LNG Market Trends and Their Implications

Structures, drivers and developments of major Asian importers

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Executive summary

The market structure and trends for the Asian liquefied natural gas (LNG) market have evolved dramatically since this fuel was introduced in the late 1960s. While traditional markets such as Japan or Korea have held their position as the largest consumers in the region, their domestic markets have changed under the influence of liberalisation policies, which have led to different stages of market opening. In parallel, the emergence of fast-growing LNG importers such as the People's Republic of China ("China") has led to substantial market growth, which has coincided with more diversification on the supply side, thus resulting in shorter and more flexible LNG contracts. Such an evolution in the contractual structure has had implications for price formation towards more diversity in indexation and more cross-influences between regional markets.

LNG market continues to grow in response to strong Asian demand

Over one hundred billion cubic metres of new LNG supply capacity is to be commissioned between 2018 and 2023, with the bulk of these additions coming from Australia and the United States. So far, this wave of new liquefaction capacity has been absorbed without any signs of looming oversupply, mostly by Asian importers. Both mature and fast-growing emerging markets strongly have contributed to this growth.

While China is expected to be the main driver of natural gas demand growth for the near future on the back of continuous energy consumption growth and strong policy support to curb air pollution, more mature Asian markets are likely to follow different paths. LNG imports are expected to gradually decrease in Japan in the longer term as further nuclear capacity restarts, while in Korea natural gas demand benefits from changes in energy policy orientations and the implementation of nuclear phase-out and the curtailment of new and existing coal-fired power generation plants. Other developing Asian economies expect to have strong, continuous population growth, which supports further electrification in this region. Additional power demand will create opportunities for natural gas growth in the region, although the sensitivity to policies and price levels remain uncertain.

LNG trade is going through an expanding transition from local, bilateral trading flows to regional (and, increasingly, global) markets. While overall LNG consumption is expected to be further concentrated in the Asia-Pacific region, the trend towards diversification of consuming countries will continue. Further diversification also happens on the supply side – apart from the United States and Australia, both traditional and new suppliers develop new liquefaction projects to capture this additional demand originating from the Asian region. While the Russian Federation is steadily adding new liquefaction trains, Qatar prepares to expand its export capacity in order to retain its leading position. Recent final investment decisions in Canada and offshore Mauritania and Senegal further reinforce the future diversity of suppliers.

Major Asian markets follow different paths towards liberalisation

Unlocking future growth in natural gas consumption implies greater domestic competition, triggered by further market opening in major Asian consuming countries. Natural gas is a major source of energy for several major Asian importers – up to one-quarter in Japan and more than 15% in Korea, for example. The history of natural gas in this region shows a close linkage to the history of LNG import activities.

Market policies have evolved over the past fifty years in conjunction with importing activities. Japan started its liberalisation in 1995 by carefully introducing structured steps that led to a gradual opening of the market and attracting new entrants for the past twenty years. The current Japanese market – fully liberalised since 2017 – comprises over 200 players operating on different market segments. However, the lack of supply alternatives to LNG imports and limited domestic pipeline interconnections still impose physical limitations to new entrants that may be alleviated once third party access to infrastructures becomes fully operational.

Korea is facing a similar supply situation but it has a smaller share of natural gas in the country's energy mix and is at an earlier stage of market opening. Incumbent KOGAS imports almost 90% of the LNG demand in the wholesale sector; it is the sole wholesale supplier providing gas to large-scale consumers and city gas companies; and it relies on long-term contracts and spare infrastructure capacity to manage seasonal demand patterns. With the government's ambition to phase out coal and nuclear from the country's electricity supply mix, the consumption pattern is expected to flatten out by 2024, and it is likely that LNG import players will become gradually more diversified. As a result of opening to direct importers in 2005, eight companies from the power, steel, and petrochemicals sectors developed additional receiving capacity to serve their own consumption needs, but it accounts for only about 10% of wholesale volumes. In 2016, the previous government set a target of 2025 for private companies to be able to import LNG and resell within the country; this target has neither been confirmed nor abandoned by the current government.

China has a different supply structure. Even with a growing share of LNG (in 2017, China became the second largest LNG importer), China's supply structure remains a complement to domestic production and pipeline imports, which, together, accounted for 80% of supply in 2017. The objectives of the 13th Five Year Plan (2016-20) to adjust the country's energy mix have created a surge in natural gas demand, resulting in accelerated infrastructure development to accommodate additional supply – both domestic and imported. This change in market structure is expected to encourage new entrants in the different links of the natural gas value chain, from exploration and production to the retail market. With the introduction of successive pricing regime changes and the development of natural gas hubs, market reform is progressing and paving the way for further reforms to ensure more competition on the domestic market.

Pricing transitions towards a more global LNG trade framework

Contrary to mature markets in North America and Europe – where diversified sources of supply and strong domestic production provided a solid base for market-based pricing – Asian natural gas development has traditionally relied on LNG as its main source of supply. Traditional price formulae still prevail for a majority of LNG imports in Asia, with over 70% of natural gas sales subject to oil price indexation as of 2017.

The demand shock caused by the aftermath of the 2011 Great East Japan Earthquake led to the emergence of an Asian LNG spot market. Acting first as an emergency, premium-priced source of additional supply, it evolved progressively to a balancing market as LNG supply expanded with the number of new buyers. Enabled by the emergence of market-priced LNG from North American export projects, the reshaping of LNG trade towards more flexible and global markets is likely to have a spillover effect on Asian natural gas pricing with the introduction of hybrid pricing formulae (including hub pricing alongside oil indexation) and the development of local trading indices. Such developments help to establish a more competitive environment and encourage enhanced market liquidity in the region for both producers and importers. However, the full transition to regional market pricing, supported by the development of trading hubs, will be possible only with the introduction of more competition along the entire value chain.

Technical analysis

Structural evolution of the LNG market

Introduction

Global natural gas trade has expanded rapidly, driven by significant demand growth in Asian markets and ample natural gas resources in Qatar, Australia, the United States and the Russian Federation. The LNG trade, which is the only viable option to connect demand and supply for long-distance trade between continents, has experienced impressive growth over the past two decades. This is based on successive waves of investment in natural gas export and import infrastructure.

LNG markets have grown in volume and also in the number of market participants. The United States played a crucial role in the structural change of the LNG market more than a decade ago. The country emerged as a potential importer which triggered large investments in liquefaction infrastructure, especially in Qatar. It also introduced technical means to provide rapid and flexible import solutions, such as floating storage and regasification units (FSRUs; see Box 2).

Traditional elements of natural gas sales agreements were challenged. This was because oil-linked indexed gas sales agreements did not reflect the competition with coal as an alternative in the power sector. In addition, the long-term nature of existing contracts was unacceptable against the background of existing liquid markets in the United States.

The shale gas revolution in the United States overturned demand projections for the LNG market in the late 2000s, after Qatar took final investment decisions (FIDs) for LNG export infrastructure. The United States did not become a major LNG importer but rather a future competitive exporter owing to the vast and cost-competitive potential of its shale gas reserves. The LNG terminals that were planned as regasification facilities were thus converted to liquefaction plants, ready to supply the global market with LNG originating from the United States.

Asian demand growth was halted after the 2008 financial crisis, and Europe emerged as the market of last resort for this additional LNG. Europe was expected to take some of the surplus volumes against a background of depleting domestic production. However, strong competition from Russian pipeline gas and limited growth in Europe led to structural oversupply and price collapse in short-term markets.

The Great East Japan Earthquake in March 2011 caused a demand shock on the LNG market. This shifted expectations of a loose supply-demand balance (i.e. LNG market oversupply) to a much tighter market with high demand for flexibility. All 54 of Japan's nuclear reactors went off line between March 2011 and September 2013 after the Fukushima Daiichi nuclear accident. This triggered significant, sudden LNG demand for Japan's power generation. Importation from Qatar was the immediate response to this demand increase because Qatar's liquefaction terminals had just been completed. LNG re-exports from Europe to Japan also filled the need for additional demand, with the continents becoming interlinked via the LNG market.

High expectations of incremental demand from China and other developing economies on the Asian continent triggered a second wave of investment. This was led by Australia followed by the United States. Both exporters together are predicted to have 35% of the total nameplate capacity by the end of 2022, which will increase from 500 bcm (2017) to 630 bcm. However, due to maintenance or technical issues during the ramp-up phase of new projects the available capacity is around 15-25% less, based on historical values between 2012 and 2017.

Asian LNG import prices dropped by more than one-third between 2015-17, compared to price levels between 2012 and 2014. This has created a clear disincentive for investments into new upstream projects, which almost came to a halt in 2016/17. In addition, exporters and portfolio players may have a significant share of uncontracted quantities or expiring contracts in their portfolios that are looking for pockets of demand. Even if the LNG market is well supplied today, this is not expected to prevail over the longer term as demand from new importing countries is growing, which has been shown by the unprecedented natural gas demand growth from China which experienced supply shortfalls over the winter of 2017-18.

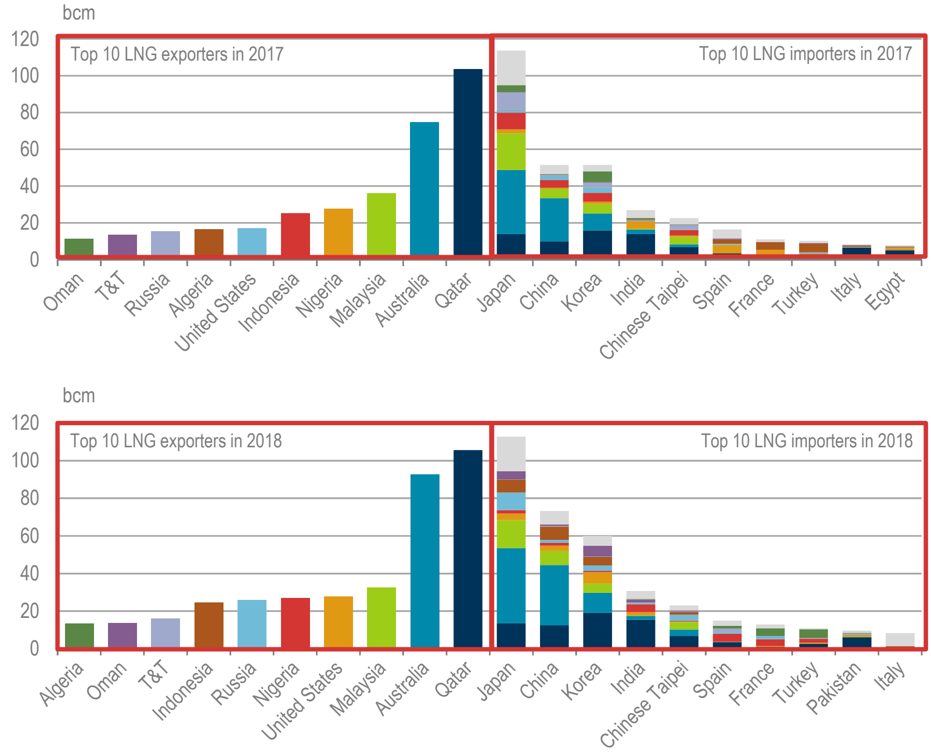
The time when a lack of Final Investment Decisions (FIDs) will develop into a structural issue for the market will therefore depend on how quickly uncontracted volumes and expiring contracts can be sold to importers. China's drive for new LNG imports will be an important factor for the dynamics of global LNG demand, also as new importers, mostly developing economies, appear on the demand side. These importers will be more price sensitive than traditional LNG importers, resulting in shorter-term agreements and less-sustainable demand, as other fuels such as coal remain price-competitive alternatives to natural gas.

LNG supply and demand balance

Natural gas markets are transitioning from local to regional and global markets, with increasing competition and diversity among suppliers and customers. LNG is the driving force to further enhance competition and market integration in international natural gas markets. Its development is favoured by the state of the well-supplied market that is assumed to continue over the coming five years. The expansion in supply capacity (nearly 200 bcm) will exceed expected LNG demand growth (forecast to be closer to 100 bcm by 2022).

The global LNG market is expanding, supported by investment decisions taken during the previous decade. The United States and China are influencing LNG market dynamics due to their size and impressive growth potential. Both 2017 and 2018 were remarkable in this respect as China is now the second-largest LNG importer, after Japan. The United States is increasing in importance on the supply side and is becoming a major source of LNG, Becoming the fourth largest LNG exporter in 2018 after Qatar, Australia and Malaysia (Figure 1).

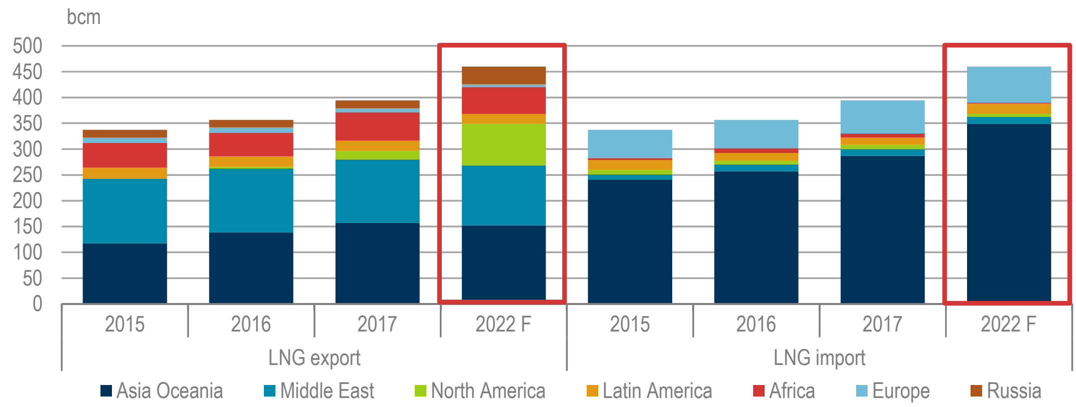
Figure 1. Selected LNG exporters and importers in 2017 and 2018



Note: Light grey bars are LNG quantities, originating from exporters other than those in the top ten.
Source: ICIS (2018), *ICIS LNG Edge*, www.icis.com/energy/liquefied-natural-gas/lng-edge (subscription required).

China's rise as a major LNG importer will strengthen Asia's dominance on the demand side. But increasing LNG exports from the United States will diversify the supply landscape, increasing global gas supply security through a greater variety of LNG exporters (Figure 2).

Figure 2. LNG supply and demand, 2015-17 and 2022 (forecast)



Source: IEA analysis based on ICIS (2018), *ICIS LNG Edge*, www.icis.com/energy/liquefied-natural-gas/lng-edge (subscription required).

Asian LNG demand has been particularly driven by Japan and Korea, which have a lack of alternative gas import options. The shutdown of nuclear power plants supported gas-fired power generation, increasing gas consumption well above business-as-usual levels with significant rippling effects on LNG spot prices, trade flows and contractual long-term obligations to purchase LNG have affected both countries. China's rise in natural gas importation is backed by policies to improve air quality in large cities. Natural gas will therefore play a role in enabling China to reduce its share of coal in heat and power generation, mainly for the industrial and residential sectors.

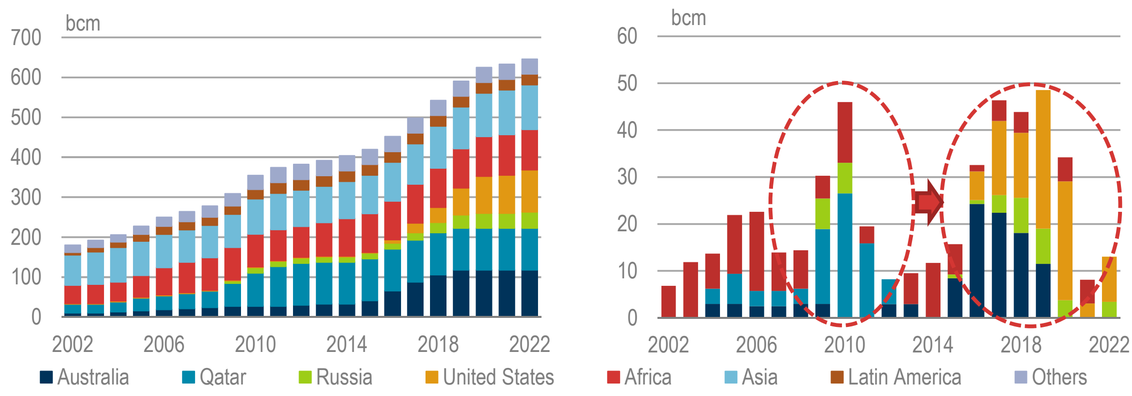
Signs of diversification on the supply side are already visible. The top five exporters will be from four different regions (Middle East, Asia and Pacific, Africa and North America) by 2022 because of the rapid increase of liquefaction capacity in the United States. Liquefaction projects under construction along the US Gulf Coast and US East Coast will connect the global LNG market to US shale gas and influence global market dynamics. US LNG exports are expected to reach levels just above 80 bcm by 2022, supported by competitive production costs and impressive growth (Figure 2).

Liquefaction capacity

Two waves of liquefaction projects have shaped the LNG supply side, increasing the overall nameplate capacity and changing its composition (Figure 3). Qatar emerged as a major LNG supplier in the mid-2000s, after the first wave of liquefaction projects. Overall nameplate capacity more than doubled from 180 bcm to 382 bcm between 2002 and 2012, and Qatar led that surge with a share of around 40%.

However, Qatar's dominance as a producer of LNG with a nameplate capacity of around 105 bcm (20% of the overall export capacity) will be challenged by two rising LNG exporters. Liquefaction capacity expansion (from 452 bcm to 646 bcm) predicted between 2016 and 2022 will be led by Australia and the United States, with shares of roughly 35% and 40%, respectively. Hence, Qatar, Australia and the United States will be the top three LNG exporters with a combined market share of around 50% by 2022, based on the projects currently under construction.

Figure 3. LNG export capacity, incremental and additional capacity, 2002-22



Source: IEA analysis based on ICIS (2018), *ICIS LNG Edge*, www.icis.com/energy/liquefied-natural-gas/lng-edge (subscription required).

LNG production can be shaped by investment decisions that date back several years, owing to the capital-intensive nature and the long lead times of export projects. The construction of LNG terminals takes about four years, after project developers have taken an FID and enough capital has been raised.

The second wave of new LNG supplies is the result of investment decisions taken between 2011 and 2016 and linked to contracts signed up to 2016. There were 17 LNG projects under construction globally for a total capacity of around 111 bcm per year as of beginning of 2018 (Table 1) but only 19.6bcm has been added to the market by the end of 2018 (Ichthys LNG from Australia and Yamal LNG train 2 from Russian Federation (hereafter, "Russia"). This is about 30% of the traded LNG volumes worldwide in 2017. The project pipeline has decreased by around 30 bcm compared to the status at the beginning of 2017, as Sabine Pass trains 3 and 4 (United States), Cove Point (United States), Wheatstone train 1 (Australia) and Yamal train 1 (Russia) were commissioned. Coral South FLNG (Mozambique) was the only project that took an FID in 2017. Persistent uncertainty of how much future capacity the market will need has made several developers cautious of progressing with FIDs.

Table 1. LNG projects under construction and planned start up (as of end Q3-2018)

Country	Project	Capacity (bcm/yr)	Major participants	FID year	Planned start-up
Australia	Ichthys LNG (T1, T2)	12.1	Inpex, Total	2012	2018
Australia	Prelude FLNG	4.9	Shell, Inpex, Kogas, CPC	2011	2018*
Indonesia	Sengkang LNG	0.7	Energy World Corporation	2011	2018*
Russia	Yamal LNG (T2)	7.5	Novatek, Total	2013	2018
United States	Elba Island LNG (T1-T6)	2.0	Kinder Morgan	2016	2018*
United States	Eagle LNG (T1, T2)	0.8	Ferus NGF, General Electric	2015	2019
United States	Freeport LNG (T1)	6.3	Freeport, Macquarie	2014	2019
Russia	Yamal LNG (T3)	7.5	Novatek, Total	2013	2019
United States	Cameron LNG (T1-T3)	18.4	Sempra Energy	2014	2019
United States	Corpus Christi LNG (T1, T2)	12.2	Cheniere Energy	2015	2019
United States	Elba Island LNG (T7-T10)	1.4	Kinder Morgan	2016	2019
United States	Freeport LNG (T2, T3)	12.6	Freeport, Macquarie	2014	2019
United States	Sabine Pass (T5)	6.1	Cheniere Energy	2015	2019
Indonesia	Tangguh LNG (T3)	5.2	BP	2016	2020
Malaysia	Petronas FLNG 2	2.0	Petronas	2014	2020
United States	Corpus Christi LNG (T3)	6.1	Cheniere Energy	2018	2022
Mozambique	Coral South FLNG	3.4	Eni, Galp Energia, Kogas	2017	2023
Total		**109.2**			

* delayed

Note: T = LNG train, KUFPEC = Kuwait Foreign Petroleum Exploration Company.

The United States represents around 60% of the total liquefaction capacity under construction as of end 2018, with the largest share along the US Gulf Coast. It was not expected to be part of a liquefaction project wave when the first investment wave was enacted in the early 2000s. On the contrary, the country was a trigger, primarily for Qatar, to take FIDs that started the first wave, ready to supply the United States with LNG from the Middle East.

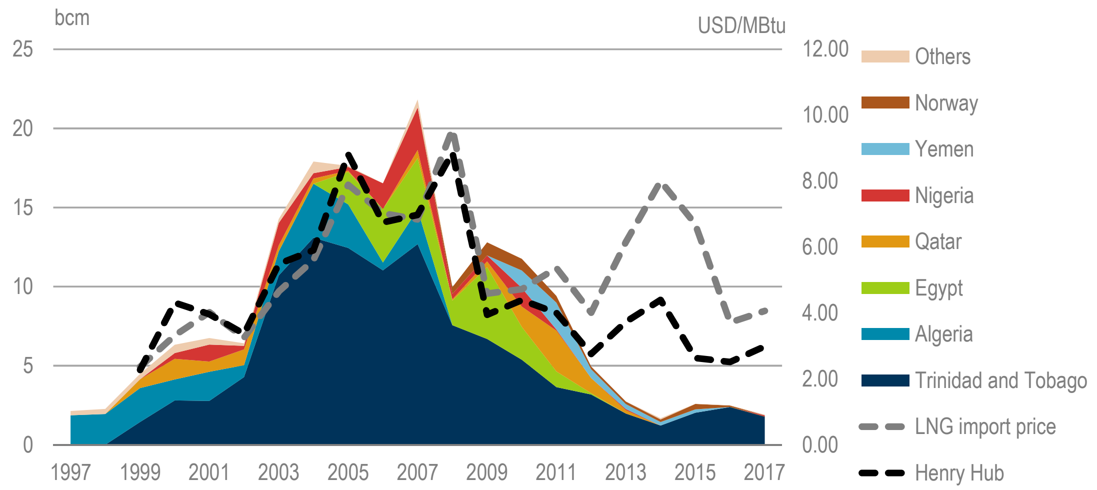
Shale gas revolution in the United States

The United States was expected to emerge as an importer of LNG in the mid-2000s. This was an option used during the first years of LNG regasification terminal development in the 1970s, starting with Everett (1971, Massachusetts) followed by Elba Island (1978, Georgia), Cove Point (1978, Maryland) and Lake Charles (1981, Louisiana). LNG imports peaked in 1979 (around 1% of total US gas demand) and fell sharply thereafter, halting operation of Elba Island and Cove Point in 1980. Everett and Lake Charles remained in operation in the following years, but at low utilisation levels.

Deregulation of the US natural gas market produced a significant shift in the market. Reforms in the 1980s and 1990s led to unbundling of natural gas transmission services and deregulation of wellhead prices. Upstream investments were stimulated by this reform process, resulting in higher indigenous production and declines in import needs. Algeria, the sole LNG supplier to the United States at the time, did not adjust prices to levels reflecting the major change in the US natural gas market.

Strong growth in gas-fired power generation resulted in increasing gas prices during the early 2000s. This was at a time when LNG exports from Trinidad and Tobago and Nigeria were increasing. These developments helped to get Elba Island and Cove Point import terminals back on line in 2001 and 2003, respectively. US LNG imports therefore experienced a steep increase and doubled between 2002 and 2003 (Figure 4).

Figure 4. US LNG imports by source, 1997-2017



Sources: EIA (2018), *US Natural Gas Imports by Country* (database), www.eia.gov/dnav/ng/ng_move_impc_s1_m.htm; ICIS (2018), *ICIS LNG Edge*, www.icis.com/energy/liquefied-natural-gas/lng-edge (subscription required); IEA (2017a), *Market Report Series: Gas 2017*, www.iea.org/bookshop/741-Market_Report_Series:_Gas_2017.

A strong consensus prevailed in the natural gas industry that US LNG imports would continue to increase rapidly. As the shale gas revolution had not yet occurred, shale gas was not even factored in as a major source of gas supply. The expectation of a tighter US gas market balance and an associated increasing dependency on LNG imports was reflected in higher and more volatile Henry Hub (HH) prices. These moved from around 3 US dollars (USD) per million British thermal units (MBtu) in 2002 to above 8 USD/MBtu in 2005.

Twenty-one projects competed to increase US LNG regasification capacity by the end of 2003, amid strong rivalry between the United States and Europe, to gain access to long-term LNG supplies. These expectations of a huge increase in LNG import requirements prompted a strong impetus to provide new LNG supplies to the United States.

Many companies were involved in developing export projects, but some governmental organisations also provided financial support, for example EXIM, the export credit agency of the United States, and the Overseas Private Investment Corporation. The United States was involved in the main LNG developments in Africa (Nigeria, Egypt and Equatorial Guinea), Americas (Trinidad and Tobago) and Middle East (Qatar) – all those destined to serve the Atlantic basin – driven by the objective to secure the required LNG import volumes.

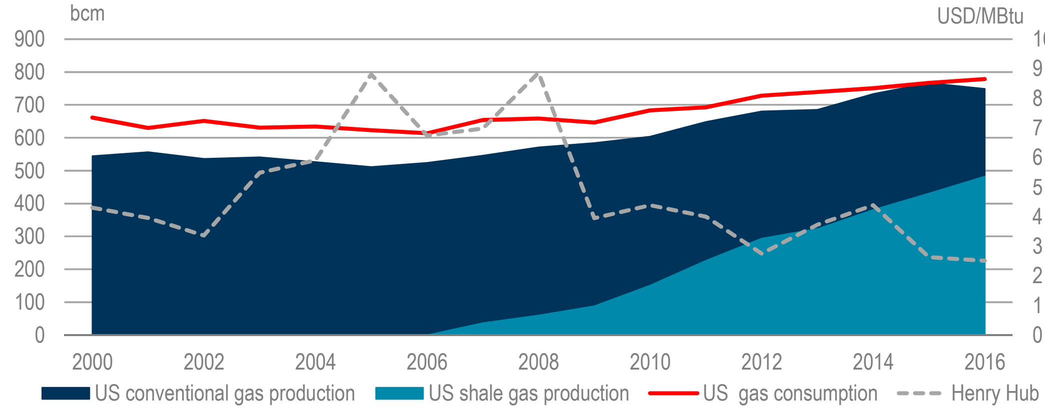
Another increase in LNG importing terminals occurred in 2008, a few years after the commissioning of Egypt's liquefaction plants. Northeast Gateway (Massachusetts, offshore Boston), Freeport (Texas) and Sabine Pass (Texas) started up in 2008, followed by Cameron (2009, Louisiana), Golden Pass (2010, Texas) and Gulf LNG (2011, Mississippi). These increased the existing regasification capacity of 62 bcm by 120 bcm. Drilling technology improved significantly, and higher prices supported developing production of more costly resources.

Shale gas started to be perceived as a meaningful supply source in 2007. It was able to provide significant production increases in the short to medium terms, coinciding with a sharp fall in HH prices in 2009 when expectations were confirmed. Although shale gas production performed much better than expected, it was not until 2011 that projections pointed to a transition of the United States to a net exporter of LNG by 2016 and a net exporter of natural gas by 2021. LNG import volumes started to decrease rapidly, after reaching a peak of around 20 bcm in 2007.

LNG imports into the United States are now only a fraction of the quantities seen a decade ago and are restricted to small volumes delivered to the Everett terminal in New England. This is a region insufficiently connected to the pipeline grid because it experiences strong seasonal demand swings and is not geologically suitable for developing underground storage infrastructures. Therefore, the use of LNG is necessary during cold winters and for gas-fired power generation.

The position of the United States was heavily over contracted after the shale gas revolution, freeing up substantial amounts of LNG for other markets. The impressive scale of the US shale gas revolution therefore resulted in a structural change in the United States' domestic supply outlook and was the main factor behind its emergence as a key provider of LNG for the global market (Figure 5).

Figure 5. US natural gas production and consumption, 2000-16

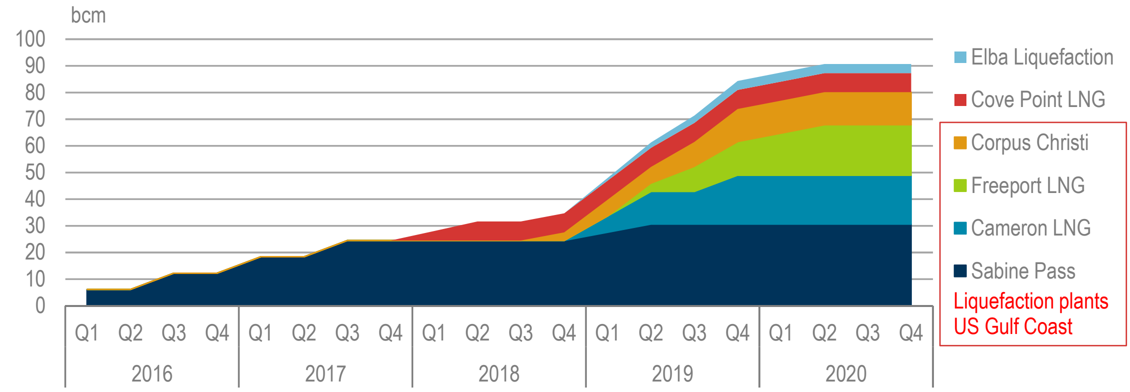


Sources:ICIS (2018), *ICIS LNG Edge*, www.icis.com/energy/liquefied-natural-gas/lng-edge (subscription required); IEA (2017a), *Market Report Series: Gas 2017*, www.iea.org/bookshop/741-Market_Report_Series:_Gas_2017.

Most proposals for liquefaction projects were brownfield projects, i.e. facilities associated with existing regasification terminals. Most projects under construction are along the Gulf Coast, but there are a few exceptions on the US East Coast. Dominion's Cove Point LNG (7.1 bcm) and Elba liquefaction (3.4 bcm) will add a total of around 10.5 bcm. Eagle LNG trains 1 and 2 aim to add 0.8 bcm, but construction has not yet started.

Sabine Pass LNG (Cheniere Energy) was the first to start construction on the US Gulf Coast, in August 2012 after the US Department of Energy granted authorisation in 2011. Four trains have since been commissioned with an overall capacity of 24.5 bcm followed by train 5. Cameron LNG (18.3 bcm) was the second liquefaction project in the United States to begin construction, after taking an FID in August 2014. It was followed by Freeport LNG (18.9 bcm), which started construction in November 2014. Corpus Christi LNG (Cheniere Energy's second project) also shipped its first cargo in late 2018. The first two trains have a total liquefaction capacity of around 12 bcm, with the third train adding another 6 (Figure 6).

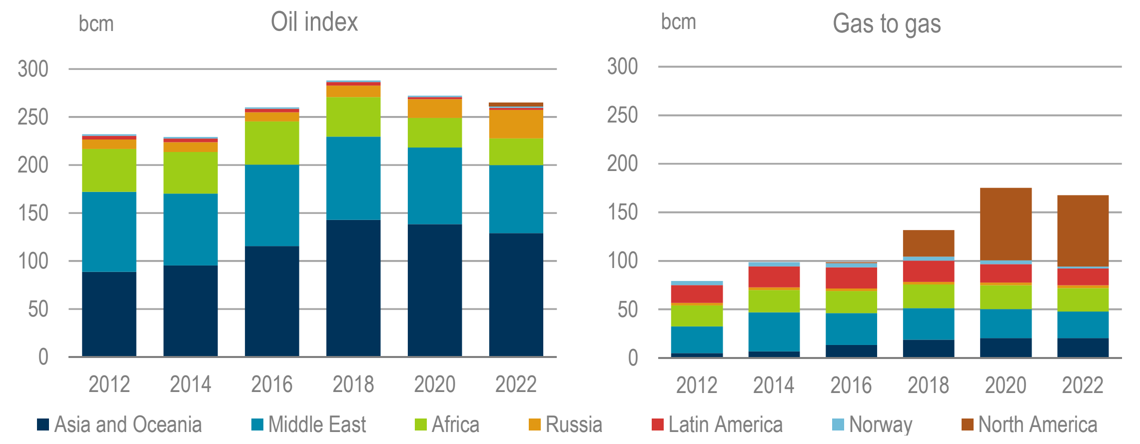
Figure 6. US liquefaction capacity operating/under construction, 2016-20



Sources: ICIS (2018), *ICIS LNG Edge*, www.icis.com/energy/liquefied-natural-gas/lng-edge (subscription required).

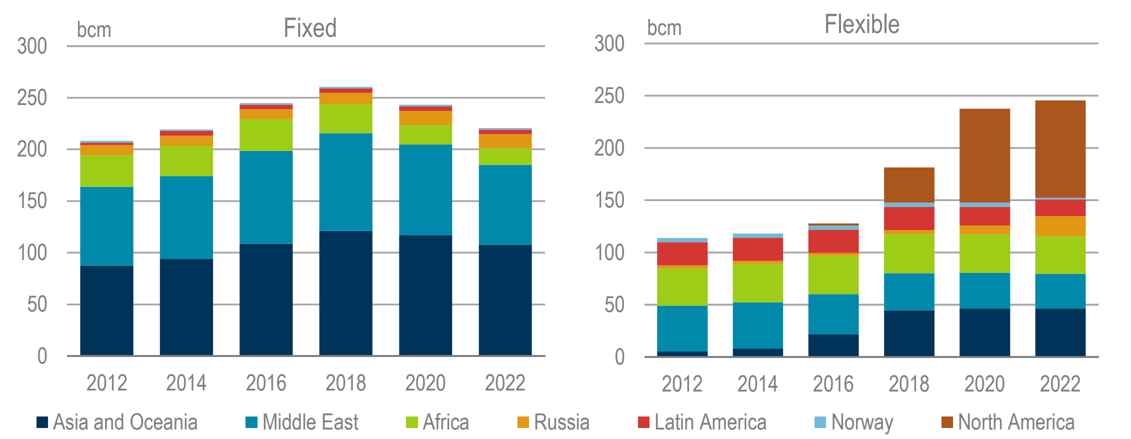
US LNG exports will have two major implications for the global LNG market. Based on signed contracts between US LNG developers and offtakers, hub-indexed pricing (to US HH prices) will be significantly pushed by US LNG quantities, as most contracts signed with offtakers are no longer linked to oil prices (Figure 7).

Figure 7. LNG export contract volumes with oil index and gas to gas, 2012-22



LNG market flexibility will increase significantly as most US contracts are not restricted to a fixed destination for primary buyers. Flexible volumes have grown slowly over recent years, but have remained roughly constant as a share of the total volume. This is beginning to change: by 2022, flexible volumes will double to 247 bcm, led by 93 bcm from North America, mostly the United States (Figure 8).

Figure 8. LNG export contract volumes, 2012-22



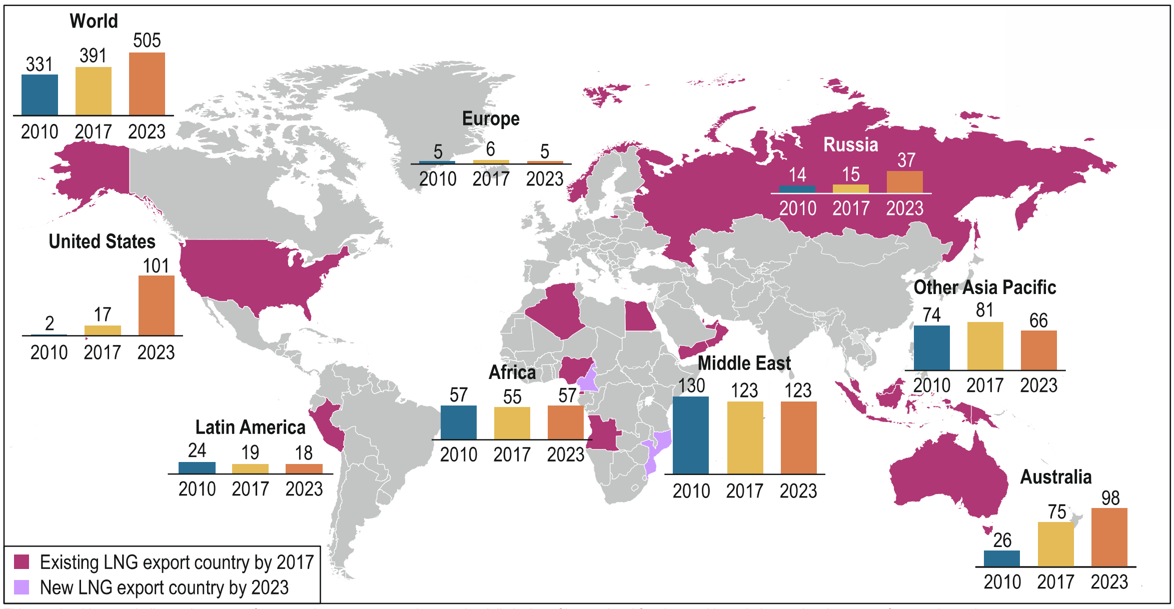
Recent developments in LNG supply

Qatar (the largest LNG exporter) made several announcements in 2017 and at the beginning of 2018. It revealed a strong ambition to strengthen its major position in view of more competition, particularly from US LNG exports. In February 2018, Qatar Petroleum (QP) introduced its new corporate strategy that confirmed objectives to expand export capacity from 77 million tonnes per annum to 100 million tonnes per annum and to maintain its role as a "leading energy provider". Its strong determination was revealed in 2017, when QP lifted a self-imposed ban on development of the North Dome field (the world's biggest natural gas field).

Russia has long overcome the threat of US LNG competition, leading to an LNG strategy that has remained largely rhetorical. But the country has recently shifted to more concrete action with respect to LNG. Novatek commissioned its first cargo from Yamal LNG in December 2017. Its ability to attract long-term buyers and deliver LNG cargoes on time made a case for the first Russian LNG export facility. The competitiveness of Russian LNG on the global market is supported by a presidential executive order in December 2017 for Gazprom, the natural gas incumbent in Russia, to sell at a below-regulated price to LNG export projects. This strong determination is supported by a Gazprom announcement that the schedule for developing the super-giant gas field Bovanenkovskoye, which will potentially feed LNG projects, accelerated to 2020 (from 2022), with a plateau target of 115 bcm (currently producing 85 bcm).

Australia is also significantly increasing liquefaction capacity, to reach slightly under 120 bcm by 2019 (Figure 9). Eight LNG facilities were operating at the beginning of 2018, providing a capacity of around 95 bcm to the market. Australia is providing new quantities to the market, with the dominant part based on a traditional oil-linked contract with fixed destinations. Japan is the main destination, with a share of around 51%, representing a contract volume of around 63 bcm (at plateau capacity), followed by China with a share of 19% or roughly 24 bcm. Korea signed contracts to take about 8 bcm from Australia, representing a share of approximately 7%.

Figure 9. LNG export volumes (in bcm), 2010-23



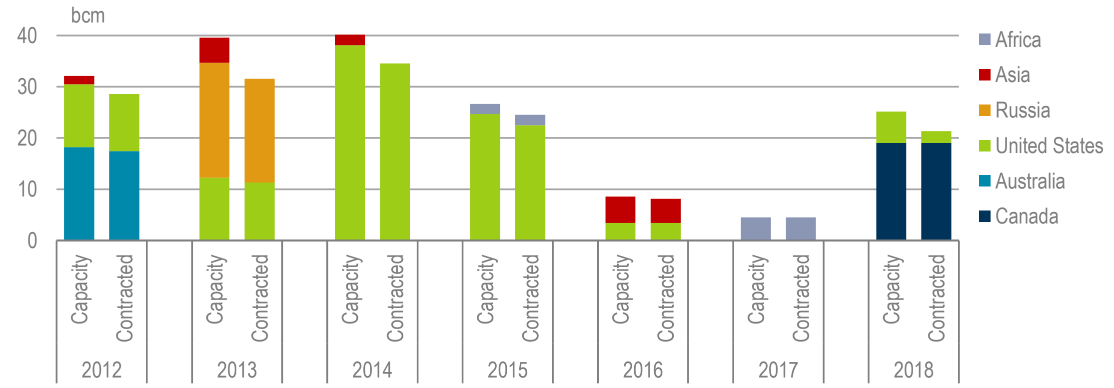
This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries, and to the name of any territory, city or area.

Source: IEA (2018), *Market Report Series: Gas 2018*, https://www.iea.org/gas2018/.

The risk of a shortfall of investment in new supply is real, despite announcements from major suppliers. Many planned projects have been delayed amid falling prices and deteriorating market conditions for investors. Investments backed by long-term contracts are becoming more difficult because the average length of LNG contracts is decreasing. This creates uncertainty for producers who claim that long-term contracts indexed to oil prices and other trade rules (notably take-or-pay clauses) are vital for financing capital-intensive upstream and infrastructure projects.

For a liquefaction plant to obtain an FID, binding long-term contracts covering most of the output (85% on average in 2009-16) have been required as a commercial guarantee to finance the investment.Figure 10 shows that this trend has continued, with 95% of the volumes contracted in 2016, and 100% for the only FID taken in 2017 (Coral FLNG in Mozambique) and LNG Canada in 2018. It is clear that risk must be shared between upstream developers and off takers in the current well-supplied market environment.

Figure 10. FID capacity versus contracted volumes, 2012-18



Source: IEA (2017b), *Global Gas Security Review 2018*, https://webstore.iea.org/global-gas-security-review-2018.

Only two projects, with a total nameplate capacity of 8.6 bcm per year, got permission for constructing new LNG export facilities in 2016 (Table 2). Yearly sanctioned new liquefaction capacity decreased from around 35 bcm annually for a four-year period between 2011 and 2014, to around 25 bcm for four projects in 2015, and to less than 10 bcm for two projects in 2016.

One of the projects was an additional train of existing liquefaction facilities in Indonesia, with an FID taken in July 2016. A newly sanctioned LNG export project in North America in 2016 was Elba Island LNG, at the site of the existing Elba Island LNG import terminal. Elba Island LNG is a two-phase project with ten small modular liquefaction facilities: six trains in the first phase and four trains in the second phase in 2019. An FID was taken by Eni for Coral FLNG in June 2017, in Mozambique. This will hold around 4.5 bcm of the annual liquefaction capacity and is expected to come on line in 2022.

Table 2. LNG projects with FIDs taken in 2016-18

Country	Project	Capacity (bcm/yr)	Major participants	FID year
Indonesia	Tangguh LNG (T3)	5.2	BP	2016
United States	Elba Island LNG (T1-T10)	3.4	Kinder Morgan	2016
Mozambique	Coral South FLNG	3.4	ENI	2017
United States	Corpus Christi LNG (T3)	6.1	Cheniere Energy	2018
Canada	LNG Canada	19.0	Shell, PETRONAS, PetroChina, Mitsubishi, KOGAS	2018
Total		**37.1**		

Note: T = train, FLNG = Floating Liquefied Natural Gas Terminal.

Obtaining a reliable picture of the global LNG supply infrastructure is more complex than simply compiling existing projects. Actual LNG production capacity differs from nominal capacity at any point in time. Many factors (from technical issues to security conditions and maintenance status) can affect LNG export capacity. Tracking these fluctuations – particularly the emergence of any lasting trend – is key to providing an accurate picture of the supply side of global LNG markets (Box 1).

Box 1. Fluctuations in LNG supply

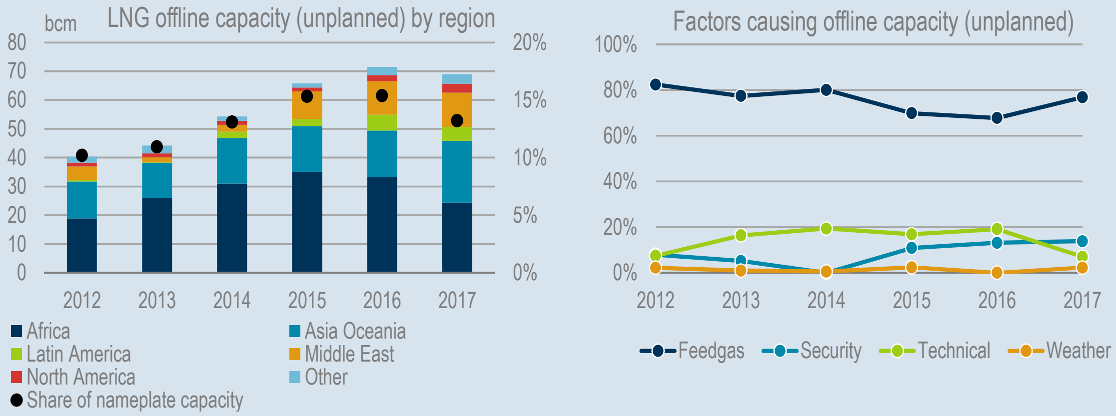
LNG liquefaction capacity is generally expressed in million tonnes per year of nameplate capacity. This refers to the intended full-load sustained output of the facility. However, nameplate capacity normally differs from the level of capacity available to the market. Various factors affect the utilisation of a facility. They usually limit (rather than increase) the available capacity relative to the designed one. The most common factors affecting the capacity of an LNG facility, in addition to planned maintenance, are the following:

- **Lack of feedstock gas.** Production from the gas fields "feeding" the LNG export plant is either in decline or insufficient to meet export needs and domestic consumption. Therefore, gas flow into the LNG plant is below the maximum level. This is the most common factor limiting the capacity of existing LNG facilities.
- **Technical problems.** LNG plants are complex sites and regularly undergo maintenance. Unexpected technical problems can emerge (often during the start-up period), causing unplanned shutdowns. The lengths of these shutdowns depend on the extent of the problem and the scale of repair work involved. They can last for years in some cases, especially during early years of operation.
- **Security problems.** Several LNG facilities are located in politically unstable regions, where there is frequent unrest and poor security. This can (occasionally or periodically) result in the evacuation of personnel and partial or total shutdown of the LNG facility. In the worst cases, the export plant can be damaged due to direct attacks or collateral damage.
- **Debottlenecking/technical upside.** This refers to the (limited) cases of LNG plants consistently running above their nameplate capacity. It is usually due to unreported debottlenecking of the facility or implementation of projects aimed at reducing boil-off. The plants can produce above their designed levels in some cases (often in cold climates) as low external temperatures allow for higher-than-average efficiencies. The positive impact from this category is much less than the impact from any of the limiting factors described above.

LNG offline capacity (unplanned) increased in absolute terms and also in relation to the overall nameplate capacity between 2012 and 2017. Feed-gas issues were the primary reason for unplanned outages, with a share of approximately 70% to 80%. Security-related issues elevated from 2015, due to the civil war in Yemen, which prompted the country to take its liquefaction facilities out of service.

2017 was the first year where the trend of increasing offline capacity was reversed. LNG offline capacity dropped in absolute terms year-on-year (y-o-y) by around 4 bcm (from 69.5 bcm to 65.8 bcm). This affected nameplate export capacity (which dropped from 15% to 13%) as the expansion of nameplate capacity was still ongoing. Technical issues ranked third in 2017 for the first time, behind feed-gas and security-related issues, due to improvements in the Angola LNG facility in Africa.

LNG offline capacity and factors, 2012-17



Source: ICIS (2018), *ICIS LNG Edge*, www.icis.com/energy/liquefied-natural-gas/lng-edge (subscription required).

Africa displayed the highest share across global regions, with around 30% of LNG capacity (including planned maintenance) on the continent not able to run in 2017. Africa predominantly suffers from lack of feedstock gas, particularly in countries like Algeria and Egypt. The Asia Oceania region shows the second-highest level of unavailable capacity in absolute terms (mostly concentrated in Indonesia, primarily due to feed-gas shortages at Bontang LNG terminal). Disruptions in Latin America are due to steep decline rates at mature producing fields in Trinidad and Tobago that are constraining the country's ability to export. The years 2015 and 2016 demonstrated double-digit export reductions for Trinidad and Tobago (11% and 15%, respectively), whereas in 2017, its LNG exports stayed almost stable at 2016 levels.

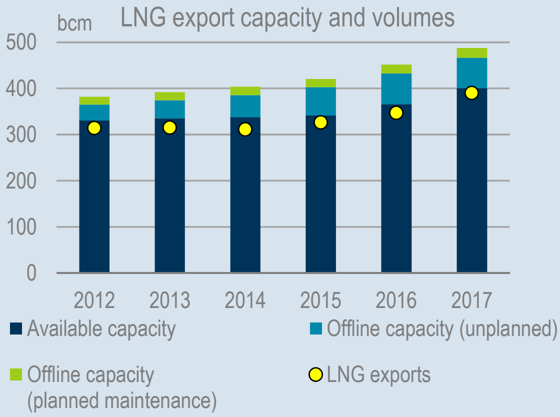
The Middle East has historically exhibited high utilisation levels due to the reliable and consistent performance of LNG plants in Qatar. However, regional exports have also fallen well below designed capacity levels due to a sharp decline in exports from countries other than Qatar. The complete collapse of Yemeni output in 2015 as civil war ravaged the country has taken 9 bcm per year of capacity out of the market. There is no indication at the time of writing when exports will resume. Oman (which also holds a sizeable LNG capacity) is faced with challenges in sustaining export levels, caught between flattening production and fast-growing domestic demand.

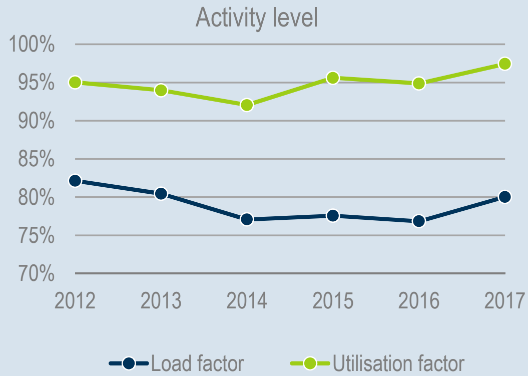
Non-availability of liquefaction plants reveals that the supply side is limited in its flexibility to provide LNG quantities to the market in times of demand shock. Two factors are important for analysis of the supply side:

- **load factor** – ratio of the actual output in a given year against the nameplate capacity
- **utilisation factor** – ratio of actual output to potential maximum output – adjusted to account for planned outages (maintenance) and unplanned outages (lack of feed gas, technical problems or weather).

Figure below shows that the activity level defined by the utilisation factor, which was 96% in 2015, fell to 95% in 2016, and increased to 97% in 2017. This can be explained by a combination of factors such as increasing new capacity development rate (13% y-o-y for 2017 against 7% in 2016 and 1% in 2015) in parallel with a steep LNG trade growth increase (12% for 2017, against 5% in 2016 and 6% in 2015).

LNG export capacity, volume and utilisation level, 2012-17





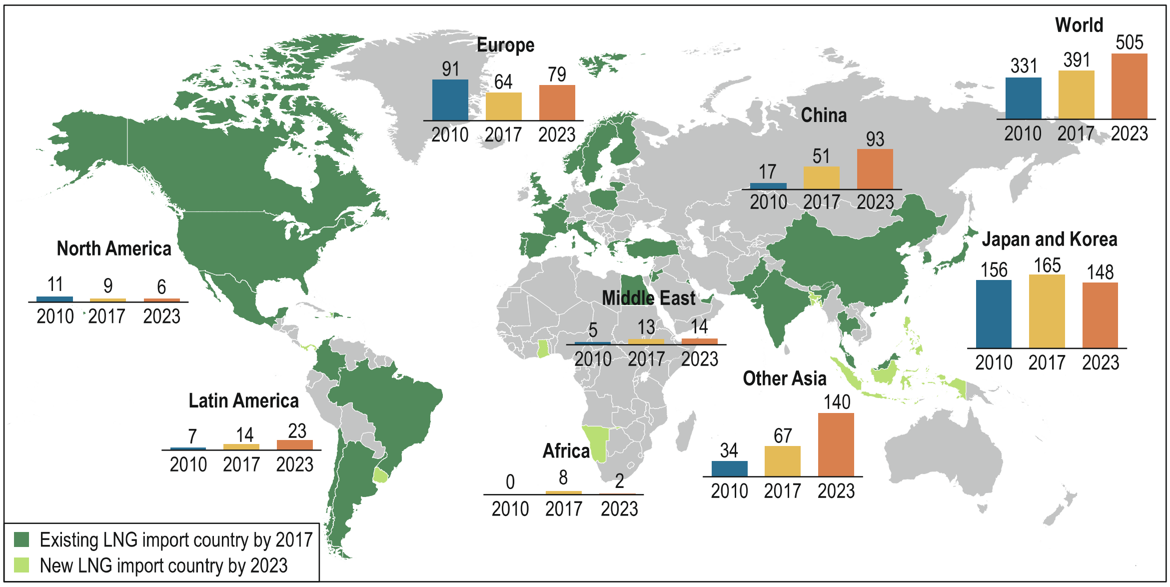
The high activity level of liquefaction plants shows that pure additions of LNG nameplate export capacity do not correctly reflect the flexibility potential of the supply side. A detailed view elucidates that nameplate capacity is not available to its full extent, and non-available capacity has increased over the last five years. The expansion of capacity in the United States and Australia might decrease utilisation slightly in the future. However, it is unlikely that low activity levels will persist over a longer period, due to the economics of a liquefaction plant (high upfront costs but low operating costs).

Recent developments in LNG demand

Japan and Korea have been undisputed leaders of LNG demand, with a combined import share of around 52% in 2010. However, China will significantly develop its demand by 2023 (Figure 11). It has strong political support for natural gas, based on its five-year plans. LNG therefore plays a significant role as an import option in the Chinese supply portfolio. Regasification capacity has increased rapidly, from around 9 bcm in 2006 to 88 bcm in 2017, and China has signed long-term import contracts amounting to around 67 bcm by 2022.

Europe's natural gas imports are dominated by pipeline infrastructure, despite Finland, Lithuania, Malta, Poland and Sweden recently becoming LNG importers in Europe. Europe's current LNG import contracts are expiring: if most of these contracts are not renewed, LNG import volumes to Europe will decrease by around 17 bcm by 2022 compared to 2010.

Figure 11. LNG import countries and volumes (in bcm), 2010-23

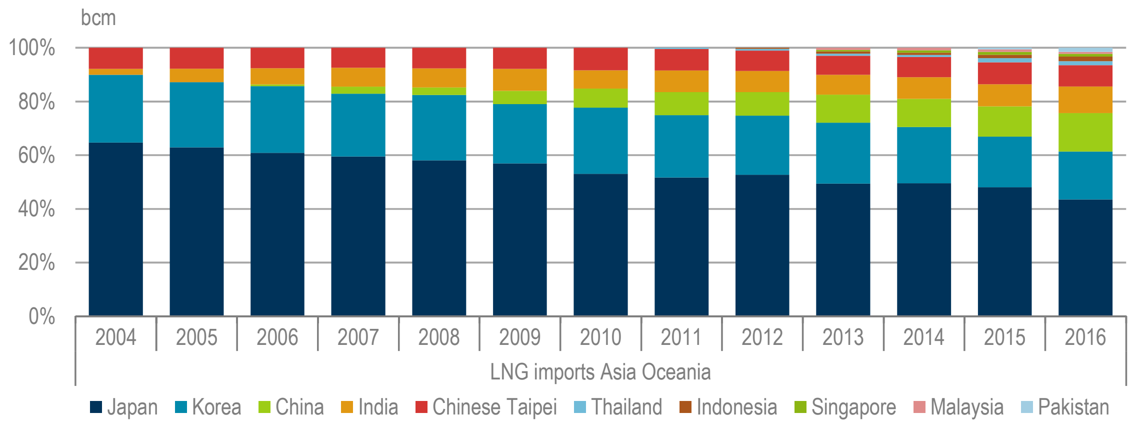


This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries, and to the name of any territory, city or area.

Source: IEA (2018), *Market Report Series: Gas 2018*, https://www.iea.org/gas2018/.

In addition to Japan, Korea and China, emerging economies in Asia have increased their share of LNG demand, enhancing the importance of growth in that region (Figure 12). This will change the composition of Asian LNG buyers, resulting in a higher need for supply flexibility. Emerging economies tend to buy LNG driven more by opportunity and price than traditional buyers of LNG, leading to a lower share of long-term contracts in their portfolio and higher activity in LNG spot markets.

Figure 12. Composition of LNG imports in Asia, 2004-16



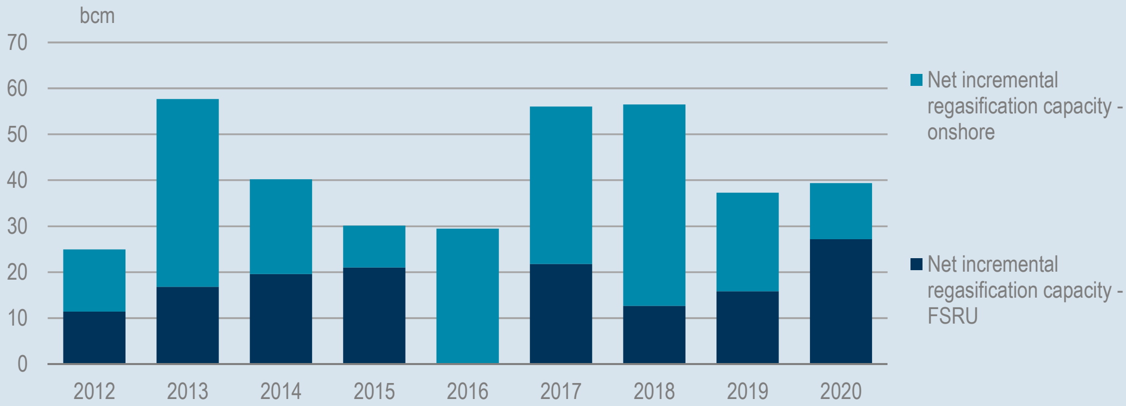
Source: GIIGNL (2017), *The LNG Industry GIIGNL Annual Report 2017*, www.giignl.org/sites/default/files/PUBLIC_AREA/Publications/giignl_2017_report_0.pdf.

In addition to lower spot prices, technological developments in regasification infrastructure, such as the use of FSRUs, support the view that emerging economies will increasingly influence LNG market dynamics (Box 2).

Box 2. Floating Storage and Regasification Units (FSRUs)

FSRUs have recently enabled additional markets that import LNG to meet short-term gas demand when the LNG price is competitive with other fuels. FSRUs are attractive for these markets because of lower initial investment costs, shorter installation periods (around 18 months for FSRUs versus more than five years for onshore conventional regasification terminals) and greater flexibility in length of commitment than onshore regasification facilities. Recent countries to invest in FSRUs are Lithuania in 2014, Egypt and Jordan in 2015, and the United Arab Emirates in 2016.

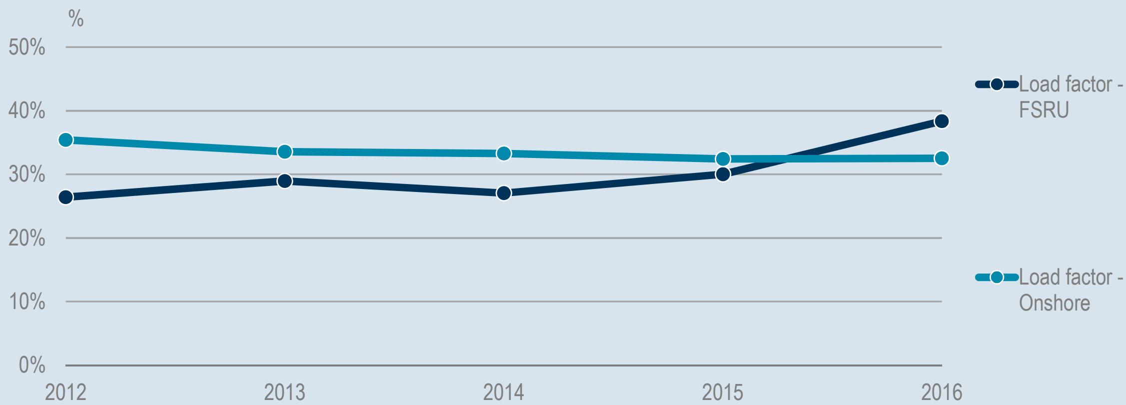
Incremental regasification capacity, 2012-20



The first FSRU started operation in the United States in 2005, and there are now 24 operating FSRUs. They globally account for 18.5% of the total number of regasification terminals and 10% of the regasification capacity. More than 60 bcm of new FSRU capacity is expected to come on line between 2017 and 2020, with around two-thirds of this due to take place in countries such as Ghana, Bangladesh and Uruguay (Figure above).

The volume of LNG received by FSRUs has grown since 2015, backed by low LNG prices. The load factor of FSRUs has also grown y-o-y. In 2016, it exceeded that of onshore regasification terminals (Figure below). Although each of these markets is much smaller than traditional large LNG buyers, such as Japan and Korea, their aggregated LNG import volumes in 2016 accounted for 41.5 bcm. This was equal to 12% of the global LNG demand, the third-largest market after Japan and Korea.

FSRU and onshore load factors, 2012-16

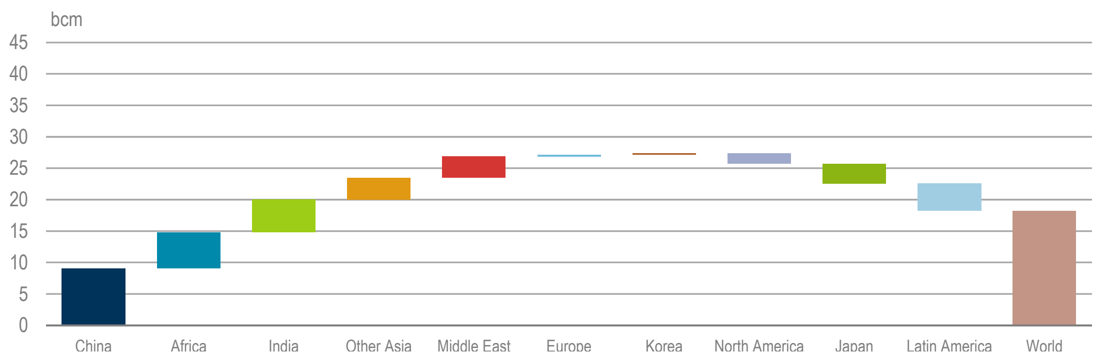


FSRUs have therefore played important roles in overcoming the short-fall in gas production or meeting emerging gas demand quickly in recent years. The demand for LNG may increase as the market expands or decreases in response to higher LNG prices. Therefore, flexibility in the global LNG market will become more important for timely and adequate response to potential fluctuations in LNG demand among these markets.

Sources: ICIS (2018), *ICIS LNG Edge*, www.icis.com/energy/liquefied-natural-gas/lng-edge (subscription required).

Asian LNG demand will take the dominant share (75%) of the LNG market by 2022. This will create a strong dependence of the LNG market on Asia's growth potential, particularly the ongoing demand pull from China. During 2016 to 2018, China has ranked top in terms of incremental LNG import demand. China's ambition to improve air quality is detailed in the thirteenth five-year plan for the medium-term period until 2020 and has reinforced the role of natural gas in the country's energy mix. As China's LNG imports were still well below their contractual level, the country significantly increased its LNG imports between 2015 and 2016 from around 27 bcm to 36 bcm, which is a y-o-y growth of 35% (Figure 13).

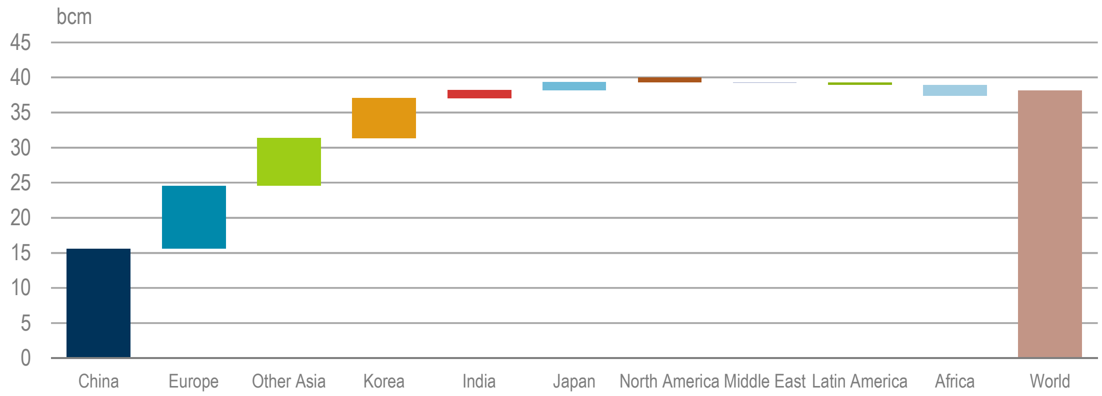
Figure 13. Incremental LNG imports, 2015-16



Source: ICIS (2018), *ICIS LNG Edge*, www.icis.com/energy/liquefied-natural-gas/lng-edge (subscription required).

For China, 2017 proved to be a record year. The ban on small coal-fired boilers in industrial applications and for residential heating in large cities led to a switch to gas-fired boilers, boosting gas demand. This increase in gas demand translated to an increase in LNG demand as alternatives were not able to provide to the extent expected (gas pipeline imports from Turkmenistan experienced a severe cut of around 40% in some winter months of 2017/2018) or did not fully meet expectations in domestic gas production. China's incremental LNG imports hence jumped to around 15 bcm between 2016 and 2017 (Figure 14).

Figure 14. Incremental LNG imports, 2016-17



Source: ICIS (2018), *ICIS LNG Edge*, www.icis.com/energy/liquefied-natural-gas/lng-edge (subscription required).

For Japan, 2016 was a turning point, as LNG demand balanced supply. From 2017 onwards, the addition of new contracts and a decreasing demand resulted in a significant over contracted position for the first time ever. A method for managing this situation is to take advantage of LNG cargoes with destination flexibility. From 2018 to 2022, Japan could utilise around 15 bcm of contracted volumes with flexible destination by diverting these volumes to other LNG importing countries where more LNG is needed.

Korea will face the same situation as Japan, but with different timing and the overcontracted volumes will be smaller. Korea's contracted level surpassed its LNG demand in 2015 resulting in 7.5 bcm of surplus, in 2017 this surplus had grown to 9 bcm. The surplus is predicted to be around 5-6 bcm per year from 2020 onwards. Korea is expected to have around 4 bcm per year of destination-free LNG until 2019 and around 7 bcm per year from 2020 onwards.

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Domestic gas markets and liberalisation policies of major LNG importing countries

This chapter introduces the current status of domestic gas markets of major LNG importing countries (Japan, China and Korea) and new policies announced by these countries which may cause changes in these domestic gas markets in the near future.

Japan

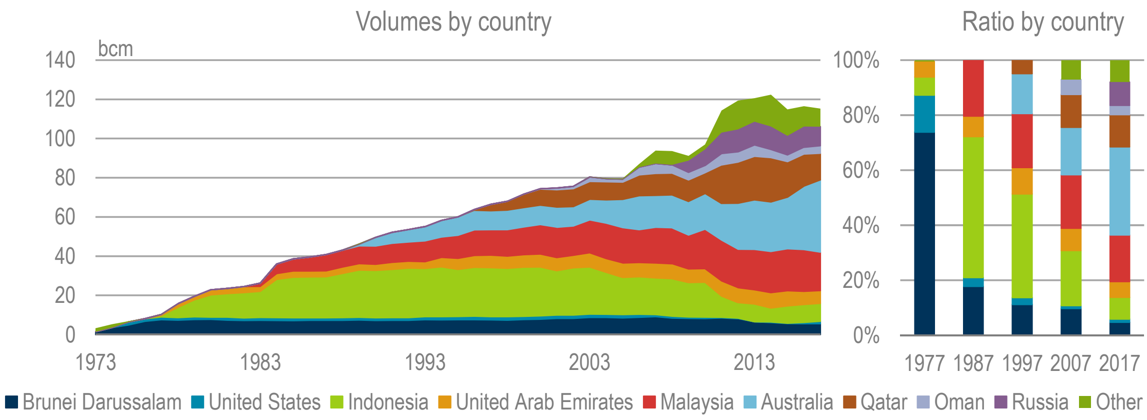
Japan's city gas companies were monopolistic suppliers within their districts until the government started to introduce liberalisation in the retail market in 1995. The gas retail market was fully liberalised in April 2017, one year after electricity market fully opened in 2016. Significant changes have occurred since then in the Japanese gas market. These include movement towards a competitive market with abolition of a regional monopoly, price competition among suppliers and combined sales of gas with other services such as electricity.

Supply and demand

Natural gas is a crucial part of Japan's energy mix. Its natural gas demand was 112.2 million tonnes of oil equivalent (Mtoe) in 2017, accounting for around a quarter of the total primary energy supply. The share of natural gas in Japan's total energy mix was 11% in 1995. It has been growing steadily for decades, with a surge in 2011 to 22%, from 18% in 2010.

LNG imports meet most of Japan's domestic demand. This is because the country has limited natural gas resources, and its domestic natural gas production is negligible (around 2.9 bcm in 2016). Imports totalled 116.5 bcm that same year, which accounted for around one-third of global LNG imports. Japan is therefore ranked as the world's largest LNG importer. It has a diverse LNG import portfolio, from various countries such as Australia, Qatar and Russia (Figure 15). Imports grew substantially in 2011 and 2012 as nuclear power plants shut down in response to the Fukushima disaster, and gas was used as a replacement in power generation.

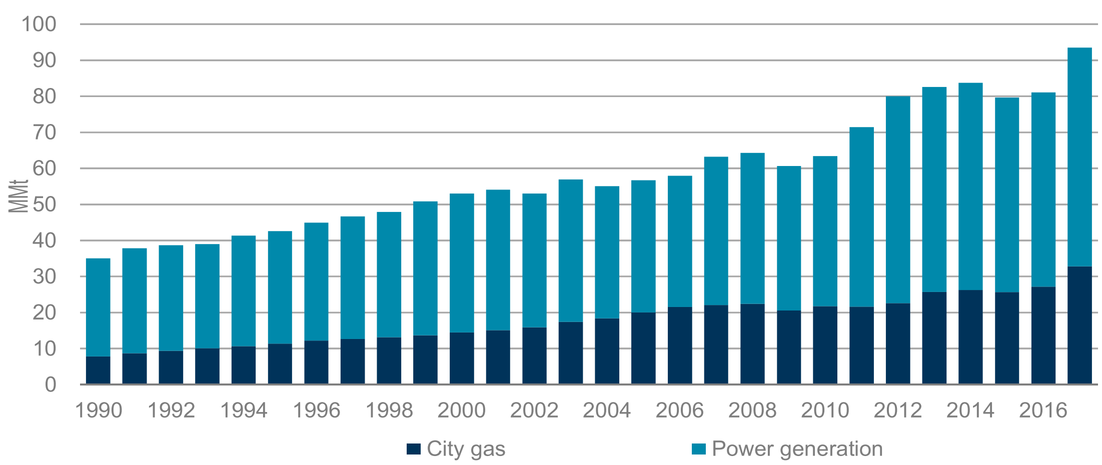
Figure 15. Japan's natural gas imports by country, 1973-2017



Source: IEA (2017a), *Natural Gas Information.*

Japan uses natural gas for electric power generation and city gas. Natural gas demand from power generation grew substantially in 2011 and 2012. There was a peak in 2014 with a share of 70% of gas demand used for power generation, but it has fallen since then with a 66% share in 2016 (Figure 16).

Figure 16. Japan's natural gas demand, 1990-2017



Note : MMt = million metric tons

Source : Institute of Energy Economics, Japan (IEEJ), National Statistics No. 19, *Supply and Demand of LNG*, http://eneken.ieej.or.jp/en/statistics.php (subscription only).

Natural gas demand from city gas has been growing steadily. Coal and petroleum products such as heavy oil, liquefied petroleum gas and naphtha were the main sources of city gas in Japan until the mid-1960s. Japan has increasingly used natural gas as a source of city gas since it began importing LNG in 1968. The Japanese government actively promoted the Integrated Gas Family 21, proposed in 1990 to standardise city gas with various combustibility groups into a single high-calorie group by 2010. As a result, natural gas has accounted for most of the city gas supplied in Japan, with a share of 97% in 2016 (JGA, 2017).

Table 3. Raw material shares for city gas in Japan, 1955-2015

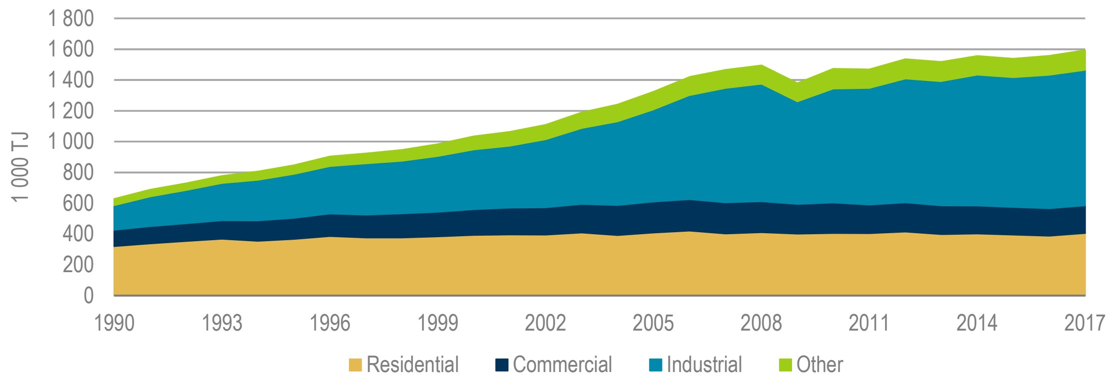
Year	Coal (%)	Petroleum products (%)	Natural gas (%)
1955	89.6	7.9	2.4
1975	22.9	44.0	33.1
1995	1.4	17.5	81.1
2015	0.0	2.8	97.2

Note: Values may not sum to 100% due to rounding.

Source: National Diet Library, Outline and Issues of Gas System Reform, Issue Brief, Number 940, Table 1., http://dl.ndl.go.jp/view/download/digidepo_10300865_po_0940.pdf?contentNo=1

Natural gas demand from city gas in the industrial sector has grown substantially (more than fivefold between 1990 and 2017), while demand has been almost stable for the residential and commercial sectors. The share of industrial use increased to 55% in 2017 from 26% in 1990, while that of residential use and industrial use decreased to 25% from 51%, and to 11% from 17%, respectively, that same period (Figure 17).

Figure 17. Japan's natural gas demand for city gas, 1990-2017



Note: TJ = terajoule.

Source: IEEJ, National Statistics No. 17, *Supply and Demand of Town Gas*, http://eneken.ieej.or.jp/en/statistics.php

Gas market structure

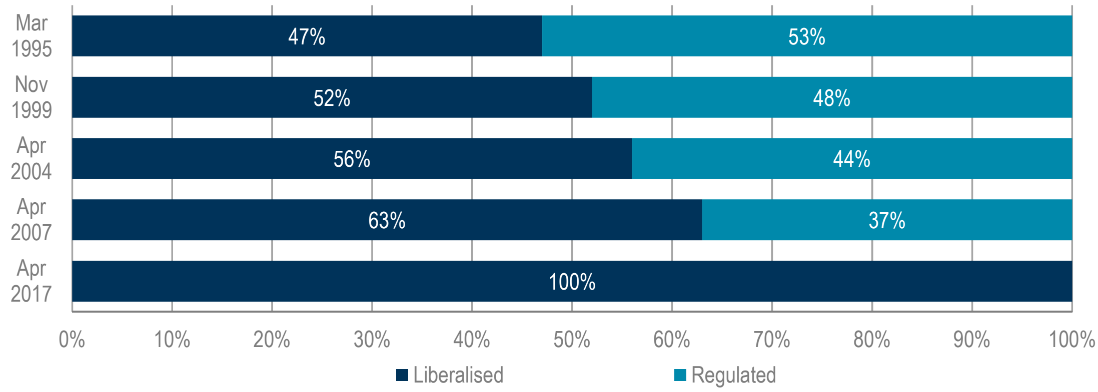
The retail market for city gas was fully regulated until 1995. The government permitted city gas companies to be monopolistic suppliers within their districts because the industry was characterised by high fixed costs and economies of scale, which are features of a natural monopoly. The government also imposed supply and safety obligations and tariff regulations on those companies.

Japan faced increasing pressure, mainly from large-volume customers, in the 1990s to open the retail market for city gas. City gas companies were able to supply high-calorie gas to customers and deliver large-scale supplies more efficiently via pipelines. This led to an increase in demand for large-scale industrial use of city gas. At the same time, large-scale industrial users from areas outside city gas supply districts also created a growing demand for natural gas.

Japan therefore started a first round of gas market reforms in 1995 by opening the retail gas market up for customers consuming more than 2 million cubic metres. These reforms resulted in the retail gas market being divided into a regulated sector and a liberalised sector. Suppliers could enter the liberalised sector by registering with the Minister of Economy, Trade and Industry, while only designated suppliers could supply city gas in the regulated sector.

The Japanese government implemented three more rounds of gas market reforms in 1999, 2004 and 2007 by expanding the liberalised sector (Figure 18). The latest round of reforms, implemented in April 2017, fully opened the market.

Figure 18. Market liberalisation in Japan, 1995-2017



Note: The share of the liberalised market (%) represents the accumulated volume of gas sales to the liberalised customers in fiscal year 2011. The balance represents the share of the regulated market (%).

Source: ANRE (Agency for Natural Resources and Energy), Energy White Paper 2013.

Retail business in the city gas market was categorised into three types before full liberalisation (Table 4). All retail business in the city gas market was categorised as general gas business supplying gas to customers only in designated areas before 1995. The liberalisation process in 1995 established large-volume supply business and the liberalisation process in 2004 established gas pipeline service business.

These new businesses were possible because the processes allowed non-traditional gas companies to enter the liberalised market and sell gas in any area. Owners of pipelines or LNG terminals, such as power utilities, oil and gas upstream companies, entered the liberalised market as their market shares increased with time. The new entrants' market share has rebounded recently due to increased demand for natural gas from the power generation sector, after decreasing for three years following the Fukushima accident (Figure 19).

Table 4. Retail business in Japan's city gas market before full liberalisation

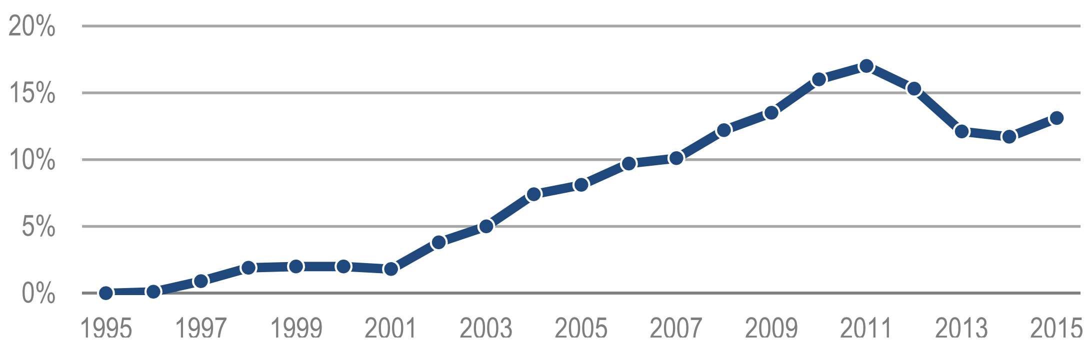
Classification	Overview	Number of companies	Targeted market
General gas business	Supply gas (mostly natural gas) to meet general demand via pipelines in designated areas	206	Regulated and liberalised
Large-volume supply business	Supply gas to large-demand customers (established in 1995)	15	Liberalised
Gas pipeline service business	Supply gas to large-demand customers via specific pipelines operated by themselves (established in 2004)	23	Liberalised

Note: Numbers given are for March 2015.

Sources: METI, Agency for Natural Resources and Energy; National Diet Library (2017), *Outline and Issues of Gas System Reform*, Issue Brief, Number 940 (2017.2.9.), Table 2, http://dl.ndl.go.jp/view/download/digidepo_10300865_po_0940.pdf?contentNo=1

There are more than 200 general gas utilities. The three largest – Tokyo Gas, Osaka Gas and Toho Gas – held a combined market share of about 70%. Nine general gas utilities, including those three, imported through their own LNG terminals, while the other gas utilities purchased gas from LNG importers and domestic natural gas producers.

Figure 19. Japan's sales volume share by new entrants in the liberalised market, 1995-2015

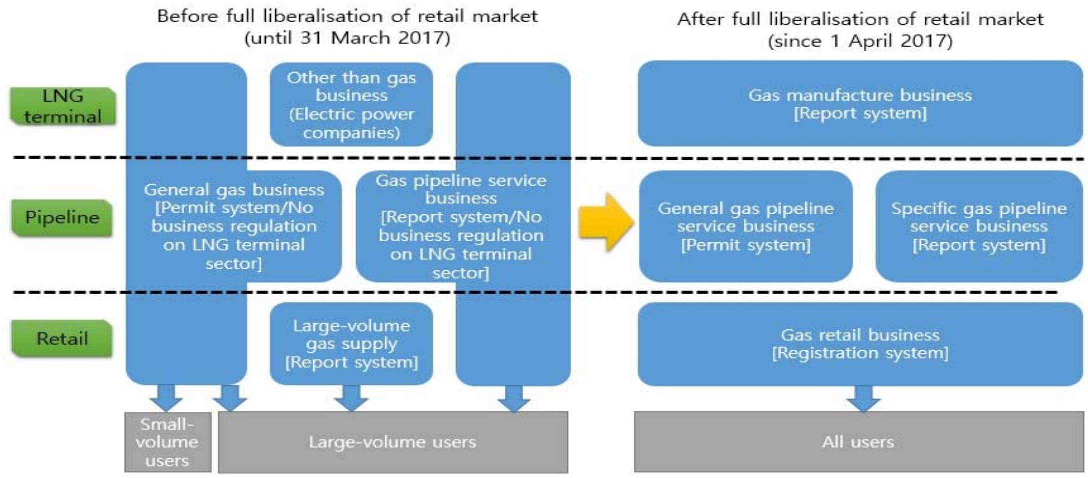


Source: METI (2017), http://www.meti.go.jp/committee/sougouenergy/denryoku_gas/denryoku_gas_kihon/pdf/003_04_00.pdf

Figure 20 compares gas businesses before and after full liberalisation. The gas businesses were vertically integrated before full liberalisation. After full liberalisation, the businesses were newly classified into the following (JGA, 2017):

- "gas manufacturing business (the LNG terminal business)", where utilities produce gas based on contracts with other companies or on requests from their own retail divisions
- "pipeline service business", which is divided into general gas pipeline service business, where a pipeline service provider operates a pipeline network from high pressure to low pressure and supplies small amounts of gas, and specific gas pipeline business, where a pipeline service provider operates only high and medium-pressure pipeline networks
- "gas retail business", where gas utilities supply and sell gas.

Figure 20. Japan's gas business before and after full liberalisation



Source: National Diet Library (2017), *Outline and Issues of Gas System Reform*, Issue Brief, Number 940, http://dl.ndl.go.jp/view/download/digidepo_10300865_po_0940.pdf?contentNo=1

Thirty-four LNG terminals were operational in Japan in July 2017 (JGA, 2017). Power and gas utilities and steel companies were the main owners and operators of these terminals. The total gas pipeline length in 2015 was 257 407 kilometres (km). Around 86% of this comprised low-pressure networks for local distribution and the remainder comprised medium and high-pressure networks.

Gas pipelines were developed and maintained by region, and there were few cross-border pipeline networks. The geographic coverage of the pipelines was only 5.7% of the entire national territory (IEA, 2016). Japan has built its pipelines primarily to connect LNG receiving terminals on the coast to high-demand areas. This is because LNG imports meet most of the domestic natural gas demand.

There was no requirement for pipelines to be interconnected because the city gas industry has historically been fragmented into many vertically integrated regional companies. Each company has expanded its distribution networks around LNG terminals by projecting demand in and near to their supply districts and investment returns. However, the Fukushima accident caused the Japanese government to consider the development of its pipeline networks with regard to stable gas supply and economic efficiency.

Gas market liberalisation

The Great East Japan Earthquake of 2011 and the Fukushima Daiichi nuclear accident, followed by the gradual closure of 30 percent of the country's electricity supply highlighted the inflexibility of Japan's regional electricity systems. This led to a review of the overall energy system. Reform of the electric power system was discussed in 2012 with a view to unbundling the electric power business (legal separation of power transmission and distribution) and full liberalisation of the retail market for electricity. The same kind of reform (hereinafter referred to as "gas system reform") was proposed by the Japanese government for the gas business in 2013.

The Gas System Reform Subcommittee under the Advisory Committee for Natural Resources and Energy was established in November 2013 to review the gas system reform. It published a review report in January 2015, which proposed full liberalisation of the city gas retail market, legal unbundling of pipeline business and TPA of LNG terminals. The revised Gas Business Act (June 2015) incorporated the findings of this report.

Japanese gas system reform, along with power system reform, was promoted to be consistent with the *Strategic Energy Plan* published in 2014, where "3E+S" – energy security, environmental protection, economic efficiency and safety – was emphasised as the basis of national energy policy. The goals of the gas system reform are as follows:

- **Ensure stable supply of natural gas.** A system will be established to supply natural gas in a stable manner, including reinforcement of supply during disaster, through construction of new gas pipeline networks, maintenance and interconnection of gas pipeline networks.
- **Restrict gas price increases to the maximum extent possible.** Increases in gas prices will be restricted through increased competition in the procurement of natural gas and retail services, thus improving consumer welfare.
- **Diversify tariff plans and expand business opportunities.** The new gas system will encourage innovation by attracting new entrants from other industries and promoting expansion of gas companies to other areas, by allowing customers to choose gas suppliers and pricing plans.

- **Expand natural gas use.** The system will encourage participation of businesses that can build new gas pipelines and develop potential demand for natural gas by proposing new utilisation methods for natural gas such as fuel cells and co-generation.

This ongoing gas system reform means more than just opening up the market. Japan views its energy system reforms in an integrated perspective, and has thus implemented the gas system reform and the power system reform in integrated ways (Table 5). Japan is moving towards a next-generation energy system that is stable and sustainable. Energy system reforms will be significant building blocks in achieving this goal.

Table 5. Energy system reform schedule in Japan, 2015-22

	1 April 2015	1 April 2016	1 April 2017	1 April 2020	1 April 2022
Electricity	First phase Establishment of the Organization for the Cross-regional Coordination of Transmission Operators	Second phase **Full liberalisation of electricity retail market**	(*)Period for transitional measure	Third phase Legal unbundling of the electricity transmission and distribution sector (*)transitional measure period continues	(*) transitional measure period ends when the competitive situation of each utility company has confirmed
City gas			**Full liberalisation of gas retail market** and abolition of regulated tariff	(*) Regulated tariffs remain for utility companies with insufficient competitive situations	**Legal unbundling of the gas pipeline service** (major three companies)
Market surveillance commission	Establishment of the Electricity Market Surveillance Commission	Renamed to Electricity and Gas Markets Surveillance Commission (EGC) to oversee gas market as well			

Source: METI Journal (April/May 2016). http://www.meti.go.jp/english/publications/pdf/journal2016_05a.pdf

The contents of the Gas Business Act revised in 2015 are summarised in the following:

- Full liberalisation of the retail market:
  - After abolition of the regional monopoly in the retail market, any registered companies can enter the gas retail market.
  - In principle, tariff regulations are no longer imposed on retail companies. However, incumbents are obliged to supply gas subject to tariff regulations as a transitional measure, in areas where competition is insufficient.
- Introduction of a licensing system:
  - Gas companies need to acquire licences for the gas manufacturing business (LNG terminal business), gas pipeline service business and gas retail business, following new gas business classifications.
  - LNG terminal business operates based on a report system, general gas pipeline service business operates on a permission system, specific gas pipeline service business operates on a report system and gas retail business operates on a register system.
- Provision of TPA to LNG terminals:
  - Businesses that own LNG terminals are prohibited from rejecting third-party use without reasonable reasons. This is also applicable to LNG terminals owned by electricity businesses.

- LNG terminal owners must report and publish their annual utilisation plan and benchmarks of their rate system. If the terms and conditions of use are inappropriate, the government can order changes in the conditions.
- Promotion of maintenance of gas pipeline networks:
  - Regional monopoly and price regulation will be maintained to secure stable supply of gas for general gas pipeline service providers.
  - All gas pipeline service providers must promote interconnection of pipeline networks.
  - A system that allows the government to order and adjust negotiations among businesses to encourage pipeline connection should be established.
- Customer safety:
  - A legal obligation should be imposed on gas pipeline services providers to inspect the safety of inner pipelines owned by customers and to provide emergency services.
  - A legal obligation should be imposed on gas retail business to investigate customers' devices and notifications, to reduce risks.
- Legal unbundling of pipeline service business:
  - New entrants should be allowed to use pipeline networks fairly with appropriate payments, to promote retail competition.
  - There must be "legal separation" of pipeline service business from major gas companies (Tokyo Gas, Osaka Gas and Toho Gas) that own the longest pipeline networks, by April 2022. The other gas companies will maintain "accounting separation" of pipeline service business.
  - A new code of conduct should be applied to prevent pipeline service providers from favouring their retail sectors.

A new registry of gas retail business began in August 2016. The number of newly registered gas retail companies was around 50 in late 2017, according to the Agency for Natural Resources and Energy. This number included new entrants who do not have any track record in gas retail business. It also included companies with retail business records, because the Gas Business Act required them to register as gas retail companies. These companies included the former gas pipeline service providers that used to sell gas to large-volume customers, large-volume gas suppliers and former general gas companies that launched retail gas business in districts other than their own supply districts. Among the newly registered retail companies, only 15 supplied gas to small-volume customers, according to the Agency for Natural Resources and Energy (2017).

Table 6 shows the size of the gas market in 2014 when competition was introduced because of full liberalisation. The total market size was estimated at around 2.4 trillion Japanese yen (JPY) and the total number of customers was about 26 million. This market was around one-third of the electricity market liberalised in 2016, when the same parameters were JPY 8 trillion and 85 million customers.

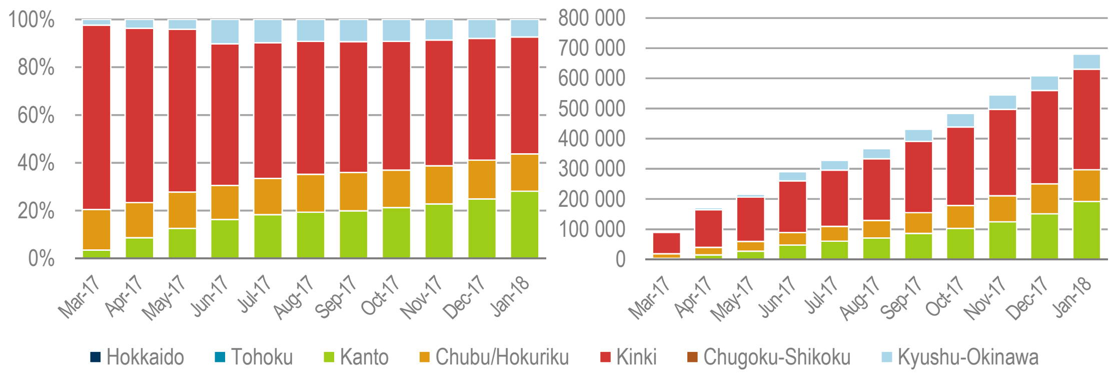
Table 6. Sales and customers of former general gas companies in Japan, 2014

Year	Sales (JPY 100 million)	Number of customers (ten thousand)		
		Residential	Commercial and office	Total
Tokyo Gas	8 634	924	47	**971**
Osaka Gas	6 015	589	25	**614**
Toho Gas	1 982	199	6	**205**
Remainder	7 867	777	44	**821**
Total	**24 498**	**2 489**	**122**	**2 611**

Source: Agency for Natural Resources and Energy (2016).http://www.kyushu.meti.go.jp/event/1610/161020_2_2.pdf

Gas retail companies began to accept customer switching in January 2017. More than 680 000 customers had switched their gas suppliers by January 2018, according to the Agency for Natural Resources and Energy (Figure 21). The number of customers switching represented 2.6% of the customers of the former general gas companies. Customers in Kinki switched the most, with a share of 48.9% of the total numbers switching in the whole country. This was in the supply district of Osaka Gas, although its share had been decreasing. In Kanto, where the supply district of Tokyo Gas is located, the number switching has increased since the Tokyo Electric Power Company started its gas retail business in July 2017. Meanwhile, no switching cases were observed in Chugoku-Shikoku, Tohoku and Hokkaido, as there were no new market entrants in those regions.

Figure 21. Share (left) and number of household (right) of customers' switching by region in Japan



Source: Agency for Natural Resources and Energy.
http://www.enecho.meti.go.jp/category/electricity_and_gas/gas/liberalization/switch/

Former general gas companies compete mainly with electricity companies in the regions where customers switch their gas suppliers. One reason why electricity companies are keen to enter the retail gas market is to recover what they have been losing of the retail electricity market since full liberalisation. It is not surprising that electricity companies enter the retail gas market in their original supply district, gven the potential for leveraging existing customer bases, the ability to procure LNG and even the prior existence of gas manufacturing facilities for some electricity companies.

Obstacles and challenges

In Japan, the progress of liberalisation in the retail gas market has been slow compared to that in the retail electricity market, in terms of the number of new entrants and the switching of suppliers by customers. However, it is not simple to compare the outcomes of market liberalisation in these two sectors. The market size differential between electricity and gas retail markets, recent trends of electrification and limited aspects of gas supply infrastructure relative to the power sector all need to be considered.

The limited number of new entrants in the retail gas market after full liberalisation is partly caused by the nature of the Japanese domestic wholesale market. There is no well-defined wholesale market where retailers could procure LNG conveniently, unlike the electricity market with its power exchange. New entrants need to import LNG by utilising LNG terminals under TPA conditions or find wholesale suppliers, except for those companies who can procure LNG by importing through their own terminals.

Importation through their own terminals may be an option for companies who can secure an annual gas demand equivalent to 60 000 tonnes of LNG, which is the amount a typical LNG carrier ship can transport (IEEJ, 2017). Importation using LNG terminals or finding wholesale suppliers may be more realistic options for new entrants. However, there are a limited number of wholesale suppliers in any region in Japan, given that those who own LNG terminals serve as wholesalers and that gas pipeline networks are not interconnected.

Active wholesale trade will be necessary to induce greater competition in the retail gas market. The Japanese government has aligned regulations on TPA, to allow greater access to LNG terminals and to encourage new entrants to enter into the wholesale business. Two TPA requests had been submitted as of February 2018, according to the Ministry of Economy, Trade and Industry (2018). Whether the third-party utilisation of LNG terminals will increase and then stimulate wholesale market development is a point of discussion.

It is likely that less capacity will be available to a third party during peak demand seasons, which may discourage entry of new wholesalers, as discussed in a recent IEEJ report (IEEJ, 2017). The IEEJ report also states that it may not be easy for new entrants to secure use of LNG terminals because owners of LNG terminals can shorten or reject long-term contracts with third-party users due to their limited ability to project available capacity. Moreover, they face challenges in forecasting their short and mid-term gas demand as there is greater uncertainty driven by growing competition in the gas retail market, uncertain nuclear restarts and increasing use of renewables.

The Japanese government runs its gas system reform in parallel with the *Strategy for LNG Market Development* proposed in 2016, which aims at promoting flexibility in the LNG market and developing an LNG trading hub in Japan. This strategy could make a significant contribution to the domestic energy market reform, as it would enhance market efficiency by promoting transparency and flexibility of LNG trade.

Korea

The natural gas market in Korea is not perfectly liberalised, and is regulated by the government under the Urban Gas Business Act. Korean Gas Corporation (KOGAS) is a public corporation and dominates the upstream natural gas sector. KOGAS owns four of the six LNG import facilities, the transmission system, almost all storage capacity and is the sole wholesaler of gas in Korea.

Although some direct importers import LNG for their own use, they are limited to reselling to other domestic gas consumers. The retail market comprises 34 local city gas companies. The central government oversees the wholesale market, and local governments and provinces oversee the retail market. Korea's government changed in May 2017, and the new government has recently targeted a phase-out of nuclear power and curtailment of coal-fired power generation, which will lead to an increase in gas use.

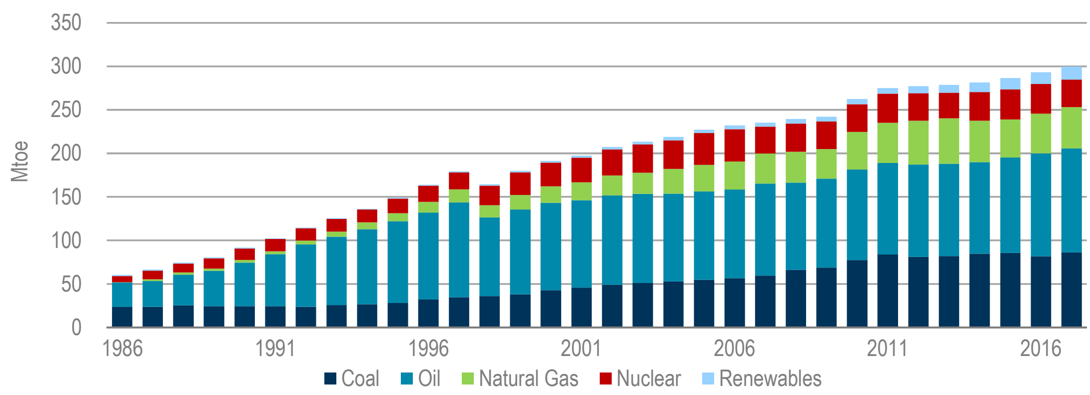
Supply and demand

Korea has historically relied on imported LNG for most of its natural gas supply, although the Korea National Oil Corporation started producing a small quantity of natural gas from one offshore field (Donghae-1) in 2003. Imports of LNG began in 1986, after foundation of the LNG importer KOGAS in 1983. Korea currently gets most of its LNG from Qatar, Indonesia, Malaysia, Oman, Russia, Brunei, Australia, Yemen and the United States, and occasional spot cargoes from elsewhere. Natural gas is mainly used in power generation and urban gas. City gas is used as a fuel for cooking and space heating in the residential and commercial sectors.

Korea's energy consumption grew rapidly due to high economic growth rates, but these growth rates have slowed in recent times. The annual growth rate of primary energy consumption (Figure 22) was 2.4% on average for the last ten years, whereas it was growing at 10.4% per year during the period 1986-96, and 3.5% per year during the period 1996-2006.

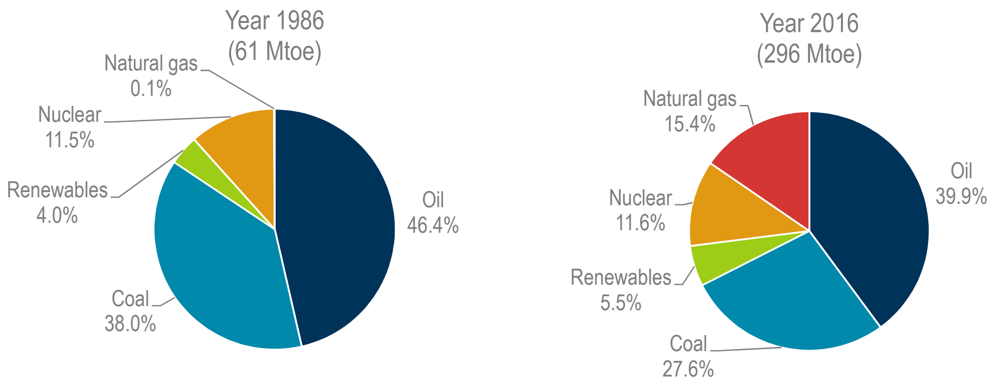
The composition of Korea's primary energy consumption has also changed (Figure 23). The share of natural gas accounted for 0.1% in 1986, while it soared to 15.4% in 2016. The share of renewable energy rose from 4.0% in 1986 to 5.5% in 2016. It is expected that the share of renewable energy will rise significantly by 2020 under the new government's revised energy policy. The shares of oil and coal have dropped continuously from 1986, due to the structural changes in Korea's industry, though oil use has quadrupled and coal use more than tripled.

Figure 22. Korea's energy consumption trends, 1986-2017



Note: Values in 2017 are provisional as of March 2018.
Source: KEEI (2018), *Monthly Energy Statistics and Annual Energy Statistics*; KEEI (2017), *Yearbook of Energy Statistics.*

Figure 23. Korea's energy consumption, 1986 and 2016

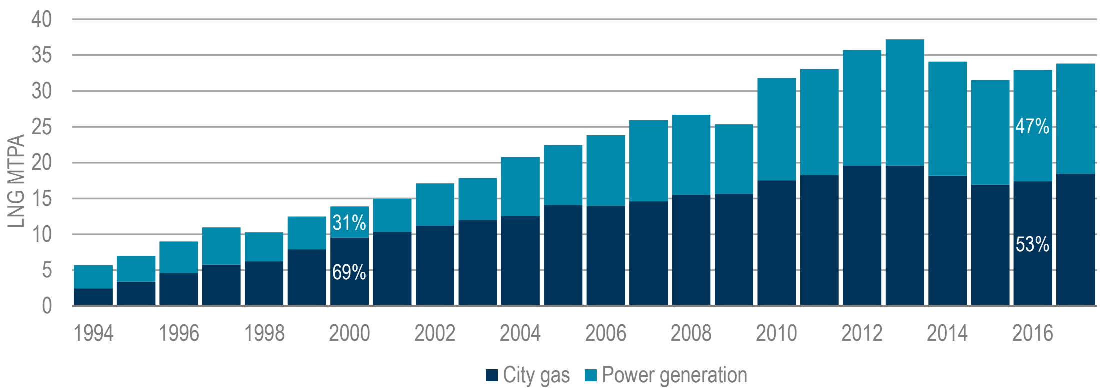


Source: KEEI (2018), *Monthly Energy Statistics and Annual Energy Statistics*; KEEI (2017), *Yearbook of Energy Statistics.*

Natural gas consumption has increased at a fast rate because of its environmental advantages compared to coal, ease of use and price competitiveness. Advances in power generation technology and active expansion policy for natural gas use in Korea are also contributing factors. Natural gas consumption reached a peak of around 37 million tonnes in 2013, and then declined. The decrease was mostly due to natural gas losing its share to cheaper coal and liquefied petroleum gas, and to new nuclear and coal-fired generation capacity coming on line. The demand for power generation has accounted for around 45% of the total natural gas demand over the last ten years.

Korean gas demand shows high seasonal fluctuations. This is due to the higher heating demand in the residential and commercial sectors during winter. However, a lower seasonal demand growth has been observed over the past decade. In the early 2000s, around two-thirds of Korea's gas demand was in the residential and commercial sectors. This fell to around 50% following growth in consumption in industry and power generation in 2016.

Figure 24. Korea's natural gas demand, 1994-2017

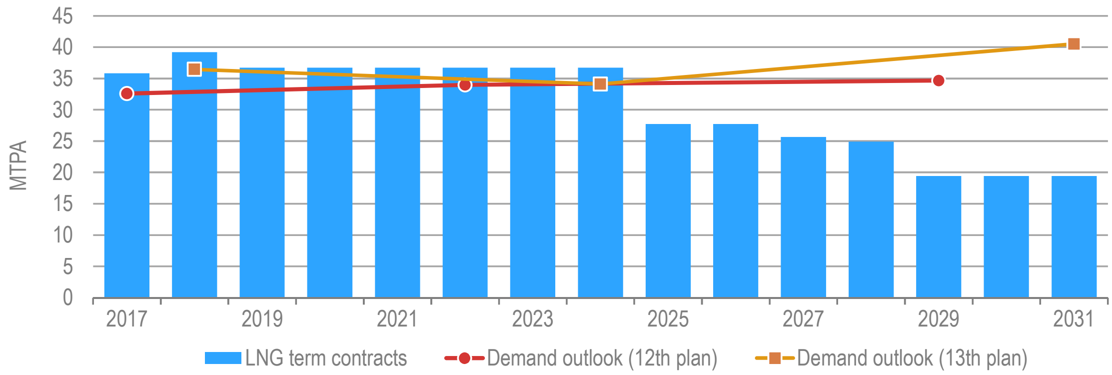


Note: Values in 2017 are provisional as of March 2018.
Source: KEEI (2018), *Monthly Energy Statistics and Annual Energy Statistics*. https://www.keei.re.kr/main.nsf/index_en.html

The demand in 2029 will be similar to the current level of demand in Korea, according to the outlook of the 12^{th} *Basic Plan for Long-term Natural Gas Supply and Demand* (MOTIE, 2015), released at the end of 2015 by MOTIE. This gas demand outlook was based on the plans of the former Korean government, which were to expand the nuclear and coal capacities.

However, the new government is targeting a phase-out of nuclear power and curtailment of coal-fired power generation, which will lead to an increase in the use of natural gas and renewable energy. The *13th Basic Plan for Long-term Natural Gas Supply and Demand* was released in April 2018 (MOTIE, 2018), showing an outlook from 2017 to 2031. The outlook shows an increasing trend in gas demand from 2025 compared to the flat trend of gas demand after 2025 in the 12th plan. This rising trend after 2025 is due to the new energy policy of the government. Although the new government announced a reduction in reliance on coal and nuclear energy, the effects of the new energy policy will not be evident until after the old coal and nuclear units are retired.

Figure 25. Korea's existing term contracts and gas demand outlooks



Sources: MOTIE (2015), *12th Basic Plan for Long-term Natural Gas Supply and Demand*; MOTIE (2018), *13th Basic Plan for Long-term Natural Gas Supply and Demand*, KEEI's own analysis.

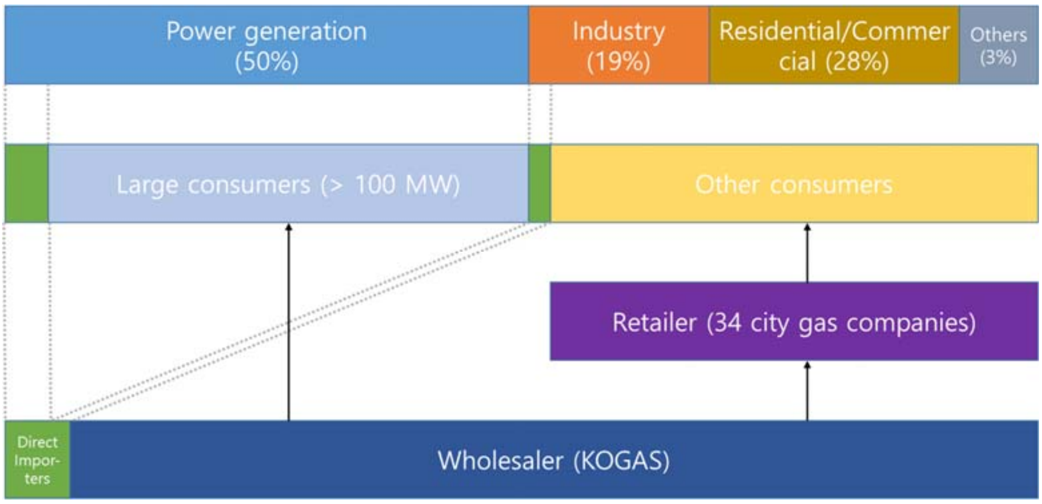
Gas market structure

KOGAS imports almost 90% of the LNG demand in the wholesale sector, and is the sole wholesale supplier providing gas to large-scale consumers and city gas companies. It is a dominant gas market player and a public corporation with over 50% ownership by the government and the Korea Electric Power Corporation (KEPCO). The Urban Gas Business Act grants exclusive selling rights to this one wholesaler, KOGAS, and 34 retailers. All city gas companies procure their gas from KOGAS, and consumers buy gas from city gas companies in their region. Large-scale consumers are those who own power plants larger than 100 megawatts (MW) and are eligible for a direct contract with KOGAS.

Large-scale consumers such as power producers and manufacturers are allowed to import LNG for their own use, and are collectively called "direct importers". LNG imports by direct importers are allowed for new gas demand only that is not committed to KOGAS supplies. The only eligible demand is that from newly commissioned facilities or that released from commitment due to termination or expiration of existing contracts with KOGAS.

Some companies have a waiver clause in contracts with KOGAS that enables them to import directly and to receive gas supplies from KOGAS. One of the subsidiaries of KEPCO has had such a mixed supply since 2015. The Urban Gas Business Act restricts sale of LNG imported by direct importers to other domestic consumers. However, importers can swap their directly imported LNG among the direct importers to offset fluctuations of their own LNG demand.

Figure 26. Structure of the gas market in Korea, 2015



Source: IEA (2017a), *Natural Gas Information* (database), www.iea.org/statistics/.

There are now eight direct importers. Four companies in the power, steel and petrochemicals sectors have been importing LNG since 2005, and an additional four players in the power and petrochemical sectors joined this group in 2017. More new direct importers are expected to enter the LNG import market in the near future, with the expansion of privately owned regasification terminals.

LNG importation by direct importers rose to 6.4% of the total demand in 2016, compared to 4.2% in 2014. It has been increasing since 2015 when the Korea Midland Power Corporation started to secure LNG through its ten year contract. There was a further increase at the start of 2017 due to new gas-fired power plants owned by SK E&S and GS EPS starting to generate electricity.

Direct importers must secure regasification and pipeline capacities to deliver gas to their own facilities. There are four regasification terminals owned by KOGAS and two privately owned by direct importers. However, direct importers use their own facilities for importation and storage of LNG. The first direct LNG import terminal started operation in Gwangyang in 2005. More recently, Boryeong LNG terminal started commercial operation in January 2017, unloading the first US shale gas cargo to Korea. The Urban Gas Business Act guarantees open access to the gas trunk lines owned by KOGAS for the direct importers. However, setting up fair TPA rules in terms of tariffs using gas trunk lines owned by KOGAS between KOGAS and direct importers is still being debated.

Reducing costs is the primary motivation for direct importation. It is possible for direct importers to import LNG cheaper than the gas supplied by KOGAS. This is because KOGAS imposes tariffs based on import costs, averaged over all the existing LNG contracts of KOGAS, mostly based on an oil-indexed pricing formula. However, direct importers need to meet their fluctuating demand by managing their LNG procurement portfolio.

LNG from the United States is attractive to direct importers because of the gas-on-gas pricing and destination flexibility. Direct importers can procure LNG at competitive prices when the HH-indexed LNG prices are lower than the oil-indexed LNG prices. Flexibilities in reselling, combined with free-on-board basis contracts, provide an important option for direct importers to manage their demand and supply balances and also provide opportunities for LNG trading businesses.

There are 34 regional city gas distributors in the retail sector, and these are registered as a monopolistic supplier. Retailers are granted concessions by local governments to supply gas in each administrative district. The gas distribution companies have exclusive retail rights within their regions, all of which are supplied by KOGAS. KOGAS also supplies gas directly to some power generating plants that are owned by power producers. There is limited direct competition among these companies, which maintain stable market shares. Therefore, there is no wholesale or retail competition due to the characteristics of the market structure in Korea.

Progress of market reform

The Korean government has attempted gas market reform since the late 1990s, to allow market competition among players and to lower the cost of LNG. The first part of the reform was to privatise and separate KOGAS into two groups: a sales group and a facilities group. KOGAS is the sole public corporation for managing imported gas and pipeline and storage facilities, and privatisation of KOGAS is considered necessary for market competition. However, the government's plan for privatisation of KOGAS failed because stakeholders such as the KOGAS labour union were reluctant to make changes.

Several bills have been proposed to remove the KOGAS monopoly on importing and reselling LNG, but none have yet been passed. For example, MOTIE submitted a bill to the National Assembly in 2009, calling for deregulation by 2010. This would allow companies to import LNG directly and resell the fuel to buyers, largely in the power sector. The 2009 bill also had a provision that required the state power company KEPCO to purchase 50% of the existing KOGAS take-or-pay contracts. The advantages and disadvantages of the gas market competition were fierce in the course of the 2009 legislation, but the 2009 bill was automatically terminated by the end of the term as the 18th National Assembly finished at the end of May 2012.

The Korean government allowed market players to import LNG for their own use only and not for sale to other domestic gas consumers. Some market players have imported LNG since 2006. Direct imports reached to more than 6% of the total demand in 2016, and it is expected that they will increase as long as the market condition is good and because of the increasing number of direct importers. Increasing competition in the wholesale market is an advantage of direct imports.

Direct importers claim that the tariff system for pipeline network access, designed and composed by the transmission system operator KOGAS, is unfair and non-transparent compared to that of large-scale gas consumers who are supplied gas directly from KOGAS. KOGAS provides a bundled service for gas buyers, mostly large-scale consumers such as the five KEPCO affiliated power generation companies, called GENCO.

Direct importers (as shippers) claim that they pay more tariffs and higher levels of penalties when they exceed the contracted capacity or volume than large-scale consumers. Direct importers, which are mostly private companies such as SK E&S and POSCO, are allowed to import LNG for their own use. The Korean government has tried to find a way to provide a non-discriminatory pipeline access service since 2016, and setting up a platform of fair TPA rule is ongoing.

The previous Korean government revived potential energy reforms to improve efficiency in the gas sector. MOTIE released a statement in June 2016, setting a target of 2025 for private companies to be able to import LNG and resell within the country. This would include a gradual opening of the gas wholesale market. According to the MOTIE statement, after 2025, wholesale competition among KOGAS and private companies would begin only for the volume beyond the KOGAS contracts remaining.

The reason for the government creating a competitive market from 2025 may be that new LNG volumes will need to be imported from 2025 when existing contracts expire. The plan was to create a wholesale market competition where importation and wholesale market competition will begin for LNG for power generation. However, this gas market reform was announced by the previous government, and no further action plans have been released. The new government has announced a new energy transition policy, but has not yet officially mentioned gas market reform.

Energy policy direction

The previous government planned to expand the country's nuclear and coal capacity. However, the new government has announced its intention to reduce the share of coal and nuclear power in the energy mix. It aims to transform the energy system of Korea into a safer and cleaner one, by promoting efficient energy utilisation on the demand side, and expanding renewable energy on the supply side, while phasing out nuclear and coal-fired power. This would lead to an increase in the use of natural gas.

The new government announced 100 policy tasks for the next five years in July 2017. The four policy tasks related to energy transition were: 1) exploring and developing environment-friendly future energy, 2) taking measures against particulate matters, 3) setting up a solid implementation system for a new climate regime and 4) energy transition to safe and clean energy.

Table 7 shows objectives of the four energy policy tasks. In the task of exploring and developing environment-friendly future energy, the measures include expanding the use of renewable energy, promoting new energy industry and improving energy efficiency. The government has set a target of increasing the share of renewables in power generation to 20% by the year 2030.

The government intends to reduce the number of coal-fired power plants to decrease particulate matter. Old coal-fired power plants have been temporarily shut down during spring time since 2017, and new construction will not be allowed. Coal-fired power plants over 30 years of age will be retired by 2022. Greenhouse gas emissions will be reduced by improving the emission trading system and by reforming the energy taxation system, in accordance with the 2015 Paris Agreement. The government intends to draw up a nuclear phase-out roadmap for transition to safe and clean energy, which is already reflected in the *8th Basic Plan for Long-term Electricity Supply and Demand* (MOTIE, 2017).

Table 7. Major energy policy tasks of the new Korean government

Task	Objectives
Exploring and developing environment-friendly future energy (# 37)	**Renewable energy:** Increase the share of generation by renewables to 20% by 2030 • Fixed price (system marginal price + renewable energy certificate price) contract; planned location system; spacing regulation improvement • Increase RPS (renewable portfolio standard) mandate to 28% by 2030 **New energy industry:** Establish eco-friendly and smart energy infrastructure; create IoE-based new businesses • Mandatory ESS (energy storage system) installation in public institutions by 2020; nationwide installation of smart meters **Energy efficiency:** Enhance demand-side management by sector; transform to a low-carbon and high-efficiency structure by promoting utilisation of unused energy sources • Adopt a Minimum Energy Performance Standard in 2018 for major industrial equipment; mandatory Zero Energy Building in the public sector; complete the Korea Heat Map by 2020

Task	Objectives
Measures against particulate matter (# 58)	**Power generation sector:** Reduce coal-fired generation • Temporary shutdown of eight old coal-fired plants in spring from 2017; prohibit new construction • Retire ten aged coal power plants over 30 years by 2022 **Industrial sector:** Strengthen emission controls in business places • Implement dust emission caps in business places; tighten emission allowances by at least 20% **Transport sector:** Reduce the diesel vehicle share and increase the eco-friendly vehicle share • Expand restricted areas for old diesel vehicles; subsidise early scrapping • Rapid deployment of eco-friendly vehicles such as EVs by 2020
Setting up a solid implementation system for a new climate regime (# 61)	**Sustainability:** Enhance sustainability of overall society and economy; enhance integrated conformity of climate, air and energy policies • Set up 2030 national goal, visions and implementing strategies for sustainable development in 2018 **Strengthen GHG abatement:** Restrict greenhouse gases emission increases by normalising the ETS • Unify an administrative process for the ETS (emission trading system) and draw up an emission allocation scheme in 2017 • Reform the energy taxation system and revise the 2030 GHS Abatement Roadmap in 2018 • Expand the Zero Energy Building; establish a greenhouse gases emission standard for larger vehicles; reduce emissions of public institutions by 30%; facilitate waste to energy, all by 2020
Energy transition to safe and clean energy (# 60)	**Establish a nuclear phase-out roadmap:** Reflect a nuclear phase-out plan for the basic electricity supply and demand plan including cancelling construction of six new nuclear reactors and prohibiting extension of old nuclear reactor operations **Tighten safety regulation of nuclear power:** Strengthen the stature and independence of the Nuclear Safety and Security Commission; modify the safety management system and consider strengthening seismic design criteria for nuclear power plants **Reform the energy taxation system:** Adjust relative tax rates for power generation fuels by reflecting social costs; improve the electricity-intensive structure by adjusting electricity tariffs for industrial use • Prepare an electricity tariff reform roadmap by 2019, for gradual rationalisation **Expand distributed generation:** Strengthen systematic support across all stages for distributed generation from licensing to rate making • Promote distributed generation including natural gas through reduction of reliance on nuclear power and coal

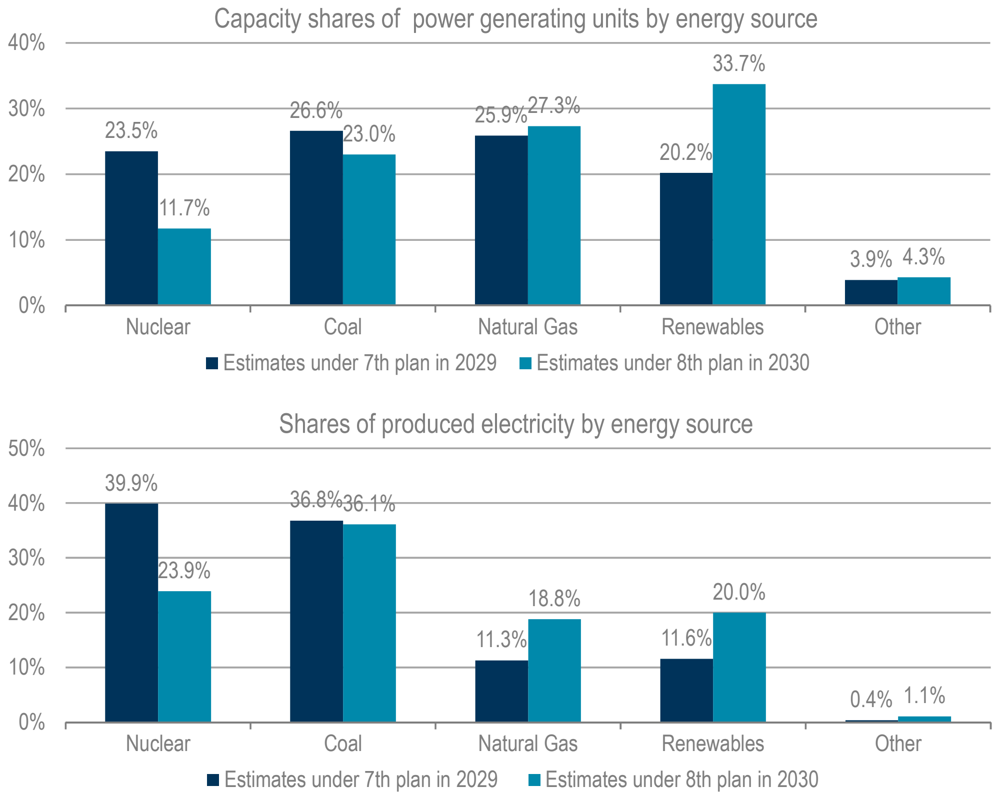
Source: Office for Government Coordination (2017), Five-Year Plan for National Affairs for Moon Jae In Administration.

The *8th Basic Plan for Long-term Electricity Supply and Demand* (MOTIE, 2017) reflects the new government's intention to reduce its reliance on coal and nuclear in the future energy mix. According to this plan, renewable energy will receive government support to meet the increased target of a 20% share of generation by 2030. LNG is also likely to benefit as a lower-emission fuel source and by replacing lost generation from coal-fired power plants during periods of suspension.

Figure 27 shows the effect of the new energy transition policy on the power generation mix by energy source. It compares the two different outlooks from the 7th and 8th plans, released in July 2015 and December 2017, respectively. The outlook of the *7th Basic Plan for Long-term Electricity Supply and Demand* (MOTIE, 2015) is for the period 2015-29 and the outlook of the 8th plan is for the period 2017-31. As the 8th plan reflects the new energy policy of the new government, the effect of the new energy transition policy on power generation mix by energy source is noticeable. The shares of natural gas and renewable energy in the power generation mix increase, but the shares of nuclear and coal power decrease, compared to the outlook in the 7th plan.

The capacity share of nuclear power is projected to reduce from 23.5% to 11.7%. The electricity produced by nuclear power units is also projected to reduce from 39.9% and 23.9%. Power capacity and electricity produced by coal is going to decrease. However, the shares of renewables and natural gas in the power mix are going to increase. The capacity share of renewable power is projected to increase from 20.2% to 33.7%. The capacity share of gas-powered units is projected to increase a little by 1.4% from 25.9% to 27.3%. However, the share of electricity produced by natural gas is projected to increase by 7.5%, from 11.3% to 18.8%.

Figure 27. Changes in shares based on the national plan for electricity in Korea



Note: The outlook of the 7th plan is for the period 2015-29 and the outlook of the 8th plan is for the period 2017-31. Under the new energy policy, the government is targeting 20% renewable power by 2030 in the power mix. Note there is a one year time disparity between the estimates in the 7th and 8th plans.

Sources: MOTIE (2015), *7th Basic Plan for Long-term Electricity Supply and Demand;* MOTIE (2017), *8th Basic Plan for Long-term Electricity Supply and Demand.*

Obstacles and challenges

A major constraint for developing the Korean natural gas market is the non-liberalised market structure. The Korean government has tried for gas market reform since the late 1990s, to allow market competition. However, the plan was unrealistic because many stakeholders, including the KOGAS labour union, were reluctant to make changes. KOGAS is the sole LNG wholesale supplier and importer of most LNG, so the number of market players is limited. There is no wholesale competition, so there is less incentive to reduce LNG import prices.

KOGAS and the Korean government have tried to reduce the costs of LNG importation. However, in a competition market, players may have more incentive to reduce import prices to maximise their profit. It is difficult for KOGAS to manage demand uncertainty in a domestic market as it has many long-term contracts with destination clauses. If the wholesale market competition opens up and trade is allowed among market players, it is possible that spot purchases may be increased to manage demand uncertainty.

Another constraint is the system of TPA rules. KOGAS owns and controls most gas facilities, thus the TPA rules including the tariff system need reform so that they are fair for all market participants. KOGAS provides bundling services to large-volume consumers that use its facilities. Prices for these are lower than the pipeline access prices imposed on small-volume direct importers under current TPA rules. Setting up fair TPA rules would be a first step for market players to create a platform of fair market completion.

China

China's natural gas market remains heavily regulated along the entire supply chain. The Chinese government has been attempting to switch from regulated pricing to market-based approaches since 2013.

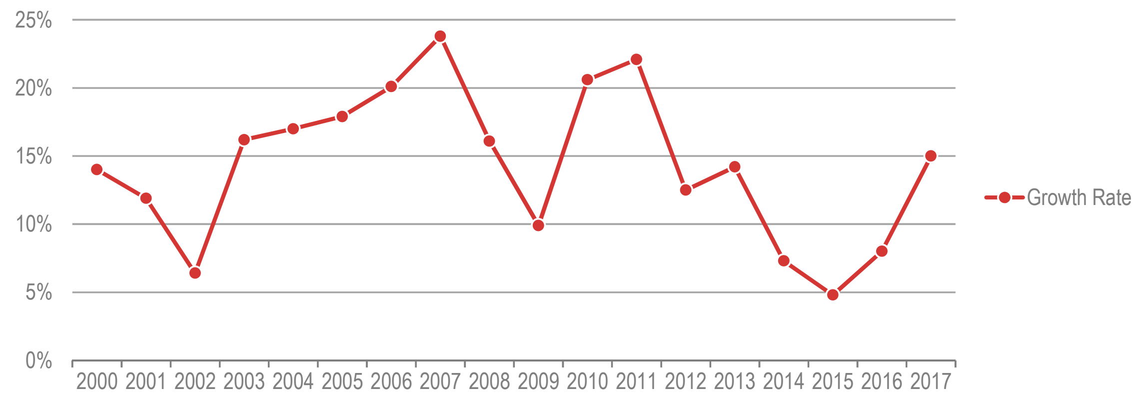
The Chinese government is trying to encourage consumers to use cleaner fuels. It has pledged to expand its share of natural gas in the primary energy consumption, under *The 13th Five-Year Plan for Natural Gas Development* (NDRC, 2017b) for the period 2016-20. This will be achieved by phasing out the use of coal by 2020. The Chinese government predicts it will expand its share of natural gas from 5.9% in 2015 to 8.3-10.0% by 2020. China consumed 237 bcm of natural gas in 2017, accounting for 7.0% of the primary energy consumption. This was 0.8% point higher than in 2016.

Chinese national oil companies recently experienced a gas supply shortage, due to a sharp increase in gas demand during winter 2017-18. Suppliers suffered economic losses by selling natural gas at prices below those of the imported gas because of Chinese gas price controls and the increase in gas demand. The price reforms passed in late 2016 introduced important elements of market-based price formation and tighter regulation of pipeline tariffs. The latest notice passed in August 2017 mentioned open and transparent trading of natural gas, but it will probably take a long time for the system to be fully liberalised.

Supply and demand

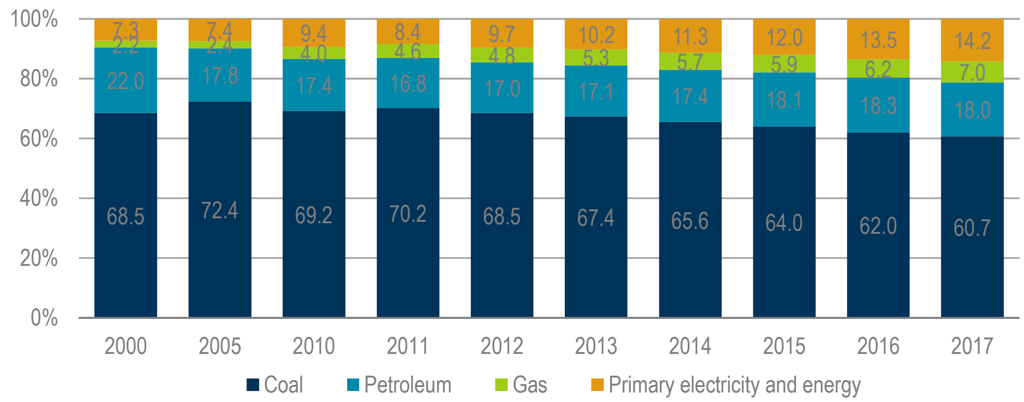
In 2017, China is the world's third-largest consumer of natural gas, behind the United States and Russia. It is expected to lead the world's natural gas consumption in the future. The China National Petroleum Corporation (CNPC) reported that Chinese natural gas consumption increased strongly at an average annual growth rate of 16% between 2000 and 2013, before slowing down in 2015 and 2016. The growth rate in 2015 was a ten-year low, which then increased slightly to 8% in 2016. However, the growth rate soared to 15% in 2017. The share of gas in the final energy consumption was still low (6.2%) in 2016 compared to that of other energy sources, but it has been increasing – it represented only 2.2% in 2000 (CNPC ETRI, 2017b).

Figure 28. China's natural gas consumption growth rate, 2000-17



Source: CNPC ETRI (2017b), *China Natural Gas Market Status and Outlook*, 2017 KEEI-CNPC ETRI Joint Workshop; NDRC (2018), *2017 Natural Gas Operation Profile.*

Figure 29. China's primary energy mix, 2000-17



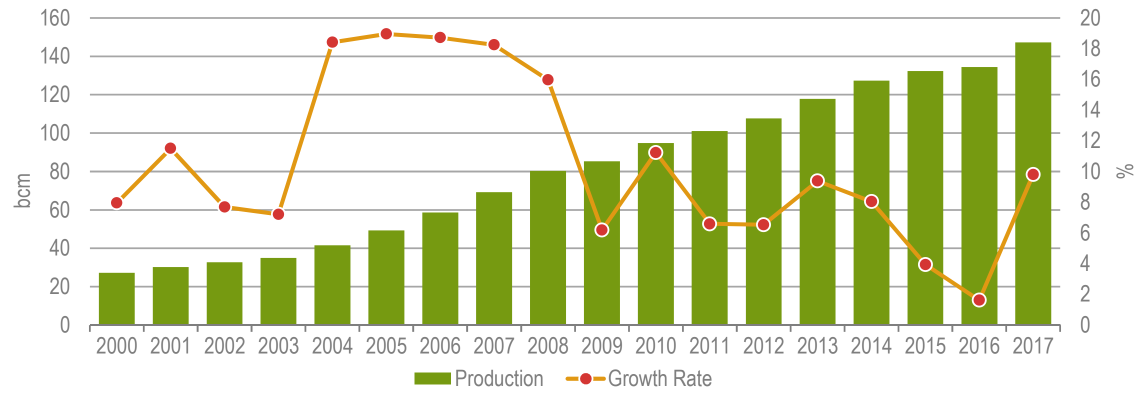
Source: CNPC ETRI (2017b), *China Natural Gas Market Status and Outlook*, 2017 KEEI-CNPC ETRI Joint Workshop.

Natural gas consumption in China in the first half of 2017 was 114.6 bcm. This was an increase of 15.2% compared with the same period in 2016 (NDRC, 2017d). It reached 237 bcm by the end of 2017, which was an increase of 15% compared with 2016 (CNPC ETRI, 2017a). The surge in natural gas consumption came at a time when the Chinese government was actively pursuing projects to replace coal-fired heating with natural-gas-fired heating and implementing policies to curb coal-fired power generation.

The amount of natural gas consumed and the areas that use natural gas have increased due to the development of technologies to save energy and improve efficiency, including combined cooling, heating and power. The Chinese government plans to increase its share of natural gas in the primary energy consumption to 10% by 2020 and to 15% by 2030, up from 7% in 2017 (NDRC, 2017a).

China's natural gas production has been increasing strongly since 2000. Production reached 134.4 bcm in 2016 and 147.3 bcm in 2017, which was the sixth-largest in the world, after the United States, Russia, Iran, Qatar and Canada. China quintupled its gas production over the period 2000-17, which has enabled huge growth in domestic consumption (Figure 30). The main natural gas production areas are Tarim, Shaanxi-Gansu-Ningxia, Sichuan and Qinghai, which produced 83.2% of the total in 2016 (National Energy Agency, State Council and Ministry of Land and Resources, 2017).

Figure 30. China's natural gas production and growth rate, 2000-17

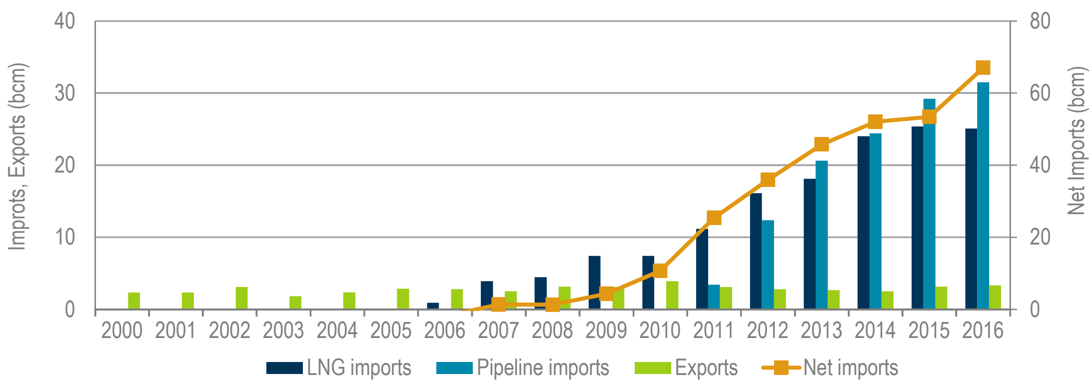


Source: CNPC ETRI (2017b), *China Natural Gas Market Status and Outlook*, 2017 KEEI-CNPC ETRI Joint Workshop.

China has been importing LNG since 2006 and pipeline natural gas (PNG) since 2009. Before 2000, most natural gas was consumed in adjacent production fields, such as in Sichuan, due to a shortage of inter-regional pipelines. Natural gas consumption expanded to the eastern part of the country with the construction of the West-East gas pipeline and the Shaanxi-Beijing gas pipeline.

China's natural gas imports reached 94 bcm in 2017, which were the fourth-largest in the world after Japan, Germany and the United States. The natural gas import volume has exceeded the natural gas export volume since 2007. Around 43.7% of natural gas imports to China in 2016 was imported in the form of LNG (from Australia, Qatar, Indonesia and Malaysia), while the remainder was delivered by pipeline (from Turkmenistan, Uzbekistan, Myanmar and Kazakhstan). The Chinese government has been seeking to develop gas pipeline infrastructure for diversification of gas import sources. The import volume by pipeline has exceeded the import volume as LNG since 2013.

Figure 31. China's export and import trends, 2000-16



Source: CNPC ETRI (2017b), *China Natural Gas Market Status and Outlook*, 2017 KEEI-CNPC ETRI Joint Workshop.

LNG imports have rapidly increased since 2016 as a result of rising natural gas consumption. China has constructed new LNG terminals and expanded existing terminals to cover the increasing demand. In 2016, Jiangsu Rudong and Liaoning Dalian terminals completed expansions to cover an additional 3 million tonnes per annum (Mtpa) respectively.(IGU, 2017) China had nine projects under construction in 2017 and the trend continues throughout the year 2018-9.

China was the world's fifth-largest regasification market by capacity at the beginning of 2017, increasing from 6 Mtpa in 2008 to almost 65 Mtpa in the end of 2018. Currently, the China National Offshore Oil Corporation (CNOOC) owns about half of the existing LNG terminals. CNOOC completed two LNG terminals in between 2017-18, and they have started operations. Three additional LNG terminals that started operation in the same period include Qidong Terminal (Guanghui), Tianjin Nangang (Sinopec), and Zhejiang Zhoushan (ENN).

Table 8. China's main LNG terminals

	Terminal name	Nameplate capacity (Mtpa)	Owners	Start year
1	Guangdong Dapeng LNG I	6.8	Local companies 37%; CNOOC 33%; BP 30%	2006
2	Fujian Putian	5.0	CNOOC 60%; Fujian Investment and Development Co. 40%	2008
3	Shanghai Yangshan	3.0	Shenergy Group 55%; CNOOC 45%	2009
4	Liaoning Dalian	6.0	CNPC 75%; Dalian Port 20%; Dalian Construction Investment Corp. 5%	2011
5	Jiangsu Rudong LNG	6.5	PetroChina 55%; Pacific Oil and Gas 35%; Jiangsu Guoxin 10%	2011
6	Guangzhou Dongguan LNG	1.5	Jovo Group 100%	2012
7	Zhejiang Ningbo	3.0	CNOOC 51%; Zhejiang Energy Group Co. Ltd 29%; Ningbo Power Development Co. Ltd 20%	2013
8	Guangdong Zhuhai LNG (CNOOC)	3.5	CNOOC 30%; Guangdong Gas 25%; Guangdong Yuedian 25%; local companies 20%	2013
9	Hebei Tangshan Caofeidian LNG	3.5	CNPC 51%; Beijing Enterprises Group 29%; Hebei Natural Gas 20%	2013
10	Tianjin	2.2	CNOOC 100%	2013
11	Hainan Yangpu LNG	2.0	CNOOC 65%; Hainan Development Holding Co. 35%	2014
12	Shandong Qingdao LNG	3.0	Sinopec 99%; Qingdao Port Group 1%	2014
13	Guangxi Beihai LNG	3.0	Sinopec 100%	2016
14	Guangdong Shenzhen (Diefu) (CNOOC)	4.0	CNOOC 70%; Shenzhen Energy Group 30%	2018

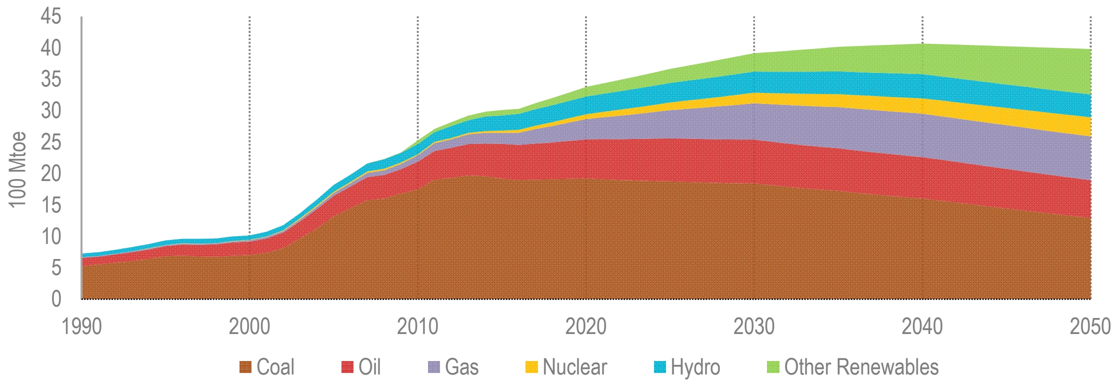
	Terminal name	Nameplate capacity (Mtpa)	Owners	Start year
15	Qidong	1.15	Guanghui (100%)	
16	Tianjin (Sinopec) Phase 1	3.0	Sinopec 100%	2018
17	Guangdong Yuedong LNG	2.0	Shenergy 55%; CNOOC 45%	2017
18	Guangdong Shenzhen (CNPC)	3.0	CNPC 51%; CLP 24.5%; Shenzhen Gas 24.5%	2019 (expected)
19	Fujian Zhangzhou	3.0	CNOOC 60%; Fujian Investment and Development Co 40%	2020 (expected)
20	Zhejiang Zhoushan (ENN)	3.0	ENN Energy 100%	2018

Note: Expansion projects under construction at existing terminals are not included in nameplate capacity.

Source: IGU (2017), *IGU World LNG Report*, ICIS (2018), ICIS LNG Edge, www.icis.com/energy/liquefied-natural-gas/lng-edge (subscription required).

One long-term prospect is that the share of natural gas in the primary energy consumption will surpass that of petroleum by 2037 and reach 17.6% by 2050, according to the *World and China Energy Outlook 2050* (CNPC ETRI, 2017c). The share of coal consumption is predicted to decrease from 65.6% in 2014 to 32.4% in 2050, while that of clean energy[1] is expected to increase to 52.5% by 2050, due to the coal-reduction policy.

Figure 32. China's primary energy consumption structure, 1990-2050



Source: CNPC ETRI (2017c), *World and China Energy Outlook 2050*.

China's gas demand is expected to rise from 198 Mtoe in 2016 to 543 Mtoe in 2040 , according to the *World Energy Outlook New Polices Scenario* (IEA, 2018c). This will make it the world's second-largest consumer behind the United States. The increase of 297 Mtoe by 2040 represents around a quarter of global demand growth, and results in a doubling in the share of gas in China's energy mix, from under 6% in 2016 to over 12% in 2040. Growth is mostly driven by the industrial sector (in particular, light industries), which accounts for 38% of the total growth, and the power sector, which accounts for over 30%. The residential sector is the third-largest contributor (more than 12%) to natural gas growth as gas use expands primarily for space and water heating in eastern parts of China.

[1] Clean energy covers gas, nuclear, hydro and renewable energy.

Table 9. China's primary energy demand outlook, 2000-40

	2000 (Mtoe)	2016 (Mtoe)	2020 (Mtoe)	2025 (Mtoe)	2030 (Mtoe)	2035 (Mtoe)	2040 (Mtoe)	2016-40 Change (Mtoe)	2016-40 CAAGR* (%)
Coal	668	1 957	1 932	1 908	1 873	1 803	1 706	-251	4.60
Oil	227	552	613	676	711	716	716	164	5.30
Gas	23	172	234	309	374	428	469	297	5.30
Nuclear	4	56	102	166	218	261	287	231	3.80
Renewables	220	269	318	380	455	534	619	350	4.70
Total	**1 143**	**3 006**	**3 199**	**3 439**	**3 631**	**3 742**	**3 797**	**791**	**1.00**

* Compound average annual growth rate.
Source: IEA (2017c), *World Energy Outlook*.

Gas market structure and pricing reform

Three national oil companies (CNPC, Sinopec and CNOOC) control almost all production and transmission in China.

CNPC is a state-owned enterprise founded in 1988, and has dominated the gas industry and market since then. It produces around 72% of the domestic natural gas production. It currently operates five LNG terminals and around 80% of the nationwide pipeline network such as the West-East gas pipeline.

The West-East gas pipeline (4 200 km) was constructed in 2005 with a capacity of 17 bcm/year. Lines A and B of the Central Asia-China pipeline (1 800 km) have been operating since 2010. This pipeline connects Turkmenistan and China via Uzbekistan and Kazakhstan. The Qinhuangdao-Shenyang gas pipeline was constructed in 2011 to prepare for connection of the gas network between China and Russia. Line C of the Central Asia-China pipeline became operational in 2014. Imports from Central Asia through the Central Asia-China gas pipelines can amount to 30 bcm/year from Turkmenistan. Imports from Turkmenistan reached 25.5 bcm in 2014, compared to 3.5 bcm in 2010.

Sinopec is China's largest oil refining and petrochemical company and the largest offshore gas producer in China. It was founded in 1998, and produced around 21 bcm of natural gas in 2015. Sinope also operates several pipelines. A 1 655 km long pipeline began operation in 2010 between Sichuan and Shanghai. Sinopec has three LNG terminals (Shandong Qingdao LNG, Guangxi Beihai LNG and Tianjin Phase 1).

CNOOC is the third-largest national oil company in China, after CNPC and Sinopec, and was founded in 1982. CNOOC focuses on the exploration and development of natural gas offshore. It produced around 14.5 bcm of natural gas in 2015, and has capacities in twelve operating LNG terminals.

Natural gas consumption has increased due to transformation of the energy consumption structure to implement a carbon emissions reduction target, and the import volume has increased accordingly. Reform of city-gate prices was determined based on domestic production using a cost-plus-profit margin until 2013. This system caused the selling price to be set at less than the import price as natural gas demand increased. Natural gas imports have therefore declined, and several cities have suffered serious gas supply shortages.

China introduced a new pricing approach for onshore piped gas linked to the import costs of oil products after a two-year trial period in Guangdong and Guangxi provinces. Most provinces had switched to city-gate price ceiling systems linked to the Shanghai city-gate price by April 2015. The Shanghai city-gate price was determined based on liquefied petroleum gas and fuel oil import prices, plus transmission costs. The Shanghai city-gate price calculation also involved a fixed discount rate for the promotion of natural gas usage, which was used by the Chinese government as a tool to influence the market.

The price reforms passed in late 2016 introduced important elements of market-based price formation and tighter regulation of pipeline tariffs. However, it seems likely that it will a take long time for the system to be fully liberalised. About half of the gas consumed in China does not have any price regulation. This includes LNG, unconventional gas (shale gas, coalbed methane (CBM) and synthetic gas), gas sold to the fertiliser industry and gas purchased directly from national oil companies by end users (mostly large industrial facilities).

Residential gas consumers, accounting for a little less than one-fifth of China's gas use, pay prices regulated by the National Development and Reform Commission (NDRC) with preferential rates. Prices for non-residential gas consumers that are not large enough to buy gas directly and which depend on existing production or import pipeline gas are partially regulated. This consumer group accounts for about 30% of Chinese gas consumption. Partial regulation means that the NDRC sets a benchmark city-gate price, but buyers and sellers can negotiate a price either lower than the benchmark or up to 20% higher. City-gate benchmark prices include pipeline tariffs and are therefore generally higher than import prices for LNG or pipeline gas.

China is expected to introduce more gas-on-gas competition as natural gas trading hubs are established in Shanghai and in Chongqing. The *Notice on Non-residential Natural Gas Reference Gate Station Price* (NDRC, 2017c) mentioned open and transparent trading of natural gas. Domestic gas consumers and producers all have important interests in gas reform.

Low gas prices encourage growth in gas demand and help to improve air quality by replacing fuels such as coal and oil that produce more pollutants. However, domestic gas prices at LNG import price levels are currently insufficient to stimulate much upstream activity, especially for unconventional gas. China has strategic reasons to develop unconventional gas. These include improving domestic welfare, developing a major indigenous energy resource, providing energy security and achieving long-term competitiveness with the aim of gaining experience and gradually reducing production costs.

Table 10. History of China's gas pricing reform

Time	City-gate prices (RMB)	Reform
2013	Average: Existing: 2.09 Incremental: 2.96	Regulation from wellhead to city-gate. • 0.4 RMB/m3 price cap for existing gas. • Incremental gas prices linked to alternative fuels
2014	Average: Existing: 2.47 Incremental: 2.96	Existing gas city-gate prices increased by 0.4 RMB/m3.
April 2015	Average: Existing: 2.51	Two prices converged. • Incremental gas city-gate prices decreased by 0.44 RMB/m3. • Existing gas city-gate prices increased by 0.04 RMB/m3.

Time	City-gate prices (RMB)	Reform
November 2015	Average: Existing: 2.09 (lower by 16.7%)	
November 2016	Negotiable city-gate prices with fertilizer producers City-gate prices liberalization trials in Fujian	Non-residential city-gate prices decreased by 0.7 RMB/m3. Negotiable non-residential city-gate price within price caps since November 2016 (20% higher than the base prices)
August 2017	The notification of lowering non-residential city-gate prices	Non-residential city gate prices were lowered by 0.1 RMB/m 3 since September 2017

Note: RMB = Renminbi (Yuan)

Source: CNPC ETRI (2017b), *China Natural Gas Market Status and Outlook*, 2017 KEEI-CNPC ETRI Joint Workshop.

Chinese government is scheduled with the plan to create a new entity who will own and operate the national pipeline network, and will be responsible for future investment decisions. The entity is to aggregate the assets which are currently owned and operated by the aforementioned main NOCs, -- Petrochina, Sinopec and CNOOC.

New energy policies

The 13th Five Year Energy Development Plan (2016-20)

The Chinese government announced it will adjust the energy mix during the period 2016-20 under *The 13th Five Year Energy Development Plan* (NDRC, 2017e). It will do this by reducing China's dependence on coal and increasing its share of natural gas in the primary energy consumption. The government adopted its position in a directive promoting the use of clean energy across China.[2]

The plan was to actively replace coal with natural gas and thereby expand the share of natural gas in the primary energy consumption from 5.9% in 2015 to 8.3-10.0% in 2020. The government's target for the natural gas supply rate in urban areas is to increase it from 42.8% in 2015 to 57.0% in 2020. The NDRC has established a policy for supplying and expanding the use of clean energy for heating, especially in the northern part of China. The policy aims at using natural gas for heating by lowering the gas price for such use. The consumption of natural gas must increase by at least 15% each year to achieve the natural gas expansion target of 10.0% of primary energy consumption by 2020. The growth rate for the period 2015-17 was 25.3%, signalling a good start to achieving the target.

Table 11. China's key natural gas indicators, 2015-20

Indicator	2015 (achieved)	2020 (planned)	Average annual increase (%) (2015-20)
Portion of primary energy consumption (%)	5.9	8.3-10.0	-
Gas supply in urban areas* (%)	42.8	57.0	-
Accumulated proven gas reserves (conventional gas, × 10^4 bcm)	1.3	1.6	4.3

[2] NDRC announced a *Notice on Opinion of Accelerating the Utilization of Natural Gas* (NDRC, 2017a) to achieve the natural gas supply objective presented in the *Action Plan on Prevention and Control of Air Pollution* (State Council of China, 2013), *Energy Development Strategy Action Plan* (NDRC,2014) The 13th Five-Year Plan for Natural Gas Development(NDRC, 2017b) and *The 13th Five Year Energy Development Plan* (NDRC, 2017e).

Indicator	2015 (achieved)	2020 (planned)	Average annual increase (%) (2015-20)
Total production (bcm/year)	135	207	8.9
Length of pipeline (× 10^4 km)	6.4	10.4	10.2
Pipeline transportation capacity (bcm/year)	280	400	7.4
Underground storage tank capacity (bcm)	5.5	14.8	21.9

* Gas supply in urban areas (%) = (non-farming population in urban areas using natural gas) / (overall non-farming population in urban areas) × 100.

Source: NDRC (2017b), *The 13th Five Year Natural Gas Development Plan*.

The Chinese government has attempted to expand the use of natural gas, to meet the target by 2020. As a result, China consumed 237 bcm of natural gas in 2017, an increase of 15.0% from 2016 and an increase of 25.3% from 2015. Natural gas accounted for 7.0% of the primary energy consumption in 2017, 0.8 and 1.1 percentage points higher than the 2016 and 2015 values, respectively. Natural gas production was 147 bcm in 2017, rising about 10% above the 2016 level and 12% above the 2015 level. This was higher than the expected average annual increase during 2015-20.

The increase of gas production was mainly due to exploration activities in the Tarim Basin, Sichuan Basin and eastern South China Sea. The pipeline length was 68 000 km in 2016, an increase of 6.3% compared to the 64 000 km in 2015. However, the gas storage tank capacity (10 bcm) in 2017 was only 3.6% of the natural gas consumption. The storage tank capacity was about 3.0 bcm higher than that in 2015 and the average annual increase for 2015-17 was about 24%, above the expected average annual increase. But the 3.6% storage capacity was still below the appropriate level of 10-15% to deal with peak demand during winter time (National Energy Agency, State Council and Ministry of Land and Resources, 2017; CNPC ETRI, 2017d).

Plan to supply and expand natural gas use

The Chinese government presented *Opinions on Petroleum and Natural Gas Reform Advancement* (State Council, 2017) to develop the natural gas industry and increase energy utilisation, and it is establishing and implementing plans[3] for each sector.

System improvement and market reform

The Chinese government decided to simplify and optimise administrative procedures for increasing regional and industrial gas consumption while providing a better support system in the gas industry. It will give priority to distribution of carbon emissions quota to companies that use natural gas as a fuel or raw material in industries such as petrochemicals, steel, non-ferrous metal, paper manufacturing and construction materials. The government introduced a carbon emission trading system in seven pilot areas in 2016 and established a plan to open a nationwide unified market (Beijing Institute of Technology Center for Energy and Environmental Policy, 2017).

[3] An implementation plan is summarised based on The 13th Five-Year Plan for Natural Gas Development (NDRC, 2017b), the Notice on Opinion of Accelerating the Utilization of Natural Gas (NDRC, 2017a) and the China Natural Gas Development Report 2017 (National Energy Agency, State Council and Ministry of Land and Resources, 2017).

To establish a fair gas market environment, the government will enhance management and supervision of areas such as market entry and exit, trading, monopoly, tax, pricing and environmental protection, whilst providing a fair and transparent management and supervision system. The government therefore plans to encourage a nationwide natural gas spot market so that the natural gas trade reflects major market elements such as changes in supply and demand, prices of alternative energy and seasonal factors. The government also plans to complete a gas pricing system as soon as possible and set reasonable residential gas prices so that a duplicate subsidy on residential and non-residential gas prices can be avoided.

China will promote gas liberalisation in the power generation and industrial sectors. It will also improve gas price competitiveness in the power generation sector by switching gas pricing to an electricity price indexed system and by implementing financial support in some regions. China plans to alleviate the entry threshold for privately owned enterprises to the upstream and infrastructure sector in the gas industry. It also plans to force local governments to strengthen management and supervision in the usage tariff of gas pipeline and gas supply prices within the country.

The government expects to allow TPA to LNG import terminals and gas pipelines by introducing pilot areas in Sichuan, Chongqing, Xinjiang, Guizhou, Jiangsu and Shanghai. China will also strengthen supervision in price increases to avoid collusion among suppliers or unfair practices such as high-pressure sales and monopolies. The government will allow pipeline service providers to take profits only from the gas transport process, while prohibiting them from selling natural gas, by separating gas transport and sales.

Improvement in exploration, development and production capacity

The 13th Five Year Energy Development Plan (NDRC, 2017e) presents a strategy on “off-shore and on-shore, conventional and unconventional gas joint development.” The Chinese government will encourage diversification of activities in exploration, development and production of four gas production sites: Tarim, Ordus, Sichuan and Southern Offshore.

The government’s target is to increase domestic gas supply (including imports) to 360 bcm/year. It will therefore expand the supply capacity by developing proven gas reserves, shale gas and CBM by 2020. The target is to increase the size of aggregate proven reserves in natural gas (to 16 000 bcm), shale gas (to 1 500 bcm) and CBM (to 1 000 bcm) by 2020. This will be achieved by acquiring new reserves in natural gas (3 000 bcm), shale gas (1 000 bcm) and CBM (420 bcm). Shale gas and CBM are expected to play a central role in this growth.

China will support the development of core technologies related to unconventional gas development. The government is also planning to conduct demonstration projects in coal gasification.

The government also plans to encourage participation from qualified companies in exploration and development by removing entry barriers in oil and gas fields. The country will strengthen financial funding in the exploration and development of oil and gas fields and complete subsidy policies on deep water, shale gas and CBM development.

Diversification of gas import sources

China is expanding a PNG transport network that connects Russia and Central Asia with the Chinese mainland. This is to aid diversification of gas import sources while expanding LNG import volumes from the United Sates.

China's CNPC and Russia's Gazprom came to an agreement in 2017 to determine the commencement date of gas supply via the East pipeline (Sila Sibiri) through which Russian gas will be exported to China (Fianz, 2017). According to this agreement, China will receive 38 bcm/year of Russian PNG for 30 years via the Sila Sibiri pipeline from 20 December 2019. China has conducted a PNG import project via the Russian western pipeline project (Sila Sibiri-2, also called the Altai Gas pipeline), the existing Sakhalin-Khabarovsk-Vladivostok gas pipeline and the Sila Sibiri PNG pipeline. CNPC made a supply agreement (30 bcm/year for 30 years) to import PNG via the western line in May 2015, but it did not come to a final agreement until November 2017. It is uncertain if China will finally proceed with the PNG project via the Russian western pipeline and the existing Sakhalin-Khabarovsk-Vladivostok gas pipeline.

China is constructing pipeline D in Central Asia, in addition to existing gas pipelines A, B and C, to ensure continuous PNG supply through a natural gas co-operation with Central Asian countries (Turkmenistan, Uzbekistan and Kazakhstan). Gas pipeline D will connect Turkmenistan with China via Uzbekistan, Kazakhstan, Kirgizstan and the Ucha region in Xinjiang. Its annual transport volume will be about 30 bcm, and construction will be completed during the 14th five year plan period of 2021-25.

Expansion of the gas transport network

China will expand a gas transport network for domestic gas fields, production sites and local demand during the period of the 13th five-year plan. China plans to extend the total length of pipelines to 104 000 km, with a new construction of 40 000 km to increase the domestic gas supply to 360 bcm/year by 2020.

The Chinese government also plans to strengthen financial support to infrastructure and private investment. It will introduce a method based on public-private partnerships to build infrastructure and encourage local governments to provide adequate financial support for local circumstances. The financial support at the state level will be based on different policies such as loans, funds, security and bonds. The government will push ahead the financial support first in severely polluted regions such as Jingjinji, Shanxi and Shandong.

Table 12. China's major gas transport network expansion plan to 2020

	Section	Length (km)	Diameter (mm)	Capacity (bcm/year)
1	West 3 lines*	3 807		
	East section (Ji'an-Fuzhou)**	817	1 219/1 016	15
	Mid section (Zhongwei-Ji'an)	2 062	1 219	30
	Fujian-Guangdong-Trunk, branch pipeline	575	813	5.6
	Zhongwei-Jingbian Trunk, branch pipeline	353	1 219	30
2	West 4 lines (Yining-Zhongwei)	2 431		
	Yining-Turpan section	760	1 219	30
	Turpan-Zhongwei section	1 671	1 219	30
3	West 5 lines (Wuchi-Zhongwei)	3200		
	Wuchi-Lianmuqin section	1 495	1 219	30
	Lianmuqin-Zhongwei section	1 705	1 219	30
4	Central Asia D line (including exterritorial section)	1 000	1 219	30

	Section	Length (km)	Diameter (mm)	Capacity (bcm/year)
5	Shanjing 4 lines (Jingbian-Beijing)	1 274	1 219	30
6	China-Russia Eastern lines			
	Heihe-Chang ling (including Changchun branch pipeline)	737/115	1 422/1 016	38
	Chang ling-Yongqing	1 110	1 422/1 219	15
	Anping-Taian	321	1 219	20
	Taian-Taising	715	1 219	20
7	Chushung-Panzhihua pipeline	186	610	2
8	Xinjiang Coal gas transport pipeline	8 972	1 219/1 016	30
9	Ordus-Anping-Changzhou pipeline	2 422	1 219/1 016	30
	Fuyang-Baoding, Trunk, branch pipeline	443	1 016	10
10	Qingdao-Nanjing pipeline	553	914	8
11	Eastern Xichuan gas pipeline (double track)	550	1 016	12
12	Mengxian coal gas exterritorial pipeline	1 200	1 219	30
13	Chongyuehaikeu-shuwon pipeline	265	914	10
14	Qingjiang natural gas pipeline	1 140	610	1.27
15	Chongqing-Guizhou-Guanxi pipeline	780	1 016	10
16	Guanxi LNG auxiliary pipeline**	1 106	813/610	4
17	Tianjin LNG auxiliary pipeline**	475	1 016/813	4
	Wuqing-Tongzhou branch pipeline	56	711	3
18	Shenzhen LNG peak control terminal auxiliary pipeline	65	813	10.7
19	Tangsan LNG terminal transport pipeline (double track)	161	1 219	20
20	Weiyuan-Longchang-Nanchuan-Fuling	440	711/813/1 016	5/6/8

Notes: * West 3, 4 and 5 lines transport gas from the western region to the eastern region; ** refers to a section under construction.
Source: NDRC (2017b), The 13th Five-Year Plan for Natural Gas Development.

The Chinese government encourages private participation in expansion of the gas transport network, and plans to strengthen management and surveillance. It plans to accelerate pipeline construction to supply gas to the Jingjinji region (Beijing, Tianjin and Hebei), to finish the gas pipeline development plan in the Changjiang Economic Zone[4] and to improve the gas supply capacity to major cities.

The government is expected to first develop the transport network around regions with a high gas demand, then construct a network that connects major cities[5] and build underground gas storage. It will also continue to construct gas pipelines to transport natural gas generated by CBM, shale gas and coal gasification.

[4] The Changjiang Economic Zone refers to an economic bloc around Changjiang comprising the regions Shanghai, Jiangsu, Zhejiang, Anhui, Jiangxi, Hubei, Hunan, Chongqing, Xichuan, Yunnan and Guizhou.
[5] There are four main network that connects major cities; North-West channel: construct the 3 lines, 4 lines and 5 lines on the West-East gas pipeline, Central Asia pipeline D; North-East channel: construct gas pipelines in the eastern section between China and Russia; South-West channel: construct branch pipelines to supply gas to Yunnan, Guizhou, Guangxi and Xichuan via the China-Myanmar gas pipeline; Offshore channel: construct LNG terminal infrastructure.

Construction of storage facilities

The government plans to construct gas storage facilities to expand the gas supply capacity and also strengthen gas peak control in city areas. Underground gas storage facilities will be connected to LNG terminals to form a gas transport network.

The government projects that the size of the underground storage facilities will increase to 14.8 bcm by 2020. This will be achieved by expanding the capacity and strengthening new construction, with a focus on eight gas storage terminals in Jingjinji, the North-West, the South-West, the North-East, the Yangtze River Delta, the Central South-West, the Central South and the Pearl River Delta. The government will construct LNG terminals to improve connection capacity and strengthen peak control in high-demand regions such as the Bohai Gulf area, the Yangtze River Delta and the South-East coast area. It will also establish LNG bunkering infrastructure at ports in key regions, and promote LNG conversion of marine fuel.

The Chinese government promotes construction of gas storage facilities for peak control, as well as clarifying the obligations and responsibilities of gas supply companies and pipeline operators for construction of such facilities. The country is preparing for supply disruptions at peak load by expanding reconstruction and new construction of underground storage tanks and by installing storage tanks and peak control facilities in LNG terminals in coastal areas.

The government plans to implement management and supervision of responsibilities in gas storage and peak control and of contracts for the purchase of natural gas (direct purchase), and will withdraw gas companies with small-scale capacity or a lack of supply capacity.

Promotion of natural gas utilisation

The government carries out gas supply promotion projects for the residential, commercial, power generation, industrial and transport sectors, to promote the use of natural gas.

The government plans to promote the use of natural gas for heating energy and to expand gas supplies to small cities and rural areas in the northern region, in the residential and commercial sectors. Major urban regions where air pollution is serious, in the Jinjian region and surrounding areas, will be converted to city gas or renewable energy within the five years from 2016.

The government also has a plan to support installation of gas facilities in regions with urbanisation construction projects and replacement of old gas pipelines and new constructions in rural areas. It plans to construct small LNG storage tanks to enhance city gas supply, while building compressed natural gas, LNG and liquefied petroleum gas storage and transport facilities to enhance gas supply capacity in rural areas.

The government plans to increase the share of power generation facilities to 5% by expanding its gas power generation facilities to 110 gigawatts by 2020 in the power generation and industrial sectors. It has a plan to develop new power supply structures such as smart grids and microgrids by building a combined heat and power plant as a distributed power source. It also plans to improve power supply safety by promoting power generation demonstration projects that combine renewable energy and natural gas. In high-pollution fuel-regulated areas, the government plans to substitute gas boilers for industrial coal boilers of 20 ton of steam per hour less and to prohibit use of fuels such as coal, heavy oil and petroleum coke in new industrial boilers.

The government is expanding the use of natural gas in public ground transportation, freight logistics and shippping fuels, and it is promoting the replacement of diesel automobile fuel by natural gas in key air pollution prevention areas such as Jingjinji. The target is to have more than ten million gas-fuelled vehicles by 2020, and the installation target is more than 12 000 gas stations for vehicles and 200 gas stations for ship by 2020.

Obstacles and challenges

China's natural gas market has been developing rapidly. Natural gas consumption has surged, and the country has become the second-largest natural gas consumer in the world. The Chinese government has been expanding the use of natural gas, to meet the 2020 target given in the 13th five year plan.

The supply line has diversified, and now includes conventional and unconventional gases, coal and gas imports. Stable supply of natural gas has become possible due to construction of natural gas infrastructure such as pipelines.

China is accelerating the pace of natural gas market reform in many aspects. The government may need to encourage more players to participate in exploration and development in the upstream sector and to increase the number of market players so that the rising natural gas demand can be met.

Natural gas market reform is under way, and market players are expected to ease entry barriers at each stage of the industry's value chain. The Chinese government may need to consider establishing supporting policies, to encourage players to enter the market. It should also set up fair and transparent TPA rules for third parties to have access to natural gas infrastructure such as pipelines and gas storage facilities. Establishing a system where the prices of natural gas are determined based on market supply and demand with increased market participants and natural gas trading hubs is also important for market development.

China is expected to put an end to its oligopolistic system of a few state-owned enterprises by introducing market competition into its energy policy. A wide range of market players are therefore expected to enter the natural gas market. A natural gas pricing system will be established based upon market transactions. Development of methods to strengthen fair monitoring of the market will be necessary to create an environment where market players can enter the market and trade natural gas among players, with no restrictions.

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Transitions in pricing mechanisms and their impact on LNG contracts

This chapter assesses developments in global natural gas pricing mechanisms and their impact on LNG contracts for major Asian LNG importers. Analysis is conducted by comparing pricing mechanisms in Asia with those of other regional markets.

Natural gas pricing mechanisms

Natural gas prices are determined according to diversified pricing mechanisms that vary from one country or region to another, usually according to the maturity of the market. Natural gas is typically priced at netback indexation on the specific competing fuel, to reflect its competitiveness, when introduced as a substitution for other fuels and in the absence of a domestic liquid trade market (Box 3). This is usually related to crude oil or oil products, and commonly followed in places where the natural gas market is under development.

Pricing is determined based on the fundamentals of supply and demand, once the natural gas market becomes established and the market framework develops to accommodate for competition. This is referred to as gas-to-gas competition pricing. The resulting price is regulated when domestic natural gas production is used in developing countries, where governments regulate the prices of commodities and market competition is not sufficiently mature. The price may also be calculated based on the cost of service including production and transportation.

The International Gas Union has been reviewing the evolution of gas pricing mechanisms in its wholesale gas pricing global survey since 2005. The methodology uses eight different gas pricing mechanisms from known data. The types of mechanisms are summarised in Table 13.

Table 13. Types of wholesale natural gas pricing formation mechanisms, 2018

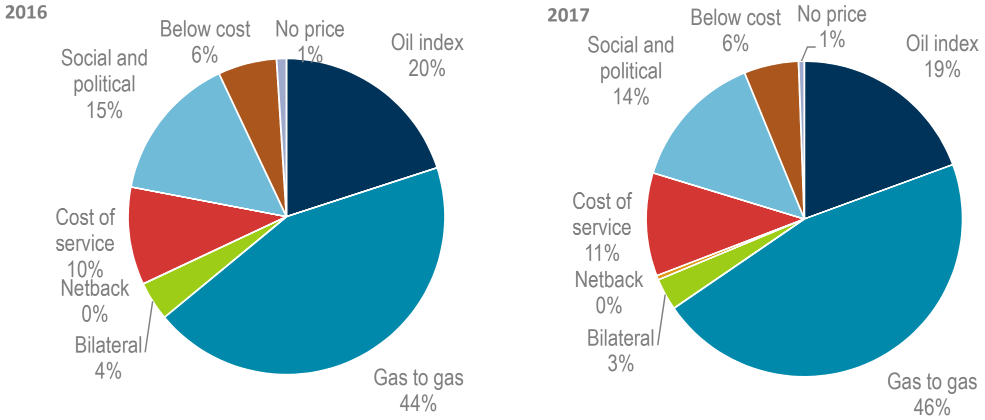
Mechanism	Description
Oil price escalation	Gas price is linked to oil or oil products
Gas-on-gas competition	Gas price is determined based on supply/demand fundamentals
Bilateral monopoly	Price of natural gas is agreed upon between two parties for a certain duration
Netback from final product	Natural gas price is linked to the end product
Regulation: cost of service	Gas price covers the costs of production and transport plus a certain margin
Regulation: social and political	Gas price is decided on an ad hoc basis by the relevant ministry
Regulation: below cost	Gas price is subsidised
No price	Gas is given for free (this tends to disappear)

Source: IGU (2018), *Wholesale Gas Price Report*, https://www.igu.org/sites/default/files/node-document-field_file/IGU_Wholesale%20Gas%20Price%20Survey%202018%20Final.pdf.

Global trends

Gas-to-gas competition accounted for around 44% of the global natural gas wholesale pricing mechanism in 2016 (Figure 33). This is more than twice as high as oil-indexed gas, which represented 20%. The different types of regulated gas prices together represented 31%, and bilateral mechanisms accounted for 4%.

Figure 33. Natural gas wholesale price composition, 2016-17

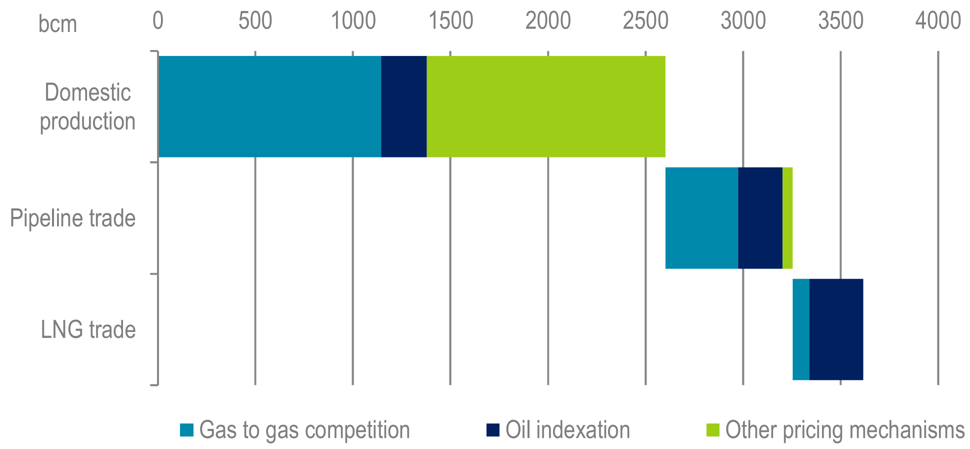


Source: IGU (2017), *Wholesale Gas Price Report*, https://www.igu.org/sites/default/files/node-document-field_file/IGU_Wholesale%20Gas%20Price%20Survey%202017%20Digital_0.pdf,
IGU (2018), *Wholesale Gas Price Report*, https://www.igu.org/sites/default/files/node-document-field_file/IGU_Wholesale%20Gas%20Price%20Survey%202018%20Final.pdf

However, a breakdown of these global data of 2016 from the supply side shows different yields per grouping as follows (Figure 34):

- The share of gas-to-gas competition amounted to 44% for domestic production in 2016, mostly owing to North America and Europe. Oil indexation only covered 9% of domestically consumed production, and the remaining 47% was for bilateral or regulated pricing mechanisms.
- The share of gas-to-gas competition amounted to almost 60% of the pipeline trade volumes in 2016, owing again to North America and a growing share from Europe. Oil indexation accounted for 35% and covered the majority of trade in Asia, Latin America, the Middle East and residual volumes in Europe.
- The share of gas-to-gas competition amounted to only 24% for LNG volumes. Oil indexation accounted for 76% of trade, with the majority of LNG being consumed by Asian importers.

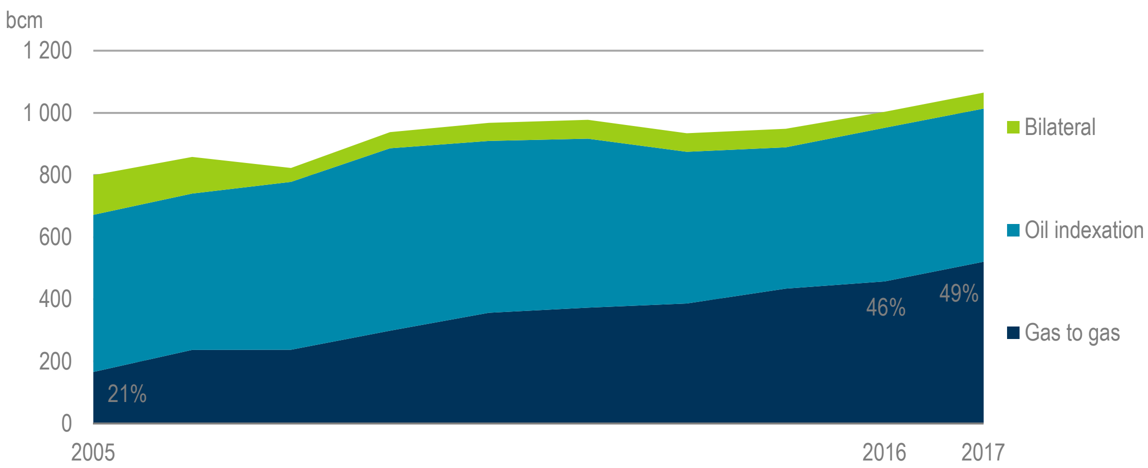
Figure 34. Pricing mechanisms for global total natural gas imports, 2016



Source: IGU (2017), *Wholesale Gas Price Report*, https://www.igu.org/sites/default/files/node-document-field_file/IGU_Wholesale%20Gas%20Price%20Survey%202017%20Digital_0.pdf.

Gas-to-gas competition has increased over recent years, moving from 21% of the total import volume in 2005 to 49% in 2017 (Figure 35). This is in line with the decrease in the share of oil-indexed trade, which represented 63% of the global import volume in 2005 and reduced to 46% in 2017.

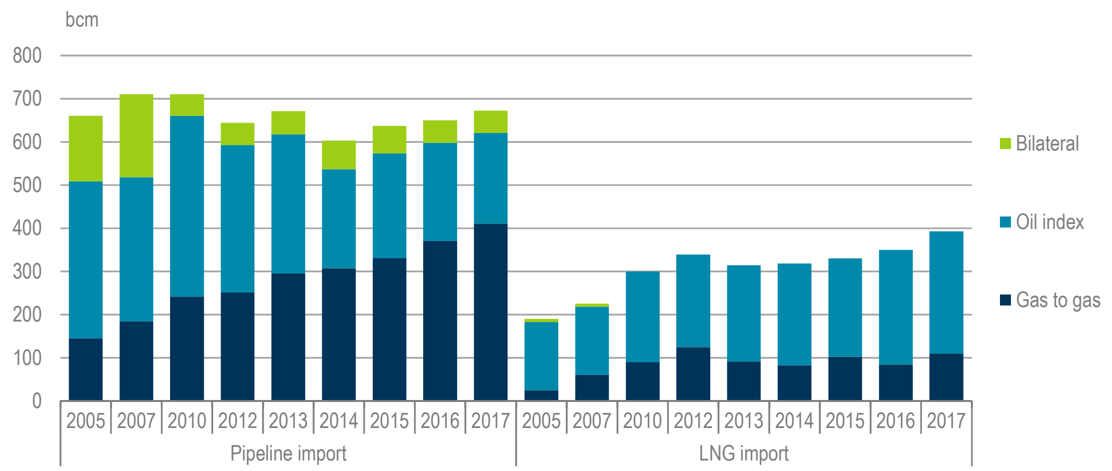
Figure 35. Pricing mechanisms for global natural gas imports, 2005-17



Source: IGU (2017), *Wholesale Gas Price Report*, https://www.igu.org/sites/default/files/node-document-field_file/IGU_Wholesale%20Gas%20Price%20Survey%202017%20Digital_0.pdf, IGU (2018), *Wholesale Gas Price Report*, https://www.igu.org/sites/default/files/node-document-field_file/IGU_Wholesale%20Gas%20Price%20Survey%202018%20Final.pdf

The majority of the trade for pipeline imports was based on gas-to-gas competition, which accounted for 60% in 2017 (Figure 36). This more than doubled over the period 2005 16, from an initial share of 23% in 2005. Most of this shift was due to the pricing evolution in Europe, as detailed hereafter. The share of gas-to-gas competition for LNG has remained limited over the past few years, despite substantial global market growth. The reason for the large share of oil indexation for LNG is because Asian LNG importers have historically priced importing LNG with oil indexation.

Figure 36. Pricing mechanisms for natural gas pipeline and LNG imports, 2005-17



Source: IGU (2017), *Wholesale Gas Price Report*, www.igu.org/news/igu-releases-2017-wholesale-gas-price-survey, IGU (2018), *Wholesale Gas Price Report*, https://www.igu.org/sites/default/files/node-document-field_file/IGU_Wholesale%20Gas%20Price%20Survey%202018%20Final.pdf

Transition from indexation to competition pricing

Gas-to-gas competition pricing (also referred to as hub pricing) results from the development of supply and demand competition in liberalised and organised markets. The presence of multiple buyers and sellers trading on short-term transactions is a prerequisite for the establishment of such competitive markets. These short-term markets were initially more likely to develop in self-sufficient markets than structurally importing ones. This was due to the capital-intensive nature of the natural gas infrastructure for long-distance transportation (pipeline or LNG) and the subsequent recourse to long-term commercial agreements to ensure the necessary financing of such infrastructure.

Such was the case in the United States and the United Kingdom when they liberalised their domestic natural gas markets. The most advanced trading hub in continental Europe is the Title Transfer Facility (TTF) in the Netherlands. Its development is associated with its vicinity to the competitive domestic production market.

North America

The natural gas market deregulation process was initiated in the United States in the late 1970s, with the enactment of the Natural Gas Policy Act by US Congress in 1978. This act started the transition from the prevailing wellhead price control pricing system (in place since the mid-1950s) to price deregulation, which was carried forward by the Natural Gas Wellhead Decontrol Act in 1989. The US Federal Energy Regulation Commission opened access to pipeline infrastructure in parallel to this process, by introducing unbundling – or separation of supply from the operation of the infrastructure – first on a voluntary basis with Order 436 (1985), then as an obligation with Order 686 (1992).

Natural gas physical trading developed over the same period. There were major points of connection among production, transportation and storage facilities, as well as close-to-consumption markets. Such physical points of connection or hubs started from bilateral (over-the-counter) trade, then moved to more elaborate trading structures that offered services and products to market operators.

Henry Hub emerged as a dominant hub and became a price setting reference for the emerging spot market. It was located on Louisiana's coast, close to the Texas border, where a dozen major natural gas pipelines converged.

Similar developments occurred in Canada, when the federal government removed price control on domestic production in 1985 with the enactment of the Agreement on Natural Gas Markets and Prices.

United Kingdom and continental Europe

The United Kingdom's supply capacity has increased and diversified, with producing companies investing in exploration and production. This is due to the development of domestic offshore oil and gas production from the late 1970s. The existence of this upstream market potential triggered a natural gas deregulation process. The Natural Gas Act initiated this process in 1986, introducing third-party access and abolishing the monopoly of the incumbent British Gas on the downstream market. The Network Code of 1996 established the National Balancing Point (NBP), a virtual point ensuring daily volume balancing, as part of the deregulation process. The NBP has rapidly evolved as a trading point. The United Kingdom was connected to Europe via the Interconnector pipeline in 1998, thus reinforcing the potential for trading.

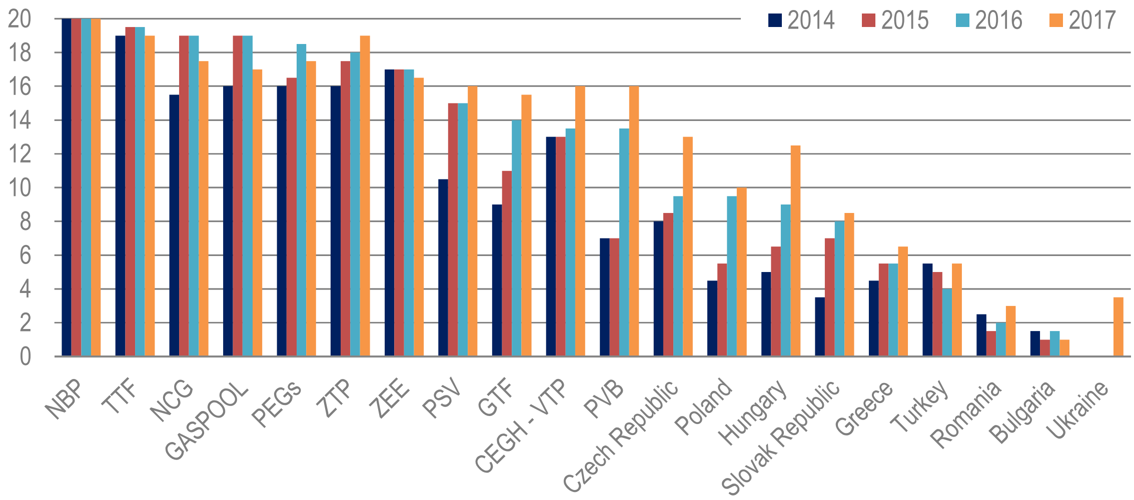
The European Commission initiated a natural gas liberalisation process in the late 1990s. This was via a regulatory framework established through successive liberalisation directives and energy packages (1998, 2003 and 2009) transposed into the legal systems of member states. A single European Union (EU) integrated natural gas market was thus created.

The regulatory packages to establish such a common market contain measures including abolishment of local monopolies and liberalisation of domestic wholesale and retail markets, guarantees on non-discriminatory access to natural gas infrastructure and cross-border networks, transparent access to market data and information, separation of commercial and infrastructure operations activities (unbundling), and independence of national regulators.

Several trading hubs across continental Europe launched in 1998 after the development of the Interconnector pipeline, in parallel with the regulatory framework process. The Zeebrugge hub (the only physical hub in Europe) in Belgium was the first. There are currently about 20 natural gas hubs in Europe, at different stages of maturity. The European Federation of Energy Traders publishes an annual scorecard assessing best practices among existing trading hubs. Figure 37 shows hub evolution over the period 2014-17 and highlights the differences among the mature markets in North West Europe and recent markets in South and East Europe.

The two most successful and liquid trading hubs are NBP in the United Kingdom and TTF in the Netherlands. These accounted for 43% and 46% of the hub traded volumes for the first nine months of 2017, according to the European Commission's quarterly report on European gas markets. Market liquidity is measured by parameters such as the number of active market participants, the number of available traded products, the traded volumes and the churn ratio (which measures the number of trades for the same molecule of natural gas, obtained by dividing the total trade volume by the physical trade volume).

Figure 37. European natural gas hubs scorecard, 2014-17



Note: CEGH-VTP = Central European Gas Hub – Virtual Trading Point (Austria); GASPOOL (Germany); GTF = Gas Transfer Facility (Denmark); NCG = NetConnect Germany (Germany); PEG = Point d'Echange Gaz (France); PSV = Punto di Scambio Virtuale (Italy); PVB = Punto Virtual de Balance (Spain); ZEE = Zeebrugge beach physical trading hub (Belgium); ZTP = Zeebrugge Trading Point (Belgium).

Source: EFET (2017), *2017 Review of Gas Hub Assessment*, http://efet.org/Files/Documents/Gas%20Market/European%20Gas%20Hub%20Study/EFET%20Hub%20Scores%202017_Final.xlsx.

Countries in continental Europe (except for the Netherlands) have historically imported natural gas given its geographical outreach to the gas resources, unlike the United Kingdom or the United States. Natural gas supply infrastructure emerged in the 1960s, with the establishment of long-term commercial contracts based on oil indexation mechanisms as a proxy for downstream competition under netback pricing (Box 3).

Box 3. Long-term pricing of natural gas in Europe

The first long-term natural gas contracts were developed in the Netherlands in the early 1960s, following discovery of the Groningen field that was then the world's largest natural gas field. Long-term contracts were later adopted as a reference for newly developed pipeline exports from the Soviet Union in the 1970s, and North European producers (Norway and the United Kingdom), as well as in the nascent LNG trade. Algeria's first shipments to France and the United Kingdom started in 1965.

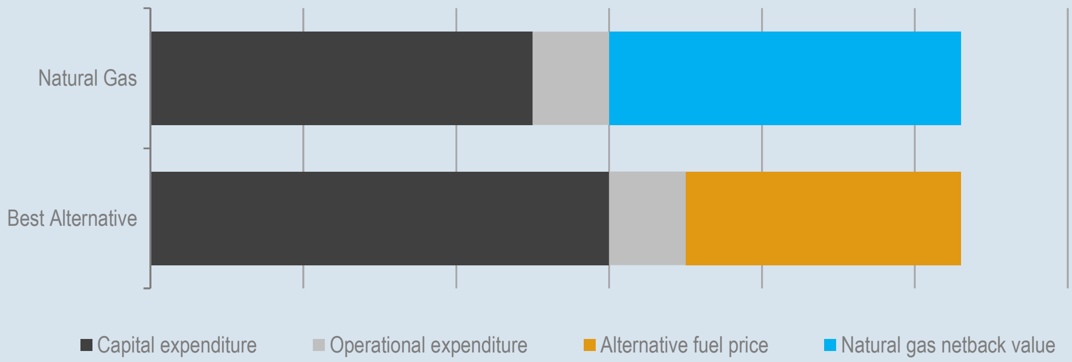
The concept of establishing a long-term contractual framework to support natural gas sales relies on several rationales:

- for the producer or seller, the objective is to maximise the rent obtained from the exploitation of limited natural resources
- for the consumer or buyer, the objective is to ensure security of supply over a foreseeable time frame
- for both parties, the objective is to provide a guarantee of revenues to cover investment in long-distance transportation infrastructure.

Long-term contracts are also a means of sharing commercial risks among parties: the buyer takes a volume risk by committing to a minimum off-take quantity (commonly known as a "take-or-pay clause"), whereas the seller takes a price risk by ensuring the competitiveness of natural gas on the buyer's final market through a price indexation mechanism.

Several options have been developed to define the pricing formula in natural gas long-term contracts. The most common one was based on the concept of netback pricing (or market value), where the price coincided with the maximum value allowed on the buyer's market by competition with other energy sources.

Natural gas netback pricing approach



Note: The nature of the best alternative depends on the type of end user and local market specificities, for example: fuel oil, electricity or coal for industry; fuel oil or coal for power generation; or liquefied petroleum gas, diesel or electricity for residential use.

Typical contractual pricing formulae take several indices into account. These indices are computed over a reference period (usually from 3 to 12 months – often referred to as a moving average) that precedes the period over which the obtained natural gas price is applied. The obtained natural gas price is used for a limited period of usually three months before being readjusted with updated values of the indices.

The choice of indices includes a definition of representative price references for competitive energy sources, weighting coefficients to factor in the influence of each index, currency definition and potential exchange rates, as well a potential constant component:

$P = Po + a\,(X - Xo) + b\,(Y - Yo)$

where:

P is the resulting natural gas price

P_o is the constant component

X and Y are indices, with X_o/Y_o being the values at the beginning of the reference period and X/Y the values at the end of the reference period

a and b are weighting coefficients.

Long-term contracts include price review clauses, which are planned at regular times during the life of the contract (e.g. every three years). Parties can also trigger price reviews if there are significant changes of economic circumstances in the country of the buyer. These changes would need to be out of the control of parties and likely to modify the competitiveness of natural gas on the market.

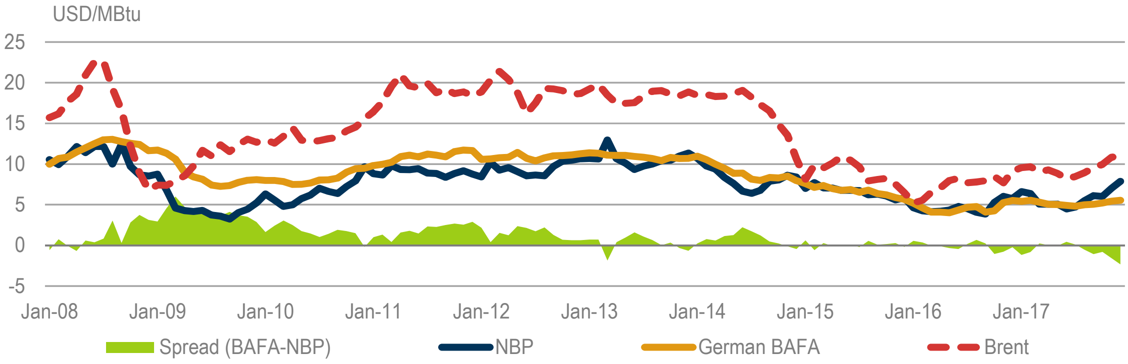
The long-term contract structure remains a substantial component of continental Europe's natural gas supply. However, pricing conditions have evolved over the past decade in Europe to take into account the emergence of gas-to-gas competition and hub price referencing.

The market environment in the post-2008 financial crisis posed a challenge to European natural gas market operators, particularly in the context of disconnected fundamentals with the crude oil market. The natural gas market share in the European power generation mix was challenged by renewable sources of energy and cheap coal, and by abundant LNG supply from the newly developed Qatari export capacity. These all pointed to a low-price environment, and so natural gas demand growth perspectives appeared limited in developing markets. However, crude oil quickly recovered after the crisis, leading to a sharp rise in prices. This left the European oil-linked supplies' price to rise as well, and faced with increasing competition.

Long-term contract price reviews over the following years led to the introduction of hub references alongside or sometimes even instead of oil price indices. Alternative adjustments were also enacted in pricing formulae components when oil indexation was conserved, to reconnect with hub pricing levels. This move to hub pricing indexation was particularly visible in North West Europe, as demonstrated by the evolution of the German average natural gas import price (Federal Office of Economics and Export Control; BAFA) (Figure 38).

The BAFA index disconnected from the hub price by the end of 2008 (owing to the lag effect of the reference moving average still reflecting high mid-2008 oil prices). It remained above oil prices recovered, leading to up to USD 5/MBtu equivalent spread (or 1 to 2 ratio) in 2009. This spread progressively disappeared as long-term contract references adapted accordingly.

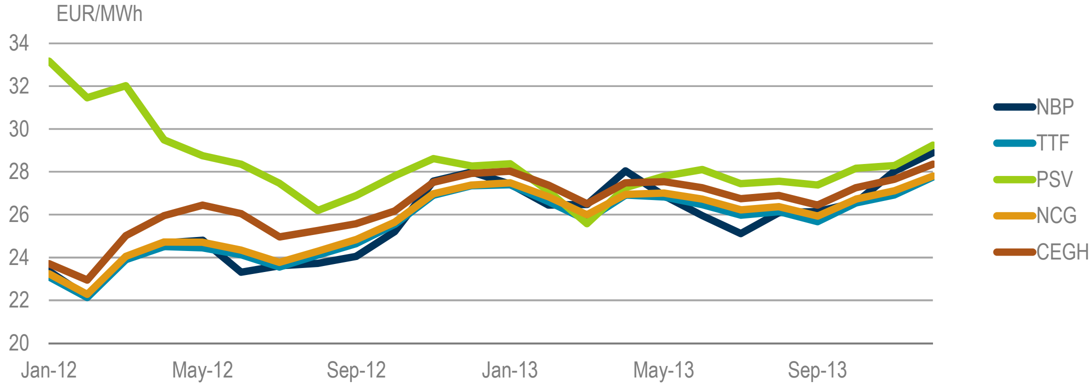
Figure 38. Germany's natural gas import price (BAFA), 2008-17



Source: Bloomberg

North West Europe is the most interconnected and liquid natural gas market. Its oil indexation accounts for 9% of the natural gas consumption in North West Europe, compared to a European average of 30%, and local ratios of 28% in Scandinavia and the Baltics, 28% in Central Europe, 32% in South East Europe and 68% in the Mediterranean. North West European hubs have a driving influence over European prices, with increasing price convergence as physical cross-border liquidity and supply availability increase over time (Figure 39). Hub pricing only accounted for 28% of consumption in North West Europe in 2005 when trading hubs and market integration regulatory frameworks were still under development.

Figure 39. European natural gas prices, 2012-13



Note: CEGH = Central European Gas Hub; EUR = euro; MWh = megawatt hour; NCG = NetConnect Germany; PSV = Punto di Scambio Virtuale (Italy).

Asia

More than 70% of natural gas sales were subject to oil price indexation in Asia in 2017. This is due to the geographical characteristics of the main natural gas importers in the region. The traditional Asian importers (Japan, Korea and Chinese Taipei) are either islands or peninsulas. They lack international pipeline connectivity, and have thus been relying on imported LNG from remote supply areas. Imports are priced at almost 100% of the oil indexation mechanism for these traditional Asian LNG consumers. This pricing was introduced to benchmark imported LNG at a fair market price compared to locally competing fuels. The development of LNG projects has required large upfront capital costs. Typical long-term contracts and oil price indexation schemes were set to ensure commercial guarantees to project lenders (Box 3).

The domestic demand of these mature LNG importers is now growing at lower rates or even stagnating. Some of the receiving terminals have been amortised and initial long-term contracts have partially expired. However, the incentive for developing natural gas pricing based on supply and demand fundamentals remains uncertain in the absence of domestic downstream competition in traditional monopoly markets. Japan remains the only Asian natural gas importing country that has enacted a market liberalisation process (see the detailed analysis on Japan in previous chapter).

Newer Asian LNG importers are still in the development phase of their domestic natural gas markets. This means that they are more likely to rely on long-term commercial schemes associated with oil indexation. Among these more recent importers, China has been relying on its domestic natural gas production. It started importing in the 2000s, mainly from Turkmenistan, as well as other countries such as Kazakhstan, Myanmar and Uzbekistan. China's imported natural gas prices are regulated at each city gate interconnected to domestic gas pipelines. China started to import LNG from Australia under long-term contracts in 2006, using traditional oil indexation pricing formulae.

Evolution of Asian LNG pricing

The Asian natural gas trade has been dominated by imported LNG. LNG importation started in Japan (1969), followed by Korea (1986), Chinese Taipei (1990), and now by emerging economies such as India (2005) and China (2006). However, Asia still lacks trading hubs to facilitate exchange of natural gas and the development of a transparent price signal that is able to steer investments in natural gas infrastructure. This is despite the existence of mature importing markets.

Japan has instead invented its own indices and methodologies for pricing LNG, owing to its physical and geographical isolation. These have also been implemented by subsequent importers in the region.

Pricing under the traditional market

The current dominance of oil indexation in Asian LNG pricing is a result of historical developments and bilateral negotiations among producers and Japanese importers. The first LNG was exported from the state of Alaska in the United States to Japan in the late 1960s and was set at a fixed price. The price was calculated from the project's capital investment cost, and this mechanism continued through the 1970s.

An oil indexation pricing mechanism was introduced in the LNG supply contract signed between Indonesia and Japan in the late 1970s. The original intention was to develop a pricing mechanism that represented a replacement fuel for power generation. This fuel was Indonesian crude oil. The Indonesian Crude Price (ICP) was therefore used because several Indonesian crude oil types were utilised for generating power in Japan. It is a price index for crude oil exported from Indonesia, based on the average spot price of eight types of crude oil sold in Indonesia. The final pricing mechanism was invented to correlate with such oil prices using gaseous calorific values.

The cost of Indonesian LNG to Japan was affected by ICP indexation, and import prices decreased as the oil price collapsed in the mid to late 1980s. LNG producers and consumers endeavoured to find an index that retained the concept of a natural gas price, reflecting competitiveness with the incumbent fuel – oil. This would take into account the vulnerability of exposure to a single oil market price of the exporting country.

The Japanese Crude Cocktail (JCC) was thus introduced into the pricing mechanism. Its purpose was to index to the imported price of crude oil where the LNG is delivered and consumed, not the exported oil price of the origin. JCC is the monthly average price (cost, insurance and freight included) of the crude oil products imported into Japan, which are published by the Ministry of Finance of Japan. The oil prices in the LNG pricing mechanism reflect the importing country's supply and demand market fundamentals of the replacing fuels, by indexing to JCC.

The new market players already had a comparable and competitive pricing benchmark when Korea and Chinese Taipei started to import LNG from Indonesia in 1986 and 1990. This benchmark was the Japanese imported LNG price indexed to JCC. There were several reasons that Korea and Chinese Taipei imported Indonesian LNG with indexing directly linked to JCC and not to ICP.

The three markets had almost the same proximity to the supply source, and their transportation fees from Indonesia were almost equal. This supported consistent comparisons for creation of an ex-ship LNG pricing mechanism. JCC could be considered as an established pricing indexation in the industry, as Japan was already importing around 40 bcm per year.

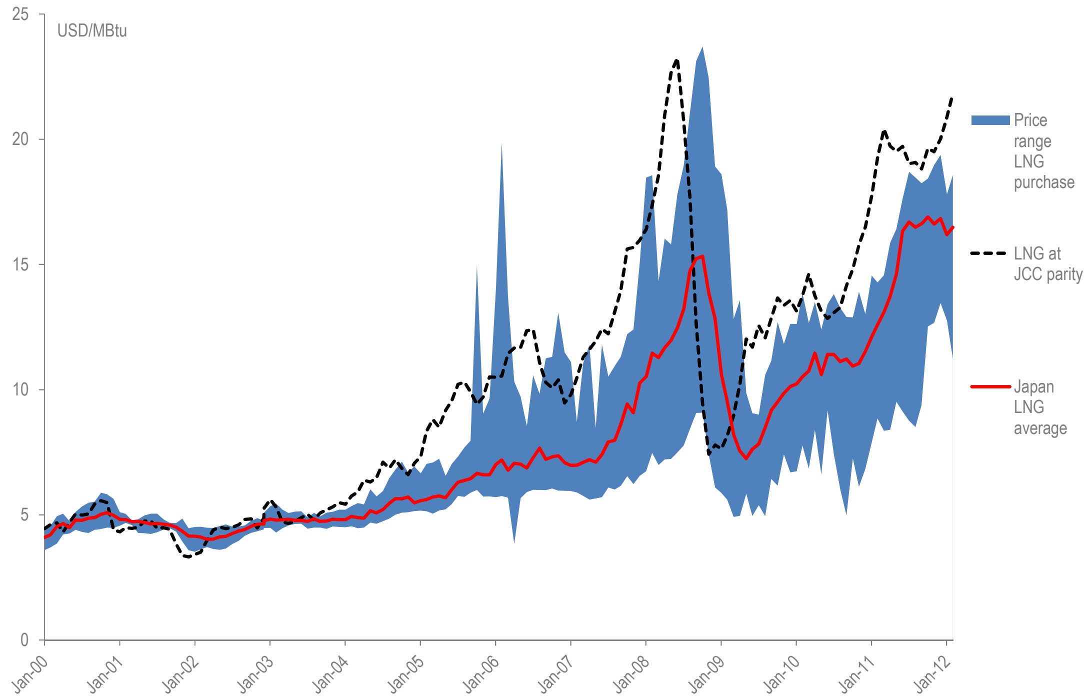
Japan represented a potential competitor to Korea and Chinese Taipei for importing LNG, as the three importers share similar dependencies on external gas and geographical difficulties for pipeline connectivity. Japan's pricing indexation was introduced to the new importers, Korea and Chinese Taipei, in a natural manner. Eventually, JCC became the dominant indexation in North East Asia.

So-called "S-curves" were introduced by producers after the decline in oil prices during the 1980s. S-curves have two kinks where the slope gently turns towards the indexed oil price. This pricing mechanism protects producers from low oil prices, while also protecting consumers against high oil prices. The idea was to introduce a "win-win solution" in the long-term contract pricing mechanism. An LNG long-term contract can last 20 years, for financing the project and for securing long-term gas supply.

Producers and consumers therefore developed S-curves to minimise exposure to oil market volatility for a long period of time. The initial aim of the first S-curve pricing mechanisms was more favourable to producers who were exposed to large upfront investments in LNG infrastructure, and thus the second kink was set high. The LNG landed price resulted in higher prices than oil parity due to the higher second kink, as the oil price range was below the USD 20 per barrel (bbl) level during the period 1985-99.

However, as the oil price continued to increase significantly above the USD 20/bbl range during the 2000s, S-curves protected LNG consumers. This meant that producers could not incentivise market inflation (Figure 40, black and red lines). A rapid rise in oil prices under the S-curve mechanism protected consumers, despite renegotiation of long-term contracts during the first half of the decade. This resulted in long-term LNG landed prices lower than the oil parity. However, LNG producers started to sell excess volumes on a spot basis, which created another trend in the Japan landed price range (Figure 40, blue shaded area).

Figure 40. Average Japanese LNG import prices and range



Sources: Japanese customs; IEA (2013), *Developing a Natural Gas Trading Hub in Asia*.

Spot pricing under tight market conditions

The number of LNG players increased on both the producer and the consumer sides during the 2000s. This enabled greater diversification in LNG trade flows in conjunction with development of LNG spot sales. These spot LNG cargoes were produced and delivered from uncommitted or excess volumes from LNG projects. Such uncommitted LNG volumes were sold on a single transaction sales basis to the market where the producers did not initially intend to sell to.

The LNG spot pricing mechanism was developed and established during this period, mainly due to increased production of LNG. Then, a sudden increase in demand arose from the Asian region after the Great East Japan Earthquake and the resulting accident at Fukushima Daiichi nuclear power plant in 2011.

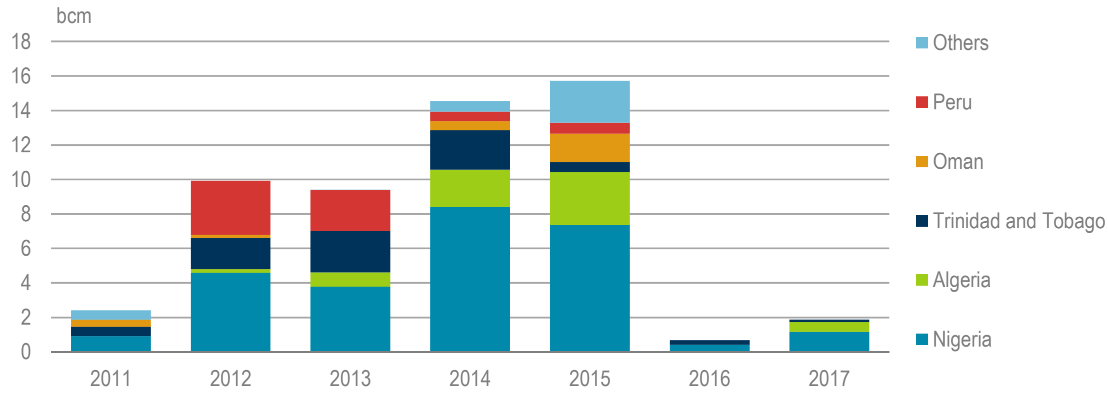
LNG spot sales have historically been transacted under closed bilateral agreements, given that limited volumes were traded. This resulted in the absence of an LNG spot price reference. However, larger volumes of LNG cargoes started to travel beyond their originally intended destination, and sometimes even to the other side of the world. The trend of cargo movements started to grow. The LNG spot market was recognised, together with spot pricing, by the mid-2010s.

Increasing demand: Sudden rise from East Asia

The development of spot LNG transactions was aided by the sudden increase in LNG demand from East Asia. The 2011 Great East Japan Earthquake created an unexpected tightness of the global LNG supply-demand balance (see first chapter). The earthquake and consequent nuclear accident led to Japan's nuclear power plants being shut down, and LNG was sourced as an alternative fuel for power generation. The rise in demand absorbed and exceeded existing excess volumes. This resulted in a higher spot LNG price than that for long-term oil-indexed deliveries in Asia.

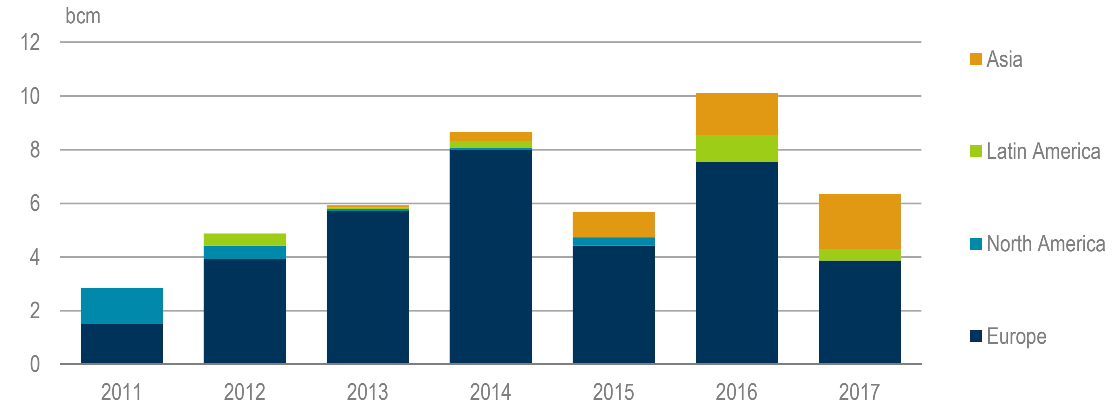
The origins of the spot cargoes were excess volumes from Qatar, and also reloaded cargoes from Europe. For example, cargoes from Algeria, Nigeria, and Trinidad and Tobago were originally sourced for consumption in Europe. However, that volume became one of the main sources diverted from Europe to Asia especially after 2012 as the demand in Europe was decreasing and given the tightness of the East Asia market (Figure 41 and Figure 42).

Figure 41. LNG volumes diverted from the Atlantic to the Pacific basin, 2011-17



Source: IEA (2016), Global Gas Security Review 2016, www.iea.org/publications/freepublications/publication/GlobalGasSecurityReview2016.pdf, LNG imports from ICIS (2018), *ICIS LNG Edge*, www.icis.com/energy/liquefied-natural-gas/lng-edge (subscription required).

Figure 42. LNG reloading volumes, 2011-17



Source: IEA (2016), *Global Gas Security Review 2016*, www.iea.org/publications/freepublications/publication/GlobalGasSecurityReview2016.pdf, LNG imports from ICIS (2018), *ICIS LNG Edge*, www.icis.com/energy/liquefied-natural-gas/lng-edge (subscription required).

As a result, the main Asian LNG importers, namely Japan, Korea and Chinese Taipei, have frequently paid a premium for spot cargoes compared to their long-term supply contracts. On average, 77% of the imported spot cargoes were priced higher than those of long-term contracts imported at the same time, according to each importer's customs data during the period 2007-12.

More than 70% of the spot cargoes imported by Japan Chinese Taipei were priced at a higher level than those of long-term contracts during 2007-12. Korea was even more exposed to the higher spot cargo prices, with 70-80% of spot cargoes being more expensive than those of long-term contracts. Moreover, Korea and Chinese Taipei procured up to 20% of their LNG portfolio under spot transactions. This was mainly related to the seasonal specificities of their markets, with Korean heating gas demand increasing during cold winters, and Chinese Taipei air-conditioning demand increasing during tropical summers (Table 14).

Table 14. LNG spot cargoes imported, 2007-2012

	Spot cargo		Spot price	
2007-Q1 2012	bcm	LNG imports (%)	> long term (%)	< long term (%)
Japan	29.6	6	74	26
Korea	32.7	20	83	17
Chinese Taipei	12.3	17	71	29
Total	**74.5**	**11**	**77**	**23**

Sources: Customs data Japan, Korea and Chinese Taipei; IEA (2013), *Developing a Natural Gas Trading Hub in Asia*, www.iea.org/publications/freepublications/publication/AsianGasHub_FINAL_WEB.pdf.

The requirement from Japan for extra cargoes of LNG to meet power demand after the Fukushima accident pushed spot cargo prices to record levels in East Asia. The incident also created East Asian LNG spot prices as a reference and benchmark for global LNG spot market price indexation.

The parallel emergence of new buyers within the Asian market resulted in increasing competition. China started to import LNG to meet its rapid economic growth, which was followed by strong demand from city gas and power plants. It began importing LNG under long-term contracts from Australia in 2006. It also started to import LNG by spot transactions from August 2007, by purchasing four cargoes towards the end of the year, to meet its tight electricity supply and peak demand. China expanded its LNG supply portfolio by beginning to import from Indonesia (2008) and Malaysia (2009), but urgent requirements for LNG spot cargoes always existed. Therefore, competition in the region became tense and the market started to grow even more.

Additional tensions on natural gas balancing from other regions created further opportunities for market arbitrages. For example, the record drought in 2012 caused hydro-dependant Brazil to suffer. The country looked for urgent alternative sources, namely fossil fuels, to cover its southern hemisphere summer requirements, and to prepare for unforeseen and unavoidable weather-related issues. While December is an air-conditioning power demand month in Brazil, it is also the start of winter peak demand season in the northern hemisphere. Brazil sought cargoes with premiums to Asian spot prices as an indexation, to compete for the LNG spot cargoes under the tight market.

Another example, Argentina, started to import LNG from 2008 and increased import volume significantly from 2011 as it faced increasing energy consumption owing to the steady growth of its economy, in parallel with a decline in domestic natural gas production. It purchased LNG on a spot basis through an open tender system, to meet its growing need for gas. The bid prices were often indexed to East Asian LNG spot prices to be competitive.

Increasing supply: Expanding LNG volumes in the market

A first period of loose LNG supply started in the late 2000s as the United States changed from being an LNG importer to being self-sufficient. This increase of global supply limited price evolution in Asia following the 2008 financial crisis, and increased competition for power-generating fuels in Europe. However, this situation was short-lived due to the consequences of the 2011 Great East Japan Earthquake.

Uncommitted volumes opened up a new era of LNG spot trade, mainly in Asia but also in Latin America or Europe. On the supply side, Qatar – and more recently Australia and the United States – have appeared as significant purveyors of uncommitted volumes. Most of the trade comes from operations from portfolio players, with major utilities or oil and gas companies holding sizeable market positions in different regions and having the ability to arbitrate among markets.

Spot pricing in the long term

There was a sharp rise in spot LNG pricing after the Fukushima incident in 2011. The long-term contracts under regular price review at this time were affected by the landed price of LNG, which resulted in higher slopes against oil prices in the pricing mechanism. LNG consumers started to experience higher landed LNG prices of both long-term and spot contract prices, with an oil price of USD 100/bbl and renewed higher slopes in the pricing mechanism. The accident triggered discussions with North East Asian consumers on their dependency on oil indexation pricing mechanisms and diversification of the mechanisms to avoid such repercussions in the future. Discussions of alternative solutions for the pricing mechanism to lower landed LNG price were then directed towards US LNG, which were priced with different mechanism from that of traditional oil-indexed.

The shale oil and gas revolution in the United States has turned the country into an LNG exporter. The pricing mechanism associated with this new source of supply was novel, as it consisted of a locally traded gas price plus a liquefaction fee. This approach was for two reasons.

First, the existence of a mature and liquid domestic gas market with many suppliers and ample transportation capacity did not require financing of specific exploration and production development for export projects, as is the case in traditional LNG schemes. This enabled natural gas to be offered at the locally traded gas price with liquefaction and transportation costs borne by off-takers only.

Second, operating or proposed projects were mainly brownfield infrastructure, which were converted from importing terminals to exporting terminals. The terminals already had the necessary infrastructure, such as LNG storage tanks and LNG vessel berths, which had required heavy upfront investment. Thus, those US LNG projects were some of the lowest capex projects in the world. They remain profitable by selling LNG cargoes at the market price of locally traded natural gas.

Asian traditional importers faced fierce global competition on the spot LNG price, which eventually affected renewal of long-term LNG prices. The alternative of HH pricing was perceived as an attractive diversification from traditional oil-linked JCC indexation. It was crucial not to confuse price level and pricing mechanism, although HH indexation appeared to be attractive in an oil price environment of USD 100/bbl. The HH is the locally traded hub price, which should also always be taken into consideration, as HH indexation did not always directly translate into low landed prices in East Asia. It could generate price fluctuations linked to specific domestic fundamentals of the US market, but with no direct connection with the fundamentals of the importer's market.

Such was the case of the 2014 polar vortex episode in the United States, when the HH price reached USD 8/MBtu. The natural gas price went over USD 100/MBtu in some areas because of the extreme, prolonged and widespread cold weather. However, the Asian spot LNG import price went down to below USD 11/MBtu during mid-June to mid-August of 2014, the highest demand season. This was mainly due to the sharp decline of global oil prices and the LNG pricing mechanism linked to such oil prices in conjunction with the earlier start-up of the new Papua New Guinea PNG LNG project, which created unexpected excess volumes in the Asian LNG market. The ample gas supply from the shale gas revolution significantly lowered HH prices and provided stability for price volatilities during the hurricane season.

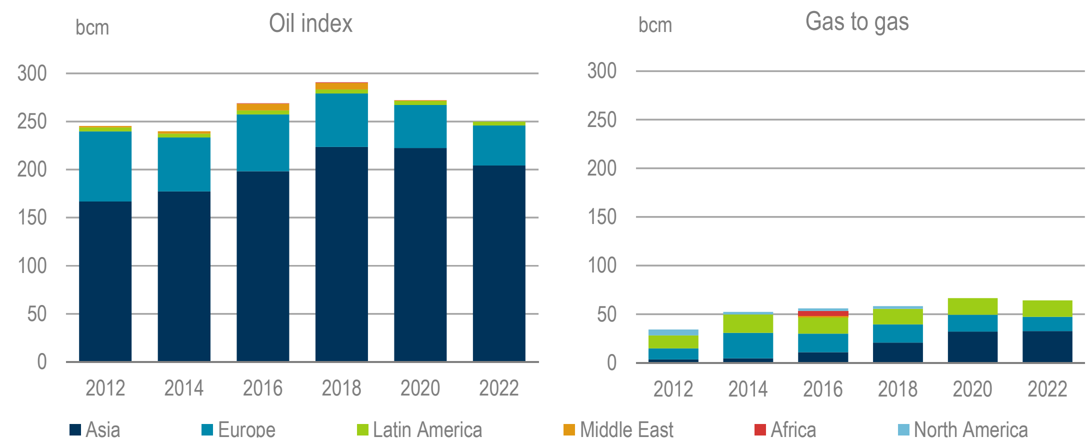
The above risks associated with linkage to market-traded local gas hub prices of a third-party country were recognised once the global oil price declined. The local gas hub price could be lower than the global oil price, but it could be reversed, and indexation to the local hub price could land at a higher price than that of the oil price indexation. Producers, emerging portfolio players and consumers therefore invented an innovative approach to a new pricing mechanism. This was to mitigate unforeseen domestically traded gas market price volatility risks and exposure to the transportation market, which often experienced larger fluctuations than those of the oil price market. The new mechanism was called a hybrid, as it usually contained a combination of oil indexation and HH price indexation.

The first type of observed hybrid pricing mechanism consisted of the introduction of an HH price reference for 10 30% of the pricing formula. The remainder, namely 70 90%, was indexed to traditional crude oil – either to Brent or JCC. This concept seemed beneficial to producers, who could still have crude oil indexation that limited exposure to local natural gas hub prices. In addition, having both crude oil and HH market future prices supported seller and buyer business plans by making it easier to find a potential financial hedge for operations.

The second concept was to introduce S-curve pricing with a crude oil linkage within the hybrid pricing mechanism. This provided both sellers and buyers with room to negotiate the kinks, and to further protect themselves from the volatility of the crude oil market.

Asian buyers have therefore created a portfolio of pricing mechanisms: fixed price, oil indexation with or without S-curves, and HH indexation with or without hybrid components and with or without S-curves. HH indexation contracted volumes have been produced and exported from 2016, and Asia is expected to account for almost 50% of the contracted volumes by 2022 (Figure 43).

Figure 43. LNG import contract volumes by region, 2012-22



Source: IEA (2017b), *Global Gas Security Review 2017*, www.iea.org/publications/freepublications/publication/GlobalGasSecurityReview2017.pdf.

The next phase of trends developed once Asian importers created several new pricing mechanisms to handle price volatility and fluctuations while the LNG market was expanding. The focus for Asian importers shifted slightly from the pricing mechanism itself to implementation of a portfolio of pricing mechanisms.

Table 15. LNG project FIDs taken, 2011-15

FID year	LNG projects	Country	Brownfield or greenfield sites
2011	Australia Pacific LNG	Australia	Green
	Gladstone LNG	Australia	Green
	Prelude LNG	Australia	Green
	Wheatstone LNG	Australia	Green
	Donggi Senoro LNG	Indonesia	Green
	Sengkang LNG	Indonesia	Green
2012	Australia Pacific LNG	Australia	Brown
	Ichthys LNG	Australia	Green
	PFLNG Satu	Malaysia	Green
	Sabine Pass LNG	United States	Brown
2013	Yamal LNG	Russia	Green
	Sabine Pass LNG	United States	Brown
	PETRONAS train 9	Malaysia	Brown
2014	PFLNG Dua	Malaysia	Green
	Cameron LNG	United States	Brown

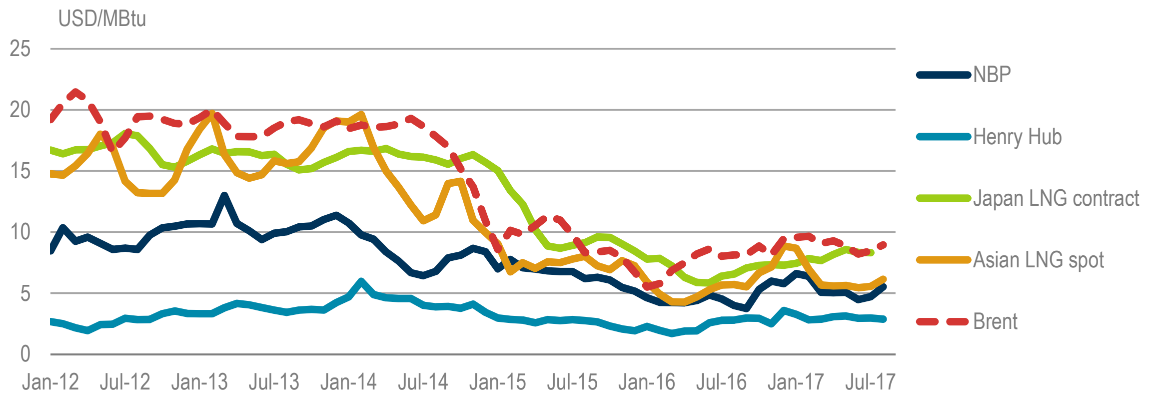
FID year	LNG projects	Country	Brownfield or greenfield sites
	Dominion Cove Point LNG	United States	Brown
	Freeport LNG	United States	Brown
2015	Cameroon FLNG	Cameroon	Brown
	Corpus Christi LNG	United States	Green
	Eagle LNG	United States	Brown
	Freeport LNG	United States	Brown
	Sabine Pass LNG	United States	Brown

Ample availability of lower priced oil indexation LNG supply started to pressurise the methods used for pricing and marketing of natural gas. This was triggered by the start-up of Papua New Guinea's PNG LNG project from mid-2014 together with the decline of global oil prices. LNG producers made FIDs for 22 events during 2011-15, supported by an oil price of USD 100/bbl, the oil-linked LNG pricing mechanism and emerging strong demand from Asian importers after the Fukushima accident in 2011 (Table 15).

The first wave of LNG shipments from the 2011-2015 projects was from Australia and Indonesia, where most of the contracts were priced with traditional oil indexation with take-or-pay provisions for supporting greenfield projects. The second wave of shipments within the Asian importer contract portfolio was scheduled from the United States with HH indexation involved. This was expected to lower the overall landed price of LNG into Asia.

However, the well-supplied market and the decline of oil prices lowered natural gas prices from mid-2014 (Figure 44). Divergences in natural gas prices among regions were seen until 2013, when imported prices in Japan and Korea were around six times greater than US domestically traded wholesale prices. The spot LNG price in Asia showed large seasonality characteristics in nature. It was higher than that of LNG long-term contracts and even higher than oil parity driven prices due to strong urgent demand because of severe winters in Asia and Europe. The regional price gaps after the 2011 Fukushima nuclear accident narrowed significantly after mid-2014, when the first wave of new LNG projects with an oil indexation pricing mechanism started to produce and send cargoes into Asia. At the same time, the oil price sharply collapsed.

Figure 44. Historical gas prices, 2012-17



Source: IEA (2017b), *Global Gas Security Review 2017*, www.iea.org/publications/freepublications/publication/GlobalGasSecurityReview2017.pdf.

Impact of pricing mechanisms on LNG contracts

Sellers and buyers create pricing mechanisms to cope with uncertainty and volatility of market conditions. These mechanisms have started to affect LNG contract provision to manage the oversupplied market. Importers have created diversified pricing mechanisms with the potential to minimise outright market exposure to oil and HH in the near future. However, the contracted volume is forecast to surpass the consumption demand, and importers need to manage the potential oversupplied portfolio of contracts.

One option to mitigate the oversupplied portfolio of contracts with take-or-pay clauses is to divert contracted LNG cargoes to other receiving terminals by reselling the overcommitted cargo to another entity. This would enable the importers, who are under take-or-pay provisions, to meet their contractual obligations and yet still maintain an option to take and consume the affordably priced cargo of choice in case of sudden demand increase.

Traditionally, long-term LNG contracts had rigid receiving obligations that specified the receiving terminals in the contracts. This rigidity worked for both producers and importers. The producer could secure the outlet for the cargo, and the importer could secure the LNG supply and limit the producer's opportunity for selling to a more attractive market at the last minute.

However, in a well-supplied market, buyers find themselves in a better position to remove or loosen the rigidity of the contractual obligations for the new contracts, so that they can divert or resell the cargo at their or both parties' discretion. Importers would therefore have the means to implement and manage their portfolio of contracts, by choosing attractively priced LNG supplies to import and others to divert (or resell).

Analysis shows a recent trend towards flexible destination provisions (Table 16). The share of contracts with flexible destination clauses is increasing, and accounted for almost 42% of newly signed contract volumes in 2016. In parallel, the average contract duration is decreasing for both fixed and flexible destination contracts. The reduction of the contract length is more important for fixed destinations (or more achievable for the producer) than for flexible destinations.

Table 16. Evolution of contract destination clauses, 2014-16

	Destination clause with flexibility	Average ACQ (bcm)	Average duration (yr)	Share of destination flexibility (%)
Signed before 2015	Fixed	1.52	15	60.6
	Flexible	2.13	17	39.4
	Total	**1.71**	**16**	**100.0**
Signed in 2015	Fixed	0.83	7	59.5
	Flexible	1.23	15	40.5
	Total	**0.96**	**10**	**100.0**
Signed in 2016	Fixed	1.14	8	58.1
	Flexible	1.26	12	41.9
	Total	**1.19**	**9**	**100.0**

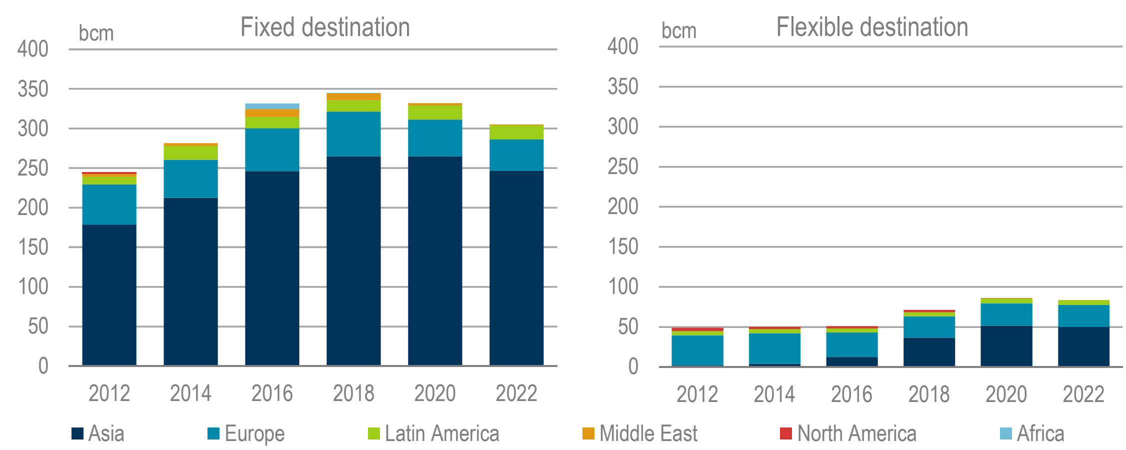
Source: IEA (2017b), *Global Gas Security Review 2017*, www.iea.org/publications/freepublications/publication/GlobalGasSecurityReview2017.pdf.

However, this trend has not yet been fully implemented in Asian LNG markets. New contracts signed in those years with loose destination clauses started deliveries in 2018. Therefore, there will be a limited impact on importing volumes into Asia at the moment. The situation is expected to shift once the legacy contracts start to expire and delayed North American projects under free-on-board (FOB) conditions start producing.

LNG cargoes may be diverted within regions once the contracts with less rigidity on destination commence, depending on their proximity to the original destination. The diverting terminal of ex-ship contracts should not affect seller shipping schedules on return. Other importing regions such as Africa, Latin America and the Middle East are relying on short-term and spot supplies to fill the potential supply gap until their domestic gas production eventually resumes. They are expected to shift to domestic gas in the near future and thus their interest for flexible destination clauses is not shown in the analysis (Figure 45).

The net share of contracts with a fixed destination will decrease over the medium term, especially as FOB contracts increase and legacy long-term contracts expire. This is assuming the expiring contracts are not renewed and without any specific assumption on future contracts yet to be signed. New contracts are more likely to have a relaxed destination clause, or even no such clause.

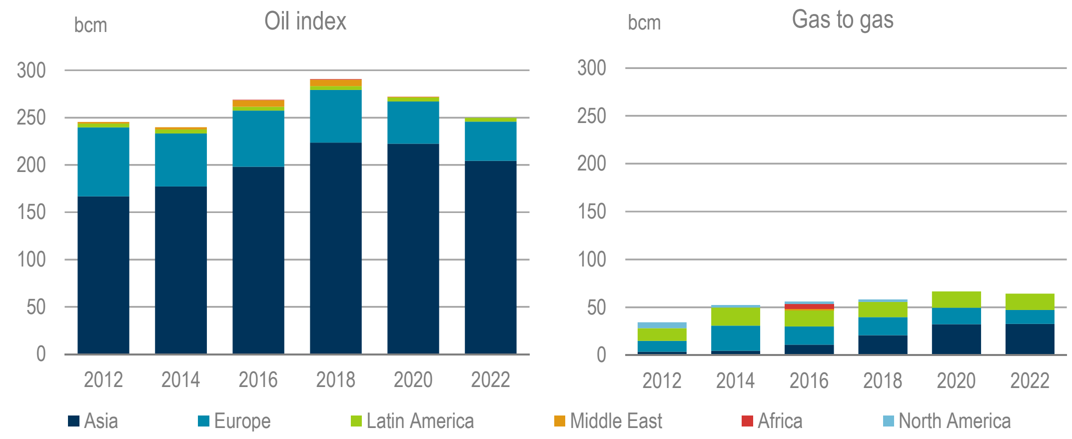
Figure 45. LNG volumes imported by region, 2012-22



Source: IEA (2017b), *Global Gas Security Review 2017*, www.iea.org/publications/freepublications/publication/GlobalGasSecurityReview2017.pdf.

Volumes with flexible destination clauses are expected to almost double by 2022, mainly due to additional US exports under development. Also, uncontracted volumes from new projects, mainly from the United States but also from expired contracts, will almost triple. They are likely to be picked up by portfolio players who require optimisation of their supply portfolio. The greater volumes to be replaced by US origin supply and portfolio players will not just relax the destination clauses, but are also expected to contribute to more gas-to-gas pricing mechanisms in Asia (Figure 46).

Figure 46. LNG import pricing mechanisms by region, 2012-22



Source: IEA (2017b), *Global Gas Security Review 2017*, www.iea.org/publications/freepublications/publication/GlobalGasSecurityReview2017.pdf.

However, the volumes from portfolio players are not necessarily linked to US gas prices. Portfolio supply sources could vary from direct purchase of supplies from a specific producing project to supplies from other portfolio players. Therefore, the US volumes that are priced based on gas-to-gas competition could be only part of the supply sources for those portfolio players. Thus, the sales and purchase contract pricing mechanisms among the portfolio players and importers may not be gas linked, but could be a traditional oil indexation mechanism with sloping and constant components (and possible S-curves).

Towards LNG market growth

LNG pricing mechanisms have evolved in conjunction with the LNG market. This was initially from fixed price to oil indexation only, and later to diversification with gas-to-gas competition and hybrid pricing mechanisms. As LNG contracts with flexible destinations are implemented in the future, pricing mechanisms will be developed to fortify growth in the LNG market.

While new destination clauses will allow Asian importers to physically divert cargoes, the destination will most likely be within the Asia Pacific region. In theory, importers will be able to deliver their cargoes to any destination, for FOB contracts. However, the shipping cost needs to be considered and thus the likelihood for the buyer is to divert the unwanted cargo to its closest destination. Therefore, a cargo of Asia Pacific origin is likely to be diverted within the region, if and when the diversion right is exercised. More collaboration among importers within the proximity for regional swapping within Asia is expected to achieve these diversions.

A recent change in the Asia Pacific market is the growing number of countries turning to LNG importation. Development of LNG imports started in emerging South East Asian countries such as India (in 2005), China (in 2006), Thailand (in 2011), Indonesia (in 2012), Malaysia (in 2013), Singapore (in 2013) and Pakistan (in 2015). This is in addition to the traditional Japan, Korea and Chinese Taipei markets. Even more Asian countries are expected to become LNG importers in the future, such as Bangladesh, Myanmar, Philippines, Sri Lanka and Viet Nam.

Such growth of the LNG market in the Asia Pacific region is important for the traditional LNG importers as it will create a framework for a more competitive environment and enhanced market liquidity within the region, for both producers and importers. It will also provide additional market outlets as the new importers could be candidates for diversion destinations by traditional importers. The physical diversions may be limited to within the proximity of the original destination for reasons such as managing the seller's fleet or saving shipping costs for FOB transportation obligations. Asian importers would therefore need to closely collaborate to deal with demand volatilities within the region.

However, further elements are important for development of the Asian LNG market. Developing markets might require long-term contracts to ensure security of supply for their fast-growing economies, and producers will look to secure return on their considerable infrastructure investments. Natural gas needs to be competitive within the energy mix of the emerging region or the countries where the gas is delivered. This will enable emerging importers to expand their market share, notably against incumbent supply sources such as oil, coal and domestically produced gas. This raises the question of developing new competitive pricing mechanisms in Asia where gas is priced based on regional gas supply or demand fundamentals.

LNG pricing mechanisms influence the willingness of LNG producers to invest in the next generation of projects. The shale gas revolution in the United States has already profoundly changed global natural gas markets by lowering HH gas prices and enhancing the competitiveness of energy-intensive industries in the country. It has also changed expectations in terms of LNG global flows. These elements have affected contract price renewal and pricing mechanisms in Asia.

Asia's LNG market is therefore not a simple matter of demand and supply in the region. The most recent LNG liquefaction projects in Australia, Russia, the United States and also Coral FLNG in Mozambique made FIDs once they were backed by long-term contracts but not necessarily with oil indexation.

Asian importers may look for more diverse forms of pricing mechanisms in the near future, to strengthen the LNG market in Asia and to enhance security of supply. Existing long-term LNG contracts may also be renewed with innovative pricing mechanisms. Producers or sellers such as portfolio players may provide flexibility to attract or retain LNG buyers who are in favour of building and managing portfolios of diversified LNG importing contracts.

Producers and Asian importers are also expected to be more flexible in innovating pricing mechanisms to envisage requirements, within the current context of ample LNG supply and market diversification. Producers are expected to provide more flexibility to fulfil the short-term requirements of importers. At the same time, Asian importers are likely to provide long-term commitments for supporting new greenfield projects to secure future supply for fortifying the sustainable Asian LNG market.

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General annex

Abbreviations and acronyms

y-o-y	year-on-year
ACQ	annual contract quantity
BAFA	Federal Office of Economics and Export Control (Germany)
EU	European Union
FID	final investment decision
FOB	free on board
FSRU	floating storage and regasification unit
HH	Henry Hub
ICP	Indonesia Crude Price
JCC	Japanese Crude Cocktail
LNG	liquefied natural gas
NBP	National Balancing Point (United Kingdom)
Q1	quarter 1
Q2	quarter 2
Q3	quarter 3
Q4	quarter 4
QP	Qatar petroleum
TTF	Title Transfer Utility (Netherlands)
US	United States

Units of measure

bbl	barrel
bcm	billion cubic metre
MBtu	million British thermal unit

Currency codes

USD	United States dollar

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