Global Gas/LNG Research

LNG Supply Outlook 2016 to 2030

By

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Contents

Essential Acronyms, Units and Conversions

Terms:	
ACQ	Annual contract quantity, as specified in SPAs.
DES	"Delivered ex ship", delivery of goods to a buyer at an agreed upon point of receipt (port of arrival).
DOE	US Department of Energy. http://energy.gov/
DQT (and UQT)	Downward quantity tolerance. As specified in SPA terms, the portion of ACQ volumes that a buyer/seller is allowed to forego without payment during a specified annual delivery period. DQT terms usually require "make good" quantities that are required to be purchased later such that DQT volumes are considered to be deferred. **UQT**, upward quantity tolerance, is the amount of volume that a buyer/seller is able to increase for a given ACQ. The remainder of ACQ after DQT and UQT is considered TOP.
EPC	Engineering, procurement, construction.
FERC	US Federal Energy Regulatory Commission. http://www.ferc.gov/default.asp
FID	Final investment decision (sanction).
FLNG (and FSRU)	Floating LNG facilities, capable of liquefying and storing natural gas for marine offloading. Facilities capable of regasification (warming the LNG back to a gas phase) are typically referred to as floating storage and regasification units or **FSRU**s.
Force majeure	"Acts of God" clauses in contracts which protect parties or specify remedies when obligations cannot be met because of extraordinary events. Force majeure quantities are typically specified in SPAs.
FOB	"Free on board", point at which seller transfers title to buyer.
FTA	Free trade agreement, within the context of US DOE approval of LNG exports.
IGU	International Gas Union. http://www.igu.org/
LNG	Liquefied natural gas; mainly methane, chilled under atmosphere pressure, to -256 F (Farenheit). See CEE's Introduction to LNG, http://www.beg.utexas.edu/energyecon/INTRODUCTION%20TO%20LNG%20Update%202012.pdf
Natural gas	A hydrocarbon mixture that can include a variety of molecules including methane (one carbon and four hydrogen atoms, CH_4), ethane (two carbon atoms or C_2), propane (C_3), butane (C_4), pentane (C_5) and other forms and compounds that result in variation in molecular size and weight. The most common reference to natural gas in this paper is methane. See http://naturalgas.org/ for basics and descriptions of natural gas value chain segments and facilities and natural gas occurrence, and http://www.beg.utexas.edu/energyecon/GlobalGas-LNG/ for similar background relative to LNG development, safety and security.
NEB	National Energy Board-Canada. https://www.neb-one.gc.ca/index-eng.html
SPA	Sales and purchase agreement, the master contract under which LNG and other goods are bought and sold. An SPA for LNG is usually in the form of a master sale and purchase agreement with associated documents that provide specifications for seller and buyer facilities and deliveries, measurement and quality, title transfer, credit and payment. The Association of International

	Petroleum Negotiators, AIPN, provides a master SPA model contract. See www.aipn.org for details.
TOP	Take-or-pay. Provisions in SPAs that require payment for contracted volumes (ACQ) regardless of whether buyers take them.
Train	Liquefaction and associated facilities to convert "feed" gas to LNG. Feed gas may be processed and treated before liquefaction. May be indicated by number at large facilities, in the form "T#".
Units and conversions:	
Natural gas quantities in cf, Btu, cm	A cubic foot, **cf**, of natural gas is the volume per cf at standard (normal) temperature (60 degrees Farenheit) and pressure (sea level). A cf of natural gas that is entirely methane, gives off about 1,011 British thermal units (**Btu**s) per cf. Energy (heat) content varies with natural gas composition. Natural gas heat values can range from 950 to 1150 depending upon molecular composition (see http://www.engineeringtoolbox.com/heating-values-fuel-gases-d_823.html). Natural gas volumes in metric are expressed in cubic meters or **cm**. Natural gas volumes in this paper are measured in thousand (M), million (MM), billion (B), trillion (T). Average throughput associated with natural gas facilities (the volume of natural gas moved through facilities such as pipelines, underground storage and LNG trains, storage and regasification is expressed generally as volumes "per day" or "cf/d" or for metric "per annum" or cma. One billion cubic feet or Bcf of natural gas converts to metric, one billion cubic meters or Bcm, using a multiplier of 0.028. The BP Statistical Review of World Energy, http://www.bp.com/en/global/corporate/energy-economics/statistical-review-of-world-energy.html includes useful conversion factors and data.
LNG quantities in t, tpa	Tonnes of LNG, **t**, a measure of LNG facilities' capacity and tonnes per annum, **tpa**, a measure of throughput from LNG facilities. LNG facility capacities and throughput are most commonly expressed as million tonnes, **mt**, and million tonnes per annum, **mtpa**. A Bcf of natural gas converts to 1 mt of LNG with a multiplier of 0.021 (rounded). A Bcm of natural gas is converted to 1 mt of LNG with a multiplier of 0.74 (rounded).
Bbl, BOE	Standard 42-gallon barrel, or **Bbl**, of crude oil, liquids, or oil equivalent (expressed as barrel of oil equivalent or **BOE**).

Note that this paper is prepared using British English style. All values expressed in "$" are US dollars.

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PREFACE

This research paper is part of a body of work undertaken to better understand demand for natural gas in key world regions and implications for natural gas trade over the next 20 years (see Appendix 4: CEE Natural Gas Research Prospectus at end of document). The research is being led by the Bureau of Economic Geology's Center for Energy Economics, The University of Texas at Austin, with external collaborators and peer reviewers.

Mr. Andy Flower, a noted LNG professional and consultant, was invited to prepare a synopsis of his views on worldwide LNG supply capacity and deliverability, including trends in commercial LNG contracting. Mr. Flower has been working as an Independent Consultant since May 2001 specialising in the LNG business where his areas of expertise include; strategy, marketing, project structures, shipping, pricing, supply and demand and project economics. He retired from BP in 2001 after thirty two years of service, including twenty two years working in the company's LNG and natural gas business units where he managed BP's interests in LNG projects in Abu Dhabi, Nigeria, Australia and Qatar and negotiated LNG sales and purchase agreements with buyers in Asia, Europe and the USA.

To address the complicated and fast-changing LNG industry and lay the foundation for this research paper, the CEE team held two research seminars. The first, on 23 September 2015, included discussion on Asian gas demand, with a focus on India, as part of CEE's detailed case study on Chinese and Indian domestic gas use and their impact on natural gas markets and trade (forthcoming as of this release). The second, held on 31 May 2016, laid out the conclusions from this paper as well as early observations and conclusions from the China/India analysis. Both events were attended by diverse audiences of industry experts. Peer reviewers for this paper were: Dr. Michelle Michot Foss, Principal Investigator for CEE's global gas and LNG research; Dr. Gürcan Gülen, research scientist and senior energy economist; Mr. Guy Dayvault, Energy Deal Solutions; Dr. Donald Knop, CEE analytics and modeling advisor; Dr. Bhamy Shenoy, CEE India/Asia advisor; and Ms. Deniese Palmer-Huggins, CEE senior energy advisor. Mr. Dayvault also contributed an executive summary (provided as a separate document and download from CEE's web site, http://www.beg.utexas.edu/energyecon/GlobalGas-LNG/.

Across a range of data sources, natural gas consumption worldwide constitutes about 24 percent of total energy use. For many countries, LNG represents the only feasible option for natural gas supply; LNG trade represents about one-third of the total of natural gas trade (by pipeline and LNG shipping) worldwide. While LNG itself represents a form of direct use of natural gas (as bunker fuel for ships, for instance, or to power medium and heavy duty trucks), it is LNG as a midstream mode of delivery from field to market that is of interest here. The value chain operations and linkages required to chill and store liquefied methane and transport LNG from point of production to point of delivery are large scale, costly, imbued with risk and uncertainty, and nothing if not complex. Previous work by the CEE has demonstrated the ability of the industry to operate safely and securely (see the knowledge base at http://www.beg.utexas.edu/energyecon/GlobalGas-LNG/). LNG incidents are very few and far between. Financial and economic risks are, however, inherent in development and operation of LNG value chain assets. These are long lead time undertakings, involving complicated commercial transactions and risk mitigation, and thus subject to the vagaries of the marketplace. Given expectations about the role natural gas could play in satisfying energy demand in key locations such as China and India, the status, growth and forward trajectory of the global LNG industry is no small matter.

1. Introduction

LNG supply returned to growth in 2015 after three years of stagnation between 2011 and 2014. It is the first stage of an expected surge in supply which will take output to close to 385 mtpa by 2020, an increase of around 55% compared with 2015. The surge in supply is taking place as demand growth weakens in the key markets of Asia, which received 72% of global supply and in an environment where natural gas, LNG and oil prices have fallen to levels last seen over a decade ago. There will be strong competition amongst projects and sellers to find markets for their LNG, which will continue to put downward pressure on prices even if oil prices rise from the current lows as is widely expected.

Over the period to 2020, LNG supply will be overwhelmingly determined by the production from projects currently in operation and under construction since it typically takes around four years to construct a new large-scale liquefaction plant. After 2020, the growth in supply will mainly come from projects currently at the planning stage. A record level of just over 700 mtpa of new capacity has been proposed, three quarters of which is in North America, where developers have been looking to take advantage of low natural gas prices and increasing production resulting from the shale gas revolution. Taking FIDs on new liquefaction capacity in an environment of low prices with buyers and off-takers of LNG reluctant to enter into the long-term commitments that most developers need to underpin the investment will be a major challenge. Yet if FIDs are delayed for too long there is a risk that at some stage after 2020 buyers could face a shortage of supply and rising prices once again.

This paper will firstly review the outlook for LNG supply based on the liquefaction capacity in operation and under construction in April 2016 and taking into account the possible reduction of output from some operating plants as gas reserves are depleted or governments prioritise domestic gas demand over LNG exports. It will then consider the prospects for growth in supply after 2020 when the contribution from projects at the planning stage will be increasingly important. The outlook for pricing and how suppliers are responding to the need of buyers for increased contractual flexibility will be discussed in Section 6.

2. LNG Supply in 2015

Global LNG supply increased by 6.61 mt (2.7%) year-on-year in 2015 (Table 1), after the last three months of the year saw the fastest quarterly growth rate for 4 years, with production increasing by 3.46 mt (5.7%). Exports from Australia in 2015 were up by 5.76 mt (24.6%) as three trains in Queensland supplied with coal bed methane were commissioned. The Queensland Curtis LNG plant, which commenced exports from train 1 in January and train 2 in July, delivered 79 cargoes (5.09 mt) to buyers during the year. Train 1 at Gladstone LNG was the third train to start-up in Queensland, when it exported its first cargo in October. It delivered 6 cargoes (a total of 0.4 mt) during the fourth quarter of 2015.

Table 1: Regional LNG Supply in 2014 and 2015 (mtpa)

Region	2014	2015	Increase/Decrease	%age Change
Pacific Basin	90.48	100.99	10.51	11.6%
Middle East	96.69	94.57	-2.12	-2.2%
Atlantic Basin	54.43	52.65	-1.78	-3.3%
Total	**241.60**	**248.21**	**6.61**	2.7%

Indonesia's Donggi-Senoro plant was the other start-up in 2015 exporting 12 cargoes (0.62 mt) by the end of 2015 and helping Indonesia's LNG output to return to growth after five years of decline. Overall output from Pacific basin LNG plants increased by 10.51 mt (11.6%) in 2015. PNG LNG which started exporting LNG in May 2014, increased its production by 3.7 mt in 2015, its first full year of operation.

The increases in supply from the Pacific basin were partially offset by declines in the Middle East and the Atlantic basin. The halting of production at Yemen LNG in April 2015, because of the civil war, reduced its output for the year by 5.29 mt. Output was also lower in Abu Dhabi and Oman but Qatar increased its exports by 3.58 mt (4.7%) as it undertook less maintenance on its fourteen liquefaction trains than in 2014.

In the Atlantic basin, the Atlantic LNG plant in Trinidad and Tobago became the latest liquefaction plant to be adversely affected by gas supply problems because of a combination of reservoir depletion, increased maintenance on offshore facilities and lack of exploration success. Its exports were down by 1.9 mt (13.2%) compared with 2014. Algeria's LNG output has continued to decline despite the 9.2 mtpa addition to its capacity through the commissioning of new liquefaction trains at Skikda and Arzew in 2013 and 2014 respectively. The need to meet growing domestic demand as the growth in gas production stalls is the main reason for Algeria's overall decline in LNG production of 0.81 mt (6.2%) in 2015. Angola LNG and Egypt's two liquefaction plants were offline throughout 2015. The only two plants in the Atlantic basin to increase their output in 2015 were Nigeria – by 0.91 mt (4.7%) – and Norway – by 0.71 mt (19.6%) – as they enjoyed a year of operations free from the problems that have affected output in previous years.

The growth in supply continued in the first quarter of 2016 but the rate of growth slowed to around 2.5% because of unscheduled shutdowns at Russia's Sakhalin 2 plant, Peru LNG and Nigeria LNG. Australia continued to lead the way in terms of the growth in output as the first train at the Australia Pacific LNG plant became the fourth of six trains on Curtis Island to start-up. Australia's output was nearly 50% above the level in the first quarter of 2015. Two other trains loaded their first cargoes during the quarter, train 1 at the Sabine Pass plant in the USA and train 1 at the Gorgon LNG plant but in Australia. The start-up of the Sabine Pass train was delayed by about 4 weeks because of a technical problem but by the end of April 2016 it had loaded seven cargoes and was ready to commence commercial operations. The start of Gorgon train 1 was also delayed by a few weeks and a technical problem caused it to be shut-down for repairs after the first cargo departed.

3. LNG Supply from Projects in Operation and Under Construction in April 2016

LNG supply over the period to 2020 will largely depend on the output from liquefaction plants in operation and under construction since it typically takes around four years to construct a green-field liquefaction plant. Some developers claim that they can build smaller scale facilities more quickly and the time taken to expand existing facilities can be a few months shorter than building a green-field plant. However, even if a FID is taken in 2016 on a plant its output is unlikely to have any significant impact on global supply by 2020. The supply from projects currently at the planning stage, which will be discussed in Section 4, will only begin to make an important contribution to LNG supply in the 2020s

3.1 LNG Supply from Projects in Operation in April

The available nameplate capacity of the 28 liquefaction plants in 16 countries that were in operation at the end of 2015 was an estimated 283.8 mtpa. However, the four trains that came on-stream in 2015 only operated for part of year while Yemen LNG was only in operation for the first three and a half months of the year. The effective capacity available in 2015 was around 277 mtpa. Output was 248.2 mtpa so the utilisation factor was 89.5%. Four liquefaction plants (two plants in Egypt and one each in Angola and Yemen) with a capacity of 24.1 mtpa were offline at the end of 2015. If those plants had been in operation for the full year the available capacity would have been 300 mtpa and the utilisation factor 83%. There were a number of reasons for the utilisation rates in 2015, which were low historically.

- Production from plants in Indonesia, Oman, Nigeria and Trinidad was below capacity because of a shortfall in natural gas supply. Depleting reserves were the reason in some cases but decisions by governments to prioritise domestic demand over LNG exports also contributed to the short-fall.
- Egypt's two liquefaction plants, Egyptian LNG (capacity 5 mtpa) and SEGAS (capacity 7.2 mtpa), did not produce any LNG in 2015 because of falling domestic natural gas production and increasing natural gas consumption. In only ten years Egypt has gone from being an LNG producer (both its liquefaction plants were commissioned in 2005) to becoming an importer with two FSRUs commencing operations in 2015.
- Production from Yemen's 6.7 mtpa liquefaction plant was halted in April 2015 because of security concerns as fighting intensified in the civil war.
- Production at the 5.2 mtpa Angola LNG plant, which exported its first cargo of LNG in mid-2013, was halted in April 2014 because of a major gas leak. Production is scheduled to restart in 2016 (see Section 3.1.1 below).

Production from the plants in operation is expected to increase over the next 24 to 36 months as the plants that came into operation in 2015 and early 2016 reach full capacity and Angola LNG and, possibly, Yemen LNG are brought back online. However, in the longer-term production from the existing plants will decline as some older trains are decommissioned and depleting gas reserves and/or increasing domestic demand lead to shortfalls in natural gas supply.

The three trains that loaded their first cargoes in 1Q16, will add 14.2 mtpa to available capacity when they are operating at full capacity.

3.1.1 The Prospects for Increased Supply from Operating Plants

Angola LNG: The operator, Chevron, said in early January 2016 that it expected the plant to load the first cargo since April 2014 in the second quarter. In late April 2016, the *Sonangol Sambizanga*, one of the project's seven ships arrived at the plant ready to load. Re-start and tendering of the first cargo was delayed again. As of late June, the tender results were announced and ship loaded and sailed for delivery.[1] The plant is mainly supplied with associated natural gas from offshore oil-fields, which is of variable quality and has contributed to the problems that the project has faced since start-up. It may mean that the plant will not be able to sustain production at its full design capacity of 5.2 mtpa.

Yemen LNG: The restart of production depends on the security situation in the country improving so that it is safe for staff to return to the plant at Balhaf. There is no sign of an end to the civil war

[1] According to Reuters, http://www.reuters.com/article/vitol-lng-angola-idUSL8N1981X2, trading house Vitol was winner of that cargo tender. Four cargos were dispatched from Angola LNG, to destinations including Korea and Kuwait, before the plant was again shut down, reportedly for maintenance.

so a restart in 2016 is unlikely and it could be several years before Yemen becomes an LNG exporter once again.

Egypt: The 5 mtpa SEGAS at Damietta halted production in December 2012 and has been mothballed since then. The 7.2 mtpa Egyptian LNG plant is being maintained in readiness to restart production at 24 hours' notice. It exported three cargoes in 2014 and none in 2015. However, a cargo was produced and exported to India in March 2016. The discovery of over 60 Tcf of reserves in the Levant basin offshore Egypt, Israel and Cyprus offers the prospects of Egypt eventually restarting LNG exports on a regular basis but progress in developing production from recent discoveries has been slow. Israel's 8 Tcf Tamar field is the only large discovery in the basin currently in operation. It supplies the local market. Non-binding agreements have been signed for the supply of gas from Israel's Leviathan and Tamar fields to Egyptian LNG and SEGAS respectively. Before its acquisition by Shell, BG, which operated the Egyptian LNG plant, and Noble, which operates the 22 Tcf Leviathan field, were reported to have finalised the terms of a contract to supply 7 Bcma to the Egyptian LNG plant by 2019. This would be sufficient natural gas to produce around 4 mtpa of LNG. BG also acquired a 35% share in the block offshore Cyprus in which the 4 Tcf Aphrodite field has been discovered. Eni's discovery in 2015 of the Zohr field offshore Egypt, with estimated reserves of 30 Tcf, could change the outlook for Egyptian LNG. There are plans for the rapid development of production from the field with Eni saying it expects production to start in 2017 and build up to 27 Bcma (equivalent to 19.8 mtpa of LNG) by 2019. Zohr could become a hub for the delivery of gas from Leviathan and Aphrodite to Egypt leading to the restart of LNG exports in 2019 or 2020. However, Egypt's future as a long-term exporter of LNG remains uncertain. Exports peaked at 10.6 mt in 2006 only one year after they commenced but they declined steadily from the peak as domestic demand increased and within 10 years of starting exports it became an importer receiving 4 mt in the first 12 months of operations of its FSRUs. The Egyptian government has been responding to developments in the supply and demand for natural gas rather than establishing a long-term policy for the sector.

3.1.2 Operating LNG Plants at Risk of Closure or Reduced Output

Indonesia: The Arun liquefaction plant reopened as an LNG import terminal in February 2015 after operating for 36 years as a liquefaction plant. Output from the plant had been in decline since the late 1990s as reserves in the Arun field, its main source of gas supply, were depleted, and some of the production from the field was diverted to meet increasing gas consumption in the Aceh region of northern Sumatra. Output at the Bontang plant in East Kalimantan has been declining for over a decade as production from the fields that currently supply the plant runs down. Bontang is expected to produce 143 cargoes (8.1 mt) in 2016 down from 170 cargoes (9.6 mt) in 2015. At its peak the plant had the capacity to produce 400 cargoes (22.6 mt) per year. Chevron and Eni have discovered reserves in offshore blocks that they operate under production sharing contracts. The largest reserves are in the Chevron-operated Gendalo, Gehem and satellite fields which, it is estimated, have the potential to produce up to 1.1Bcf/d of gas (which could support around 7mtpa of LNG). A FID has been taken on the first phase of development, which involves the production of 120 MMcf/d from the Bangka field and gas production is scheduled to start-up in 2016. The second, much larger development has been deferred by two years because the Indonesian government has not made a decision on the extension of the production sharing contract, which Chevron needs before it will commit to fund the capex. Start-up of the second phase is not now expected until 2020 at the earliest. Eni and its partner Engie (formerly GDF Suez) are developing the Jangkrik field to supply up to 450 MMcf/d to the Bontang plant. Around 50%

of the LNG produced using gas from the Jangrik field will meet Indonesian demand. The Chevron and Eni fields are in deep water and have complex structures which make them high cost developments. In the current low cost price environment the economics of development are likely to be marginal.

Australia: Reserves depletion may be a problem in the 2020s for Australia's two oldest LNG plants, North West Shelf, which commenced operations in 1989 and Darwin LNG which followed in 2006. The North West Shelf's contracts for output from the three oldest trains, which came on stream between 1989 and 1994, are now mainly on a medium term basis and will expire between 2016 and 2022. However, some contracts for output from trains 4 and 5, which came on stream in 2004 and 2008, respectively will continue until after 2030. The project's joint venture partners have committed to the Greater Western Flank project to access a further 1.6 Tcf of reserves to supply the plant. However, at some stage in the later 2020s, reserves in the fields that supply the plant will probably be depleted to a level, which will require access to third party reserves or a reduction in LNG production. There are a number of natural gas discoveries close enough to supply the plant, including in the Browse basin if the planned Browse LNG project is not developed, which makes a continuation of production at the current level of around 15 mtpa a likely outcome through 2030.

Darwin LNG's contracts with its Japanese buyers expire in 2022. It may be possible to extend them for a few years using remaining reserves in the Bayu-Undan field that supplies the plant but new reserves will be required for a longer-term extension. There are a number of discoveries that could be tied into the plant so a continuation of production to 2030 appears to be feasible.

Brunei: Brunei LNG's current long-term contracts expire by 2023 by which time the plant will have been in continuous operation for over 50 years. It has been extensively refurbished and should be able to continue production until 2030 and possibly beyond. As is the case with most of the projects that have been in operation for many years, the main issue is gas supply. In the case of Brunei, there is considered to be the potential for reserves to be discovered in deep-water blocks but the status of exploration activity is unclear.

Malaysia: There have been questions how long reserves offshore Sarawak can continue to support the production of around 25 mtpa from the eight liquefaction trains in operation at Bintulu. The decision to build a ninth train, which is due to start production in 2016, and talk of a tenth and even an eleventh train suggest that Petronas is confident of the ability to continue production over the long-term, although it is possible that when the new trains are in operation one or more of the original three trains, which will have been in operation for 40 years by 2023, could be taken out of service.

Alaska**:** ConocoPhillips restarted the Kenai plant temporarily in 2014 delivering five cargoes (0.25 mt) to Japan in 2014 and a further six cargoes (three each to Japan and Taiwan) in 2015. In February 2016, the US Department of Energy approved ConocoPhillips request for a two-year extension to the export permit, giving it the right to export up to a total of 40 Bcf (around 0.8 mt) in the period up to February 2018. It is doubtful that the reserves in the Cook Inlet will be able to support production over the longer term. (See also Section 4.3.2).

Abu Dhabi: ADGAS's contract with Tokyo Electric for 4.7 mtpa of LNG expires at the end of March 2019 and there have been indications that the government may decide not to renew the contract because of a shortage of gas supply. Abu Dhabi has already reached the stage where it needs to import LNG to meet growing natural gas demand, especially in the power sector. It has chartered a FSRU from Excelerate Energy to be moored at Ruwais from August 2016. Initial indications are that imports could be around four to five cargoes per month (3 to 3.5 mtpa). Emirates LNG, a joint venture of two government owned companies, has been planning a 9 mtpa capacity onshore import terminal on the Indian Ocean coast of Fujairah but project has been suspended as the focus of activity turns to the immediate needs for imports. The continuation of production from the ADGAS plant depends on whether natural gas supply is available. One possibility that has been suggested is the supply of natural gas from Iran now that sanctions have been lifted. Discussions between Iran and Abu Dhabi over natural gas supply are reported to have taken place but two sides appear to be a long way from reaching an agreement. Even if it were decided to continue operating the ADGAS plant beyond 2019, the first two trains, which were commissioned in 1977, may be taken out of service, reducing capacity to 3.3 mtpa from train 3, which started-up in 1994.

Oman: The three train Oman LNG plant has been operating at less than 75% of its capacity because the government restricts natural gas supply to the level needed to meet the long-term contractual obligations with buyers as it prioritises meeting rapidly increasing domestic natural gas demand. The government is hoping that the development of the Khazzan tight gas project by BP will increase supply available for the Oman LNG plant but first gas is not expected before 2017 and by then Oman's domestic gas demand will have increased further. The best prospect for production at Oman LNG to be increased appears to be the supply of 1Bcf/d of Iranian gas to Oman, which has been in discussion for many years. An Iranian spokesman has recently said that around one-third of the gas could be delivered to the LNG plant, which would, potentially, boost production by around 2 mtpa. However, no decision has yet been made on the pipeline route and supply from Iran is not yet a done deal. Long-term contracts for 8 mtpa from the Oman LNG plant expire between 2020 and 2025.

Trinidad and Tobago: March was the fourteenth consecutive month of lower production year-on-year from the 15 mtpa capacity Atlantic LNG plant as natural gas supply has been curtailed because of a collapse in upstream investment and increased maintenance on ageing upstream facilities. Long-term contracts for the output from the 3 mtpa capacity train 1 expire at the end of 2018 and from trains 2 and 3 between 2022 and 2024. Exploration in deep-water blocks off the east coast have been disappointing and efforts to reach agreement with Venezuela for the development of gas reserves in exploration blocks that straddle the maritime border between the two countries have yet to succeed. There is considerable uncertainty about the level of production from the plant over the medium to longer-term.

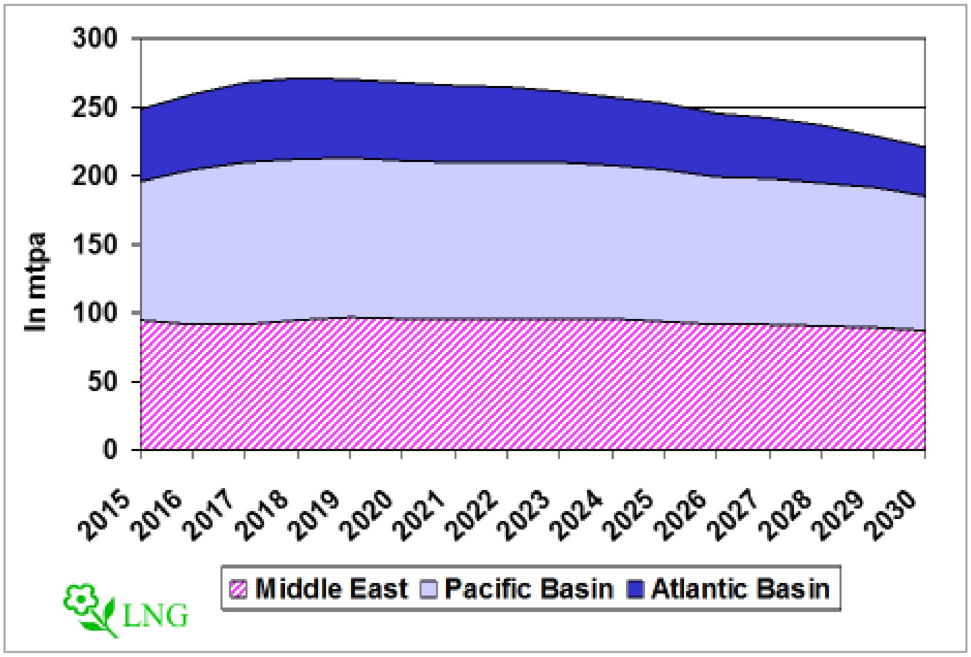
Equatorial Guinea: The sales contract with BG for the entire output from its single train 3.6 mtpa plant expires in 2024. The continuation of production after that date depends on the availability of gas supply.

3.1.3 Forecast LNG Supply from Plants in Operation at the End of April 2016

Production from plants in operation in April 2016 will increase over the medium term as production from trains commissioned in 2015 and the first four months of 2016 builds-up to full capacity and production restarts from Angola LNG. It is forecast to peak at 270 mt in 2019 and then decline to 252 mt in 2025 and 220 mtpa in 2030 as some of the older trains are taken off line and natural gas supply problems reduce production at other trains. (See Figure 1 below.) LNG output holds up best in the Middle East where it is dominated by Qatar. The country's North Field has sufficient reserves to ensure that production at around the 77.5 mtpa capacity of the Qatargas and RasGas plants can continue until 2030 and beyond. However, achieving a long plateau period will require considerable investment in compression to maintain production from the North Field.

Output from the other three plants in the Middle East will begin to fall after 2020 but the rate of decline will be slowed if plans for the export of natural gas from Iran to Oman and/or Abu Dhabi are implemented.

Figure 1: Forecast Production from Plants Which Started Production by April 2016

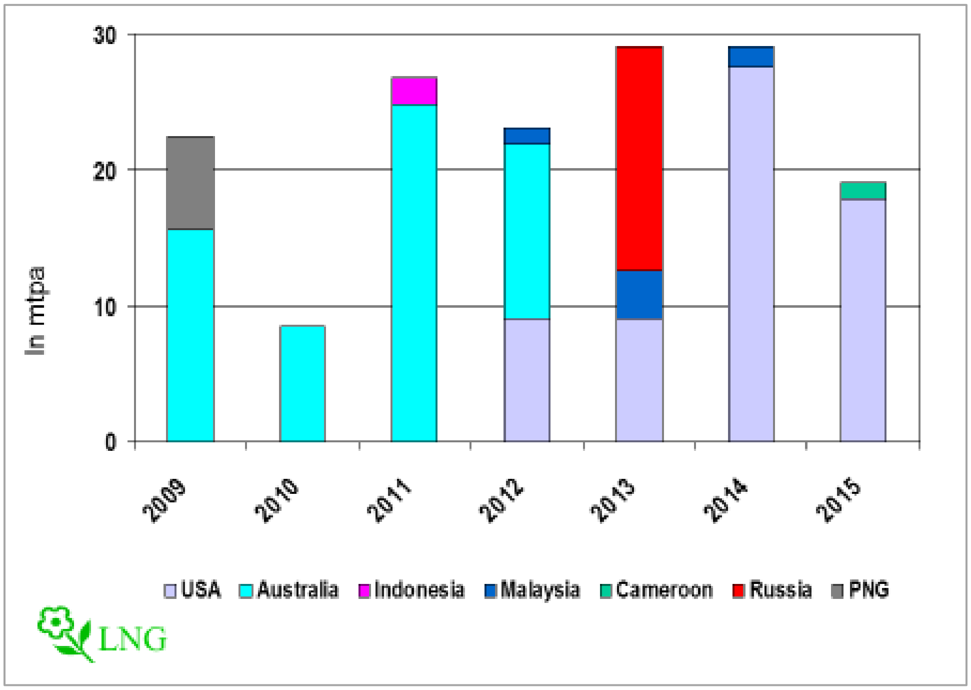


The build-up of production from Sabine Pass train 1 which started-up in February 2016 and the possible restart of Angola LNG and Egyptian LNG has the potential to stabilise production from the Atlantic basin over the next 5 or 6 years. However, it will then begin to decline falling to 35 mt by 2030 through production declining or being halted in Algeria, Trinidad and Equatorial Guinea as natural gas reserves supplying the plants are depleted. Production from existing plants in the Pacific basin is expected to remain at around 115 mtpa until 2025 but declines to 98 mtpa by 2030 because of shortfalls in natural gas supply to some of the region's older plants.

3.2 Liquefaction Capacity Under Construction in April 2016

In April 2016, 123.9 mtpa of liquefaction capacity was under construction globally, all of which is scheduled to be on-stream by 2021. Australia and USA have dominated FIDs on liquefaction capacity since 2009 (Figure 2) and as a result they account for 32% and 48% respectively of the capacity under construction. The only other countries with capacity under construction in April 2016 were Russia (Yamal LNG), Malaysia (two floating liquefaction units – the work on one of which has been suspended - and Bintulu train 9) and Cameroon (Kribi floating liquefaction unit). As figure 2 shows, Australia accounted for most of the FIDs from 2009 to 2012, the last of which was for the second train at Australia Pacific LNG (APLNG) in July 2012. Since then there has been a switch to FIDs on US projects, which accounted for nearly two-thirds of the total commitments over the last four years.

Figure 2: FIDs on Liquefaction Capacity 2009 to 2015



Note: Figure 2 excludes the conditional FID made by Petronas and its partners for the Pacific North West project in Canada's British Columbia Province because in April 2016 the partners were still not in a position to make the decision unconditional.

Table 2 lists the projects under construction in April 2016. The start dates in the last column of Table 2 take into account the most recent targets announced by the project operators for first LNG export. All the projects under construction are scheduled to produce their first LNG between the third quarter of 2015 and 2020. However, some of the targets appear optimistic and there may be slippage in start-up times. The start dates of several of the projects listed have been delayed compared with the expected dates when FID was first announced. In the case of multiple train projects, operators generally expect a gap of six to nine months between the start-up of individual trains. This means that after taking into account the build-up of production, it will probably be 2021 before production from the plants under construction reaches the plateau level of 123.9 mtpa.

Table 2: Liquefaction Capacity Under Construction in April 2016

Country	Project	Operator	Capacity (mtpa)	Start-up
Australia	Gorgon Trains 2 and 3	Chevron	10.4	3Q16
Australia	Gladstone LNG Train 2	Santos	3.9	2Q16
Australia	Australia Pacific LNG Train 2	ConocoPhillips	4.5	3Q16
Australia	Wheatstone	Chevron	8.9	3Q17
Australia	Ichthys	Inpex	8.9	4Q17
Australia	Prelude	Shell	3.6	4Q17
Malaysia	Floating LNG Unit 1	Petronas	1.2	3Q16
Malaysia	Bintulu Train 9	Petronas	3.6	3Q16

Country	Project	Operator	Capacity (mtpa)	Start-up
Malaysia	Floating LNG Unit 2*	Petronas	1.5	2020?
USA	Sabine Pass Trains 2 to 4	Cheniere	13.5	2Q16
USA	Freeport LNG Trains 1 to 3	Freeport LNG	13.9	3Q18
USA	Cameron LNG	Sempra	13.5	1Q18
USA	Cove Point	Dominion	5.3	4Q17
USA	Corpus Christi Trains 1 & 2	Cheniere	9.0	4Q18
USA	Sabine Pass Train 5	Cheniere	4.5	4Q18
Cameroon	Kribi Floating Liquefaction	Perenco	1.2	4Q17
Russia	Yamal LNG	Novatek	16.5	4Q17
	Total		**123.9**	

Note: Petronas announced in February 2016 that work on the project had been suspended but did not say when work would restart. A two year delay has been assumed.

3.2.1 The Status of Projects Under Construction in April 2016

The status of each of the projects under construction is summarised below:

Australia – Gladstone LNG (GLNG) train 2: The first LNG from train 1 was loaded in October 2015 and delivered to Korea Gas, a partner in the project, which has committed to purchase 3.5 mtpa on a long-term basis. Train 2 is expected to come on stream around the end of the second quarter of 2016 but the build-up to full capacity may take up to 2 years to allow time for the coal bed methane wells to be drilled and gas-gathering pipelines to be completed.

Australia – Australia Pacific LNG (APLNG): The first cargo was loaded and delivered to Korea in January 2016. The second train is expected to start-up in the third quarter of 2016.

Australia – Gorgon: When FID was taken in September 2009 the start of production was scheduled by the end of 2014. It was delayed several times and the first cargo was eventually loaded in March 2016 and delivered to Japan. However, immediately after loading the cargo, Chevron, the operator, announced that there had been a problem with the propane pre-cooling system and production was halted for repairs to be made. Operations are scheduled to restart by the end of May. Chevron still expects to start train 2 by the end of 2016.

Australia – Wheatstone: In January 2016, during the presentation of its 2015 results, Chevron, the operator of the Wheatstone project, said that because of delays in the delivery of modules from Malaysia start-up has been delayed to mid-2017.

Australia – Ichthys: In September 2015, the operator, Inpex, said that start-up had been delayed from late 2016 and was now expected between July and September 2017. The capacity of the two-train plant has been increased from 8.4 mtpa to 8.9 mtpa.

Australia – Prelude: Shell has provided very little information on the progress of construction of the floating liquefaction unit which is under construction in the Samsung yard in Korea. There are persistent rumours that it is significantly over budget and the start of production has been delayed from early to late 2017 and possibly into early 2018. In addition to 3.6 mtpa of LNG, 1.3 mtpa of condensate and 0.4 mtpa of LPG will be produced. The unit will have the capacity to store 220,000m^3 of LNG, 90,000m^3 of LPG and 126.000m^3 of condensate. When fully loaded the unit, which is 488m long and 74m wide, will have a displacement of over 600,000 tonnes.

Malaysia – Floating Liquefaction 1: Petronas's first floating liquefaction unit (PFLNG1), which has been built in the Daewoo yard is due to leave the yard in the second quarter of 2016. It will be used initially to liquefy natural gas from the Kanowit field 100 miles offshore Sarawak with production schedule to commence before the end of 2016. When the reserves in the field are depleted, which is expected to be in five to six years' time, the unit will be moved to a second field and then possibly to a third. The move to a new location will probably require the unit to be out of action for a period of time as modifications are made to accommodate a different quality natural gas in the field.

Malaysia – Floating Liquefaction 2: In February 2016, Petronas announced that it had suspended work on its second FLNG vessel (PFLNG2), which it has ordered from the Samsung yard in Korea. It did not say when work would recommence or give a new date for start-up, which was originally scheduled for 2018. Unofficial reports suggest the delay could be at least two years. The unit is intended to liquefy gas from the Rotan and satellite fields offshore Sabah.

Malaysia –Bintulu LNG Train 9: Start-up is expected in 2016 but Petronas has not given a definitive date. It has been assumed that it will be around mid-year.

USA – Sabine Pass: A wiring fault in a cold-box delayed start-up by about a month and the first cargo was loaded in late-February 2016. By the end of April, seven cargoes had been loaded and exported totalling just under 0.5 mt of LNG. At the beginning of May 2016, Cheniere, the owner and operator, submitted a request to FERC for the train to be placed into service which will trigger the start of the contract with Shell for output from the train. The commissioning of train 2 started in April and commercial operations are scheduled to start in August. Substantial completion of trains 3 and 4 is in April and August 2017, respectively.

USA – Sabine Pass Train 5: At the end of June 2015, Cheniere took FID on train 5, the first of a planned two train expansion of the plant. It will have a capacity of 4.5 mtpa and Cheniere has said start-up will be as early as 2018.

USA – Cameron LNG: Sempra LNG (50.2%) and its partners, Engie, Mitsui and Mitsubishi (16.6% each), took FID on the three train, 13.5 mtpa Cameron LNG project in August 2014. According to Sempra all three trains are expected to start operations in 2018 with 2019 the first full year of operation.

USA – Cove Point: The owner, Dominion Resources, has not made a formal announcement on FID on the 5.3mtpa single train Cove Point LNG plant but construction commenced in the fourth quarter of 2014. Start-up is reported to be on schedule for late-2017.

USA – Freeport: Freeport LNG took FID on trains 1 and 2 in November 2014 and on train 3 in April 2015. Each train will have a nominal capacity of 4.64 mtpa giving a total capacity of 13.9 mtpa. On its website, Freeport LNG says that train 1 is scheduled to start-up in September 2018, train 2 in February 2019 and train 3 in August 2019.

USA – Corpus Christi: Cheniere took FID on the first two 4.5 mtpa trains at its Corpus Christi plant in Texas in May 2015. It is the first green-field project in the US Lower-48 states which has reached that stage - the other four liquefaction plants are conversions of existing receiving terminals. Cheniere is targeting start or production in 2018.

Russia - Yamal LNG: FID on the project, which will have three 5.5 mtpa liquefaction trains, was taken December 2013. The start of production targeted for late 2017. Construction is reported to be progressing close to plan despite US and European Union sanctions, which slowed the raising of finance. Initial funding has come from the shareholders and from Russia's National Wealth Fund. At the end of December 2016, Novatek announced it had reached an agreement with China's Silk Road Fund to sell a 9.9% share from its 60% holding which provided much needed funds for Novatek's remaining 50.1% share of the project. It has also helped open the way for $12Bn of loans from Chinese banks, which Novatek announced had been secured at the end of April 2016. With funding in place and contracts for over 90% of the output signed with the project partners (Novatek, CNPC and Total) and with Gazprom and Spain's Gas Natural Fenosa, there appear to be no further constraints to the completion of the project. However, despite assurances that the project is on schedule for a late -2017 start-up, there is a risk that there will be a delay of start-up into 2018 given the delays in arranging funding and the challenging location of the plant in the Arctic region of northern Russia.

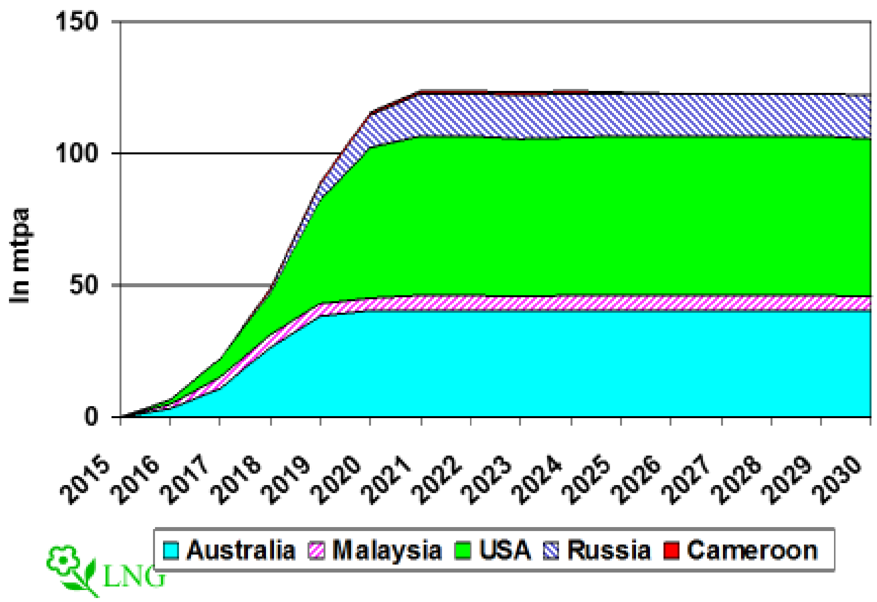
Cameroon – Kribi Floating Liquefaction: Perenco, a UK based independent oil and gas company, and its partner, Cameroon's national oil and gas company SNH, took FID in November 2015 on a project to liquefy natural gas production from the Sanga fields offshore Kribi in Cameroon using a floating liquefaction unit supplied by Golar LNG. The conversion of the 1977-built LNG ship, the *Hilli*, which has a storage capacity of 126,200m^3 into a floating liquefaction unit in Keppel yard in Singapore is due to be completed in early 2017 and start-up of production is scheduled for 4Q17. The project will produce 1.2 mtpa (around half the capacity of the FLNG unit) for eight years. Gazprom has committed to the purchase of the entire output from the project and will market it as portfolio LNG.

3.2.2 Forecast LNG Supply from Projects Under Construction in April 2016

Figure 3 shows the forecast of production from the projects under construction in April 2016. The forecast takes into account the target start dates shown in Table 2 but delays have been assumed for projects where the schedule appears optimistic. It has been assumed that PFLNG2 in Malaysia will be delayed by two years although it is possible that the project may be cancelled. The build-up of production for individual trains is assumed to take six to 12 months and the gap between the commissioning of trains in multi-train plants is assumed to be six to nine months. The full 123.9 mtpa capacity of the projects under construction is assumed to be reached in 2021.

It is possible that some of the new trains will operate above their design capacities and output may, in some cases, be further increased through debottlenecking. This could add up to 14 mtpa (i.e. assuming all the projects under construction and those that have been commissioned in the first four months of 2016 operate at 10% above design) to the output by 2025. However, the timing and the amount of additional production that might be available are uncertain. Furthermore, past experience shows that some trains may not operate at full capacity because of technical problems or gas supply shortfalls. Therefore, the possible upside on production is not taken into account in Figure 3 (or Table 2).

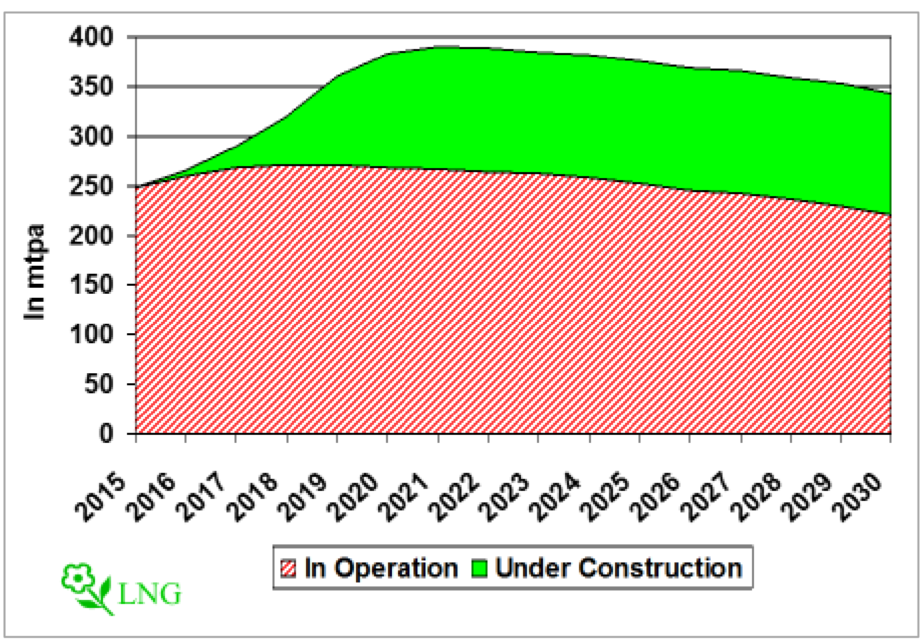
Figure 3: Forecast Production from Plants Under Construction in April 2016



3.3 Total Production from LNG Projects in Operation and Under Construction in April 2016

Production from the projects in operation and under construction is forecast to increase from 248.2 mt in 2015 to 385 mt in 2020 before declining to 375 mt in 2025 and 340 mt in 2030 (Figure 4) as some of the projects in operation are taken off-line and production is reduced at others due to declining reserves and/or growing domestic natural gas demand.

Figure 4: Forecast Production from Plants In Operation and Under Construction in April 2016



There is always uncertainty in forecasts of this type. There is upside potential if gas supply problems ease at some of the plants where it is constraining production and if trains under construction operate above their design capacity, as has often been the case in the past when new capacity have been brought on stream. On the other hand, delays in the start-up of new plants and continuing or increasing problems with gas supply could result in the outcome being lower than is shown in Figure 4. However, the forecast is based on facilities already in operation or under construction, which means that the range of outcomes is relatively narrow compared with forecasting the possible output from the many projects at the planning stage discussed in Section 4 below.

3.4 The Impact of Low LNG and Natural Gas Prices on Projects in Operation and Under Construction

The decision to invest in the projects currently under construction and for those that have recently started production (PNG LNG, Australia's QCLNG, Gladstone LNG, APLNG and Gorgon, Indonesia's Donggi-Senoro and the USA's Sabine Pass) were probably taken against what at the time were considered "conservative" assumptions of crude oil prices in the $60 to $80/Bbl range with LNG prices in Asia expected to be between $9 and $12.5/MMBtu and in Europe between $8 and $10/MMBtu. In the first four months of 2016, crude oil prices averaged around $37/Bbl and most forecasters expect them to remain low for an extended period.[2] There is a lag of several months built into the oil-indexed price formulae in the majority of Asian LNG contracts and sellers are looking at prices in long-term prices around $6/MMBtu by the middle of 2016 when the crude oil prices in early 2016 will have fully fed through. Spot prices in Asia, as measured by Platts' Japan Korea Marker (JKM), declined to $4/MMBtu in mid-April 2016, the lowest level since JKM was first published in February 2009. Natural gas prices at European trading hubs averaged $4.2/MMBtu in the first 4 months of 2016.

A frequently asked question is whether low prices will result in operating liquefaction plants being taken off-line, the start-up of projects under construction being delayed or, in the extreme, projects being abandoned. Production has not been halted at any of the operating projects as a result to low prices nor has there been any evidence of output being reduced in response to the low prices. Similarly, the owners and operators of projects under construction have continued to progress work as quickly as possible. Any delays have been due to technical problems.

The response is not surprising given the capital intensive nature of the LNG business and nature of project financing decisions. Operating costs are relatively low and for all the operating projects they are fully covered by the revenues, even at the current low natural gas and LNG prices. This means that keeping them in operation results in sufficient cash generation to contribute to the servicing any debt and contributing to the remuneration of the capital investment by the shareholders. Many of the projects will struggle to cover the cost of capital and will not earn the

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[2] CEE's own research suggests a lower, flatter oil price path but a possible tendency toward higher and more volatile natural gas (Henry Hub) prices. This outcome would derive from reduced drilling activity in response to low oil and gas prices (with unconventional oil and liquids drilling targets, in particular, yielding the cheapest sources of associated methane). In the US demand response to low commodity prices and ample supply has been powerful. A "call" on natural gas for the array of power generation, petrochemical and export projects (including to Canada and Mexico) due to come online beginning 2017-2018 would be matched with substantially reduced domestic production outputs. See http://www.beg.utexas.edu/energyecon/thnkcrnr.php for current research or contact CEE for details.

returns that had been expected when the decision to invest was made unless, of course, prices increase. However, as long as the sale of the LNG generates a margin which contributes to servicing any debt and remunerating the capital investment, production can be expected to continue.

In the case of US projects, the issue for companies that have committed to pay a liquefaction fee (which remunerates the capital investment and covers the operating and maintenance costs) under a tolling structure or through the purchase LNG on an FOB basis is whether the revenues from the sale of the LNG are greater than the cost of acquiring natural gas supply and transporting the LNG to market. If they are, then continuing to lift the LNG as contracted will make a contribution to the liquefaction fee which has to be paid whether or not LNG is lifted. If the revenues do not cover the cost of gas supply and shipping, then off-takers can be expected to exercise the option not to lift cargoes since to do so would only add to their losses. However, LNG prices in markets to which US LNG is delivered would probably have to fall below their level in early 2016 for that to be an option that would be exercised or US gas prices would have to increase significantly above the $2/MMBtu level around which they moved during the early months of 2016.

4. Planned LNG Projects

There is a long list of planned projects targeting the expected requirement for additional LNG supply after 2020 to meet growing demand and offset the expected reduction in output from some of the operating projects. If all were developed they would add over 700 mtpa to global LNG capacity (Table 3), several times more than any realistic assessment of what will be needed. Consequently, there will be strong competition between the sponsors of projects to secure the long-term commitment to the output that they need to underpin the investment. Ensuring that the project has the prospect of generating a reasonable return on the investment will be a key challenge in a lower price environment than that in which FID was taken on the majority of the projects now under construction. The capital cost of these projects will, therefore, be a critical factor in their economic viability.

Table 3: Proposed Liquefaction Capacity – April 2016

Country	**Capacity (mtpa)**
USA	248
Canada	333
East Africa	70
Australia	0
Russia	30
West Africa	20
Rest of Pacific Basin	20
Total	**721**

Over three-quarters of the planned projects are in North America as companies attempt to take advantage of the abundant gas resources and low natural gas prices to join the rush to export LNG. The sponsors of many of these projects have no previous experience of developing an LNG project, which means that gaining credibility with buyers, off-takers and investors will be a major challenge for them.

4.1 How Has the Oil Price Collapse Affected Planned LNG Projects?

The oil price collapse appears not to have had a major impact, as yet, on the plans for new liquefaction capacity with only a limited number of projects having been cancelled or deferred. The structure of US projects, with buyers and off-takers paying a fixed liquefaction fee, means that the oil price does not have a direct impact on the project economics. However, oil prices have an indirect effect since, with many non-US projects looking for oil-indexed prices, the price competitiveness of LNG delivered to the market will depend on the relative prices of crude oil and of US natural gas prices. This will be an important consideration for companies committing to buy or off-take LNG from planned US liquefaction plants. For projects outside the USA, oil prices have a more direct impact on the economic viability since a linkage to crude oil remains the pricing basis for many LNG sales. Sponsors will be hoping for a recovery in oil prices but that is outside their control so cutting costs will be of critical importance. Project operators, designers, contractors and equipment suppliers have come under increasing pressure to find ways of reducing costs and this pressure will continue.

Projects that have been abandoned because of the direct or indirect impact of low oil and natural gas prices include:

- Excelerate Energy's 3 to 4 mtpa floating liquefaction unit at Lavaca Bay in Texas on which work was suspended in December 2014 and the project cancelled in 2015. Excelerate said that the uncertainty generated by a steep decrease in oil prices had forced it to make a "strategic reconsideration of the economic value of the project.
- Pacific Rubiales (now renamed Pacific Exploration and Production) cancelled its 0.5 mtpa project in Colombia in early 2015, shortly before the floating liquefaction barge was due to leave the Wison yard in China. Market conditions were given as the reason for the decision.
- Oregon LNG was cancelled in April 2016 after its main backer, Leucadia National, halted funding.

Lower prices have been one of the reasons for the delay in FIDs on planned projects. At the beginning of 2015, FID was targeted on a total of 98.8 mtpa of capacity. In the event, only four projects, with a total capacity of 19.3 mtpa, reached that key milestone and three of those were in the USA, the only exception being the 1.2 mtpa Kribi project in Cameroon.

The changed oil price environment was the reason given by BG for a delay in its commitment to the Lake Charles liquefaction project in Texas, for which it intended to commit to the entire15.6 mtpa capacity – a decision on the project now rests with Shell after its acquisition of BG.[3] Petronas gave the need to reduce costs as the reason for not taking FID on Pacific North West LNG in Canada in December 2014, as had been originally planned. Low oil prices were also given as a reason for FID on the Woodside-led Browse LNG project in Australia being firstly delayed to the end of 2016 and then halted as Woodside and its partners review the options for development. BHPBilliton has said that the planned development of the Scarborough field offshore West Australia, in which ExxonMobil is the other partner, is on hold because of low oil prices.

A number of potentially high cost projects are still making progress despite the possible impact of low oil prices on future revenues. Despite the delay in FID, Petronas is still targeting FID on the

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[3] Shell has since announced that it will not proceed with Lake Charles at this time. Numerous news sources have reported this decisions

13.4 mtpa Pacific North West LNG project.[4] Shell and its partners are reported to be still giving priority to their 13 mtpa LNG Canada project although FID has been pushed back from mid-2016 to end-2016 and recent comments by a senior executive cast doubt on whether the new target will be met.[5] Anadarko is still expecting to take FID on its planned 12 mtpa project in Mozambique before the end of 2016, although it has said that spending on the project in 2016 will be minimal. Eni and its partners are also targeting FID in 2016 on their plans to develop natural gas in the Coral field using a 3.4 mtpa floating liquefaction unit.[6]

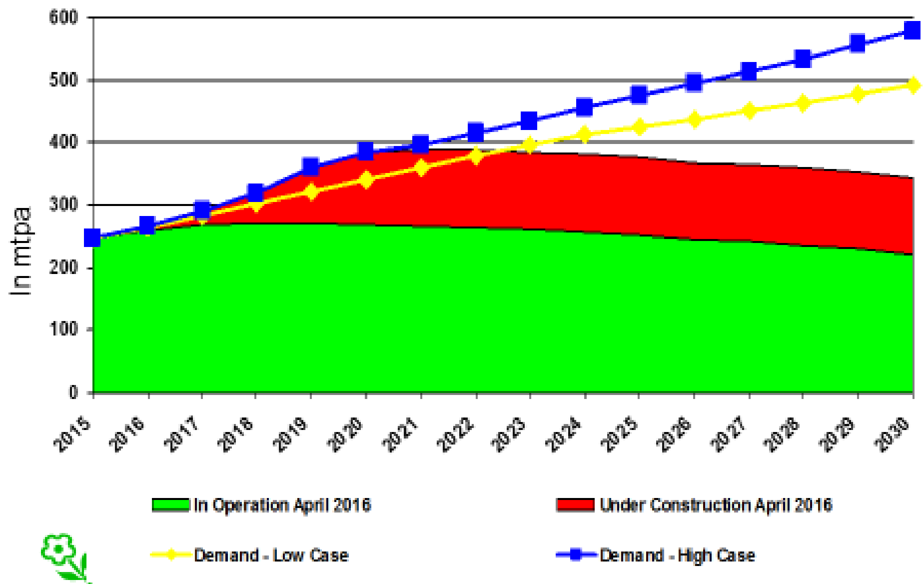
There is an expectation that the low oil price environment will reduce some of the cost pressures that the wider oil and gas industry has been facing in recent years, at least to some extent and for some period of time, and that this will lead to a reduction in the cost of liquefaction plants. There have been indications that the collapse in oil prices and lower commodity prices resulted in an initial fall of around 15% in the cost of LNG developments and that has been doubled as operators have focused on finding ways of reducing costs in an industry where a $100/Bbl oil price had taken some of the pressure off controlling costs.

4.2 How Much New Liquefaction Capacity is Required?

It is not the purpose of this paper to make a forecast of LNG demand.[7] However, the need for new liquefaction capacity in addition to that in operation and under construction depends on how demand from LNG will increase after 2020. Figure 5 shows two demand scenarios based on recent demand forecasts and compares it with the potential supply from projects in operation and under construction at the end of 2015.

[4] In early August 2016 Petronas announced further delays to FID.
[5] Shell also announced plans to delay the British Columbia, Canada near Kitimat. Numerous news sources have reported this decision.
[6] Mozambique upstream and LNG asset ownerships are likely to change substantially. Both ENI and Anadarko are in negotiations with ExxonMobil and partner Qatar Petroleum for sales of interests. Numerous news sources have reported these developments.
[7] Importantly, forthcoming CEE case studies will not incorporate original demand forecasts either, but rather constitute very detailed analyses of domestic gas demand, aggregate and sectoral, and value chain realization within the framework of published, public domain outlooks for future gas use. See Appendix 4: CEE Natural Gas Research Prospectus.

Figure 5: Global LNG Demand and Supply 2015 to 2030



The two scenarios show demand ranging from 425 to 475 mt in 2025. The high case assumes that LNG demand is equal to the forecast output from projects in operation and under construction until 2020 and then increases at 4.5% pa to reach 475 mt in 2025. It has been assumed that the growth rate slows to 4% pa from 2025 to 2030 leading to a demand of 580 mt in 2030. The low case assumes an average annual growth rate of 5.5% pa from 2015 to 2025, which takes demand from 248 mt to 425 mt, and that it then slows to 3% pa over the following five years to 2030, when it reaches 490 mt.

On the high case, the requirement for supply from planned projects starts in 2021 and increases to 100 mt in 2025. On the low case, new supply from planned projects is not required until 2023 and grows to 50 mt by 2025. In 2030, an additional 235 mt is required from planned projects on the high case while on the low case the requirement is 150 mt. The demand scenarios show that on the high case only 14% of the capacity currently at the planning stage is required by 2025 rising to just over 33% in 2030. In the low case, 7% is required by 2025 and just under 21% by 2030. These estimates of the requirement for new capacity do not take into account projects that will inevitably be proposed in the future as more stranded gas reserves are discovered.

4.3 Planned Liquefaction Capacity

4.3.1 USA – Lower 48-States

Despite the collapse of oil prices and weaker demand growth in key markets in Asia, there has been a steady stream of new proposals for US LNG export projects to add to the already long list of planned projects worldwide. On 18th April 2016, the FERC website listed projects with a total capacity of 245 mtpa (Table 4) that are at various stages in the permitting process.

Table 4: Planned US LNG Export Projects

	in Bcf/d	in mtpa
Approved Construction Not Yet Started	4.68	36.0
Proposed to FERC as at 18th April 2016*	8.56	65.8
Proposed to MARAD/Coastguard	1.80	13.8
Projects in Pre-Filing with FERC	14.60	112.3
Alaska LNG (Proposed to FERC)	2.55	19.6
Total	**32.19**	**247.6**

**Excluding Oregon LNG*

Source: FERC Website Dated 18th April 2016. Note: Appendix 1 lists the projects shown on the FERC website on 18th April 2016.

The permitting process requires projects to obtain US DOE approval for exports to countries with which the US has a FTA, which is a formality since, under the 1938 Natural Gas Act, the DOE must approve applications without delay or modification. A permit to export to non-FTA countries is also required. The DOE has to review applications to ensure that exports would not be against the national interest but the studies it has commissioned of the impact of LNG exports have shown an overall positive benefit and all its decisions to date have been in favour of allowing exports to non-FTA countries.[8]

Sponsors must also obtain FERC approval for the siting, construction and operation of the proposed facilities. FERC approval is the most demanding both in terms of the cost, estimated at up to $100 million for the preparation of the various reports required to support the application, and in terms of the time taken to process the application, which is typically around 18 to 24 months. Under new DOE rules introduced in mid-2014, applications for a permit to export to non-FTA countries are only considered after the project has received approval from FERC. The permitting process has not been a constraint on the development of US LNG exports since all the projects that have completed the DOE and FERC reviews, with the exception of the Jordan Cove project in Oregon, have been approved. Securing the funds needed to take a project through the approval process has not been a problem for many projects at an early stage of development but it has prevented others from continuing.

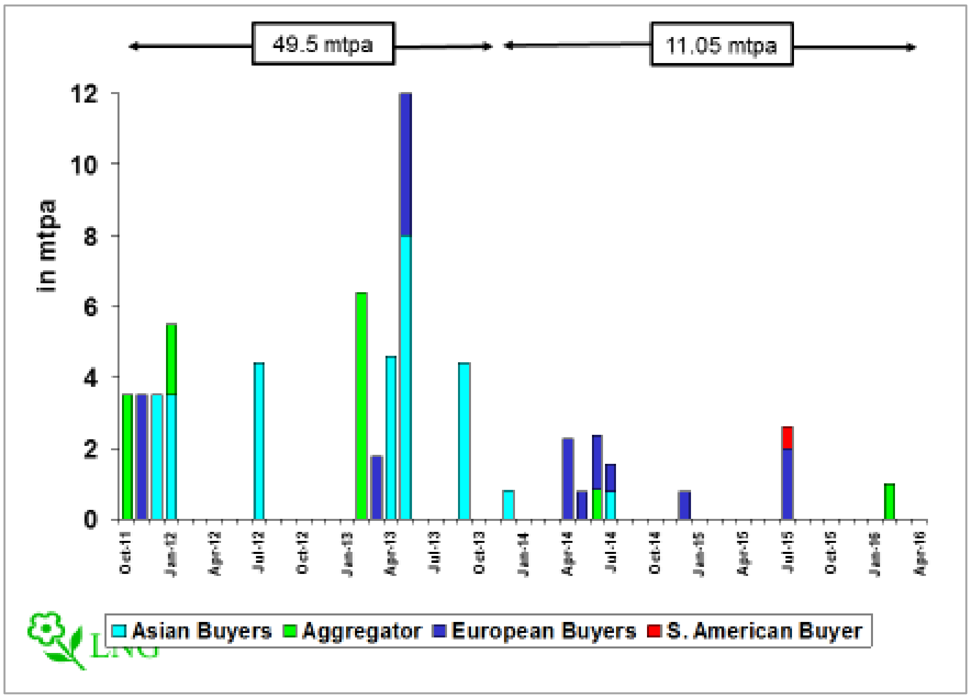
The main constraint on the development of projects is now securing commitments from creditworthy companies to either purchase LNG on an FOB basis or to toll gas through the facility, which is the preferred option for most of the projects now at the planning stage. Commitments from creditworthy buyers or off-takers are needed to raise loans, which are typically needed to cover up to 70% of the investment. There has been a slow-down in the level of interest in US LNG exports from potential buyers and off-takers, which can be seen in the number of binding agreements finalised in the last 18 months.

From October 2011, when Cheniere signed its first sales contract with BG, until September 2013, when Freeport LNG secured commitments to train 3 capacity, there were regular announcements of agreements being signed for the purchase or off-take of LNG from Sabine Pass, Cove Point, Freeport LNG and Cameron. The early deals were for relatively large volumes of LNG – 2.2 mtpa to 5.5 mtpa – and commitments were made to total of 49.05 mtpa of capacity over the two year

[8] See http://energy.gov/fe/services/natural-gas-regulation for DOE's authority and activity.

period (Figure 6). The majority of volume commitments were from buyers in Asia and from aggregators such as BG, BP, Mitsui and Mitsubishi that have built a portfolio of supplies to market or trade to buyers. In the 30 months since September 2013, binding commitments have been made to only 11.05 mtpa, the level of individual commitments have been smaller (0.75 to 2 mtpa) and there have been fewer commitments from buyers in Asia.

Figure 6: Binding Long-term Commitments to US LNG October 2011 to April 2016



In 2015, only one binding commitment was made to capacity at a US LNG export project, Meridian LNG's commitment to toll 2 mtpa through Magnolia LNG's planned 8 mtpa liquefaction plant at Lake Charles in Louisiana. Meridian plans to deliver the LNG to an FSRU to be moored in the Irish Sea off the west coast of England. At the end of January, LNG Ltd, the owner and operator of Magnolia LNG, announced that it had reached agreement with Meridian to extend the validity of the tolling contract by six months to the end of December 2016 because the timing of finalising further binding contracts for the project is uncertain due to market conditions.

The sponsors of planned US LNG export projects say that there is still interest from prospective off-takers and/or buyers. However, it is clear that securing binding long-term commitments from creditworthy companies is proving to be difficult.

Some of the sponsors of planned US projects are trying to respond to the changed market and price environment by planning for trains with capacities in the 1.5 to 2 mtpa range rather than the 4.5 to 5.3 mtpa trains being used by the five projects under construction in April 2016. Economies of scale have, in the past, been the way in which the LNG industry has tackled the need to reduce unit costs. In the process, the capacity of trains increased from 0.3 mtpa in the first liquefaction train in Algeria in 1964 to 7.8 mtpa in Qatar's mega-trains which were commissioned between 2009 and 2011. The capacity of trains currently being built or planned is typically in the 4 to 6 mtpa range. The companies planning smaller trains argue that by using alternative liquefaction technologies and value engineering they can reduce unit costs to a similar level to that for the larger, more conventional sized trains. For example, Magnolia LNG has said that based on its EPC contract with the SK/KelloggBrownRoot joint venture the cost of four 2 mtpa trains at the greenfield project will be between $495 and $544 per tpa of liquefaction capacity. This compares with the unit EPC cost of $440 to $500/tpa for the Sabine Pass plant which has 4.5 mtpa trains and is the conversion of an existing receiving terminal with storage tanks and marine facilities already in place.

The companies planning smaller trains also argued that they are a better fit with the changed requirements of buyers, who are looking to commit to lower annual off-take volumes. Furthermore, trains can be added sequentially to match more closely market requirements. There seems little doubt that a second phase in the development of US exports will see a slower growth in capacity and smaller commitments from buyers and off-takers.

4.3.2 USA - Alaska

Plans for the development of over 30 Tcf of natural gas reserves on the North Slope of Alaska date back to the 1970s. The plans have alternated between piping the gas to the Lower-48 states through Canada and LNG exports to Asia. Low natural gas prices as a result of the shale gas revolution have turned the focus back to LNG exports to Asia. The latest plan is for a plant with a capacity of up to 20 mtpa at Nikiski on the Kenai Peninsula, 60 miles south-west of Anchorage. The gas supply will be through an 800 mile pipeline from the North Slope. The estimated cost of the project, which is being planned by a joint venture of the three reserves owners, ExxonMobil, BP and ConocoPhillips and the State of Alaska, each with a 25% share, is between $45 and $65 billion. The project is currently in the pre-FEED stage, which will continue in 2016 with the objective of being in a position to award a FEED contract in mid-2017. The partners have already spent $350 million with a further $230 million budgeted for 2016. Creating an economically viable project and securing buyers for up to 20 mtpa will be major challenges. The earliest possible start date is in the mid-2020s.

4.3.3 Canada - British Columbia

The British Columbia Government website listed 19 projects at various stages of development in the province in April 2016 (see Appendix 2: Proposed Canadian LNG Projects). The total capacity is of the order of 260 mtpa. Seventeen of the projects have approval from Canada's NEB to export LNG but most still require environmental and other approvals from the provincial and federal governments. Progress has generally been slow to the disappointment of the Government of British Columbia which has made the development of LNG exports one of its key objectives. It has watched as projects in the USA have taken FID and in the process reduced to opportunities for Canadian projects to secure buyers.

Amongst the most advanced projects which have said that they are targeting FID in 2016 are:

LNG Canada: Shell (50% share) and its partners PetroChina (20%) and Mitsubishi (15%) and Korea Gas (15%) are planning a two-train, 13 mtpa plant at Kitimat in the north-west of British Columbia.[9] The project has been awarded a permit to export LNG for 40 years by the NEB, which replaces the previous 25 year permit. It has also received an LNG facility permit from the British Columbia Oil and Gas Commission, the first to be granted to a project in the province. The partners will lift LNG in shareholding proportions, with Shell and Mitsubishi probably marketing it as

[9] See previous footnote 5.

portfolio LNG while Korea Gas and PetroChina will probably deliver it to their own terminals, so finding buyers for the output is not an issue. The cost of the 13 mtpa phase 1 will be in the range \$35 billion to USD\$40 billion, including the cost of the pipeline from the reserves in the north-east of British Columbia to the plant site and the cost of developing the reserves. Shell has said that FID, which was targeted for mid-2016, has been deferred to the end of the year which with a five-year construction period, would lead to start-up by end -2021. However, in a conference call following the announcement of Shell's first quarter 2016 results, its chief financial officer cast some doubt on the end-2016 target for FID, saying that the project is competing for funding dollars with other Shell projects in the USA.

Pacific North West LNG: In June 2015, Petronas (62%) and its partners – Japex (10%), Indian Oil (10%), Sinopec (15%) and PetroleumBrunei (3%) – took a provisional FID on the planned two-train 13.4 mtpa LNG project on Lelu Island near Prince Rupert in the north-west of the province. They are still awaiting environmental approval from Canada's federal government before being in a position to go-ahead with the construction. The government was expected to make a decision in the first half of 2016. However, in March 2016, it granted a request from the Canadian Environmental Agency for an additional three months to review submissions from interested parties delaying a final decision into the second half of the year. The delay in taking FID (it was first targeted for the second half of 2014), has enabled Petronas to carry out some further work on the project design which has resulted in an increase in the capacity of the liquefaction plant from 12 mtpa to 13.4 mtpa and a reduction in its cost, but they remain in the \$30 to \$40 billion range.[10]

Woodfibre LNG: The 2.1 mtpa project on the site of a former pulp mill at Squamish, 43 miles (70 kilometres) north of Vancouver is being developed by Pacific Oil and Gas, a subsidiary of the privately owned, Singapore based RGE Energy, the largest paper and pulp company in Asia. FID on the project which has an estimated cost of \$1.6 billion has been delayed into 2016 by the need to work with the Squamish First Nation and local residents to gain support. In March 2016, a multi-phased contract was awarded to KBR covering FEED optimization, pre-FEED, FEED and the development of a fixed price offer for EPC services. RGE Energy has not given an updated schedule for the project but the scope of the KBR contract appears to indicate that FID is unlikely until late-2016 and could slip into 2017. A Strategic Co-operation Agreement has been signed with the Beijing Gas Group outlining how the two companies will work together including reaching an LNG off-take agreement. Pacific Oil and Gas has shares in gas-fired power plants in China and is a partner, with a 30% share, in CNPC's Rudong receiving terminal in Jiangsu Province

4.3.4 Eastern Canada

Four exports projects have been proposed in eastern Canada (see Appendix 2: Proposed Canadian LNG Projects), a fifth to convert Canada's only LNG import terminal in a liquefaction plant was cancelled in early 2016. The total capacity is just over 40 mtpa. They are mainly targeting the European market, taking advantage of the shorter shipping distance compared with projects in the US Gulf of Mexico region (for example Halifax in Nova Scotia to Rotterdam is 2,800 nautical miles versus 5,000 nm from Lake Charles in Louisiana), which could reduce the transport cost by \$0.40 to \$0.50/MMBtu. The sponsors of all the projects say the Marcellus shale basin in Pennsylvania and neighbouring US states is a potential source with reserves offshore Nova Scotia

[10] See previous footnote 4 for project status.

and possible shale gas production in New Brunswick alternative sources of supply. It is doubtful that reserves offshore Nova Scotia could support a large export project while the potential for shale gas in New Brunswick has yet to be tested and there is considerable local opposition to fracking. Marcellus and Utica undoubtedly have the reserves but the main issue will be transporting the gas through New England to eastern Canada. Spectra Energy's Maritimes and North Eastern pipeline, which runs from Nova Scotia into Massachusetts, was built to transport gas production from natural gas reserves offshore Nova Scotia to New England, but has limited capacity.

The most advanced of the projects is Pieradae Energy's 2-train, 10 mtpa Goldboro LNG in Nova Scotia. It has a Heads of Agreement with Germany's E.On for the output for one-train and is targeting FID by the end of 2016.

4.3.5 Australia

The focus of LNG activity in Australia has been on commissioning the seven liquefaction plants with a total capacity of 62.3 mtpa for which FID was taken between 2009 and 2012. The six onshore plants have all been designed to allow the addition of liquefaction trains but all work on expansions has been halted. A number of green-field projects have also been proposed. If all the possible projects were to be developed they would add over 40 mtpa of capacity to the 86 mtpa in projects in operation and under construction in the country. However, development work on all of them has been halted because of current market conditions. The decision by Woodside and its partners to cease work on the proposed Browse LNG project using three floating liquefaction units means that the last of the projects on which significant funds were being spent is now on hold.

4.3.6 Papua New Guinea (PNG)

PNG is looking at two options to expand its LNG exports now that its first project, PNG LNG, is operating well above its 6.9 mtpa design capacity, exporting 7.2 mt in 2015.

PNG LNG Expansion: The addition of a third liquefaction train with a capacity of 3.5 to 4 mtpa is being actively progressed. The main source of supply will be the P'nyang field, which is estimated to have reserves of 3.5 Tcf. Further appraisal drilling in 2016 and 2017 is aimed at increasing the confidence in the reserve base. The field is relatively close to the Hides field and the gas can be transported to PNG LNG by the existing pipeline from the Hides field to the plant site near Port Moresby.

Papua LNG: Recent appraisal drilling in the PRL 15 permit, which contains the Elk and Antelope discoveries, is reported to have been successful and further drilling is expected to increase the size of the reserves further. The current plan is for a single 5 mtpa train or two smaller trains on a site next to the PNG LNG plant. LNG marketing is scheduled to start in 2H16 and FEED in 2017 leading to FID in 2018 and start-up in 2022.

4.3.7 Indonesia

Tangguh LNG Train 3: BP, the operator of the two train 7.6 mtpa Tangguh project, which came into operation in 2009, first submitted plans for a 3.8 mtpa third train to the Indonesian Government in August 2012. At that time, it said FID was targeted for mid-2013 with the start of production in 2019. FID has still not been taken but in mid-April, BP signed a contract with Indonesia's power utility, PLN, for the supply of 20 cargoes a year (1.1 mtpa) from Tangguh from 2017 to 2019 and 44 cargoes per year (2.5 mtpa) from 2020 to 2033. This extends an earlier agreement for the supply of 1.5 mtpa to PLN. The president of BP Asia Pacific said it was a positive step for Tangguh train 3. The Indonesian upstream regulator, SKK MIGAS, was more positive saying that FID on the train could be expected by June 2016.

Masela: Indonesia's President, Joko Widodo, rejected plans to develop the Abadi field in the Masela block in the Arafura Sea close to Indonesia's maritime boundary with Australia using a floating liquefaction unit. He wants an onshore plant on an eastern island to help lift the impoverished local economy. INPEX, the operator, and its partner Shell had already pushed back FID from 2018 to 2020 to give time to increase the capacity of the planned FLNG unit from 2.5 mtpa to 7.5 mtpa in response to lower oil prices. Switching to an onshore plant will probably increase costs and lead to further delays in FID into the 2020s and may call into question the economic viability of the project.

4.3.8 Russia

Russia's plans for pipeline gas and LNG projects in both the east and west of the country are in a state of flux as the economy is hit hard by the combination of low oil prices and sanctions imposed by the USA and the European Union. Despite ambitious official targets for Russia's share of global LNG activity and the announcement of several planned projects, Yamal LNG is the only other project on which FID has been taken since the start-up of the Sakhlain-2 project in 2009.

Sakhalin 2 Train 3: Gazprom and Shell announced their plans to add a third 5 mtpa train at the 9.6 mtpa Sakhalin 2 plant in early 2014 and have confirmed their intent since then but progress has been slow. Shell Global Solutions and Giprogazcenter are reported to be working on FEED but no specific timing has been given for the implementation of the project. As an expansion the project is probably the most cost effective way of expanding Russia's LNG production but, given the delays, not until after 2020.

Vladivostok LNG: In October 2014, Gazprom's CEO, Alexei Miller, said that the planned 15 mtpa project may be dropped as his company focuses on the supply of gas by pipeline to China.

Sakhalin 1: Rosneft and ExxonMobil say that they still plan to develop their 5 mtpa project, which was first proposed in 2013 with start-up targeted in 2018. However, progress has been slow and there have been no recent indications of a timetable for the development of the project.

Baltic LNG: In January 2015, Gazprom held a meeting "dedicated to the execution of the project" according to a press release at the time. A site has been selected at Ust Luga near St Petersburg for the planned 10 mtpa plant, which could be expanded to 15 mtpa. However, there has been no further news and uncertainties remain over when and if it will be developed.

4.3.9 Nigeria

The Nigerian National Petroleum Corporation (NNPC) says that it is still pursuing plans to increase the capacity of Nigeria LNG by 8 mtpa and to develop the 10 mtpa greenfield Brass LNG project but there has been no progress in the last 4 years. In early 2016, NNPC announced that Brass will initially be developed as a single train, 5 mtpa project. Although a smaller scale project is a better fit with potential demand the economics are unlikely to be very attractive. The expansion of Nigeria LNG appears to be the better economic option but the probability of either project being built within the next 10 years is low.

4.3.10 Equatorial Guinea

Fortuna LNG: Seven gas discoveries have been made in Block R offshore Equatorial Guinea which the UK company, Ophir, operates currently with an 80% working interest (GEPetrol, Equatorial Guinea's national oil company holds the other 20%). Ophir has reached a preliminary agreement with Golar to charter the *GoFlo Gandria,* the conversion of the *Gandria*, a 1977 built ship with a storage capacity of 125,800cm, into a floating liquefaction unit at the Keppel yard in Singapore. Ophir has signed Heads of Agreement (HoAs) for offtake from the Fortuna project with six counterparties, all of which are established LNG buyers in the European or Asian markets. The total demand under the HoAs is several times the planned production of 2.2 mtpa. A number of the potential buyers have offered to pre-pay for LNG offtake in the early years of the contract which Ophir estimates could cover 30 to 50% of the total net costs to first gas. Ophir says that upstream FEED work is 50% complete and the total cost has already been reduced from $800 million to $600 million (Ophir share $480 million) partly as a result of the current deflationary environment. A preliminary agreement for Schlumberger to acquire a 40% share in the project from Ophir was cancelled in April 2016 and Ophir has said that FID will be delayed from mid-2016 to the end of the year.

4.3.11 Mozambique

Anadarko and its partners in Block 1 and Eni and its partners in block 4 are pursuing different approaches to initiate LNG production from the over 150 Tcf of recoverable reserves discovered to date off the coast of northern Mozambique.[11] Both groups are targeting FID on their respective projects in 2016 with the start of production on 2020 or 2021.

Block 1: The 25 wells drilled in the Anadarko operated block have discovered recoverable reserves of 75+ Tcf. Anadarko is planning an initial two-train, 12 mtpa onshore development at Afungi in the north of Mozambique. The site has space for up to 10 trains and the plan is for both the Anadarko and Eni joint ventures to own trains at the site. Agreement has been reached for each JV to have access to 12 Tcf in the fields that straddle both blocks and to develop the first phase of the project separately. It is recognized that some sharing of facilities will be in the interests of reducing costs and increasing efficiency, but it has been agreed that either or both projects can go-ahead with their own stand-alone project to avoid progress being delayed by extended negotiations.

The Anadarko JV has signed non-binding Heads of Agreement for the offtake of a total of over 8 mtpa of LNG with buyers in Singapore, Japan, China, Thailand and Indonesia. Work is underway to turn the HOAs into full Sales and Purchase Agreements. Letters of Interest have been received for a total of $13.5 billion of finance, which is close to the $14 to $16 billion target for debt for the first two train project. The government has passed a decree law guaranteeing 30 years of fiscal stability, establishing labour laws for the project and giving the right to import the materials needed for the project. The engineer, procure and construct (EPC) for the onshore plant has been awarded to a consortium of CB&I, Chiyoda and Saipem. Construction will take around 5 years so FID by end-2016 should lead to start-up in late-2021 but it is uncertain whether these targets will be met.

Block 4: Eni and its partners have opted for a 3.4 mtpa floating liquefaction unit to develop reserves in the Coral field, which is located entirely within block 4. KBR and Daewoo were awarded

[11] See previous footnote 6.

the FEED contract in mid-2014. The award of the EPCIC (engineer, procure, construct, install and commission) contract will be made to one of three competing consortia. FID is planned for 2016 with the start of production in 2020. An agreement has been negotiated with BP for the sale of the entire output from the unit on an FOB basis. Eni is reported to be in discussions with potential buyers of a part of its 50% share in block 4 which could delay FID until late-2016 or even 2017,

Eni is also developing plans for onshore trains to develop reserves in the Mamba field which straddles blocks 1 and 4. It says it is in preliminary discussion with potential buyers.

4.3.12 Tanzania

Successful exploration and appraisal wells have confirmed that the reserves in the Statoil/ExxonMobil and the BG/Ophir/Pavilion blocks have sufficient reserves for each to support two LNG trains of around 5 mtpa of capacity. Presidential and parliamentary elections in October 2015 have delayed progress but 2016 has started with the government announcing the allocation of land at Lindi in the south of the country for the liquefaction plant. An optimistic scenario is FID in 2017 or 2018 with start of production in 2022 or 2023 but delays are possible.

4.4 Final Investment Decisions on Liquefaction Capacity in 2016

At the beginning of 2016, FID was targeted on 92.7 mtpa of capacity in 2016 (table 6) according to project sponsors. This is similar to the capacity of FIDs targeted by sponsors in each of the last three years. The success in achieving the targets for FID has declined – from a 29% success rate in 2013 to 19% in 2015 – as the amount of capacity under construction has built up and the economic environment has become more challenging.

The majority of the projects shown in Table 5 were also on the list in 2015 but were delayed, the exceptions are LNG Canada, Douglas Channel LNG (which has now been cancelled) and Goldboro LNG in Canada and Equatorial Guinea's Fortuna LNG. The success rate in 2016 is unlikely to be better than in 2015 and it could be 10% or lower of the targeted total, since all the projects listed in table 6 are struggling to secure binding commitments for buyer or off-takers and to reduce costs to a level that enhances the prospects of achieving economic viability. Although the US projects do not take price risk, they will find it difficult to secure buyers or off-takers willing to commit to a 20-year contract, especially since the liquefaction fee, which typically amounts to $150 to $175 million per year for each 1 mtpa of capacity, is on a use-or-pay basis.

Table 5: Projects targeting FID in 2016

Country	Project	Capacity (mtpa)
US	Sabine Pass Train 6	4.5
US	Corpus Christi Train 3	4.5
US	Magnolia Trains 1 to 4	8.0
US	Jordan Cove	6.0
US	Elba Island	2.5
US	Lake Charles	15.0
Canada	Pacific North West	12.0
Canada	Woodfibre	2.1
Canada	LNG Canada	12.0
Canada	Douglas Channel LNG	0.6
Canada	Goldboro' LNG	5.0

Country	Project	Capacity (mtpa)
Mozambique	Coral FLNG	2.5
Mozambique	Mozambique LNG	12.0
Equatorial Guinea	Fortuna LNG	2.2
Indonesia	Tangguh Train 3	3.8
	Total	**92.7**

In late-2015, the projects best placed to take FID in 2016 appeared to be Cheniere's Sabine Pass train 6 and Corpus Christi train 3. They are both expansions of projects under construction and they have all the necessary permits in place from the FERC and the US DOE. However, following the ousting of Charif Souki as CEO, Cheniere, directors have said they will focus on commissioning and operating the seven trains that the company has under construction to generate cash flow and profits for a company that has been loss-making since it first announced its plans to enter into the LNG business 15 years ago.

5. LNG Contracting in A Buyers' Market

The developers of the proposed new liquefaction project face a major challenge in securing commitments from buyers or off-takers (in the case of project planning to use a tolling structure) who are prepared to commit to the capacity on a long-term basis. They will need to offer counter-parties contractual arrangements that meet their changing requirements if they are to compete with the many other proposed projects and with projects in operation and under construction. The pricing environment is changing as buyers and off-takers seek to take advantage of lower prices and new pricing structures are emerging as LNG from the USA, with prices indexed to Henry Hub, enters the market in potentially increasing volumes. Spot and short-term pricing is also playing an increasing role in the marketing of LNG.

Buyers are seeking more contractual flexibility to manage the increasingly uncertain demand in their downstream power and natural gas markets. They are looking for volume flexibility (the ability to vary volumes without incurring penalties), destination flexibility (the right to divert cargoes to alternative markets without needing permission from sellers and having to share any additional revenues), shorter-term contracts and a mix of price linkages.

5.1 LNG Pricing

Linking the LNG price to crude oil or oil product prices continues to be the main method of pricing in long-term contracts. Annual surveys by the IGU[12] have shown the share of oil linked contracts to be consistently above 70% and tending to increase as Asia's share of global LNG trade grows while imports decrease into Europe and the Americas. This is because in Asia linkage to crude oil has been, and remains, the dominant pricing method in long-term contracts in contrast to Europe and the Americas, where linkages to natural gas prices at trading hubs are frequently used. The recent trends could reverse as Asia's share of imports decreases and LNG exports from the USA potentially increase.

5.1.1 Oil Indexed Pricing in Asia

The typical price formula in long-term contracts in Asia is of the form:

P(LNG) = A * P(Crude Oil) + B,

[12] See http://www.igu.org/publications for the current and previous surveys.

Where

P(LNG) = price of LNG in $/MMBtu,

P(Crude Oil) = price of crude oil in $/Bbl,

A and B are constants negotiated between the buyer and seller.

The most frequently used crude oil price is JCC – the custom cleared crude oil price in Japan, which is frequently referred to as the Japanese Crude Cocktail. It is the average price of crude oil imported into Japan each month and is published by the Ministry of Finance. Since Japan imports large volumes of crude oil from many producers around the world, it is seen as a reliable indicator of Asian crude oil prices and is used by buyers in other Asian LNG importing countries. Recently, Brent crude oil prices have been used in some contracts since Brent is widely traded which makes it possible to hedge some of the price exposure. Indonesian LNG contracts use the Indonesian crude oil price, which is based on basket of international crude oil prices.

JCC lags Brent crude oil prices by about one month and many Asian contracts link the LNG price in month n to the JCC price three months earlier, which means that it takes around four months for a change in the Brent crude oil price to feed through fully into Asian LNG prices.

The constant "A" in the typical Asian LNG is commonly referred to the slope and quoted as a percentage. Thus, if A is 0.1485 (which has been used frequently historically) the slope would be 14.85%.

If LNG was to be priced at crude oil parity the price formula would be:

P(LNG) = 0.172 * P(Crude oil),

since the average barrel of crude oil contains 5.8 MMBtu of energy.

The constant "B" has historically often being linked to the cost of transportation and has been around zero for FOB deals, where the buyer pays the cost of transportation and $0.60 to $0.80/MMBtu for DES deals from the Pacific basin to north-east Asia, where the sellers pay for the transportation. However, negotiators have varied the constant B to increase (decrease) the fixed element in the price and reduce (or increase) the linkage to crude oil prices.

The pricing formula shown above became widely established in Asia in the late 1980s and a value of A around 0.1485 became common. It tended to be higher when sellers were in a strong position and weaker when the market moved in favour of buyers. "S"-curves which reduce the linkage to crude oil at high and low oil prices have also been used to mitigate the impact on buyers of high oil prices and on sellers at low oil prices.

In the current buyers' market for LNG, A has come under pressure and deals done in 2015 and early 2016 have seen it reduced below 14% and even as low as 11% in some 2016 deals. This puts pressure on the potential revenues for sellers, negatively affecting the economics of new projects. However, for existing projects with the investment already amortised or for projects which have been recently commissioned or are under construction with most of their output contracted, it has helped them sell uncontracted output.

In markets outside Asia, oil indexation is playing a much lesser role in pricing LNG and hub based pricing increases. However, where a linkage to crude oil is used, the multiplier of crude oil is generally coming under same sort of pressure as has been seen in Asia.

5.1.2 US LNG Prices

US LNG is bringing a new pricing approach into the LNG market. The typical DES price formula is effectively:

P(LNG) = (1+A)*HH + liquefaction fee + shipping cost,

Where

HH = is the Henry Hub natural gas price,

A = an uplift on the Henry Hub price to cover the cost of natural gas used in the plant and other costs incurred in securing natural gas and delivering it to the plant.

Cheniere's FOB contracts for Sabine Pass and Corpus Christi, which are in the public domain, show that in all cases, A is 0.15 – i.e. a 15% uplift on the Henry Hub price.

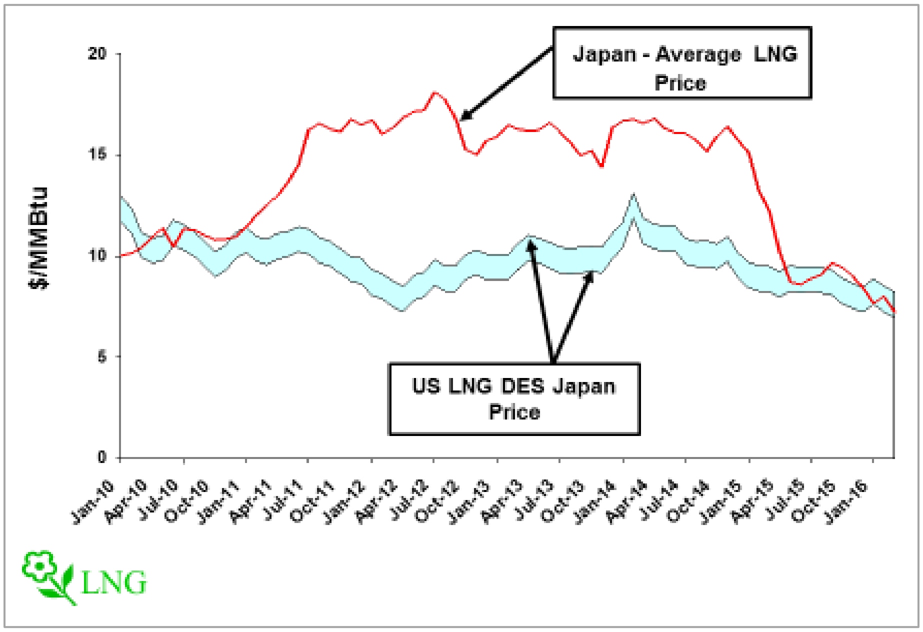
The liquefaction fee varies amongst the projects. In the case of Cheniere it varies for $2.25/MMBtu to $3/MMBtu for Sabine Pass, which is a brownfield project and is $3.50/MMBtu in all its contracts for output from the greenfield Corpus Christi project. The general view is that the liquefaction fees for the other three projects under construction in the US are around $3/MMBtu.

The shipping cost depends on the distance to the destination, the charter rate, the cost of fuel (including boil-off gas), port fees and the cost of Panama or Suez Canal transit (if used). They will probably be around $1.25 to $1.50/MMBtu to Europe (using a ship on long-term charter) and $2 to $2.50/MMBtu to north-east Asia.

Figure 7 shows the cost of delivering US LNG to Japan from January 2010 to March 2016 (assuming that US LNG export plants were in operation) and compares it with the average price of LNG imported into Japan over the same period.[13] It shows that when US exports were first proposed they appeared to offer buyers in Asia a significant discount compared with the prices they were paying under traditional long-term contracts. However, the collapse in oil prices had, by mid-2015, eroded the potential cost advantage of US LNG in Japan (and other Asian markets).

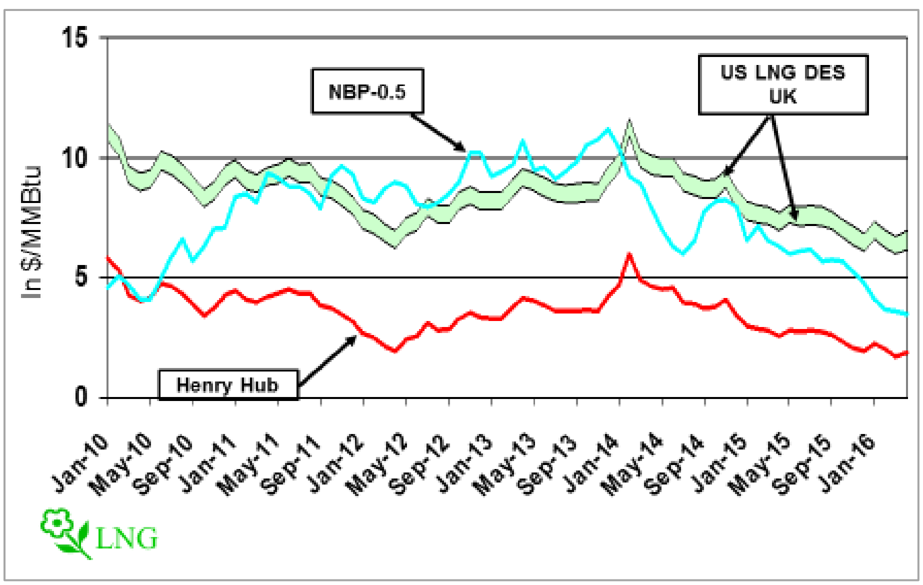
[13] CEE monitors competitiveness of US LNG projects for both Atlantic and Pacific basins in order to integrate our research and views on US gas supply and deliverability. See http://www.beg.utexas.edu/energyecon/thnkcrnr.php for recent posts.

Figure 7: US Export Price v Average LNG Import in Japan January 2010 to March 2016



The same analysis for US LNG delivered to north-west Europe shows US LNG would have been at a premium from 2010 to mid-2011, then at a small discount until early 2014. Since then it would have been at an increasing premium as hub prices at European hubs declined.

Figure 8: Cost of US LNG in Europe and the Price on Natural Gas in North West Europe January 2010 to April 2016



5.1.3 Price Diversification and Hybrid Pricing

In the current pricing environment buyers are generally seeing US LNG as diversifying the price risk rather than offering the price discount that first attracted them. Some have indicated that there is a limit to the share of Henry Hub indexed LNG in their supply portfolios with 25% being the typical maximum share that they are seeking. Indexation to Henry Hub prices has been introduced into some LNG contracts with LNG aggregators under which supply will not necessarily be from the USA. Some contracts now provide for hybrid pricing, with the price partially linked to crude oil and partially to US natural gas prices.

5.1.4 An Asian Pricing Hub?[14]

Oil indexation effectively bases the price of LNG on the global supply and demand for crude oil, while linking the price to Henry Hub links it to the supply and demand for natural gas in North America, which has little relevance to the supply and demand for natural gas in Asia, Europe and other markets that import LNG. Asian buyers and their governments want to develop LNG trading hubs in Asia, where prices would respond to the supply and demand for LNG and natural gas in Asian markets.

The Singapore Exchange (SGX) and the Energy Market Company (EMC) have introduced an LNG index, SLInG, which is intended to provide an industry pricing benchmark for the FOB price of an LNG cargo at a virtual point off Singapore. It is based on an assessment of prices from a balanced mix of LNG producers, consumers and traders. It was launched in mid-2015 and a derivatives contract followed in January 2016. However, it is early days, and there have been few trades using the index.

The Tokyo Commodity Exchange (TOCOM) also launched a futures market for LNG in September 2014 but, as yet, there have been few trades. In May 2016, Japan's Ministry of Economy, Trade and Industry (METI) announced its intention to launch an international LNG trading hub by the early 2020s. However, it accepted that relaxing destination clauses in LNG contracts, encouraging market development of price indices reflecting LNG supply and demand, and continued dialogue among stakeholders are crucial to achieve its ambition.

Shanghai is seen by some as another possible location for an LNG and natural gas trading hub in Asia and while some natural gas trading is taking place in Shanghai, it is a long way from establishing itself as a pricing hub accepted elsewhere in Asia.

In the absence of a trading hub that is accepted by market players as providing a reliable pricing point for LNG, Platts' JKM has become most quoted and used pricing index in Asia. It has been used for some spot sales and is reported to have been included in the indexation in at least one long-term contract. There is also some trading of LNG using JKM futures[15] but the volume remains a small fraction of the physical cargoes imported in Japan and Korea each year.

5.2 Contract Flexibility

The development of the international LNG business over the last 50 years has been underpinned by long-term contracts, typically of 20 years or longer duration, which gave buyers very limited

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[14] In other work, CEE researchers have evaluated the status of natural gas use and LNG trading in the Asia Pacific region. See "European and Asian Natural Gas Market Developments – Swamped by the Present?", Chapter 6 in *Managing Energy Price Risk*, 4th Edition (Dr. Vince Kaminski, editor), Risk Books, 2016, http://riskbooks.com/managing-energy-price-risk-4th-edition-1. CEE web for updates.

[15] Based on data from Platts', trading in JKM futures lots, each for 10,000MMBtu, has been: 2012 201; 2013 270; 2014 1654; 2015 2791. About 1,200 trades occurred during the first two months of 2016. An LNG cargo contains about 3 TBtu, implying the equivalent of nine cargoes traded during 2015. For context, Japan and Korea imported a total of 1,930 cargoes in 2015.

flexibility to vary the volume of LNG that they purchased each year. Take-or-pay clauses meant that if buyers did not take delivery of the annual contract quantity, adjusted by limited rights to exercise DQT, then they had to pay for any quantities not taken.

Although take-or-pay provisions have rarely been imposed, they were a major incentive for buyers to lift the contracted volume of LNG. So-called destination clauses, which required that the LNG should be delivered to a buyer's own terminals, even in the case of an FOB sale, where buyers lifted the LNG from the sellers' liquefaction plants, also limited the ability of buyers to manage variations in demand by diverting cargoes to alternative destinations. Some contracts gave buyers the right for LNG cargoes to be delivered to other terminals in their own country but did not allow them to be diverted to markets in other countries in an over-supply situation. Even where diversions were allowed it was often on the basis that the seller had to give permission and it shared in any additional revenues that were generated.

Most buyers were able to accept these conditions since they had a monopoly or near monopoly position in their own markets and, while demand varied as economic conditions changed, DQT and upward flexibility provisions in contracts enabled them to manage year on year changes in requirements. The changing market environment means that buyers in both established markets and new buyers are seeking contracts of shorter duration, often of 5 to 10 years duration, rather than 20 or more years. They are also looking for more downward volume flexibility than the 10% DQT that has become the norm in many contracts especially in Asia. Finally, and probably most importantly, is destination flexibility. In the case of FOB contracts, buyers are looking for the right to divert cargoes to alternative destinations without requiring approval from the seller or the sharing any upside. For DES contracts, buyers want increased rights to divert cargoes but recognise that the capacity of the sellers' shipping fleet has to be taken into account and any additional transport costs incurred will have to be paid.

5.2.1 The Supply of Flexible LNG is Set to Rise Strongly

The supply of flexible LNG that can be marketed on a spot or short-term basis is set to increase strongly as the 123.9 mtpa of capacity under construction in April 2016 comes on stream to add to the 28.6 mtpa of capacity in trains that have been commissioned since the beginning of 2015. A significant proportion of the new output has not been committed to specific markets on a long-term basis and, hence, will potentially be tradeable as flexible LNG.

Leading the way in terms of destination flexibility will be output from the five liquefaction plants under construction in the US, with a nameplate capacity of 64.2mtpa, for which buyers and off-takers (in the case of projects with a tolling structure) are free to deliver the output to any destination they choose since all five have permits to supply the output to non-Free Trade Agreement (non-FTA) countries. Some of the companies with commitments to US LNG, either directly with the project owners or through contracts with primary off-takers, only plan to take advantage of flexibility in exceptional circumstances. However, with around 22 mtpa of the LNG in the hands of aggregators and a further 27 mtpa controlled by gas and power companies, who are likely to want to trade some or all of their US commitments, the potential addition to tradeable LNG could increase the volume of LNG marketed on a spot or short-term basis by over 50% compared with the level in 2015.

However, US LNG does not provide the volume flexibility that is available from other suppliers since the contracts do not provide for any DQT. Buyers and off-takers do have the right to cancel cargoes at relatively short notice (two months in the case of Cheniere's contracts) but they have to pay the liquefaction fee, which will amount to between $7.5m to $12m per cargo, which is a significant penalty. In a typical take-or-pay contract the payment for any cargoes not taken is offset against the cost of the cargo when it is eventually lifted, so the payment is not lost as it is in the case of US LNG.

5.2.2 Most of the Output from New Australian Projects Has Been Sold Under Take-or-pay Contracts

The second largest source of new supply is Australia where seven liquefaction plants with a total capacity of 62.3 mtpa have either started-up since the beginning of 2015 or are scheduled to start-up by 2018. A total of 43 mtpa of the output from these plants was committed to buyers in Asia under long-term take or pay contracts mainly signed between 2009 and 2012, which probably gave the buyers limited flexibility to reduce annual volumes or to divert cargoes to alternative markets. A further 1.8 mtpa is equity LNG, which buyers are entitled to lift after acquiring a share in the project as part of the deal to purchase output. They have the right to market this LNG without restriction. The remaining 17.6 mtpa is either uncontracted or has been contracted to LNG aggregators who are partners in the project. There will probably be additional output from most if not all of these plants as they operate above capacity and/or are debottlenecked.

5.2.3 Up to 60% of the New LNG will be Flexible

It is difficult to give definitive estimates of how much of the LNG supply, which will be added to global production between 2015 and 2020, will have the flexibility to be traded on a spot and short term basis but the indications are that it could be between 40% and 60%, potentially doubling the volume of LNG traded on that basis by 2020. Furthermore, the volume of flexible LNG available from plants currently in operation is likely to increase as around 35 mtpa of existing long-term contracts expire and, if they are renewed, it will be on more flexible terms.

5.2.4 US, Qatar and Australia will be the Main Sources of Flexible LNG Supply

Global LNG supply in 2020 will be dominated by three countries, US, Australia and Qatar. They will account for around 55% of total global production, which is expected to reach close to 385 mt. The three countries will also be the main sources of flexible LNG. The companies controlling the flexible LNG will not necessarily pass on that flexibility but they are coming under increasing pressure for flexible contracts from buyers. They will have to respond if they are to secure sales. It is an environment in which spot prices will come under increasing pressure. With capital a sunk cost, it is the marginal production costs which will set a floor on prices.

Qatar is in best position when it comes to marginal costs since it has the benefit of revenues from associated condensate and LPGs to offset marginal production costs. US LNG is likely to have the highest marginal costs since the gas supply for the plants has to be purchased from the market. Output from projects in Western Australia and Australia’s Northern Territory will be somewhere between the two. The projects in Queensland supplied with coal seam gas will be less competitive because of the ongoing drilling costs required to maintain gas supply to the plants.

5.2.5 Flexibility Will be a Challenge for Some Planned Projects

The increasing pressure from LNG buyers for more flexibility in contracts will be met as the new generation of LNG projects come on stream. Flexible LNG will also have an important role to play in the development of new LNG markets, which are needed if the potential surplus of LNG production over the next few years is to be managed. Projects in operation in operation and under construction are, in most cases, able to respond to the needs of buyers for more volume and destination flexibility. They are also able to offer buyers shorter term contracts for uncommitted output as, for example, has been the case with Chevron's recent 10 year non-binding agreements with Chinese buyers for uncommitted volume from its share of Australia's Gorgon project.

The consensus view is that the output from projects in operation and under construction will meet expected demand until after 2020 but final investment decisions on projects currently at the planning stage will be needed before 2020 to meet longer-term demand growth. The challenge of meeting buyers' requirements for flexibility will be greater for these projects since security of long-term off-take is likely to remain a requirement of boards of directors approving investment and, in cases of project financing, the bankers. The easiest of the requirements to meet will be destination flexibility, especially where a contract is on an FOB basis, but diversions under a DES contract should be possible provided there are protections in the contract to avoid the seller having to invest in additional shipping capacity. Buyers already argue that, when project shareholders purchase output from their own projects to market as portfolio LNG, they are given destination flexibility so why shouldn't they have the same rights.

Increasing the downward quantity tolerance to, say, 20% should also be possible for projects with good economics. The main challenge will be shorter term contracts which will increase the uncertainty over the longer-term performance of the investment. If the share of spot and short-term trading increases, as is generally expected, then the longer term demand risk may be seen as acceptable by investors. Portfolio players could have an increasing role to play, purchasing LNG on a long-term basis and entering into shorter term contracts with secondary buyers.

It is unlikely that LNG will reach the flexibility of the oil or other commodity markets. The cost and limited amount of available storage, meeting the different quality requirements of markets and the need for long-term contracts to underpin the investment in new projects will be constraints. However, a more flexible future is important if the growth in the LNG business is to continue.

6. Summary

The surge in LNG supply as projects under construction are commissioned will take global LNG supply to 385 mt by 2020, an increase of 137 mt (55%) compared with the outcome in 2015. The growth in the demand for LNG in the key markets in Asia which imported 72% of global production in 2015 and the increase in supply as new trains are being brought on-line has been outpacing the demand. The result has been a weak market for producers and sellers which is expected to continue until the early 2020s. However, there is considerable uncertainty over when new supplies will be needed – on a low demand scenario it could be as late as 2023.

Demand will grow as new markets emerge and with output from some operating projects constrained by declining natural gas supply, leading to a requirement for new LNG sources. Just over 700 mtpa of new capacity has been proposed by sponsors to fill the gap between demand and supply which is expected eventually to emerge. Three quarters of the proposed projects are in North America as companies see the opportunity to take advantage of low natural gas prices resulting from the shale gas revolution. The proposed capacity is well in excess of any likely requirement before 2030, which means that many of the projects face long delays and abandonment. The successful projects will be those that can make an offer to buyers and off-takers that meets their changing requirements which include lower prices, flexibility and shorter-term contracts. Reducing costs to a level that ensures economic viability will be essential in a low price environment that the industry faces in the medium to longer-term.

Appendix 1: Proposed US LNG Export Plants

Project	Quantity in Bcf/d	in mtpa
Approved - Not Under Construction		
Sabine Pass Train 6	0.70	5.40
Corpus Christi Train 3	0.70	5.40
Lake Charles	2.20	16.90
Magnolia LNG	1.08	8.30
Total	***4.68***	***36.00***
Proposed to FERC		
Elba Island	1.25	9.60
Golden Pass	2.10	16.20
Gulf LNG (Pascagoula)	1.50	11.50
Freeport LNG (Additional Trains 1 to 3)	0.34	2.60
Venture Global	1.41	10.80
Cameron LNG Trains 4 and 5	1.41	10.80
Texas LNG	0.55	4.20
Alaska LNG	2.55	19.60
Total	**11.11**	**85.50**
Proposed to Marad/Coastguard		
Delfin LNG	1.80	13.80
Projects in Pre-Filing with FERC		
CE FLNG	1.07	8.20
Louisiana LNG	0.30	2.30
Downeast LNG	0.45	3.50
Eagle LNG Partners	0.075	0.60
Annova LNG	0.94	7.20
Port Arthur LNG	1.40	10.80
Rio Grande LNG	3.60	27.70
Freeport LNG Train 4	0.72	5.50
Corpus Christi Trains 4 and 5	1.40	10.80
Venture Global LNG	2.80	21.50
G2 LNG	1.84	14.20
Total	***14.59***	**112.30**
Total	**32.19**	**247.6**

Source: FERC Website 18th April 2016. See http://ferc.gov/industries/gas/indus-act/lng/lng-proposed-export.pdf for updates. Note: Although the application by the Jordan Cove project, 6.0 mtpa capacity, was denied in March 2016, FERC subsequently issues a "tolling order" extending the review period for a rehearing as requested by the project sponsors.

Appendix 2: Proposed Canadian LNG Projects

Project	Capacity in mtpa
British Columbia	
Discovery LNG	20.0
WesPac	3.0
Cedar LNG	6.4
Kitimat LNG	10.0
LNG Canada	24.0
Kitsault Energy	20.0
Nisga'a	?
Pacific North West LNG	18.0
Prince Rupert LNG	21.0
Aurora LNG	24.0
Grassy Point	20.0
New Times	12.0
Orca	24.0
Watson Island	?
West Coast Canada	30.0
Woodfibre	2.1
Canada Stewart Energy	30.0
Triton	2.3
Steelhead LNG	24.0
Total British Columbia	***290.8***
Eastern Canada	
Goldboro LNG	10.0
Bearhead	8.0
H-Energy	13.5
Energie Saguenay	11.0
Total Eastern Canada	***42.5***
Total Canada	**333.3**

Source: Information on LNG Projects in British Columbia from https://engage.gov.bc.ca/lnginbc/lng-projects.

Appendix 3: LNG Capacity by Country (in mtpa)[16]

Country	LNG capacity in April 2016	LNG capacity under construction	Proposed LNG capacity	Comments
Qatar	77.5	0	0	
Australia	46.0	40.2	0	Constructing Prelude FLNG unit + Icthys + Wheatstone + AP T2+ Gladstone T2 + GorgonT2&3
Indonesia	27.1			Planning Tangguh T3 & Abadi LNG
USA	4.9	59.7	248.0	
Malaysia	25.0	6.3		Constructing 2 FLNG + Bintulu T9
Trinidad	15.0	0		
Yemen	6.7	0		Off-line since April 2015
Canada	0	0	333.0	
Brunei	7.2	0		
Oman	11.0	0		
Other Pacific basin proposed	0	0	20.0	
Abu Dhabi	5.7	0		
Peru	4.3			
Egypt	12.2	0	0	Offline
Equatorial Guinea	3.6	0		Proposed shown with West Africa
Nigeria	22.3	0		Proposed shown with West Africa
Angola	5.2	0		
Cameroon	0	1.2		
West Africa proposed	0	0	20.0	Includes Equatorial Guinea, Nigeria
Papua New Guinea	7.2	0		Planning PNG T3 and Papua LNG
Norway	4.1	0		
Russia	10.6	16.5	30.0	Planning Sakhalin T3, Baltic LNG, Sakhalin 1
Algeria	26.5			
Mozambique	0	0	50.0	
Tanzania	0	0	20.0	
Totals	**322.1**	**123.9**	**721.0**	

[16] The capacities of liquefaction plants normally take into account routine maintenance – trains are typically taken off-line once every three years for around one month. Thus, for example, while the Pluto project in Australia has a capacity of 4.7 mtpa operating 24 hours per day, 365 days per year, Woodside quotes its capacity as 4.3 mtpa to take into account scheduled shut-downs.

Appendix 4: CEE Natural Gas Research Prospectus

In fall 2015 BEG/CEE initiated a multi-year research effort to investigate major natural gas markets. Our overall goal is to build a range of demand uncertainty globally and within each of the key regions based on results of country-level analysis. For each of the major countries or groupings identified we are profiling current gas markets: demand sectors; price regimes; policy towards natural gas; infrastructure; key players. We are reviewing existing outlooks; quantitatively and qualitatively identifying demand drivers for each sector, along with upside and downside risks to those demand drivers, including unrecognized or under-appreciated uncertainties; and drawing out implications for the range of total natural gas demand. Our main objective is to establish a range for natural gas demand and highlight key signposts to watch for which point to acceleration or deceleration of gas utilization. The research approach is:

1. Evaluate the critical "wedges" of demand growth by region along with attendant risks to future outcomes.
2. Overlay pricing policies on wedges.
3. Use case studies as our lenses for deeper looks at market structure, price policy, risk factors, contracting and other elements.

The study will focus on markets and regions where demand uncertainty is high and where trend variances could make a significant difference to supply needs. The following are examples of potential markets of interest.

- **Middle East** regional markets with high energy demand growth, pervasive price subsidization regimes, large role for energy exports in some cases, and/or expected need to grow power generation based on natural gas (include analysis of Saudi Arabia, Iran, Iraq, Egypt, and Israel).
- In **China** (*case study in progress*) all forms of energy are required to sustain economic growth and continue to improve living standards. Can gas demand in power generation, industry and even the residential sector be accelerated to meet the environmental challenges of local air pollution and eventually carbon? Can we assess the economic competitiveness of natural gas versus other fuels in these key sectors? Does transmission and distribution infrastructure put speed bumps or long-term constraints on potential for demand growth?
- **India** (*case study in progress*) has made significant investments in both domestic natural gas resource development and in LNG import facilities in order to allow growth in the domestic gas market. However, risks stem from endemic challenges to affordability of gas in the key demand sectors; from the fragmentation and limited investment capacity of the power generation sector, dominated by state-level utilities; from the limited gas supply and distribution infrastructure.
- **Japan** is the largest LNG market, with no indigenous natural gas supply. In the near-term, the pace and extent of the return of nuclear generation capacity is the key variable. Longer-term, even if a significant share of nuclear power generation is restored, license extensions for the nuclear fleet will likely be extremely problematic. What will be the role of gas in a post-nuclear Japan?
- In **Southeast Asia**, natural gas exporters such as Indonesia and Malaysia increased domestic use encroaching on export sustainability.
- **Russia** is not only the largest gas exporter, but also one of the world's largest domestic markets, supported for decades by subsidized prices and extremely inefficient end-use in buildings, industry and power. The pace of demand growth in Russia will influence how

much gas is available for export, particularly as new supply development for gas export projects is technically and economically challenging.

- **Europe** is still important. In Western Europe currently, natural gas demand is stagnating at best, a result of the slow pace of recovery from the economic morass of recent years and of the aggressive policy push to expand the role of renewable energy in the major economies. To what extent is this trend “built in” and to what extent could we see a return to natural gas growth in a bid to enhance economic competitiveness and reduce the overt and hidden costs of massive renewables deployment?
- A great deal of demand growth is expected in **African** markets, especially linked to power generation and, in some locations, industrial development. Africa presents a particular set of risks and uncertainties, especially in the interplay between domestic pricing and international LNG commitments. Africa is an emerging priority focus for U.S., Canadian, and European governments for investment and trade development.
- A number of smaller markets worldwide, such as those in **Latin America and the Caribbean**, could expand given the right conditions of domestic gas market development and affordable supply. Collectively these markets could add up to a significant call on global gas. It is interesting to note, however, that Latin America has largely underperformed relative to widely held expectations for regional gas demand during the 1990s project development wave.
- **North American** markets are of course very significant on a global scale, but the range of uncertainties, particularly in power generation, heavy industry, chemicals and new sectors such as transport has been studied extensively, at least for the U.S. and Canada. **Mexico** deserves a closer look. Beyond Mexico, CEE researchers have already completed many in depth analyses of North American and US gas demand and market dynamics.

The CEE research team has published reports on or gained experience and insights through technical assistance and training for many of these regional markets. See our web site for details.

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