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WIDER Working Paper 2020/80

The energy transition in Asia

The role of liquefied natural gas and implications for East African producers

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June 2020

United Nations University World Institute for Development Economics Research

wider.unu.edu

Abstract: This study provides an overview of the use of natural gas and liquefied natural gas in Asia, both historic, current, and with an outlook for the future. Traditionally, Asia has been a strong liquefied natural gas producing region as well as the premier liquefied natural gas market. This continues to be the case today, and it is expected to continue as well in the future. There are significant lessons to be obtained from the Asian gas market for other new liquefied natural gas producing nations and developing gas markets, such as Mozambique. This report also describes potential developments in the energy transition, and how these affect the role of (and demand for) gas going forward in Asia. Asia is expected to be the largest growth market for gas worldwide during 2018–35, although drivers do vary per country, and depend on the degree of disruption caused by the growth in electrification and renewables.

Key words: energy, energy utilities, fuel, gas, renewable resources

JEL classification: Q2, Q4

Note: This study was first written in November 2018. It is complemented by another working paper by the same authors (Romsom and McPhail 2020).

Abbreviations and acronyms at the end.

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This study has been prepared within the project on Inclusive growth in Mozambique—scaling-up research and capacity implemented in collaboration between UNU-WIDER, University of Copenhagen, University Eduardo Mondlane, and the Mozambican Ministry of Economics and Finance. The project is financed through specific programme contributions by the governments of Denmark, Finland, and Norway.

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ISSN 1798-7237 ISBN 978-92-9256-837-5

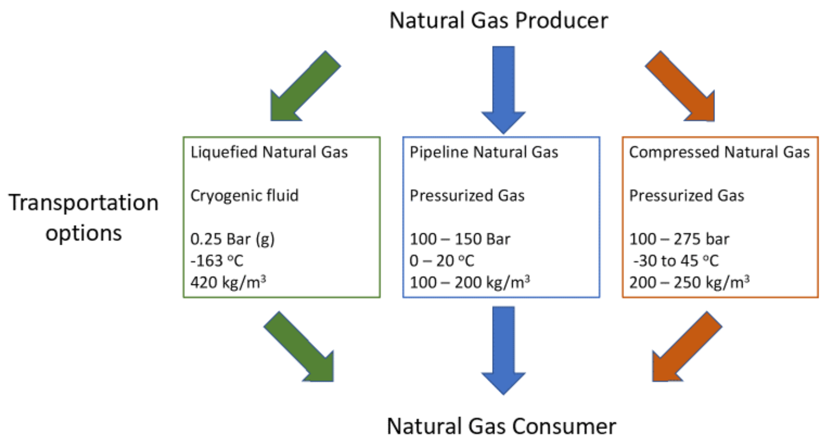
https://doi.org/10.35188/UNU-WIDER/2020/837-5

Typescript prepared by Siméon Rapin.

1 What is the use of LNG?

Liquefied natural gas (LNG) is a condensed, lean, clean natural gas (NG) containing predominantly methane and possibly some ethane. Any contaminants and heavier carbon components are removed as part of the (pre)processing during the liquefaction process. There is no standard for the amount of ethane in LNG and hence the calorific value of LNG can vary and needs to be matched with downstream consumer needs. The purpose of the liquefaction process is to reduce the volume of NG with a factor of ~600 compared to its gaseous state at standard conditions, thereby increasing its energy density to 2.5 times that of compressed natural gas (CNG), comparable to propane and ethanol but only 60 per cent of diesel. The purpose of the liquefaction process is to make transport more efficient, or indeed possible if pipelines are not a feasible option. Particularly for large distances (more than 1000-2000 Nautical miles) LNG transport by ship can be more economically efficient than transport by pipeline. This is not withstanding the capital expense for the liquefaction and regasification facilities and the operational cost of the gas cooling process to -163 °C (-260 °F). Another benefit of LNG over pipeline is that the cargo can go to multiple market destinations from its liquefaction point.

Figure 1: Properties of LNG compared with pipeline NG and CNG



Source: authors' illustration.

2 History of LNG market in Asia

LNG has a long history in Asia. The first LNG[1] cargo to Asia was delivered by Philips[2] from Alaska to the LNG receiving terminal at Negishi Japan[3] in November 1969. The first LNG production in South East Asia (SEA) took place in 1972 by Brunei LNG and was followed by

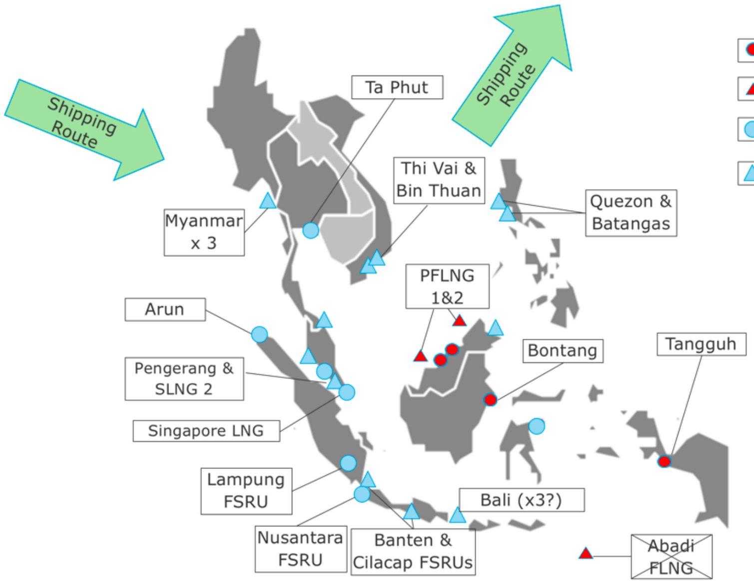
[1] A good overview of the history of LNG by the Center for Liquefied Natural Gas (CLNG) is available at: www.lngfacts.org/about-lng/history-of-lng/ (accessed November 2018).

[2] Phillips (now ConocoPhillips) is one of the pioneering companies in LNG technology and LNG development. Its optimized Cascade Process has been enhanced many times since 1969 and is currently one of the most commonly used LNG process technologies with over 100 mtpa installed LNG capacity by 2020.

[3] The Negishi LNG receiving terminal, currently the world's sixth largest, is owned by Tokyo Gas, currently Japan's second largest LNG buyer after TEPCO.

Bontang (1977) and Arun (1978) LNG developments in Indonesia. Since then there has been further growth in LNG supply through capacity expansions and new LNG facilities, including Malaysia. An interesting aspect of SEA is that it is both an LNG producing region as well as a downstream market for LNG. Both Indonesia and Malaysia have LNG liquefaction and LNG regasification in the same country. LNG export facilities can later be converted into an LNG import terminal when the local source of NG depletes and there is a local gas demand. LNG storage tanks are a significant part of the regasification (regas) facility cost and can be reused when switching from export to import, as is the case for Arun LNG in Indonesia.

Figure 2: Some large LNG projects in SEA



Source: authors' illustration based on IGU (2017), with permission.

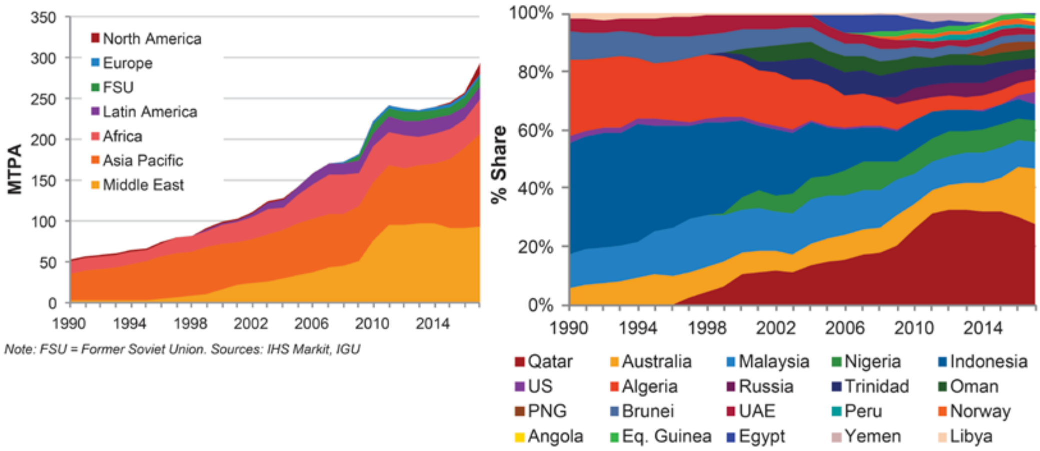
LNG accounts for about 10 per cent of the global gas market, long distance pipelines account for 20 per cent, and 70 per cent of NG is consumed where it is produced. Although global LNG has posted a higher annual rate of growth (6 per cent) over the past 15 years than either production for indigenous consumption (1.7 per cent) or international pipeline exports (3.3 per cent), much of that impressive growth was focused in the first decade, with pipeline trade displaying a similar growth rate to LNG over the past few years. In 2017, there were 18 LNG exporting countries and 36 LNG importing countries globally. After a dip in LNG growth in the period 2012–2015 when few new developments came on stream, 2016 saw an increase of 5 per cent (+12.2 MT) over 2015 to set a record LNG volume of 258 MT for the year. In 2017, the record was broken again with LNG growing further to 293 MT (+13.6 per cent, +35 MT) as new developments in Australia (+11.9 mtpa) and the United States (+10.2 mtpa) came online. The top five LNG exporters are Qatar (81 mtpa and 28 per cent market share), Australia (56.2 mtpa, 19 per cent), Malaysia (26.4 mtpa, 9 per cent), Nigeria (21.3 mtpa, 7.3 per cent), and Indonesia (16.2 mtpa, 5.5 per cent), respectively. Supply is set to continue its rapid expansion in 2018 as new plants and additional trains across the world come online, including Yamal LNG (Russia), Prelude FLNG (Australia), and Ichthys LNG (Australia). In addition to its 9 mtpa online capacity, the US has a further 57.2 mtpa under construction at January 2017 (IGU 2017)[4]. Global LNG nameplate capacity of LNG

[4] IGU (2017) gives a comprehensive overview of the current LNG market including individual liquefaction and regasification facilities.

plants totalled 369.4 mtpa by 2018, an increase of 32.2 MTPA from the end of 2016 indicating an overall utilization of 84 per cent in 2017 (82 per cent in 2016).

On the demand side the fastest growing LNG markets during 2016–17 period were China (+19.6 MT), India (+6 MT), South Korea (+5.3 MT), Pakistan (+4 MT), and Spain (+3.3 MT). By end 2017, Japan remained the world's largest LNG importer with 84.5 mtpa and 28.8 per cent market share, followed by China (39.5 mtpa, 13.5 per cent) that had overtaken South Korea (38.6 mtpa, 13.2 per cent). India is the world's fourth largest LNG import market (20.7, 7.1 per cent). New markets that started LNG imports in 2016–17 are Colombia, Jamaica, and Malta, albeit at small mtpa volumes.

Figure 3: Global LNG producers over time



Notes: capacity additions appear to come in waves in a cyclical market. A lack of major project final investment decisions (FIDs) from mid-2013 to mid-2018 is expected to result in another period of flattening in the supply curve, and this should allow LNG demand to catch up with supply by ~2023.

Source: World LNG Report (IGU 2017). Reproduced with permission.

3 LNG contracts and pricing

Historically, LNG in Asia was governed by long term offtake agreements with fixed or indexed pricing, take-or-pay (and reciprocal send-or-pay) provisions and with strict destination clauses prohibiting on-selling of LNG. These contracts reflected a sellers' market as LNG facilities were scarce, technically complex and high cost. This was in contrast with the Atlantic Basin LNG market[5] where LNG trades were historically more short-term and spot. However, over time the LNG market has become considerably more diverse with a proliferation of suppliers and buyers. The Asia and Atlantic Basin markets finally converged into a single global LNG market. Despite increases in spot market volumes, long term LNG contracts still make up 70 per cent of all global LNG trade (reduced from 85 per cent a decade earlier). One reason for this is that long-term

[5] The Atlantic Basin LNG market includes the following LNG producers (current and projected): Abu Dhabi, Algeria, Angola, Egypt, Equatorial Guinea, Iran, Libya, Nigeria, Norway, Oman, Qatar, Russia, Trinidad & Tobago, Venezuela, and Yemen. It also includes the current and likely future LNG-consuming countries: Argentina, Belgium, Brazil, Canada, Cyprus, Dominican Republic, France, Germany, Greece, Italy, Mexico, the Netherlands, Poland, Portugal, Puerto Rico, South Africa, Spain, Turkey, the UK, the US, and possibly the Bahamas and Jamaica. Available at: https://www.risk.net/definition/atlantic-basin (accessed February 2020).

contracts are essential to get project financing for high capital cost LNG infrastructure. In addition, on the buyers' side, long-term contracts provide protection against market volume and price disruptions due to externalities (see below on the impact of the Fukushima LNG incident in Japan). To hedge against price swings and to establish increased alignment under these long-term offtake agreements, key buyers ('anchor customers') have customary been taking small participating interests (5–20 per cent) in the LNG supply ventures.

In further protecting buyers and sellers from sharp price swings, LNG under most long-term contracts is indexed to oil, for example Japan Crude Cocktail (JCC), under what are known as 's-curves'. When oil prices rise quickly, the s-curve grants buyers a 'slope' once oil has reached a pre-defined level, under which the price for LNG rises more slowly and with a time-lag. Sellers of LNG are granted a similar 'slope' which slows down a price fall in oil, once crude has fallen to a certain level. Buyers prefer a flat slope at high oil prices, while LNG producers and sellers prefer flat slopes at low oil prices. In most existing contracts, a slope of around 15 per cent of oil prices is applied under a time lag versus crude of several weeks or even months. Many buyers have recently been asking for a lower slope of 11 to 12 per cent. At prices for Brent crude oil of around US$63 per barrel, a reduction of the slope from 15 to 12 per cent for buyers would lead to a fall in the LNG price of US$2 per million British thermal units (MMBtu) to US$7.50 per MMBtu.

Although gas prices differ country by country, the globalization of LNG and less onerous commercial terms on destination flexibility have caused global LNG spot prices to converge at the lower end of the range under a global oversupply of LNG in the market since 2015. Balancing of the LNG market and recovery of LNG prices (with intermittent price swings) are expected to take until 2023.

For a market that is in equilibrium, the relationship between LNG spot prices and long-term indexed prices are generally trending well. Long-term contracts are expected to have a price premium built in for security of supply and for reducing exposure to externalities that drive price fluctuations. Spot prices are more volatile and spot cargo's volume/delivery flexibility can create additional margins while balancing the short-term market. However, when LNG markets are moving away from a state of equilibrium, a tension occurs between short-term/spot prices and long term/indexed prices. This was very obvious after Japan's nuclear disaster in Fukushima in March 2011 that triggered all of Japan's 50 nuclear reactors to go offline (representing 20 per cent of Japan's installed power generation capacity). Conventional power plants had to make up the difference and LNG demand increased 40 per cent, causing the LNG spot price to rise by a staggering 80 per cent in the period 2011–14.

When the global LNG market became oversupplied after 2015, the reverse situation occurred and a growing volume of spot-priced LNG was offered at a considerable discount to long-term contracts. This caused considerable pressure on LNG buyers to seek improved prices for their long-term contracts or to have flexibility in take-or-pay conditions (see section below on renegotiation). With gas (LNG) markets maturing globally, energy market reforms underway in China and SEA, and North America forecast to become a major global LNG supplier, there will be increased opportunity and demand to move further away from oil-indexed LNG prices towards gas-on-gas indexed prices (using Henry Hub, NBP and TTF as markers)[6], as has been the case in Europe (Fulford and Pereira 2016). For LNG buyers, this would avoid large future price

[6] Gas-on-gas indexation works technically similar to oil-indexation of LNG: a gas price marker (or combination of price markers) is used to determine the price of LNG. Commonly used gas price markers are: Henry Hub (US based), UK's National Balancing Point (NBP) and Title Transfer Facility (TTF), a virtual trading/price point for natural gas in the Netherlands.

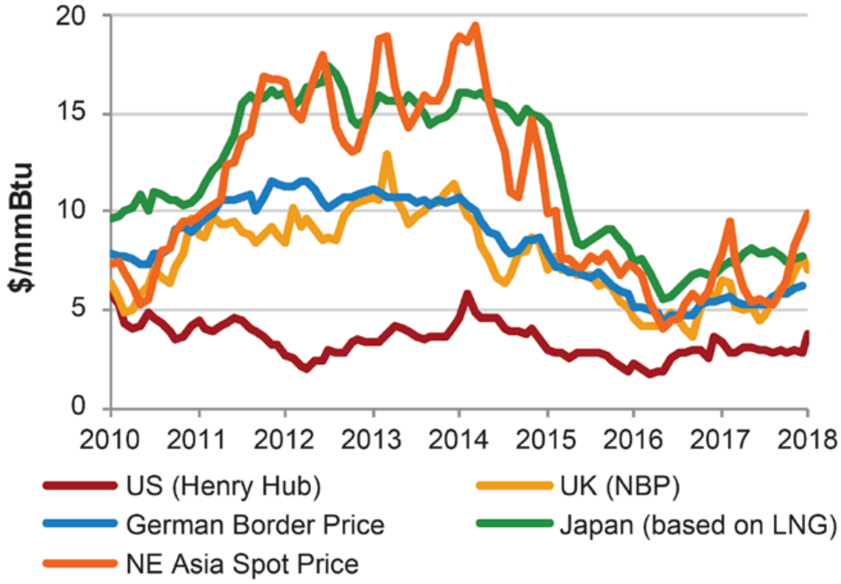
differences between geographical markets, that could become evident again if oil and gas prices continue to decouple. It would also be good for developers as market prices will be determined more by gas development, liquefaction, and transportation costs. However, to establish an LNG market in Asia that is majority gas-on-gas priced within a ten-year period, we would need to see an annual migration of 5 to 10 per cent of existing LNG contracts from oil-indexation to gas-on-gas arrangements, in addition to all flexible[7] LNG volumes becoming gas priced.

In 2017, average Asian LNG prices (both spot and contracted) increased by US$1.33/MMBtu over 2016. This was caused by a combination of higher oil prices and stronger LNG demand in Asia Pacific. However, spot prices showed large variation during the year as the supply/demand balance struggled with new LNG supply that became available. The Asian spot price (East Asia Index EAX) fell to US$6.3/MMBtu in August 2017 and rose again to US$9.9/MMBtu by January 2018 as a result of cold winter and strong Chinese demand. The United Kingdom National Balancing Point (NBP) similarly experienced large variation during 2017, from a low of US$4.5/MMBtu in June to a high of US$7.8/MMBtu in December. Differentials between basins were similar to their level in 2016, with EAX again lower than NBP in the middle of the year. However, by January 2018, Asian spot prices had climbed back to a US$2.91/MMBtu premium over NBP (IGU 2018).

In 2018, spot LNG prices recovered further. By August 2018, the EAX had risen to US$11.5/MMBtu, an 82 per cent rise from a year before, which was at US$6.3/MMBtu (Froley 2018). Spot price differentials with North West Europe ranged US$2.5–3.5 in favour of EAX. Henry Hub gas prices in 2018 hovered in a relatively tight range around US$3/MMBtu, resurrecting hopes for these positive price differentials to drive competitive LNG exports from North America to Asia. On the back of these pricing trends, Shell took FID on its (US$14 bln) greenfield LNG Canada development in October 2018. It is the first greenfield LNG export terminal approved in five years and the largest since Russia's Yamal LNG terminal in 2013 (DiChristopher 2018). This could spark the return of new LNG megaprojects. LNG Canada will launch with two LNG trains with a combined capacity of 14 mtpa and it has potential for further expansion of two more trains.

[7] Flexible LNG is LNG that is uncommitted, i.e. subject to new contracts or rolled-over contracts.

Figure 4: LNG market supply



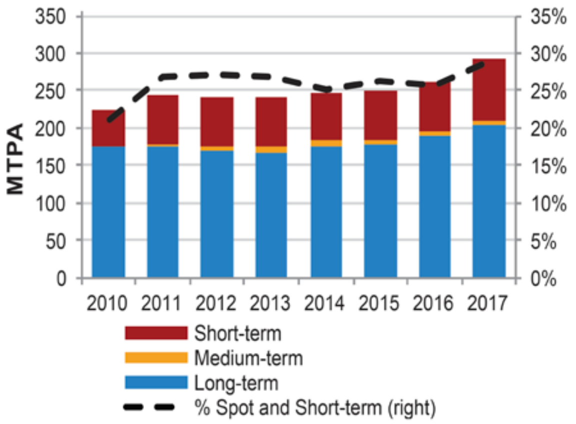
Notes: since 2015, the LNG market is experiencing oversupply due to large volumes of new capacity coming on stream. This has caused global gas prices to collapse and converge. With new capacity still coming on stream in 2018 (from pre-2013 FIDs), the oversupply situation is expected to continue to ~2023. However, continued strong LNG demand in particular from China (and India) may accelerate balancing of the market. A partial LNG price recovery in 2017–18 appears to support this view. Due to the 4+ year lag time between FID and start of LNG production, many new projects that are expected to take FID in 2019 will start a new wave of supply in 2023–224.

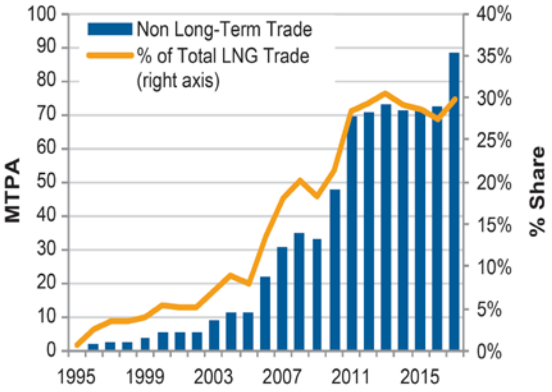
Source: World LNG Report (IGU 2018). Reproduced with permission.

Buyers have made it clear they want flexible contracts. This makes it hard to secure the long-term fixed off-take agreements that are needed to secure funding for multibillion-dollar projects. The implication is that those companies with strong balance sheets that they can leverage, will enjoy greater chances of success in developing a new LNG plant. The LNG Canada project is responding to these market changes in the way the investment is financed by a group of equity holders, rather than by using the traditional model of lining up long-term contracts with buyers. Each of the project's five joint venture partners[8] will be responsible for recouping their investment by feeding NG supplies into the terminal and either using or selling the LNG themselves. This structure gives the partners the option to sell LNG for delivery in the near future on the spot market, though Shell is also in negotiations to sign long-term contracts with potential buyers.

[8] Shell Canada Energy is the majority stakeholder in the joint venture, which also includes subsidiaries of Malaysia's Petronas, PetroChina, Mitsubishi, and Korea Gas Corp.

Figure 5: Short-, medium-, and long-term LNG trade, 2010–17 (LHS), and non-long-term trade increasing to 30 per cent (80 mtpa) in 2017, up from 15 per cent a decade ago (RHS)





Source: IGU (2018), IHS Markit. Reproduced with permission.

4 Renegotiation windows and arbitration

Despite price dampening commercial structures such as s-curves, the longevity of LNG contracts (some lasting decades) causes potential frictions between buyers and sellers if market conditions change significantly beyond expected ranges. For this purpose, long term LNG contracts incorporate windows for contract terms and pricing reviews at defined periods, typically each 5 to 7 years. Should no agreement be reached during such review periods, the contracts include the possibility of going into 'arbitration', where both sides agree an arbiter to resolve the dispute without involving a legal court. Between 2008 and 2014, European utilities entered into dozens of cases against producers at specialist courts in Paris, London, and Stockholm, mostly winning awards in their favour. In Asia, the Singapore International Arbitration Centre (SIAC) is lobbying to become the key LNG arbitration centre (Tan 2018).

The KOGAS[9] case against Australia's North West Shelf is Asia's first LNG arbitration. The two sides failed to reach an agreement before the contract expired in 2016 and have gone to court-administered arbitration. Although the deal at stake seems insignificant (a 500,000-tonnes-per-year legacy contract that expired in March 2016), the arbitration sets a precedent for the LNG industry in Asia, where 'relationships' have always played a dominant role over commercial considerations. However, with increased diversity in LNG supply (including an increasing spot market) and a perception that traditional buyers in Japan and Korea have faced excessive prices in the past, the arbitration case is indicative of the changing market forces for Asia LNG. Combined with structural oversupply, growing market flexibility, and downstream liberalization, these shifts are threatening the traditional LNG business model—based on long-term contracts, oil-linked prices, destination restrictions, and take-or-pay clauses—and gradually shifting risk up the supply chain from buyers to sellers. In addition, the arbitration case occurs ahead of the expiration of several legacy long-term LNG contracts. Approximately 15 per cent of global contracts are set to expire in 2018–20, and an additional 15 per cent 2021–23. Buyers can either replace contracts with spot volumes or recontract under more favourable conditions. The KOGAS pricing dispute could set

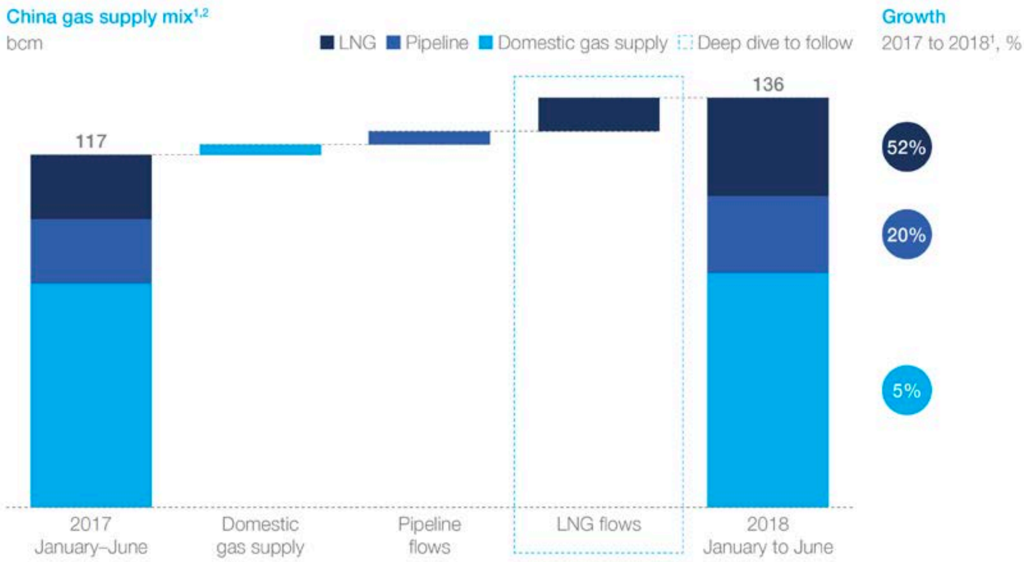
[9] Korea Gas Corporation (KOGAS) is a South Korean public natural gas company and the world's second largest corporate LNG buyer.

a precedent and open the floodgates for future renegotiations and pricing reviews in the global LNG industry with potential implications for all its stakeholders.

5 China and India as key drivers of LNG growth in Asia

Regasification capacity grew in 2017 from 795 mtpa to 851 mtpa by March 2018. The five countries where LNG imports increased the most during H1 of 2018 are all in Asia and all experienced LNG import volumes up at least 12 per cent year-on-year. In China, LNG import volumes grew faster than other delivery mechanisms (e.g., pipeline, domestic production) at 52 per cent p.a. during H1 of 2018.

Figure 6: China gas demand growth for domestic gas, pipeline imports, and LNG imports for H1 2018 compared with H1 2017



Note: although each element in the gas supply mix is growing, LNG imports are growing fastest (both in per cent and in bcm).

Source: Global Gas & LNG Outlook to 2035 (McKinsey & Company 2018b). © McKinsey & Company. All rights reserved. Reproduced with permission.

In 2017 (as in 2016), the largest single country increase in LNG imports also occurred in China, owing to increased enforcement of environmental policies that mandate the use of gas instead of coal in industrial and heating boilers across the population centres in the north of the country. In 2017, Chinese LNG imports rose by 12.7 mtpa compared to 2016 (when its imports rose by 6.9 mtpa), to a total of 39.5 mtpa, making it the second-largest single LNG market by the end of the year as it overtook South Korea.[10] China now has 57 mtpa of installed regasification capacity (world's fourth largest), operating at a relatively high utilisation of 73 per cent in 2017 (up from 56 per cent in 2016). It added additional regasification capacity of 2.6 mtpa and 12 mtpa in 2017 and 2016, respectively.

In 2016, India LNG imports grew by 4.5 mtpa (second largest growth after China), while in 2017 India grew only by 1.5 mtpa (ranked 8th in growth that year) to 20.7 mtpa. India has 27mtpa of

[10] China's overtaking of South Korea as the world's second largest LNG market is despite growth in LNG demand in South Korea with 4.9 mtpa to a total of 38.6 mtpa in 2017.

installed regassification capacity, operating at an even higher utilisation of 77 per cent.[11] The country also has 19 mtpa of regasification capacity under construction.

In the near term, well over half of the anticipated global growth in regasification capacity is expected in China and India. China has seven terminals under construction, along with four expansion projects, while India has four new terminal projects. Eastern India requires additional LNG imports as domestic gas projects have under-performed and/or been delayed. In addition, new gas-consuming sectors such as refineries, city gas consumption, and other industrial uses are actively being developed. Similar gas development and regasification activity is gaining traction in NE and SW India as well. Despite this, new pipeline connections will be needed to maximize gas penetration throughout the country. The lack of connectivity near the Kochi terminal located in the Indian state of Kerala, in particular, has limited throughput thus far and current expectations by the operator are that the pipeline will be completed by 2019 at the earliest.

In China, a strong drive for gas utilization (and thereby LNG imports) is already established based on environmental (air quality) considerations and there is orchestrated government action to implement the new energy policy. In India however, there is less efficiency in top-down policy, and issues concerning affordability, infrastructure, jobs, and local resources all compete for priority.

6 Further growth of LNG in SEA

Further growth of LNG in SEA is expected, particularly as a replacement for pipeline NG where local field resources are declining. Consequently, there is a shift in emphasis in further developments from LNG liquefaction to regasification projects. Due to depleting local gas fields, there is limited opportunity in adding liquefaction trains to existing facilities, although Indonesia (Tangguh and Abadi) and Papua New Guinea (PNG) still have some scope in this respect. As gas resources become smaller and more remote, Floating LNG (FLNG) has become operational as a new technology for LNG supply.

Whereas up to 2010 the trend was in designing and building ever larger LNG trains and projects, recent market demand growth has become more fragmented with smaller volume gas contracts. For operational as well as a commercial flexibility, the preference now is for more standardized (smaller) sized LNG trains for most projects. This is also driven by smaller sized undeveloped gas fields and more widely distributed demand.

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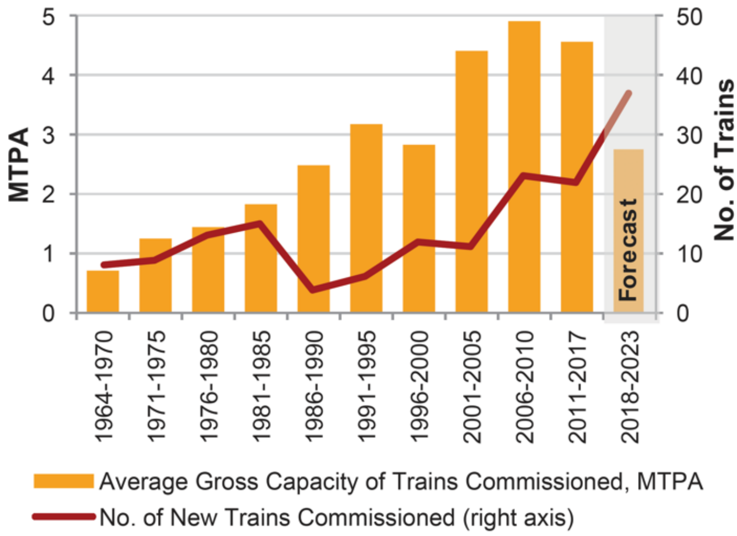
[11] For comparison, utilization of regassification capacity in Japan is 43 per cent, Korea 30 per cent, Spain 24 per cent, and Singapore 21 per cent.

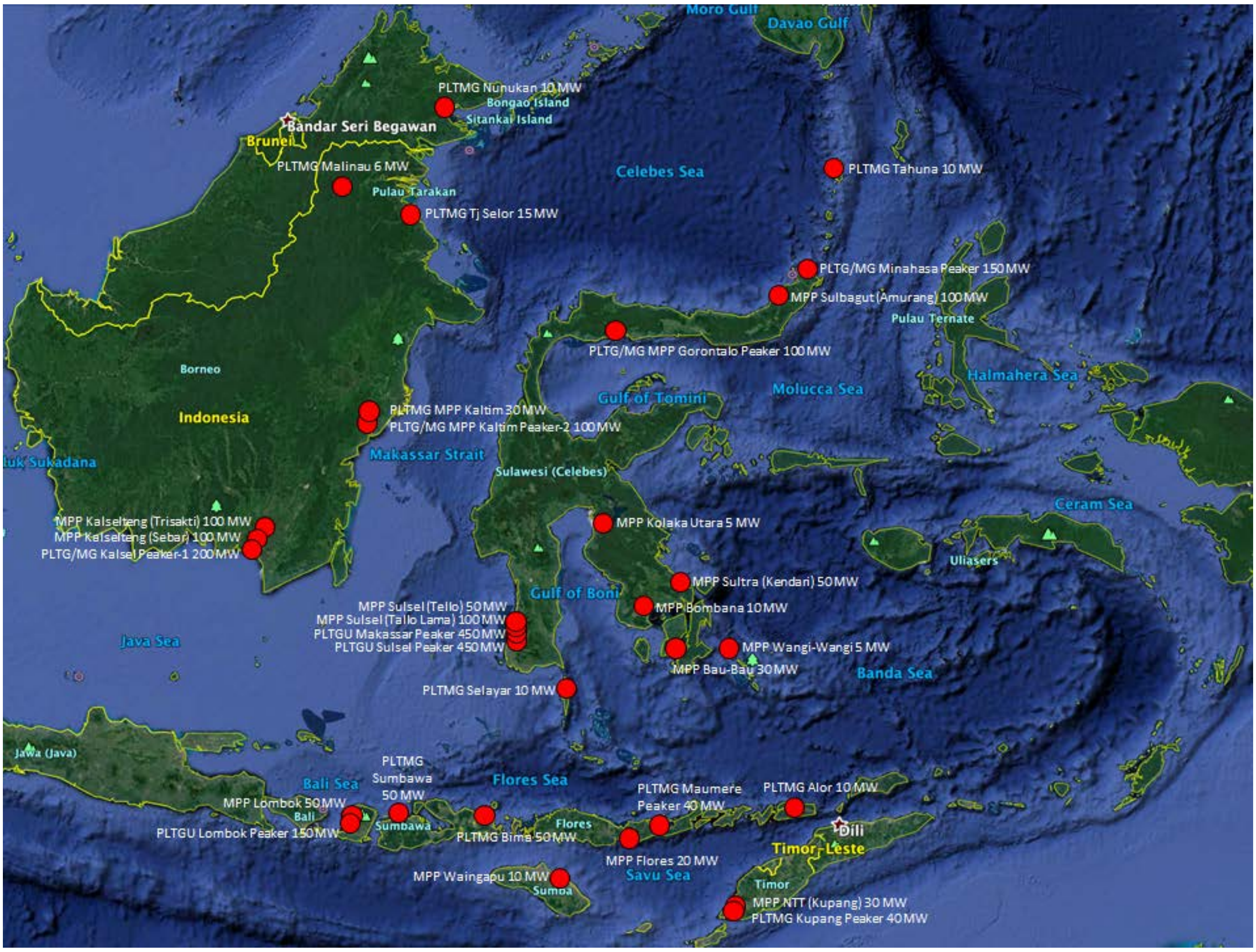
Figure 7: After a period of increasing LNG train sizes to obtain economies of scale from mega LNG developments, the foreseeable trend is now for on average smaller LNG train sizes.



Source: World LNG Report (IGU 2018). Reproduced with permission.

Gas demand in SEA pushes the size envelope even further to small scale LNG and mini-LNG. Local power development projects, such as those by PLN in Indonesia, similarly show a distributed demand driven by energy access. Such projects are often economically marginal due to the small scale and commercial complexity involved in establishing a full value chain from upstream resource to LNG plant, to LNG transportation, to LNG receiving terminals, to LNG offtake agreements with local power producers.

Figure 8: PLN gas fired power projects in Indonesia involving 32 small to large LNG regas facilities for a total 2.8 GW



Source: authors' illustration based on PT PLN's Electricity Supply Business Plan for 2016–25[12] and Google Earth.

In 2017 in SEA, Thailand imported 3.9 mtpa LNG, Singapore 2.3 mtpa, Malaysia 1.4 mtpa. Indonesia LNG regas is supplied solely from domestic LNG resources. Singapore aspires to become a world scale LNG (strategic) storage and trading hub for LNG. SLNG (incorporated by Singapore's Energy Market Authority, EMA) started commercial operations from its S$1.7 bln project on 7 May 2013. The project is the first open-access multi-user terminal in Asia. It is capable of importing LNG and re-exporting it to various suppliers.[13] SLNG has built a fourth LNG tank sized 260,000 m^3, the largest in the world, and able to receive a full cargo load from a Q-Max carrier (which is currently the largest LNG carrier in the world). With the fourth tank and associated infrastructure in place, the throughput capacity of the terminal is currently around 11 mtpa.

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[12] Available at: http://www.gbgindonesia.com/en/main/legal_updates/pln_issues_10_year_electricity_supply_business_plan_ruptl_for_2016_2025.php (accessed March 2020).

[13] See *Hydrocarbons Technology*: 'Singapore LNG Terminal, Jurong Island'. Available at: https://www.hydrocarbons-technology.com/projects/singaporelngterminal/ (accessed November 2018).

Figure 9: Singapore LNG (SLNG) regasification facilities

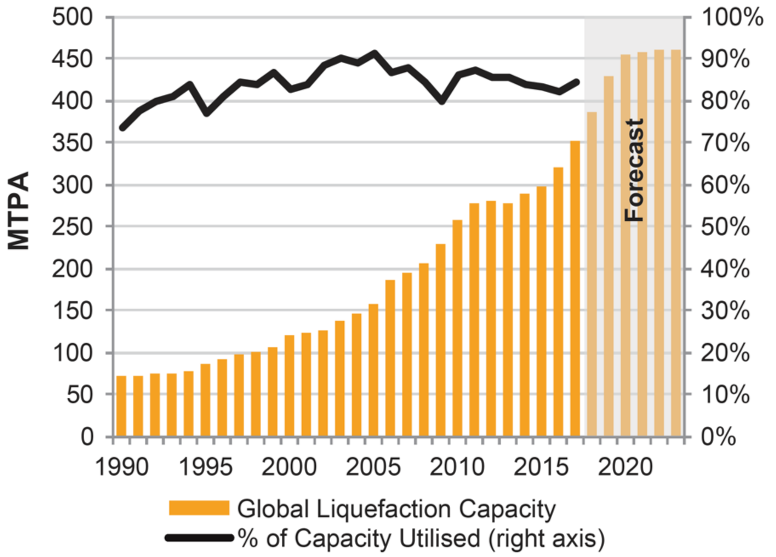
Source: courtesy of Singapore LNG Corporation.

7 Near term LNG supply developments

The momentum behind LNG Canada reflects the drastic improvement in the LNG market over the past 12 months. Steep demand increases in China combined with new LNG supply from the US and Australia disrupted historical LNG flow patterns in 2018. A clutch of new projects are targeting FIDs, including four mega trains in Qatar, Arctic LNG-2 in Russia, at least one development in Mozambique, and several U.S. projects. 2019 could be the busiest year of LNG FIDs ever, catching up from a six year period when no major LNG developments were sanctioned, but many large developments were completed. In 2017, only one large-scale LNG project achieved FID (Mozambique's 3.4 mtpa Coral South FLNG), the lowest volume of sanctioned LNG in 20 years. This was even less than in 2016, when only two projects achieved FID for a total sanctioned capacity of 6.3 mtpa. These small volumes are in large contrast with the >20 mtpa capacity sanctioned annually in the period 2011–15.

These anticipated new project sanctions in 2019 will add to the 92 mtpa of global LNG capacity already being constructed as at March 2018. More than half (48.6 mtpa) of under-construction capacity is in the US, followed by Australia (17 mtpa, all expected to become online in 2018) and Russia (13.7 mtpa). An overview of the growth in global LNG supply capacity is presented in Figure 10.

Figure 10: Global existing LNG liquefaction capacity and utilisation



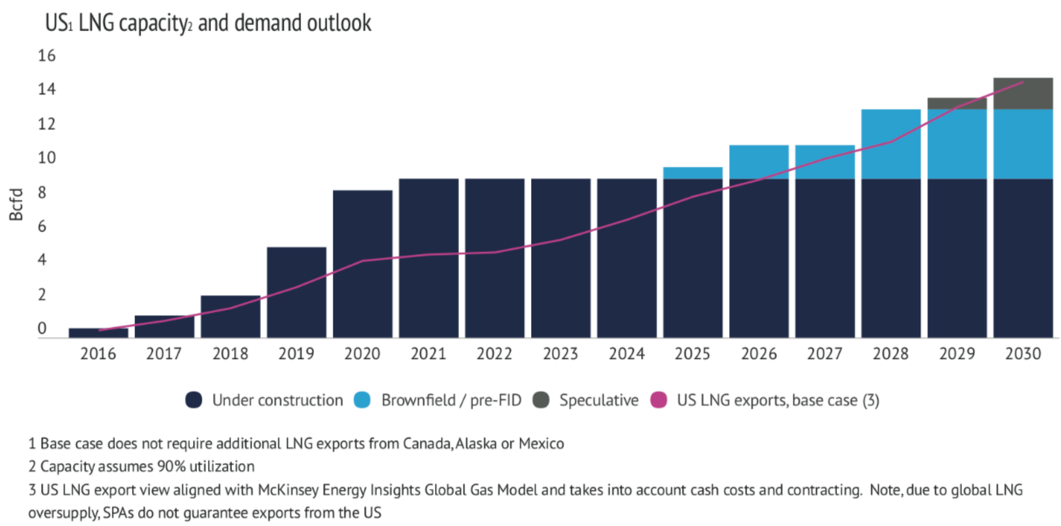
Note: in 2017, global liquefaction capacity utilization was 84 per cent, a rise from 82 per cent in 2016 after several years of utilization decline.

Source: World LNG Report (IGU 2018). Reproduced with permission.

7.1 North America to add 48 mtpa of LNG capacity by 2024

The US is ramping up LNG exports in 2018 and delivering 5.9 mtpa to Asia, of which ~70 per cent is going to Chinese and South Korean customers. In its North American Gas Outlook report (McKinsey & Company 2017), McKinsey predicts that by 2021, over 68 mtpa of LNG export capacity will be online. However, a global LNG market that is long on supply will keep US utilization low until ~2025. Only 55 per cent of 2021 LNG capacity is expected to have end user contracts, leaving ~4–5 Bcfd of potential swing demand. US LNG exports will account for 54 per cent of North American demand growth with ~15 Bcfd of capacity by 2030. In addition, LNG Canada will add a further 14 mtpa by 2023 with potential for more Canadian LNG export growth thereafter.

Figure 11: US LNG export capacity and demand outlook (1 Bcfd = 7.6 mtpa of LNG



Source: North American Gas Outlook to 2030 (McKinsey & Company 2017).

7.2 Qatar to add 23–30 mtpa of LNG supply by 2024

Qatar Petroleum is planning to begin LNG production from its North Field expansion by the end of 2023. It aims to reach 100 mtpa of output from its current 77 mtpa capacity, by adding three new 7.8 mtpa liquefaction trains and the possibility of a fourth additional train that would take output to 107.8 mtpa. Qatar LNG has an excellent track record of building LNG plants on projected cost and time, and has a strong market reputation as a very reliable supplier. Due to the scale of its North Field for gas supply, low infrastructure cost and smart standardization on LNG technology, its mega expansion is expected to be lowest cost source of supply. Regarding Qatar's position as the world's largest LNG supplier, it firmly states that global LNG gas demand will outstrip supply by around 2024 and that buyers want diversification of supply. Therefore, there should be sufficient gas demand for all suppliers although price competitiveness will remain as a key differentiator.

7.3 Australia to add 17 mtpa of LNG supply by 2024

Australia's recent supply growth is strongly supported by Chinese demand. In 2017, China imported 26 MT (66 per cent of its total LNG imports of 39.5 MT) from Australia (17.8 MT, 45 per cent) and Qatar (8.2 MT, 21 per cent), compared with 17.4 MT from these two countries in 2016. After Japan (25.9 MT) and China (17.8 MT), Australia's biggest export markets in 2017 were South Korea (7.1 MT) and India (1.8 MT). In 2018, Australia is expected to (temporarily) overtake Qatar (77 mtpa) as the world's largest source of liquefaction capacity with 85 mtpa, up from 66 mtpa in 2017 (and 56.5 mtpa in 2016). In terms of LNG exports however, Qatar may still rank first as its utilization in 2017 was 105 per cent of name plate capacity, while Australia managed 88 per cent. All projects currently under construction in Australia (17 mtpa) are soon expected to come onstream: Wheatstone LNG T2 (4.5 mtpa), Ichthys LNG T1-2 (8.9 mtpa), and Prelude FLNG (3.6 mtpa). After the current Australian construction wave is completed, the focus will switch to backfilling existing LNG plants as existing supply into the older LNG plants starts to decline. This reconfiguration of supply is likely to come at the expense of new LNG train opportunities. For example, Browse is now no longer targeting a new FLNG project but it is considered as backfill gas supply to North West Shelf LNG. Although these solutions are likely to result in lower cost of LNG supply for Australia, the developments have their own challenges, both technical (lengthy pipelines) and commercial (alignment of upstream and liquefaction partners).

7.4 Mozambique to add 15 mtpa of LNG supply by 2024

Coral South FLNG (3.4 mtpa), Mozambique's first LNG project, was the only project globally that achieved a final investment decision (FID) during 2017. Operator Eni expects LNG from this development to come onstream in 2022 and the total LNG volume has been contracted to BP. It is the first in a series of projects aiming to commercialize large gas discoveries offshore East Africa. Proposed liquefaction capacity targets are 50 mtpa in Mozambique and 20 mtpa in Tanzania, and new projects developing these new LNG volumes are expected to come on stream from mid-2020s onwards Another Mozambique LNG project is operated by Anadarko. This 12 mtpa LNG supply opportunity received government approval in March 2018 and is aiming to reach FID once marketing and financing arrangements are completed. Site preparation and resettlement processes commenced in Q4 2017. LNG is being marketed jointly by the Area 1 partners[14] with 8.5 mtpa of contracted offtake targeted for FID, of which 5.1 mtpa had been secured by March 2018.

7.5 Papua New Guinea to add 8 mtpa of LNG supply by 2024

PNG is planning to augment its LNG supply with three additional LNG trains through PNG LNG expansion and the Papua LNG project. The ExxonMobil-operated PNG LNG plant capacity would double from 8 to 16 mtpa at a cost of around US$12-14 billion. The expansion at around US$1,600 per ton is expected to be much (~35 per cent) cheaper than the original US$19.5 billion cost of building the greenfield PNG LNG plant. Additional gas supply will come from the upstream development of the Elk-Antelope gas fields and the P'nyang gas field project. By Q4 2018 Gas Agreements between developers and PNG government were still under negotiation, with the government seeking higher taxes, an increased project state ownership, domestic gas market obligations, and local content requirements from the expansion investment (Murtaugh and Clark 2018). However, the country's susceptibility to persistent civilian backlash drags on its appeal as an investment destination, and this will need to be addressed in order to ensure stable export flows and future growth. Despite a 2009 agreement that landowners of the PNG LNG project were due to receive a 2 per cent royalty payment with royalty pay-outs starting in September 2017, the majority of landowners are still largely disgruntled and production activities at the Hides, Angore, and Juha fields are continuing to be at risk as a consequence. For example, in June 2018, armed civilian groups vandalized wellhead and pipe construction equipment at the Angore site, leading Exxon and Oil Search to reassign workers and suspend operations. Similar to the situation in Qatar, the partners in PNG are racing to start producing from the new trains by around 2023 or 2024, when the LNG market is expected to need new supply due to rapidly growing demand in Asia: thereby capturing market ahead of other new projects.

8 Pricing structures for competitive new LNG supply

With the above diversity in new LNG supply projects, covering many geographies (from West to East), a wide range in infrastructure (from Greenfield LNG, Brownfield Infrastructure, to LNG Train expansions) and market conditions (gas versus oil-indexed priced, spot and long-term offtake), a debate is taking place on how the LNG (gas) market will be shaped under these developments(Nijoka et al. 2014). As mentioned earlier, a transition for the Asian LNG market towards gas-on-gas pricing models is likely to be a slow process and more likely is a mix of contracts that are long-term, short/medium-term and spot, based on oil-indexation, gas indexation, or a mixed indexation.

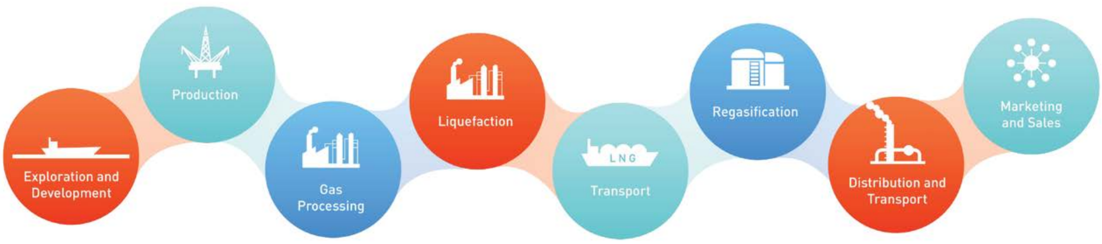
Price transparency is a key requirement for expanding the liquidity of LNG. The most effective way to gain price transparency is through the mechanism of a functioning Asian LNG hub that is based on an accepted price marker. LNG hubs exist in key markets such as the United States and Europe. LNG hubs are currently proposed by Singapore, Japan, and China. Each of the proposed LNG hubs has hurdles that must be overcome, but are actively being supported. Progress for developing an Asian LNG hub will take time, as seen in the history of HH and NBP. Singapore appears most advanced due to a regulatory structure that supports free trade. However, it has a

[14] Area 1 partners are Anadarko (operator), Mitsui, ONGC Videsh, Oil India, Bharat Petroleum, PTT, and ENH (Empresa Nacional de Hidrocarbonetos, Mozambique's national oil company).

small market size and almost no pipeline gas competition that would make it a nearly pure LNG market.

Oil indexation of gas contracts will become more difficult with greater competition between sellers, more price-sensitive buyers, growing energy deregulation, more gas-on-gas competition from new pipeline infrastructure, increasing spot market liquidity, and most importantly increasing availability of spot-price-based LNG exports. Developers of higher-cost projects will find it more difficult to protect their returns through contracts that do not reflect the realities of spot price pressures. The other side of the coin is that for most greenfield LNG projects, the cost of supply is high and incentives must be maintained to develop a regular pipeline of new LNG capacity. Huge market swings in bringing on new supply as seen recently (no big FIDs between mid-2013–mid 2018 and a flurry of FIDs expected in 2019) are putting a huge strain on the supply chain, cost, and quality. LNG is a very expensive and capital intensive industry, and prices (however they are formed) must reflect this reality. New LNG projects, which buyers point to as ensuring LNG prices will decrease, will not proceed unless developers can make their economics work. Cost competitiveness and strong balance sheets to carry the LNG development cost with less than 100 per cent of capacity underwritten by long-term contracts, are likely to be important differentiators in an increasingly competitive market. In addition to cost and finance, historical performance track record is a third key competitive differentiator, particularly in an increasingly uncertain world. In addition to operational performance (supplying on time, on quality, without incidents or accidents), performance is also driven by how well the LNG value chain is structured and managed. In particular for greenfield LNG projects, the LNG value chain is a key focus for financial lenders' and LNG buyers' due diligence. With the increasing diversity and complexity of the LNG market, this is a challenging process. Understanding of the different (and sometimes conflicting) aims of stakeholders' in support of an LNG project is critical. This requires a deep understanding of the choices in design and implementation of a specific business model out of a range of options.[15]

Figure 12: The LNG value chain



Notes: demonstration of performance track record is a key differentiator for LNG ventures. For greenfield projects, this is focused on how well the value chain is structured and managed.

Source: Understanding Gas and LNG options (US Department of Energy and USEA 2017).

9 The role of LNG in the energy transition

This chapter describes the most important expected developments in the energy transition and how gas (and LNG) markets are impacted. This includes the evolution of demand by types of

[15] A useful resource is the comprehensive handbook with practical information on LNG and LNG commercial structures/value chains by US Department of Energy and USEA (2017).

LNG use—gas-for-power, industry (petrochemicals), and transport. Gas (LNG) is particularly versatile as it has a wide range of different applications. Therefore, the role of gas can be expected to be adapted to the specifics of local geographies as well as market segments.

9.1 Drivers for the energy transition

Demand–supply scale

The global energy transition will impact energy growth and the energy mix in the future. Some growth drivers are likely to have positive effect on natural gas (LNG) demand (such as air quality), while other drivers (such as cheap coal or energy efficiency) may affect this demand negatively. Global energy growth is the result of the combined effect from, on one side of the demand-supply scale: 1) improved energy access to those currently not connected to electricity, 2) increasing urbanization and expanding middle class, 3) ongoing population growth. On the other side of the scale are: 4) falling energy intensity, 5) some downward pressure on economic growth.

There are currently in excess of 1 billion people globally who have no access to energy, and 3 billion people that have no access to clean cooking fuels. This has a huge negative impact on the degree of both economic participation and on public health. Hence, improved access to clean and affordable energy is a strong global priority (Sustainable Development Goal 7).[16]

More than 50 per cent of the world population now lives in cities, by 2050 this number is forecast to increase from 3.5 to 6.5 billion people (+86 per cent). This expansion of cities will occur almost entirely in the developing world. Although cities only comprise 3 per cent of the earth's landmass, they account for 60–80 per cent of energy consumption and 75 per cent of carbon emissions.[17] Of the cities and towns that monitor local pollution, 56 per cent have pollution levels 3.5 times or more above WHO guidelines.[18]

Population is forecast to grow from 7.4 billion people in 2015 to 9.8 billion in 2050. This increase is concentrated in Asia (excluding China) and Africa. From a capacity perspective, energy growth is specifically concentrated in small geographical areas (cities) in the developing world, where a large part of the population currently unconnected to energy will become connected. The concentrated pressures to meet this demand growth are unprecedented. At the same time, public health concerns (clean air) and climate change challenges are clearly requiring a significant decrease in emissions and these considerations will impact the future energy mix in meeting the demand growth.

The elements on the other side of the demand-supply scale are providing some relief to this tension. Global energy intensity is forecast to decline from 9 to 5 MJ/US$2015, with a shift to services and higher end-use efficiency. China is expected to see the largest decline in energy intensity from 16 to 6 MJ/US$2015, see Figure 13. Most of the impact mitigation (climate change and air quality) will have to come from the energy transition to cleaner fuels and Carbon Capture,

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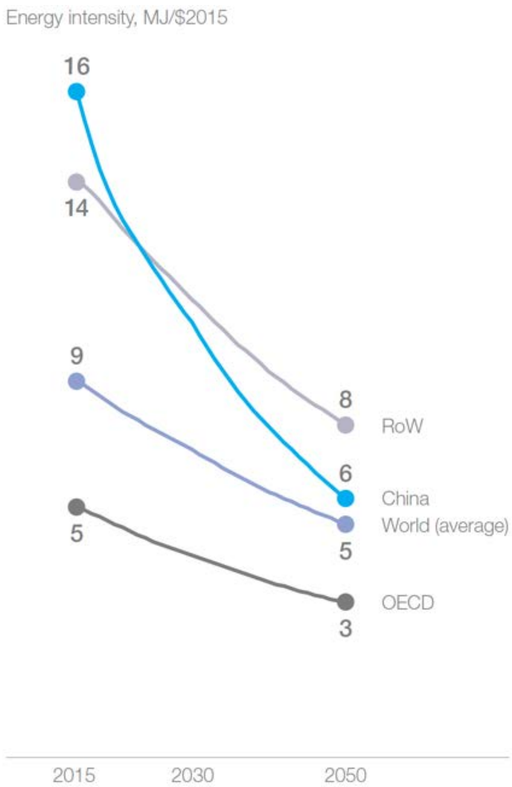
[16] United Nations Development Programme. SDG 7 Affordable and Clean Energy. Available at: http://www.undp.org/content/undp/en/home/sustainable-development-goals/goal-7-affordable-and-clean-energy.html (accessed November 2018):

[17] United Nations Development Programme. SDG 11 Sustainable Cities and Communities. Available at: http://www.undp.org/content/undp/en/home/sustainable-development-goals/goal-11-sustainable-cities-and-communities.html (accessed November 2018).

[18] See BreatheLife. It is a joint campaign by WHO, UN Environment, and CCAC to mobilize cities, governments, and citizens to protect health and planet from effects of air pollution. Available at: http://breathelife2030.org/the-issue/who-it-affects/ (accessed November 2018).

Use & Sequestration/Storage (CCUS). The changes in demand growth are also going to have a large impact on energy demand types, geographies, and customer affordability.[19]

Figure 13: Energy intensity is forecast to decline

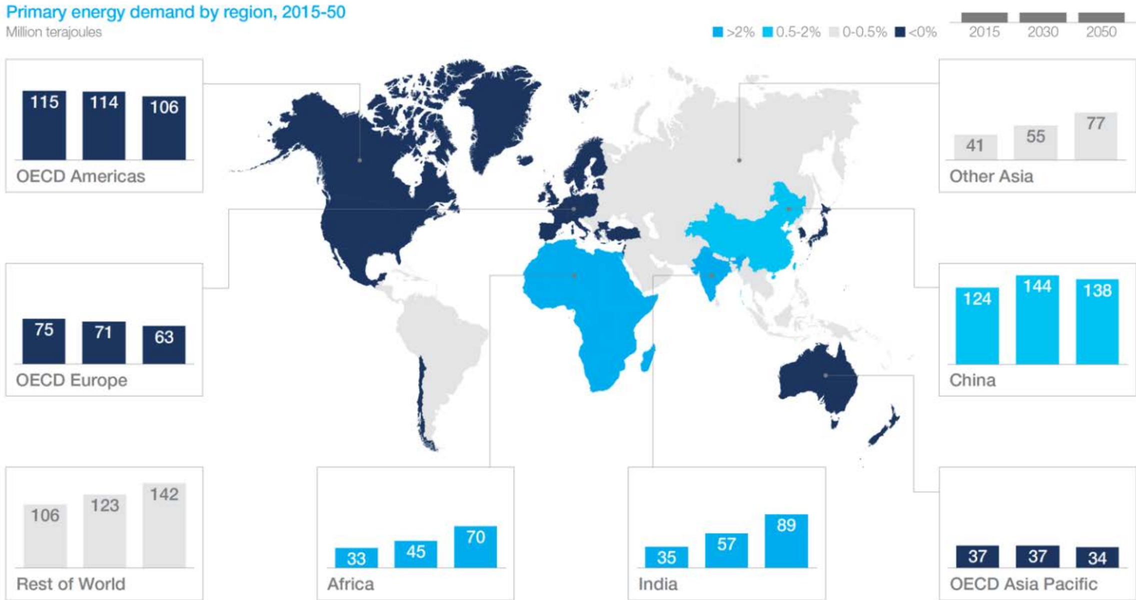


Non-OECD drives the demand growth

As primary energy demand growth continues to shift from OECD to non-OECD (see Figure 14) with the rapidly expanding middle class, this opens up new markets for LNG as a fuel for domestic power, for industry, and for transportation. However, at the point of supply, opportunities also exist where historic LNG suppliers to existing markets run out of feed gas to their liquefaction plants. The impact of this phenomenon can already be observed in Indonesia. New LNG suppliers are expected to take over supply to the existing Asian customers (particularly in Japan and South Korea).

[19] EPA Global Emissions Data. Available at: https://www.epa.gov/ghgemissions/global-greenhouse-gas-emissions-data (accessed November 2018).

Figure 14: Primary energy demand is shifting economies and geographies, from OECD to non-OECD and from China to Africa, India, and other Asia



Notes: the trios of bars represent primary energy demand in 2015, 2030, and 2050, whilst the different colours of the bars and on the map represent the magnitude of the primary energy demand growth rate for each region.

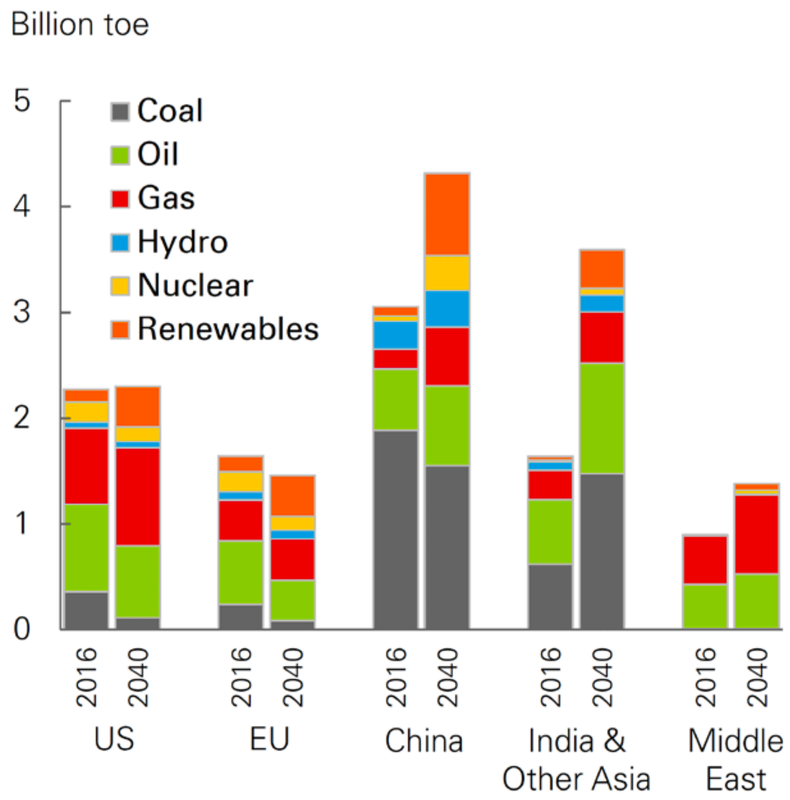
Source: Global Energy Perspective Reference Case (McKinsey & Company 2018a).

The energy mix is changing

Electrification is going to be by far the fastest growing source of energy demand between now and 2050. The global energy mix is already experiencing a profound change with the increasing global investments in renewables for power generation. Significantly, 2016 was the first year in which solar and wind net power capacity additions (in GW) exceeded coal and gas (McKinsey & Company 2018a). In parallel, the cost of renewable power continues to decline, rapidly improving the economics of renewables. Already by 2020, renewables are expected to be the most economic new-build option across regions including China and India. By 2030, new renewables are likely to become cheaper than even existing Combined Cycle Gas Turbines (CCGTs) in some markets. Decreasing costs of power storage further reduces the utilisation potential of gas fired power. On paper, gas (and especially LNG) has been hailed as the ideal transition fuel to coexist with renewables. In practice however, this has not turned out to be the symbiotic partnership once expected (see also section below on lacklustre gas-for-power growth). In addition to the power market, energy demand and fuel mix are also expected to change for industry and transportation sectors.

Every region (and country) will follow its own distinct path in establishing its future energy mix, see Figure 15. China provides an important example of how energy mix is forecast to change. Soon to become the country with the largest economy globally, China is simultaneously experiencing a rapidly changing energy mix due to its push for cleaner air as well as a transition of its economy from industry-based to consumer-driven growth. BP's energy outlook (BP 2018) forecasts that between 2016 and 2040 China's energy demand growth will slow to a 1.5 per cent compound annual growth rate (cagr), less than one third of its growth rate in the past 20 years (6.3 per cent cagr). By 2040, demand is forecast to have expanded for oil by 28 per cent and for gas by 194 per cent, while coal demand is expected to have declined slightly (-18 per cent). Renewables in power grow significantly with solar and wind (+789 per cent), nuclear (+574 per cent), and hydro (+32 per cent). Nonetheless, coal will still remain the largest fuel source in China in 2040 (at 36 per cent of the total energy mix, reduced from 62 per cent in 2016). In this period, the share of renewables rises from 3 per cent to 18 per cent, while the NG share is forecast to nearly double, but only to a 13 per cent share.

Figure 15: Primary energy demand forecast by fuel and region



Notes: figure shows significant differences in energy mix for different regions. China stands out as the world's largest energy consumer (now and in the future) and as the second largest energy growth region (in billion toe) after India & other Asia.

Source: BP's Energy Outlook (BP 2018).Reproduced with permission.

9.2 Electrification drives demand

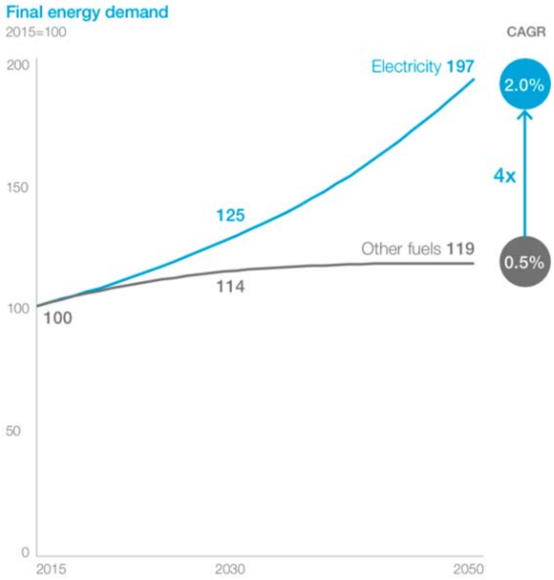
The power market is important, as electricity demand is growing at four times the rate (2 per cent cagr until 2050) of all other fuels (0.5 per cent), see Figure 16. Rapid electrification, including electric vehicles for road transport, is changing the electricity demand profile. McKinsey (McKinsey & Company 2018a) expects the split to change from 2015 to 2050 as follows:

Per cent of final energy demand:

- Buildings: 31 per cent → 43 per cent
- Transport: <1 per cent → 20 per cent
- Industry: 21 per cent → 24 per cent

Buildings electricity demand growth in non-OECD Asia (17 per cent of global buildings demand) comes predominantly from space cooling and electrical appliances. The global electricity demand growth from transport includes both electric-vehicle passenger cars (27 per cent vehicle sales in 2030) and trucks (13 per cent vehicle sales in 2030). Declining battery costs will drive the total cost of ownership of electric medium-duty trucks below that of diesel alternatives by 2027.

Figure 16: Electricity demand is growing at four times the rate of other fuels



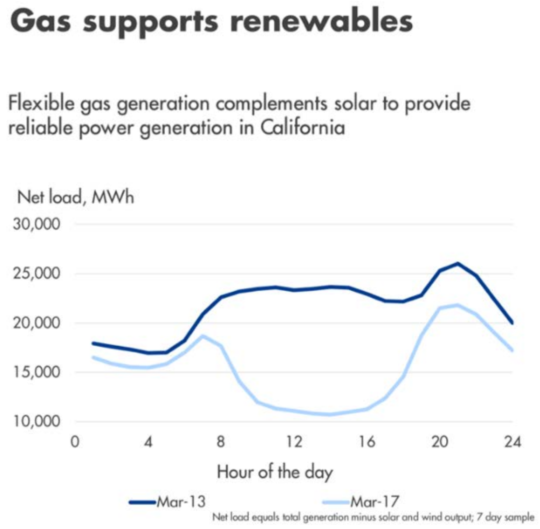
Source: : Global Energy Perspective Reference Case (McKinsey & Company 2018a). © McKinsey & Company.

Gas supports renewables in power generation

With electrification by far the largest growing source of energy demand, it raises the question of what the role of LNG will be in meeting the demand for electricity. As part of the energy transition, LNG can have significantly lower greenhouse gas emissions than coal (see section below about LNG having a smaller CO2 footprint than coal fired power). Gas-fired power can also manage power output variations with a higher degree of flexibility than coal. Gas is a fast-firing fuel and therefore a strongly symbiotic to intermittent renewables, much more so than coal. With renewables providing a larger share of the base load power generation, other fuels have to make up the difference at lower load factors to meet total power demand (see Figure 17). Because LNG is on the downstream side of the value chain much more Opex heavy than Capex heavy, it can compete head-to-head with coal on a cost basis at lower load factors.

In the medium-term (existing and new) coal is the key competing fuel with LNG in the power sector. In the longer term the energy mix is expected to evolve to solutions that are increasingly carbon neutral, i.e. more renewables (including hydro) combined with industrial scale batteries. By then the key competitor to NG will be industrial batteries.

Figure 17: Natural gas complements intermittent energy supply from renewables



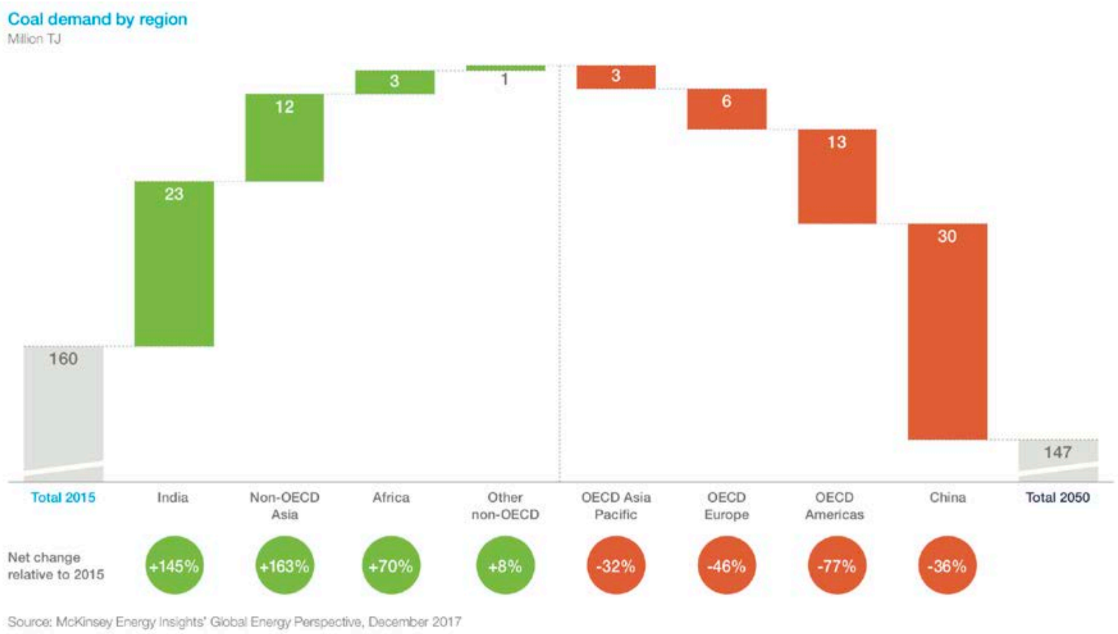
Notes: due to the inherent intermittency of renewable resources, the power-generation mix requires a fast-firing load-balancing fuel to mitigate against the variable supply. The curves in the figure represent the non-renewable power generated at two separate days, March 13 and March 17. The 'duck curve' on March 17 illustrates that when there is deep penetration of weather-dependent renewables into the power-generation mix, the load factors on thermal generation vary quite substantially. At lower load factors, gas can compete head-to-head with coal on a cost basis. Gas-fired power is also more flexible to adapt to the rapidly changing electricity load. Hence, renewables is the way to back coal out of the system, and gas is a facilitator to enable this. However, the roadmap for how this would happen hasn't really been borne out by the facts. Germany and other European countries show that coal contribution in the power-mix is resilient and its decline slow unless it is actively reduced by regulation. Renewables and gas (LNG) need closer collaboration on this issue.

Source: Shell LNG Outlook 2018 (Shell 2018). Shell interpretation of Wood Mackenzie Q4 2017, IHS Markit, and CAISO data. Reproduced with permission.

Despite its merits, gas-for-power shows lacklustre growth

Notwithstanding the symbiosis between gas and renewables, gas (and therefore LNG) seems, in practice, to benefit less than expected from the global electrification drive. SEA is no exception: non-OECD Asia (excluding China) is the second largest growth region for coal demand after India, at the expense of gas growth. China's large decline in coal demand is as the result of strong government policy to replace coal demand with other energy sources to improve air quality. However, in SEA, the share of gas in the global power generation mix is forecast to reduce from current 43 to 28 per cent by 2040, while coal at 40 per cent will take the most prominent role (IEA 2017).

Figure 18: Coal demand by region



Note: coal demand is still expected to grow in a number of regions, including India and non-OECD Asia (excluding China), while declining elsewhere. China is reported as a separate region in this figure.

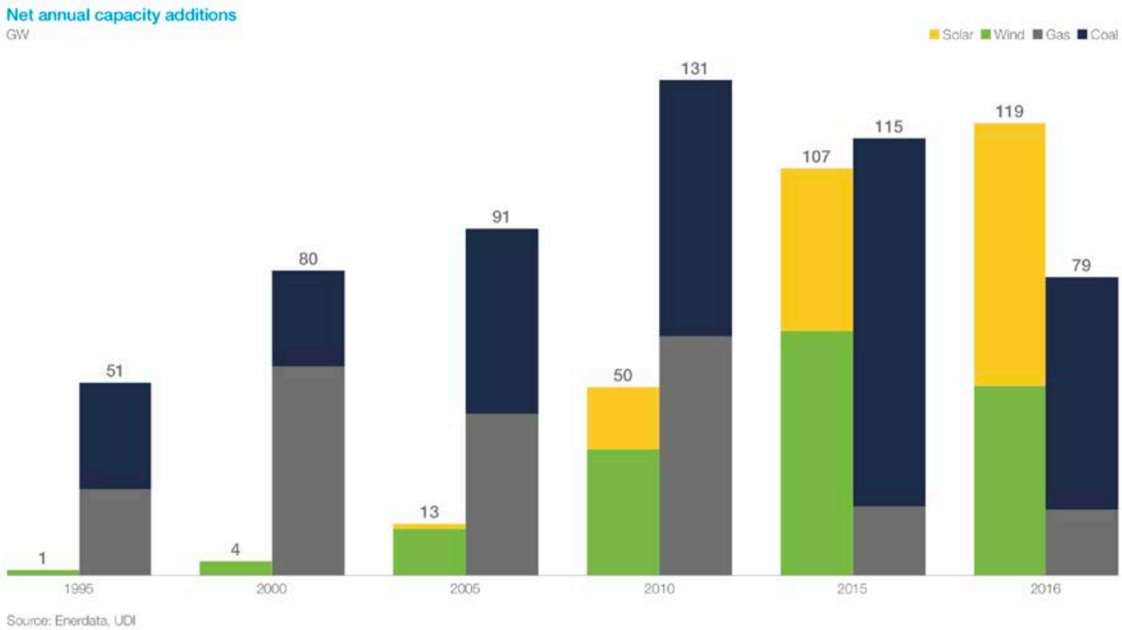
Source: Global Energy Perspective Reference Case (McKinsey & Company 2018a).

The reasons for the lacklustre gas-for-power growth are the following:

- Persistent low-cost coal and coal interests squeeze out gas-fuelled power opportunities in some countries (including Indonesia).
- Fast growing installed capacity for renewables, combined with battery storage, limit utilisation the rates of gas fired power.
- Cost inflation of gas (LNG) pre-oil/gas price recession impacted economic competitiveness. New gas resources are more remote, more difficult to develop, smaller, more contaminated, etc. The upstream gas resources that remain to be developed are more expensive.
- Growing demand from local energy access often has insufficient scale for gas infrastructure to be economic.
- There is increasing negative public sentiment towards gas as 'just another fossil fuel' and this is negatively affecting customer demand.
- NGOs raising concerns against 'methane slip', i.e. methane losses to the atmosphere along the gas value chain. This puts the focus on producers and transporters to verify and certify the extent of any methane losses.

The annual global net power capacity additions for the period 1995–2016 are presented in Figure 19. After 2010, gas-fired power capacity additions declined significantly from previous periods, while coal increased.

Figure 19: Global net annual power capacity additions in GW



Note: renewables are winning market share from carbon-based fuels. Among carbon options, coal is winning from gas.

Source: Global Energy Perspective Reference Case (McKinsey & Company 2018a).

LNG has a smaller CO2 footprint than coal fired power

Although LNG production per ton is less CO_2 efficient than coal production, LNG has a higher energy density per tonne than coal and emits less CO_2 during power generation. The comparison of the overall CO_2 footprint of these two fuels depends of course on a large number of variables, including the type of power plants. Two parameters that could swing the balance negatively for gas are the CO_2 content of the gas and the energy required to compress and transport the gas to the LNG plant. Unless the CO_2 content in the LNG is captured and sequestered into a disposal reservoir (as is done for the Gorgon LNG development in Australia), any gas fields containing 8–17 per cent CO_2 could cause an additional 50 per cent of CO_2 emissions in the upstream operations and liquefaction processes (e.g. Ichthys LNG development in Australia), compared to fields that have no or negligible CO_2 in their gas content (Reuters 2011).[20]

Substitution with low/zero carbon fuels to meet climate change targets

Despite the success of renewables in growing its market share, these efforts currently are insufficient to meet the two degrees global climate objective. The carbon budget for a 2 °C scenario is 3,700 Gt CO_2-equivalent. Subtracting from this budget 800 Gt CO_2-eq to allow for non-CO_2 related emissions (such as methane) from land use changes, agriculture, or waste provides a CO_2 budget of 2,900 Gt CO_2. DNV GL (2017a) forecasts in its energy transition outlook an overshoot of the CO_2 budget by 700 Gt by the year 2100. The figures suggest that the world is heading towards something that looks like a 2.5 °C warming above pre-industrial levels in the second half of this century. Faster substitution of carbon heavy fuels (coal) for carbon light fuels (including gas) is needed to bring emissions in line with the carbon budget.

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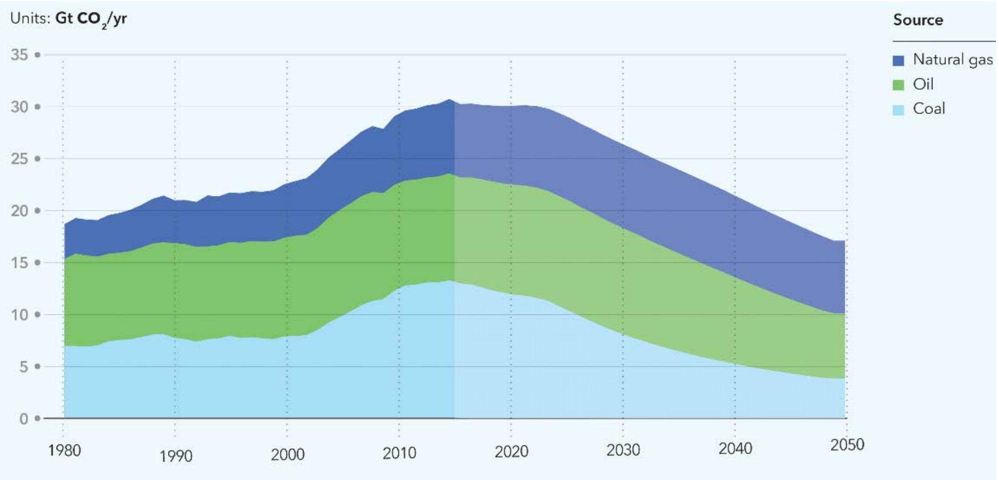
[20] See Reuters (2011) for a comparison of CO_2 emissions between LNG and coal.

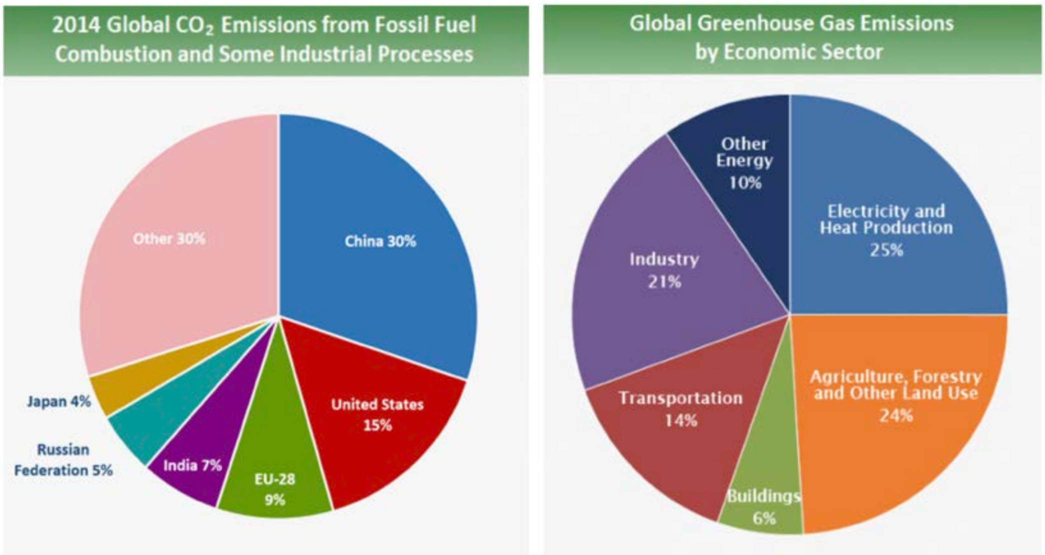
Figure 20: World total energy-related CO_2 emissions by energy carrier



Source: Energy Transition Outlook (DNV GL 2017a). Reproduced with permission.

Moreover, consumers (including large buyers of electricity) are becoming increasingly active in support of efforts on climate change. There is increasing evidence that corporations (including FAANG[21] companies) are turning clean energy commitments into action. In 2017, corporations signed contracts to procure 5.4 gigawatts of renewable energy (Glover 2018). FAANG companies are particularly important as these are big players in the fast-growing data centre sector that is forecast to utilize 20 per cent of all global electricity demand by 2025 (Vidal 2017). Without changes in the energy mix, global emissions from ICT industry would rise from 3.5 per cent of global emissions by 2020 to potentially 14 per cent by 2040 (this is the same fraction of global emissions that the USA currently emits in totality).

Figure 21: Global CO2/GHG emissions by country (2014) and sector (2010)



Source: Global Greenhouse Gas Emissions Data, United States Environmental Protection Agency.[22]

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[21] FAANG is an acronym for the market's five most popular and best-performing tech stocks, namely Facebook (FB), Amazon (AMZN), Apple (AAPL), Netflix (NFLX), and Alphabet's Google (GOOG)

[22] Available at: https://www.epa.gov/ghgemissions/global-greenhouse-gas-emissions-data (accessed February 2020). Based on the Intergovernmental Panel on Climate Change (IPCC) report: *Climate Change 2014 – Mitigation of Climate Change* (2014).

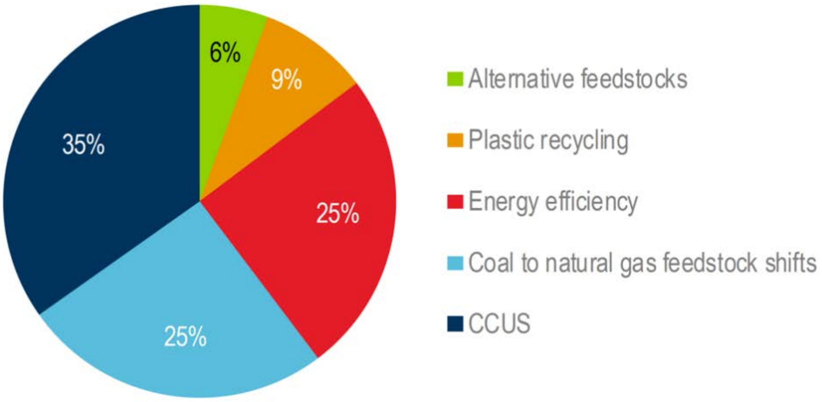
9.3 Industrial demand—petrochemicals

As gas is losing out in competition in the electricity market against renewables and coal, other markets are being sought to stimulate gas demand. Gas as feedstock for petrochemicals is expected to grow significantly. In market value it is expected to grow from US$514.5 billion in 2014 to US$758.3 billion by 2022, benefiting from the growth of key end-use industries such as construction and transportation, particularly in BRIC nations, as well as a favourable regulatory framework, particularly in the Asia Pacific region (GlobeNewswire 2015).

Products manufactured by petrochemical firms, such as ethylene, propylene, butadiene, benzene, xylene, styrene, and methanol, are widely used as chemical building blocks in a range of industries, including rubber, plastics, electronics, and packaging. In 2014, ethylene was the leading product segment, valued at over US$140 billion and accounting for 28.4 per cent of total market volume. Rising polyethylene demand, particularly from the packaging industry, is expected to drive this segment over the forecast period. Methanol is forecast to emerge as the fastest growing product segment, growing at an annual rate of 8.1 per cent from 2015 to 2022. This is because methanol is widely used in the manufacture of biodiesel and demand for biodiesel is anticipated to increase significantly during this period. However, plastic recycling and efficient packaging could cause disruption to the petrochemical driven growth in gas demand. At present, the petrochemicals industry uses 8 per cent (300 bcm) of global gas demand (3750 bcm), mostly as feedstock. The petrochemical sector is expected to account for 7 per cent of the 850 bcm global increase in gas demand (to 4600 bcm) by 2030. Petrochemicals' gas demand is therefore predicted to consume an incremental 56 bcm (+19 per cent) by 2030 and 83 bcm (+28 per cent) by 2050 (IEA 2018). The chemical sector consumes as much energy as the steel and cement sectors combined, yet it emits less CO_2 than either sector. Still, chemicals emit 1.5 Gt CO_2, which is 18 per cent of all industrial-sector CO_2 emissions, or 5 per cent of total combustion-related CO_2 emissions. This is in part because the chemical industry consumes more oil and gas than other heavy industries, which tend to rely more on coal. Also, most of the carbon is locked into its products (plastics).

An additional opportunity exists to displace coal and naphtha feedstock with NG in the chemical sector (see Figure 22). For example, coal-based methanol-to-olefins capacity in China is to nearly double between 2017 and 2025. The sector's clean transition is led by CCUS, catalytic processes, and a shift from coal to NG. Some of the most cost-effective opportunities for CCUS can be found in the chemical sector, which explains its leading role among scalable options for reducing emissions. Catalytic alternatives to traditional process routes can provide more than 15 per cent of energy savings per unit of production. Shifts from coal to NG for both ammonia and methanol production, mainly in China, result in decreases in both process emissions and energy intensity.

Figure 22: Opportunity for cumulative direct CO_2 emission reductions in the petrochemical sector due to feedstock shifts.

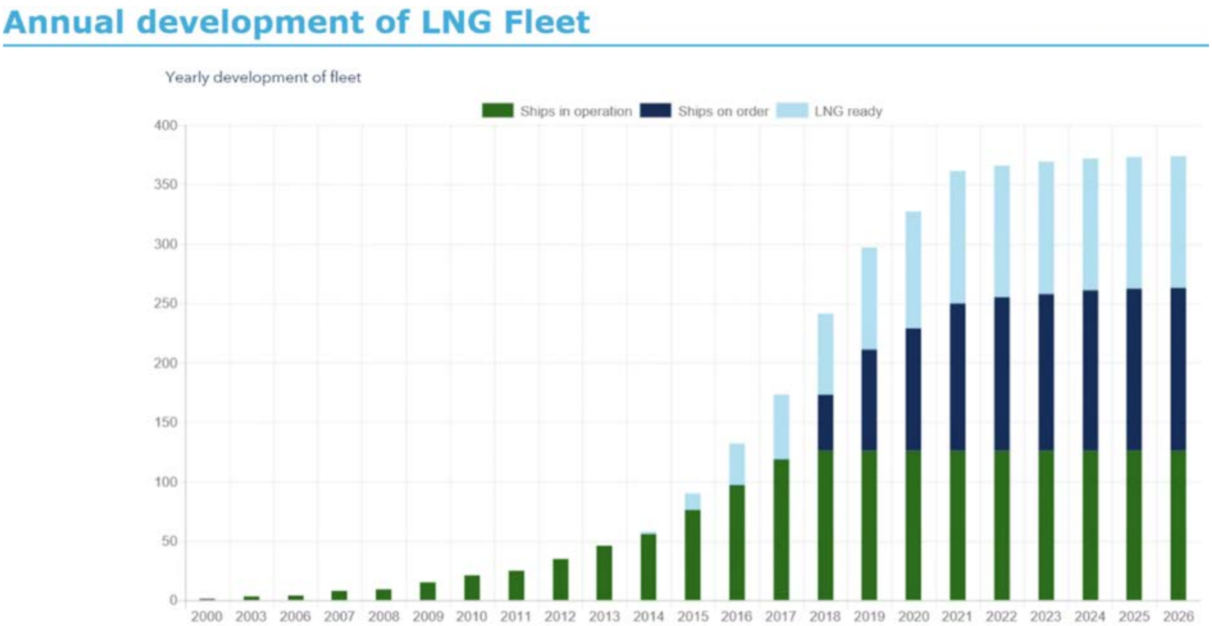


Note: chemical sector emissions can be reduced, with coal-to-natural-gas feedstock shifts accounting for 25 per cent of the total reduction. In the energy efficiency component (25 per cent), there is also an element for feedstock shift from naphtha to ethane (NG).

9.4 Transportation—LNG as fuel

LNG-fuelled shipping (DNV GL 2017b) is a new LNG market opportunity is maturing in the transportation sector. Although low oil prices have reduced DNV GL's expectation of the number of LNG fuelled ships by 2020 from 1000 to 350 vessels (Figure 23), the trend remains positive and the market potential remains high (Figure 24). At present, there are globally 125 vessels fuelled by LNG, of which more than two-thirds are operating in Europe (in Asia: 6 vessels). A confirmed order book of 111 vessels (7 of which are in Asia) will see that figure double. In addition, there are 114 vessels that are classified as LNG-ready.

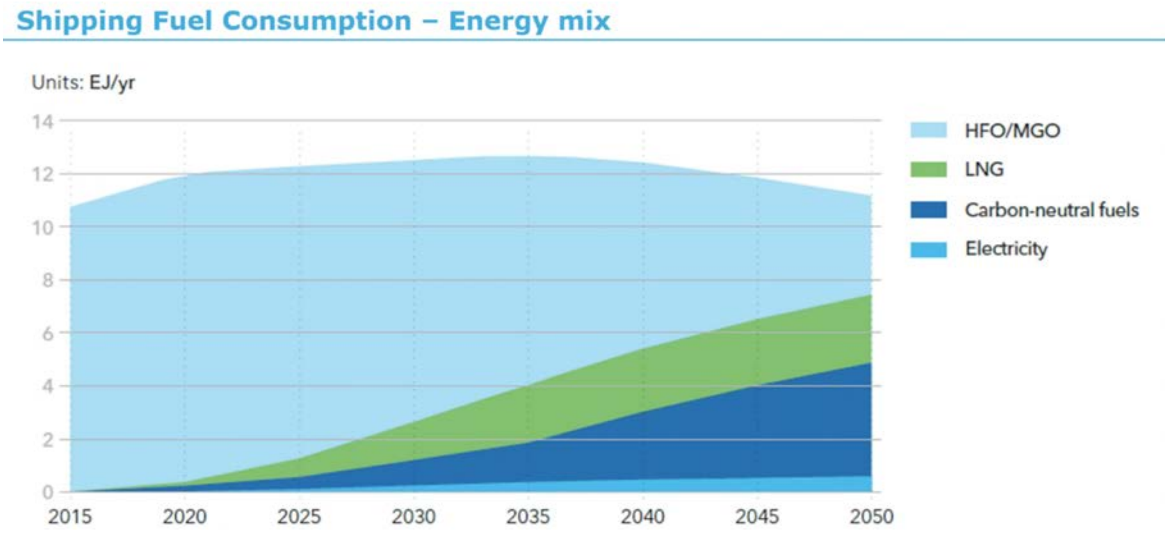
Figure 23: LNG-fuelled shipping taking off



Note: number of ships excludes LNG carriers and inland waterway vessels.

Source: Maritime forecast to 2050 (DNV GL 2018). Reproduced with permission.

Figure 24: LNG-fuelled shipping market potential

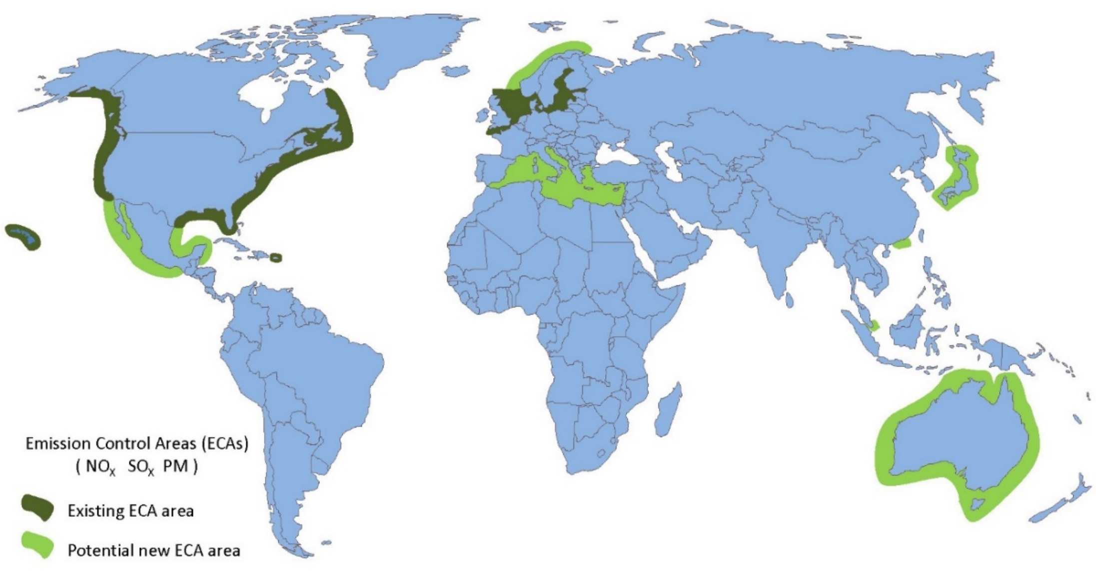


Note: LNG is forecasted to grow to 22 per cent of shipping energy demand (excluding LNG Carriers).

Source: Maritime forecast to 2050 (DNV GL 2018). Reproduced with permission.

In addition to fuel cost considerations, another key driver for selecting LNG as a shipping fuel concerns the need to meet environmental constraints on fuel emissions. Many Heavy Fuel Oil (HFO)/Marine GasOil (MGO) fuelled ships are considering to retrofit LNG as a hybrid/dual fuel system. This allows LNG to be used in those Emission Control Areas (ECA) and Sulphur Emission Control Areas (SECA) that have strict emission standards, while also providing flexibility to opt the most commercial fuel option at any specific time outside of those areas. Hybrid systems (e.g. LNG fuel in combination with industrial batteries) are another cost effective development, in particular for applications that have a dynamic variation in power demand.

Figure 25: Maritime Emission Control Areas (ECAs) are expanding globally



Notes: LNG-as-maritime-fuel market development is supported by increasingly greater impact of emission control regulations in the shipping sector, both in terms of the expansion of ECA and SECA areas as well as more stringent emission limits in these areas. Disclaimer: the map is for illustration purposes only, and does not imply the expression of any opinion whatsoever.

Source: authors'illustration. World map by www.freeworldmaps.net.

LNG bunkering options are expanding on a global scale. Today, there are 60 supply locations worldwide, including in Singapore, the Middle East, the Caribbean, and Europe. A further 28 facilities have been decided and at least 36 are under discussion. By 2018, six LNG bunker vessels were in operation globally, and four more projects are confirmed. Major players, including Total, Shell, Gas Natural Fenosa, ENN, and Statoil, have announced plans for new LNG bunker vessels, which are likely to materialize at key locations in northern Europe, the Middle East, the Gulf of Mexico, Singapore, and the Mediterranean.

The growth of LNG in transport applications will also facilitate the definition of a fuel standard for LNG that is currently lacking. This is an important consideration for LNG supply ventures in the design of their LNG specifications. Part of this is driven by the composition of the gas fields that supply the gas to the LNG plant, while LNG technical process design will determine how much ethane, propane, and trace elements will remain in the export LNG. LNG that is in compliance with the properties of the expected LNG fuel standard will be another differentiator for LNG ventures.

10 Conclusion and early learnings

10.1 LNG has a key role in Asia

Asia has an established LNG market, with existing infrastructure that is rapidly expanding across the region. Whereas before there were few suppliers and few buyers, there is now much more diversity on both sides of the market. In particular in the smaller markets in SEA, there is a proliferation of LNG regassification facilities to supply increasing power demand and to substitute declining domestic gas supply. Worldwide, LNG is growing significantly faster than domestic gas and international pipeline gas. On LNG demand growth, China stands out as having recently overtaken South Korea as the world's second largest LNG importer after Japan. China's long-term energy demand growth however is expected to slow considerably from 6.3 to 1.5 per cent cagr. By 2040, the share of gas in China's energy mix will have increased from 6 to 13 per cent, but by then will still be less than half of coal's share (36 per cent). In terms of market potential, India stands out as a key opportunity, but with a less well orchestrated strategy there is less clarity about how the energy mix will evolve.

On the supply side, limited further LNG supply growth in SEA is expected, driven by smaller projects enabled by FLNG and cost-efficient expansions of existing LNG infrastructure. The next wave of LNG supply is expected to be dominated by North America (+48 mtpa), Qatar (+23-30 mtpa), Australia (+17 mtpa), Mozambique (+15 mtpa), and PNG (+8 mtpa). The clearing of a large volume of available North American gas into LNG supply may delay FIDs for other greenfield projects. Singapore is well positioned as an LNG bunkering hub, a strategic LNG storage facility, an LNG trading hub (including a potential LNG price marker), and an International Arbitration Centre (SIAC).

10.2 LNG pricing and financing developments

The global LNG market oversupply after 2015 and the associated fall in global gas prices changed the traditional LNG business model. Long-term contracts (some lasting decades), which incorporate windows for contract terms, pricing reviews, and arbitration, are now being complemented by a growing share of contracts with shorter duration and higher volume flexibility. Shorter contracts and gas-on-gas competition have reduced the linkage of LNG to oil prices, stimulating growth, but also creating more price volatility. Some projects, such as LNG Canada have taken FID without secured long-term contracts (and therefore without project financing). Key differentiators for new LNG supply projects include cost competitiveness, strong balance sheets, and performance track record. For greenfield LNG projects, the design and management of the LNG value chain is a key focus for due diligence by financial lenders and LNG buyers.

10.3 LNG has a strong value proposition to contribute to the energy transition, but the gas-for-power growth could be lacklustre in many countries in Asia

A rapid increase in electrification globally is going to have a large impact on the energy market both globally as well as in Asia. Global electricity demand is expected to grow at four times the growth rate of other fuels. In 2016, renewables grew faster than fossil fuels in terms of installed electrical power capacity, but they start from a much smaller base and with lower average utilization for wind and solar. In non-OECD Asia excluding China, new coal-fired power gained significantly in 2015 and 2016, against other energy sources, including NG. Even in China, coal is expected to remain the largest energy source, although its share in the energy mix is forecast to decline from 62 (2016) to 36 per cent (2040). In comparison, the share of NG in China in the same period is expected to grow significantly, more than doubling from 6 to 13 per cent. Nonetheless, NG (and LNG) is struggling for market share in most electricity markets. Consequently, market opportunities are being promoted for gas demand growth, including petrochemicals and LNG-as-transportation-fuel.

The energy transition is very geography- and situation specific, and it needs to take into account several factors, including in-country local contexts and the particular opportunities these offer. More effort is needed by gas producers (transporters and consumers) to demonstrate that NG and LNG is a superior fuel compared to other fossil fuels, particularly in a symbiotic energy mix with renewables. More transparency is required to verify and certify the extent of any methane and CO_2 losses in the gas value chain, and pursue actions to mitigate these (such as carbon capture and sequestration).

10.4 The way forward

Governments and institutions advising governments play a crucial role in steering the energy mix. Increasingly, externalities, such as air quality and its impact on health, need to be 'priced in' when making decisions on energy policy and projects. The affordability assessment with respect to energy needs has to look beyond commodity prices and project financial returns. Singapore is the first country in SEA to introduce a carbon tax, starting in 2019. As 2018 Chair of Association of South East Asian Nations (ASEAN), it is well positioned to support ASEAN countries in establishing a more aligned approach on policies supporting the energy transition. The technologies are mature, what is needed is a mature stance of producers, consumers, regulators, and governments to address the true cost of energy and its emissions in their economic assessments and financial obligations. In particular, the gas sector and the renewables sector need to collaborate much more closely to capitalize on the opportunities for symbiosis between these two energy sources of the future.

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Abbreviations and units

ASEAN	Association of Southeast Asian Nations
Bcfd	Billion cubic feet per day (1 Bcfd NG = 7.6 mtpa of LNG)
bcm	Billion (= one thousand million) cubic meter
BRIC	refers to the countries of Brazil, Russia, India and China
cagr	Compound annual growth rate
capex	Capital Expenditure
CCGT	Combined Cycle Gas Turbine
CCS	Carbon Capture and Storage (Sequestration)
CCUS	Carbon Capture, Use and Storage (Sequestration)
CNG	Compressed Natural Gas
DMO	Domestic Market Obligation
EAX	East Asia LNG price marker
ECA	Emission Control Area
EMA	Energy Market Authority (Singapore)
FAANG	FAANG is an acronym for the market's five most popular and largest tech stocks
FLNG	Floating LNG (liquefaction facility)
LNG	Liquefied Natural Gas
FID	Final Investment Decision
GT	Giga tonnes (1 GT = 10^{12} kg)
GW	Giga (one thousand million) Watt
H1	First half of the year
HFO	Heavy Fuel Oil
HH	Henry Hub - USA natural gas price marker
J	Joule - measure of the energy (1J = 1N × 1m)
JCC	Japan Crude Cocktail
Kg	Kilogram – SI unit of mass
LHS	Left Hand Side (of a graph)
m	Meter – SI unit of distance
MGO	Marine Gasoil
MJ	Mega (one million) Joule
MMBtu	Million British Thermal Unit - measure of the energy content in fuel (1 BTU = 1.06 J)
MT	Megatonne (Mt), a unit of mass equal to one billion kilograms (10^9 kg)
mtpa	Million tonne per annum
MW	Mega (one million) Watt
MWh	Megawatt hour - unit of measure of electric energy
N	Newton – SI unit of force (1N = 1Kg m/s^2)
NBP	National Balancing Point - UK natural gas price marker
NE	North East
NG	Natural Gas
NGO	Non-Governmental Organisation
OECD	Organization for Economic Cooperation and Development

opex	Operational Expenditure
Regas	Regassification (of LNG)
RHS	Right Hand Side (of a graph)
s	Second – SI unit of time
s-curve	Indexation based pricing formula with a smaller slope at bottom and top of the range
SDG	Sustainable Development Goal (as defined by United Nations)
SEA	South East Asia
SECA	Sulphur Emission Control Area
SIAC	Singapore International Arbitration Centre
SLing	SGX LNG Index Group – Singapore LNG price marker
SPA	Sales and Purchase Agreement
SW	South West
S$	Singapore dollar
TJ	Terra Joule (10^{12} J)
TTF	Title Transfer Facility - a virtual trading/price point for natural gas in the Netherlands
US$	United States Dollar
W	Watt – SI unit of power (1W = 1J/1s)
WHO	World Health Organisation
°C	Degree Celsius - unit of temperature
°F	Degree Fahrenheit – unit of temperature