

## Is U.S. LNG Competitive?

By Michelle Foss and Gürcan Gülen

### FROM "NEED TO IMPORT" TO "MUST EXPORT"

As late as 2007, many believed that the U.S. would need to import LNG to compensate for declining conventional natural gas production in the country (e.g., 2007 Hard Truths report by the NPC). Four new regasification (import) terminals were built and the capacity of existing facilities was increased in the 2000s. However, the expectation of increasing prices for natural gas also lured new investment to domestic geologic plays, including emerging shale gas locations. With the turnaround in domestic supply, imports were no longer needed, and U.S. natural gas prices collapsed by mid-2009. Despite occasional spikes, the Henry Hub spot price averaged \$3.64 per MMBtu since that time through the end of 2015 with extended periods below \$3 (Figure 1).

By contrast, global conditions appeared to be moving in a different direction. Outside of the U.S., LNG importing countries typically purchase natural gas via contract pricing indexed to crude oil. Oil prices had recovered fairly quickly to \$90 per barrel by the end of 2010, at which time the Brent price started to diverge from the WTI benchmark in the U.S. for a variety of reasons. Until late 2014, oil prices remained generally between \$90 (WTI) to \$110 (Brent) per barrel. Perhaps, more importantly, throughout this period, forward curves were indicating the persistent expectation of high oil prices. The gap between Henry Hub and global natural gas prices (delivered via pipelines or as LNG) encouraged the idea of exporting excess natural gas production from the U.S. The increase in LNG prices in the Asia-Pacific market following the Fukushima accident in Japan was also an important driver for LNG exports from the U.S. as well as other global developments including Australia and Papua New Guinea. Owners of new LNG import, regasification, and storage capacity built in the U.S. in the 2000s had incentive to enhance the value of their now mostly idle facilities.

For a while, public discussion and media coverage focused on the Department of Energy (DOE) permits to export. This focus was somewhat misplaced. DOE permits for exporting to countries, with which the U.S. had a free trade agreement (FTA), were routinely granted to project developers. More than 30 applicants received these permits. The permitting of exports to non-FTA countries was crucial as most of the likely buyers in Europe and Asia were in this category. Nonetheless, the DOE permit is only one of many permits in a long process. The environmental impact assessment and other studies necessary for the Federal Energy Regulatory Commission (FERC) review, and any other permits that might be required by local authorities were more expensive and time-consuming. Pursuing a DOE permit before at least some of these more demanding requirements were met was probably necessary for developers and customers to feel confident that natural gas from the U.S. could legally be exported to those countries. But, this process became unacceptable to the DOE. Since August 2014, the DOE requires the FERC environmental impact assessment to be completed before considering non-FTA export permits.

At the time of writing (late April), seven terminals received eight permits to export LNG to non-FTA countries. All have FERC approval. Construction to expand the Sabine Pass terminal, originally built in the 2000s to import LNG, to include liquefaction and export facilities was initiated in August 2012. The first train was completed and the first cargo was shipped in late February 2016. At the time of writing, seven cargoes were shipped. Although significant symbolically and in terms of providing some price

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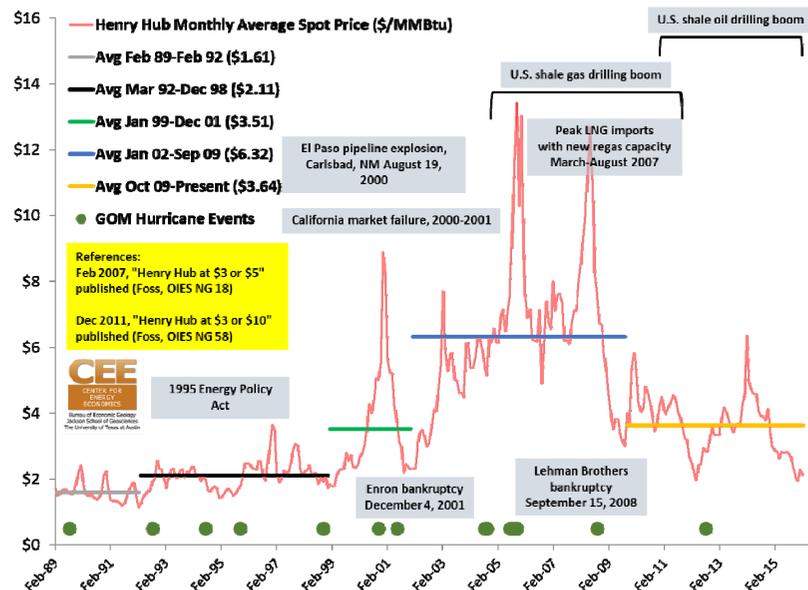


Figure 1. History of Henry Hub Spot Price

relief at Henry Hub (5-10 cents per MMBtu according to some market analysts), these cargoes represent a fraction of the first train's send-out capacity. Two more trains are expected. Construction in four other terminals started in late 2014 or early 2015. These facilities are expected to start producing LNG at various times from late 2017 through 2019.

#### NORTH AMERICAN DEMAND AND SUPPLY CONSIDERATIONS

It is important to underline that DOE permits do not imply any guarantee by the U.S. government that supplies will be available to buyers, who should be fully aware that they are exposing themselves to the volatility of the gas-on-gas competition in North America. The share of natural gas in power generation has been expanding significantly, driven, to a large extent, by cheap natural gas and the retirement of large capacities of coal and nuclear plants across the country. Environmental regulations and market conditions are expected to force more base-load capacity and older cycling units to retire. Our electricity dispatch modeling suggests that gas burn in power generation can increase by 5 BCFD (about 25%) by 2020 relative to 2013-14. Industrial use of natural gas in the petrochemicals sector and other facilities has been increasing as well. Our petrochemicals projects database, which covers primarily Texas and Louisiana, indicates the potential for several BCFD of new demand in the next couple of years. Finally, pipeline exports to Mexico have been increasing significantly, averaging 2.9 BCFD in 2015 and surpassing 3.2 BCFD in early 2016. With new pipelines under construction, and gas and power sector reforms in Mexico, pipeline exports may double by 2020. Although there are uncertainties associated with these expectations (especially in the power sector), these volumes add meaningfully to a U.S. natural gas market of roughly 73 BCFD (annual average).

On the supply side, all of the added capacity to monetize U.S. domestic gas production must be viewed through the lens of reductions in supply as the upstream cycle follows an inevitable path of adjustment. Low oil and gas prices finally seem to have led to natural gas production plateauing in early 2016; oil production started to decline in early 2015. A great deal of pressure exists on upstream operators to rationalize their businesses and reach solid footing on a financially sustainable basis.<sup>1</sup> About 100 companies declared bankruptcy and more bankruptcies are expected; capital budgets have been cut 50% or more. The decline in oil prices forced the operators as well as oilfield service companies to become more efficient and reduce costs, often pushing beyond maintainable efficiency gains. Including the support services, the oil and gas industry laid off close to 400,000 employees globally, a large portion of which occurred in the U.S. unconventional industry. It is safe to assume that all of the cost decline is not permanent. Given the historical relationship between the oil price and upstream capital and operating expenses, we expect a noticeable and rapid increase in costs as the oil price recovers (e.g., 30-35% of the increase in the price of oil from current levels). Accordingly, the future pace of drilling is highly uncertain even when the natural gas price recovers to \$3 or more.

Since the collapse of the natural gas price, operators increased efficiencies and high-graded acreage to best locations, nearly always targeting locations with liquids that could improve realized values. They drilled in-fill wells and reduced levels of water and proppant to manage costs of completing wells with hydraulic fracturing. They followed similar completion techniques in cluster drilling of new acreage.<sup>2</sup> These short-term responses might have helped to sustain drilling but potentially at the risk of exhausting good acreage that could have been developed with higher recovery factors in the future. The remaining acreage is not likely to be fully drilled. Financial rationalization in the industry will ultimately lead to consolidation. Companies emerging from this phase will hold on to the best acreage and discard the lowest productivity areas. Without robust liquids price signals and suitable margins, drilling investment that has yielded the cheapest incremental source of gas supply – associated gas or non-associated gas that includes sufficient ethane for value added – will not continue or return at the pace we have seen in recent years. This implies that a gas price signal sufficient to support drilling and exploitation in dry gas locations must eventually be detected. Based on our analysis of producer costs since 2009, we believe that a minimum price to support dry gas drilling investment in many locations is \$3.50-4.00; many others will require a higher gas price. The increase in drilling and completion costs resulting from the recovery of oil prices will further support the need for a higher gas price as will the need for better technology and completion practices required to develop lower productivity acreage, without which expected gas demand growth might not be fully satisfied with domestic resources by the mid-2020s.

#### IMPLICATIONS FOR U.S. LNG EXPORTS

It is useful to discuss several scenarios to capture the intricacies of how North American and global

market forces can interact in the future (Figure 2). The “Attraction” of U.S. LNG exports since 2010 was realized in an environment of low Henry Hub prices (represented as \$3/MMBtu) and high natural gas prices in Europe (around \$10 at National Balancing Point in the UK) and very high spot LNG prices in the Asia-Pacific market, driven by Japan’s need to substitute for shut-down nuclear generation. Note that U.S. LNG would not have been competitive today even with \$3 Henry Hub given landed prices averaging around \$4 in recent months and \$4 breakeven price for the Gorgon facility in Australia unless one treats the take-or-pay liquefaction fees as sunk cost. Henry Hub price has been below \$2.5 since the beginning of 2016, which helps shipments from Sabine Pass be competitive. Also note that shipping costs are roughly half of what they were in 2014.

However, per our North American demand-supply discussion above, we do not expect the Henry Hub price to stay low in the long-term. Given our expectations of increased gas use in the power and industrial sectors, increasing exports to Mexico and via LNG, and pressures on the upstream segment, \$3 by 2017 and \$4 by 2018 are strong possibilities. Without the support of higher oil and liquids prices, operators’ need for higher natural gas prices became more acute. An increasing number of analysts are suggesting, and our work indicates, that a \$3-\$3.5 price range could emerge by the summer of 2017. The CME forward curve (April 28, 2016) reflects a similar market view, staying around \$3 +/-0.25 between December 2016 and March 2018. Interestingly, to the extent that expected growth in natural gas demand from electric power and industrial sectors and exports to Mexico are realized within the next few years, any sustained volumes of LNG exports within the same timeframe will likely have a disproportionately strong impact on the Henry Hub price as they will represent marginal volumes, undermining their global competitiveness.

Accordingly, we evaluate scenarios of \$4 (“Cost of Supply”) and \$5 (High Cost). In these scenarios, it is difficult to see how U.S. LNG can compete even if one treats liquefaction fees as sunk cost unless the oil price recovers to \$80 or more. Even then, the global LNG market will be in excess supply until the early 2020s. There has been a surge in new liquefaction capacity in recent years with more facilities planned. Projects under construction will take global LNG supply to 388 million tonnes by 2022, an increase of 140 million tonnes compared to capacity in 2015. In contrast, demand growth has been less stellar and there are signs that natural gas demand cannot reach levels expected in some forecasts. Emerging economies have been growing at slower rates with attendant negative multiplier effects on the rest of the global economy and energy demand. More directly, investment in coal, nuclear, and renewables have been increasing or at least maintained, constraining the need for natural gas in power generation (e.g., gas-fired plant utilization in China has been 30% or less in recent years). Our in-depth review of natural gas market development in China and India confirm these trends and raises questions regarding the expansion of gas use in other sectors given regulatory and physical infrastructure shortcomings.

Often, contracted volumes are seen as evidence of actual volumes that will be exported out of the U.S. facilities. However, 15-20% of liquefaction capacity remains unsubscribed and about half of the contracted volumes are not tied to specific destinations. Global LNG trade has a sizable short-term market, representing about 28% of the total volumes since the Fukushima accident. The share of the short-term market grew from zero in 1994 to 20% just before Fukushima. As Japan re-powers its nuclear fleet as expected, short term deliveries will decline; slower economic performance already led to a drop in Japanese LNG imports.

Access to U.S. LNG might be a good option to have at hand for global LNG traders to take advantage of arbitrage opportunities that appear throughout the year. As always, “optionality” must be financed, and it is not cheap. Thus, a persistent question as the LNG industry evolves is which market participants

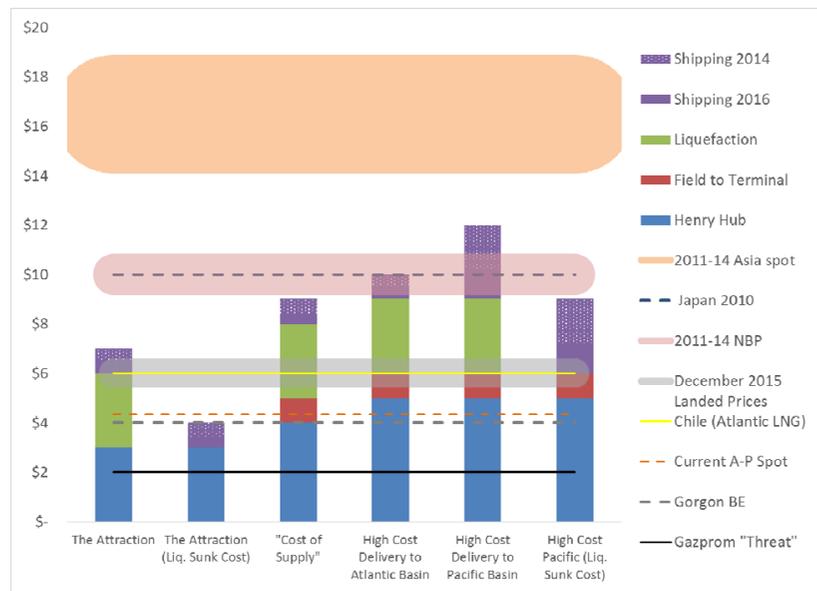


Figure 2. U.S. LNG Scenarios

have and will have the strongest balance sheets and sources of financing to engage in such risk-taking for commercial portfolios. Even the state-owned buyers such as GAIL (India) and KOGAS (South Korea), which are often driven by energy security concerns, have traded some of the volumes they contracted at U.S. terminals. These actions are taken at least partially because gas demand has not grown as expected and can stagnate in the future (e.g., because of new coal and nuclear capacity in South Korea).

In this excess LNG supply environment, not only do short-term prices fall, oil indexation also is renegotiated to reduce the impact of the oil price on the price of delivered LNG. In the European market, which is emerging to be more attractive for U.S. LNG, price competition by Gazprom cannot be ruled out (see Gazprom "Threat" in Figure 2).

In conclusion, market forces in the North American natural gas and global LNG markets are moving in opposite directions. It is likely that North American prices will increase while global LNG will be under strong downward pressure until the early 2020s even if oil prices recover sooner. In that case, the U.S. LNG exports will likely be seasonal with low capacity utilization through the early 2020s and the U.S. could well find itself serving as host for surplus LNG that needs a market in which to land. It has long been thought that LNG cargo receipts could serve to shave peaks in U.S. gas prices. Such a turnabout would be a boon to U.S. customers, but a surprise for many others.

#### Footnotes

<sup>1</sup> See CEE Research Snapshot "Upstream Matters! 2015 Update" at <http://www.beg.utexas.edu/energyecon/thnk-cnr.php>.

<sup>2</sup> See Bureau Shale Studies at <http://www.beg.utexas.edu/research/programs/shale>.

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