Global gas prices: A random walk or inevitable convergence?

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With many informed studies predicting natural gas to be the fastest-growing fossil fuel, in terms of global energy market share over the next few decades, it is nevertheless strange that perceptions of gas and its 'value' still vary so much across geography and supply chains. The relatively low energy density of natural gas, the relatively high cost of transporting and storing it – by pipelines or as a liquid (LNG) at minus 160 °C – has allowed many gas markets to remain separated by geography, with disparate price levels and formation structures. However, change is afoot. The huge disparities between regional gas prices at the present time has awakened the powerful force of 'enlightened economic self-interest'. Where this coincides with receptive government and regulatory policy we have the potential for the creation of new channels for gas trade-flows (through investment in infrastructure) by market players seeking to exploit regional price differentials. This paper examines how this dynamic, mapped onto today's regional gas price disparities might serve, through arbitrage, to bring about a more connected, if not convergent, global gas price system.

Regional gas prices 2007 to 2013

The chart opposite shows the key regional gas prices, and for reference the Brent price expressed in US$/million British thermal units (mmbtu), for the period 2007 to 2013. While prices were reasonably bunched in the 2008 commodities 'bull run' era, the post-2010 period has seen a marked divergence, such that by end 2013 Asian spot LNG prices were almost five times the US Henry Hub price.

With the build-up of shale gas production in the US running ahead of demand growth, the post 2010 period has seen Henry Hub prices below \$5/mmbtu. Although the trend since 2012 implies a slow recovery to levels where marginal dry shale gas drilling remunerates investment (in the range of \$5 to \$7/mmbtu) further price recovery will likely be slowed by coal-gas fuel switching in the US power sector.

New LNG supply capacity from Qatar and elsewhere came on stream in 2010 and 2011. Much of this was originally intended for the US. However, with shale gas production obviating the need for LNG imports much of this supply ended up in Europe. A combination of stagnant demand, plentiful supply and pro-market competition policy resulted in increased liquidity at European trading hubs and a significant spread between hub prices (represented by NBP) and oil-indexed contracted gas prices (brown dashed lines). Midstream utilities caught between these prices suffered significant financial exposure. A series of arbitrations and negotiated concessions led to a lowering of oil indexed prices for Russian imports while a significant proportion of Norwegian and Dutch supply moved away from oil to hub indexation. By end 2013 the difference between European hub prices and Russian oil-indexed gas (after concessions and rebates) was reported to be less than five per cent.

The average Japanese LNG price (blue) represents over 60 individual contracts linked to crude oil price and also spot cargoes. This price tracks Brent but with a lag, and has been above \$15/mmbtu since early 2011. The purple line is the Japan/Korea spot LNG price which, prior to the Fukushima accident (March 2011), was reasonably in line with European hub prices. A tightening of the Asian LNG spot market post Fukushima, when Japan's LNG import needs increased to cover the shutdown of nuclear power plant, resulted in high and volatile Asian LNG spot prices. Although much LNG supply has been redirected away from Europe towards Asia since 2011 one might suspect that Asian spot LNG prices are to an extent maintained by flexible suppliers ensuring sufficient LNG remains in Europe in order to maintain this 'Asian premium'.

The current state of play

The current situation can be best described by looking at the motivations of key groups of players and some of the key overarching uncertainties which may temper their business strategies.

The first group are the participants in the long list of proposed US LNG export projects to reconfigure import terminals through investment in liquefaction plant into export facilities. Some 70 billion cubic metres per annum (bcma) of export approvals have been granted to date with offtake agreements or Heads of Agreements for a total of 110 bcma. Sabine Pass is the only project currently with all necessary approvals in place and start-up is expected end 2015. Depending on the time taken for further project approvals the main 'wave' of US export capacity should come onstream around 2019. Even at a Henry Hub price of \$6/mmbtu these projects could deliver LNG to Asia at around \$12/mmbtu (attractive at today's oil-related LNG contract prices) and to Europe at current hub prices of around \$10.50/mmbtu.

In addition to US supply, there is very significant potential for new LNG supplies from Canada (West coast), East Africa, Russia and Australia. These are either greenfield projects or expansions in locations which will likely suffer high construction costs. To date such projects would have relied on traditional oil-indexed contract prices at crude prices above US\$100 a barrel to ensure project viability.

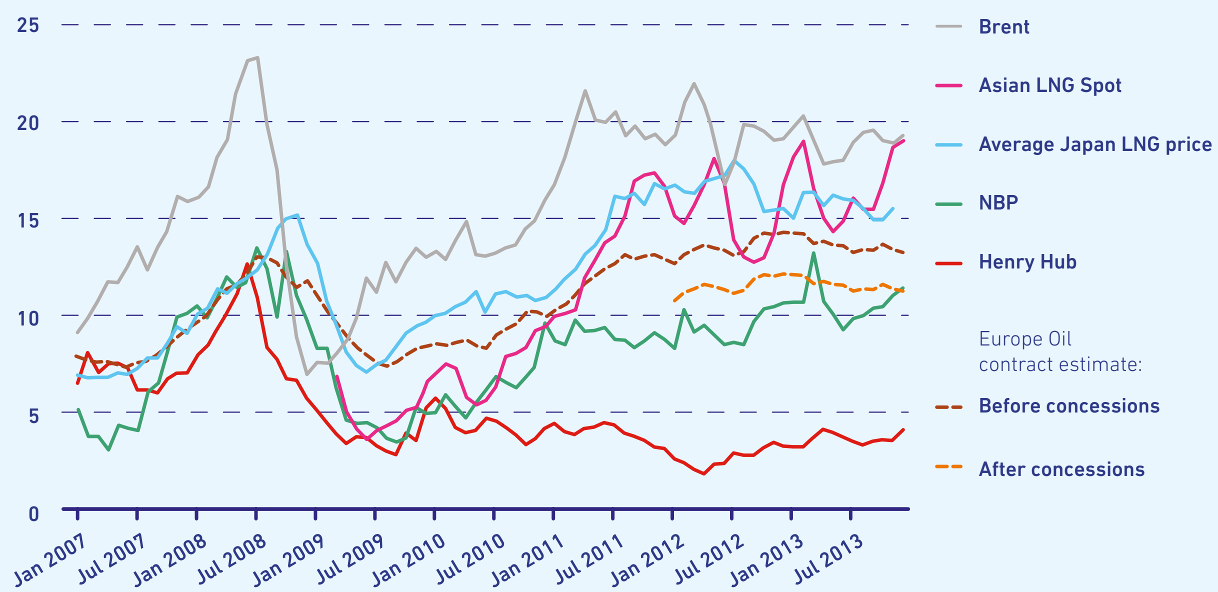
The third group of players, the Asian LNG buyers and in particular Japan, would welcome a reprieve from current contract and Asian spot LNG prices. At present (excluding TEPCO) the largest nine Japanese power generation companies are collectively losing US\$10 billion per year with nuclear plant closed and high LNG prices. Although there is a lack of consensus on what a more suitable price formation mechanism might be, prospective LNG volumes from the US priced at Henry Hub plus liquefaction and transport costs have much more appeal than new supplies at JCC contract prices from elsewhere.

The final player in this dynamic is Russia. While it has made concessions to lower prices in Europe from a 'pure' oil indexed price for pipeline gas, its position of market power (supplying 25 per cent of Europe's gas) is unlikely to materially change. With up to 100 bcma of production capacity headroom, it will probably become the 'shock absorber' in an increasingly connected international system. A change to hub-indexation for its contracts to Europe would still leave it in a position to influence European pricing through physical flow management. While high hub prices would be desirable the consequences would be a further reduction in demand and the encouragement of more LNG export projects in the US.

These players will be subject to two major 'known unknowns' over the course of the next decade, namely the future growth trend for Chinese LNG imports and the price-production response of US domestic producers. Chinese LNG import requirements are a function of future natural gas demand (highly uncertain) and the supply contribution from domestic production (including shale gas and coal bed methane), the scale of future pipeline imports from Turkmenistan and Central Asia and whether the much awaited agreement

Transporting LNG is the only way for linking the world's major gas markets

Regional Gas Prices 2007 to 2013 (US$ millions)



Source: Platts, EIA, Argus, Own Analysis

for pipeline gas from East Siberia will be signed. Thus the most significant fast-growing LNG market in the world is extremely difficult to forecast.

With the overwhelming majority of commentators betting on robust US shale gas production for decades to come, this is perhaps a strange uncertainty to highlight. Much of the current production surge is from wet gas shale plays including a 'backlog' effect in the Marcellus play where many wells have been drilled and still await pipeline infrastructure. As LNG exports from the US commence, will wet shale plays be sufficient to supply the additional volumes, or will the industry move back into dry shale gas areas – and at what price trigger? This US production price response will impact the spread between US and destination market prices and so impact the physical quantity of US LNG exports.

Prospects for Price Convergence

In a balanced market the emergence of material flows of US LNG and the actions of arbitrage could result in a world where Henry Hub is around $6/mmbtu, European hubs around $10 or $11/mmbtu and Asian spot LNG price around $12 or $13/mmbtu. Whether Asia moves away from pricing gas on Japan's TCC oil import prices by creating, in time, a liquid hub on which to base its future LNG contract reference price is a moot point. The commercial advantages conferred on US energy-intensive industries in such a world is obvious. The main driver of such regional price differentials is the cost of liquefaction plant, and to a lesser degree, shipping costs. Whether technological or competitive changes can reduce these fundamental costs of the LNG value chain is as yet unclear.

There is still room for great uncertainty. If Chinese LNG demand grows less quickly than expected we have the prospect of increased LNG volumes looking for a home in Europe, causing Russia to ponder whether to protect price or market share. A price war is a possibility which could reduce hub prices in Europe, the US and Asia in an attempt to reduce shale drilling in the US. Another possibility is that potential LNG projects other than those in the US delay investment into the 2020s in order to avoid competition with US LNG volumes. This would tend to amplify the LNG 'commodity cycle' on the supply side but also perhaps bring some much needed cost control and competition into this sector. ■