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The LNG market has seen dramatic shifts in its underlying fundamentals since the mid 2000s. In parallel with the rollercoaster of pricing, the rise of LNG spot and short-term trading, and the emergence of the USA as a source of 'destination flexible' supply, are just two of the many dimensions of the industry which appear to be in a state of flux, not least due to the imminent arrival of new supply from projects in Australia and the USA. In September 2016 OIES and KAPSARC publish *LNG Markets in Transition: The Great Reconfiguration*. This issue of the *Oxford Energy Forum* comprises articles from authors of several of the book's chapters and from its editor.

*James Henderson* describes the supply outlook; he starts with the dramatic scale of the new wave of Australian and US LNG both from facilities under construction and from those that have come on line since 2015. He describes how the rapid demand growth and rising oil and LNG prices of the early 2010s created the signal to reach Final Investment Decisions (FIDs) for US and Australian projects but how, during subsequent years, demand expectations and prices have fallen. While projects in both countries have low variable costs once completed, investment returns for Australian projects will be low until prices recover towards \$10 MMBtu. Offtakers

of US LNG selling to Europe at summer 2016 prices will cover variable costs but only a portion of the fixed, annual tolling fee.

In terms of the wider LNG supply landscape, *Henderson* then describes how the Cameroon project (which achieved FID in 2015) and the next phase of Tangguh in 2016 are rare examples of new projects moving forward, possibly to be joined by Fortuna in Equatorial Guinea in 2016. In the 2020s, resource maturity is likely to result in output decline for Trinidad, Indonesia, and Malaysia while in Algeria and Egypt, the more immediate problem is one of burgeoning domestic demand spurred by low prices which are only slowly being reformed. With the exception of Yamal LNG, sanctions and cost levels will hold back Russian LNG projects, while Iran will likely focus on its domestic and neighbouring pipeline export markets for most of the 2020s. East Africa, having no pre-existing hydrocarbon sector, 'missed the window' to monetize its giant early-2010s discoveries as has Canada, not least due to long pipeline distances between resource basins and liquefaction locations and the multi-level approval processes, including indigenous First Nation authorities. Qatar shows no sign of lifting its self-imposed North Field moratorium and hence can be assumed to maintain current output to 2030.

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In summary, even for those suppliers most advantaged in terms of cost base, investment and regulatory framework, and proven resource base, the key question is the timing of market rebalancing, and hence the prospect of prices rising to levels supportive of FID.

Asia has dominated the demand side of the LNG market for most of its existence. *Howard Rogers* reprises the range of demand trajectories for existing and potential Asian LNG importers. In the period to 2025 the key drivers are: the pace and extent of Japan's nuclear restart programme, and the rate at which China implements its policy of displacing a share of coal consumption with some 115 bcma of gas. In the case of India, the establishment of a gas market architecture allowing price and demand centres is needed to signal new supply through expanded infrastructure. At present this makes the country's future LNG requirement difficult to assess.

Through the 2020s there is significant potential for LNG import growth in countries facing resource maturity and the decline of domestic production. In general, however, there are few countries which have an explicit policy role for gas; GHG targets are, in many cases, assumed to be met by a combination of renewables growth and energy efficiency measures, creating headroom for continued coal consumption. The key opportunity for gas in Asia, however, is as an agent for improving the particulate pollution produced by coal and biomass combustion, which is a growing threat to public health. While the creditworthiness, investment framework, together with governance issues, may have ruled against LNG import projects in some countries in the past, the advent of Floating Storage and Regas Units (FSRUs) may prove to be an important enabler in this regard.

*Anouk Honoré* addresses the European market where, although gas demand has fallen since the mid to late 2000s, there is some potential for demand to recover modestly through the 2020s, as coal and nuclear generation plant are retired at a rate in excess of renewable capacity build. Europe's domestic gas production will continue to decline and hence the requirement for imports will rise. Europe has some 154 mtpa of LNG import capacity; in 2015 this capacity was utilized at only 24 per cent, and more is under construction. As such, Europe is uniquely placed to be able to physically absorb LNG surplus to the requirements of other regions, although we should expect Russia to defend its current 30 per cent market share. If Asian LNG demand growth is at the low end of the range identified, hub prices in Europe will fall to the level where the market 'clears'. One such mechanism would be the partial shutting in of US LNG supply – specifically that with the higher short-run costs.

Turning to South America, *Anouk Honoré* then describes the limited extent to which pipeline trade has served to integrate the individual national markets, with periodic failures to maintain export flows as planned/contracted. Supply reliability and, to a degree, geopolitical strains led individual countries to look to LNG to supplement pipeline supplies, with first imports in 2008. LNG importers Argentina, Brazil, and Chile will be joined by Uruguay and Colombia when their terminals complete construction. In 2015, the region imported 11 mt of LNG and this is expected to grow to around 15 mt by 2030 – but if Bolivian pipeline contracts are not renewed this figure could rise to 23 mt. And year to year variation in hydro availability in Brazil alone could require an additional 26 mt of imports on top of these figures. With limited (if any) underground gas storage, much of

this flexibility will be met by LNG, with implications for short-term impacts on other LNG importing markets.

While Compressed Natural Gas (CNG) has been adopted in passenger cars and buses in specific geographies, it is a moot point whether it will grow significantly in this sector, especially in the face of advances in electric vehicles. *Chris Le Fevre* sees greater potential for LNG rather than CNG in road trucking and marine transport. While the cost advantage for LNG varies with regional gas prices, it is clear that this advantage has eroded with the fall in oil prices since 2014, but a rise in crude relative to gas (hub and spot) prices could restore this margin. Equally important is the advantage held by LNG compared with oil products in terms of SO<sub>x</sub> and NO<sub>x</sub> emissions. While it is still 'early days', LNG transport sector (road and marine) demand could grow to between 25 and 50 mtpa by 2030.

*Brian Songhurst* appraises the development of Floating Liquefaction (FLNG). The cost and schedule overruns witnessed in many recent Australian projects highlight the industry's need to reduce its cost base, especially in light of current destination market LNG prices in 2016. The past ten years have seen the remarkable success of floating regasification units (FSRUs), with some 18 having entered service. Although the processing plant associated with floating liquefaction is more complex than that in an FSRU, and creates considerable challenges, FLNG is about to 'come of age', with the Petronas Kanowit unit expected to start up offshore Malaysia in 2016. Seven units are in construction, five will be offered on a leasing basis. While it is too soon to establish whether the unit cost of these vessels will be comparable with US Gulf Coast onshore liquefaction plant, they offer the attractions of shorter construction time and a 'controlled' shipyard



environment compared with onshore plant in remote locations, where labour availability and infrastructure are a challenge.

*Jonathan Stern* sets out the rationale for the differing historic pricing mechanisms for LNG and describes the period 2011 to early 2014 when, supported by contractual crude oil linkage and a tight LNG spot market post-Fukushima, LNG prices reached \$15–18/MMBtu – significantly higher than European hub price levels at the time. By 2016 the falling oil price, together with an increasingly well supplied market (and lower demand growth), has virtually eroded Europe–Asia LNG price differentials. During the period of high oil (and Asian contract LNG prices), the prospect of term purchases of US LNG on the basis of Henry Hub (plus ‘tolling fee’ and process fuel and shipping costs) looked an attractive alternative. However, this is less the case in 2016 as LNG spot prices (linked to European hubs through arbitrage) offer a much lower price. While the logical end point for pricing in Asia will be the creation of Asian gas and LNG hubs, this is likely to take five (and more likely 10) years, based on the experiences of North America and Europe.

The most promising locations – provided that governments and regulatory authorities implement the requirements necessary for completion of this process – appear to be:

- Singapore (possibly as a virtual regional LNG hub),
- Shanghai as a gas hub with diverse supply sources (domestic production, pipeline imports, and LNG),
- Japan (an LNG hub).

These requirements include: workable third-party access to pipelines and LNG terminals, price discovery, a critical mass of buy and sell side participants, and the development of a futures curve. Clearly the period to the early 2020s – with large volumes of spot LNG – is likely to see the end of the long-term oil-indexed LNG contract model, but whether this proceeds as a ‘smooth transition’ or a ‘contractual train wreck’ remains to be seen.

Finally, *Anne-Sophie Corbeau* argues that the LNG world is undergoing a ‘great reconfiguration’, not simply in terms of volume expansion but also in relation to regional development and changes in commercial models, as well as the dominance of long-term contracts. She suggests that the

LNG business may be approaching a ‘tipping point’ where LNG markets move towards greater commoditization; at this point, there would be no turning back to the traditional long-term contract model. Existing long-term contracts will not be (or will only be partially) extended; the decision on whether new projects take decisions to proceed without long-term contracts will depend on lenders accepting that short-term LNG trade will become the norm, with reliable spot price benchmarks and lower LNG costs supporting project economics. This should enhance the role of LNG in the development of flexible international gas trade, and hence make a major contribution to the increasing globalization of the gas business.

#### Note on units

In this issue (as in the book), LNG volumes are quoted in million tons of LNG per annum (mtpa) while gas demand is in billion cubic metres per annum (bcma). The approximate equivalent is 1 mt of LNG = 1.36 bcm of gas.

\$ refers to the US dollar



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## The supply outlook: Australia and the USA

James Henderson

High oil prices in the period 2010–14 combined with the impact of growing energy demand in China and the shock of the Fukushima disaster in Japan to create a world in which high LNG prices in Asia (often above \$15/MMBtu) catalysed a wave of new LNG investment. Australia was at the forefront of this wave, and was later joined by the USA, where companies saw an arbitrage opportunity to export the rising tide of cheap shale gas to markets prepared to pay a premium price. As a result, these two countries embarked on a period of construction that, by 2020, will see them having increased their LNG liquefaction capacity by 126 mtpa. Unfortunately, this expansion is being completed at a time when LNG demand expectations are being downgraded, and prices have fallen dramatically; this will have significant consequences for future projects in both countries.

### Australia

In spite of the impact of the current downturn in prices, the gas industry in Australia has much to be proud of. Australia is set to become the largest LNG exporter in the world by the end of this decade, with sales volumes set to reach 86 mtpa by 2019, moving the country up from its second position in 2015 to overtake Qatar. Seven new projects have been developed since 2009 and these have started to come on stream since early 2015, adding to the three projects already operating. Significant innovation has accompanied this surge in industrial activity, with the first coal seam gas (CSG)-to-LNG schemes in operation in Queensland, the first floating LNG (FLNG) project set to come online offshore Western Australia, and the largest carbon dioxide (CO<sub>2</sub>)

sequestration plant being built at the Gorgon field on the North West Shelf. In addition, the intense levels of construction and the spillover effects into the rest of the economy have significantly boosted Australian GDP. However, despite these successes, the intensity of the LNG expansion in Australia has also brought unique challenges, with demand for labour and equipment causing both sharp cost escalation and project delays. These factors, combined with the appreciation of the Australian dollar during the period 2010–13, have challenged the economics of a number of the schemes that are now coming on stream. This means that if the LNG price does not return to within a range of \$10–14/MMBtu, none of these schemes is likely to generate positive returns on a full cost basis.

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Despite these setbacks, the companies involved (who have spent a combined total of over \$200 billion) must generate cash to start the process of recovering their costs and servicing debt repayments, meaning that further extensive delays are unlikely. Indeed, the start-up of production at the three CSG projects on the East Coast since late 2014 underlines the fact that progress is being made. However, the industry’s growth thereafter is likely to stall as project developers struggle to generate sufficient cash to reinvest in new projects. Evidence for this is already clear in the number of possible new projects which have been cancelled or delayed in 2014 and

2015. Even brownfield expansions, which would normally be an obvious way of generating synergy from existing assets, are likely to be deferred until signs of an oil and gas price recovery emerge. Some good news can be found in the easing of cost and currency pressures on projects in production or under construction, but concerns are now emerging about the willingness of buyers to fulfil purchase obligations under current contracts. Although it seems unlikely that terms will be changed dramatically, it is clearly possible that if demand in Asia remains weaker than expected, offtakers may be forced to sell any surplus gas on the spot market, further weakening prices and competing with uncontracted equity volumes being sold by project developers. Such developments could further undermine project economics and act as an additional barrier to new projects, but it could benefit the Australian domestic market, where complaints over rising prices could be eased if spare gas becomes available. However, the federal and state budgets are set to suffer from lower tax revenues in a low-price environment, meaning that the Australian government is likely to have little opportunity to provide further investment incentives to LNG operators.

These factors suggest that we are reaching the end of the Australian LNG boom, although the extent of the country’s gas resources offers the potential for further, more modest, expansion in the mid-2020s once the current global LNG oversupply has dissipated. Indeed, while a pessimistic view would suggest that Australian LNG is likely to plateau at 86 mtpa for some years, there is clearly the potential for further brownfield expansion at the





current projects. While it is difficult to tell exactly which might take FIDs for new trains in the next five years, an upside case might see up to 20 mtpa of new capacity being approved by 2020 (to come online before 2025) as and when the oversupply situation in the global market looks to be coming to an end. It would therefore not be unreasonable to assume that, if gas prices head back towards a \$10–11/MMBtu range, Australia could be producing more than 100 mtpa of LNG by the middle of the next decade in a more positive investment scenario, given the lower cost of brownfield expansion compared to the recent greenfield developments that have dominated the Australian industry.

### The USA

The emergence of the USA as an LNG exporter has arguably caused the greatest transformation in the LNG industry in the past three decades. Not only has gas become available at prices related to a market benchmark (Henry Hub) rather than to the price of oil, but the traditional contractual model has also been challenged by the emergence of aggregators, who will purchase gas from liquefaction tolling plants and distribute it globally according to demand and price trends. As a result US LNG will provide consumers not only with new volumes of LNG but with an alternative, and competitive, marketing offer.

By mid-2016 the US Department of Energy had received 25 applications for new LNG export projects, offering potential future capacity of 311 mtpa. However, while most of these have received non-FTA approval for export sales, only six have received the more stringent FERC (the US Federal Energy Regulatory Commission) approval

### ‘... THE GLOBAL OVERSUPPLY OF GAS IS LIKELY TO CONTINUE TO THE END OF THE DECADE AT LEAST.’

which allows construction to begin. Of these, five (with a total capacity of 64 mtpa) were under construction and one (Sabine Pass owned by Cheniere Energy) is now in production. Numerous cargoes, including two bound for Europe, have been loaded, heralding the arrival of US gas onto the global market. The Sabine Pass liquefaction facility, like the four other projects under construction, is based at existing sites with regasification (import) capacity; this reduced the initial capital expenditure and meant that the tolling fee paid by companies who have contracted to take the LNG was a relatively modest \$3.00–3.50/MMBtu. As a result, the total cost of US LNG, delivered to Europe, can be calculated as: the US Henry Hub price (at present around \$2/MMBtu) multiplied by 1.15 (to allow for gas purchase, boil off, and fuel use) plus liquefaction, transport, and regasification costs. Given the current low rate of shipping tariffs, this effectively means a landed cost in Europe of around \$6.5–7.00/MMBtu.

However, this full cost is well above the current spot price either in the UK or continental Europe, which was approximately \$4/MMBtu in mid-May 2016. US LNG exporters may therefore be forced to sell their gas at a price that is close to the short-run marginal cost in order to compete – in other words treating the tolling fee as a sunk cost. On this basis, US LNG could be sold into Europe at a very competitive price (around \$3.50–4.00/MMBtu), but the consequences for offtakers could be profound. They will clearly not be

making a return on their investment, and will actually be losing money on a cash basis as they meet their contractual obligation to pay the tolling fees to the LNG plant owners – such as Cheniere. As a result, two interesting questions emerge:

- How long will they be prepared to continue selling LNG at a loss?
- Will there be any incentive to build new LNG export facilities in the USA?

The answer to the former would seem to be ‘at least a year or two’ given the robust nature of the counterparties involved, but the answer to the latter would equally appear to be ‘there will be little new construction activity beyond the existing committed facilities’. Some project sponsors continue to trumpet the prospects for their projects, and schemes such as Golden Pass, owned by ExxonMobil and Qatargas, may have some logic within a global LNG portfolio that can maximize synergy benefits between markets and supply. However, it must now be increasingly uncertain whether any other new projects will receive FID before the end of this decade, or before the gas price in Europe (and/or Asia) rises above \$7–8/MMBtu.

### Conclusion

As a result, although the growth of the LNG industries in Australia and the USA have transformed the global gas economy, their current state reflects the problems faced by the industry as a whole. Large projects are unlikely to make expected returns and some smaller project participants may go bust as a result. Nevertheless, the infrastructure has been built and will continue to produce while it can cover cash costs, meaning that the global oversupply of gas is likely to continue to the end of the decade at least.



# The prospects for future LNG supply outside Australia and the USA

James Henderson

As mentioned in the previous article, the main contributors to LNG supply growth during this decade will be the USA and Australia, but 18 other countries owned liquefaction facilities in 2015 (although not all were operational) and others have both short and long-term plans to join the industry. This article explores the plans of a number of those countries and also discusses the challenges being faced by existing and future producers.

## Challenges facing current exporters

One important emerging trend amongst current LNG suppliers is that a number are showing declines in exports, offsetting the growth trends in other countries. For example, domestic demand growth in Malaysia and Indonesia will see net exports fall, while a similar theme can be seen in the Middle East where Oman and Abu Dhabi have been importing pipeline gas since the late 2000s to supplement their own production. In North Africa, rising gas demand, encouraged by subsidized prices, has strongly impacted exports from all countries, while the volatile politics of the region are further undermining the ability of operators to maintain LNG exports, with Libya and Egypt having shut in their export facilities altogether.

Meanwhile in April 2015, Yemen declared force majeure on its LNG exports due to the civil war in the country, while a number of countries (such as Trinidad) are experiencing natural declines in output after many years of production. In addition, Chevron's 5.2 mtpa Angola LNG scheme has suffered operational issues and has been shut since 2014, but it may come back online in 2016.

Above ground risks are affecting the

outlook for Nigeria, where the possibility of additional LNG output is based on its gas reserves (which are the ninth largest in the world). However, while LNG exports increased in 2014 and 2015 after a number of disappointing years, poor governance and an uncertain legislative and judicial system do not encourage foreign investment, especially in a low commodity price environment. Nigeria's gas production is expected to be stagnant to 2020, and LNG exports will most likely remain stable or slightly decline.

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## Rare example of a new project and stable output in Qatar

On a more positive note in Africa, in 2015 Cameroon took FID for a new FLNG scheme, developed by Perenco and Golar to liquefy gas produced by GDF Suez and the Cameroon state oil and gas company SNH. The 1.2 mtpa plant is expected to commence operations in 2017, based on the timetable agreed by the project partners. In addition, existing supply from Equatorial Guinea, where Shell (formerly BG) is buying all the current output, could be supplemented by a second project run by Ophir. The Fortuna project has a 2.2 mtpa capacity and FID may be taken in 2016.

Within this volatile picture of existing producers the stability of *Qatar* remains a constant; in 2005 the country introduced a moratorium on further development of the North Field, limiting LNG output to 77 mtpa, and

it seemingly has no plans to alter its position in the foreseeable future. The country's low cost of production, estimated at below \$2/MMBtu (helped by condensate and LPG co-production), means that it is one of the few suppliers able to maintain robust margins despite the low prices seen in 2015, and it is set to remain one of the world's largest exporters for many years to come.

## Problems facing other producers

However, for other producers with the ambition to export the outlook is not so positive. Over the past few years eight new projects have been discussed in *Russia* (including one brownfield expansion), but a combination of high costs, uncertainty over sources of supply, the impact of sanctions, and reduced availability of investment funds has meant that many of these have now been delayed or effectively cancelled. Indeed only one (Novatek's Yamal LNG project) is likely to be online by 2020, while two others (a third train at the existing Sakhalin 2 project plus Baltic LNG) may be operational by 2025. This would take Russia's overall LNG output to 36 mtpa. However, it now appears that other projects, such as Shtokman and Vladivostok LNG, will be postponed until the end of the 2020s at least. One other notable aspect of Russia's LNG future is that Gazprom is unlikely to dominate as it does with pipeline exports, and it is conceivable that Novatek could become and remain the country's major participant in the LNG market.

In Eastern Africa, where discoveries in *Mozambique* and *Tanzania* have created the potential for major LNG developments, progress has slowed not only due to market conditions



but also because of the difficulties inherent in establishing the regulatory, legislative, and operational foundations for major investments in countries with a limited hydrocarbon industry. The upside potential in both countries is clear, but the need to resolve issues such as local content, domestic gas market development, and logistical support for major industrial developments, as well as the more fundamental tax and governance regimes, has meant that delays have been inevitable. We see no prospect of LNG production before 2020, but believe that Eni and Anadarko's projects in Mozambique could produce a total of 32.5 mtpa by the end of the next decade, while in Tanzania output could reach 15 mtpa on the same timescale. However, we also acknowledge that in a downside low-price environment, Tanzania could fail to develop an LNG export business altogether, while Mozambique's output could be limited to 10–15 mtpa.

Canada is another country facing the possibility of its LNG ambitions being severely limited by market conditions and domestic issues. Although theoretically 350 mtpa of new capacity has been mooted, no project has yet taken FID, highlighting the contrast with the situation in the USA. A major stumbling block is cost, as all the Canadian projects would be new greenfield schemes – as opposed to the brownfield conversions that account for many of the US projects. In addition, the projects on the west coast of Canada will rely on gas being brought by pipeline 1,500 km through the Rockies, across territory where negotiation with the indigenous First Nations population can be lengthy and expensive. On the east coast, meanwhile, the gas supply would come mainly from the USA, implying both infrastructure issues in the north-western US states as well as regulatory hurdles to be crossed

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**‘... CANADA HAS MISSED THE SHORT-TERM LNG WINDOW AND WE WILL NOT SEE ANY CARGOES FROM ITS PROJECTS UNTIL WELL INTO THE 2020s.’**  
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with the US authorities. Furthermore, project developers have been seeking to sign oil-linked, relatively high-priced, contracts with consumers who are now keener to use market-based mechanisms; this means that no projects have yet secured adequate sales contracts to move ahead. The overall conclusion is that Canada has missed the short-term LNG window and that we will not see any cargoes from its projects until well into the 2020s.

#### Potential for the future

Despite this rather negative outlook a few other potentially large new sources of LNG are emerging. The ending of sanctions against *Iran*, the country with the world's largest gas reserves, has led to a flurry of excitement about the rekindling of LNG plans at the giant South Pars field. To date Iran's gas has been used domestically or has been reinjected to sustain oil production, but if a number of IOCs can be tempted back and encouraged to invest, then gas exports are certainly feasible. However, current interest appears to be more focused on ensuring supplies for the domestic market, to catalyse GDP growth, and also on selling to regional markets that can be accessed via pipeline (and where it has already signed contracts – Iraq, Pakistan, and Oman). It may therefore be some time before LNG exports are approved. Furthermore, continued uncertainty over the future of Iran's relationship with the USA may undermine the confidence of IOCs in making multi-billion dollar investments in new long-term gas projects when shorter term returns may be made from refurbishing the country's oil industry.

Elsewhere, politics will also have a significant role to play in the possible development of LNG in the East Mediterranean, where discoveries offshore *Israel* and *Cyprus* could underpin the construction of a liquefaction plant. However, numerous issues remain, not the least being the impact of the conflict in Syria. Other concerns include the difficult decision of where to locate the plant, the potential for using underutilized facilities in Egypt, the option of piping gas to Jordan or Turkey, and the need to satisfy the domestic markets in both countries. Again, both above and below ground risks have been exacerbated by the gas market conditions since 2015, meaning that rapid development of an LNG project is unlikely.

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**‘ALL THIS POINTS TOWARDS COUNTRIES WITH EXISTING PROJECTS BEING ADVANTAGED WHEN IT COMES TO THE NEXT STAGE OF LNG DEVELOPMENT POST 2020.’**  
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#### Conclusion

Despite the clear impact of political events and other non-operational risks, the fundamental principles of LNG economics will ultimately form the cornerstone of the industry's future development. Brownfield expansion is likely to be preferred over greenfield development, thanks to the lower cost brought by synergy benefits. Developments in countries with stable fiscal and regulatory regimes will be preferred over those associated with significant political and fiscal risk. Access to low-cost sources of gas will remain vital, as will the size of the reserve base, while existing industrial infrastructure with high quality local contractors will remain an advantage.

All this points towards countries with existing projects being advantaged when it comes to the next stage of LNG

development post 2020. However, this does not mean that new regions cannot emerge and prosper, but it does mean that in order to succeed, governments will have to ensure that they offer terms that allow companies to make adequate returns in an increasingly competitive global gas (and energy)

market. They will also need to put in place secure regulatory regimes that encourage multi-billion dollar long-term investments. Again, this may suggest that the prospects for politically and commercially volatile areas (such as Africa, the Middle East, and Latin America) have been significantly

undermined by the current collapse in energy prices, meaning that brownfield expansion of existing projects in more stable areas is the most likely source of new LNG capacity, once the current oversupply situation has started to dissipate.



## LNG demand potential in Asia

Howard Rogers

The Asian LNG importing markets (and those expected to become LNG importers) loom large in the aspirations of LNG supply project investors.

### The mature Asian LNG importers

Japan, South Korea, and Taiwan commenced LNG imports in 1969, 1986, and 1990 respectively. As a group these 'mature' Asian LNG importers accounted for two-thirds to three-quarters of global LNG imports from 1980 to 2016. These countries have minimal domestic gas resources and depend on natural gas to differing degrees in their power and non-power sectors. All three markets have enjoyed economic growth based on export-oriented manufacturing and technology goods production; however, with the slowdown in Chinese growth and the limits to growth inherent in this economic model, there are questions regarding their future economic performance. Japan in particular is struggling to stimulate domestic demand in the face of ongoing deflationary tendencies. Declining population trends are also a relatively new challenge for these countries, threatening domestic consumption growth and workforce renewal.

The largest uncertainty impacting future gas (LNG) consumption trends, however, is that of future energy consumption growth and energy mix.

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**'AS A GROUP THESE "MATURE" ASIAN LNG IMPORTERS ACCOUNTED FOR TWO-THIRDS TO THREE-QUARTERS OF GLOBAL LNG IMPORTS FROM 1980 TO 2016.'**  
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With the challenge of GHG emission reduction, especially post COP21, strategies incorporating energy efficiency and renewables have been proposed and nuclear power generation aspirations constrained either by public opinion or (in the case of Japan) restart logistics and approval processes. While an indicative share for gas in the energy mix is often included in policy documents, competition with (cheaper) coal in the power sector is an open issue which requires a more robust policy framework than generally exists at present. Typically the planned continued growth of coal in the energy mix is offset by assumed future energy efficiency gains and aggressive renewable capacity growth. The reality of such aspirations will presumably become clear once the Nationally Determined Contributions agreed at COP21 are tracked by the Monitoring, Reporting and Verification process – albeit not until 2020 at the earliest. The issue of poor air quality due to particulate emissions remains a challenge in India and China. Displacing coal with gas could bring

major improvements in this area, though only China appears to have recognized this to date.

The key future LNG demand uncertainties for these countries are:

- *Japan* – the pace and extent of nuclear restarts could, in a 'smooth restart scenario', reduce LNG demand by some 20 mtpa. At present, the track record of restarts is not encouraging. The country's aspirational goals for energy efficiency and renewables growth would also reduce LNG requirements but goal fulfilment is questionable in practical terms.
- *South Korea*, like Japan, appears to be facing economic headwinds, dampening its energy consumption. In addition, the restart of nuclear plant after safety concerns, and higher coal burn in power generation, have reduced LNG demand. Government policy is tepid at best for LNG in the energy mix.
- *Taiwan* is determined to close its nuclear power generation capacity in the mid 2020s. Although committed to expand renewables, the main issue will be the extent to which gas fills the 'gap' – given COP21 constraints on additional coal-fired generation. LNG demand growth is likely to remain robust, albeit small in global terms.



### Other Asian LNG importers

In addition to the more established markets, the Asian region includes China and India where LNG, as an already established channel of gas supply, could grow to levels of major global importance. For more recently emerged and potential new importers such as: Singapore, Thailand, Indonesia, Malaysia, Pakistan, Bangladesh, and Vietnam, future LNG requirements are uncertain. Each country has specific LNG import needs based on gas demand expectations, and domestic production and pipeline gas import outlook. In China, gas represents only some 6 per cent of the primary energy mix. Increased gas consumption relies heavily on government policy to constrain future coal consumption and to promote gas. Although there are plans to switch from coal to gas consumption in the residential space heating, industrial, and power sectors (115 bcm over five years) it remains to be seen how rapidly this can be accomplished.

The outlook for India's LNG requirement is complicated by an arbitrary regulated wholesale pricing policy and a two-tier supply allocation system. While energy policy does not specifically favour gas, changes to

pricing and allocation mechanisms in 2015 served to increase gas demand and (as domestic production is constrained) LNG imports. Uncertainty over the expansion of the gas transmission network to access pockets of demand is also a factor clouding the potential scale of future LNG requirements.

### Three drivers determining future LNG requirements

Whilst difficult to draw common conclusions for such a diverse group of countries, it is perhaps worth grouping them in terms of three drivers which will determine their future LNG import requirements. The first is the likely/impending decline in existing domestic production or pipeline gas supplies. This is especially relevant where natural gas represents a significant share of the energy mix, which would be difficult to markedly reduce in the space of five to 10 years. Countries where a *decline in domestic production or pipeline gas supplies* will likely lead to increased LNG imports to 2030 are: Singapore (pipeline supply), Indonesia, Pakistan, Bangladesh, Thailand, Malaysia, and Vietnam.

The second driver is *uncertainty around the future energy mix* and government

policy. Thus Taiwan and China have the potential for increased LNG imports depending on their choice of coal dependency levels (and GHG emission targets). This category also includes Thailand, India, Malaysia, Pakistan, and Bangladesh insofar as they may be unable to achieve acceptable (to other COP21 parties and domestic populations) energy mixes without significantly increasing LNG imports to displace coal, especially if renewables targets and energy efficiency goals are not met.

The third driver relates to *investment frameworks and regulated domestic gas price levels*. If these are deficient, they may slow the development of domestic gas resources and give rise to increased LNG imports (albeit these may cost more in the short- to medium-term). Examples are: Bangladesh, Pakistan, Vietnam, Malaysia, India, and Thailand. Note that some recent and emerging LNG importing countries appear in more than one of the above categories.

A 'low' and 'high' case has been derived (in the table 'Asian LNG imports 2010–30') for each of the Asian countries currently importing (or likely to do so in the future).

### Asian LNG imports, 2010–30 (mtpa)

	Low case					High case				
	2010	2015	2020	2025	2030	2010	2015	2020	2025	2030
Japan	70.9	85.1	63.3	63.6	59.3	70.9	85.1	91.7	91.7	88.4
South Korea	32.7	33.4	32.9	33.7	34.9	32.7	33.4	34.5	36.5	38.7
Taiwan	11.2	14.5	14.9	15.9	16.8	11.2	14.5	16.5	19.7	23.6
China	9.6	20.0	39.7	33.8	55.1	9.6	20.0	58.1	48.5	77.2
India	9.0	14.6	22.1	36.8	48.5	9.0	14.6	26.5	44.1	58.2
Singapore	-	2.1	4.8	7.9	10.1	-	2.1	5.1	8.4	10.9
Thailand	-	2.7	8.1	15.0	16.5	-	2.7	10.2	19.7	22.9
Indonesia	-	-	-	-	6.9	-	-	-	3.6	15.3
Malaysia	-	1.5	2.8	3.7	4.6	-	1.5	2.8	3.7	7.9
Pakistan	-	1.0	7.4	10.3	10.3	-	1.0	8.8	11.8	19.1
Bangladesh	-	-	2.9	5.9	13.2	-	-	4.4	11.8	19.1
Vietnam	-	-	-	3.2	6.7	-	-	-	4.2	8.4
<b>Total</b>	<b>133.3</b>	<b>174.9</b>	<b>198.8</b>	<b>229.6</b>	<b>283.0</b>	<b>133.3</b>	<b>174.9</b>	<b>258.5</b>	<b>303.6</b>	<b>389.8</b>

Source: *GIIGNL and LNG Markets in Transition: The Great Reconfiguration, OIES and KAPSARC (2016), Chapter 6*

In both the low and high cases the dominant markets, in terms of absolute volumes, are Japan, South Korea, China, and India. By 2030 the total LNG import volumes from all countries considered here ranges from 283 to 390 mtpa, compared with the 2015 total of 175 mtpa. In the low and high cases the annual average aggregate growth in LNG demand is 3.2 per cent and 5.2 per cent respectively. It is instructive to look at the country-level variances between low and high cases – shown in the table ‘Differences between low and high cases’ – as this highlights the key uncertainties for the period.

China and Japan dominate the picture between 2015 and the early 2020s. The pace of China’s policy-driven coal-to-gas switching is key, as are

uncertainties in the gas supply mix. These uncertainties include domestic gas production (both conventional and unconventional) and the scale and timing of future pipeline imports (from Turkmenistan and Central Asian, and of Russian gas from East and West Siberia). For Japan, the main uncertainties are the pace and extent of the start-up of nuclear power plant (which would reduce the requirement for LNG imports) and the achievement of long-term energy efficiency goals.

In the case of Taiwan and South Korea, the scale of future LNG imports depends on uncertain economic growth prospects and energy mix policy. With Thailand, Indonesia, Malaysia, and Vietnam a major uncertainty is the future decline of

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**‘CHINA AND JAPAN DOMINATE THE PICTURE BETWEEN 2015 AND THE EARLY 2020s.’**  
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domestic production as exploration prospectivity declines due to province maturity, often exacerbated by low regulated domestic pricing policies. While the future scope of LNG imports is difficult to ascertain, this is likely to be an increasingly widespread dynamic and an important source of new global LNG demand in markets where natural gas already has a strong presence. The same issue applies to Pakistan and Bangladesh but with the added complication of delays to the building of import infrastructure, due to poor investment frameworks, governance or end user creditworthiness. While a continuation of 2016 spot LNG prices of \$4–5/MMBtu is expected to support demand growth in these markets, questions of sustainability would arise if they rose to long-run marginal cost levels of around \$10/MMBtu. This highlights an opportunity for future LNG supply projects, but it would require a markedly more proactive marketing stance and credit risk management capability than has traditionally been the case in the LNG business. The use of floating LNG regas units, however, is an added incentive to ensure that LNG supplied is paid for.

**Difference between low and high cases (Asian LNG imports, 2010–30, mtpa)**

	2010	2015	2020	2025	2030
Japan	-	-	28.4	28.1	29.2
South Korea	-	-	1.5	2.8	3.8
Taiwan	-	-	1.6	3.9	6.7
China	-	-	18.4	14.7	22.1
India	-	-	4.4	7.4	9.7
Singapore	-	-	0.3	0.5	0.8
Thailand	-	-	2.1	4.7	6.4
Indonesia	-	-	-	3.6	8.5
Malaysia	-	-	-	-	3.3
Pakistan	-	-	1.5	1.5	8.8
Bangladesh	-	-	1.5	5.9	5.9
Vietnam	-	-	-	1.0	1.7
Total	-	-	<b>59.7</b>	<b>74.0</b>	<b>106.8</b>

Source: LNG Markets in Transition: The Great Reconfiguration, OIES and KAPSARC (2016), Chapter 6

## What role for Europe in the global LNG market?

Anouk Honoré

Europe acts as the swing market for LNG, and as a result the region is expected to help absorb the LNG ‘wave’ coming onto the market in the second half of the 2010s and early 2020s. But the gas industry in the

region is facing major uncertainties: the future role of natural gas in the whole energy system is in question, primarily as a result of greater governmental support for renewables. Nonetheless, with declining indigenous production,

the region will see its imports rise, but by when, by how much, and from which sources is still unclear. This section focuses on regional gas market fundamentals and the repercussions for LNG up to 2030. (Unless otherwise



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stated, the term ‘Europe’ applies to a region that encompasses 35 countries: EU28 plus Albania, Bosnia and Herzegovina, Macedonia, Norway, Serbia, Switzerland, and Turkey. Due to availability of data, some statistics may apply to different groups of countries representing Europe; details will be given where appropriate.)

#### **Europe as the residual market for LNG**

In 2015, the European market(s) represented 15.3 per cent of global LNG trade. Eleven countries imported 38 mtpa of LNG: Belgium, France, Greece, Italy, Lithuania, the Netherlands, Poland, Portugal, Spain, Turkey, and the UK. Total regasification capacity was 154 mtpa, which represented a rate of utilization of about 24 per cent on average. Notwithstanding this low utilization rate, 13 mtpa of additional capacity is under construction across Europe and 126 mtpa is planned. Despite this apparent keen interest for LNG, the fundamentals of the gas industry in the region are complex.

#### **Gas demand in question ... will it recover?**

Natural gas is a significant contributor to the European energy supply, with a 22.4 per cent share of the total primary energy supply (TPES) in 2014. However, contrary to earlier scenarios, gas demand fell in the early 2010s and reached 494 bcm in 2015. Most of the sectors of consumption have been hit by the combined effects of: slow economic growth, improvements in efficiency measures, relatively high gas prices, low coal prices, and the development of renewable energy.

The power sector, which had been the driver of gas demand growth in the 2000s, peaked in 2010 and then lost about 75 bcm between 2010 and 2015. A combination of lower gas prices in the second half of the 2010s and the closure of firm generation capacity (especially coal and nuclear plants as a result of the Industrial Emission Directive and national decisions) in the 2020s is likely to favour some gas demand growth, even if not at previous levels. In the non-power sectors, demand should remain flat and then decrease thanks to better efficiency, changes in market structures, and technological improvements. An interesting new market is the use of LNG as a marine fuel, but this would probably equate to rather small volumes (see Le Fevre in this issue).

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#### **Unknown pace and scale of the region’s production decline**

Indigenous production still represented 250 bcm (approximately 50 per cent of regional gas needs) in 2014, but the trend is downward everywhere apart from Norway. However, even for this country, there are uncertainties post-2020. In a low energy price environment, it is difficult to envisage more optimistic scenarios. The author expects total European (conventional) production to decline by 25 bcma in 2020 (compared with 2015) and 89–117 bcma (about 41 per cent) by 2030. There is interest in the development of unconventional gas reserves, but no serious research sees any significant output in our timeframe, and green (bio) gas production offers better potential. Our scenario of total indigenous production vs demand leaves a gap unfilled of about 235–261 bcma in 2020 and 336–364 bcma in 2030.

#### **Limited options for additional pipeline gas, apart from Russia**

As a result, Europe anticipates an increase of imports, but by how much, and from which sources, is unclear. In 2015, most of the gas imported arrived in the form of pipeline gas, accounting for 88 per cent of total demand. The main exporter was Russia with 158 bcm of natural gas (physically) delivered, or about 33 per cent of total demand. Gazprom is expected to maintain its market share between 27 per cent and 33 per cent, as indicated by deputy chief executive Alexander Medvedev in early 2016. Pipeline imports from other sources (aside from Azerbaijan) are not expected to increase substantially, although some additional pipeline gas could be sourced from East Mediterranean countries, Central Asia, and the Middle East, but these volumes are highly uncertain and at best will only arrive post-2025. Due to these limited supply options, competition in our timeframe is likely to be principally between Russian gas and LNG.

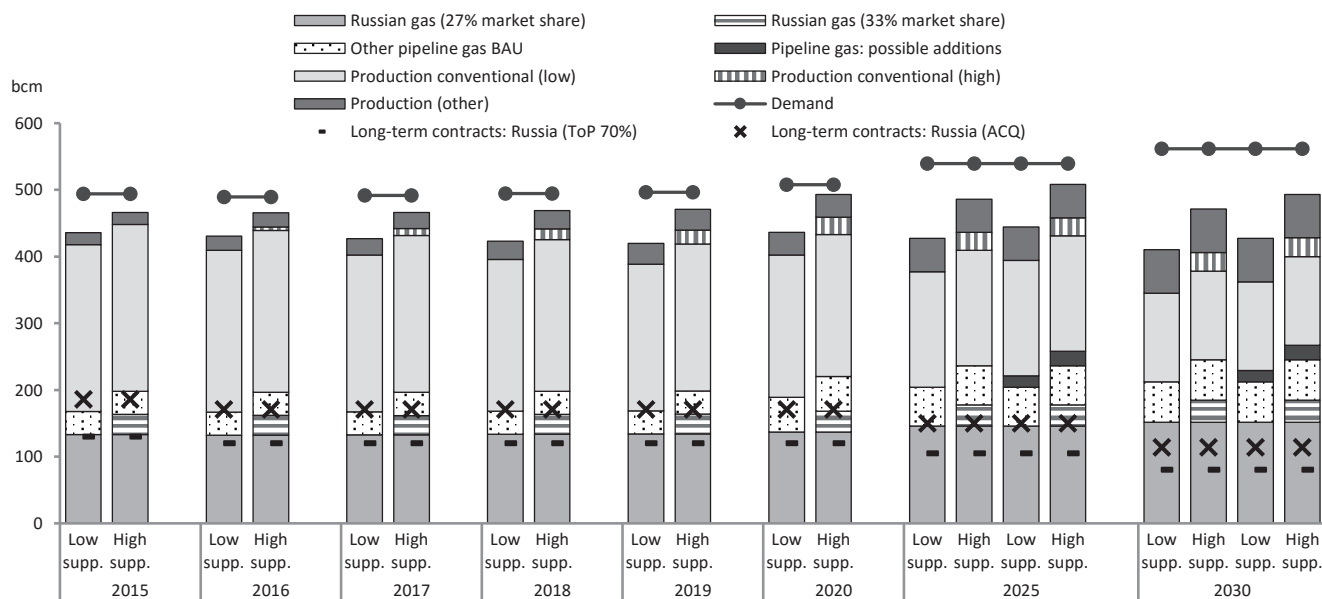
#### **Gas supply challenges: what role for LNG?**

With global LNG production on the verge of significant increases, interest in unused capacity at European regasification facilities is growing. In a surplus global LNG market in 2015–20, the region could be the recipient of substantial LNG supplies at prices competitive with pipeline gas. However, Gazprom will likely look to retain its market share at 27–33 per cent, and with a surplus of about 100 bcma of relatively low-cost gas, it will be in a position to compete not only with all other pipeline gas but also with LNG (including US LNG) supplies throughout the period to 2030. Gazprom could keep gas prices at \$4–6/MMBtu (or Henry Hub + \$2/MMBtu) for quite a long time, even if it would prefer to avoid such a situation. If there is a price war, Gazprom is likely

to win. If the company maintains its market share, then the gap remaining to be filled in 2020 is 15–71 bcm (11–52 mtpa). This gap is likely to be filled by LNG, due to the lack of options other than Russian gas. In 2030, this gap expands to 90–151 bcm (66 to 111 mtpa). However, after that date,

Gazprom will need to export volumes not covered by current long-term contracts to keep its market share within the bracket. In addition, some further pipeline gas may have become available by this date, especially from Azerbaijan and Iraqi Kurdistan. If this happens, then the need for LNG would

reduce to 68–129 bcm (50–95 mtpa), depending on the level of indigenous (especially Norwegian) production and the market share of Russian gas. Different scenarios for these elements are shown in the figure 'Scenarios for natural gas demand in Europe (2015–30)'.



### Scenarios for natural gas supply and demand in Europe (2015–30)

Notes: Indigenous production: high and low

Pipeline imports: Russian gas at 27 per cent and 33 per cent of the market

Source: LNG Markets in Transition: The Great Reconfiguration, OIES and KAPSARC (2016)

## Natural gas markets in South America and the role of LNG

Anouk Honoré

South America has long been isolated from other global natural gas markets, focusing instead on achieving self-sufficiency and regional integration. However, the region turned to LNG to source additional supply in 2008, and although the volumes imported represent less than 5 per cent of world LNG trade, they have grown rapidly. If this pace continues the region could become an important player, reducing the scale of flows to Europe, the swing market for LNG. This article focuses on the continental gas market fundamentals and the future role for LNG up to 2030.

### Why LNG in South America?

Discussions concerning natural gas trades across the continent of South America date back to the 1950s and 60s, but gas integration only really started in the early 1970s with the Yabog pipeline between Bolivia and Argentina. Until the mid-1990s, this was the only cross-border gas pipeline in the region. Exports did not really take off until abundant gas reserves were found in Argentina in the 1980s. Looking to monetize its own gas supplies, seven pipelines were built

‘... THE REGION COULD BECOME AN IMPORTANT PLAYER, REDUCING THE SCALE OF FLOWS TO EUROPE, THE SWING MARKET FOR LNG.’

between Argentina and Chile between 1996 and 2001. Additionally, exports to Uruguay started in 1998 and to Brazil in 2000. This was intended as the first stage of a more ambitious project and also to compete with Bolivian gas, which started to flow to Brazil via the Gasbol pipeline in 1999. In the



north, a pipeline between Colombia and Venezuela started operation in 2007. These pipelines should have provided the basis for regional pipeline integration, but ran into a number of problems.

- The most important of these problems was the decline of Argentinian domestic production to less than its domestic demand, an unintended consequence of its 2001 economic crisis. The country broke its export contracts and gave priority to national consumption. This decision had a major impact on the importing countries, especially Chile, which was 100 per cent dependent on pipeline gas from Argentina. Repeated interruptions created major economic problems for industry and electricity generators, which had to resort to more expensive alternative fuels. The impact was less severe in Brazil and Uruguay, but in addition to supply constraints, this episode created major distrust of Argentina as a reliable supplier, and towards regional integration as a goal.
- Bolivian gas exports to Brazil have been reliable in terms of volumes, but disagreements over prices have increased over the years.
- Not all has gone according to plan in the north, either. Colombia was to export gas to Venezuela until 2011, and then the pipeline flow was to be reversed in 2012. This did not take place due to delays in developing reserves in Venezuela, but despite political tensions, security of gas supply was relatively good. In 2015, Colombia reduced (and then stopped) gas exports to meet its own demand when the Perla field started operation in Venezuela. However, reverse flow, which was expected in January 2016, was again delayed and the under-supplied national market was prioritized.

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**'SOUTH AMERICA RECEIVED ITS FIRST GAS FROM OUTSIDE THE CONTINENT IN THE FORM OF LNG IN 2008, AND VOLUMES HAVE BEEN RISING RAPIDLY.'**

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As a result, natural gas integration never really took off despite political support for the concept of energy, and more specifically natural gas, integration. Since harmonized regulation, pricing, and policies were non-existent, cross border exchanges were arguably more bilateral initiatives between producers and consumers than attempts to create a truly regional market. At times of shortage, producing countries gave, and will continue to give, priority to their domestic markets. This atmosphere of distrust led importing countries to look for new gas import sources; they turned to LNG to increase security of supply, add much needed additional volumes, and provide increased flexibility.

South America received its first gas from outside the continent in the form of LNG in 2008, and volumes have been rising rapidly: from 0.4 mtpa in 2008 to 13 mtpa in 2015. In Chile (3.2 mtpa in 2015), imports are rather flat throughout the year; in Argentina (4.5 mtpa) they are concentrated during winter months, while in Brazil (6.8 bcm), they are mostly driven by the level of hydropower in power generation. As of January 2016, South America had 33.5 bcma (24.5 mtpa) of LNG import capacity with a utilization rate of 51 per cent (2015), albeit with important differences among the countries (60 per cent in Argentina, 57 per cent in Chile, and about 43 per cent in Brazil). Two additional regasification terminals were under construction in Uruguay and Colombia, with capacities of 2.7 mtpa and 3.0 mtpa respectively.

**Natural gas demand: trends and uncertainties**

In 2014, gas demand reached 144 bcm, a 20 per cent increase over 2010 (+64 per cent since 2000) driven mainly by rapid economic growth, expansion of the grid to areas not previously covered, addition of new gas-fired capacity, substitution of gas for oil in industry, and the rise of gas use for the transport sector.

As the region's economy and population grows, energy demand is expected to continue to increase and to become more reliant on natural gas, especially in electricity generation, even if drivers for additional gas demand are as diverse as the markets themselves (size, maturity, infrastructure, generation mix, subsidies, and energy policies). Despite the fact that weaker economic growth will slow down energy demand growth in all sectors for the rest of the 2010s, gas demand is still expected to increase. Meeting the needs for both additional generation and additional flexibility will be one of the greatest challenges. Most new generation will be in the form of renewables, especially hydropower, but most new hydro will be run-of-the-river or have small reservoirs. As a result, generation will be even more significantly reduced in dry periods, thus needing more back-up capacity (notably from gas plants). In the non-power sectors, there is also some potential for more gas penetration in industry and for additional use of CNG in road transport (but if oil prices remain low, expectations may be over-optimistic). There is virtually no need for space heating in the region, which explains the low expectations in the residential and commercial sector, despite plans to develop gas distribution infrastructure. All in all, this author expects gas demand to increase to 151 bcm in 2020 and 191 bcm in 2030. Brazil is one of the major question marks, especially in relation to

the normalization of the hydro situation. During wet years, it may be that gas for power will be limited at 8–10 bcm, while potentially shooting up to 40–45 bcm during dry years in 2030.

### Natural gas supply: meeting the challenge

Supply shortage and/or delay in increasing indigenous production will constrain these demand scenarios. In addition, flexible supply will be increasingly needed in order to match the seasonal, and often volatile, dispatch of power plants fired by gas – whether from indigenous production (if possible) or from imports, especially LNG.

South American countries will have to increase upstream investment and develop new resources in order to boost production. Geopolitical uncertainties, along with economic, geographic, social, and regulatory issues have impacted the pace and the level of natural gas production in the past. While regional diversity needs to be taken into account, the major challenges to increasing indigenous production will be geography, the changing regulatory environment, and low oil prices. Cutbacks in exploration investment may have a particular

impact on high-cost unconventional plays (especially in Argentina), offshore pre-salt projects in Brazil, and on all offshore prospects in general. This author expects production to rise to 149 bcm in 2020 and 183 bcm in 2030.

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**‘SOUTH AMERICA IS NOT EXPECTED TO BE A MAJOR FUTURE LNG MARKET UNLESS THERE ARE EXTREME CLIMATIC CONDITIONS...’**  
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### Conclusions on the future role of LNG

Brazil, Argentina, and Chile will continue to import LNG and will be joined by Uruguay and Colombia, while Peru is likely to remain the only exporter. There will be no region-wide pipeline integration, but there is a possibility of sub-regional integration around LNG import terminals, as suggested by projects in Uruguay and Colombia – or even LNG arriving in Chile and being sold to Argentina. This author expects that the region will import about 5.1 mtpa of LNG in 2020 under ‘normal’ weather conditions, with Bolivian export commitments fulfilled and contracts prolonged. If the Bolivia–Brazil agreement is not prolonged, then LNG imports could soar to 13.2 mtpa in 2020 under ‘normal’ weather

conditions. By 2030, our scenarios show a potential of 14.3 mtpa of LNG under ‘normal’ weather conditions and if Bolivia renews both its pipeline export contracts at levels allowing Argentina and Brazil to balance their demand. If these contracts are not renewed, LNG imports could rise to 22.4 mtpa under ‘normal’ weather conditions. Cold winters in Argentina and dry weather across the region could have a significant impact on LNG imports. In Brazil alone, it could add up to 25.7 mtpa (on top of already-needed imports) in a dry year by 2030.

In conclusion, South America is not expected to be a major future LNG market unless there are extreme climatic conditions, which will not happen every year and will not last for many years. LNG will remain necessary to supply much needed flexibility, additional volumes, security of supply, and to reach new markets far from infrastructure. However, there are also major uncertainties on volumes, prices, timeframe, location, and even direction of the LNG flows, as some importers could become exporters at times of low demand towards the end of the timeframe.



## LNG as a transport fuel

Chris Le Fevre

The use of natural gas as a transport fuel (primarily in the form of compressed natural gas – CNG) has failed to make significant inroads in most markets. LNG provides two and a half times the energy of an equivalent volume of CNG and the consequent greater range and efficiency makes it a practical fuel for heavy road vehicles and ships, particularly where it can also provide cost and environmental advantages

over existing fuels. The market is still in its early stages though the long-term potential could be significant.

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**‘THE USE OF NATURAL GAS AS A TRANSPORT FUEL (PRIMARILY IN THE FORM OF COMPRESSED NATURAL GAS) HAS FAILED TO MAKE SIGNIFICANT INROADS IN MOST MARKETS.’**  
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### The main drivers

There are both demand pull and supply push factors. From a *demand perspective*, the attractions of LNG arise from its financial and environmental advantages in comparison to other fuels.

- The financial case for LNG is dependent on the price differential with diesel in road transport and with

heavy fuel oil (HFO) in marine markets (marine gasoil, or MGO, is also important in some marine markets). Comparative taxation rates can also play an important role in inland markets.

- The environmental advantage of LNG arises from lower emissions of carbon dioxide (CO<sub>2</sub>) and of virtually no nitrogen oxides (NO<sub>x</sub>), particulate matter (PM), or sulphur oxides (SO<sub>x</sub>). The latter pollutant is a concern in maritime transport where fuel oil use still dominates; the International Maritime Organization (IMO) has introduced restrictions on sulphur content in fuel oil in the MARPOL mandated emission control areas in North America and Europe.

*Supply side* factors include the increased availability of LNG and of LNG terminals (many of which have spare capacity) and the presence in some markets of an existing off-grid sector supplied by LNG.

The volumes consumed by different vessels or vehicles can vary widely – for example, the annual LNG consumption of a large ferry is approximately equivalent to the combined consumption of 130 fishing boats, or of nearly 11,000 taxis. The relative scale makes large marine vessels the most prospective market for LNG sales.

### Obstacles to be overcome

There are a number of barriers that can hinder the uptake of LNG in the various market sectors. The most important obstacles are:

- comparative prices,
- cost and availability of appropriate vehicles and of refuelling infrastructure, and
- regulatory uncertainty.

Fuel costs are a critical consideration for any transport operator. In shipping for example the cost of fuel can account for 60–80 per cent of a

### THE BENEFITS OF LNG IN TERMS OF REDUCED FUEL COSTS HAVE TO BE CONSIDERED AGAINST THE HIGHER CAPITAL CHARGES FOR A NEW OR CONVERTED LNG-FUELLED VESSEL.

vessel's operating expenses. The commodity price of LNG has been well below that of oil products in non-Asian markets for many years, though the gap has decreased since 2015 with the fall in oil prices. This narrowing of differentials is illustrated in the figure 'Marine fuel price differentials with regional gas prices' which shows the differential with gasoil in the emission control areas of North America and Europe, and with fuel oil in Asian markets. This figure shows that natural gas has generally been cheaper than gasoil in Europe and the USA, whereas the differential between LNG and fuel oil in Japan is generally narrower, which is to be expected given that the price of most Japanese LNG is still linked to crude oil prices.

The actual price paid by LNG marine fuel users will depend on factors such as point of delivery and other contractual terms. Various pricing arrangements are beginning to emerge.

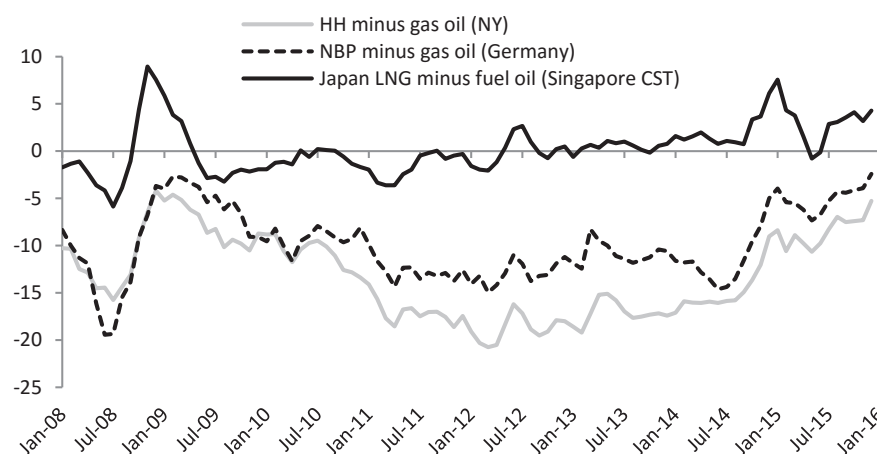
These include:

- 'hub plus' pricing, where the LNG price is linked to a gas trading hub such as HH or NBP;
- 'oil product minus' pricing, where there is a guaranteed margin against a competing fuel such as fuel oil or marine gas oil.

In the first instance, buyers are likely to prefer an 'oil minus' arrangement that limits risk, although there is the possibility of a new LNG bunkering index emerging once liquidity has reached a satisfactory point.

The benefits of LNG in terms of reduced fuel costs have to be considered against the higher capital charges for a new or converted LNG-fuelled vessel. These relate primarily to the higher costs of an LNG-fuelled engine and of the storage and delivery system. Studies suggest that a discount of \$2–4/MMBtu to the equivalent fuel is required for most vessel types, while very large bulk carriers require a discount of around \$6/MMBtu.

In the road market, the financial case is a trade-off between the discounted price of LNG versus the higher capital cost for an LNG-fuelled vehicle. The commodity price of LNG, whilst it varies



**Marine fuel price differentials with regional gas prices**

Note: Negative differential means gas is cheaper

around the world, is usually below the price of diesel, though the actual differential will often depend heavily on taxation at the point of sale. In most EU countries, taxation accounts for around two-thirds of the retail price of diesel, while in the USA the equivalent taxation figure is only around 13 per cent. Retail LNG is generally taxed at lower rates, though the differential is much greater in Europe than in the USA.

The second barrier to be overcome is thus the cost and availability of appropriate vehicles, and of refuelling infrastructure. A Lloyds Register survey of 22 ports in 2014 showed that nearly 60 per cent had specific plans for LNG bunkering. The survey indicated that most progress was being made in European ports, where 76 per cent expected to have LNG available by 2020.

In road transport, a wider range of trucks is becoming available, though the extensive maintenance and repair network that is available for diesel vehicles is presently lacking. Only a small number of countries have an LNG refuelling network and only large-scale operators are in a position to invest in their own facilities. Until vehicles can establish a reliable track record, and there is reasonable coverage for refuelling, many operators will be reluctant to change from the well tried and tested diesel option – particularly if there is little pressure from their customers or governments.

The third obstacle concerns the regulatory framework and in particular the status of environmental legislation. There is still a great deal of uncertainty over the timing and extent of the MARPOL restrictions on fuel oil being extended to more regions. There is also a great deal of debate over the measurement and control of emissions from freight vehicles. Various trials

suggest that LNG can generate well-to-wheel (WTW) CO<sub>2</sub> reductions of 8 per cent, together with reduced NO<sub>x</sub> and PM emissions of 85.6 per cent and 97.1 per cent respectively. The efficiency of engines and the venting of unburnt LNG (known as methane slip) are also important (methane is a potent greenhouse gas), though growing worries over the health impacts of NO<sub>x</sub> and PM emissions could outweigh these concerns.

### Key regional markets for LNG

The prospects are greatest in the three major markets of North America, Europe, and China. These markets share some common characteristics such as: large long-haul road freight and coastal/inland shipping sectors and existing LNG infrastructure (including storage facilities, coastal import terminals, and a growing number of refuelling/bunkering facilities).

The North American market also has the advantage of low-cost indigenous gas production, an innovative LNG vehicle and engine sector with a number of players, and the North American Emission Control Area (extending 200 miles from the coast) which encourages the use of LNG in shipping. The main barriers to uptake have been the fall in oil prices, LNG taxation, and gaps in the refuelling network.

In Europe differential taxation means that LNG prices for road hauliers are much lower than diesel, and the Baltic and North Sea Emission Control Areas have boosted the LNG marine fuel market – most notably in Norway. The EU Alternative Fuel Infrastructure Directive and the LNG Blue Corridors project are encouraging the use of LNG, though take-up is still relatively slow.

In China growing concern over air quality has resulted in a Government target of 10 per cent of total inland transportation fuel consumption to be LNG by 2020. There is already an extensive LNG supply chain in China and at the end of 2013 the country had an estimated 100,000 LNG vehicles, making it by far the largest LNG-fuelled fleet in the world.

### ‘THE NARROWING OF THE OIL/GAS PRICE SPREAD SINCE 2015 HAS REDUCED GROWTH EXPECTATIONS FOR LNG IN TRANSPORT ...’

### Conclusions

It is not yet clear whether LNG will break out from its current, relatively minor niche role in some regional markets to become a significant global transport fuel. The key determinant is likely to be whether LNG prices remain competitive, both with existing fuels and new alternatives.

The narrowing of the oil/gas price spread since 2015 has reduced growth expectations for LNG in transport, but the combination of legislation limiting sulphur in marine fuels and growing concerns over particulate emissions from diesel in urban areas means that demand growth in the sector is expected to be positive. Most forecasts expect global volumes in the sector to grow to between 25 and 50 mtpa by 2030.

Developments in the maritime sector are likely to be key, as this will provide a platform of significant scale to allow road-based usage to develop in a relatively risk-free environment. Growth timescales could, however, be extended by the fact that most decisions to switch to LNG will take place at the point of vehicle/vessel renewal.



# FLNG has come of age

Brian Songhurst

The term 'floating LNG' now covers both the liquefaction (FLNG) and import terminal (FSRU) parts of the LNG value chain.

Over the past 10 years, 18 floating storage and regasification units (FSRUs) have been installed and could now be regarded as the import terminal of choice as they offer a quick and flexible way of delivering LNG into a new gas market. A measure of this is in Egypt where two FSRUs were recently delivered in a matter of months, compared to the four years required for a traditional onshore terminal, thus enabling early revenue for exporters and supply for importers. Five-year leasing contracts provide commercial flexibility with limited sunk costs.

Following the success of the FSRU market, floating liquefaction (FLNG) is about to come of age with the first unit – Petronas Kanowit – expected to start up in offshore Malaysia this year. However, the development of FLNG has been a far longer process, having taken some 40 years of research and development before the first unit was sanctioned in 2011. There are now seven units in construction as shown in the table 'FLNG projects currently under construction' (although Rotan has just been delayed). Five are being offered on a leasing basis by the same contractors who supply and operate

FSRUs. This leasing option enables the energy companies to minimize the high sunk costs experienced with traditional onshore plant construction. In addition, shorter construction schedules than those of onshore plants offer the attraction of earlier revenue and improved project cash flow. The first of these leased units will be supplied and operated by Golar LNG to Ophir for development of the Fortuna field and to SNH/Perenco for Cameroon just two years after project sanction, compared to the typical four years for an onshore plant.

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**'... THE DEVELOPMENT OF FLNG HAS ...  
 TAKEN SOME 40 YEARS OF RESEARCH  
 AND DEVELOPMENT BEFORE THE FIRST  
 UNIT WAS SANCTIONED IN 2011.'**  
 .....

## Different approaches to construction

The Prelude and Kanowit units have been developed on a traditional capital project basis with the energy companies managing the overall project, arranging the financing, and awarding the engineering, procurement, and construction to engineering and shipyard companies. They have been designed specifically for the gas fields where they will operate and in accordance with the owner's specifications and standards,

in the same way as large-scale onshore plants.

However, the leasing companies have adopted a completely different approach. Their intention is to re-use the units following the initial lease; they have therefore designed the units on a more generic basis, meaning they can be relocated to other fields with limited modification. This way of working – using standardized modular units which may not be a perfect fit for that specific application, but which provide a lower cost and shorter delivery time than a bespoke unit – is applied in other process industries and it is essential to capture, and economically serve, the leasing market in just the same way as for FSRUs. This commercial approach, rather than a bespoke technical one, is seen as the key success factor for the leasing market. Golar LNG is offering converted LNG tankers with even shorter schedules than newbuild units and both Golar LNG and Exmar are considering building speculative units.

## Costs

The real costs of FLNG have not yet been established as the units are still under construction and information has not been released by the companies involved. An indication can be gathered from various press releases regarding contract award figures, but these costs

## FLNG projects currently under construction

Project	mtpa	Start up	Location	Operator	Contractor
Caribbean FLNG	0.5	2016	TBA	Exmar	Exmar/Wison/B&V
Kanowit	1.2	2016	Sarawak, Malaysia	Petronas	Technip/DSME
Prelude	3.6	2017	Timor Sea, Australia	Shell	Technip/Samsung
Kribi	1.2	2017	Cameroon	SNH/Perenco	Golar/Keppel/B&V
Speculative	0.6	2017	TBA	TBA	Exmar/Wison
Fortuna	2.2	2018	Equatorial Guinea	Ophir Energy	Golar/Keppel/B&V
Rotan	1.5	2020	Sabah, Malaysia	Petronas	JGC/Samsung

Source: Collated by author from various industry sources

will have increased due to the 'first of a kind' nature of these projects. From industry press reports, the cost of the Prelude FLNG unit would appear to be of the order of \$2,000/tpa (\$7/MMBtu) and that of the Kanowit FLNG unit \$1,000/tpa (\$3.5/MMBtu), but these figures need to be handled with care as it is not clear what is included in the scope. However, the leasing companies – Golar LNG and Exmar – are far more forthcoming and have stated costs of around \$600/tpa (\$2.1/MMBtu) for their units. These costs are for the FLNG units only (excluding the wells, subsea systems, risers, and infrastructure) and are very similar to the cost of the onshore plants currently under construction in the USA which are regarded as relatively low due to their construction in a highly developed oil and gas industrial area. Operating costs for FLNG will be higher than those for onshore plants, due to offshore logistical support services, and would likely be of the order of \$1.3/MMBtu.

### Timescale

Regarding construction schedules, the Caribbean FLNG barge took 32 months and the Golar LNG units are expected to take a similar time. However, the Kanowit and Prelude units are taking 42 and 66 months respectively. By comparison, a typical greenfield onshore plant would take about 48 months, but probably longer in a new and difficult environment. This FLNG schedule advantage is probably why ENI are looking to initially use it for offshore Mozambique, to enable early revenue whilst the onshore project is developed.

### Advantages of FLNG

The original reason to develop FLNG was to monetize remote offshore gas fields which were often referred to as 'stranded gas'. However, FLNG units

### THE ORIGINAL REASON TO DEVELOP FLNG WAS TO MONETIZE REMOTE OFFSHORE GAS FIELDS WHICH WERE OFTEN REFERRED TO AS STRANDED GAS.'

can also be used inshore or nearshore, as an alternative to traditional onshore plants. In this arrangement, the unit would be connected by pipeline to receive gas from onshore for liquefaction. Caribbean FLNG was planned as inshore, where the unit would be moored to a jetty. Cameroon will be located nearshore, with the unit moored using anchors. These arrangements enable developers to take full advantage of the flexibility that term leasing contracts offer, rather than sinking the full cost of constructing an onshore plant. Further FLNG units are likely to be delivered more quickly

than an onshore plant, enabling earlier revenue.

The use of FLNG units offers many advantages and opportunities; these are listed in the table detailing the relevant SWOT analysis and should be considered during the field development option screening process.

### Disadvantages of FLNG

Weaknesses and threats are also listed in the SWOT analysis. The main weakness is currently the need for a benign sea state to allow offloading to the shuttle tanker on a side-by-side basis, restricting offloading to a significant wave height of around 2.5 metres. This does not mean that the vessel cannot operate in harsher sea states, but it cannot offload. Loading availability must be evaluated during the screening process, to ensure the full production capacity can be offloaded and a reliable revenue stream

### SWOT analysis

Strengths	Weaknesses
Wide range of production – 0.5 to 6.0 mtpa Option to lease Lower CAPEX for high-cost locations Avoids costly gas pipeline from field to shore Likely quicker schedule – fast track Higher confidence in schedule and cost Less 'NIMBY' issues Technology backed by IOCs Onshore site (land) is not required No jetty or breakwater required	Uptime of berthing and transfer due to sea state Unproven offshore experience Tanker conversions have a limited design life High OPEX, high maintenance cost Perception that it is 'too difficult' Congested layout Minimal local content Safety design and risk analysis not mature Offloading system sea state limitations Marine classification process not mature
Opportunities	Threats
Relocation so not a 'sunk cost' as onshore Monetize stranded offshore gas fields No land for onshore Little infrastructure onshore Limited onshore permitting required Early monetization (EPF) Opening for smaller energy companies Convert retired LNG tankers adding value Meeting increasing demand for gas Financing by banks when technology proven	Low LNG prices due to lower oil prices Low-cost onshore shale gas LNG from the USA Lack of finance from commercial banks Shipyard capacity or willingness to bid Unproven contractors enter the market Geopolitics demand high local content

Source: Author



achieved. Stern offloading systems which can operate in harsher sea states have been developed, but these require the use of specially modified LNG tankers fitted with bow loading connections and dynamic positioning.

### Summary and conclusions

FLNG is not just a technical but also a commercial breakthrough. It offers developers the option of leasing and of thus avoiding the high sunk costs of a capital project. Further shorter

construction times will enable earlier revenue and improved cash flow. Leased units are currently offered by Exmar and Golar LNG but several leading oil FPSO leasing contractors (such as: SBM Offshore, BW Offshore, Bumi Armada, and MODEC) are actively looking to enter the FLNG market, which will increase competition.

To summarize, FLNG has come of age and can be regarded as a valuable new field development tool in the gas field monetization process – not only for offshore fields, but onshore

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**‘FLNG IS NOT JUST A TECHNICAL BUT ALSO A COMMERCIAL BREAKTHROUGH.’**  
 .....

as well, using inshore or nearshore arrangements.

*OIES will be publishing paper number NG 107 in September 2016 titled ‘Floating liquefaction (FLNG): potential for wider deployment’. This will provide a detailed technical and commercial review of the current FLNG offerings.*



## Asian LNG pricing: evolution or revolution?

Jonathan Stern

### Introduction

Market (hub)-based gas prices have been dominant in North America for the past quarter century. The UK has had a similar mechanism for nearly 20 years and, since 2008, major continental European gas markets have made a transition away from oil-linked to market prices. But in all of the major gas markets of these regions, prices were related to (domestic or imported) pipeline gas, with LNG as a marginal source of supply. The exception is Spain where – due to the influence of LNG and lack of pipeline links to the rest of Europe – oil-related gas prices remain dominant, largely due to Asian LNG prices remaining tied to the traditional JCC crude oil-related formula. Because two-thirds to three-quarters of global LNG cargos are delivered to Asian markets, in particular Japan, Korea, and Taiwan, changes in pricing in those markets will be crucial to the overall future pricing of LNG. Long-term Asian LNG contracts have traditionally been based on JCC (colloquially known as the Japan Crude Cocktail) pricing, according to

which the LNG price is based on, and indexed to, an average of the prices of crude oils imported into Japan.

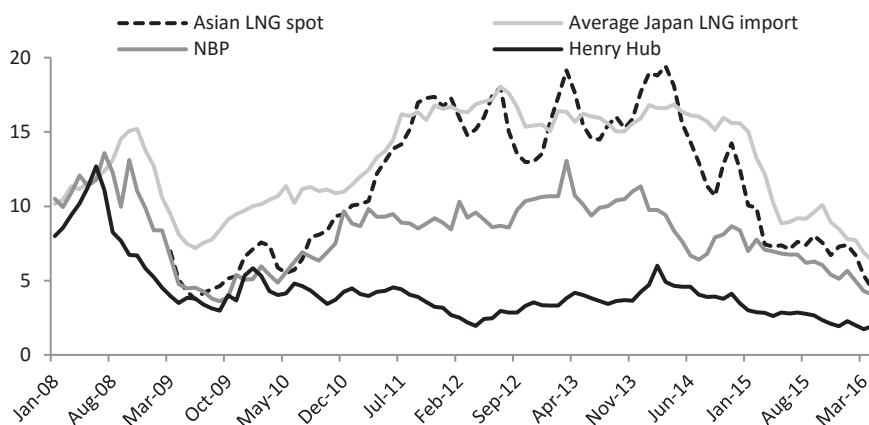
.....  
**‘BY 2010 IT HAD BECOME CLEAR THAT ... 100 PER CENT LINKAGE TO CRUDE OIL (LET ALONE TO JAPANESE CRUDE OIL IMPORTS) HAD CEASED TO BE A LOGICAL WAY TO PRICE LNG.’**  
 .....

### The 2010–16 period: peak followed by collapse

By 2010 it had become clear that although market fundamentals differed between the Asian LNG importing countries, even in countries such as South Korea, India, and China where oil products remained important competitors to gas, 100 per cent linkage to crude oil (let alone to Japanese crude oil imports) had ceased to be a logical way to price LNG. In 2011, two major events occurred in Asian LNG markets: oil prices rose and remained above \$100/bbl, and the Fukushima nuclear accident (and subsequent closure of

all Japanese nuclear power stations) created significant additional demand for LNG which had not been foreseen. The result was that LNG imports rose substantially – mainly in Japan, but also in China where gas demand was increasing in double digits annually. These sudden, and unforeseen, additional requirements led to companies having to rely on spot and short-term cargos – bid away from Atlantic Basin (principally European) markets often at even higher prices than JCC at \$100/bbl equivalent – to meet their demand. The result was huge differences in regional gas prices with Asian (and particularly spot) LNG substantially above European and North American prices (shown in the figure ‘Asian LNG prices compared with NBP and HH’).

Since 2014, oil prices have fallen from more than \$100/bbl to around \$45–50/bbl by May 2016. Asian LNG prices fell from highs of \$15–18/MMBtu (and higher for spot prices) to less than \$5/MMBtu in the second quarter of 2016. Over this period, regional gas price differentials have narrowed



### Asian LNG prices compared with NBP and HH (\$/MMBtu)

substantially, with the spread between US gas prices and those of Europe and Asia narrowing from \$6 and \$11/MMBtu respectively in early 2014, to \$2 and \$5/MMBtu respectively by early 2016. Within a very short time the famous 'Asian premium' in relation to LNG import prices had disappeared. (It is a little difficult to find a precise definition of the 'Asian premium' but it generally refers to excess prices paid by Asia-Pacific countries for oil and gas relative to those paid in other regions for the identical products.)

#### Henry Hub-based pricing

The 2010–14 period had forced Asian buyers to consider a number of different options, including spot indexation and pricing at different hubs. During that period, a number of tolling (and modified tolling) contracts were signed for imports of US LNG which would result in Asian buyers signing 20 year contracts containing a formula of: 1.15 times the Henry Hub price, plus a fee for liquefaction (in the range of \$3–3.5/MMBtu) plus transportation. While this formula looked very attractive in comparison with JCC when Henry Hub prices were at \$2–3/MMBtu and oil prices were at \$100/bbl, the benefit very much reduced, and then reversed, at oil prices below \$50/bbl, especially if Henry Hub prices increase. This

highlighted the importance for Asian LNG buyers of focusing on price formation as opposed to price level, and on supply/demand fundamentals in their national markets as opposed to the fundamentals in US (Henry Hub) and European (NBP/TTF) markets.

.....  
**'THE 2010–14 PERIOD HAD FORCED ASIAN BUYERS TO CONSIDER A NUMBER OF DIFFERENT OPTIONS, INCLUDING SPOT INDEXATION AND PRICING AT DIFFERENT HUBS.'**  
 .....

#### The emergence of Asian gas and LNG hubs

The logical endpoint of this process will be the development of Asian gas and LNG hubs – along the lines of those operating in North America and Europe. There are a number of different requirements for hub development, starting with third-party access to facilities and moving on to price discovery, OTC and futures trading. Eventually one or more hubs will develop with a forward curve of prices several years ahead, which is sufficiently liquid to be accepted as a price reference for long-term contracts. In North America and Europe this process required a minimum of five – and mostly closer to 10 – years (and in many European countries has yet to be completed).

The only existing Asian gas hub is in Singapore, which has a liberalized gas market and where trading teams from many major companies have based their operations. Singapore has first-mover advantage but the disadvantage of being a physically small market with limited growth potential. Nevertheless, the Singapore hub could evolve from its current small physical status to a virtual hub encompassing the whole of south-east Asia – given the potential noted above for LNG demand growth in that region.

In Shanghai, there is a benchmark price at the city gate where gas is priced against fuel oil and LPG, but it is intended that this evolves to encompass prices of gas from a range of sources – domestic and international, pipeline and LNG. The Shanghai Petroleum Exchange is trading small quantities of LNG, but volumes are currently too small and erratic to constitute a significant traded market. Thus despite the use of the term, a 'Shanghai hub' does not yet exist in terms of a deep liquid traded market, but there is great potential for a significant gas hub to develop in that location. The likely growth in Chinese gas demand (albeit more slow than was experienced and expected a few years ago), and the diversity of sources of gas supply – domestically produced and imported, pipeline gas and LNG – are ideal conditions for the establishment of a physical gas hub. A key development will be third-party access rights to pipelines and LNG terminals which currently exist but at the discretion of the owners of those facilities.

In Japan, there has been discussion of an LNG hub for several years. The passage of liberalization legislation to open up the LNG terminals to third-party access in 2017 (with separation of supply and transportation functions of the main gas companies by 2022)





has been an important step. But this needs to be accompanied by a commitment of all parties to spot and short-term trading, and the establishment of common trading rules and regulations. The publication of the Japanese government's LNG strategy in May 2016 demonstrated a level of seriousness which had not previously been evident. However, that strategy confirms the likelihood that a hub will emerge in the early 2020s. Because of the lack of pipeline connections between the different regions in Japan, the initial establishment will probably need to be a physical LNG hub which in time (with greater regional pipeline connectivity) could evolve into a virtual hub for the whole of the country.

#### Asian LNG pricing: evolution or revolution?

The surplus of global LNG supply over demand which began in 2014, and is accelerating as new supplies come on line, will create a much larger and more liquid short-term traded market. This will be a catalyst for a more radical change in long-term contract LNG prices, leading to the use of spot indices in long-term contracts, and eventually to hub creation. This interim five to 10 year period will see

#### ..... 'THE SURPLUS OF GLOBAL LNG SUPPLY OVER DEMAND ... WILL BE A CATALYST FOR A MORE RADICAL CHANGE IN LONG-TERM CONTRACT LNG PRICES ...' .....

the evolution of hybrid pricing with short – and perhaps also longer – term contracts based on a mixture of hub (Henry Hub, NBP/TTF), spot (JKM, Argus, RIM, ICIS), and traditional JCC prices. A potential alternative is a price based on an average of all LNG (under long-term and spot contracts) imported into a specific market such as JLC for Japan and KLC for Korea. However, all of these can be regarded as transitional measures from which a price mechanism will eventually evolve which will reflect supply/demand conditions on a flexible basis, and will be accepted by the majority of Asian LNG players.

This in turn raises the question of whether such a transition can be achieved without the contractual discontinuities and litigation which have been experienced in Europe and North America. Liberalization of access to LNG terminals and pipelines could allow new players to import cargoes

at prices which would significantly undercut those of established utilities under long-term JCC-linked contracts. With demand not increasing as fast as expected, and perhaps falling in Japan and Korea, the established utilities could find themselves losing market share to new entrants and struggling to meet their take-or-pay commitments.

At that point, established utilities would be forced to offer lower prices to prevent their customers switching to new entrants, while being contractually required to continue to take-or-pay for minimum volumes at JCC-linked prices. A consequence of such developments could be severe financial hardship, and possibly litigation launched by buyers. This would be revolutionary in a region with no culture or tradition of long-term gas contract litigation, but in North American and European markets it has been a catalyst for (painful) change. Buyers must hope that by the time they face exposure to such risks, sufficient long-term contracts will have expired for them to be able to renegotiate the volume and price terms of their contracts (or terminate them), in order to ensure a 'smooth transition' to a new contractual status quo. The alternative could be a 'contractual train wreck' of litigation with uncertain outcomes.



## Conclusion – LNG markets: the great reconfiguration

Anne-Sophie Corbeau

The LNG world has been hit by a 'triple whammy'. The LNG supply capacity coming to the markets over the period 2015–20 looks much greater than required as LNG demand in Asia – the premium market targeted by most LNG exporters – is weaker than expected and actually declined in 2015. Meanwhile, oil and spot gas prices have fallen to levels unseen for a decade, threatening the economics

of the most recent projects coming on line.

#### ..... 'BESIDES CHANGES IN LNG'S FUTURE SUPPLY/DEMAND BALANCE, THE INDUSTRY'S BASIC BUSINESS MODEL ... IS CHANGING.' .....

As we look forward, the LNG industry seems ripe for 'a great reconfiguration'. Besides changes in LNG's future

supply/demand balance, the industry's basic business model – in which capital intensive infrastructure is underpinned by long-term, oil price-linked, and often inflexible, gas contracts – is changing. Given present and future market uncertainties, existing buyers are unwilling to accept such contractual terms, while many new buyers are less creditworthy than sellers might wish. These new buyers

are seeking to operate and structure contractual arrangements in a different way. The challenge for the industry will be to find a workable balance between buyers' concerns in relation to competitiveness and flexibility, and sellers' needs to secure financing and to make acceptable investment returns.

Over its 52-year lifetime, the LNG industry has evolved in many ways, adapting itself to various supply and demand events. LNG has in fact proved itself resilient to multiple shocks. The LNG community has also changed: for a long time, it was a small cosy club with a 'relationship culture', especially in Asia. LNG trade increased from 102 mtpa in 2000 to 245 mtpa in 2015. Today, 35 countries import LNG and the number and diversity of LNG players along the gas value chain has substantially increased. A further step may be towards a world where the distinction between buyers and sellers is no longer clear cut. Buyers will increasingly invest into the upstream to secure strategic stakes in LNG projects, while portfolio sellers will increasingly become involved in marketing the gas. Consolidation between suppliers and cooperation among buyers (or between buyers and sellers) is now taking place.

The future of LNG is linked to that of natural gas. Despite optimistic outlooks for natural gas, the fuel is struggling to compete against cheap coal and renewables. Coal remains extremely competitive in most regions, except the USA, and this commercial argument is currently outweighing environmental concerns. Meanwhile, the United Nations Climate Change Conference (COP21) in December 2015 failed to fully recognize the key role of natural gas in the reduction of CO<sub>2</sub> emissions and in the transition to a carbon-constrained world.

### Demand trajectory

ExxonMobil envisages a tripling of LNG demand by 2040 to around 760 mtpa, from today's levels. The assumptions that prevailed until 2014 – Asian LNG demand is 'infinite', and these buyers will pay a premium for LNG – are certainly worth revisiting. By adding together the regional demand perspectives we have arrived at four cases, with LNG demand ranging from roughly 390 to 610 mtpa by 2030. Asia shows the highest potential for growth, but also the largest uncertainty. Developing markets such as Latin America, the Middle East, and Africa could emerge as significant demand centres. Europe is likely to be in a position to absorb surplus LNG and balance the market, depending on the demand in other regions. Finally, the development of small-scale LNG is still in its infancy, though the market is developing in a number of directions. Probably the most important driver will be the rate of adoption of LNG as a marine fuel. Cumulatively the volumes could grow to between 25 and 50 mtpa by 2030.

.....  
**'THE SUPPLY SIDE TRANSFORMATION  
 AHEAD OF US IS EXCEPTIONAL, AS  
 EXPORT CAPACITY WILL RISE BY 50 PER  
 CENT (150 MTPA) OVER 2015–20.'**  
 .....

### Expected supply and investment uncertainties

The supply side transformation ahead of us is exceptional, as export capacity will rise by 50 per cent (150 mtpa) over 2015–20. The previous LNG supply wave, led by Qatar from 2009 to 2011, saw only half of that volume (77 mtpa). Meanwhile, the existing LNG supply picture is not set in stone since some LNG suppliers may disappear by the 2020s while others may face a further decline from their current LNG export levels due to gas shortages.

The LNG industry may face a major supply boom-and-bust cycle. The compounded effects of low prices and growth in capacity are setting the stage for a potential dearth of final investment decisions, and already many projects have been postponed. Around 1,000 mtpa of LNG projects are proposed as of 2016, most of these in Australia, North America, Eastern Africa, and Russia. Unless costs can be drastically cut, very few projects will be sanctioned in an environment with a \$40–50/bbl oil price and a \$4–5/MMBtu spot price in Europe and Asia. Meanwhile, the current consensus about the timing of markets rebalancing is 'sometime between 2020 and 2025'. If markets rebalance faster than expected, there is a danger that supply will be inadequate (given the four to five year lead time between FID and first production), striking a damaging blow to the gas industry. Projects moving ahead will be the most cost-competitive, located in countries with a stable fiscal and regulatory framework, and enjoying political stability.

### Price/cost relationship

As James Henderson observes above, the USA is set to become the third-largest holder of LNG export capacity by 2020. Its tolling model means that off-takers may not lift the LNG under certain market conditions. The 'premium' price gap between the USA and Asia is gone: since early 2016, US LNG projects have been competing on the basis of their variable costs, while the liquefaction fee will have to be partly – or even fully – considered as a sunk cost. Under these conditions, it is unclear how long some capacity holders will be willing (or able) to continue paying the tolling fee (although this may not become serious until bigger volumes come on stream later in the decade). Meanwhile, as Anouk Honoré notes, should large quantities be left for Europe to absorb,



these LNG supplies will challenge Russia's market share, and Gazprom's response is not clear. If US Henry Hub prices are significantly above \$2/MMBtu, US LNG projects will have to price their gas below their variable costs to compete against Russian gas.

Prices and costs will determine at what pace future LNG supply comes to markets, and influence demand developments. Prices have to be high enough for investors to convince lenders that their project is viable. But gas also needs to be affordable given that domestic wholesale prices in many new LNG importing countries remain below \$4/MMBtu.

### Pricing mechanisms

The issue of pricing mechanisms remains unresolved in Asia. As Jonathan Stern concludes, it is likely that the coming decade will see the coexistence of different pricing mechanisms – oil linkage, HH, spot indices, and average import prices – until a regional trading price emerges. Meanwhile, an LNG FOB trading hub could be developed in the Gulf of Mexico or in Eastern Australia, with Asian hubs perhaps emerging in the 2020s, given the obstacles to market liberalization to be overcome. Oil-linked long-term contracts will represent the majority of aggregate LNG supply for at least the coming decade. For existing contracts, the absence of effective price review clauses will complicate

moves to change the pricing mechanism. Buyer motivation to do so would increase should a significant gap emerge between spot and term prices. Buyers' financial distress could be a powerful reason for a change, as was the case in Europe's gas market evolution to traded hubs in the 2005 to 2016 period.

### Moves towards commoditization

Several trends support the expected growth in spot and short-term trade from 28 per cent in 2015 to up to 43 per cent by 2020: uncontracted capacity, aggregators using portfolio LNG, the role of the USA and Qatar, and buyers' reluctance to extend existing long-term contracts as they seek flexibility to deal with demand uncertainties. The current pressure on margins is likely to drive cargo swaps on a greater geographical and corporate scale, not just within one seller's portfolio, to optimize shipping.

### ••••• 'IF SOME CREDIBLE AND TRANSPARENT SPOT PRICING ALTERNATIVES EMERGE, LONG-TERM CONTRACTS MAY INCLUDE THEM MORE WIDELY.' •••••

Given current prices and market conditions, it seems highly unlikely that LNG projects could move ahead without long-term contracts. But the industry has already shown its ability to adapt to change: US and Qatari LNG projects have taken FID based

on market-based pricing in long-term contracts. If some credible and transparent spot pricing alternatives emerge, long-term contracts may include them more widely. The rise of spot and short-term does not mean the immediate end of long-term (20-year) contracts, as lending institutions still prefer them to guarantee cash flow. But buyers need more flexibility such as a mix of long-term, short-term, and spot LNG contracts, and spot indexation in these contracts. Meanwhile, lower investment grade buyers and traders are increasing in importance. Consequently there might be a tipping point where LNG markets move towards a greater commoditization, and should this happen there would be 'no turning back' for long-term contracts. Existing long-term contracts will not (or only partially) be extended; this would not threaten their economics as their associated capital costs have already been amortized. Whether new projects take decisions to proceed without long-term contracts will depend on lenders accepting that spot LNG trade will become the norm, with reliable spot price benchmarks in place and lower LNG costs supporting project economics. The great reconfiguration of the LNG business, toppling 50 years of business practice, should enhance the role of LNG in the development of flexible international gas trade, and hence make a major contribution to the increasing globalization of the gas business.



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September 2016  
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