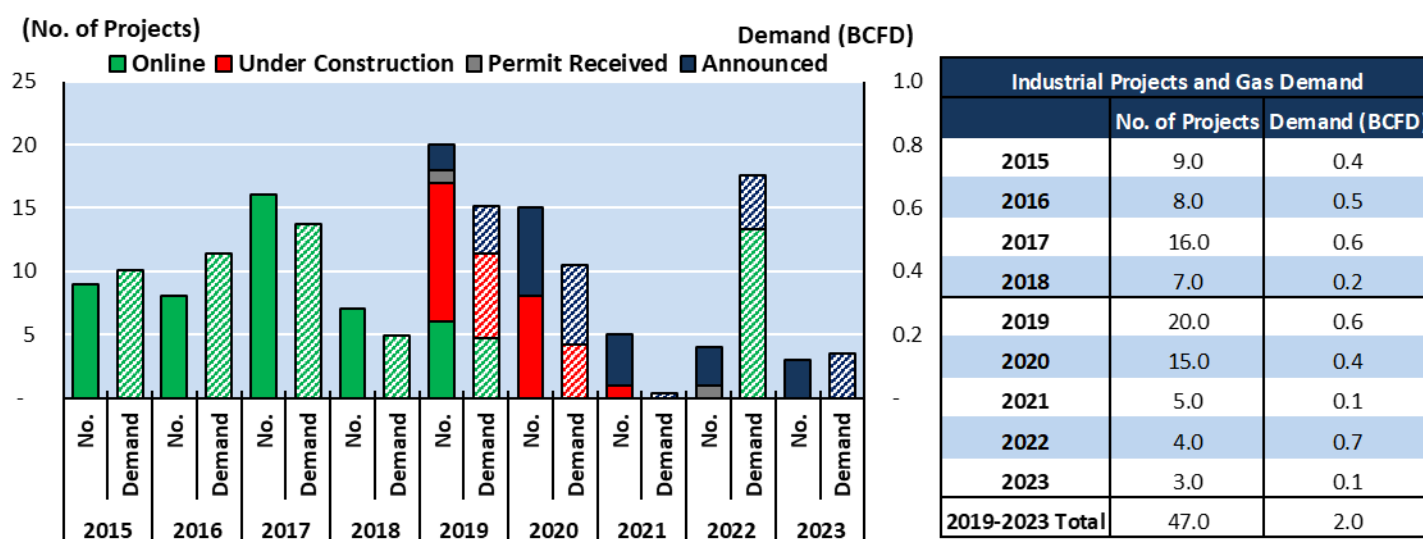
Source: U.S. Federal Reserve

¹⁰ Industrial demand can swing 3-4 BCFD depending on seasonality, representing 10-15% of industrial gas demand.

Manufacturing energy consumption data, conducted by an EIA survey, shows that the U.S. manufacturing sector has increasingly shifted away from coal and petroleum products to natural gas¹¹. The switch was the result of increased availability of natural gas, lower natural gas prices relative to other fuel options, and the ability of manufacturers to comply with environmental regulations when using natural gas. These factors led manufacturers to focus on natural gas use and invest less in fuel-switching flexibility.

2015 to 2018 represents an active period for the development of new industrial facilities (**Exhibit 11**). A total of 40 projects came online from 2015 through 2018, which are estimated to bring about 1.7 BCFD of gas demand. An additional 47 projects are expected to come online between 2019 and 2023, which could potentially add 2.0 BCFD of incremental gas demand. Among these projects, petrochemical projects will still dominate the new and expansion projects over the next five years.

Exhibit 11: Industrial Projects and Estimated Gas Demand



Source: Energy Ventures Analysis

40 projects were completed from 2015-2018, with total gas demand of 1.7 BCFD and total investment of \$50 billion

47 projects are expected to come online from 2019-2023, with total gas demand of 2 BCFD and total investment of \$82.8 billion

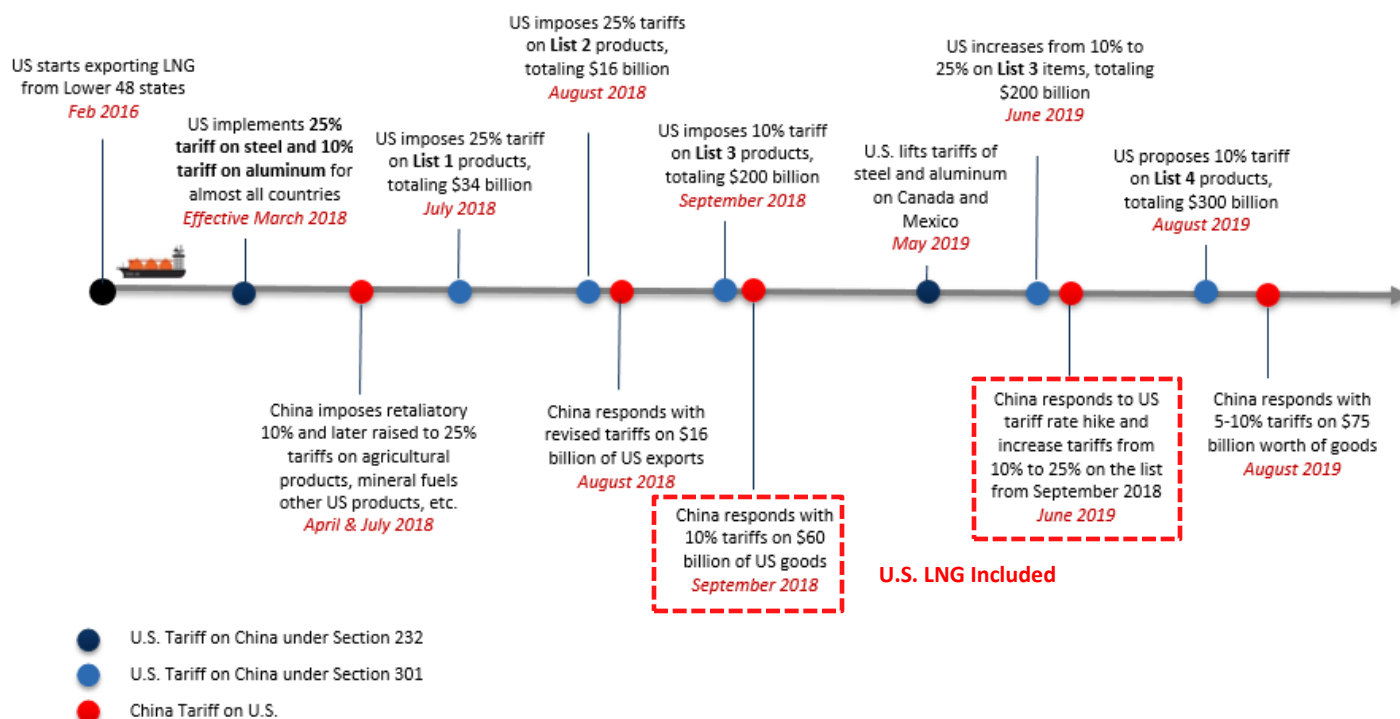
These new projects are expected to drive industrial gas demand higher in the short term. As the 25% steel tariff strengthened the domestic steel industry, steelmakers have either announced plans to build new facilities or to restart shuttered steel mills. Nucor, the largest steel manufacturer in the U.S., announced plans to build a new 1.2 million tons per year (mt/y) steel mill in Kentucky by 2022 and to expand capacity at its Gallatin facility in the state by 2021. U.S. Steel has also planned to resume construction on an Alabama mill to take advantage of higher steel prices. In addition, petrochemical plants are being planned and developed to take advantage of low-cost natural gas. Two new methanol plants on the Gulf Coast—the Big Lake 1 and St. James 1 facilities—are expected to enter service in 2019 and 2020, respectively. In addition to Gulf Coast methanol projects, a few methanol plants have been developed in West Virginia. Two smaller methanol-producing facilities—Primus Green Energy and Liberty One—are planned to begin operations in 2020 and 2019, respectively. Their proximity to the Appalachian Basin ensures feedstock natural gas supply at a relatively low cost.

¹¹ U.S. manufacturers' short-term capability to switch fuels continues to decline:

<https://www.eia.gov/todayinenergy/detail.php?id=37292>

The ongoing trade war and several rounds of import tariffs are expected to have a mixed impact on U.S. industry in the medium term. **Exhibit 12** shows a timeline of the U.S.-China trade war, with several rounds of tariffs being imposed since the first quarter of 2018. In March 2018, the U.S. implemented a 25% tariff on imported steel and 10% tariff on imported aluminum, which led to higher prices for U.S.-made steel and boosted domestic steel production. However, other industries might struggle amid the ongoing trade war between the U.S. and China. Overall, four phases of tariffs were imposed by the U.S. on Chinese goods, with the latest round in August 2019 proposing a 10% tariff on an additional \$300 billion worth of Chinese products. In response, China imposed retaliatory tariffs against U.S. goods and in June 2019 raised the tariff on U.S. LNG to 25% from the previous level of 10%. The tariff will increase production costs for industries ranging from automobiles to petrochemical manufacturers. Business uncertainty and weakening global economy are typically a drag on the industry.

Exhibit 12: Timeline of U.S.-China Trade War



Source: Energy Ventures Analysis

Export

Pipeline Exports to Mexico

Since 2014, U.S. pipeline exports to Mexico have grown from 2.2 BCFD to 4.8 BCFD thanks to cross-border pipeline buildouts and declining Mexican gas production (**Exhibit 13**). To date, Mexico has imported pipeline natural gas from the U.S. mainly through South Texas, West Texas (Waha), Arizona, and California, with exports from Texas leading the way. Recent pipeline development has almost tripled the gas exports from Texas to Mexico since 2014. In 2018, a few more pipelines were placed in service (**Exhibit 14**), including the 0.5-BCFD Nueva Era pipeline, the 2.6-BCFD Valley Crossing Pipeline, and the downstream pipelines connecting El Encino westward to Topolobampo and eastward to La Laguna.

Exhibit 13: Historical U.S. Gas Exports to Mexico

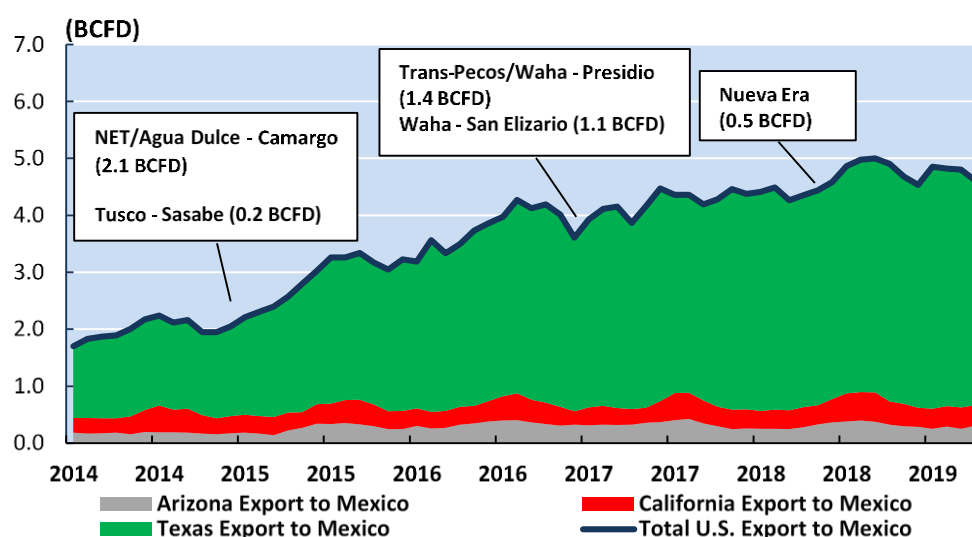


Exhibit 14: Recently constructed and Upcoming Gas Pipelines in Mexico

Pipeline Name	Begin Region	End Region	Developer Name	Project Status	Online Date	Capacity (BCFD)
Valley Crossing Pipeline	Nueces	Brownsville	Spectra Energy	Completed	Oct-2018	2.60
El Encino - La Laguna	El Encino	La Laguna	Fermaca	Completed	Mar-2018	1.50
Nueva Era	Colombia	Escobedo	Nueva Era	Completed	Jul-2018	0.50
El Elcino - Topolobampo	El Elcino	Topolobampo	TransCanada	Completed	Jun-2018	0.67
La Laguna - Aguascalientes	La Laguna	Aguascalientes	Fermaca	Under Construction	2019	1.19
Villa de Reyes - Guadalajara	Villa de Reyes	Guadalajara	Fermaca	Under Construction	2019	0.89
Samalayuca - Sasabe	Samalayuca	Sasabe	Carso Gasoducto Norte	Under Construction	2019	0.47
Sur de Texas - Tuxpan*	Sur de Texas	Tuxpan	TransCanada - Sempra	Completed	2019	2.60
Tuxpan - Tula	Tuxpan	Tula	TransCanada	Construction Halted	Unknown	0.89
Tula - Villa de Reyes	Tula	Villa de Reyes	TransCanada	Construction Halted	Unknown	0.89
Salina Cruz - Tapachula	Salina Cruz	Tapachula	TAG Pipelines Comercial	Under Construction	2019	0.04

* Sur de Texas - Tuxpan interconnects with Valley Crossing Pipeline.

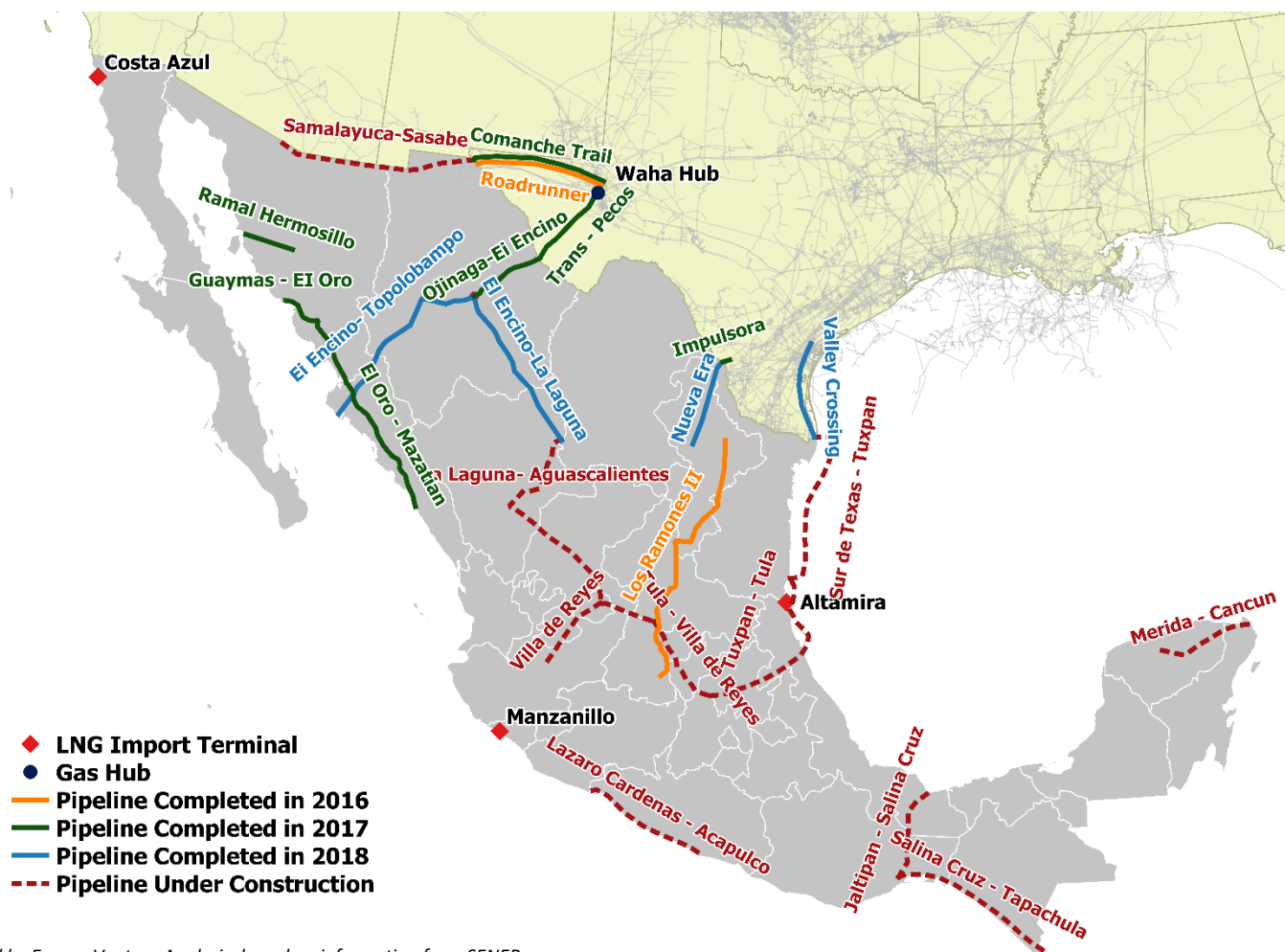
Source: Energy Ventures Analysis

The completed 2.6 BCFD Sur de Texas-Tuxpan pipeline, which is a marine pipeline running almost entirely under the Gulf of Mexico (See **Exhibit 15**), faced additional delays as the state electric utility CFE delayed the issuance of its operating certificate. CFE previously requested seven international arbitrations, seeking reimbursement for the capacity payment during pipeline delays. Just recently, in late August 2019, CFE announced that it had resolved the issue and reached an agreement with pipeline developers, therefore withdrawing the arbitration process. In September 2019, the Sur de Texas-Tuxpan marine pipeline has begun operating. The increase in natural gas flow via Sur de Texas-Tuxpan is expected to replace LNG import at the Altamira terminal.

Another important export corridor is the Wahalajara system – a collection of Fermaca-built pipelines that connect Waha to the central Mexican market around Guadalajara and Villa de Reyes (See **Exhibit 15**). The system was previously delayed to mid-2019 but was reported to begin receiving natural gas flow in April 2019. However, the natural gas flow is largely restricted by the uncompleted Wahalajara segments and interconnections further downstream. Upon its completion, the Wahalajara system could ultimately provide takeaway for Permian gas production.

EVA estimates that U.S. natural gas pipeline exports to Mexico will average 5.8 BCFD for the 2019-2020 winter, 1.0 BCFD (21%) higher winter-over-winter, driven largely by these pipeline completions.

Exhibit 15: Recently Completed and Under Construction Gas Pipelines in Mexico



Mapped by Energy Venture Analysis, based on information from SENER

LNG Exports

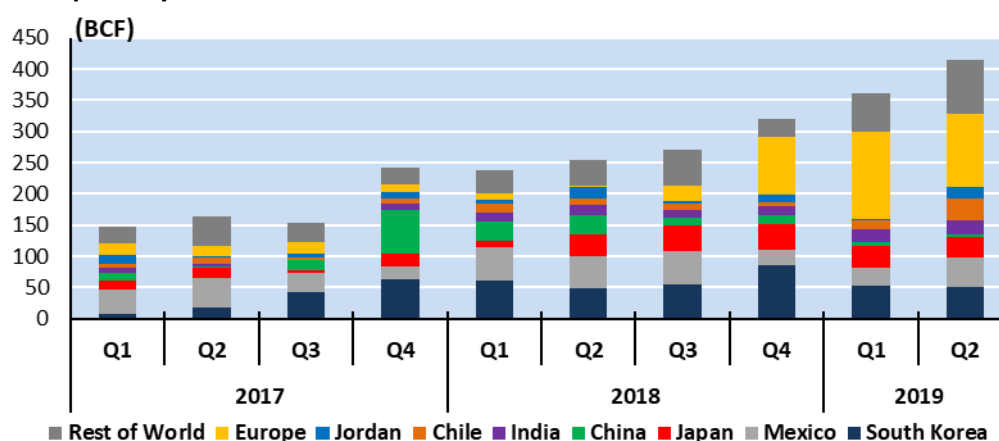
Starting in 2016, U.S. LNG exports have increased steadily, with six projects (eleven export trains) totaling 6.8 BCFD of export capacity currently under operation or commissioned (See **Exhibit 16**). For the 2019 summer, Cameron Train 1 (0.7 BCFD) and Corpus Christi Train 2 (0.7 BCFD) joined the LNG export fleet and entered commercial operation while Elba Island (0.2 BCFD) and Freeport Train 1 (0.7 BCFD) are currently conducting commissioning activities.

Exhibit 16: U.S. Operating and Commissioning LNG Export Projects

Company	Project	Train	Capacity (mmtpa)	Capacity (BCFD)	Status	ISD
Cheniere	Sabine Pass	T1	4.7	0.7	Operating	Feb-16
Cheniere	Sabine Pass	T2	4.7	0.7	Operating	Aug-16
Cheniere	Sabine Pass	T3	4.7	0.7	Operating	Jan-17
Cheniere	Sabine Pass	T4	4.7	0.7	Operating	Aug-17
Cheniere	Sabine Pass	T5	4.7	0.7	Operating	Mar-19
Cheniere	Corpus Christi	T1	4.7	0.7	Operating	Dec-18
Cheniere	Corpus Christi	T2	4.7	0.7	Operating	Aug-19
Dominion Energy	Cove Point		5.8	0.8	Operating	Feb-18
Kinder Morgan	Elba Island	Phase 1	1.5	0.2	Commissioning	Sep-19
Sempra	Cameron	T1 (Phase 1)	4	0.6	Operating	May-19
Freeport	Freeport	T1	5	0.7	Commissioning	Sep-19
Total			49.2	6.8		

Source: Energy Ventures Analysis

Recent supply and demand shifts as well as ongoing trade tensions between U.S. and China have led to rapid changes in U.S. LNG sales (See **Exhibit 17**). According to U.S. Department of Energy data, South Korea, Japan, Mexico and Chile are the top destinations for U.S. LNG overall. Historical data shows that peak demand in South Korea and Japan has generally occurred during winter heating seasons, while Mexico typically has imported more U.S. LNG for summer cooling demand. China, the fastest-growing importer of U.S. LNG in 2017, sharply cut U.S. LNG imports starting in the fourth quarter of 2018 as the 10% import tariff (which has recently been lifted to 25%) was imposed between the two countries, leading Chinese buyers to source LNG elsewhere. The trade tension is expected impact 0.3-0.4 BCFD of U.S. export demand to China¹². Apart from trade tension between the U.S. and China, a warmer-than-normal 2018-2019 winter in Asia also led to limited growth in U.S. LNG exports to Asia. On the other hand, the shrinking price premium of the Asian and European natural gas markets have directed U.S. LNG cargoes to European destinations. Since the fourth quarter of 2018, U.S. LNG exports to Europe nearly tripled, with surging intakes from all U.S. export terminals. Due to the strong inflow of LNG, natural gas storage levels in many European countries are currently higher than the five-year average ahead of the upcoming heating season. However, despite storage being more full than usual for this time of year, LNG imports in Europe remained strong throughout 2019 summer. This summer Spain imported high volumes of LNG as a summer heat wave drove electric sector natural gas demand higher amid coal-to-gas switching and lower-than-normal hydropower generation.

Exhibit 17: U.S. LNG Exports by Destinations

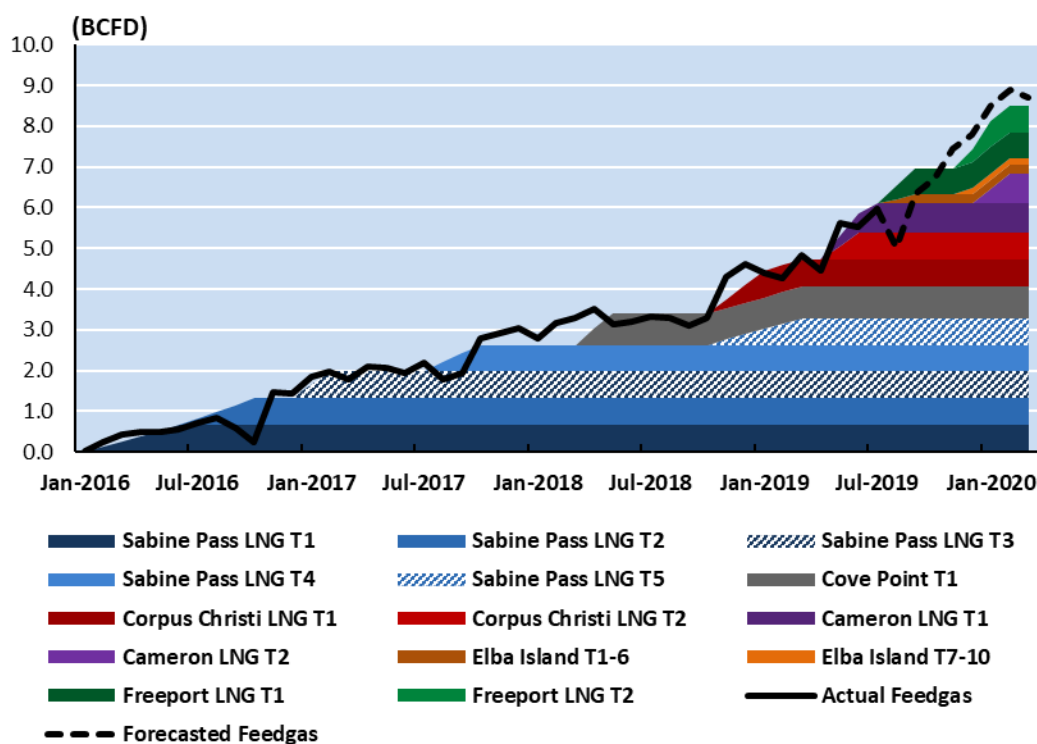
Source: U.S. DOE, Energy Venture Analysis

¹² This is estimated based on actual export volumes from U.S. to China in 2018 Q1.

For the first two quarters of 2019, about 15% of the U.S. LNG export sales occurred on a spot basis, with Cheniere’s Sabine Pass and Corpus Christi facility showing the greatest flexibility. Globally, spot and short-term¹³ LNG trade also rose to a new high, indicating growing liquidity in physical LNG trading as the industry moves closer towards commoditization. The rise in spot and short-term trading can also be attributed to the growing volumes of LNG transacted by portfolio traders.

Looking ahead to the 2019-2020 winter, three new trains—Elba Island Phase 2 (0.1 BCFD), Freeport Train 2 (0.7 BCFD), and Cameron Train 2 (0.7 BCFD)—are expected to start up this winter, bringing total LNG export capacity to 8.5 BCFD by March 2020 (See **Exhibit 18**). Assuming normal winter conditions globally, EVA forecasts LNG export demand to average 8.3 BCFD for the 2019-2020 winter.

Exhibit 18: U.S. LNG Export Capacity by Train, Historical and Forecasted LNG Feedgas Demand



Source: U.S. EIA, Energy Venture Analysis

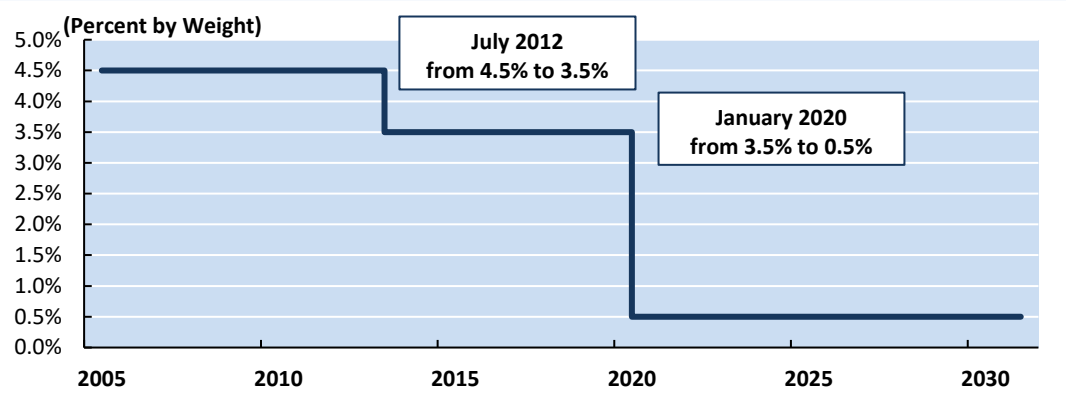
Beyond this coming winter, a few more projects have made progress by reaching positive Final Investment Decisions (FIDs) and joined the second wave of U.S. LNG exports. Cheniere Energy made FIDs to build the third train at its Corpus Christi and the sixth train at the Sabine Pass export facility, raising the company’s total nameplate export capacity to 42.3 mmtpa (~5.9 BCFD). In early 2019, ExxonMobil and Qatar Petroleum jointly announced that they made FID at the 15.6-mmtpa (~2.1 BCFD) Golden Pass export facility and will proceed with construction, with the first of the three trains due for completion in early 2024. Venture Global made official an announcement that its 12-mmtpa (~1.7 BCFD) Calcasieu Pass facility received a positive FID and has already started construction. Assuming all the projects that cleared FIDs will proceed and finish construction on time, U.S. LNG export capacity will reach 14.6 BCFD by the end of 2025.

¹³ The distinction between “short-term” and “spot” LNG transaction matters. EVA defines “short-term” as contracts with terms of four years or less, while “spot” is defined as an one-time transaction where delivery takes place 90 days or less from the date of the transaction.

IMO Implications on LNG Demand

Globally, marine vessels are moving more than 80% of global trade volume and more than 70% by value of goods traded. Finalized in 2018, the International Maritime Organization (IMO) mandates a global 0.50% sulfur cap on vessel emissions to be implemented on Jan 1, 2020—which is commonly referred to as IMO 2020 (See **Exhibit 19**).

Exhibit 19: IMO Marine Fuel Sulfur Limit



Residual oil currently accounts for the largest component of bunker fuel. Vessel operators of marine vessels have several compliance options for the upcoming IMO regulations. They can switch their fuels to a lower-sulfur fuel and/or blend with distillate to comply with the new IMO regulations. Another option is to continue to use higher-sulfur fuels but install scrubbers to remove sulfur from ships' exhaust. Vessel operators also have the option to move away from petroleum-based fuels completely and switch to LNG. Compared to other compliance options (e.g. low-sulfur fuel oil, marine gasoil, scrubber retrofit), LNG is proven to emit only trace amounts of sulfur oxides—well below even the 0.1% fuel-equivalent threshold in some cases¹⁴. LNG also has the capabilities to reduce carbon emissions, which could enable operators to meet potential carbon regulations in the future. The growing availability of LNG could also give it a cost advantage compared to fuel alternatives such as marine gasoil (MGO).

U.S. LNG bunkering currently takes place in two locations—Jacksonville, FL, and Port Fourchon, LA—with a third bunkering facility under development in Tacoma, WA. Jacksonville is the largest LNG bunkering operation in the U.S., with two bunkering facility—the operating JAX LNG and upcoming Eagle LNG facilities—positioned to serve not only a domestic fleet but also larger international vessels. At Port Fourchon, LA, Harvey Gulf International Marine (Harvey) operates LNG bunkering to fuel its small fleet of LNG-powered vessels. At the port of Tacoma, WA, Puget Sound Energy has proposed an LNG liquefaction and bunkering facility to mainly serve vessel owners who operate along the 200-mile journey between Washington and Alaska.

Large-scale LNG bunkering requires specialized infrastructure development for LNG supply and a large fleet of LNG-fueled ships, which usually requires high upfront investment. To date, the number of LNG ports across the U.S. is limited and the LNG distribution infrastructure remains in its infancy. Although newly built ships were either built with or offered to be equipped with LNG-burning engines, reconfiguring existing ships appears to be less desirable because of the extra space required for the larger fuel tanks. As the IMO compliance date draws near, it is still unclear how vessel operators will choose to optimize their fleets through operational, engineering, and logistical decisions. EVA forecasts that in the near-term, the use of LNG in marine bunkering will remain limited, due to high upfront investment cost and limited LNG supply infrastructure. In the medium and long term, increased fuel availability and buildout of infrastructure would allow LNG's share of U.S. bunkering to grow more rapidly.

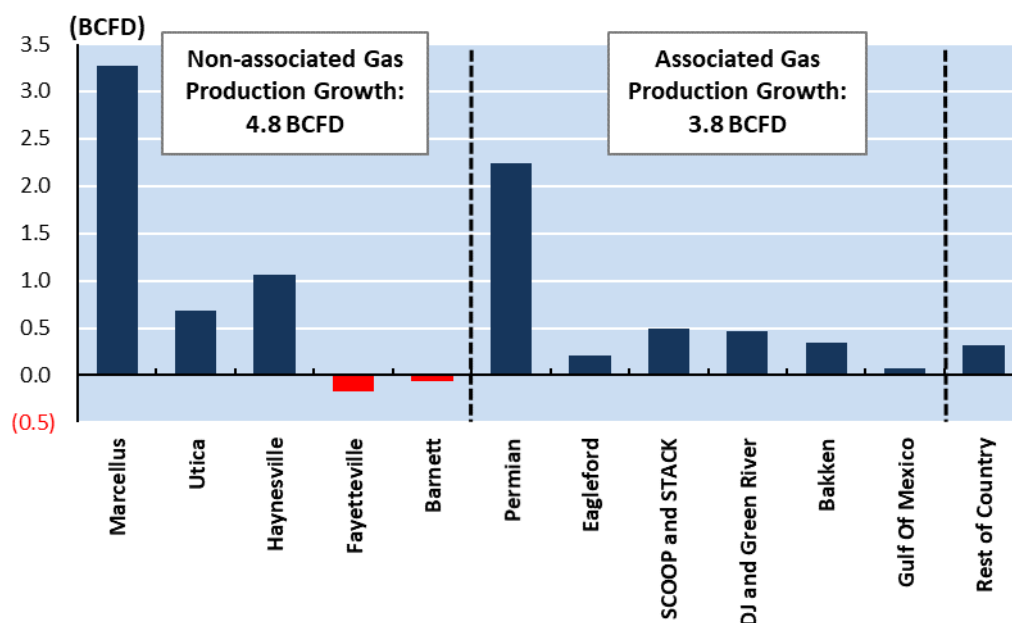
¹⁴ LNG as a Maritime Fuel: Prospects and Policy:
<https://fas.org/sgp/crs/misc/R45488.pdf>

Supply Outlook

Production

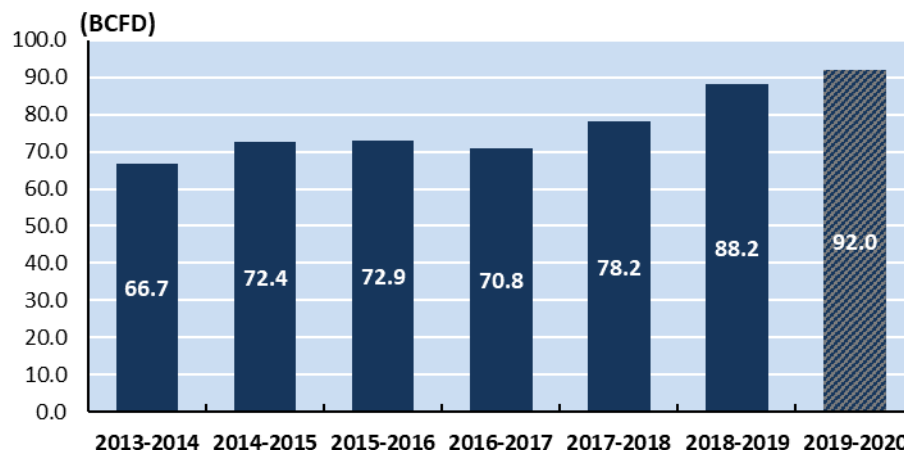
Dry gas production has showed strong momentum so far this year, thanks to more than 12 BCFD of Northeast takeaway pipelines that were placed in service in 2018, as well as strong crude oil-associated production (See **Exhibit 20**). Year-to-date dry natural gas production climbed to 89.6 BCFD, or 8.9 BCFD (11%) higher than the same period last year. EVA estimates that non-associated and associated natural gas production contributed approximately 43% and 54% of the total year-over-year growth, respectively. Among basins, Marcellus production continued to lead the growth by adding 3.3 BCFD. Driven by higher oil production activity, Permian associated gas jumped 2.2 BCFD (29%) year-over-year. In July 2019, Hurricane Barry hit the Gulf Coast and curtailed nearly 1.5 BCFD (60%) of Gulf of Mexico production. However, the production disruption only lasted about five days and then quickly recovered to the pre-storm level of 2.7 BCFD by late July.

Exhibit 20: Production Growth by Basin, 2019 vs. 2018 (through August)



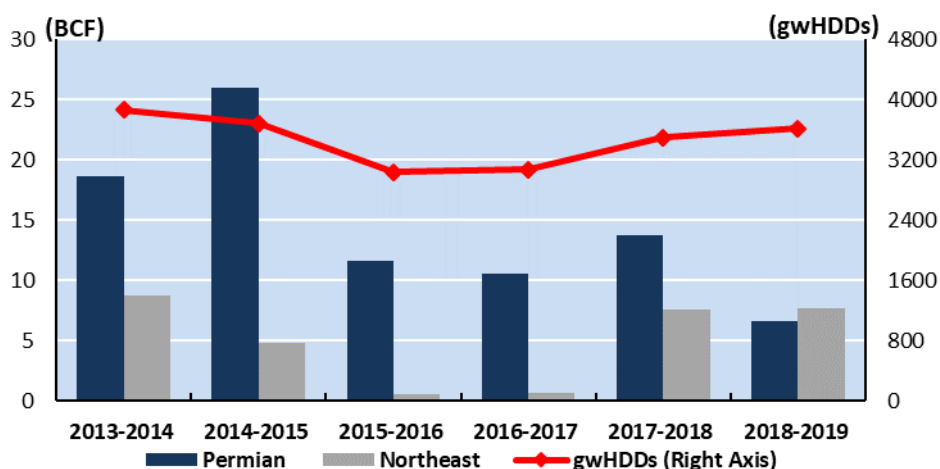
Source: OPIS PointLogic, Energy Venture Analysis

EVA expects lower-48 production to grow further during the 2019-2020 winter. Dry natural gas production is forecast to average 92 BCFD this winter, which will represent 3.8 BCFD (~4%) of growth winter-over-winter (See **Exhibit 21**). This winter, associated gas production from Permian will contribute to the largest gains since production can ramp up quickly as the 2-BCFD Gulf Coast Express pipeline and cross-border Mexico export pipelines enter service by the winter. EVA expects that production from the Permian will account for ~12% of lower-48 production. Elsewhere, production from the Marcellus, Utica, Haynesville will grow further to meet regional demand and fill takeaway capacity. The strong growth from these areas will more than offset declines from conventional plays.

Exhibit 21: Historical and Forecasted Dry Gas Production

Source: U.S. EIA, Energy Ventures Analysis

However, there are a few factors that could alter the production outlook heading into the winter. The first and probably the most important variable is natural gas prices. A lower gas price environment could increase the risk for producers, especially those who do not hedge a significant portion of production volumes. Should natural gas prices fall towards average breakeven costs, gas plays where breakeven costs are at the margin would have the most production risk, including the Utica wet gas and Haynesville dry gas. However, associated natural gas production as well as Marcellus and Utica dry gas present less risk as their breakeven costs are below average. Secondly, a strong supply glut will reach the Gulf Coast this winter. Production that previously targeted the Gulf Coast area will have to compete with lower cost Permian production. Finally, production freeze-offs may impact the pace of U.S. production growth. **Exhibit 22** reviews the impacts of historical freeze-off events in Permian and Northeast producing areas. The analysis measures the production disruption¹⁵ when the region's daily minimum temperatures fell below 32 degrees, the freezing point of water. Overall, wet gas production in the Permian has a higher likelihood of freeze-offs than dry gas production in the Northeast. In addition, colder and icier winters like the 2013-2014 and 2014-2015 winters showed higher level of freeze-offs. The risk of weather-based supply disruption remains especially as Permian production gains momentum.

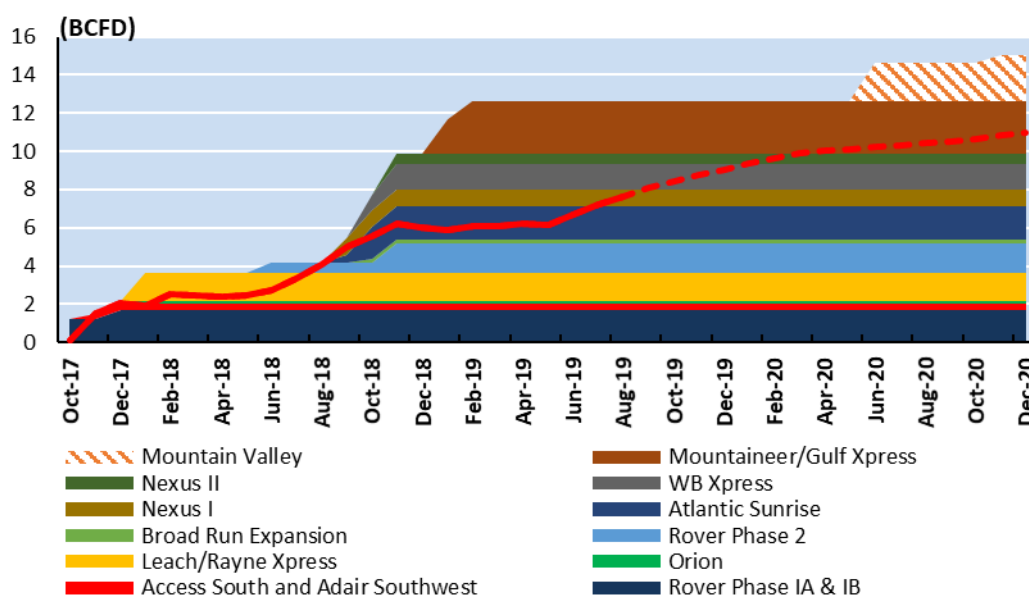
Exhibit 22: Estimated Production Disruption Due to Freeze-offs

Source: OPIS PointLogic, NOAA, Energy Ventures Analysis

¹⁵ EVA defines a production disruption when daily production dropped below 2% of the monthly average production. In Permian, historical daily production showed much higher volatility, so we use a 5% threshold for Permian. Total disruption is measured in BCF, over the entire winter.

In terms of takeaway capacity, new capacity installations in the Northeast peaked in 2018 at more than 12 BCFD (See **Exhibit 23**). This huge wave of new takeaway capacity, along with stronger regional demand, allowed Appalachian gas production to grow by nearly 8 BCFD. However, while the region appears to have ample spare capacity, the effective capacity might actually be smaller given downstream pipeline constraints. For example, the Mountaineer Xpress pipeline has flowed approximately 1.8 BCFD of natural gas, only 70% of the pipeline's design capacity. Projects which have been proposed may face further delays due to environmental obstacles. Under the process of seeking all required regulatory approvals, Mountain Valley Pipeline is still targeting a mid-2020 in-service date. The 1.5-BCFD Atlantic Coast Pipeline has pushed its full in-service date to early 2021 as a number of permits are currently on hold by the 4th U.S. Circuit Court of Appeals.

Exhibit 23: Northeast Production Takeaway Capacity vs. Production Growth



In the Permian, takeaway capacity constraints have put downward pressure on regional gas prices so far this year. Starting in late March 2019, El Paso Permian and Waha delivered prices traded in the negative territory for a few times as production growth outpaced takeaway capacity. In addition, the completion of several crude oil takeaway pipelines, which allowed incremental growth of oil and associated natural gas production, further added to this imbalance. In late April 2019, a producer announced it would curtail gas production in response to low gas prices. However, Permian natural gas production is still showing strong growth this year, mainly as most of the gas production is associated with oil, and can even have a negative breakeven cost¹⁶, as the investment decision for the well is driven by oil economics. Higher crude oil prices as well as improvement in drilling efficiency have also led to an increase in Permian's Drilled but Uncompleted Wells (DUCs) (See **Exhibit 24**) due to the infrastructure constraints. As of August 2019, Permian DUCs inventory stands at 3,839 wells, nearly 40% higher year-over-year¹⁷. This large backlog of DUCs will add a new wave of supply of up to 5.5 BCFD¹⁸ when takeaway pipeline capacity becomes available.

¹⁶ The "negative breakeven cost" here means the economic considerations for Permian associated natural gas production is beyond the natural gas pricing environment, and the decision to produce is mostly driven by crude oil profitability. Given current market conditions, Permian crude oil production is still profitable to produce.

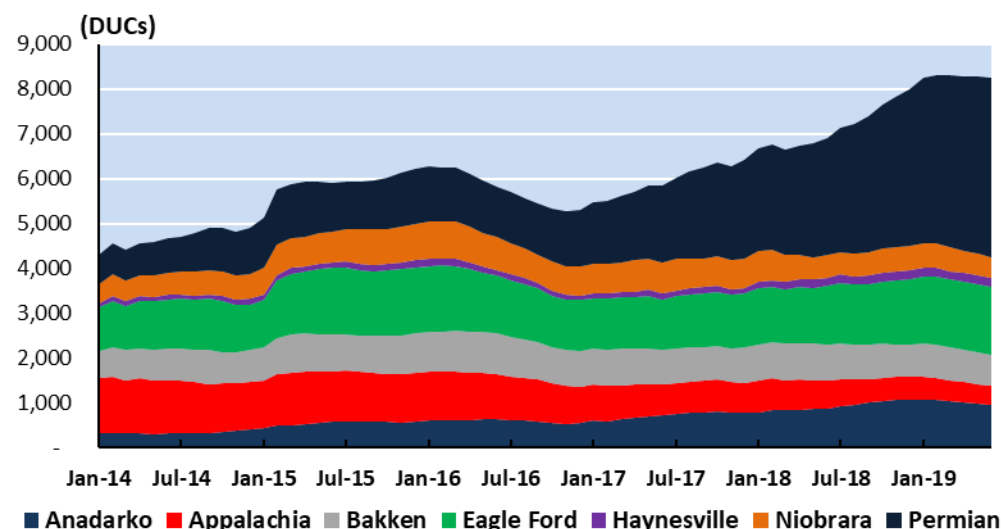
¹⁷ EIA Drilling Productivity Report, released on September 16, 2019:

<https://www.eia.gov/petroleum/drilling/>

¹⁸ This is estimated based on Permian DUCs inventory and an initial gas production of 1,450 MCFD.

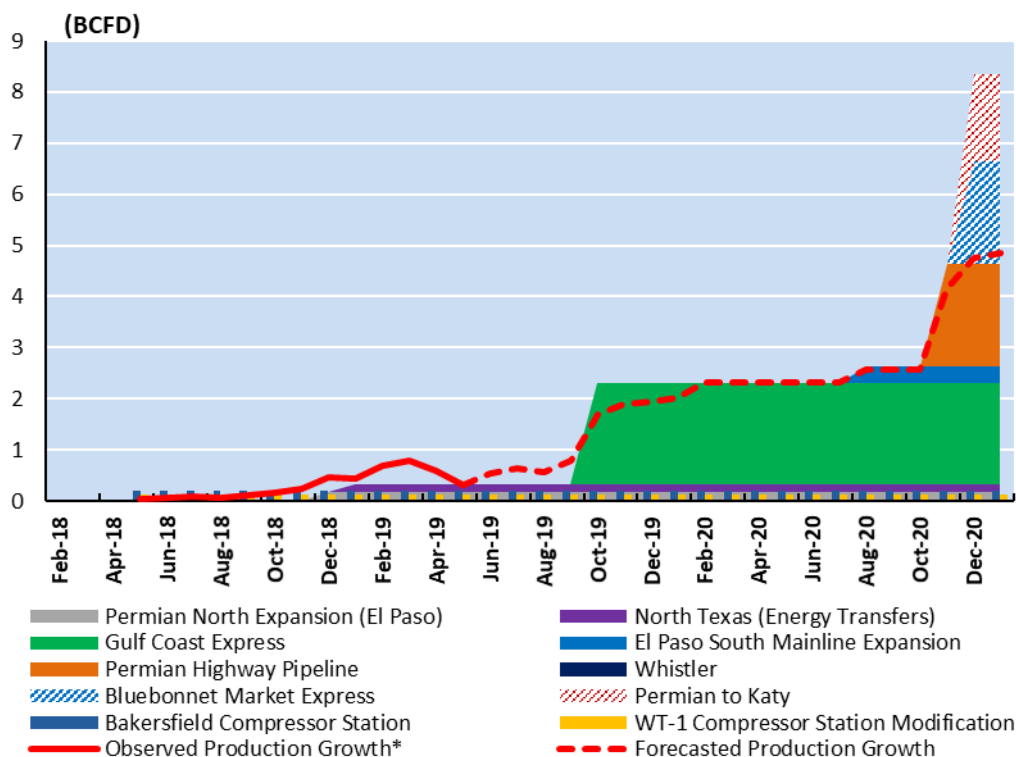
Several projects in various stages of development will enable Permian production to grow (**See Exhibit 25**). The 2-BCFD Gulf Coast Express will transport Waha gas to South Texas and has entered service in September 2019. In addition, the 2-BCFD Permian Highway and 2-BCFD Whistler projects have reached positive FIDs and are scheduled to come online in late-2020 and mid-2021, respectively.

Exhibit 24: Drilled but Uncompleted Wells, 2014 – June 2019



Source: U.S. EIA Drilling Productivity Report

Exhibit 25: Permian Pipeline Takeaway Capacity vs. Production Growth



Source: OPIS PointLogic, Energy Ventures Analysis

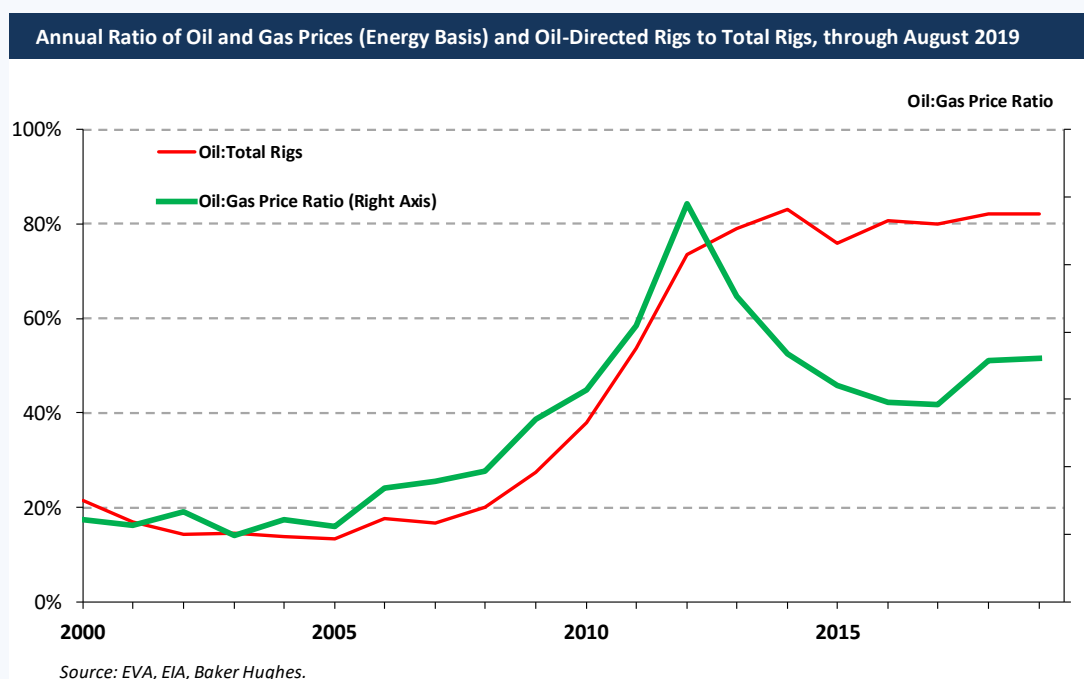
The Interconnection of Natural Gas and Crude Oil

Natural gas and crude oil are distinctive forms of energy and often are inseparable in their overall production and use. Both are produced using largely the same equipment and expertise and are often co-produced from wells drilled in many geologic formations in the U.S. and around the world. The transportation systems differ to accommodate the physical form of each commodity, and each commodity has differing, as well as overlapping, end uses.

The co-production of natural gas with crude oil is usually referred to as Associated Dissolved, or AD gas, and is defined by its comingling with crude oil in a reservoir. AD gas production then is defined as the production of natural gas that occurs when producing crude oil. The implementation of horizontal drilling and hydraulic fracturing to produce tight oil has also led to the co-production of natural gas as well as hydrocarbon gas liquids (HGL).

The **Exhibit 26** below shows the relative value of crude oil, as measured by WTI prices, as compared to natural gas, as measured by Henry Hub prices, over several years on a constant energy basis (i.e., where prices for both commodities are in \$/MMBTU) as compared to the percentage of oil-directed rigs as compared to all U.S. rigs deployed. From 2000 to 2005 the oil-to-gas price ratio (OGPR) hovered at, or just above, one signifying that oil and gas were priced at the same level to each other when measured on an energy-equivalent basis. After 2005 oil prices were seen to rise rather rapidly as compared to natural gas which boosted the OGPR to nearly 6:1 by 2012. Since that time the OGPR has declined largely as a result of the significant decrease in crude oil prices. During the past two years the OGPR has hovered at around 3.6:1, indicating that crude oil remains 3.6 times more valuable than natural gas on an energy-equivalent basis.

Exhibit 26: Higher Crude Oil Prices Relative to Gas Drives Drilling Rig Deployment

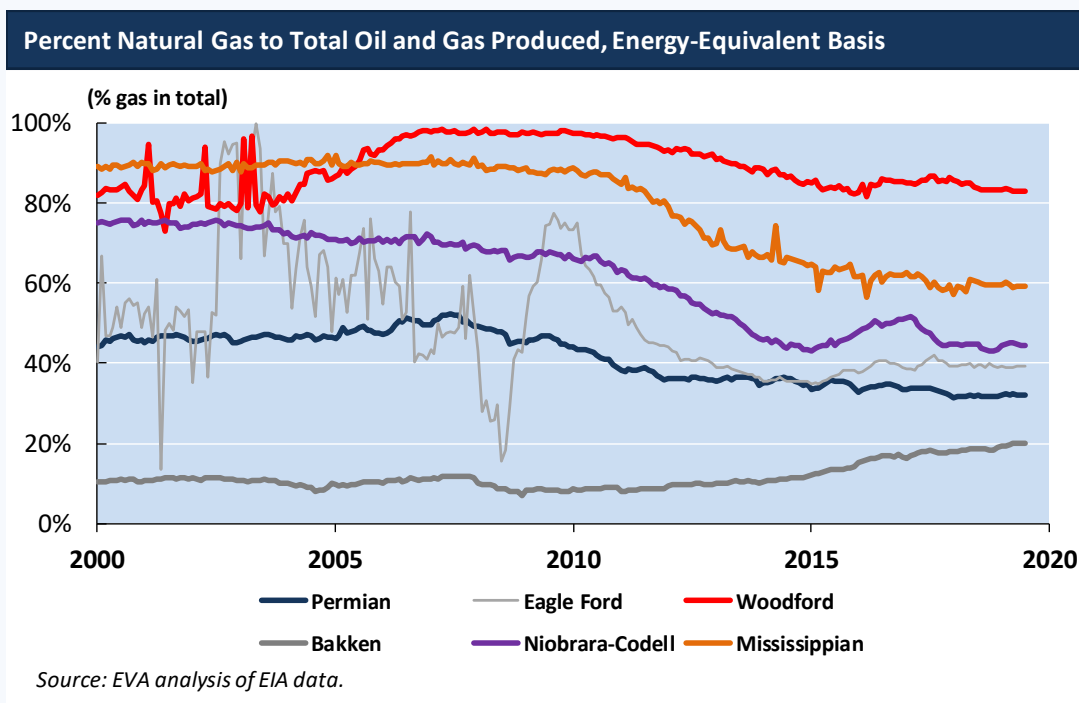


Balancing supply: Focusing on crude oil production versus natural gas has its limits

The exhibit above also shows how exploration and production companies have endeavored to shift investments toward oil-directed drilling. The percentage of drilling rigs directed at oil grew from being about 16% of all rigs from 2000 to 2005 to flipping above 70% of all rigs deployed in the U.S. by 2012. The percentage of oil-directed rigs has leveled off at the 80% level through 2019. Arguably, tracking rigs by what companies say they were drilling for could be problematic analytically. However, it does indicate how producers have sought more oil and minimize natural gas production in response to market prices.

Shale gas and tight oil plays have been the main drivers of the U.S. renaissance in hydrocarbon production. As the **Exhibit 27** provided below shows, each of the shale plays can be characterized by how much natural gas is produced as a fraction of crude oil produced. Some plays, such as the Marcellus, produce almost no crude oil while the Permian basin does produce significantly higher levels. Indeed, within each of the crude oil-producing plays there exists a variation in how much natural gas is produced with crude oil.

Exhibit 27: Tight Oil and Gas Plays Produce Natural Gas



Note: Production from Marcellus, Haynesville and, Barnett is 100% gas; Utica Shale production is also 100% gas since 2008; Fayetteville Shale production is 100% gas starting 2004.

The reasons why natural gas continues to be produced with crude oil are based on geology and global crude oil prices. While it is possible to direct drilling into reservoirs that produce almost no natural gas, the technology of production favors the production of lighter crudes that have shorter hydrocarbon chains making it easier for the molecules to pass through the cracks in the shales. These shorter-chain molecules are more likely to be collocated with even shorter chain molecules, such as HGL, and even the shortest chain hydrocarbon of them all, natural gas. With regards to economics, natural gas provides an assist in producing crude oil, much like a propellant, in that it helps to push the heavier hydrocarbons out into the borehole. The natural gas-driven crude enhances the rate of production, and hence, the financial return.

Balancing demand: The higher price for crude oil drives demand for natural gas

The continued industrial tug of the potential substitution of crude oil and petroleum products with natural gas has driven significant investments across a range of technologies, which the industry often refers to as midstream and downstream investments. Many, if not most, of the industrial capacity expansions discussed in this report, are driven by low natural gas prices that allow for producing commodities, such as bulk chemicals, that have a higher value based on international petroleum and natural gas prices, and are more easily transported and consumed than natural gas. An excellent current-day indicator of investment in capacity to drive the demand for natural gas instead of petroleum is LNG, as discussed previously in this report. Demand for U.S.-sourced LNG often goes toward heating and power generation that would otherwise be provided by higher-cost petroleum fuels.

Gas Flaring in Bakken and Permian

High natural gas production and lack of takeaway infrastructure have led to negative pricing and gas flaring in some regions. As production growth continues to outpace pipeline takeaway capacity, gas flaring and venting in the Permian basin reached a record high in Q1 2019, averaging 661 MMCFD¹⁹, up more than 50% year-over-year (See **Exhibit 28**). In Q1 2019, gas flared in the Permian region accounted for nearly 5% of the basin's gross production. The basin-wide flaring is expected to ease as soon as the 2-BCFD Gulf Coast Express enters service, providing an outlet for strong production growth.

Natural gas Production in the Bakken basin reached 500 MMCFD in Q1 2019, more than double the level a year-ago (See **Exhibit 29**). As a result, the percentage of gas flared in Bakken reached 20%, surpassing the 12% goal imposed by North Dakota Industrial Commission in Order No. 24665. In the Bakken basin, climbing oil and associated gas production combined with a lack of pipeline and processing capacity have resulted in record gas flaring so far this year. The looming constraints and increasing oil production have provided opportunities for more investment in takeaway capacity and gas processing facilities, which will consequently reduce gas flaring.

Exhibit 28: Permian Gas Flaring, 2017 – March 2019

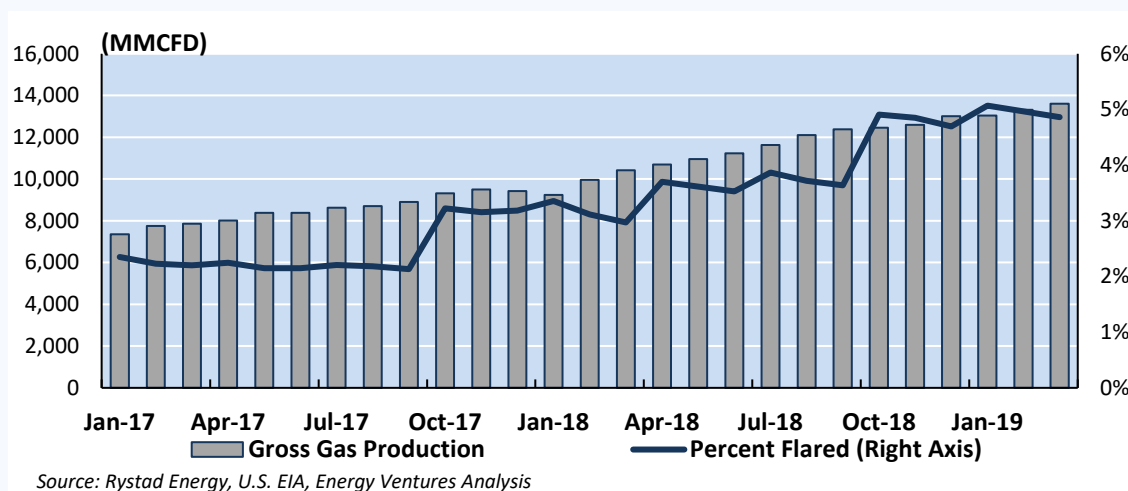
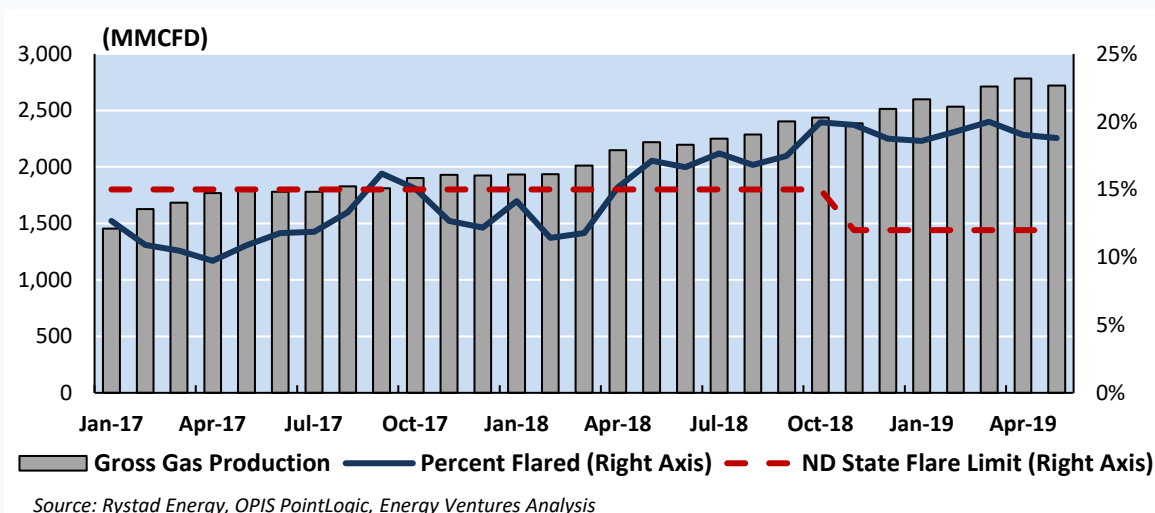


Exhibit 29: Bakken Gas Flaring, 2017 – May 2019



¹⁹ Permian Natural Gas Flaring and Venting Reaching All-time High:

<https://www.rystadenergy.com/newsevents/news/press-releases/Permian-natural-gas-flaring-and-venting-reaching-all-time-high/>

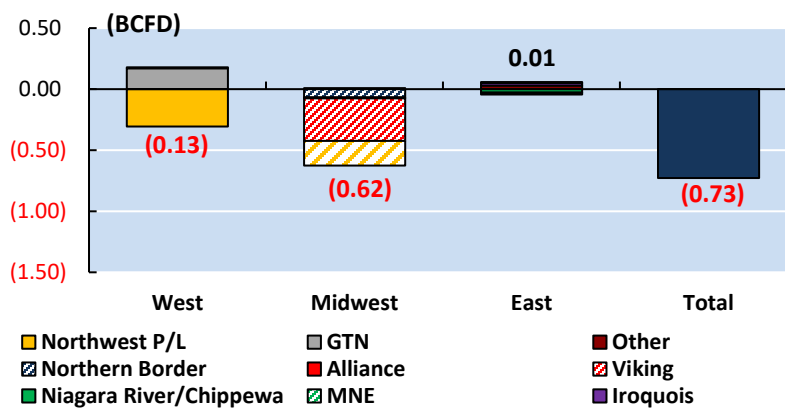
Import

Pipeline Imports from Canada

Net imports from Canada to the U.S. declined from 6.7 BCFD in 2017 to 6.5 BCFD in 2018. Moving into 2019, the declining trend continued into the second quarter, when net Canadian imports fell over 20% year-over-year. In the short-term, Canadian imports into the U.S. are forecast to decline mostly due to the strong competition from low-cost U.S. Appalachian gas.

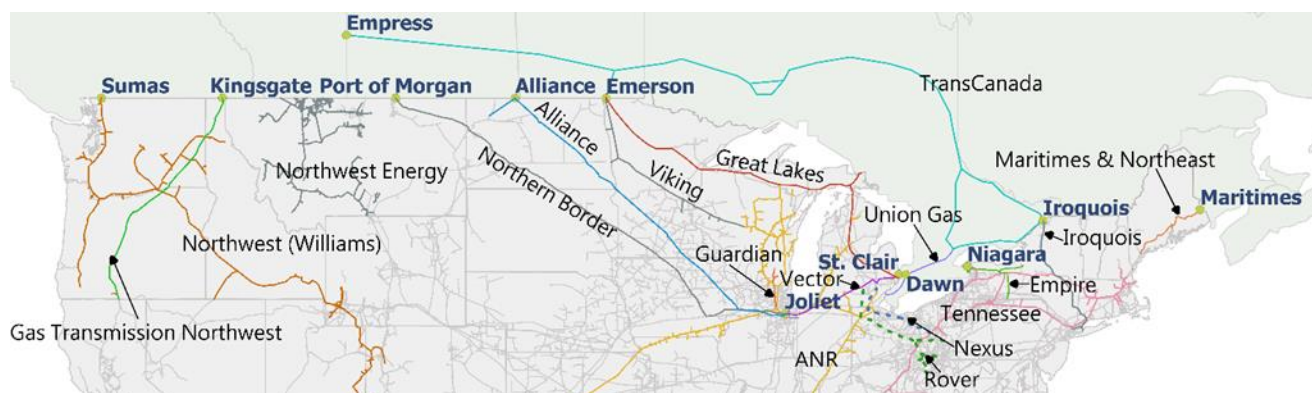
From a regional perspective, Canadian imports into the U.S. Midwest via the Vector Pipeline were substantially displaced by U.S. gas via the Rover and NEXUS pipelines (See **Exhibit 30**). In the past, the Vector Pipeline received a mix of Canadian and western U.S. gas from Alliance, Northern Border, Guardian pipelines at the Joliet junction and exported across U.S.-Canada border to Dawn, Ontario (See **Exhibit 31**). Since August 2018, Rover and NEXUS entered service and quickly displaced Canadian gas along Vector by up to 1 BCFD. However, the Canadian gas was able to flow northward from Joliet to interconnect with Great Lake Pipeline, making its way to Dawn. During winter seasons, the Northeast tends to import more gas from Canada via Iroquois and Maritimes & Northeast Pipelines as heating demand surges and domestic supplies are constrained by pipeline capacity. In the western corridor, the year-to-date Canadian imports dropped by about 0.3 BCFD from the same period last year, mainly due to the planned and unplanned maintenance at Westcoast Pipeline. While more Rockies gas was routed to backfill for supply loss, tight supply and demand balance in the U.S. Pacific Northwest sent Sumas cash prices to nearly \$160/MMBTU, the highest cash settlement on record. Such price volatility is still foreseeable in the near future when pipeline capacity is restricted, especially as Canadian gas from the Westcoast Pipeline is one of the most important supplies in the region.

Exhibit 30: Canadian Net Imports by Region, 2018-2019 Winter vs. 2017-2018 Winter



Source: U.S. EIA, Energy Ventures Analysis

Exhibit 31: US-Canada Border Crossing Pipelines

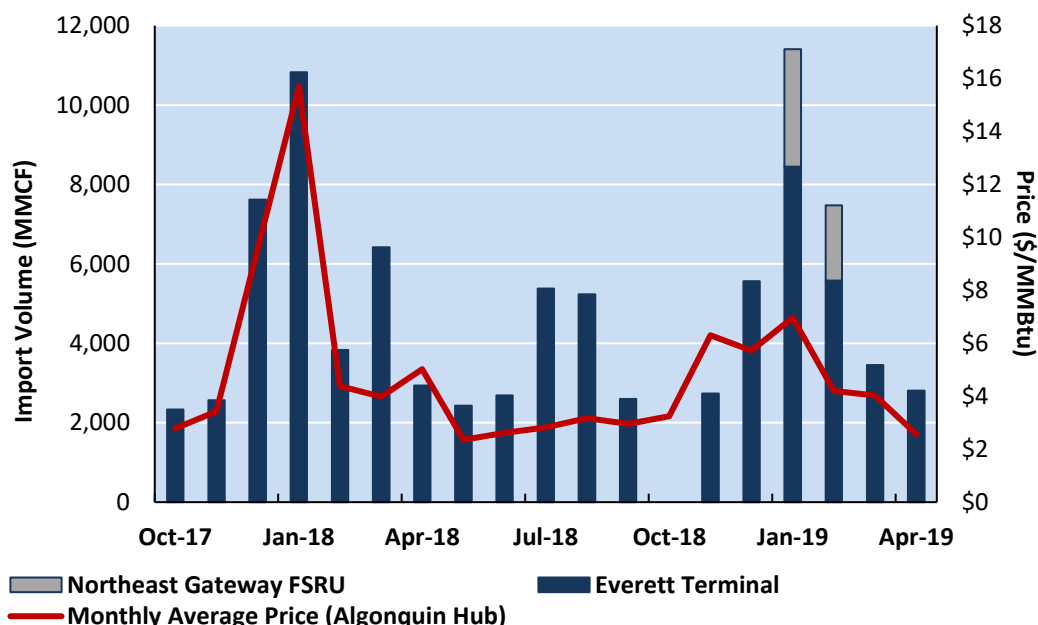


Assuming a normal winter, EVA forecasts that net Canadian imports for the 2019-2020 winter will remain flat to slightly lower compared to last winter due to declining Canadian domestic gas production and strong gas exports from U.S. Appalachia to Dawn, Ontario.

LNG Imports

LNG imports are critical to the New England area, especially during wintertime when heating demand soars. This region receives LNG from three major import terminals: the Everett Terminal in Boston, the offshore Northeast Gateway Deepwater Port in Massachusetts Bay, and the Canaport Terminal in New Brunswick, Canada. Historically, most of the LNG imports came from Trinidad, with a few vessels coming from Russia. In winter 2018-2019, natural gas prices at Algonquin Citygate hub experienced fewer spikes than during the winter of 2017-2018 (See **Exhibit 32**). The highest Algonquin Citygate price in the 2018-2019 winter was \$13.5/MMBtu whereas prices reached \$78.0/MMBtu during the 2017-2018 winter. The lower price volatility was largely due to the timely arrival of inbound LNG cargoes and the quick responses to sporadic demand spikes at LNG regasification facilities. In addition, ISO New England (ISONE) implemented arrangements to reward power generation resources that made the investments needed to ensure performance during periods of system stress, such as by contracting for adequate fuel²⁰. In the near term, LNG imports will continue to serve a key role in balancing winter supply and demand in New England considering there are limited pipeline expansions in the region.

Exhibit 32: Northeast LNG Imports and Algonquin Citygate Prices, 2017-2018 Winter vs. 2018-2019 Winter



²⁰ ISONE: Natural Gas Infrastructure Constraints:

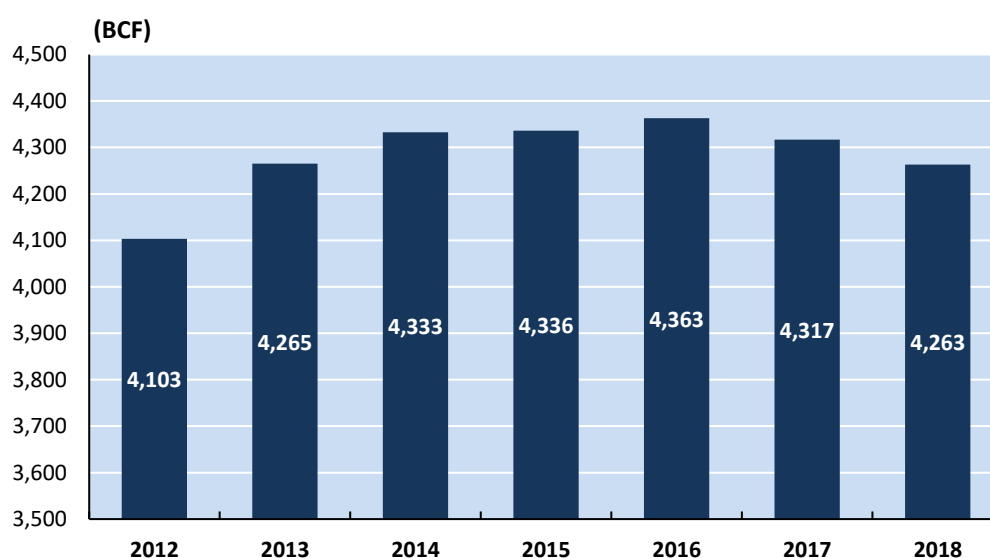
<https://www.iso-ne.com/about/what-we-do/in-depth/natural-gas-infrastructure-constraints>

Storage Outlook

Storage Capacity

Lower-48 natural gas storage capacity has increased steadily from 2012 through 2016 due to the increase in natural gas demand across sectors (See **Exhibit 33**). Since 2016, the demonstrated peak storage capacity, or total demonstrated maximum working gas capacity, has declined slightly in response to market supply and demand shifts. According to EIA's 2018 survey, no new natural gas storage facilities began operating for the fifth consecutive year. The change in working gas capacity came entirely from the expansion of existing facilities, reclassifications between base and working gas, and the decommissioning of inactive facilities.

Exhibit 33: Lower 48 Demonstrated Peak Capacity*, 2012 -2018



Source: U.S. EIA, Energy Ventures Analysis

Storage Capacity and Season-End Storage Levels	2012	2013	2014	2015	2016	2017	2018	2019 est.
Total Working Gas Capacity - Demonstrated Peak*	4,103	4,265	4,333	4,336	4,363	4,317	4,263	4,266
Total Natural Gas Storage Design Capacity*	4,521	4,629	4,666	4,668	4,687	4,723	4,712	4,715
Annual Design Capacity Addition	107	37	2	19	35	-11	3	-
End of Withdrawal Season (End of March) Storage Level	2,474	1,706	834	1,447	2,461	2,035	1,359	1,155
Percent of Capacity	60%	40%	19%	33%	56%	47%	32%	27%
End of Injection Season (End of October) Storage Level	3,929	3,794	3,565	3,917	3,977	3,777	3,197	3,712
Percent of Capacity	96%	89%	82%	90%	91%	87%	75%	87%

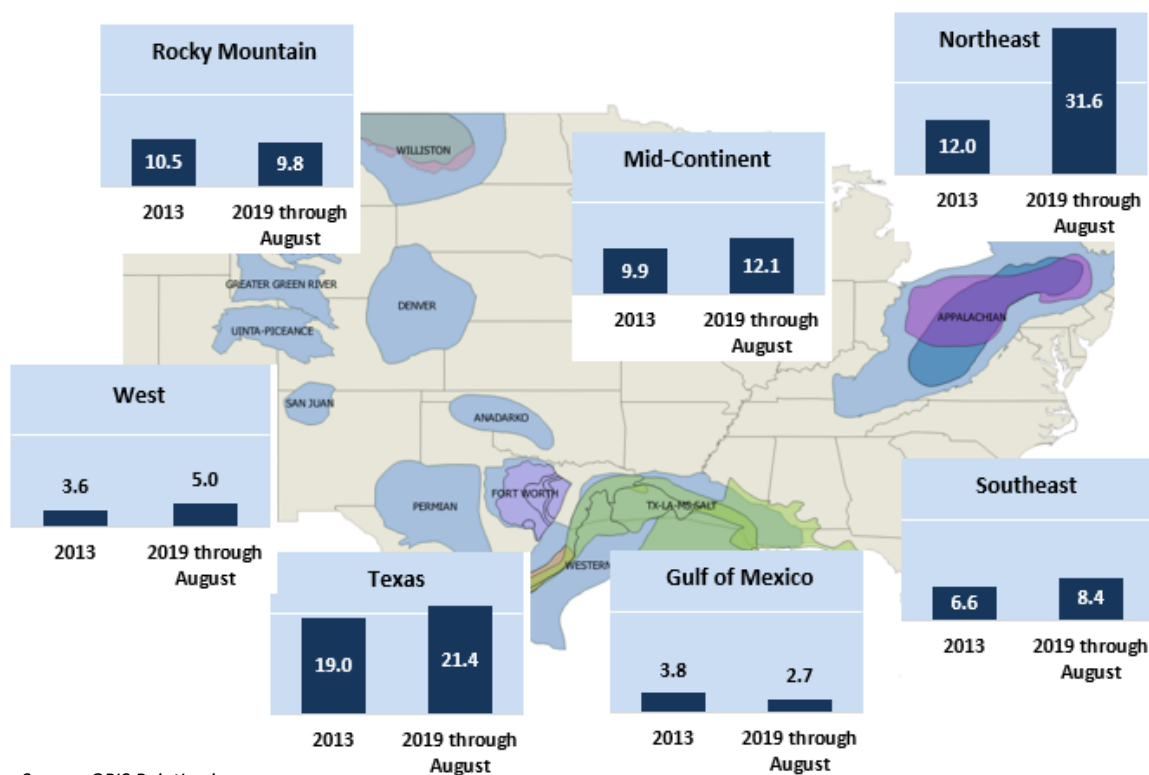
Source: U.S. EIA, Energy Ventures Analysis

*Note: According to EIA, demonstrated peak capacity, otherwise known as the maximum demonstrated working gas volume, is the sum of the highest storage inventory levels of working gas observed in each distinct storage reservoir. The timing of the peaks for different facilities do not need to coincide. Design capacity is the sum of all the lower-48 active storage fields' working gas design capacity, as reported in EIA's Underground Natural Gas Working Storage Capacity data. The metric is a theoretical limit on the total amount of natural gas that can be stored underground and withdrawn for use. The change in design capacity resulted from a combination of expansions or deactivation at existing facilities as well as reclassifications between base gas and working gas.

The decrease in demonstrated peak capacity since 2016 is largely due to several changes in gas supply and demand on a national level. First, strong production growth from the Northeast, Permian, Haynesville Shale regions has reduced reliance on conventional storage services as strong production volumes even during wintertime can meet natural gas needs (See **Exhibit 34**). This also has coincided with the active midstream infrastructure buildout, which enhanced grid connectivity and flexibility, allowing natural gas to more easily reach end-users, and therefore reducing dependence on

scheduling gas withdrawal or injection through storage. Finally, the shrinking winter and summer price differentials have also lowered the economic incentive for storage operators to invest in new storage or storage expansion.

Exhibit 34: Gas Production Growth by Area, 2013 vs. 2019 YTD



Source: OPIS PointLogic

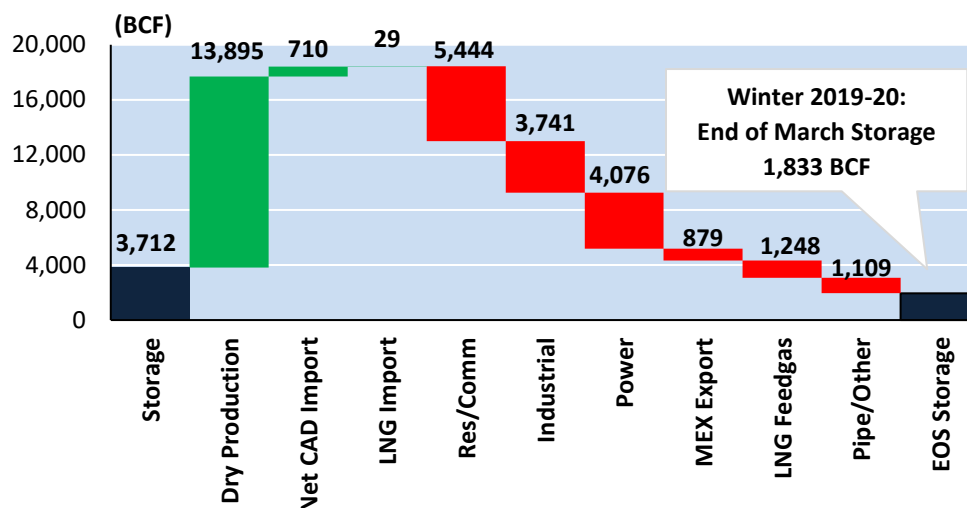
However, storage capacity has become more important in certain areas with tightening available supplies or increasing gas demand. In the South Texas and Gulf Coast areas, the anticipated growth for both LNG and Mexico export demand will increase the need for flexible gas storage to account for variability with respect to weather and price. In the Northeast, where pipeline expansion is relatively limited, on-site gas storage for gas-fired generators is critical to ensure winter reliability. Since the gas leak event in late 2015, the working gas capacity of Aliso Canyon in Southern California has been reduced by nearly 50%. The limited gas delivery of Aliso Canyon has caused volatile gas and power prices on high demand days. Recent development has allowed SoCal Gas to withdraw up to 30% of Aliso Canyon's gas storage inventory, which will provide more flexible supply for the coming 2019-2020 winter²¹.

Storage Forecast

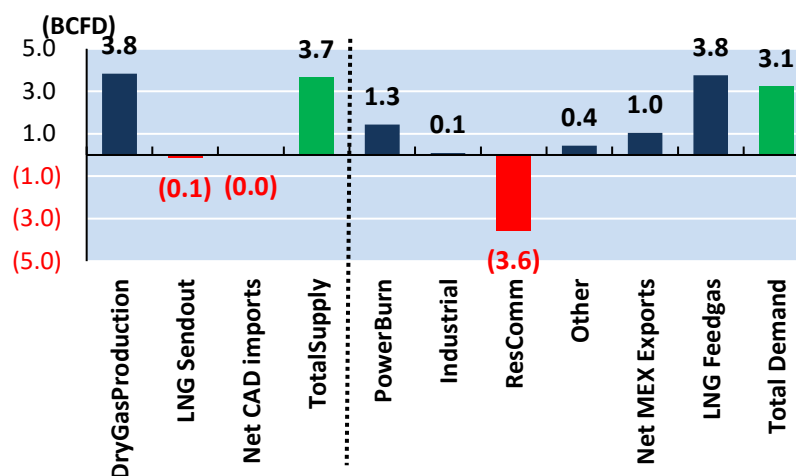
Based on the near-term supply and demand dynamics, gas storage level is expected to bring the 2019 October season-end inventory to 3,712 BCF, which is near the five-year average level. Under EVA's base case, which uses a 10-year normal weather condition, the end-of-March storage level is forecast to be 1,833 BCF (See **Exhibit 35**), about 140 BCF above the 5-year average. Among the demand sectors, structural demand from power, Mexico exports, and LNG exports will create a strong base for demand and drive total gas consumption growth (See **Exhibit 36**). On the supply side, production growth is expected to respond quickly to demand gains, resulting in lower-than-average storage withdrawals for the coming winter.

²¹ CPUC's Aliso Canyon Working Gas Inventory, Production Capacity, Injection Capacity, and Well Availability for Reliability Summer 2018 Supplemental Report:

https://www.cpuc.ca.gov/uploadedFiles/CPUCWebsite/Content/News_Room/NewsUpdates/2019/UpdatedWithdrawalProtocol_2019-07-23%20-%20v2.pdf

Exhibit 35: 2019-2020 Winter Natural Gas Supply and Demand Outlook


Source: Energy Ventures Analysis

Exhibit 36: Changes in Natural Gas Supply and Demand, 2019-2020 Winter vs. 2018-2019 Winter


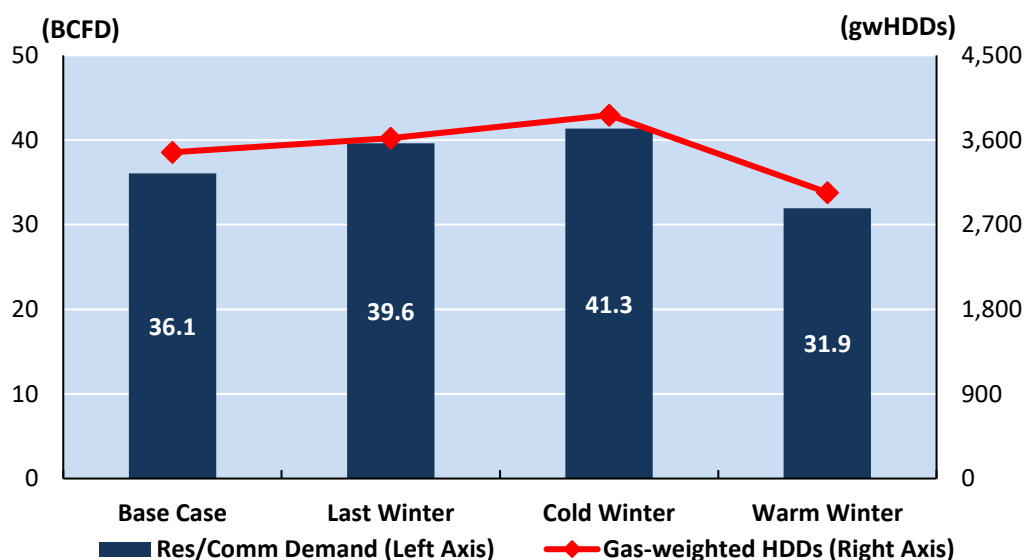
Source: Energy Ventures Analysis

Storage Scenario Analysis

Winter weather can play an important role in Residential and Commercial gas demand. Apart from a 10-year normal weather assumption, EVA analyzed end-of-March storage level under three other scenarios:

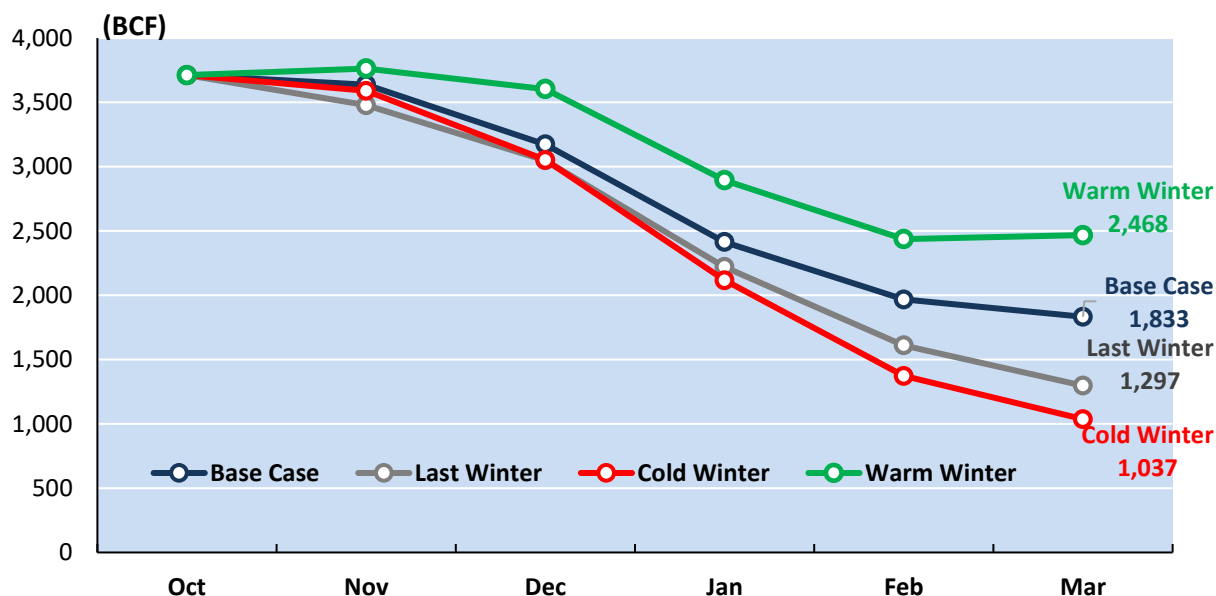
- Base Case: 10-year normal
- Last Winter: 2018-19 Winter
- Cold Winter: 2013-14 Winter
- Warm Winter: 2015-16 Winter

As shown in **Exhibit 37**, the differences in Residential and Commercial gas demand under cold and warm winter scenarios can swing 4 BCFD or more than 10% from our base case Residential and Commercial demand forecast. If weather is similar to last winter's, Residential and Commercial demand will average near 40 BCFD, only 1.7 BCFD behind the cold winter scenario.

Exhibit 37: Weather Assumption for Storage Scenarios


Source: U.S. EIA, NOAA, Energy Ventures Analysis

According to the weather sensitivity analysis, end-of-March storage levels will drop below the five-year average under a cold winter scenario, such as last winter (See **Exhibit 38**). Structural demand growth from power and export sectors will provide a strong base for winter demand. However, as production growth is still forecast to outpace that of demand, cold weather will help to lift Residential and Commercial demand, which can balance the supply gap for the coming winter.

Exhibit 38: End-of-March Storage Levels under Different Weather Scenarios


Appendix

1. Short Term Henry Hub Price Forecast

Henry Hub Prices (Nominal \$/MMBTU)			
	Q4 2019	Q1 2020	2020
EIA Forecast	\$2.43	\$2.91	\$2.75
NYMEX Futures (As of 8/28/2019)	\$2.32	\$2.52	\$2.41

Source: EIA Short-Term Energy Outlook (STEO) August Release; CME

2. Existing and Future U.S. LNG Export Facilities

U.S. LNG Export Facilities					
Project	Train	Capacity (mmtpa)	Capacity (BCFD)	Status	ISD
Sabine Pass	T1	4.7	0.65	Operating	Feb-2016
Sabine Pass	T2	4.7	0.65	Operating	Aug-2016
Sabine Pass	T3	4.7	0.65	Operating	Jan-2017
Sabine Pass	T4	4.7	0.65	Operating	Aug-2017
Sabine Pass	T5	4.7	0.65	Operating	Mar-2019
Corpus Christi	T1	4.7	0.65	Operating	Dec-2018
Corpus Christi	T2	4.7	0.65	Operating	Aug-2019
Cove Point		5.8	0.80	Operating	Feb-2018
Elba Island	Phase 1	1.5	0.22	Commissioning	Sep-2019
Elba Island	Phase 2	1.0	0.15	Under Construction	Dec-2019
Cameron	T1 (Phase 1)	4.0	0.57	Operating	May-2019
Cameron	T2 (Phase 1)	4.0	0.57	Under Construction	Jan-2020
Cameron	T3 (Phase 1)	4.0	0.57	Under Construction	Apr-2020
Freeport	T1	5.0	0.70	Commissioning	Sep-2019
Freeport	T2	5.0	0.70	Under Construction	Jan-2020
Freeport	T3	5.0	0.70	Under Construction	Apr-2020

Source: Energy Ventures Analysis

3. Winter Gas Imports and Exports

(BCFD)

Winter 2018/2019								
Canada			Mexico			LNG		
Imports	Exports	Net Import	Imports	Exports	Net Import	Imports	Exports	Net Import
7.88	3.17	4.71	0.00	4.75	(4.75)	0.28	4.49	(4.21)

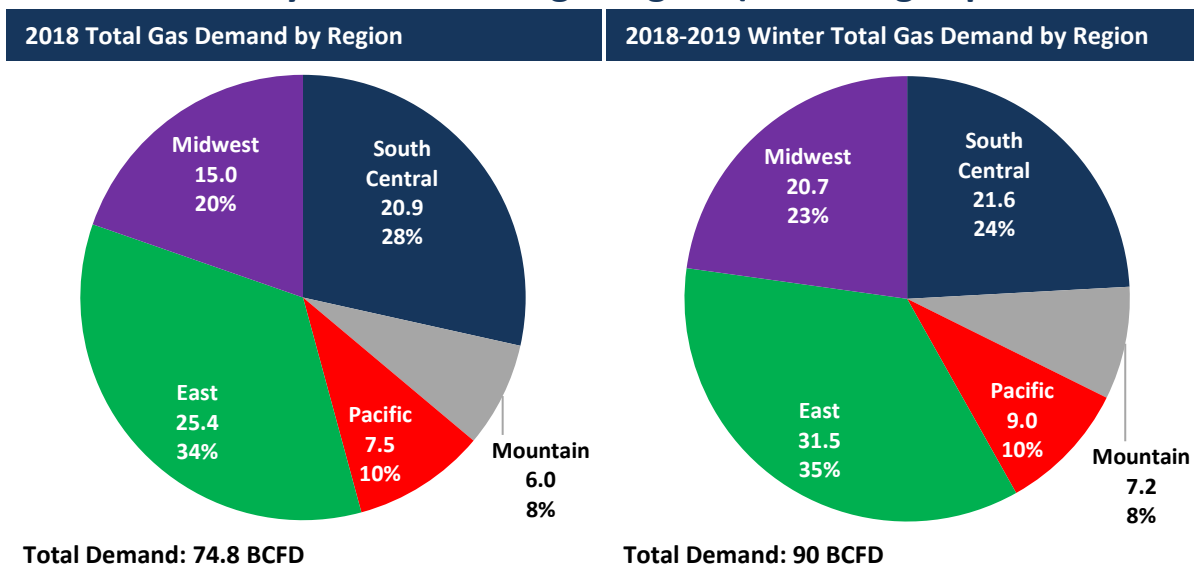
(BCFD)

Winter 2019/2020								
Canada			Mexico			LNG		
Imports	Exports	Net Import	Imports	Exports	Net Import	Imports	Exports	Net Import
7.88	3.18	4.70	0.00	5.82	(5.82)	0.19	8.27	(8.08)

Source: U.S. EIA, Energy Ventures Analysis

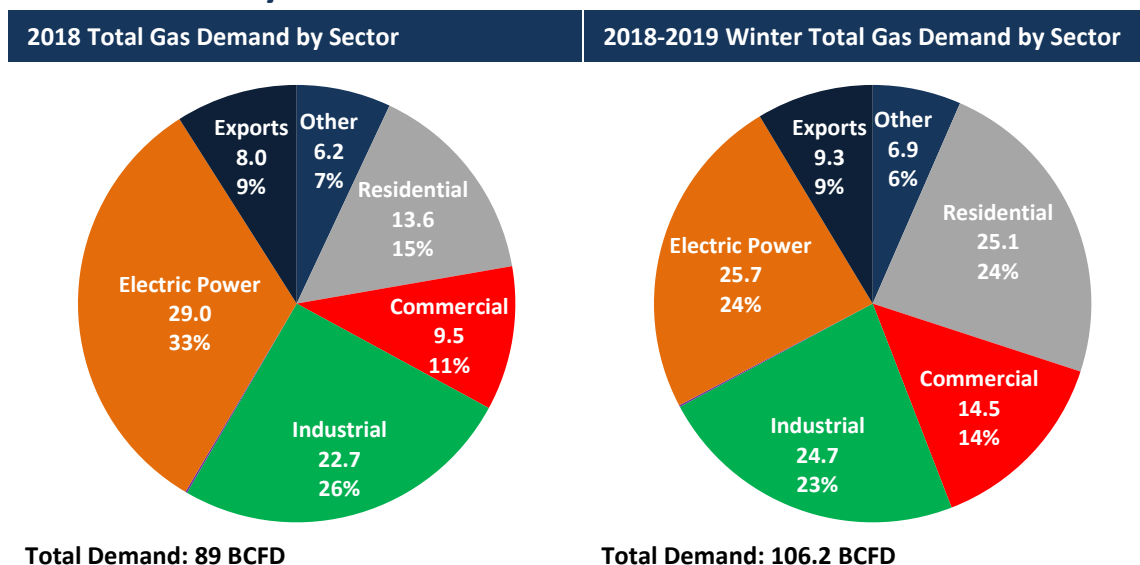
Note: Negative numbers mean net exports

4. Total Gas Demand by EIA Gas Storage Region (Excluding Exports and Other)



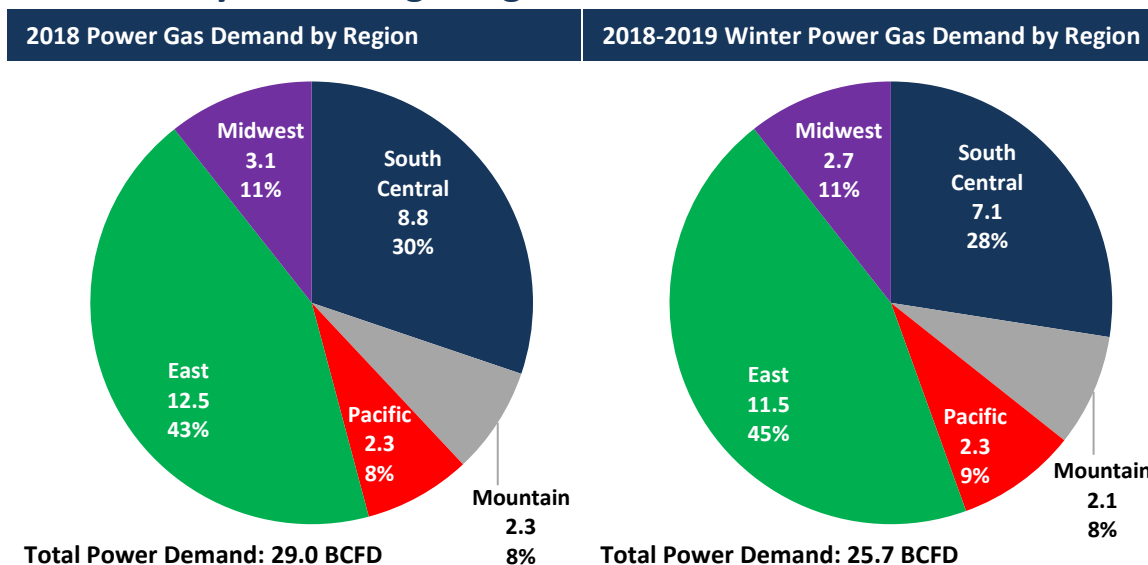
Source: U.S. EIA, Energy Ventures Analysis

5. Total Gas Demand by Sector



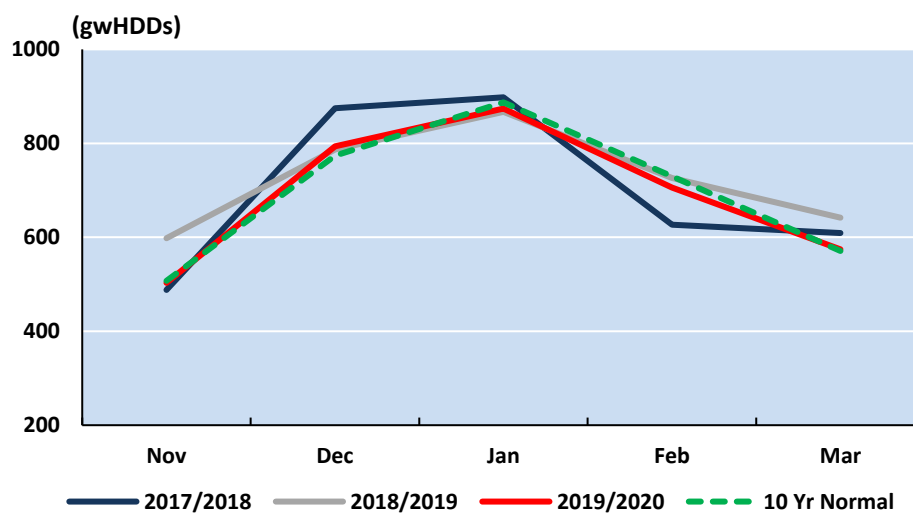
Source: U.S. EIA, Energy Ventures Analysis

6. Power Demand by EIA Storage Region



Source: U.S. EIA, Energy Ventures Analysis

7. Winter Heating Degree Days



Source: NOAA CPC, Energy Ventures Analysis

8. U.S. Macro Indicators

Historical and Forecasted Macro Economy Indicators							
	2013	2014	2015	2016	2017	2018	2019*
Inflation	1.62%	1.59%	0.81%	1.45%	1.99%	2.44%	1.80%
Real GDP Growth	1.68%	2.57%	2.86%	1.49%	2.25%	3.08%	2.20%
Household Growth	0.89%	0.60%	1.00%	1.57%	1.44%	1.48%	1.47%
Industrial Production Growth	2.05%	3.56%	1.20%	-0.20%	1.27%	3.06%	1.80%

Source: Moody's

* Note: 2019 macro indicators are estimates

9. Winter Gas Consumption by Sector

(BCFD)

Winter	Res/Comm	Industrial	Electric	Other	Exports to Mexico	LNG Feedgas	Total Demand
2012-2013	35.9	21.3	19.7	5.8	1.7	0.0	84.5
2013-2014	41.3	22.7	20.1	5.9	1.7	0.0	91.7
2014-2015	39.5	22.4	21.8	5.9	2.2	0.0	91.8
2015-2016	31.9	22.1	24.3	5.7	3.2	0.1	87.4
2016-2017	33.6	23.0	21.2	5.6	4.0	1.4	88.8
2017-2018	38.2	24.1	24.2	6.3	4.4	3.0	100.3
2018-2019	39.6	24.7	25.7	6.9	4.8	4.5	106.2
2019-2020	36.1	24.8	27.0	7.3	5.8	8.3	109.3

Source: U.S. EIA, Energy Ventures Analysis

Note: 2019-2020 consumption is EVA's forecast

10. Winter Gas Supply by Sector

(BCFD)

Winter	Production	LNG Imports	Net Imports from Canada	Storage Withdrawals	Total Supply
2012-2013	64.7	0.4	4.7	15.0	84.8
2013-2014	66.7	0.1	5.7	20.2	92.6
2014-2015	72.4	0.3	5.6	14.5	92.9
2015-2016	72.9	0.3	5.5	9.8	88.5
2016-2017	70.8	0.3	5.5	13.0	89.7
2017-2018	78.2	0.3	5.9	16.1	100.5
2018-2019	88.2	0.3	4.7	12.9	106.1
2019-2020	92.0	0.2	4.7	12.3	109.2

Source: U.S. EIA, Energy Ventures Analysis

Note: 2019-2020 consumption is EVA's forecast

11. Winter Gas Production by Type

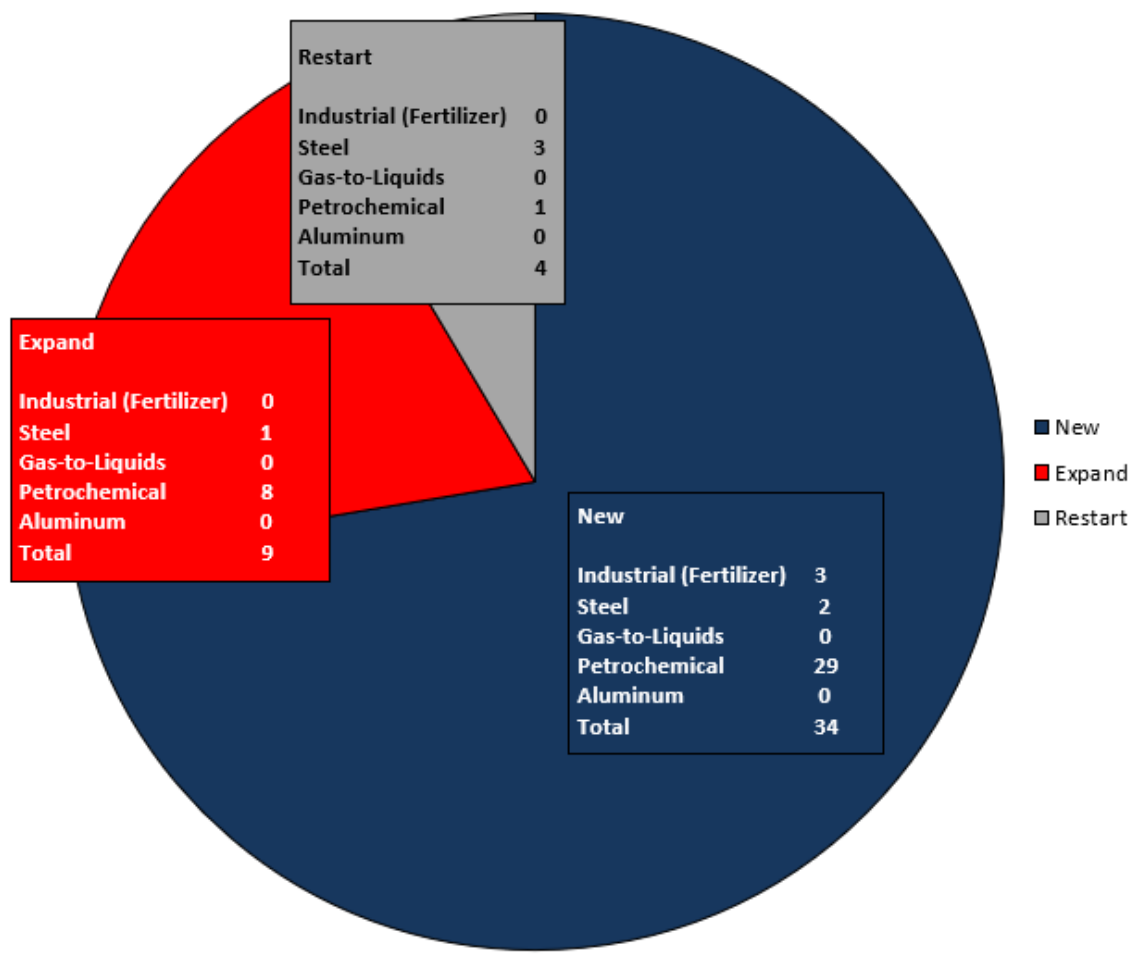
(BCFD)

Winter	CBM	Conventional/Tight	Offshore	Shale	Others	Total
2012/2013	3.9	28.5	4.4	27.8	0.1	64.7
2013/2014	3.5	27.8	3.7	31.6	0.1	66.7
2014/2015	3.2	27.9	3.6	37.7	0.1	72.5
2015/2016	3.0	26.3	3.6	40.3	0.1	73.3
2016/2017	2.7	23.7	3.4	40.7	0.2	70.8
2017/2018	2.6	24.4	2.6	48.4	0.2	78.2
2018/2019	2.6	24.4	2.8	58.1	0.2	88.2
2019/2020	2.6	23.9	2.9	62.4	0.3	92.0

Source: U.S. EIA, OPIS PointLogic, Energy Ventures Analysis

Note: 2019-2020 consumption is EVA's forecast

12. Industrial Projects by Type and Industry (2019-2023)



Source: Energy Ventures Analysis

13. Performance Characteristics of Natural Gas CCGT by Census Region

Annual Capacity Factor										
Census Region	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
New England	53%	58%	55%	45%	43%	49%	48%	44%	40%	33%
Middle Atlantic	46%	51%	58%	54%	56%	61%	60%	50%	52%	52%
East North Central	23%	31%	48%	34%	35%	54%	59%	51%	58%	64%
West North Central	18%	15%	26%	21%	17%	26%	32%	24%	38%	36%
South Atlantic w/o Florida	43%	52%	61%	58%	56%	66%	67%	67%	61%	64%
South Atlantic	53%	58%	62%	59%	57%	64%	64%	62%	59%	59%
East South Central	45%	49%	60%	49%	52%	64%	68%	58%	61%	57%
West South Central w/o ERCOT	36%	38%	47%	37%	39%	49%	49%	43%	56%	48%
West South Central	41%	43%	49%	44%	45%	54%	51%	44%	53%	48%
Mountain	41%	35%	40%	43%	40%	44%	44%	39%	46%	43%
Pacific Contiguous w/o CA	51%	26%	33%	51%	47%	56%	49%	40%	52%	49%
California	54%	40%	57%	55%	54%	53%	43%	39%	40%	30%
Total U.S.	44%	45%	53%	48%	48%	56%	55%	49%	53%	52%

Source: U.S. EIA, Energy Ventures Analysis

Note: 2019 numbers are from January through June

Winter (Nov-Mar) Capacity Factor									
Census Region	2010-11	2011-12	2012-13	2013-14	2014-15	2015-16	2016-17	2017-18	2018-19
New England	51%	53%	39%	32%	37%	40%	40%	40%	35%
Middle Atlantic	46%	54%	51%	52%	57%	56%	51%	51%	52%
East North Central	28%	47%	35%	35%	51%	63%	52%	59%	63%
West North Central	12%	14%	20%	16%	20%	28%	19%	31%	32%
South Atlantic w/o Florida	50%	58%	57%	51%	57%	62%	56%	59%	64%
South Atlantic	50%	58%	57%	51%	57%	62%	56%	59%	57%
East South Central	43%	57%	53%	47%	62%	65%	55%	61%	55%
West South Central w/o ERCOT	32%	41%	37%	41%	48%	48%	37%	42%	43%
West South Central	32%	41%	37%	41%	48%	48%	37%	42%	44%
Mountain	30%	33%	31%	34%	32%	40%	29%	33%	44%
Pacific Contiguous w/o CA	41%	54%	51%	57%	45%	48%	38%	39%	58%
California	44%	55%	54%	56%	47%	45%	37%	38%	41%
Total U.S.	39%	49%	45%	45%	49%	52%	44%	48%	51%

Source: U.S. EIA, Energy Ventures Analysis

Annual Heat Rate (Btu/kWh)										
Census Region	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
New England	7,522	7,470	7,492	7,531	7,548	7,592	7,533	8,048	7,430	7,487
Middle Atlantic	7,764	7,746	7,431	7,423	7,453	7,650	7,519	7,821	7,131	7,073
East North Central	8,718	8,275	7,437	7,561	7,517	7,838	7,690	7,699	7,523	7,411
West North Central	7,795	7,819	7,433	7,584	7,621	7,391	7,437	8,683	7,345	7,474
South Atlantic w/o Florida	7,486	7,433	7,311	7,215	7,270	7,279	7,236	7,249	7,162	7,083
South Atlantic	7,489	7,416	7,313	7,274	7,299	7,287	7,270	7,308	7,189	7,168
East South Central	7,409	7,375	7,296	7,327	7,345	7,306	7,238	7,404	7,073	6,980
West South Central w/o ERCOT	7,885	7,957	7,302	7,419	7,362	7,517	7,479	7,534	7,280	7,350
West South Central	8,197	8,195	7,316	7,336	7,343	7,839	7,726	7,902	7,200	7,209
Mountain	7,596	7,706	7,492	7,495	7,534	7,543	7,533	7,621	7,548	7,589
Pacific Contiguous w/o CA	7,550	7,781	7,182	7,282	7,305	7,427	7,538	8,233	7,333	7,444
California	7,441	7,595	7,308	7,276	7,346	7,518	7,486	7,569	7,269	7,276
Total U.S.	7,734	7,730	7,359	7,362	7,383	7,555	7,485	7,641	7,243	7,220

Source: U.S. EIA, Energy Ventures Analysis

Note: 2019 numbers are from January through June

Winter (Nov-Mar) Heat Rate (Btu/kWh)									
Census Region	2010-11	2011-12	2012-13	2013-14	2014-15	2015-16	2016-17	2017-18	2018-19
New England	7,460	7,435	7,489	7,643	7,509	7,516	7,808	7,896	7,447
Middle Atlantic	7,731	7,483	7,438	7,499	7,589	7,662	7,554	7,661	7,064
East North Central	8,463	7,520	7,520	7,591	7,847	7,718	7,482	7,678	7,389
West North Central	7,848	7,513	7,429	7,687	7,425	7,348	8,496	8,143	7,639
South Atlantic w/o Florida	7,378	7,304	7,252	7,306	7,250	7,271	7,276	7,281	7,052
South Atlantic	7,378	7,304	7,252	7,306	7,250	7,271	7,276	7,281	7,126
East South Central	7,328	7,286	7,266	7,365	7,261	7,243	7,307	7,280	6,955
West South Central w/o ERCOT	8,414	7,603	7,268	7,385	7,625	7,864	7,477	7,993	7,285
West South Central	8,414	7,603	7,268	7,385	7,625	7,864	7,477	7,993	7,156
Mountain	7,713	7,506	7,518	7,462	7,585	7,521	7,589	7,728	7,543
Pacific Contiguous w/o CA	7,536	7,313	7,250	7,273	7,440	7,520	7,516	7,620	7,428
California	7,507	7,338	7,261	7,271	7,458	7,537	7,410	7,494	7,229
Total U.S.	7,721	7,419	7,322	7,381	7,477	7,535	7,449	7,596	7,188

Source: U.S. EIA, Energy Ventures Analysis