Winter 2021-2022 Natural Gas Market Outlook

Executive Summary

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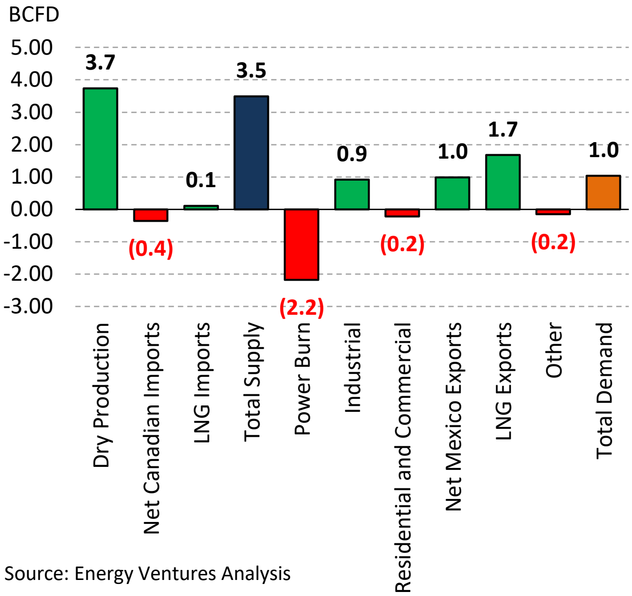
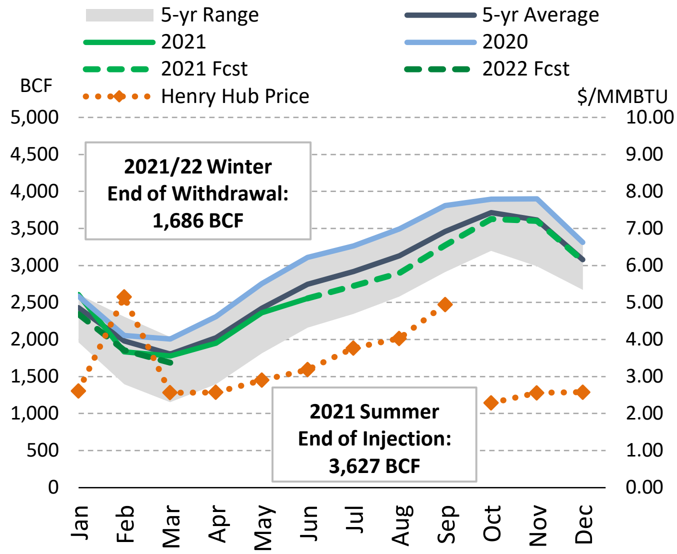
Summer of strong domestic and export demand, mixed with hurricane activity, sets up tightening winter market and storage

Changes in Natural Gas Supply and Demand, 2021-22 Winter vs 2020-21 Winter



Source: Energy Ventures Analysis

U.S. Working Gas in Underground Storage



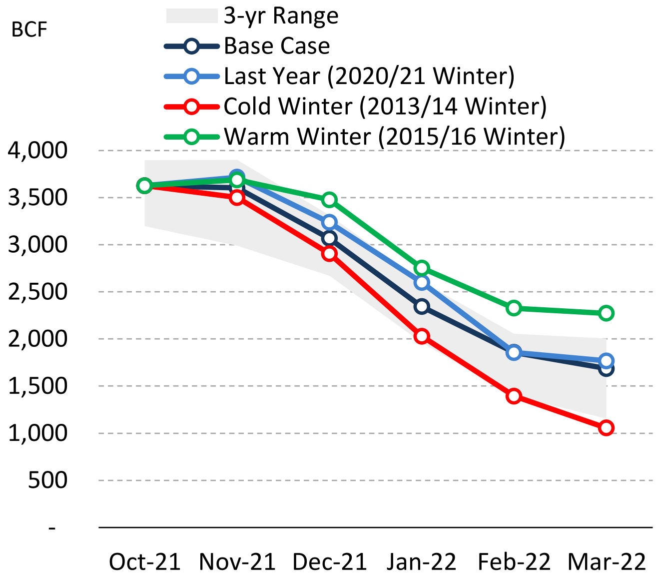
Henry Hub prices are monthly averages of daily cash settlements from Oct-2020 to Sep-2021
Source: EIA, Energy Ventures Analysis

- U.S. natural gas market became significantly tighter this past summer. Improved fundamentals and escalated supply concerns during the hurricane season sent September Henry Hub prices to the highest seasonal level in a decade.
- Since the outbreak of COVID-19 in March 2020, U.S. L48 dry gas production reported months of consecutive year-over-year declines as the uncertain economy signaled operators to focus on capital discipline.
- On the demand side of the ledger, expanded U.S. LNG exporting capacity and improved Mexican downstream pipeline utilization have resulted in a material increase in export volumes. Domestically, natural gas consumption has remained resilient despite higher prices relative to the low prices of the prior winter. Record low water levels for hydroelectric generation in the West and a busier schedule of nuclear maintenance have all lent support to power burn over the past several months.
- Driven by a tighter supply/demand balance, EVA expects the 2021 summer-end U.S. working gas storage to close at 3,627 BCF. If actualized, this level would be around 88 BCF below the five-year average.
- Buoyed by slow production growth and strong spring and summer demand for natural gas, particularly LNG, the Henry Hub benchmark nearly doubled since the start of the last withdrawal season and continues to gain strength ahead of the upcoming winter.
- Outside of the U.S., natural gas prices in Europe and Asia continued to hit all-time highs. Strong demand rebound and unplanned production outages across major supplying countries earlier this year largely slowed down the refill of global gas storage.
- Increased price pressure could also come from slower production growth and diminished switching from gas- to coal-fired generation. EVA expects the winter 2021-2022 price to reflect supply tightness in the market.

Price rally sends signal for higher winter production while demand steadily climbs, led by export growth—

Winter Natural Gas Supply and Demand Summary			
BCFD	2021-2022 Winter	2020-2021 Winter	Difference vs Last Winter
Supply			
Dry Production	93.7	89.9	3.7
Net Canadian Imports	5.2	5.5	(0.4)
LNG Imports	0.3	0.1	0.1
Total Supply	99.1	95.6	3.5
Demand			
Power Burn	24.5	26.7	(2.2)
Industrial	24.9	23.9	0.9
Residential and Commercial	37.1	37.3	(0.2)
Net Mexico Exports	6.4	5.4	1.0
LNG Exports	12.0	10.3	1.7
Other	7.1	7.2	(0.2)
Total Demand	111.9	110.9	1.0
Estimated Withdrawals (Daily Average)	12.9	15.3	(2.5)
Estimated Withdrawals (BCF)	1,943	2,313	(370.3)
HDDs	3,436	3,398	38.0

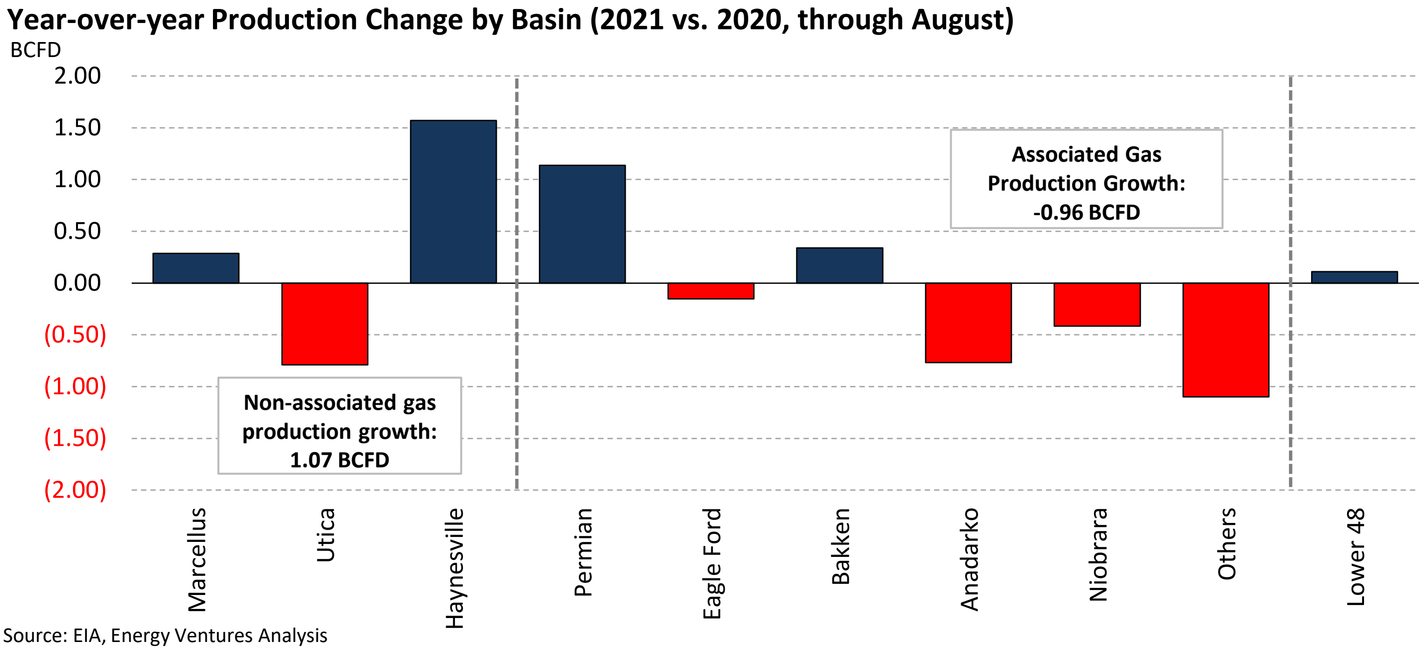
End-of-March Storage Level under Different Weather Scenarios



Weather is the only changing variable across all scenarios.
Source: Energy Ventures Analysis

- EVA expects a gradual production recovery during the winter months to offset the year-over-year increase in demand. Despite the steady but cautious response from producers over this summer, a sustained price rally will likely translate into increased investment in new development, especially for independent gas-centric producers in North America.
- The completions of LNG and Mexican pipeline projects will continue to drive structural export growth. Sabine Pass Train 6 (0.65 BCFD) and Calcasieu Pass LNG Train 1-6 (0.43 BCFD) will start receiving feedgas by the end of 2021. Pipeline deliveries to Mexico will also gain support from partial completion of the 0.89-BCFD Tula Villa de Reyes pipeline, which could improve the utilization of the main Wahalajara system.
- Forecast power burn for the upcoming winter is marginally lower than last year, mainly due to higher prices, while the recovery in industrial demand is expected to offset the loss.
- Under EVA's base case, which uses the latest NOAA seasonal weather forecasts, the end-of-March storage level in 2022 is forecast to be 1,686 BCF, approaching the average of the three-year range. Projected winter 2021/22 withdrawal averages 12.9 BCFD, 2.5 BCFD lower than last year.
- Apart from the base case, EVA analyzed three other weather scenarios: Last Winter (2020-2021 winter), Cold Winter (2013-2014 winter), and Warm Winter (2015-2016 winter). According to modeled results, residential and commercial gas demand could swing 6 BCFD depending on the weather. EVA's weather sensitivity analysis shows that the end-of-March storage levels could drop well below the three-year average under a cold winter scenario.

Modest growth in 2021 U.S. natural gas production in response to strengthening prices—

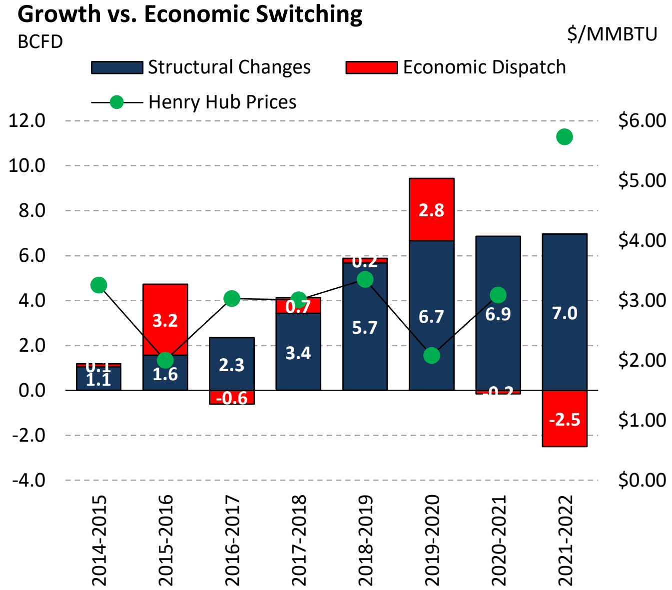


Source: EIA, Energy Ventures Analysis

- Under the shadow of the pandemic and related economic uncertainty, the NYMEX winter prices for natural gas played a less dominant role in deciding new drillings. Despite the rally in crude oil prices, U.S. oil majors stayed focused on reducing debts and boosting returns. Most operators strictly obeyed the production guidance, which suggested a nearly flat annual output. Monthly natural gas production remained below 2020 for the first four months of 2021, primarily driven by lower associated gas output in oil-producing basins. Non-associated gas production, less impacted by global oil prices, generally reported yearly growth.
- Rig counts have been building up since the deepest cut in April-May 2020. However, operators prioritized limited capital spending to sustain activities in the most productive regions, such as Marcellus, Haynesville, and Permian. Other areas had significantly fewer drillings. As of August, Haynesville was the only region where rig counts had recovered above the pre-pandemic level.
- Through August, non-associated gas production rose by 1.07 BCFD while the associated gas counterpart fell by 0.96 BCFD, leaving the total U.S. L48 production in 2021 0.1 BCFD higher than last year. EVA expects modest production growth in winter 2021/22 - 2% higher than summer 2021.
- Extensive hedging program locked over 80% of the 2021 planned volume at prices below $3/MMBTU, tempering incentives to ramp up short-term supply.
- As an alternative to new wells, operators utilized drilled but uncompleted wells (DUC), which provide a cheaper and quicker option to maintain supplies. DUC inventories have been declining at a rate of 4% each month since March.
- Two major pipeline projects in the Northeast faced further delays due to regulatory and legal challenges. The in-service dates of Mountain Valley Pipeline (2 BCFD) was pushed back to summer-2022. The PennEast Pipeline Phase 1 (1.1 BCFD) was shelved in September 2021 due to permitting issues.
- The expansion of Appalachian takeaway capacity was meant to ease congestion and narrow the price differences between producing and demand centers. Because of the delayed schedule, Northeast customers will not benefit from the cost reduction associated with those projects this winter.
- Leidy South expansion project (0.6 BCFD) will be the only pipeline to come online in the 2021/22 winter season. This project would improve flows in the existing Transco pipeline system, providing more takeaway capacity for northern and western Pennsylvania gas suppliers.

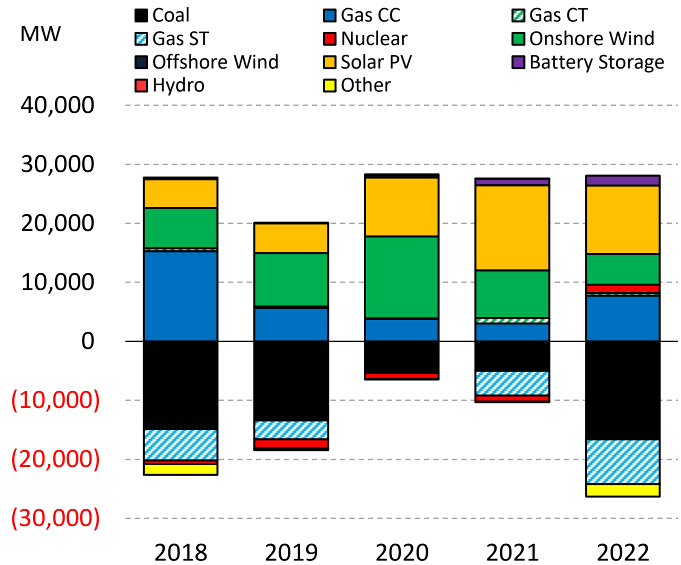
Continued long-term structural switching to natural gas-fired generation but less short-term economically-driven switching this winter—

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



Source: Energy Ventures Analysis
Note: 2021/22 winter prices are NYMEX settlements as of 9/27

Net change in U.S. generating capacity

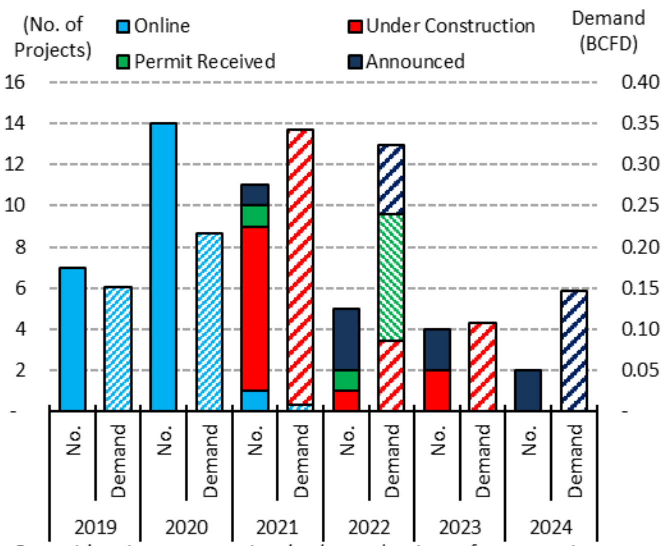


Source: Energy Ventures Analysis, U.S. EIA

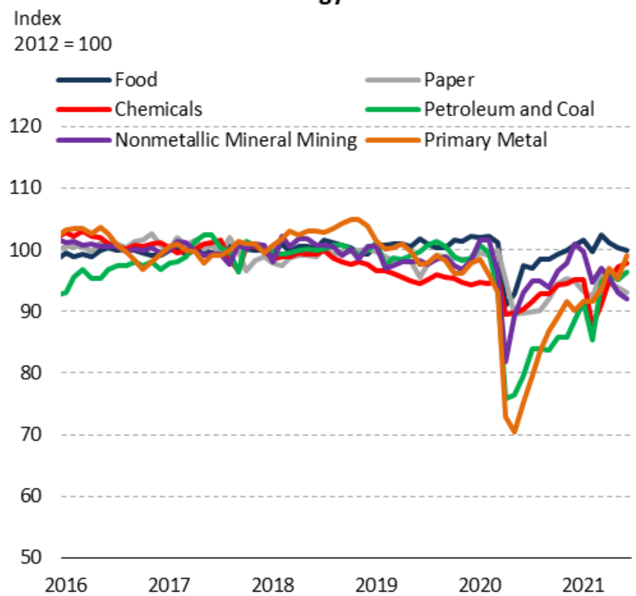
- As Henry Hub jumped by more than $1.50/MMBTU year-over-year, power generation by natural gas was weaker by 1.7 BCFD in 2021 as of August. Coal generation regained market share this year following a 2020 with gas prices below $2/MMBtu that triggered considerable economic switching from coal to gas — with a resulting 22% drop in coal output that year.
- Based on EVA's power market modeling, power burn is expected to average 24.5 BCFD for 2021/22 winter. Power burns for the upcoming heating season fall by 2.2 BCFD compared to the 2020-2021 winter. While the additions of new CCGT units will provide 0.1 BCFD of structural demand growth, the economic-driven change in gas consumption is expected to offset the gain with a 2.5-BCFD year-over-year decline due to higher natural gas prices.
- However, the potential of gas-to-coal switching will diminish if natural gas prices continue to rally. The price elasticity of gas demand has been declining as coal-fired units approach the maximum capacity factor.

- According to the latest project announcements, 20 GW of coal capacity will be retired in 2021-2022, whereas gas combined cycle units will gain over 10 GW capacity. While natural gas retained its position as the nation's dominant fuel, wind and solar capacity have made significant gains and now boast a combined market share of over 15%, up seven-fold from a decade ago. The growth of wind and solar goes hand in hand with natural gas-fired generation's ability to ramp up and down rapidly.
- Any supply shortages of other power-generating resources will likely cause a demand surge for natural gas consumption. In the near term, the record drought in the West that largely drove down the reservoir level and the busy nuclear maintenance schedule following the COVID-19-related delays have both created an upside for gas power burn.

Industrial demand experienced lagged growth while the overall economy improved—



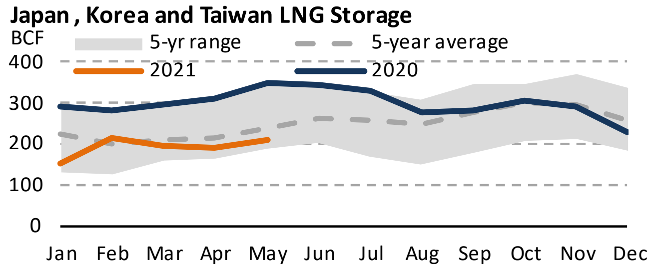
Bars with stripes representing the demand estimate for new projects are indexed in the same color as the project status.
Source: Energy Ventures Analysis



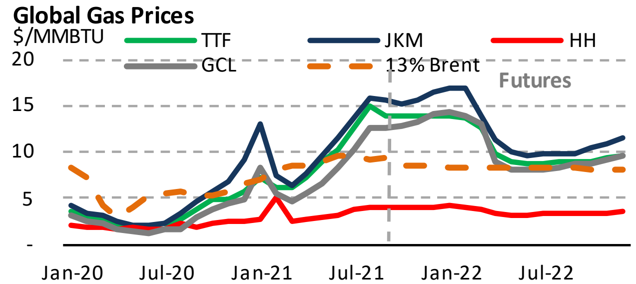
Source: U.S. Federal Reserve

- Industrial natural gas demand in 2021 remained nearly level to the prior year despite recovering economic activities. Some of the demand lag resulted from project delays as the COVID-19 pandemic interrupted permitting and construction. Recent restrictions related to the Delta variant could also play a role.
- Overall, the weather-adjusted industrial demand has been on an upward trend over the last five years thanks to the development of new industrial facilities. A total of 53 projects came online during 2016-2020 and drove an estimated 1.7 BCFD of natural gas demand. An additional 22 projects are expected to come online between 2021 and 2024, potentially adding 1.0 BCFD of incremental gas demand.
- EVA expects industrial demand to average 24.9 BCFD for winter 2021/22, 0.9 BCFD higher year-over-year.
- According to the U.S. Federal Reserve, the industrial capacity utilization rate rose to 76.4% in August, four percentage points higher year-over-year while still one percentage point lower than the pre-pandemic level. The manufacturing of primary metal, chemicals, petroleum, and coal led to recovery, while other sectors showed weakness in the second quarter.
- Looking forward, the rally in natural gas prices could decrease industrial gas consumption. The elevated cost of feedstocks and power will likely signal industrial operators to reduce utilization rates or switch to alternative fuels.

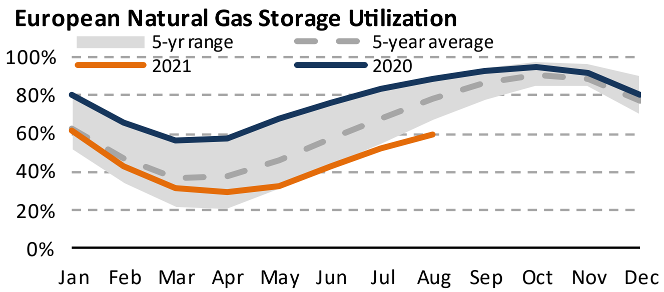
Global gas supply markets pushed prices to record levels and expanded margins for U.S. exports—



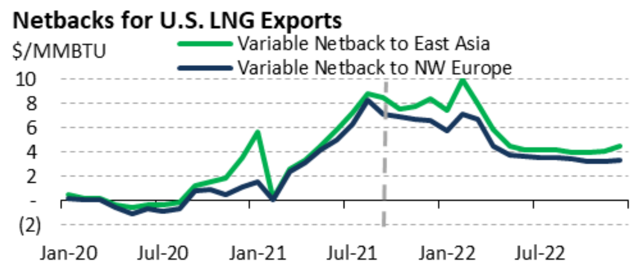
Source: Japan Ministry of Economy, KESIS, Taiwan Bureau of Energy



Source: ICE. Future curves are based on August 19 settlements



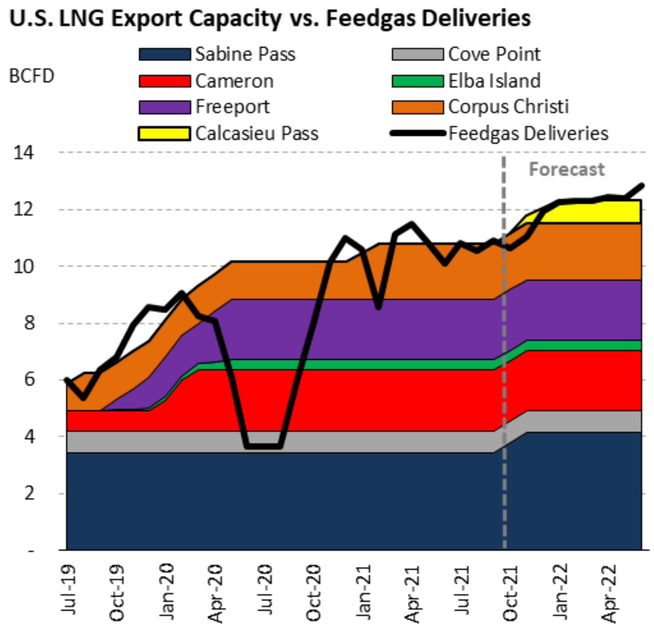
Source:GIE



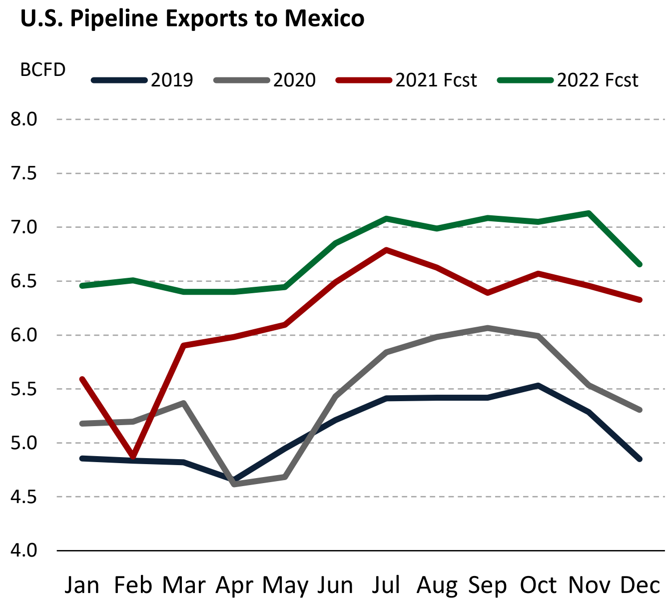
Source: Energy Ventures Analysis. Historical netbacks are based on cash settlements. Future netbacks are based on August 19 forward curves.

- Gas prices in NW Europe and NE Asia extended their rally in 2021. Primary LNG price indices at the European and Asian natural gas hubs TTF and JKM indicated trading at record levels as overseas buyers sought any available cargoes to prepare for their upcoming heating seasons.
- European gas storage was only 60% full in mid-August, well below the five-year average. The current market situation is the inverse of last year, when there was an ongoing concern about running out of natural gas storage space. Lower pipeline deliveries from Norway and Russia in the past summer, a result of unplanned maintenance at Troll field and fire outage at a critical gas processing plant feeding Yamal pipelines, significantly tightened the market. LNG imports provided little help in accelerating the injection rate as European imports sharply fell year-over-year in the intensified global competitions for cargoes.
- Asian buyers bid the highest prices for LNG shipments as it is the primary energy source for many countries. Regional prices also gained support from elevated crude oil prices, which were indexed to most traditional LNG contracts. Additionally, the growing consideration of ESG worldwide may have also prompted fuel switching from coal to gas, which generated substantial opportunities for U.S. LNG.
- As a result of higher global LNG prices, the estimated netback of U.S. LNG cargoes jumped above $8/MMBTU this past summer. EVA expects LNG prices to stay at that level throughout the 2021-2022 winter. The widening arbitrage sends a signal to U.S. LNG liquefaction terminals to operate at their max utilization.
- In terms of the primary destinations of U.S. LNG cargoes, South Korea, Japan, and Europe were still the largest buyers. The most noticeable changes came from China and India that respectively quadrupled and doubled U.S. natural gas imports in the second quarter compared to the same period last year. Brazilian import of U.S. LNG also broke records in Q2 as severe droughts in the country significantly reduced its hydroelectric generation. Part of the growth was attributed to the development of LNG-to-power projects.

U.S. exports to set new high this winter with LNG projects and Mexican pipelines coming online—



Source: Energy Ventures Analysis, EIA



Source: Energy Ventures Analysis, EIA

- U.S. LNG feedgas demand has stabilized around the highest level since 2016. The April volume set a record of 11.5 BCFD, with Corpus Christi Train 3 entering full service. As of August, six projects totaling 77.3 MTPA of exporting capacity (10.2 BCFD) are operating or are currently undergoing commissioning. Two upcoming projects – Sabine Pass Train 6 (0.65 BCFD) and Calcasieu Pass LNG Train 1-6 (0.43 BCFD) are set to start production by the end of 2021, both ahead of schedule by nearly one year. Calcasieu Pass Phase II (0.88 BCFD) will be completed by summer 2022.
- LNG exports will remain a primary driver of U.S. natural gas demand growth in this decade. EVA expects LNG feedgas deliveries to average 12.0 BCFD in winter 2021/22, up 1.7 BCFD year-over-year. Three U.S. LNG projects anticipate the Financial Investment Decision later this year. In recently signed contracts, U.S. LNG operators leveraged flexible pricing mechanisms and carbon neutralization technologies to attract more financing opportunities.

- As of August, U.S. natural gas exports to Mexico averaged 6.0 BCFD in 2021, 0.7 BCFD higher than the same period last year. The expansion of cross-border takeaway capacity and improved utilization rate in the downstream pipeline network drove the structural growth in this sector.
- EVA expects pipeline exports to Mexico to average 6.4 BCFD in winter 2021/22, which would be 1 BCFD higher than last winter.
- In early August, Mexico's state-run utility CFE signed an MOU with TC Energy to consolidate its operations across several existing pipeline projects. The ramp-up of the Samalayuca-Sasabe pipeline (0.47 BCFD), which came online in February, transports Permian gas to the Northeast region of Mexico. Feedgas to the Energeia Costa Azul LNG exporting terminal (0.45 BCFD), which achieved Final Investment Decision in 2020, will be primarily supplied by the U.S. flows through the new pipeline. The 0.89-BCFD Tula Villa de Reyes pipeline connecting to the Wahalajara system is expected to reach partial in-service by the end of 2021, with the rest of the construction expected to be completed in H1 2022.