The impact of US LNG exports on global markets

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Despite its relative maturity as a gas producing province, the USA has defied the expectations of market participants and observers over the past two decades. Figure 9.1 shows the make-up of supply to the US market comprising: US gas production, Canadian pipeline imports (net), net LNG imports, and pipeline exports to Mexico (net).

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Increasing demand for natural gas in the 1990s was supplied by growing US production but also required an increasing contribution from Canadian pipeline gas imports. US gas production going into decline from 2001 came as something of a shock; the Henry Hub price rose accordingly and served to 'ration' supply for much of the early to mid-2000s (Figure 9.2).

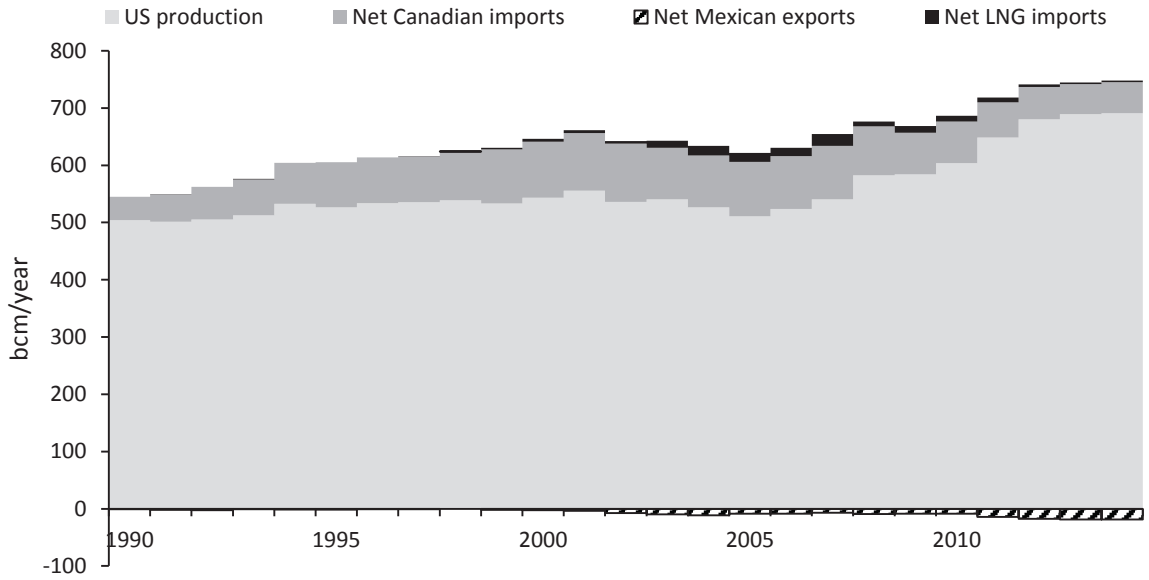

Figure 9.1. US gas production, imports and exports, 1990–2014

Source: US Energy Information Administration

In the early 2000s, the prospect of an apparent future US burgeoning import requirement catalysed the development of new LNG supply projects, notably in Qatar, with the USA as a destination market. US LNG re-gasification import terminal capacity grew from 49.2 bcm/year in 2006 to 186 bcm/year by 2013, equating to some 25 per cent of the gas demand of the USA in 2014.

Unexpected development of US gas production

Meanwhile, back at the ranch – literally – US Independents, spurred by the high mid-2000s US gas price, combined the technologies of horizontal drilling and fracking to exploit the numerous US shale gas plays, with increasing success. Their combined efforts account for the unforeseen, but no less dramatic, increase in US gas production from 2007 onwards. Although US gas demand increased, especially in the power sector where gas at lower prices was able to displace coal, the surge in shale gas production was sufficient to markedly reduce LNG and Canadian pipeline gas import requirements. In a reverse of the situation of the early 2000s, low prices placed higher-cost producers under huge financial pressure. Operators

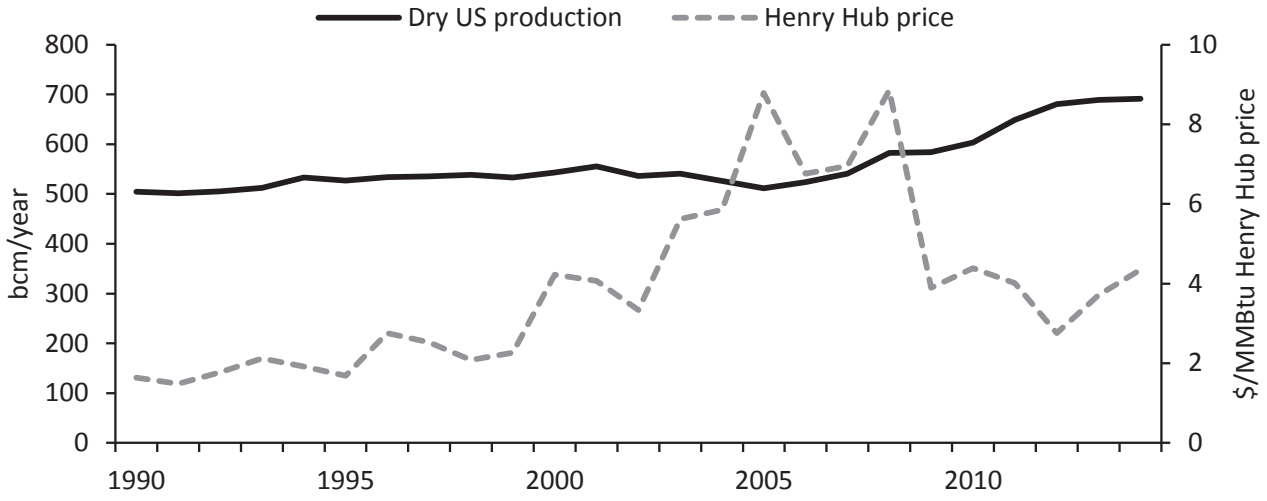

Figure 9.2. US gas production and Henry Hub price, 1990–2014

Source: US Energy Information Administration

tended to focus on plays with NGL co-production and hence more favourable investment economics. The commercial pressure to stay in business created a dynamic of technological innovation and cost reduction – possibly the only example in this era within the international upstream industry in general.

Switch from LNG imports to exports

Cheniere Energy are generally acknowledged as the 'first mover' in the race to gain government approvals and secure volume commitments to convert the ('built in haste' but subsequently under-utilized) LNG re-gasification import terminals to LNG export terminals. While this requires, in the case of Sabine Pass Trains 1 to 4, some $9 to $10 billion dollars of incremental investment to add liquefaction facilities to the existing import terminal, this figure is still significantly cheaper (per unit of output) than an international greenfield LNG project. The US Gulf Coast, in contrast to other potential LNG project locations, is also advantaged in terms of accessibility and availability of skilled, reasonably priced labour.

Sabine Pass is one of five US projects which have taken FID to convert re-gas terminals to export facilities, with an aggregate capacity of some 85 bcm/year. While the first Sabine Pass trains will start up in late 2015 and 2016, the later projects (Freeport, Dominion Cove Point, Cameron, and Corpus Christi) will commence production towards the end of the 2010s.

Utilization of gas from US domestic market for export

The US LNG projects are differentiated from their competitors in East Africa, Australia, Canada, and Russia in that they are essentially taking feed gas from the US transmission grid, rather than from a dedicated upstream field developed as an integrated element of the LNG project.

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The offtake agreements generally take the form of a fixed 'take-or-pay' tolling fee of typically $2.25 to $3.50/MMBtu (to remunerate the capital cost of the liquefaction investment) plus a charge of 115 per cent of the Henry Hub price, for the procurement of feed gas. Marine transportation and re-gas fees are the responsibility of the off-taker and/or downstream counterparties. This contrasts with the 'traditional' Asian LNG contract where the buyer pays a price for LNG linked to Japanese Customs Cleared crude price or (in the case of north-west Europe) a price related to a gas hub in the importing market.

US LNG is, therefore, attractive to midstream portfolio players or end-user market wholesalers who believe that future destination market reference or alternative prices (whether Asia, Europe, or South America) will have a spread to Henry Hub in excess of the 15 per cent procurement markup, tolling fee, and cost of transportation and re-gasification. This looked like a safe bet prior to the slump in European hub prices and Asian LNG spot prices in early 2014, and the collapse in the oil price (and hence Asian LNG contract prices) in late 2014. In mid to late 2015, however, it looks more questionable.

Effects on regional markets

With doubts around Chinese (and more generally Asian) future LNG requirements and at best tepid demand growth for gas in Europe, the LNG market at present looks markedly less bullish than it did in the early 2010s, especially with 85 bcm/year of new Australian LNG projects adding to an equivalent US LNG volume coming onstream by 2020. The 170 bcm/year of new Australian and US LNG exports represent a 50 per cent increase over 2014 global LNG trade.

With this as context, in order to understand the market dynamics of the next five to ten years, we also have to jettison some traditional mental gas industry 'baggage', specifically:

- Flexible LNG trade flows have created, and will continue to create, a more 'connected' global system. As previously anticipated regional demand paths change, this will accelerate the need for LNG destination flexibility.
- Oil-indexed LNG (and pipeline gas) contracts, once regarded as the 'gold standard' of the gas world, will increasingly be seen as an absurd indicator of gas market dynamics and, as oil prices recover, as a liability for midstream utilities who are encumbered with them.
- Erstwhile 'comfortable' regional oligopoly positions will come under attack as LNG volumes, seeking customers, undermine what were previously regarded as 'captive' markets.

The above points contrast with the comforting platitudes frequently aired at LNG conferences; but with justification. The 85 bcm/year of Australian LNG projects currently starting up or nearing completion have very high capital costs (especially in light of adverse exchange rate movements and cost overruns) and very low variable costs (specifically any uncontracted shipping costs). Even if Asian buyers renege on contract volumes, these projects will produce to their maximum capability in order to recoup capital outlays.

The 85 bcm/year of US projects under construction will similarly operate to maximum capacity, although with different dynamics. The tolling fee for the US LNG export facilities is a 'fixed' or sunk cost. Once these plants are built, exports will proceed providing that destination market prices exceed US prices by a figure representing at least the 15 per cent procurement fee, variable shipping costs, and re-gas costs. In plain terms, these US LNG volumes will move to market, provided European Hub and Asian LNG spot prices are at least some $2 and $4/MMBtu, respectively, above Henry Hub.

With 200 bcm/year of re-gas capacity (utilized at less than 25 per cent in the period 2012–14), Europe is the obvious destination for LNG which is 'unwanted' in other markets. However, this will create problems for other European supply sources; with UK and Dutch production in decline, declining future pipeline export volumes from North Africa, and Norwegian production in all likelihood declining post 2020, the player with most to lose is Russia and, by association, those of its buyers still committed to long-term oil-indexed contracts.

Over the next five years we are likely to see LNG imports in Europe which lead to lower hub prices and which threaten the ability of buyers of Russian gas under long-term contracts to meet their contractual take-or-pay requirements. As the world's largest gas exporter, Russia could choose to take control of the emerging situation by moving to a position whereby:

- It moves its long-term contract delivery points to the established European hubs.
- It meets buyers' nominations with a planned mixture of physical gas transported from its West Siberian Fields and gas purchased from trading hubs by its Marketing and Trading subsidiary in London.
- In this way it can effectively set European hub and (by arbitrage) Asian spot prices.

Once rising demand has absorbed the current slate of new LNG projects, Russia could decide:

- whether to deter new LNG FIDs by demonstrating its willingness to maintain European and (by arbitrage) Asian spot prices below those necessary for future LNG project FIDs, or
- whether to maximize revenues in the short term by withholding physical volumes from the European market, raising prices but thereby encouraging competing supplies in the form of Canadian, East African, and new Australian LNG projects.

'WE APPEAR TO BE APPROACHING AN ERA WHERE THE NORMAL LAWS OF COMMODITY MARKETS ARE BEGINNING TO APPLY TO GAS AND LNG …'

In summary, the outlook for gas internationally has never been so 'interesting'. We appear to be approaching an era where the normal laws of commodity markets are beginning to apply to gas and LNG – long regarded as 'different and special'. This status has not served gas, as the lowest carbon intensity fossil fuel, particularly well to date in the minds of policy makers, especially in Europe. The challenge, albeit late in the day, is to demonstrate that gas is indeed a plentiful, low-carbon fuel, which global markets can supply, with low security of supply risk, through 'normal' market forces.