Chapter 3

US LNG Supply Security

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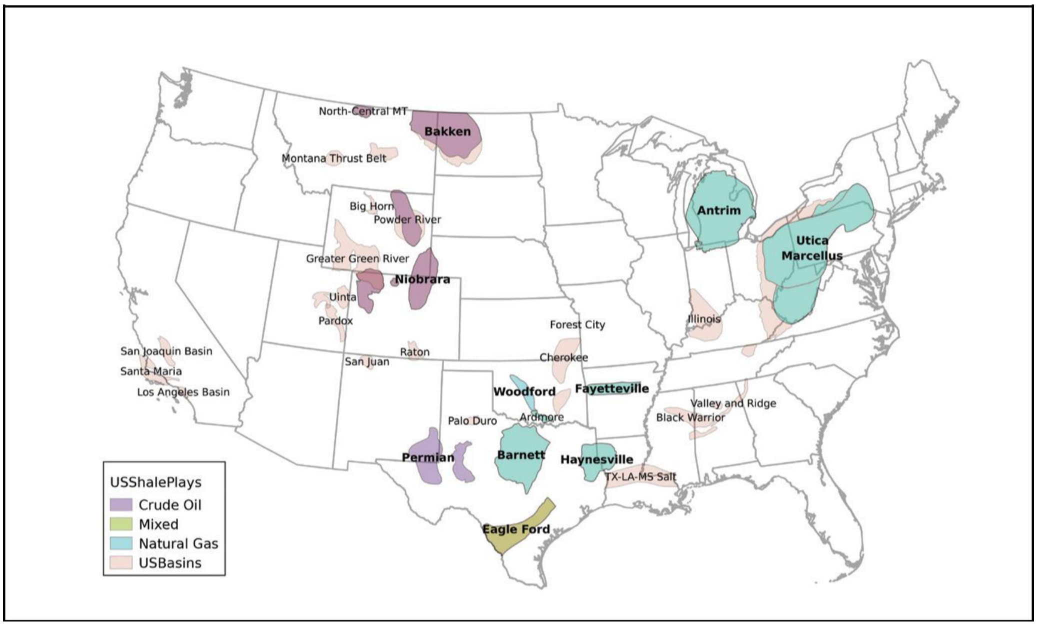
3-1. Pace and Outlook for US Upstream Natural Gas Development

The North American natural gas production platform is drawing upon a rapidly growing, low-cost reserve base. These reserves are prolific and distributed widely throughout the continental US. The distribution of these so-called tight (also known as unconventional or shale) gas plays are shown in Figure 3-1 below.

Figure 3-1. Main US Shale Basins and Plays



Source: US Energy Information Agency.

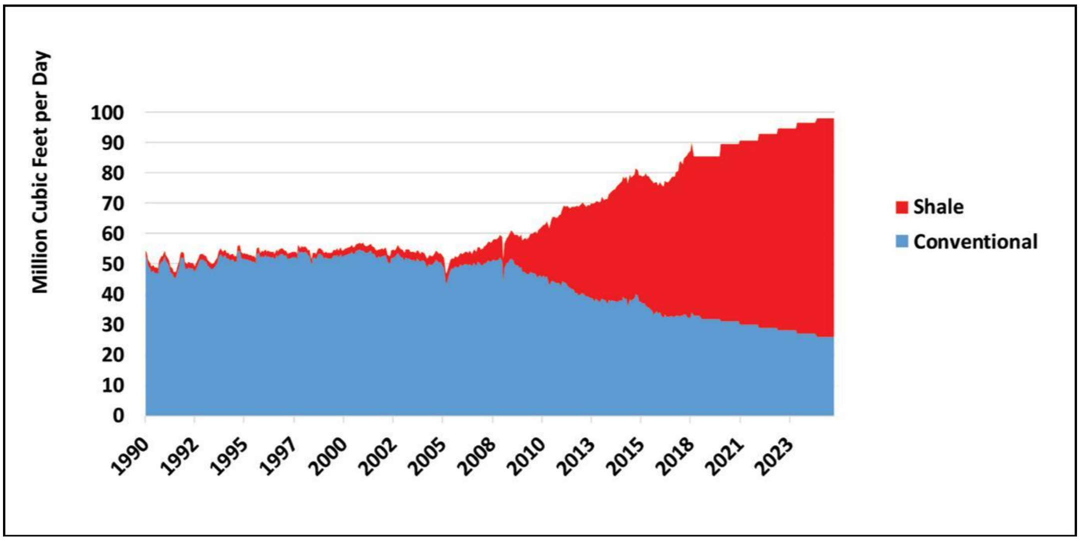
US natural gas reserves reached an initial peak of 201.7 Tcf in 1982, before declining to 164 Tcf in 1998. Since then, the US Energy Information Administration (EIA) estimates that domestic dry proved natural gas reserves have almost doubled, and are now estimated at 324 Tcf, most which are tied to additions from certified recoverable shale gas formations. However, reserves alone do not fully describe the potential size of the resource. According to the Potential Gas Committee, technically recoverable US natural gas resources are estimated to be 3,141 Tcf as of year-end 2016 (Millkov, 2017). When combined with EIA proved reserve estimates, the US future supply of natural gas represents the highest in the history of record keeping for US reserves.

In EIA's 2018 Annual Energy Outlook, US dry natural gas production is expected to increase through 2050 across many alternative assumptions. If there is no major change in US law or policies, US natural gas production is likely to rise in 2018 from approximately 80 Bcf/d to over 100 Bcf/d by 2022. These numbers are after processing and hence lower than wellhead production. More importantly, EIA forecasts natural gas production after 2020 growing faster than consumption in virtually all scenarios. EIA's high resource and technology case expects US natural gas production to reach over 150 Bcf/d by 2050. Even in a more constrained outlook, an expansion of 40 Bcf/d (14.6 Tcf/yr) by 2040, or 50% above current production, is well within the potential of the US oil and gas resource base.

As gas production continues to increase, the US is projected to become the third-largest LNG exporter in the world by 2022, surpassing Malaysia and remaining behind only Australia and Qatar. According to EIA data, by that year, the US is forecasted to generate almost 40% of the rise in global gas output, which could position LNG exports to supply over a quarter of the global LNG demand. However, the projected LNG exports may vary significantly depending on several factors like oil prices, economic growth, international pipeline trade, and market share of natural gas versus other fuels.

The size of the unconventional natural gas resource base, combined with continuing emergence of new extraction technologies and improved efficiencies in drilling operations, all point to significant production growth in the coming decades. Natural gas production in the US is more likely to be limited by inadequate demand than a lack of advances in technology or growth of the resource base. Figure 3-2 shows the rapid growth in US natural gas production since the shale discoveries in 1990 and the likely growth through 2025.

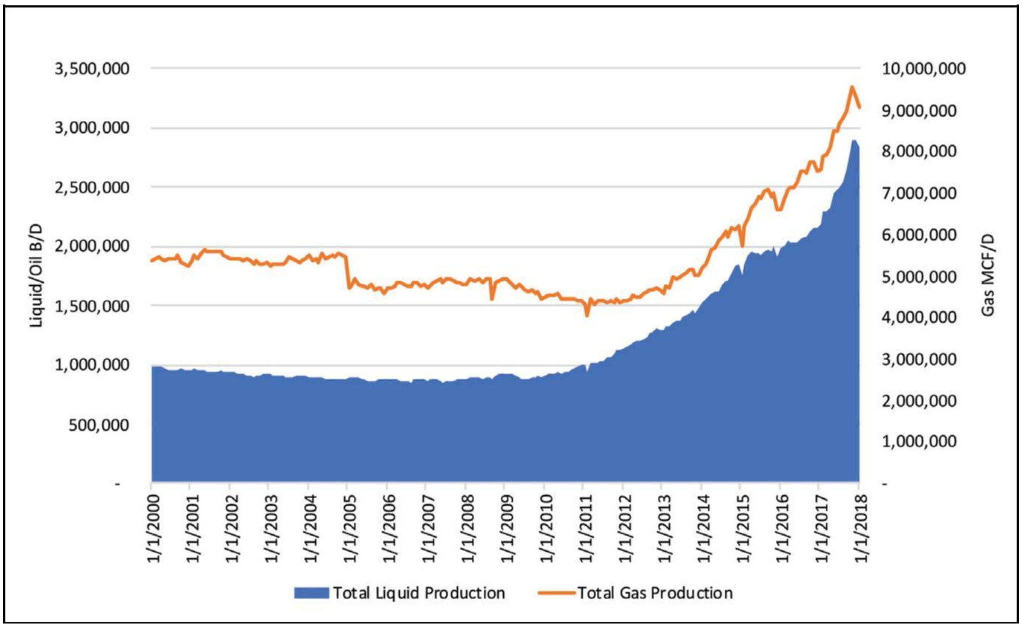
Figure 3-2. Natural Gas Production in the US, 1990 to 2018 (Estimated) and Forecast through 2025



Source: US Energy Information Agency.

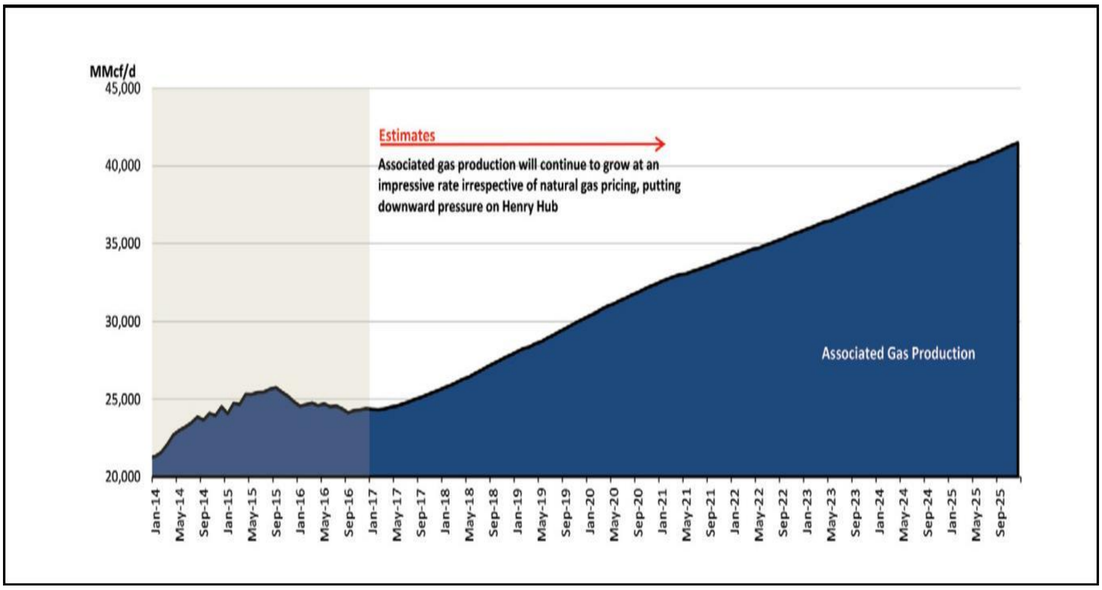
Another important feature of the US natural gas extraction process is the growing volumes of associated gas. This is natural gas production that flows up the well bore during the production of crude oil from shale formations. Associated gas production is a common occurrence in the oil production plays throughout the Permian Basin in Texas and New Mexico, and is a by-product of expanding oil production in this geologic formation. As shown in Figures 3-3 and 3-4, natural gas production in the Permian Basin closely tracks expanded oil production throughout the play.

Figure 3-3. Permian Basin Oil and Natural Gas Production



Source: Trisha Curtis, EPRINC Fellow and Founder, PetroNerds. Presentation at EPRINC Natural Gas Workshop, Washington, DC, 19 April 2018.

Figure 3-4. US Associated Dry Natural Gas Production



Source: US Energy Information Agency, Raymond James Research.

3-2. Prospects for Sustained Low Henry Hub Prices for Export Markets

As shown in Figures 3-3 and 3-4, approximately half of the natural gas produced in the Permian Basin is classified as associated gas. This is very low-cost natural gas, which most producers are willing to sell at whatever price needed to move it to market. The primary reason is that a failure to find a market outlet for the gas would require producers to flare the resource at the well site to maintain oil production, an outcome that state regulators are not likely to permit.

The recent expansion of US natural gas production, combined with continued investment and development of new production, points to sufficient supplies to limit substantial increases in natural gas prices both for the domestic market and as a feedstock for processing into LNG. There is growing evidence that the US is not reserve-limited in terms of the natural gas resource, but that future cost pressures on natural gas are more likely to come from rising costs of production from deploying and operating drilling rigs. Analysis from Vello Kuuskraa, shown in Table 3-1, shows that, in the case of the Haynesville play in Texas, even with rising drilling costs (day rate and completion costs), improvements in estimated ultimate recovery and hydraulic fracturing performance protect against increases in development break-even costs at current levels through 2025. This assessment reinforces the outlook that the US natural gas production platform can expand without substantial per unit cost increases. US major natural gas production plays are shown in Figure 3-5.

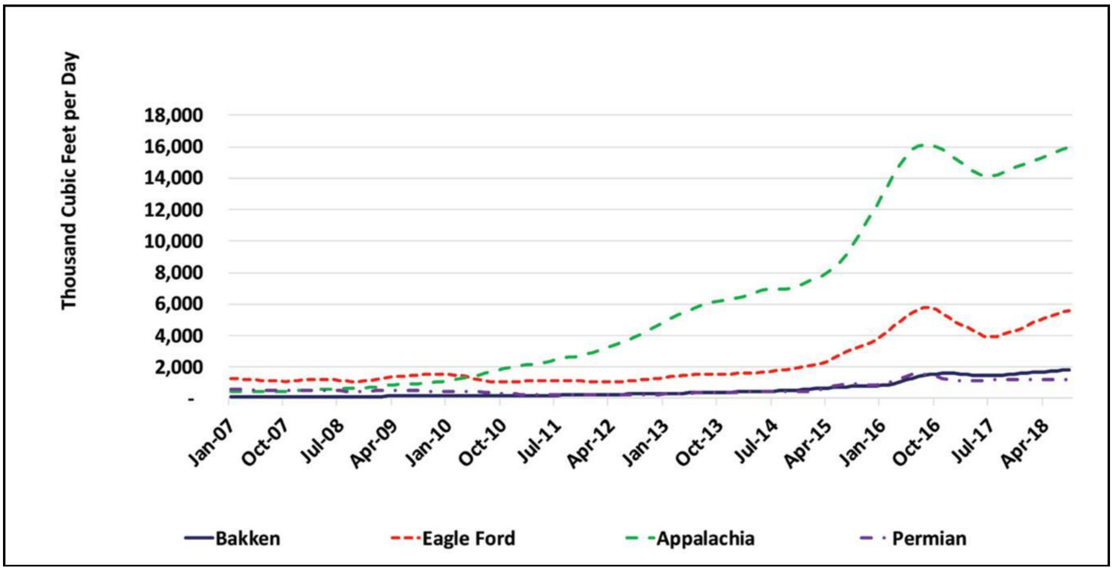
Table 3-1. Drilling Efficiencies in Natural Gas Production in the Haynesville Play

	Actual 2017 (@US$50/Bbl)	**Projected 2025 (@US$65/Bbl)**
Lateral Length	7,400	8,500
1. Well Drilling		
Days to Drill	30	21
Rig Day-Rate (US$/day)	15,000	23,000
Total Well Drilling Costs (US$M)	**3,400**	**3,710**
2. Well Completion		
Frac Stages	25	33
Frac Cost (US$/Stage)	60,000	79,000
Total Completion Costs (US$'000)	**5,100**	**6,430**
Total Well D&C Cost (US$'000)	**8,500**	**10,140**
Gross EUR/Well (Bcf)	**18.4**	**21.2**
'Break-Even' Costs (US$/Net Mcf)	**2.50**	**2.60**

Note: D&C = drilling and completion, EUR = estimated ultimate recovery
Source: Vello Kuuskraa, Advanced Resources International.
Presentation at EPRINC Natural Gas Workshop,
Washington, DC, 19 April 2018.

Figure 3-5. US Major Plays: Natural Gas Production per Rig

(Thousand cubic feet per day)



Source: US Energy Information Agency.

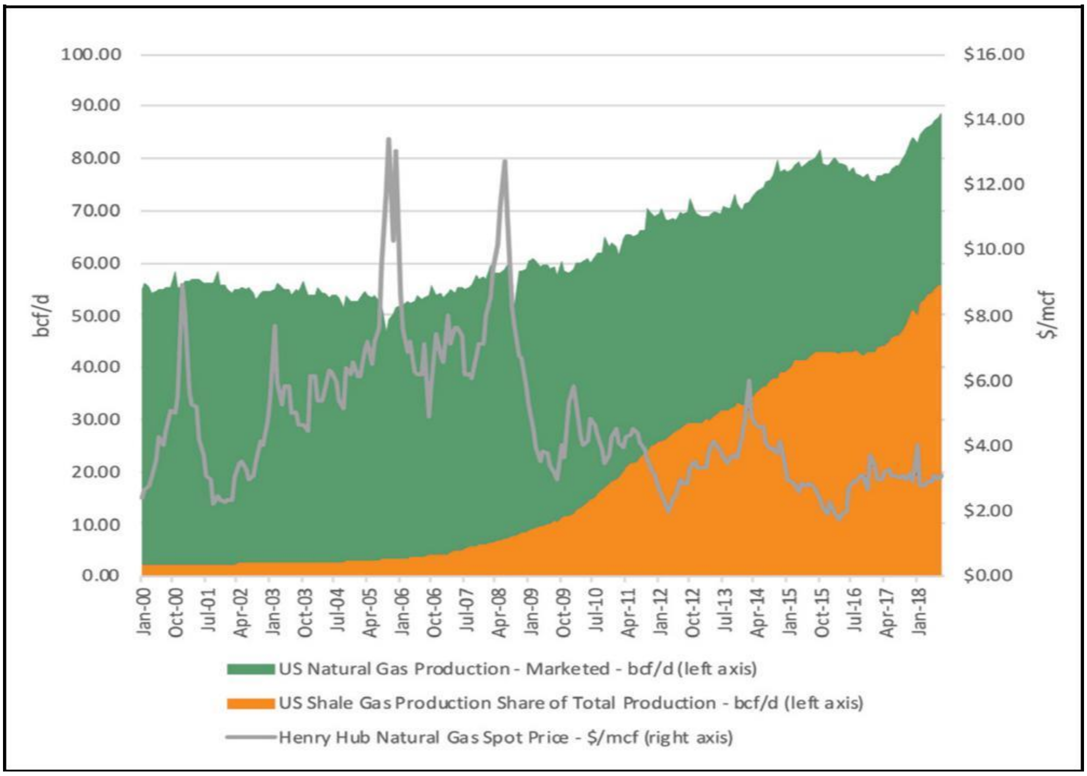
An often overlooked but important feature of US natural gas production is the high degree of operational efficiency and liquidity of service providers across the entire value chain. Although not entirely unique, the development of US natural gas resources is distributed amongst many players, subject to constant cost reductions and technology improvements, and rapid infrastructure expansion (although delays have occurred in getting essential transportation infrastructure in place). Additionally, the US natural gas market is segmented across its supply chain. Exploration and production entities are generally separate from distribution (pipeline LNG) and storage operations, and the latter is separate from utilities that make deliveries to final points of consumption. These industrial features keep the US natural gas market active and competitive, which eventually benefits Asian natural gas markets through the export of competitive LNG cargoes.

Lastly, the US market is characterised by widespread transparency in the reporting of gas pipeline capacity utilisation, tariffs, and prices at market hubs. There is also broad liquidity in both physical and financial markets. This is due in part to the consistent and coherent regulation and enforcement from government agencies such as the Federal Energy Regulatory Commission (FERC), the Commodity Futures Trading Commission (CFTC), and the

Securities and Exchange Commission (SEC). These forces are likely to keep the long-term price of US natural gas based at its primary trading location, Henry Hub.[4]

The analysis of the Eagle Ford cost structure is reinforced by Figure 3-6 below, which shows that the US natural gas production has continued to expand even as prices declined to US$2/Mcf in late 2015. There was some flattening and even a mild downturn in US natural gas production from the middle of 2015 through late 2016. But this was tied to delays in moving gas supplies out of the Marcellus to domestic processing centres and export markets. Although prices have recovered somewhat and are now approximately US$3/Mcf for 2017, shale gas output will continue to expand and take a growing percentage of total US natural gas production.

Figure 3-6. Monthly US Natural Gas Production (LHS) vs Henry Hub Price (RHS)



Source: US Energy Information Agency.

[4] Henry Hub pipeline is in Erath, Louisiana and is the pricing point for natural gas futures on the New York Mercantile Exchange (NYMEX). The NYMEX contract for deliveries at Henry Hub began trading in 1990 and is deliverable 18 months in the future. The settlement prices at Henry Hub are used as benchmarks for the entire North American natural gas market and parts of the global liquid natural gas market. Henry Hub is an important market clearing pricing concept because it is based on actual supply and demand of natural gas as a stand-alone commodity.

3-3. US Regulatory Outlook for LNG Exports

It should also be noted that, under the policies of the Trump administration, the US federal government through the Department of Interior is now expanding oil and gas development on public lands on an accelerated schedule. In an oil and gas lease sale held in New Mexico in the first week of September 2018, the federal government collected nearly US$1 billion for the rights to develop the oil and gas resources on public land in the Permian Basin. These are very large bid values for onshore plays. The lease sale covered over 50,000 acres prospective for oil and gas shale development. One bid alone for 1,240 acres in Eddy County brought in more than US$100 million. The lease demonstrates that development of shale reserves on federal lands will supplement US oil and gas production.

3-3-1. US Department of Energy

Many local, state, and federal agencies are involved in reviews and permit approvals to produce natural gas, distribute it to processing centres, and build and operate LNG export facilities. Two federal agencies dominate the review process: the US Department of Energy (DOE) and FERC.

DOE’s Office of Fossil Energy (DOE/FE) is responsible for authorising exports of domestically produced natural gas under US law. DOE/FE reviews applications to export natural gas to countries with which the US has not entered into a free trade agreement (FTA). As of 21 June 2018, DOE/FE issued 29 final long-term authorisations to export LNG and compressed natural gas to non-FTA countries in a cumulative volume totaling 21.35 Bcf/d. These authorisations have a term of 20 years, with additional time provided for LNG export operations to commence. Some stakeholders have raised concerns that, under the DOE approval process, LNG exports face a revocation risk, which can raise the cost of financing new projects and limit market access.

In response to buyer concerns over revocation risk, DOE Deputy Secretary Dan Brouillette publicly reinforced DOE/FE policy on the stability of US LNG exports at the Annual LNG Producer Consumer Conference in Tokyo in 2017. In a public statement in the US Federal Register (21 June 2018), DOE/FE pointed out that it has never rescinded a long-term non-FTA export authorisation for any reason, unless so requested by the exporter or if the exporter abandons efforts to develop the project. Further, DOE has repeatedly stated that it has no record of ever having vacated or rescinded an authorisation to import or export natural gas once approval has been granted over the objections of the authorisation holder. The one order vacated was strictly due to the exporter's inaction in proceeding with the project.

3-3-2. Federal Economic Regulatory Commission

There have been concerns raised by industry experts and policy makers that the approval process for the siting and operation of new LNG export facilities is taking too long and delaying construction. In response, on 31 August 2018 FERC issued a Schedule for Environmental Review (SER) to 10 new LNG export projects, and reissued SERs for two others (Driftwood and Jordan Cove). Between April 2012 and December 2016, FERC issued 12 certificates to export facilities. Since President Trump took office in January 2017, FERC has issued no orders for new LNG export facilities, and had issued SERs for only two projects: Venture Global's Calcasieu Pass, and Tellurian's Driftwood LNG. Of those, FERC has only issued a draft environmental impact statement to Calcasieu Pass. FERC's stalled LNG export facility review process does not directly follow the Trump administration's stated objective of accelerating energy infrastructure reviews. In June, Chairman Kevin McIntyre acknowledged to Congressional committees that the Commission was having difficulty keeping up with the enormous workload requirements. However, since August 2018, FERC has made progress in resolving this slowdown.

In September 2018, FERC released a new MOU with the Pipeline and Hazardous Materials Safety Administration, which is assuming review responsibilities for the design and operation of feedstock pipelines and LNG operations. This should relieve some of FERC's workload and improve the timing of construction permits.

FERC is also preparing full environmental impact statements for the eight new projects that received SERs on August 31 (Port Arthur, Texas LNG, Jacksonville Eagle, Gulf LNG, Annova LNG, Rio Grande LNG, Venture Global Plaquemines LNG, and Jordan Cove). Driftwood and Alaska LNG received revised SERs. The new SERs indicate that FERC is attempting to adhere to a 4-month window between draft and final environmental impact statements, a shorter interval than in the past. A further 10 projects could be approved by the summer of 2019. Table 3-2 shows the FERC review schedule for pending LNG projects.

Table 3-2. New FERC Review Schedule for Pending LNG Projects

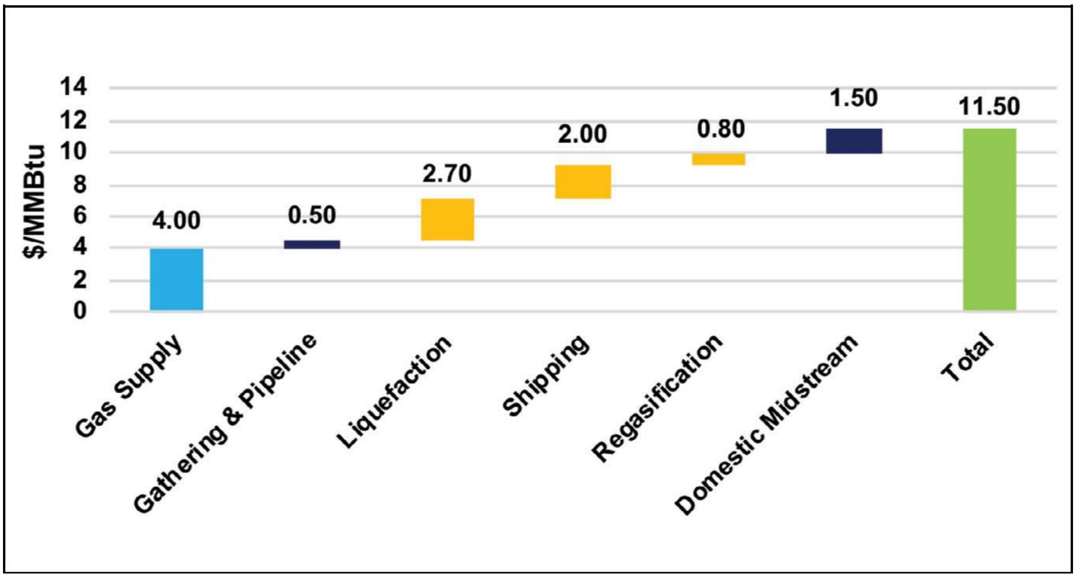
Project	Date When Project Will Be Ready for Final Approval
Transco NE Supply Enhancement	17 September 2018
Calcasieu Pass	26 October 2018
Driftwood LNG	18 January 2019
Port Arthur LNG and PA Pipeline	31 January 2019
Texas LNG	15 March 2019
Eagle LNG Partners Jacksonville LLC	12 April 2019
Gulf LNG	17 April 2019
Annova LNG	19 April 2019
Rio Grande LNG	26 April 2019
Venture Global Plaquemines LNG	3 May 2019
Jordan Cove, Pacific Connector	30 August 2019
Alaska LNG	8 November 2019

FERC = US Federal Energy Regulatory Commission, LNG = liquefied natural gas.
Source: FERC as of 30 September 2018.

3-3-3. Cost Competitiveness of US LNG Exports

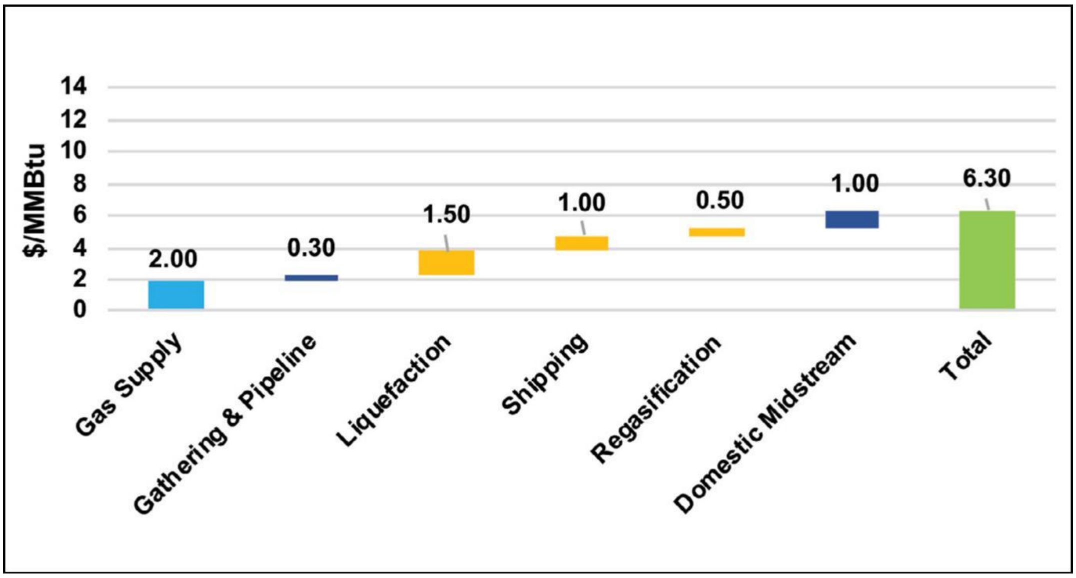
Figures 3-7 and 3-8 below capture the range of uncertainty regarding the competitive position of US LNG exports delivered to Asian markets from facilities via the Gulf of Mexico. As the figures show, the cost of delivered US LNG to Asian markets will be driven by both the cost of construction and operation of liquefaction facilities and the availability of low-cost feedstock. The vast scale of the US natural gas reserve base, combined with rising volumes of associated gas, increase the likelihood that US feedstock costs will remain very low across a wide range of export volumes. Challenges remain on sustaining a timely build-out of domestic midstream infrastructure in the US and permits for construction on new liquefaction plants, but considerable progress has been made in implementing a more timely and predictable approval process as part of the administration’s energy policy. Advances in project design and technological innovations can keep liquefaction and shipping costs low and US LNG exporters are well positioned to sustain a cost structure that is competitive for Asian markets.

Figure 3-7. Asia-Delivered LNG: Low-Cost Structure Scenario



LNG = liquefied natural gas.
Source: Bloomberg Data.

Figure 3-8. Asia-Delivered LNG: High-Cost Structure Scenario



LNG = liquefied natural gas.
Source: Bloomberg Data.

3-4. Panama Canal

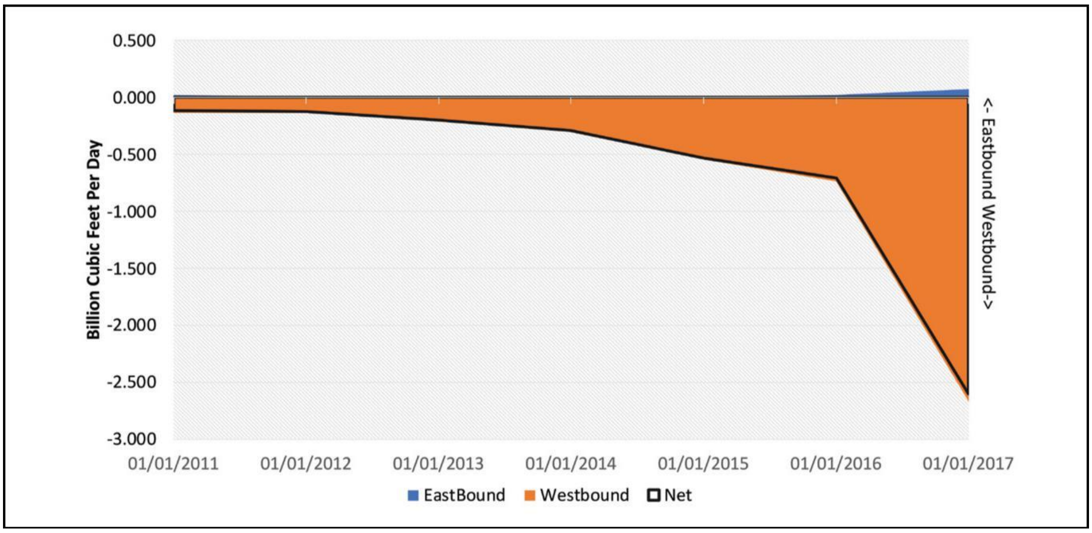
The Panama Canal represents a potential transit chokepoint on the movement of LNG from the East Coast and Gulf Coast of the US to selected Asian destinations. The importance of this emerging LNG trade route has increased focus on the Panama Canal by both US LNG producers and Asian countries hoping to meet rising demand with US LNG exports. Expectations on the Panama Canal's capacity to efficiently permit transit of growing volumes of LNG shipments from the US have been subject to misinformation and scheduling practices that have created the appearance that it is a severe constraint on Gulf Coast LNG shipments to Asia. This prompted the government-run Panama Canal Authority (ACP) to adjust their operating policies to expand annual LNG transit capacity.

This is not the first attempt by the ACP to increase the Panama Canal's capacities since lock size is the limiting factor for ship size (the locks are only 34m wide). On 26 June 2016, a wider third lane of locks that had taken 9 years to build opened and can now handle so-called Neopanamax vessels. Such vessels can be up to 294.1 meters long, with a beam of 32.3 meters and draught of 12.04 meters, with LNG carrying capacity up to 3.9 billion cubic feet (Bcf).

The expansion significantly affected LNG trade as it reduced both transportation costs and travel time for LNG shipments and provided additional access to previously regionalised LNG markets (EIA, 2016). As evidenced in Figure 3-9, LNG transit volumes through the Panama Canal remained relatively low until 2017, when a steep spike in volume occurred, specifically westbound towards the Pacific Ocean. This increase is clearly related to the Panama Canal's expanding in 2016, but it was not as prepared to meet the demands of the LNG industry. For reference, Figure 3-10 below shows the transit volumes of the Suez Canal, a much more mature LNG transit route with a much steadier curve. Even so, the spike in Figure 3-9 indicates that the LNG industry pushed the Panama Canal and the ACP to respond to demand requirements.

Figure 3-9. Panama Canal LNG Transit: January 2011 to January 2017

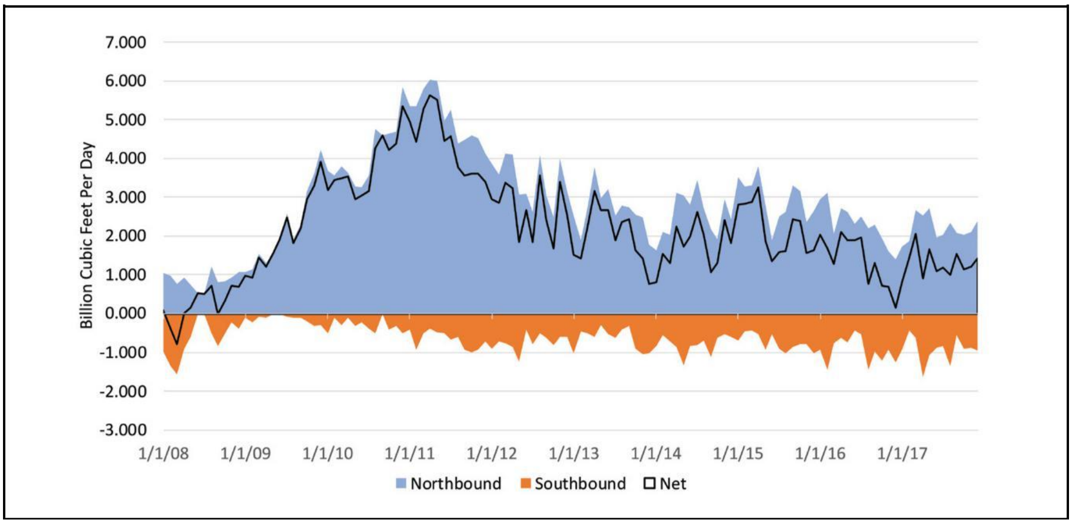
(Billion cubic feet per day)



LNG = liquefied natural gas.

Source: Annual Panama Canal data.

Figure 3-10. Suez Canal LNG Transit: January 2008 to December 2017



LNG = liquefied natural gas.

Source: Monthly Suez Canal data.

The ACP has recognised that the expansion was insufficient to meet transit requirements for LNG shipments to Asia without some operational changes. Recently, ACP released several changes to the regulations surrounding LNG shipping to accommodate the increase in demand and to mitigate the effects of some undesirable practices of some LNG carriers. One major issue, as the ACP puts it in their *Advisory to Shipping No. A-29-2018,* is 'the current practice by some LNG customers of acquiring booking slots during the first period competition, to the point where these slots are nearly sold out up to 365 days in advance, while in reality these slots are only used on average 60% of the time' (Canal de Panama, 2018). Those booking slots are very valuable because, until recently, the ACP limited the number of LNG vessels to one per day in one direction. By purchasing booking slots that they did not intend to use, other nations could limit the amount of US LNG that could reach Asia, tightening the bottleneck in Panama. This would, of course, keep LNG prices from dropping due to increased supply, and limit the amount of LNG that could be sold west from the Gulf Coast.

On 1 October 2018, the policy changes laid out by the ACP took effect. Several were specifically designed to change this sort of behaviour. The text from the ACP's *Advisory to Shipping No. A-29-2018* that addresses the practice of buying booking slots without intending to use them reads:

> *This practice is detrimental since it creates the perception that the Panama Canal does not have the capacity to handle the actual LNG demand, affecting not only the best interests of the Panama Canal Authority (ACP) and the LNG industry, but of other customers as well. These modifications will allow the Panama Canal to better handle the present and expected demand for LNG vessel transit slots by providing the certainty and flexibility required by the LNG market segment.* (Canal de Panama, 2018)

Beginning on 1 October 2018, some navigational restrictions were lifted that enable several LNG vessels to inhabit Gatun Lake. That means that the Panama Canal will be able to transit LNG vessels in different directions on the same day, contrary to recent practice. As a result, the maximum number of LNG vessels has been increased from one to two per day, either two northbound or one northbound and one southbound.

According to recent communications with the ACP via the Embassy of Panama in Washington, DC, 'the beam of vessels allowed to transit at night has been increased, depending on the type (Advisory to Shipping A-31-2018). For example, container vessels of up to 335.28m length overall will be able to transit at night if their beam is less than or equal to 43.28m. This will help liberate some slots during daytime, improving Canal capacity overall.' This method of increasing the LNG transit capacity is a direct response to frustration from US LNG transport companies, who insisted that safety regulations limiting nighttime operations of their vessels in the Panama Canal were too strict.

Another major regulatory change made by the ACP that will have a direct effect on the Asian LNG market was made in the way their slot booking process works. A special booking period 1a in between Booking Periods 1 and 2 was created for LNG vessels 80 to 22 days before the transit date in which LNG vessels specifically will have one slot allocated to them (Canal de Panama, 2018). That time frame is also important, as, under the previous system, Booking Period 1 was sold 365 days before the transit date, which was a limiting factor on the flexibility of LNG and a variable that hindered the liquidity of the spot market.

Finally, cancellation of slots for LNG vessels will incur an additional fee on top of cancellation fee. LNG vessels that do not cancel and fail to arrive by 0600 on their booked date will be charged a cancellation fee and an additional fee of US$35,000. Also, if the vessel fails to arrive within 5 days of the booked date, the customer who booked the slot, 'will be penalized with the reduction of 0.5 transits in the transit portion of the customers ranking' (Canal de Panama, 2018), which may affect their ability to win future slots. To avoid accidentally penalising customers who are missing their booked slot or were late for valid reasons, the ACP has added that the above penalties will not apply if the, 'vessel's late arrival or cancellation of the reservation is due to a medical or humanitarian emergency, fortuitous event or force majeure' (Canal de Panama, 2018).

It is difficult to precisely estimate the shipping volume capacity expansion from the regulatory changes enacted by the ACP. What is clear is that Panama has addressed the concerns of LNG customers, and has eliminated both unfair practices and physical limitations of their vital portion of the LNG transportation infrastructure. LNG shippers and buyers should continue to engage the ACP on a regular basis so that operations can be adjusted to shifting patterns of LNG transit requirements.