WINTER 18/19

ENERGY VENTURES ANALYSIS

NATURAL GAS MARKET WINTER OUTLOOK 2018/2019

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Prepared for:

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I. OVERVIEW

Winter 2018-2019[1] is forecast to start the season with a low natural gas storage inventory level of 3.30 TCF at the end of October, the lowest level since over a decade. Weather is forecast to be near normal and slightly warmer than last winter.

Total demand for gas[2] is forecast to grow by 3.4 BCFD over the prior winter (see summary table below). The exports sector is forecast to dominate the growth, with LNG demand to grow by 1.7 BCFD as three new LNG trains are coming online. Exports to Mexico will also grow by 0.8 BCFD thanks to the domestic pipelines that have been, and will be, completed this year. Having grown 3 BCFD summer-over-summer, power burn's growth in the winter will be less significant, only 0.7 BCFD due to the high efficiencies of new gas units and less electricity demand in the winter. Industrial demand will contribute 0.4 BCFD of growth winter-over-winter because of the additions of gas feedstock projects as well as petrochemical projects. Residential and commercial demand (ResComm) will relieve some of the demand pressure, declining by a total of 1 BCFD due to the return to normal weather as well as efficiency gains.

WINTER OUTLOOK FUNDAMENTALS SUMMARY TABLE			
BCFD	WINTER 2018/2019	WINTER 2017/2018	WINTER-OVER-WINTER CHANGES
Dry Production	84.9	77.4	7.4
Net Canadian Imports	5.2	5.4	-0.2
LNG Imports	0.2	0.5	-0.2
Total Supply	90.3	83.3	7.0
Power Burn	24.8	24.1	0.7
Industrial	24.5	24.1	0.4
Residential and Commercial	36.9	37.8	-1.0
Lease Plant and Pipeline Fuel	6.7	5.9	0.8
Mexico Exports	5.2	4.4	0.8
LNG Exports	4.7	3.0	1.7
Total Demand	102.7	99.3	3.4
Withdrawals	12.4	16.0	-3.6
HDDs	3,455	3,497	-42.0

Source: EVA

Production is forecast to grow at a rate more than adequate to make up the difference between low storage and elevated winter demand. Production for the lower 48 is forecast to grow by 7.4 BCFD winter over winter. Most of this growth will come from the Northeast. Having increased by 2.3 BCFD since the beginning of the year, the Northeast will push higher by another 3 BCFD from August to the end of March. Associated gas production will also add to the growth this winter, however, it is likely to run into infrastructure constraints. Permian's drilled but uncompleted wells have started to accumulate, representing both challenges and opportunities.

Partially offsetting the growth of production, net Canadian imports and LNG imports are forecast to decline by 0.2 BCFD each. The addition of Rover and Nexus pipelines this winter will lead to more Northeast gas flowing to East Canada. This increase in exports could lead to a decrease in net imports from Canada. Although Elba

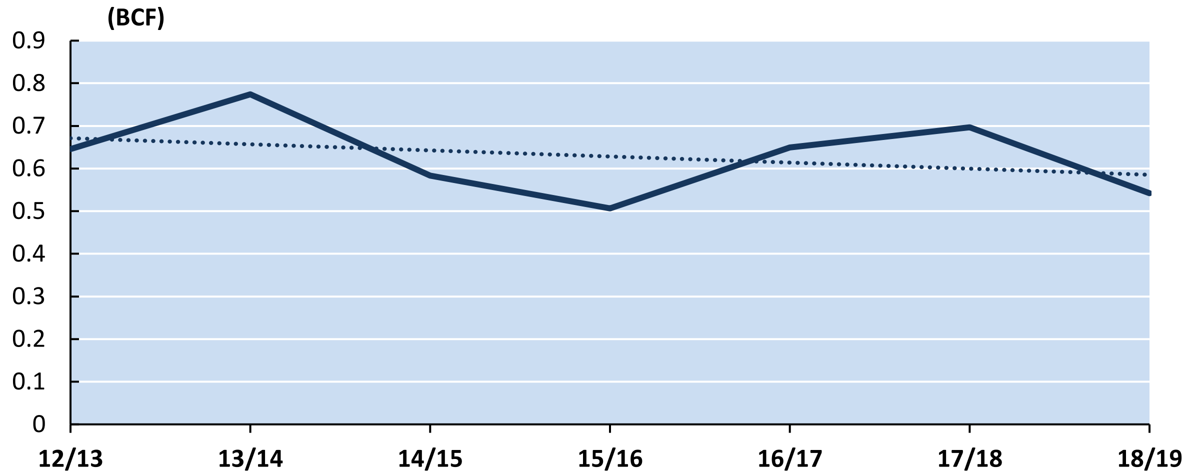
[1]For the purpose of this report, winter refers to November through March which is, in general, the natural gas withdrawal season.

[2] Gas is a short form for natural gas in this report.

Island and Cove Point will become bidirectional LNG terminals, it would be rare to see the terminal import and export at the same time unless regional demand comes in way above normal. Therefore, LNG imports are likely to be restricted to only the Everett terminal in New England.

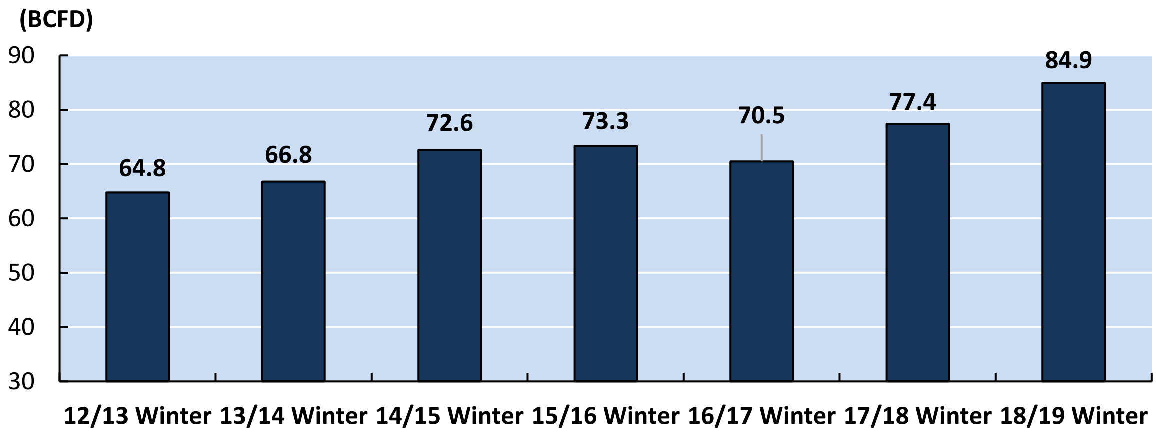
Storage inventory is forecast to reach 1.43 TCF by March 2019, which is 200 BCF below the five-year average. Withdrawals will be 3.6 BCFD lower than last winter thanks to the high production that currently exists, and which is forecast to grow. The inventory deficit has become less of an issue as production has ramped up by 14 BCFD since 2013, partially offsetting the need for storage, particularly as some pipeline expansions are scheduled to come online just before the winter season. An interesting emerging trend is that winter storage withdrawals per HDD have slightly declined (see figure below), further evidence of a reduced market reliance on storage.

WINTER SEASON WITHDRAWAL PER HDD



Source: EVA

WINTER PRODUCTION



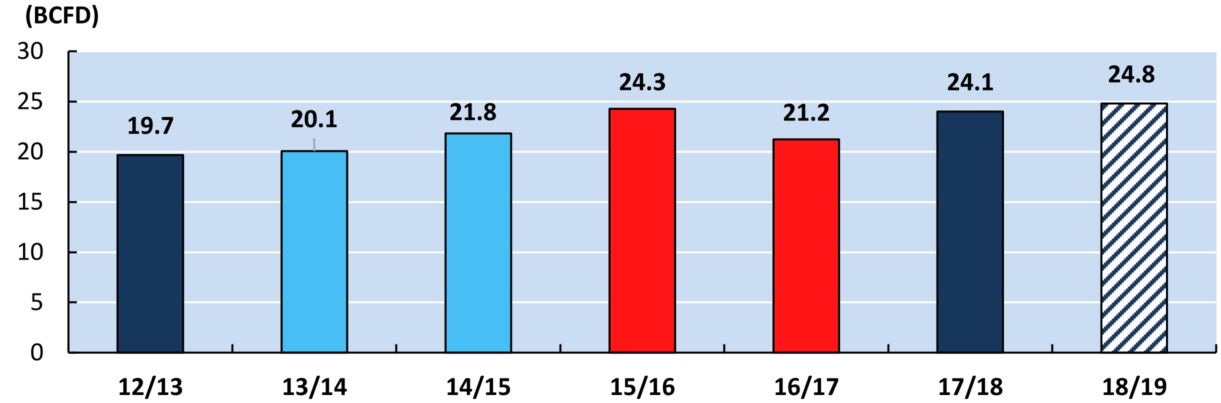
Source: EVA

II. OUTLOOK FOR DEMAND

Power

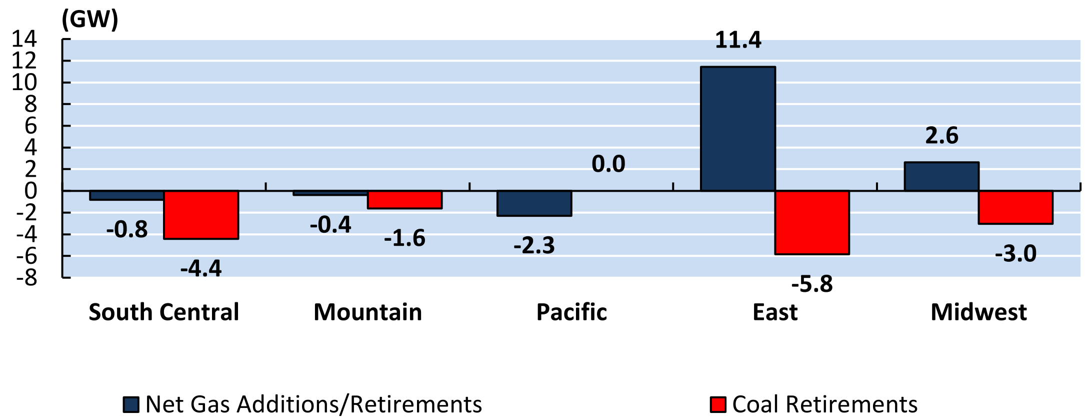
Power demand for natural gas is forecast to increase by 0.7 BCFD winter over winter, averaging 24.8 BCFD (see figure below). The forecasted winter growth appears relatively low in comparison to summer of 2017 to summer of 2018's power burn growth of 3 BCFD. Part of that 3 BCFD is due to above normal temperatures this summer. In comparison, the low winter-over-winter growth appears counterintuitive at first, as 2018 has seen massive combined cycle gas turbine (CCGT) capacity additions, especially in the East region (see figure below).

WINTER ELECTRIC DEMAND FOR GAS



Note: light blue=cold winter, red=warm winter, dark blue-normal winter. Source: EVA

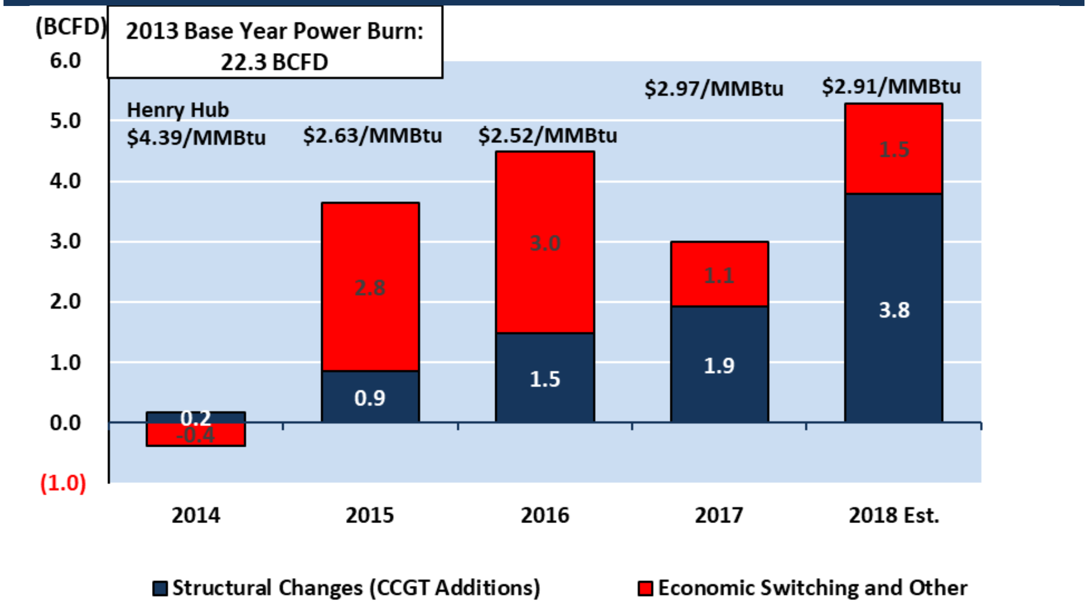
GENERATION CAPACITY CHANGES FROM NOV 17 TO NOV 18



Source: EVA

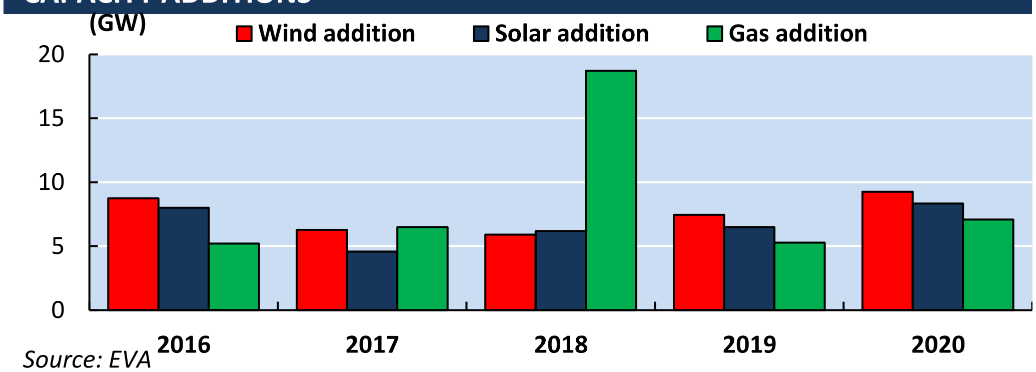
One of the reasons for the limited growth of power burn is the weather. HDDs are expected to be slightly lower this coming winter, reducing electric heating demand. Secondly, fundamentals are expected to place slightly upward pressure on Henry Hub prices this winter compared to the last, which will discourage coal-to-gas switching. Thirdly, the CCGT units added in the East region feature lower heat rates than the existing fleet, which will create gas-on-gas competition, displacing generation from inefficient gas units. This trend can be illustrated by the structural growth in gas burn as demonstrated in the figure below. Total coal-to-gas switching compared to the base year 2013 after adjusted for weather can be divided into structural growth and economic switching. Structural growth represents increased gas generation from units that were built after 2013. The economic switching portion represents coal-to-gas switching at existing units given fuel economics. Economic switching can be negative. For example, in 2014, prices were higher, power producers partially switched back to burning coal. More recently in 2017 and 2018, more generation was observed to come from new gas units which crowded out the switching that could have happened at the older gas units. These more modern and more efficient units are limiting gas burn growth as they consume less gas for each MWh generated. This phenomenon is more prevalent in the winter time, as electricity demand is low, only the more efficient units are dispatched versus in the summer time, more units, old or new, are dispatched when demand is at its peak.

WEATHER ADJUSTED POWER BURN INCREASES FROM BASE YEAR 2013



Last but not least, 2018 saw continued gains in wind and solar capacity. Going forward, wind and solar capacity additions are forecast to exceed gas capacity additions (see figure below). The buildout of renewables has also limited the growth in gas burn and will continue to compete for market share.

CAPACITY ADDITIONS



Source: EVA

YEARLY NET CAPACITY ADDITIONS AND RETIREMENTS (GW)

	Coal	CCGT	Gas Turbine	Steam – Gas & Oil	Nuclear	Hydro	Peaker & Other	Wind	Solar
2016	-7.8	4.5	0.8	0.9	0.7	0.3	0.6	8.8	8.0
2017	-8.5	7.7	-1.2	-5.3	-	-0.1	0.3	6.3	4.6
2018	-16.8	17.3	1.5	-3.7	-0.6	0.0	0.2	5.9	6.2
2019	-4.7	4.5	0.8	-0.6	-1.5	0.0	0.0	7.5	6.5
2020	-3.7	6.6	0.5	-2.3	1.6	-	0.0	9.3	8.3

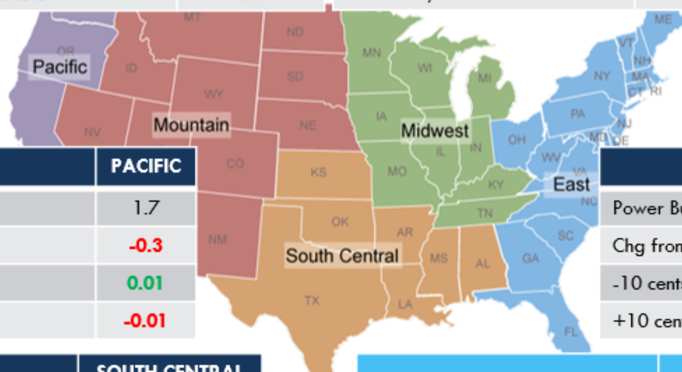
Regionally, the Pacific region will see some declines in power burn (see map below). The drop is due to the retirement of 2.3 GW of gas generation capacity since the beginning of the last winter. Burn in the East and South Central regions will grow the most, as more than 10 GW of coal capacity retired in the two regions since last winter. Also included in the map is the sensitivities of power burn given a 10-cents increase or decrease in average winter season Henry Hub prices. At the U.S. level, more downside exists for power burn when prices increase by 10 cents. Given the current lower prices, the coal-to-gas switching potential is almost exhausted, therefore, if prices drop by 10 cents, there will not be as much upside potential for gas burn as the downside potential when prices increase. However, if prices fall below $2/MMBtu like the winter of 2015-2016, power burn can average as high as 27.9 BCFD, 4.2 BCFD higher than the base case.

2018-2019 WINTER POWER BURN 0.7 BCFD HIGHER THAN 2017

Base Case NYMEX Nov-Mar Average Price as of Sep 10: **$2.90/MMBtu**
2017 Nov-Mar Average Price: **$2.95/MMBtu**

	MOUNTAIN
Power Burn 2018/2019	1.7
Chg from 2017/2018	+0.1
-10 cents/MMBtu	0.03
+10 cents/MMBtu	-0.1

	MIDWEST
Power Burn 2018/2019	2.7
Chg from 2017/2018	+0.1
-10 cents/MMBtu	0.1
+10 cents/MMBtu	-0.01



	PACIFIC
Power Burn 2018/2019	1.7
Chg from 2017/2018	-0.3
-10 cents/MMBtu	0.01
+10 cents/MMBtu	-0.01

	EAST
Power Burn 2018/2019	11.1
Chg from 2017/2018	+0.5
-10 cents/MMBtu	0.0
+10 cents/MMBtu	-0.1

	SOUTH CENTRAL
Power Burn 2018/2019	7.5
Chg from 2017/2018	+0.3
-10 cents/MMBtu	0.1
+10 cents/MMBtu	-0.1

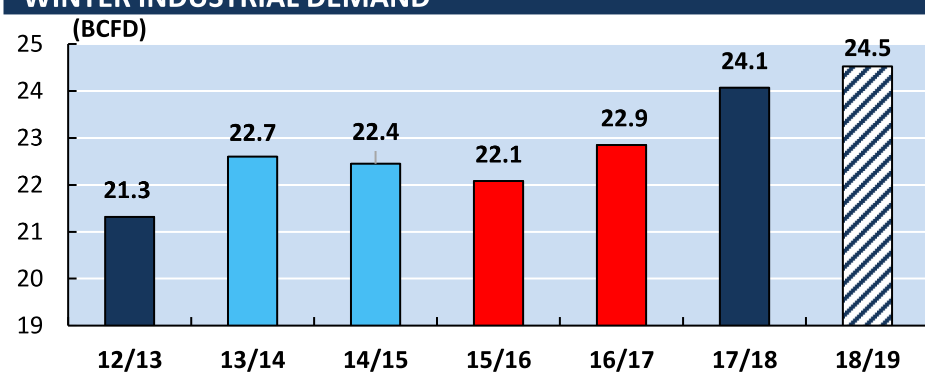
	U.S. TOTAL
Power Burn 2018/2019	24.8
Chg from 2017/2018	+0.7
-10 cents/MMBtu	0.24
+10 cents/MMBtu	-0.32

**Numbers are in BCFD*

Industrial demand

Industrial demand has been quite robust this year, growing by 1.2 BCFD YTD compared to demand during the same period last year. While some of this growth can be attributed to below-normal temperatures from January to April, the rest are structural growth which is expected to continue into the winter. Industrial demand is forecast to grow by 0.45 BCFD winter over winter to average 24.5 BCFD.

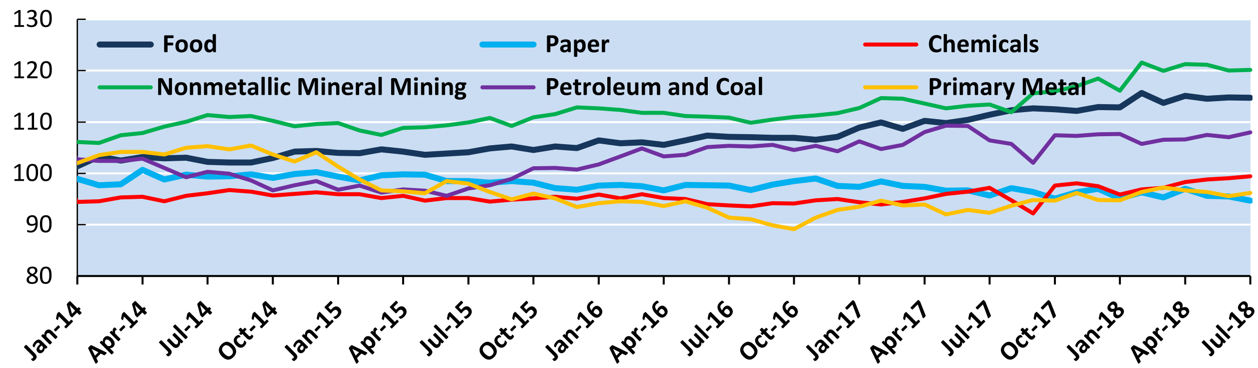
WINTER INDUSTRIAL DEMAND



Note: light blue=cold winter, red=warm winter, dark blue-normal winter. Source: EVA

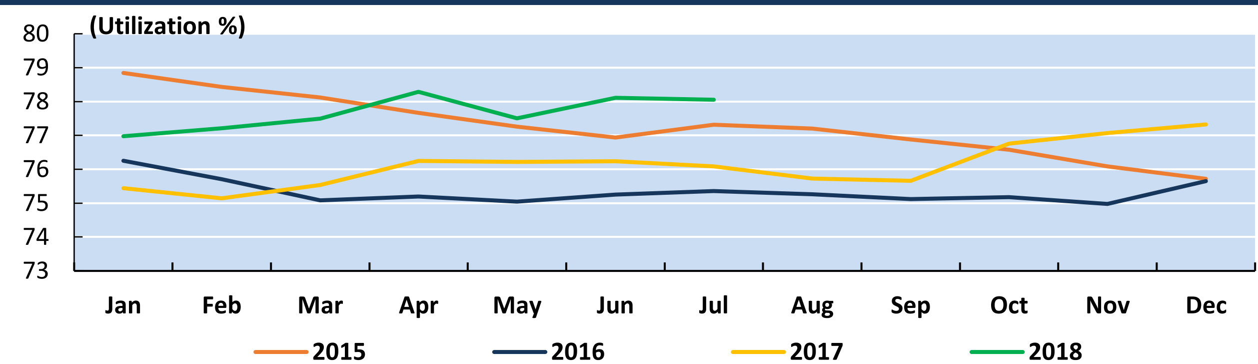
In 2018, healthier activity in the energy-intensive industries provided a solid base for industrial sector demand, and new facilities have also contributed to growth. The industrial sectors' performance, as measured by the U.S. Federal Reserve's production indices, as well as industrial capacity utilization, has recovered from the lows of 2016 and 2017. Among the six energy-intensive industries shown in the chart below, production indices of nonmetallic mineral mining,[3] food, as well as chemicals are trending much higher than the same period last year. Capacity utilization for the industrial sector as a whole is above 2016 and 2017 levels. From April to July, capacity utilization has surpassed 2015 levels.

PERFORMANCE OF THE SIX ENERGY INTENSIVE INDUSTRIES (INDEX 2007 = 100)



Source: U.S. Federal Reserve

INDUSTRIAL CAPACITY UTILIZATION



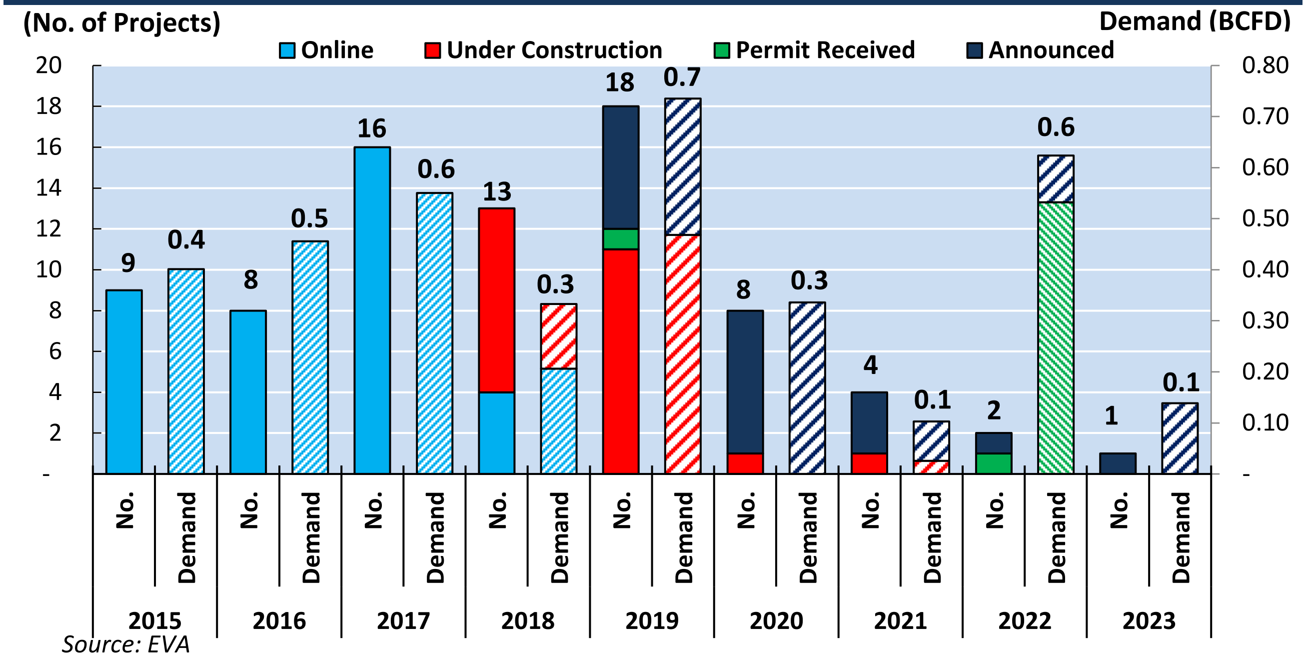
Source: U.S. Federal Reserve

In addition, new projects have come online this year and boosted demand. Noticeably, Yara and BASF started up an ammonia plant in Freeport on April 11, 2018. The plant has a capacity of 750,000 mt/year (60-70 MMCFD of gas demand when running at full capacity). The NatGasoline methanol plant, owned jointly by OCI and G2X Energy, started at the end of June and is now running above nameplate capacity. The project has a 1.75 million mt/year capacity which is equivalent to 163 MMCFD of demand when running at capacity. According to EIA, most natural gas in the bulk chemicals industry is used for heat or power applications, but about 25% of bulk chemical natural gas consumption is used for feedstocks in agricultural chemicals (i.e., fertilizer) and methanol production.

Besides fertilizer and methanol plants, new ethylene, propylene, and polyethylene facilities will also boost natural gas and natural gas liquids (NGL) demand this winter. Increased NGL production in the shale era has led to more NGL exports in 2018. Domestically-produced NGL are also being absorbed by new domestic facilities that turn that feedstock into downstream products. Most of these new projects that will be added this winter are located in Texas and Louisiana. Some of these facilities also use natural gas for heat and power. Besides natural gas demand, these projects have also increased electricity demand in the Gulf region.

[3] Major products for the industry in the U.S. include crushed and broken limestone, construction sand and gravel, and potash, soda, and borate.

INDUSTRIAL PROJECTS AND GAS DEMAND



Source: EVA

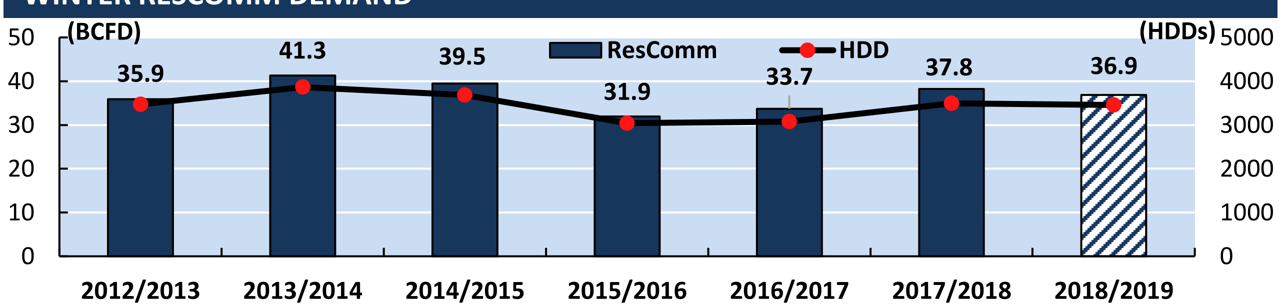
33 projects (2015-2017), total natural gas demand: 1.5 BCFD, total investment $53 billion
46 projects (2018-2023), total natural gas demand: 2.1 BCFD, total investment $79 billion
**A couple projects in 2018 are steel/aluminum plants restarts, which could be the results of the section 232 imports tariffs on steel and aluminum. A couple fertilizer projects were eliminated in the estimates as they have had no news on further developments, likely a result of the ammonia market saturation. The green bar in 2022 is a methanol facility being developed by IGP Methanol, LLC (IGPM) near Myrtle Grove, in Plaquemines Parish, Louisiana.*

In the medium to long term, import tariffs could have mixed impacts on U.S. industrial gas demand. Steel tariffs could encourage moderate expansion in domestic steel production. However, it could increase costs for consumers such as the oil and gas industry, the petrochemicals industry as well as second-wave LNG exports terminals. Furthermore, the potential tariffs on chemical products could hurt domestic manufacturers as the chemical industry touches 96% of all manufactured goods.

Residential and Commercial

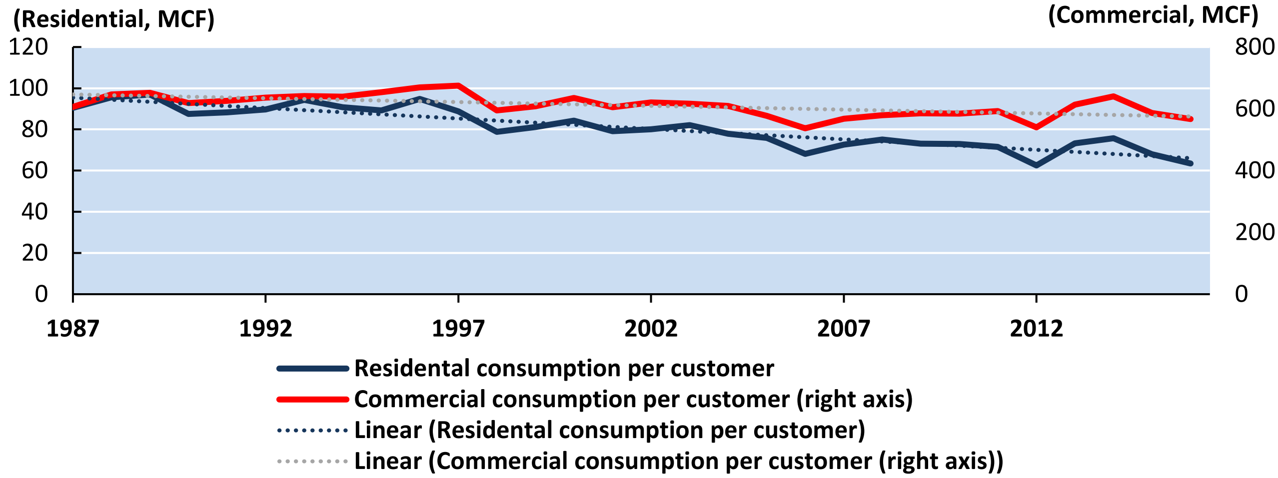
Residential and commercial demand in the winter follows an almost perfect linear relationship with total HDDs. Assuming NOAA's weather forecast, which is only slightly warmer than the 10-year normal, ResComm is estimated to average 36.9 BCFD for the winter, about 1 BCFD lower than last winter. Note that ResComm can swing from 32 BCFD to 41 BCFD in the winter depending on the weather (see figure below). This one factor alone can swing total winter storage withdrawals by 0.6 TCF from the forecasted level.

WINTER RESCOMM DEMAND



Source: EVA

ANNUAL CONSUMPTION PER CUSTOMER

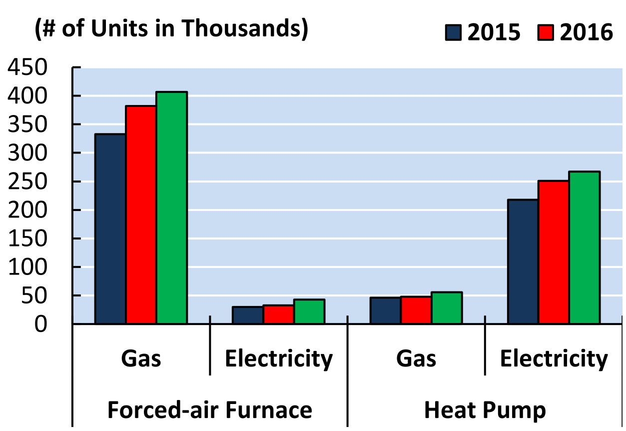


Source: EVA

ResComm demand has not shown visible structural growth even though numbers of customers in the residential and commercial sectors have grown in the past ten years, by 6.6% and 3.8% respectively. One of the reasons for the sluggish growth is efficiency gains. Average annual consumption per customer exhibits a downward shaping trend as shown in the figure above.

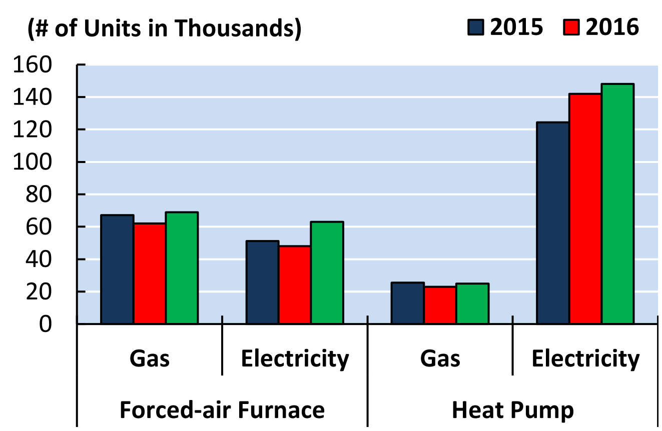
Second, U.S. population continued to migrate to the South and the West from the Northeast and the Midwest,[4] resulting in less heating need in the winter time. Third, electric heat pumps continued to gain popularity in new housing, especially in the multifamily units (see figures below).

SINGLE FAMILY HOUSES COMPLETED BY TYPE OF HEATING FUEL



Source: EVA

MULTIFAMILY UNITS COMPLETED BY TYPE OF HEATING FUEL



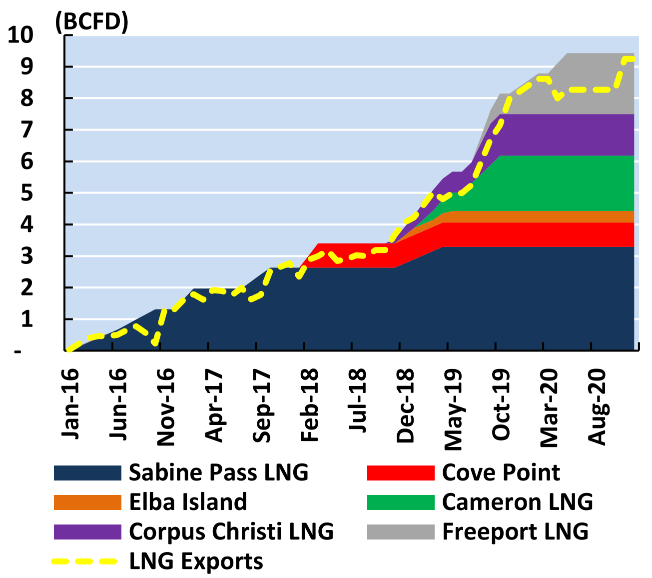
Source: EVA

[4] According to U.S. Census data that was released in 2016.

Exports

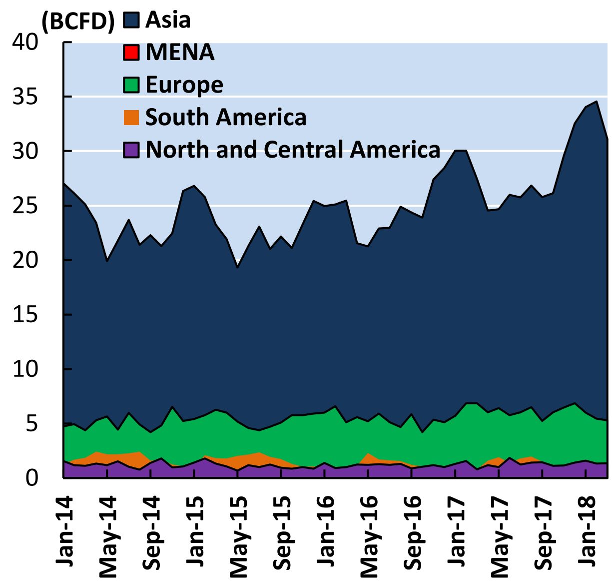
Winter 18/19's LNG exports demand is forecast to average 4.7 BCFD (see figure below). Winter is the global peak in LNG demand season. The trough to peak demand gap from the lowest demand month in summer 2017 to the highest demand month last winter was about 7.3 BCFD (see figure below). Three new LNG trains are expected to come online this winter in the U.S. to serve peak LNG demand, translating into a 1.7 BCFD of LNG exports growth winter over winter.

U.S. LNG EXPORTS CAPACITY BY PROJECT



Source: EVA

GLOBAL LNG IMPORTS SEASONALITY



Source: EVA

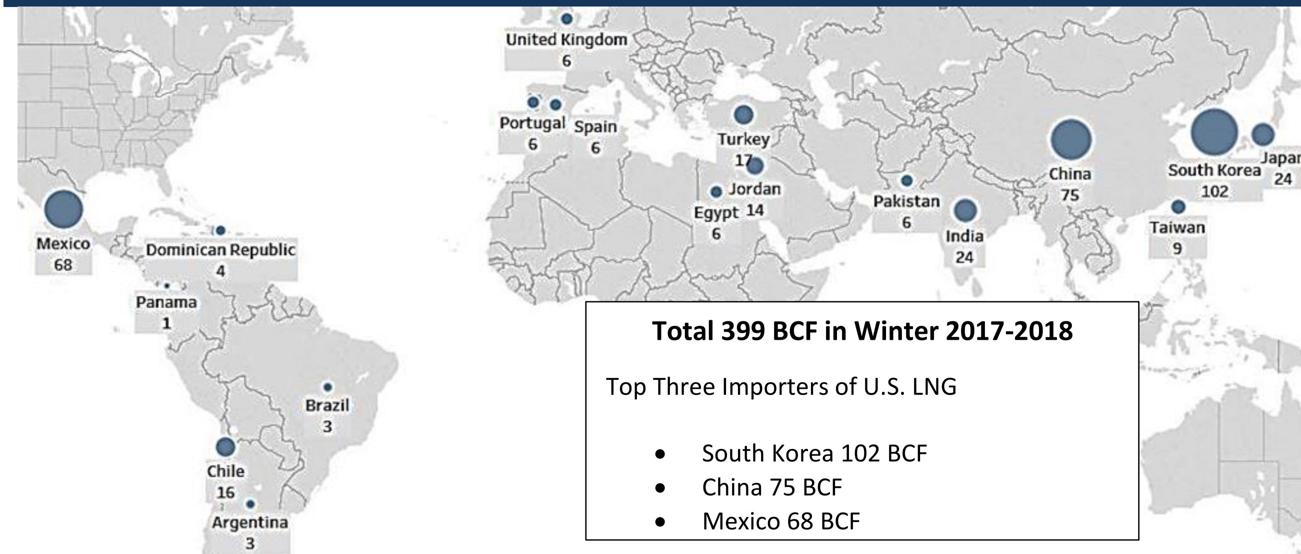
The new trains that are coming online include Elba Island Phase I (0.22 BCFD), Corpus Christi Train 1 (0.66 BCFD), and Sabine Pass Train 5 (0.66 BCFD). These new trains have contracts with utilities in Spain, U.K., and portfolio traders, indicating that some of the cargoes could land in Europe. This past June, Rough Storage, a facility that provided 70% of U.K.'s total gas storage capacity, closed after 30 years of operations. The closure means that U.K. now has about five days of storage capacity instead of 15 days, which could cause NBP to spike sharply over the winter months, attracting U.S. cargoes.

The majority of U.S. LNG cargoes are still expected to head to Asia. 60% of the U.S. cargoes were shipped to Asia last winter (see map below). The global LNG market has been tight this year to date. The global supply glut of LNG caused by the newly commissioned U.S. and Australian trains was quickly absorbed by the fast growth of global demand, most noticeably in China. Policy interventions, aimed at lowering particulate emissions, are pushing natural gas to play a more significant role in China's transportation, industrial and power sectors.

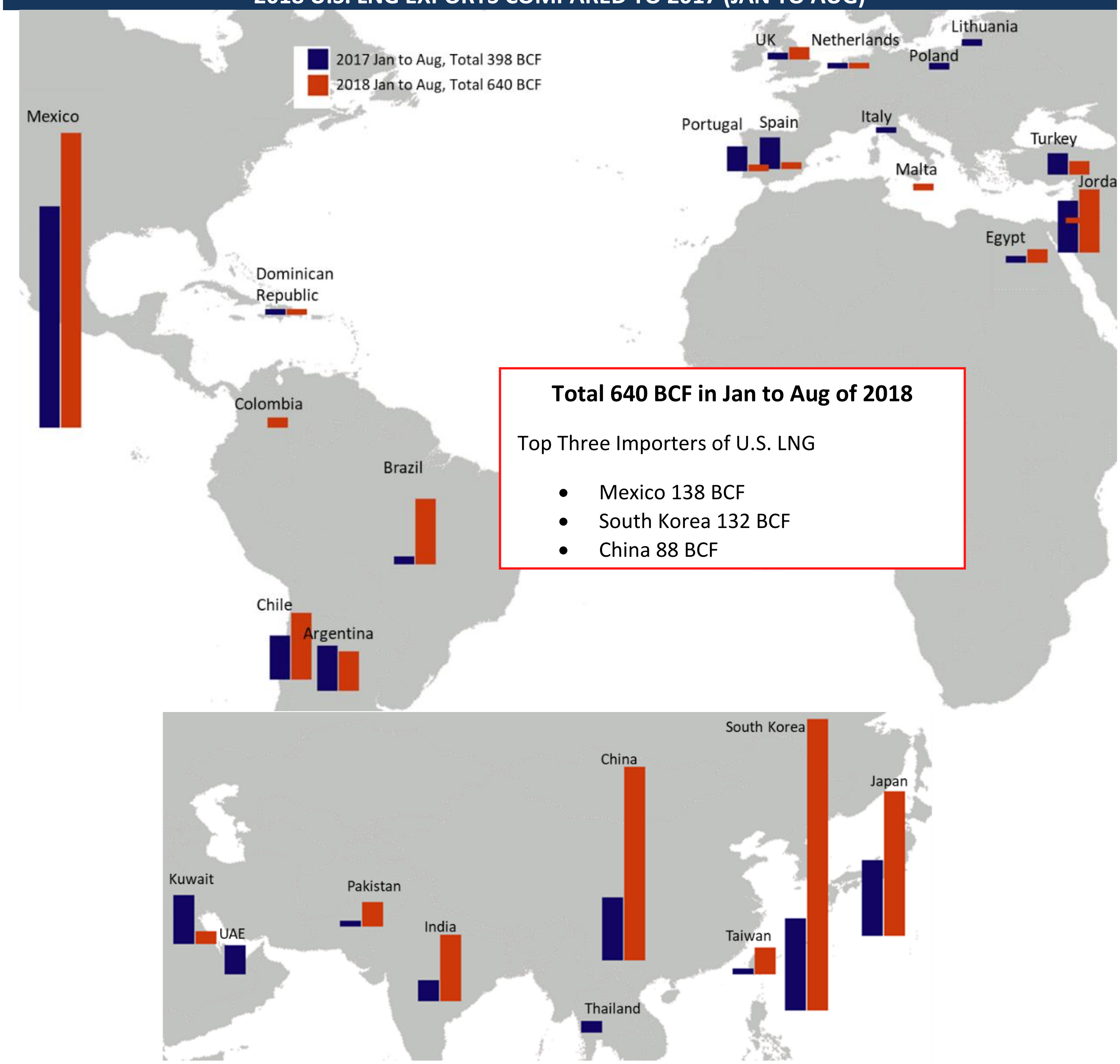
Further boosting demand in China this winter, ENN's Zhoushan terminal (3 MMTPA) and CNOOC's Shenzhen terminal (4 MMTPA) have come online in August. Another terminal in Tianjin (3.5 MMTPA) is on track to start in October. Indian LNG demand is also poised to take off. LNG demand was reportedly 20% higher in the first half of 2018. The Mundra and Ennore LNG terminals (a combined 10 MMTPA in regasification capacity) are expected to begin taking shipments in the second half of this year.

Given the growing demand, global prices are looking strong this winter, judging from the forward prices. Based on the forward prices, EVA's estimated netbacks, even after including the fixed costs, are looking profitable for the U.S. cargoes, ensuring strong exports this winter (see chart below).

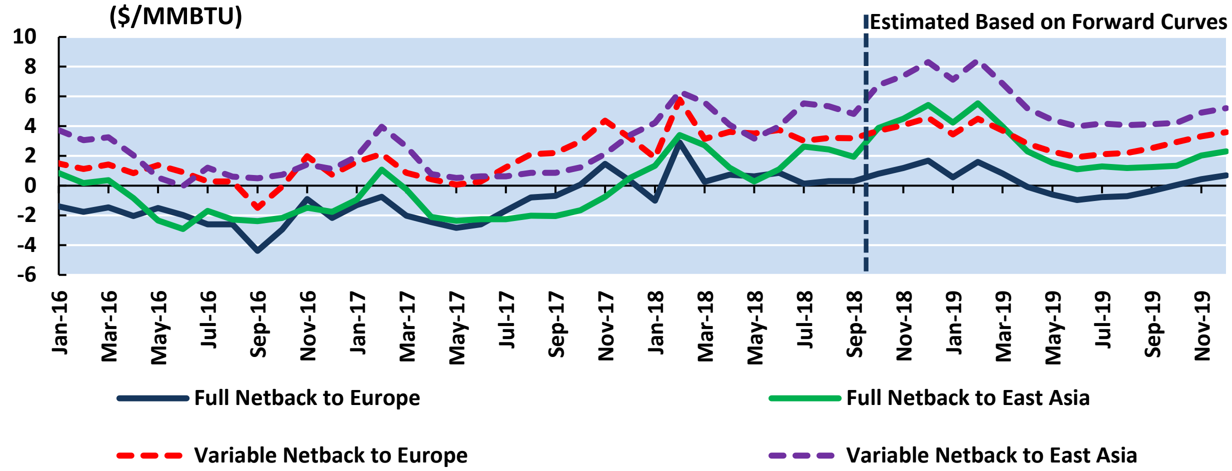
WINTER 2017-2018 U.S. LNG EXPORTS



2018 U.S. LNG EXPORTS COMPARED TO 2017 (JAN TO AUG)



NETBACKS OF US LNG



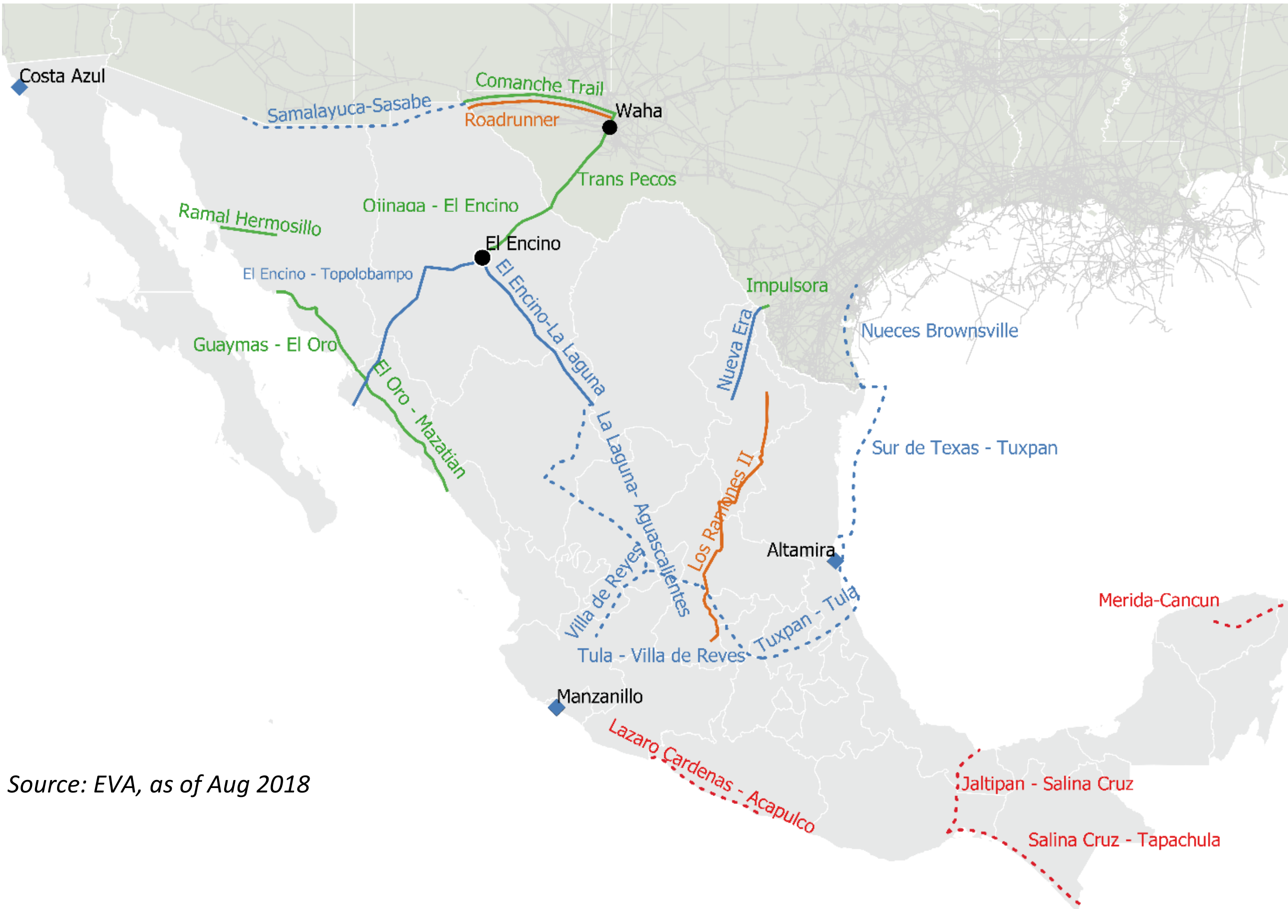
U.S.'s LNG exports to Mexico remained high this year. Even though a few pipelines that were delayed in Mexico finally came online, their reach to the market is limited as downstream pipelines are still under construction. Mexico's domestic production has stabilized this year after a fast decline in 2017. However, production has shown no signs of recovery. On the other hand, the growing demand in Mexico is calling for more imports in the form of either LNG or pipeline imports. Pipeline imports have already pushed above 5 BCFD thanks to the pipelines that came online this summer (see table below). As more pipelines get completed later this year (see second table below), it's likely that LNG imports could be partially displaced. But more displacement will be seen in 2019. TransCanada's Sur de Texas – Tuxapan pipeline is delayed until 2019 and this pipeline will be able to bring gas from South Texas to Tuxapan where demand used to be served by LNG imports at Altamira. Once this 2.6 BCFD pipeline comes online, LNG imports to Mexico are expected to drop. The La Laguna-Aguascalientes pipeline will be able to ship gas from La Laguna to central Mexico, completing the supply route all the way from Permian. If completed in time later this year, exports from West Texas to Mexico are also expected to grow.

Pipeline exports to Mexico are forecast to grow by 0.8 BCFD winter over winter. This forecast is risk-weighted, assuming there could be some delays to the pipelines as well as the power plants that the pipelines are expected to serve. In the long term, pipeline exports to Mexico is forecast to grow to 6.1 BCFD by 2020.

PIPELINES THAT HAVE COME ONLINE SINCE MAY 2018	
Pipeline Additions	**Capacity (BCFD)**
Tarahumara expansion	0.2
Nueva Era	0.5
TGP cross-border capacity increase	0.4
El Encino – La Laguna	1.5
El Encino-Topolobampo	0.7
Argüelles pipeline capacity increase	0.15

PIPELINES THAT ARE COMING ONLINE THIS WINTER		
Pipeline Additions	**Capacity (BCFD)**	**Expected Online Month**
La Laguna Aguascalientes	1.2	Nov 2018
Samalayuca-Sasabe	0.5	Nov 2018

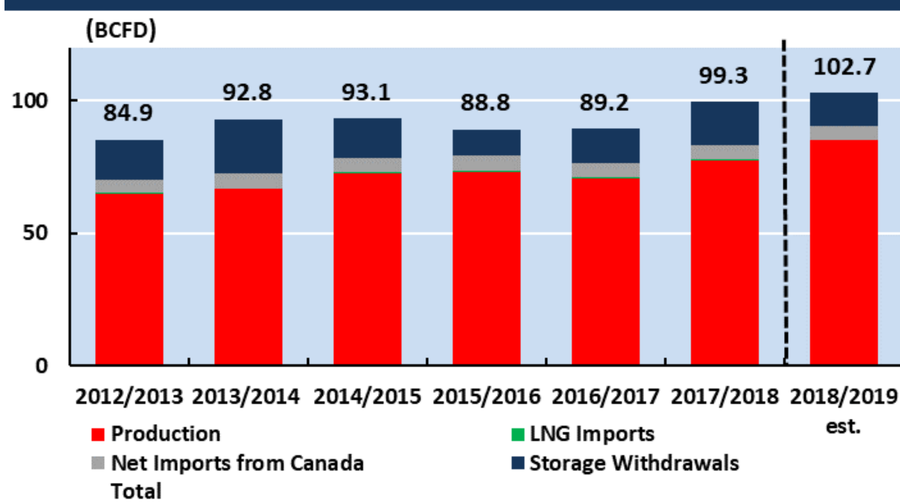
MEXICO'S GAS PIPELINE EXPANSIONS



Source: EVA, as of Aug 2018

III. OUTLOOK FOR SUPPLY

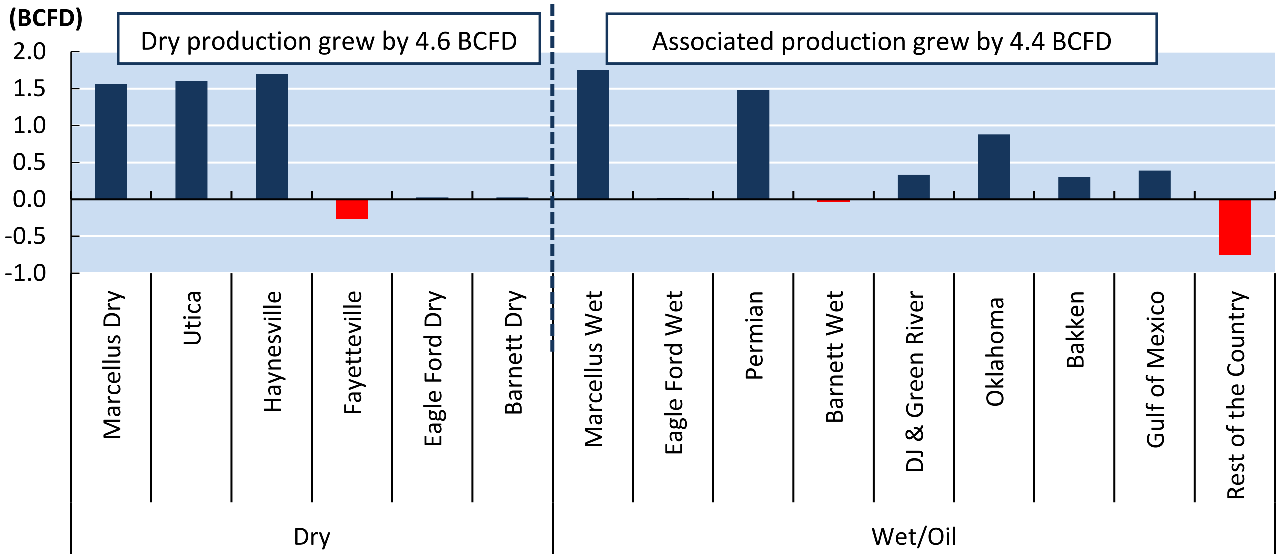
TOTAL WINTER SUPPLY



Production

Production has grown by 9 BCFD year over year to 81.9 BCFD as of August 2018 and will continue to push higher to 85.5 BCFD by the end of winter 18/19. The growth so far has been split between dry gas and associated gas (see chart below). Although Permian grabbed the headlines this year, most of the increase in gas production happened in the Marcellus and Utica in the Northeast.

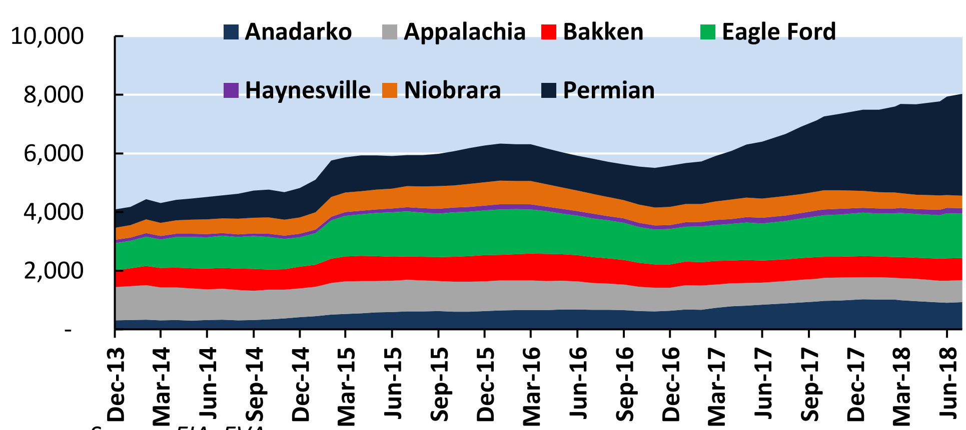
PRODUCTION TRENDS BY PLAY (AUGUST 2018 VS. AUGUST 2017)



Source: PointLogic, EVA

One of the reasons why Permian has not contributed more to the gas production is that Permian wells have lower gas initial production rate (IP rate) compared to a typical Northeast well. Approximately, three Permian wells are equivalent to one Northeast well regarding initial gas production. Secondly, although Permian has added rigs, part of the drilling activities has resulted in increasing DUCs (drilled but uncompleted wells, see figure below) due to the infrastructure constraints on both the crude and the natural gas side. The 3,470 DUC wells in Permian could translate into 6 BCFD of production if all were to come online in one year. Realistically, one-third of these DUCs represent a "base" inventory which will remain. Secondly, DUC completions are usually phased in over a time period. Therefore the 6 BCFD potential could be reduced to 2 BCFD when the pipelines become available in Permian.

DRILLED BUT UNCOMPLETED WELLS

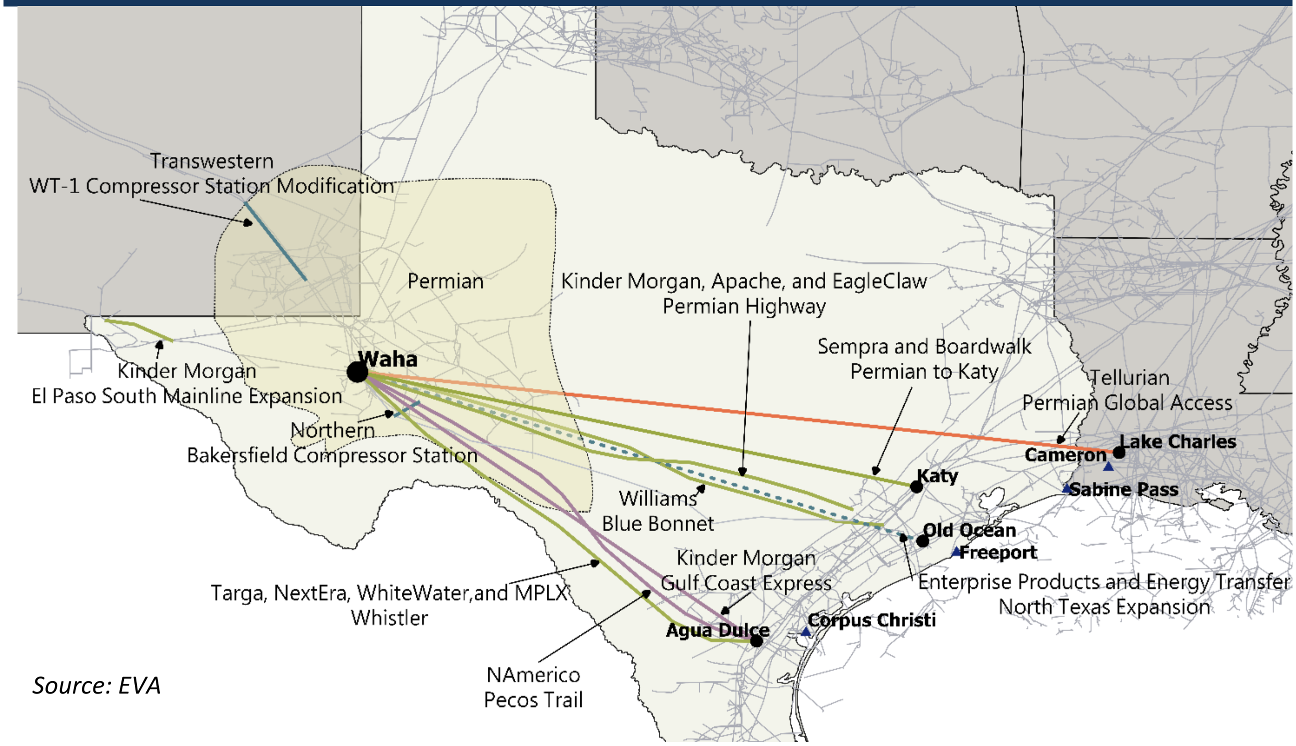


Source: EIA, EVA

A handful of gas pipeline projects have been announced to provide gas takeaway outlets from the Permian Basin. In a sense, Permian has become the new Northeast in terms of pipeline proposals. The difference is that Permian has a crude oil focus versus the Northeast producers are mostly targeting dry gas and NGL. A couple of small brownfield projects are expected to be completed in 2018 and increase takeaway capacity slightly. The big greenfield projects won't be ready in time for this winter, instead will come online later in 2019 (see map below). The infrastructure situation has, and will, limit the growth in Permian until late 2019. Currently, the

Midland crude differential to WTI has widened to $15/bbl due to the crude takeaway constraints, which has slowed down rig activities in Permian.

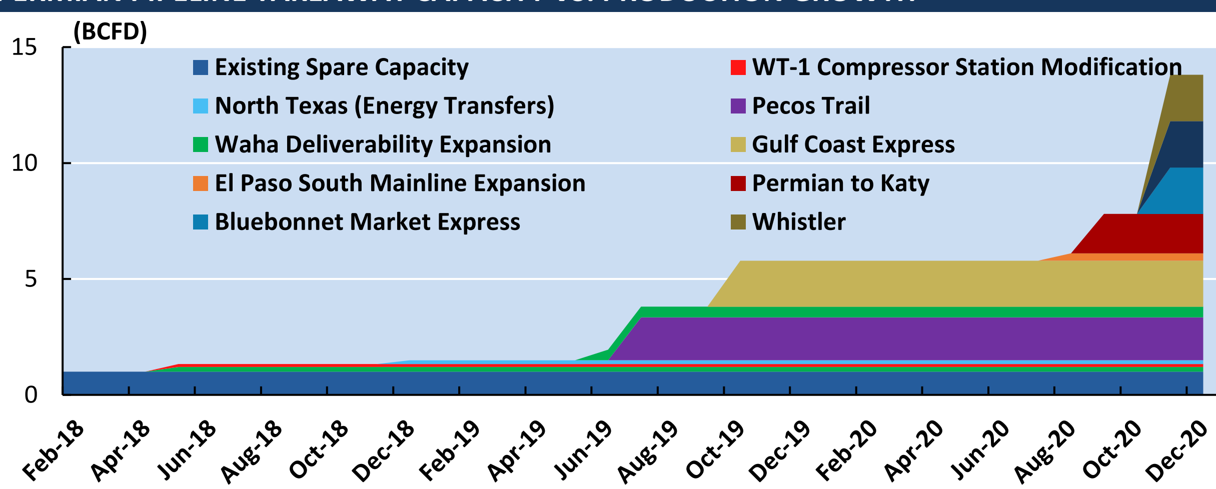
PERMIAN TAKEAWAY GAS PIPELINES



Source: EVA

In the long term, Permian gas production is expected to grow to 11 BCFD by the end of 2020 assuming the buildout of planned pipeline additions. Given the low breakeven prices of Permian crude, the relatively friendly environment in Texas to build petroleum and natural gas infrastructure, as well as the high DUC inventories, there appear to be few risks to the growth in Permian production.

PERMIAN PIPELINE TAKEAWAY CAPACITY VS. PRODUCTION GROWTH



Source: EVA

Given that associated gas (excluding Marcellus Wet) is more than one-third of the total production, the price fluctuations in the crude and NGL markets will impact total U.S. gas production in the medium to long-term. As shown in the figure below, when crude oil prices plummeted in late 2014, associated production started to decline, and as oil price picked up this year, associated gas production resumed growth. If global demand for oil drops or OPEC increases production, the impact on crude oil markets will also be felt in natural gas markets,