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US LNG: window of opportunity

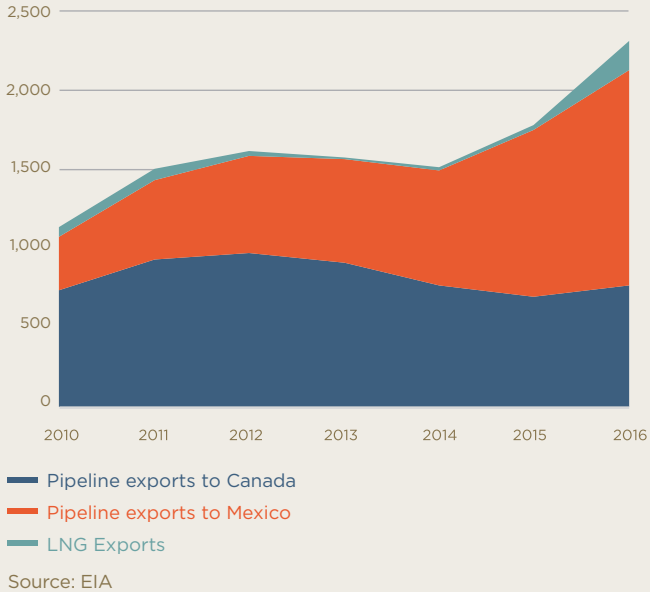
The US has emerged as a potential LNG giant in a field already populated with major players including Qatar and Australia. President Trump's plans to reduce red tape and speed up industrial development could give the US a further competitive advantage. But, for investors, the attraction of the country's LNG-export business is built on assumptions around long-term gas-price arbitrage windows between Europe, the US and Asia; sustained demand growth in target markets; and weak competition from pipeline gas suppliers and other energy sources. These assumptions bear fresh scrutiny. While it is true that US LNG will boast structural competitive advantages, the global gas market looks crowded out beyond 2020. Whether gas is ultimately viewed as a bridging or a destination fuel in a carbon-constrained global economy will also be critical to the success of the US LNG push.

The past decade has yielded dramatic changes in the global natural gas industry, with the rapid progress of fracking technology in the US driving a surge in gas supply and lower prices. An industry-friendly White House will give additional boosters to an industry already expanding at a breakneck pace. High rig counts have vastly expanded estimates of technically recoverable tight gas. The US Department of Energy (DOE) cites a conservative figure of 18.8 trillion cubic metres (cm); some assessments put the figure more than three times as high. According BP's latest Statistical Review of World Energy, proven reserves of conventional gas now stand at over 10.4 trillion cm, a 75% increase since 2006. The US is now the world's largest gas producer, supplying about 767bn cm in 2015, or nearly 22% of the world's total.

Regulatory bottlenecks ease

The discovery of additional gas reserves prompted the DOE and the Federal Energy Regulatory Commission (FERC) to approve several gas liquefaction plants and export terminals in 2011-15, six of which are now under construction. This followed the completion of the first phase of Cheniere's Sabine Pass (7.5mn tonnes per year, or t/y), the first LNG-export facility to be built in the US since Alaska's Kenai plant in the 1970s (see Figure 01). Earlier this decade, the DOE presented a bottleneck for export projects with proposals queued for licences to export LNG to countries lacking a free-trade agreement (FTA) with the US. A debate raged between proponents of US LNG exports, who argued that the abundance of shale gas resources should support uninhibited exports and opponents, and those who believed that allowing exports would disadvantage domestic consumers and manufacturing. The DOE responded by delaying licensing to non-FTA countries with a gap of two years occurring between the issuance of the first license for a lower-48 project in May 2011 (Sabine Pass LNG) and the second in May 2013 (Freeport LNG).

FIGURE 01: **US GAS EXPORTS 2010-16 (BN CUBIC FEET)**



Source: EIA

FIGURE 02: **STATUS OF US GAS LIQUEFACTION PROJECTS**

Project	Developer	Capacity (mn t/y)
Under Construction		
Cove Point LNG	Dominion Energy	6.0
Elba Island	Southern LNG	2.6
Corpus Christi	Cheniere	15.7
Freeport	Freeport LNG	15.7
Hackberry	Sempra/Cameron	15.4
Sabine Pass (ext)	Cheniere	20.6
Filed		
Calcasieu Pass	Venture Global LNG	10.0
Plaquemines	Venture Global LNG	20.0
Texas LNG	Texas LNG	4.0
Gulf LNG	KinderMorgan	10.0
Port Arthur LNG	Sempra/Cameron	13.5
Annova LNG	Annova LNG	6.0
Rio Grande LNG	NextDecade	27.0
Proposed (Not-Filed)		
Monkey Island LNG	SCTE LNG	12.0
American LNG	American LNG LLC	8.0
WesPac GulfGate	WesPac/Alturas LLC	1.5
Approved (No FID)		
Lake Charles	Magnolia LNG	8.0
Lake Charles LNG	Shell	16.2
Hackberry (ext)	Sempra/Cameron	10.0
Sabine Pass (ext)	Cheniere	4.5
Corpus Christi (ext)	Cheniere	4.5
Golden Pass	ExxonMobil/QP	15.6
Pre-Filed		
Corpus Christi (ext)	Cheniere	9.0
Driftwood LNG	Tellurian	26.0
Downeast LNG	Kestrel Energy	3.0
G2 LNG	G2	14.0
Freeport (ext)	Freeport LNG	5.0
CE FLNG	Cambridge Energy	8.0
Delfin LNG	Fairwood LNG	12.0
Alaska LNG	ConocoPhillips	20.0

Source: Company data

But in 2013-15, the DOE accelerated the pace of permitting. First, it issued eleven export licences in quick succession starting from May 2013 (see Figure 02). Then, in August 2014, it finalized a procedural change in its licensing process, processing applications only after projects had completed the FERC's environmental reviews. This change increased the likelihood that only serious projects with adequate funding would attempt to move through the DOE licence approval process, reducing the number of projects under review and speeding approvals.

The FERC, which supervises the construction and conversion of LNG terminals, is now focused on the six projects under construction. Two East Coast projects at Cove Point (Dominion Energy — 6mn t/y) and Elba Island (Southern LNG — 2.6mn t/y). The remaining projects all lie on the Gulf Coast, from Corpus Christi and Freeport in Texas to Hackberry in Louisiana. These are being developed by Cheniere, Freeport LNG, and Sempra/Cameron, respectively. In total, the three projects will add around 47mn t/y of export potential. In addition, there is a major expansion of Cheniere's Sabine Pass plant underway with two new 10.3mn t/y units.

By 2020, the US should become the world's second-largest LNG supplier

Six schemes are awaiting final investment decision (FID). These include three projects in Louisiana: two at Lake Charles (Shell — 16mn t/y; and Magnolia LNG — 8mn t/y), in addition to a planned extension (10mn t/y) of the Hackberry plant of Sempra/Cameron. In Texas, ExxonMobil and QP are to convert their Golden Pass LNG import terminal to an export facility (15.6mn t/y). Cheniere is to build a third phase at Corpus Christi (4.5mn t/y) and another at Sabine Pass (4.5mn t/y). Fifteen more gas liquefaction projects are now near, or at the end, of their FERC/DOE reviews. These schemes fall into two sub-categories: "filed" or under formal review; and "pre-filed", or under informal review.

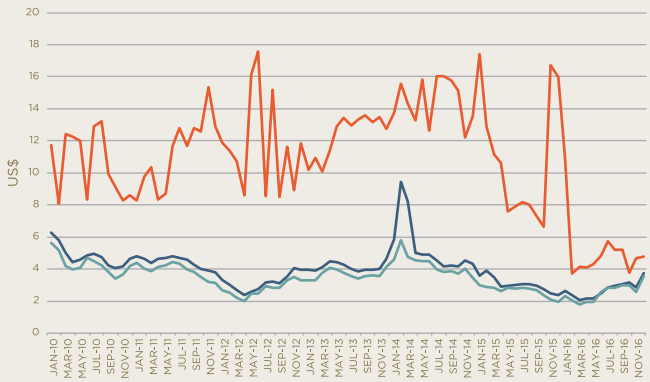
By 2020, the US is expected to become the world's second-largest LNG supplier with capacity of more than 83mn t/y coming from seven export terminals now under development. Approved projects would add a further 60mn t/y of capacity in the first half of the next decade. If all projects come on line as planned, the fifteen LNG export projects, which have been filed and pre-filed, could well provide an additional total capacity of more than 187mn t/y.

Price advantage?

While such projected number and capacity of US LNG export facilities are truly massive, closer examination of the projects reveals a more nuanced outlook. US LNG export projects are poised to compete favourably with comparatively low construction costs, especially for brownfield projects where existing import capacity is converted to liquefaction. Low US energy prices provide a construction cost edge and the country offers significant skilled labour at a reasonable cost. Moreover, US LNG pricing, based on Henry Hub, may give US projects a competitive advantage compared to oil-indexed pricing.

Yet these conditions cannot be guaranteed to continue in the medium term. On pricing, there are three assumptions that underpin US LNG investments. First, that Henry Hub prices will remain at historical lows and therefore cheaper than oil-indexed LNG prices used by most importers (see Figure 03). While Henry Hub prices are relatively weak, they have risen from their 2016 lows and are projected in most forecasts to rise steadily in coming years. Unless the cost of liquefaction, transportation and regasification can be reduced — and signs that they can are scant — marginal shifts in the US benchmark could become significant in determining how competitive US LNG is to importers.

FIGURE 03: **US EXPORT, HUB GAS PRICES 2010-16**



US Gas Pipeline Exports ($/'000 cf)
US LNG Exports ($/'000 cf)
Henry Hub ($/mmBtu)

Source: EIA

The second assumption is that prices in Asia and Europe will remain high relative to Henry Hub, creating the arbitrage window. While Henry Hub prices have remained historically low, at around $3 per mmBtu, spot prices in Asia and Europe have tumbled since mid-2014 to levels where it would be increasingly difficult for US LNG to be considered competitive. The fall in oil prices, softer economic growth and stiff competition from other energy sources has also undermined demand.

The third pricing assumption — that oil-indexed LNG prices will remain high, to the advantage of Henry Hub-based US LNG — is also shaky. When oil prices fell by more than 50% after October 2014, the fiscal solvency of many LNG projects was called into question. Even with prices having recovered somewhat, investors remain cautious about the economics of new LNG projects.

The rule of thumb for US LNG economics is that projects relying on $4/mmBtu Henry Hub are threatened when Brent moves below $60 a barrel, while $3/mmBtu Hub prices require Brent above $53. The reason oil prices matter so much is that global LNG is still 70% traded on long-term, oil-indexed contracts — just 15% of those contracts will expire in the next five years. Even these long-term contracts are becoming flexible, as demonstrated by Gazprom's move toward new market-driven tools and mid-contract renegotiations by other sellers.

Asian demand growth questions

Likewise, the fundamentals of global LNG look challenging for the coming five years. Additional US LNG will come on stream just as Asian demand growth slows and a supply glut worsens through 2020. The assumption that Asia, accounting for around 70% of all imports, is still the main global growth market, based on forecast rising demand from China and India, needs careful examination (see Figure 04).

China might be the world's largest incremental gas consumer and importer, but will rely more heavily on pipeline gas rather than LNG in the years ahead. In 2014, China signed a $400bn gas deal with Russia, comprising a framework whereby Gazprom would start supplying huge volumes of piped gas in 2019 for 30 years. The two countries share a 4,300km border making a gas alliance between Russia, holder of the world's largest gas reserves and the world's second-largest producer, and China, the world's largest energy consumer, a natural match. It is likely that disagreements between the two on price and route will eventually be ironed out.

While China could more than double its gas demand by 2020-22, those best positioned to meet that growth are pipeline suppliers. Turkmenistan has committed to maintaining its market share of Chinese gas imports and the rest could well be supplied through Russian pipes. Suppliers including Kazakhstan could also enter the Chinese gas market.

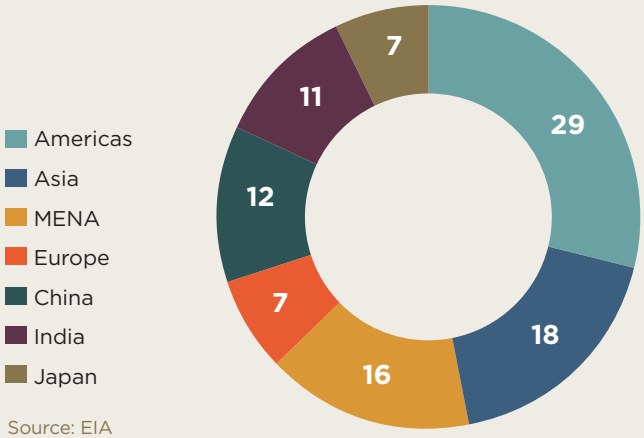
Other factors that may limit China's LNG imports include rising domestic conventional and tight gas output. Domestic gas production has boomed over the past decade, up nearly 175% between 2005 and 2015 to about 140bn cm per year, based on a solid 3.8 trillion cm of proven reserves. In addition, China holds the world's largest recoverable shale gas resources, estimated at around 31.6 trillion cm, according to the US Energy Information Administration. The development of this resource in China will be critical to the prospect for LNG in the country. Meanwhile, China will continue to burn more coal, more cleanly and more efficiently.

Even after COP21, LNG import leaders Japan and South Korea are also using more coal, with a combined 60 new coal plants set to be built over the next 10 years. Coal for power in Asia is cheaper than LNG. Accenture estimates coal-fired electricity costs just $0.05 per kilowatt-hour (KWh), compared with $0.11/KWh for LNG. COP21 commitments, serving to depress demand elsewhere, could perversely lower its cost further, driving more use in Asia. Nuclear power, priced at just $0.04/KWh, will also spur growth in South Korea, undermining the case for LNG.

As a key growth market, India has sought to diversify away from its dependence on LNG imports, where it is 90% reliant

on Qatar. It has inked a $20bn deal to invest in Iran's oil and gas industry and is moving towards a $40bn gas pipeline project with Russia (although this project would be complex). India's gas demand has also fallen in recent years, down by about 18% between 2010 and 2015. And just like China, India is also installing some of the most efficient coal plants with its Ultra Mega Power Projects programme.

FIGURE 04: **US LNG EXPORTS BY DESTINATION IN 2016**



Source: EIA

Europe's competitive market

In Europe, LNG competes with cheap coal, strong support for renewable energy and competitive piped gas from Russia, Norway and Algeria. Existing gas suppliers can be expected to reduce prices rather than give up market share if threatened by a wave of competing US LNG. Of the nearly 70% of gas demand in the EU that comes from imports, about 85% arrives by pipeline. Russian piped gas, now constituting 30-33% of these supplies, will remain the largest source of external gas in Europe, and with the export infrastructure already in place, Russian gas is cheap and its operating costs are low.

With domestic demand in decline, Russia needs the European gas market: the EU is buying 80% of Gazprom's sales. As long as new Russia's gas-export projects take time to arrive, Gazprom's imperative will remain to protect its share of the key European market.

Russia's ability to produce additional gas to meet any growth in European demand is clear. Gazprom's core European contracts run beyond 2025 and it has shown willing to be flexible on price when it perceives threats. Its cost of production is also low and falling — from $1.20/mmBtu in 2013 to $0.84/mmBtu in 2015, giving it ample capacity to undermine US LNG economics if it chooses. US LNG's capacity to penetrate the European market is likely to come down to Russia's pricing strategy or the willingness of European countries to accept higher prices to reduce their reliance on Gazprom. The Eastern European market is where US LNG is mostly needed to reduce reliance on piped Russian gas, although LNG import infrastructure is scarce.

There are other structural hurdles for European gas. Efficiency gains, renewables and weak economic growth have led to the contraction of the continent's gas demand. Brussels policymakers have made it clear that their energy policies are driven by renewables and efficiency, not natural gas, regardless of the cost.

One growth market that should not be overlooked is the Middle East, where the International Energy Agency forecasts gas demand to more than double by 2030. Middle East countries are increasing their LNG imports and US supplies could provide a high level of supply security and would also be favoured for geopolitical reasons. So long as inter-regional gas supply initiatives remain stunted, US LNG may find a home.

Competition from other growing supplies could also affect the development of US LNG. Australia has invested over $250bn in its sector since 2009 and capacity now stands at 60 MTPA and will reach 85mn-90mn t/y by 2019. The country is also installing floating liquefaction to monetize as much as 2.8 trillion to 3.2 trillion cm of offshore stranded gas. Australia benefits from lower shipping costs and times to Asia (7-10 days) and its projects will be up and running before most US capacity arrives.

Qatar, which is looking to expand LNG supply over the next decade, already exports 77mn t/y and is also well-positioned to ride out low prices as it focuses on efficiency and lower costs. About 33% of Qatar's export LNG volumes are currently unsold and could push out many of the higher-cost suppliers in the spot market.

Conclusion

In short, the outlook for US LNG is more complex than the bullish headline expansion story suggests. For the country's new liquefaction projects, timing will be crucial. US LNG export projects are not competing with current LNG but for the market share that will emerge from future demand growth. Planned US projects will not go into operation until 2020-25, by which time global markets are expected to tighten.

At that time, oil-indexed LNG contracts will start to expire, which should create a window of demand for US LNG. There are additional drivers of demand for US LNG including price transparency, diversity and flexibility in LNG supply and destination, and above all security of supply, as utilities prioritize reliability.

While the US regulatory process has accelerated, and could ease further under the present administration, the challenges to the build-out of a world-scale US LNG sector are mostly exogenous. Even if Henry Hub prices stay close to historical lows, the erosion of the Asian premium and the growth in spot trading will reduce the pricing advantage for future US cargoes. Long-term weakness for oil prices could also underpin a new favourable era for oil indexation, reducing the attractiveness of Henry Hub pricing to international buyers. Assumptions about the progress of tight gas recovery outside the US are also key.

China's record to date on shale gas development has been unsteady — but a strategic shift in favour of speeding development of its vast resources could pivot domestic demand away from LNG imports over the longer term. Finally, US LNG will have to compete increasingly with renewables, where costs continue to fall, and with new electrification efforts — a critical issue that will decide whether gas is a short-term answer to energy needs or a long-term destination fuel.