International Energy Agency
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Global Gas Security Review

Meeting Challenges in a Fast Changing Market

2018

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INTERNATIONAL ENERGY AGENCY

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Foreword

Since the foundation of the International Energy Agency (IEA) in 1974, energy security has been one of its core missions. But in the nearly forty-five years of its existence, the global energy landscape has changed, evolving to a more complex and interdependent system in which local energy security issues can have global consequences.

The IEA, too, has changed, opening the doors of the IEA family to new partners: last year Brazil joined as our seventh Association country and, earlier this year, Mexico became our 30th member country. This global expansion makes our energy security mission even more urgent. In a more complex global environment, with an expanded IEA family, energy security is more relevant than ever. The annual *Global Gas Security Review* is a concrete manifestation of this mission, following the mandate given by our IEA member countries in 2015, and reinforced by the Group of Seven (G7) countries under the presidency of Japan in 2016.

This year's report shows that concerns about energy security in the global gas market are as present as ever. For example, the recent and unprecedented growth in natural gas demand from fast-growing economies has also brought to light new supply issues, with supply shortfalls experienced in the People's Republic of China last winter that resulted in higher prices for most other gas importers. Furthermore, while we can see real improvement in liquefied natural gas (LNG) flexibility, which keeps on growing and contributes to easing supply shortages, uncertainties remain for the future evolution of gas markets. This brings a risk of tightening from insufficient investment in production and infrastructure capacity. It also highlights the uncertainty surrounding future shipping capacity growth, a precondition to maintaining LNG market flexibility. This issue could affect price volatility and therefore hurt consumers – especially the most price-sensitive emerging buyers – and cause additional security concerns.

This report aims at contributing to a better understanding of gas security of supply by providing more transparency on LNG markets and their role in global gas system balancing. It is my hope that it will be a useful and positive tool for policy makers and market stakeholders and support efforts to ensure greater energy security worldwide.

Dr. Fatih Birol

Executive Director

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The individuals and organisations that contributed to this study are not responsible for any opinions or judgements it contains. Any error or omission is the sole responsibility of the IEA.

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Executive summary

2017 marked a turn in the recent evolution of natural gas markets, with the robust growth of the People's Republic of China (hereafter, "China") as a major consumer and importer, and the emergence of the United States as a major source of natural gas supply and future global trade growth. These transformations will be instrumental in the shaping of natural gas medium-term market evolution, as highlighted in the International Energy Agency's (IEA) *Market Report Series: Gas 2018*, with continuous demand growth from emerging Asian buyers led by China's strong policy support to fight against air pollution, while US flexible and hub-indexed LNG exports will provide the bulk of global supply growth.

This changing environment raises new concerns in terms of security of supply, in the context of more interdependent markets and with more demand volatility and price sensitivity especially for emerging buyers. This year's *Global Gas Security Review* provides a focus on the most recent trends in terms of demand and supply flexibility, and also addresses some risks associated with this growing flexibility, such as short-term LNG deliverability and shipping fleet availability.

Security lessons learned from last winter

China's unprecedented natural gas demand growth led to supply shortfalls over the last winter, which prompted immediate emergency measures as well as a range of policy and investment decisions being enacted since the beginning of 2018 to reinforce security of supply. These decisions include several new supply contracts signed and ongoing talks on future supply options to further develop and diversify China's natural gas supply portfolio. Last winter's events also highlighted the network's limits in terms of natural gas interconnection and storage capacity, which prompted a series of investment decisions to reinforce the country's infrastructure with new pipelines, regasification terminals and underground storage facilities. The government issued several new policy guidelines since last winter for natural gas medium-term targets and priority areas for deployment in order to "*win the battle for blue sky*".

Also during last winter, several episodes of cold spells combined with unplanned supply reductions occurred in Europe, without any physical supply shortage consequences observed for end users as supply flexibility enabled shippers to provide alternative sources of supply or use alternative routes. Several European Union member states used the crisis management measures as implemented by the 2017 update to the EU Gas Security of Supply Regulation. These events showed the resilience of the integrated European natural gas systems, highlighting the importance of implementing coordination policies, the role of network integration and the cooperation between network operators.

Contracts' flexibility enables the emergence of LNG midstream trade

Flexibility in the LNG trade keeps on improving towards a liquid and global market. The trend seen over the recent past, with a growing share of long-term volumes signed from new projects with flexible destination, has enabled the development of midstream flexibility sourced and procured by major portfolio players. These companies, who are the main long-term buyers of recent liquefaction projects, resell those volumes to third parties and provide an access to the LNG market to smaller buyers and new entrants through the development of a secondary market.

Term contracts signed in 2017 show a strong growth of short-term contracts with smaller volumes, alongside with a rebound in fixed destination contracts for those shorter-term volumes (Table ES.1).

Table ES.1 • Contract evolution by volume, before 2014, 2015-17

	Signed before 2014	Signed in 2015	Signed in 2016	Signed in 2017
Short-term (up to 1 year)	8%	16%	2%	24%
Flexible destination	39%	41%	42%	22%
Average contract duration (y)	16	10	9	4
Average contract volume (bcm/y)	1.7	1.0	1.2	1.0

Notes: Short-term excludes single spot transactions; y = year.
Source: IEA analysis based on ICIS (2018), *ICIS LNG Edge* (*subscription required*).

This recent evolution highlights the development of secondary markets where sellers source volumes from their portfolio of flexible long-term resources to meet the short term, small volume requirements of new entrants, who do not have access to primary sourcing from liquefaction projects and for whom destination flexibility is less of a priority. This development of a primary/secondary LNG market, alongside with existing traditional back to back contracts between producers and end users, is enabled by the development of destination-free, long-term contracts which provide the backbone of portfolio player's sourcing.

LNG market changes yet legacy contracts still weigh in medium-term outlook

In spite of the shift towards flexible LNG contracts with shorter duration and more destination flexibility in new contracts, a substantial number of fixed destination legacy contracts still remain. Existing flexible contracts (in force and future) will account for over half of contracted volume beyond 2021 but the uncertainty remains on currently uncontracted volumes, which more than double over the next five years.

As for pricing mechanisms, gas-to-gas indexation is becoming more common in new contracts, largely due to the development of US LNG. Oil indexation remains however the major component of price determination for export volumes, and even more for import volumes – especially in the Asia and Pacific region. The risk of a tighter crude oil market, together with seasonal tensions on LNG supply, puts additional pressure on LNG pricing. The lasting influence of oil indexation continues to impact the development of a flexible and liquid global LNG market.

Timeliness of LNG is a key issue for unexpected additional short-term supply

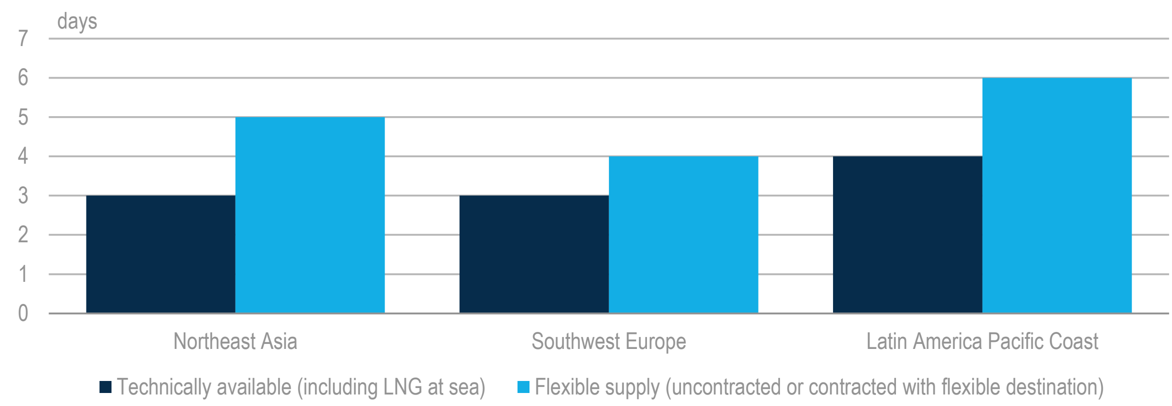
As LNG plays an increasing role in meeting mature and emerging markets' natural gas supply needs and the number of importing countries more than doubled over the past decade, the timeliness and readiness of LNG supply to cover for unexpected additional supply needs becomes a growing issue – especially for countries or territories which primarily rely on LNG to supply both volume and flexibility.

While the development of a global and flexible LNG market is a positive sign for the improvement of natural gas security of supply, the time it takes to ship or redirect cargoes of LNG (Figure ES.1) limits its immediate effectiveness in addressing an unplanned supply shortfall.

Hence spot and flexible LNG has to be considered as part of a broader range of security of supply shortfall mitigation tools including midstream components – network integration and line pack capability, storage capacity – as well as downstream – fuel switching capability in the power sector and demand response measures.

The markets analysed in the report's case studies have already developed most of these capabilities and are committed to further reinforce them in the future. Emerging gas markets – still in the early development phases of their natural gas infrastructure and regulatory framework – should not focus only on the upstream aspects of security of supply, but also on the development of downstream capabilities and the implementation of regulations fostering the creation of flexible domestic markets.

Figure ES.1 • Number of days needed to receive and regasify an unplanned additional LNG cargo

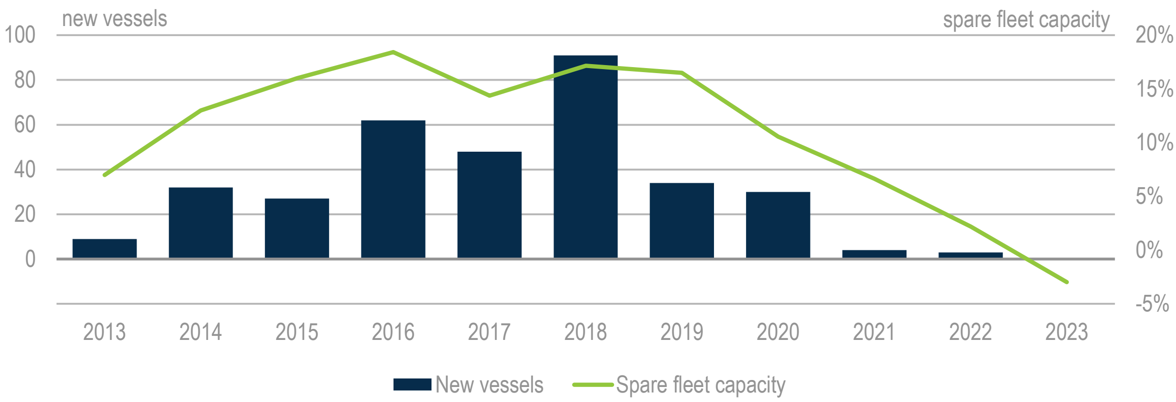


LNG market reshaping impacts shipping needs and could lead to a tight market

Once considered as a non-flexible complement supporting long-term sales and purchase agreements, the LNG carrier fleet is being affected by changes in the LNG market, with increasing demand for flexibility in supply and contracts of shorter duration. Such changes challenge the traditional LNG shipping business model, with greater uncertainty in medium-term fleet development and availability, and potential impacts on shipping price levels and volatility.

The "wave" of liquefaction projects development from investment decisions taken in the first half of this decade led to a strong level of new vessel deliveries, which ebbs after reaching a peak in 2018 (Figure ES.2). The absence of further growth of the LNG fleet poses a limit to future trade development both in terms of volume and flexibility delivery.

Figure ES.2 • LNG carriers additions and utilisation, 2013-23



The risk of a lack of timely investment in the LNG carrier fleet could pose a threat to market development and security of supply, which could materialise even earlier than the risk of insufficient liquefaction capacity.

1. Recent natural gas market developments and related security of supply issues

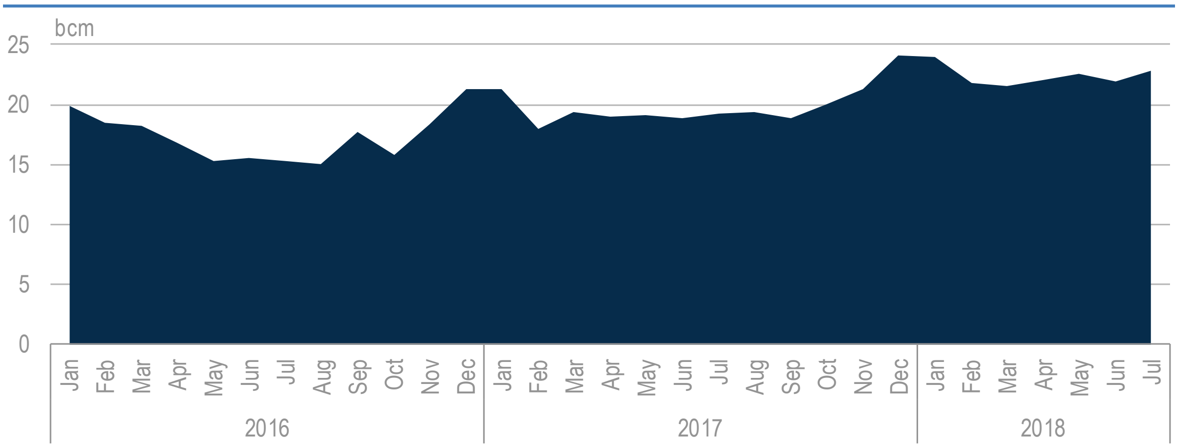
Global demand for natural gas grew by 3% during 2017, the highest increase since 2010, principally driven by the People's Republic of China (hereafter "China"), which accounted for 37% of the total increase. This chapter reviews four key gas security events from the past year:

- **China's gas shortages in the winter of 2017/18:** China's natural gas demand grew by an astonishing 14.5% during 2017, principally driven by strong government policies, particularly the coal-to-gas switching programme in the residential and industrial sectors. The country's increasing need for natural gas was largely met by imports of liquefied natural gas (LNG), which increased by 46% y-o-y and represented around 80% of the total increase in imports. The jump in demand was so strong during the winter that it grew faster than available supply, resulting in shortages in some regions and soaring import prices over the winter months. This chapter analyses the situation in greater depth, including implications for future infrastructure investment.
- **Technical issues in the European gas system on 12 December 2017**: A series of technical faults affected the United Kingdom's supply of natural gas, driving a response from the market. On the same day, a major technical incident at the Baumgarten facility in Austria disrupted flows of gas to Italy and other countries.
- **The "Beast from the East"**: An unusually cold spell at the beginning of March 2018 created a 20-year record surge in natural gas prices in the United Kingdom and a strong supply and demand response.
- **Ukrainian gas crisis**: Ukraine experienced gas shortages on 1 March 2018 when flows from the Russian Federation did not resume as had been anticipated.

Gas security events in China during 2017/18

The Chinese economy grew by 6.9% in 2017 (compared to global economic growth of 3.7%) and the country's total energy consumption grew by 2.9% to reach 3 143 million tonnes of oil equivalent (NBS, 2018). Natural gas increased its share of primary energy consumption to 7%, while experiencing a remarkable 14.5% growth in demand during 2017 compared to 2016. Data show that demand almost reached 135 billion cubic metres (bcm) in the first half (H1) of 2018, or a 17% year-on-year (y-o-y) increase on H1 2017, when demand totalled 115.6 bcm (Figure 1.1).

Figure 1.1 • Natural gas demand, China, 2016-18



Source: Data from Argus Media (2018a), *Argus Direct* (subscription required).

During 2017 the move towards a cleaner energy mix was strongly supported by the government, which intensified its policies in order to achieve the objectives in its 2013 Action Plan on Prevention and Control of Air Pollution. The policies created major growth in demand for natural gas. With domestic production not being able to ramp up as quickly, LNG regasification terminals working over capacity in northern China, and pipeline natural gas suppliers (Turkmenistan and Uzbekistan) dealing with domestic issues of their own, China faced supply tensions, especially during the winter of 2017/18, which caused natural gas shortages in several regions.

Causes of 2017 natural gas demand growth and winter imbalance

Strong policy-driven demand push to alleviate air pollution

During the winter of 2012/13 Beijing and the surrounding regions went through what the media called the "airpocalypse". In September 2013, the State Council officially issued the Action Plan on Prevention and Control Air Pollution (MEE, 2013) in order to improve overall air quality across the nation during a five-year period. The main objectives of the action plan were to reduce heavy pollution and improve air quality in the Beijing-Tianjin-Hebei region, the Yangtze River Delta and the Pearl River Delta.

Following introduction of the action plan, China's national oil companies (NOCs) made refinery upgrades to meet the new fuel standards. Power companies completed retrofits on over 800 gigawatts (GW) of coal plant capacity and shut down over 100 GW of old and inefficient coal plants. During this period, gas-fired power generation capacity grew rapidly, reaching 76 GW, and wind and solar energy capacity also expanded quickly. Gas demand grew steadily, averaging about 15 bcm per year for the period 2011-16.

The 2013 action plan's objectives included the elimination of coal-fired boilers with an average rate of 10 tonnes per hour (t/h) of steam or less. In 2014, the country had a total of 460 000 such coal-fired boilers with an average capacity of 4 t/h (1 77 million t/h of total capacity), consuming around 16% of overall coal consumption (IEA, 2017).

The situation in relation to coal-fired boilers in Beijing-Tianjin-Hebei can be summarised as follows (IEA, 2017):

- By 2016, industrial and residential coal-fired boilers with a steam capacity of less than 10 t/h had been eliminated in urban areas and newly built rural areas. Beijing and Tianjin had been accelerating the replacement or retrofitting of coal-fired boilers since 2012. During 2012-16 approximatively 1 300 coal-fired boilers were shut down or substituted by gas.
- During the spring of 2017 the switch from coal to gas gained momentum. In March 2017 the government issued the Beijing-Tianjin-Hebei and surrounding areas 2017 Air Pollution Control Work Plan in order to ensure the objectives and tasks defined for 2017 in the 2013 Air Pollution Prevention and Control Action Plan were achieved. Coal-fired boilers of less than 10 t/h in urban areas were expected to shut down by October 2017 (1 500 boilers in Beijing, 5 640 in Tianjin, 17 000 in Hebei, 15 700 in Shandong, 2 900 in Henan and 970 in Shanxi).
- At the end of 2016, the National Development and Reform Commission (NDRC) and the National Energy Administration (NEA) released a new five-year energy development plan, where the share of gas was to be increased from 5.9% in 2015 to 8.3-10% by 2020 (the 2018 National Gas Development Plan estimates 10% by 2020). The 2016 plan also sought to replace 189 000 t/h of coal-fired boilers with gas-fired by 2020 (equivalent to 45 bcm incremental gas capacity compared to 2015) (IEA, 2017).

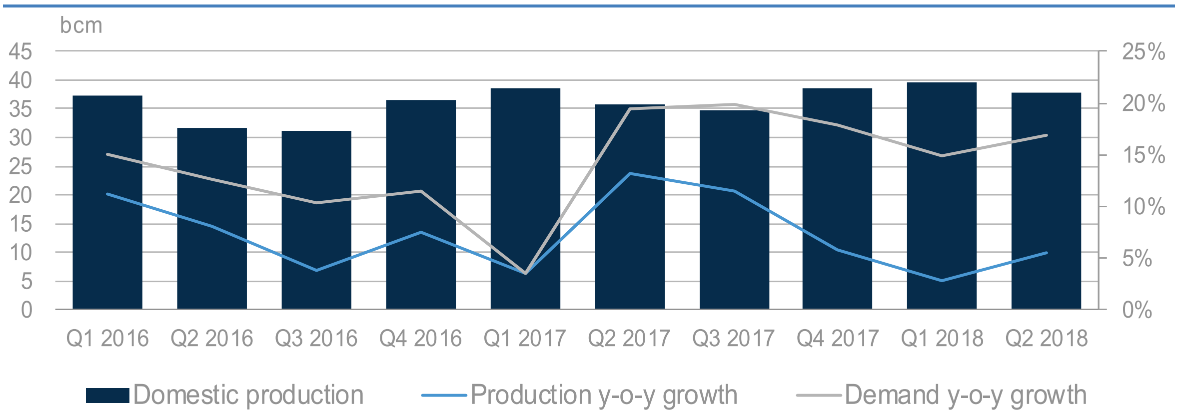
Between May and September 2017, the Ministry of Ecology and Environment (at the time known as the Ministry of Environmental Protection) fined or disciplined around 18 000 companies for not complying with the emission rules. The punishment included a total of USD 130 million in fines and disciplinary action against around 12 000 officials (SCMP, 2017). President Xi repeatedly stressed the need for environmental protection during his speech at the 19th Congress of the Chinese Communist Party, when he stated that, among other goals to be met between 2020 and 2035, there would be a fundamental improvement in the environment to achieve a "Beautiful China" (China Daily, 2017).

Largely as a consequence of these initiatives, natural gas demand in China increased by over 30 bcm in 2017, double the average of the previous five years. A portion of the conversions targeted residential coal use for heating, meaning that peak demand would increase even more quickly in the colder northern provinces. Additionally, the robust industrial recovery experienced during 2017 also helped boost the need for natural gas: in 2015 industry consumed 58 bcm, while in 2017 industrial consumption reached almost 78 bcm (a 34% increase).

Domestic production ramp-up slower than demand growth

Such robust growth in demand needed to be met by corresponding increases in supply. In the case of China these supplies came from domestic production, imports via pipeline from Turkmenistan and Uzbekistan, and increasingly from imported LNG. In fact, domestic production was able to increase output by 10 bcm to 147 bcm in 2017, far below the targeted production of 170 bcm (CEC, 2017) but nonetheless offsetting nearly a third of the increase. However, growth in production was much lower during the heating season, the last quarter of 2017 and first quarter of 2018, with just 6% and 3% y-o-y growth respectively (Figure 1.2). Production increased during the second quarter of 2018 with a 5% y-o-y increase.

Figure 1.2 • Domestic natural gas production, China, 2016-18



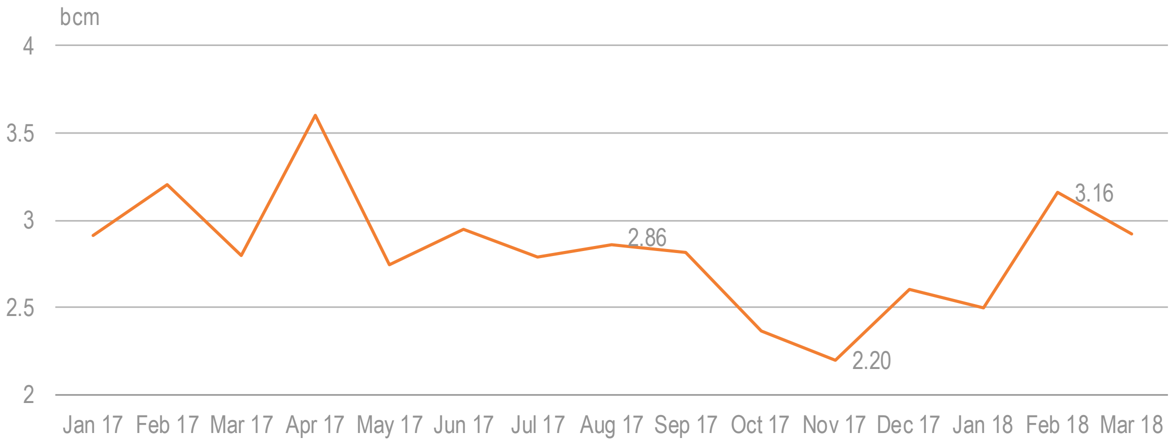
Source: Data from Argus Media (2018a), *Argus Direct* (subscription required).

According to NEA 2018 Energy Work Guidance, released earlier this year, domestic production is expected to rise to a target of around 160 bcm (8.8% y-o-y growth on production of 147 bcm in 2017). In September 2018, the State Council issued an order on natural gas for both local governments and companies (State Council of People's Republic of China, 2018c) setting a target for 2020 of 200 bcm.

Pipeline suppliers unable to deliver natural gas

In addition to domestic production falling well short of target, particularly in the winter months, pipeline imports also failed to keep pace. During the first quarter of 2018 volumes from Turkmenistan decreased by 3.8% compared to the same period last year. Turkmenistan has experienced a series of upstream limits and compressor failures since November 2017, especially during January when volumes dropped by 14.2% y-o-y. According to Petrochina, the Chinese state-owned NOC, the country suspended deliveries three times during that month (Argus Media, 2018b), reducing supply by 20 million cubic metres (m^3) per day compared with planned volumes. Consequently Petrochina had to limit gas supply to 12 major distributors across the country, including 4 located in north western Shaanxi (where supply was reduced by 9% on average), Gansu (where some industrial gas users were forced to shut down and gas-fuelled heating boilers had to run intermittently) and Qinghai provinces. Supplies returned to normal in February (Figure 1.3).

Figure 1.3 • Turkmenistan natural gas exports to China, 2017-18



Source: Data from Argus Media(2018a), *Argus Direct* (subscription required).

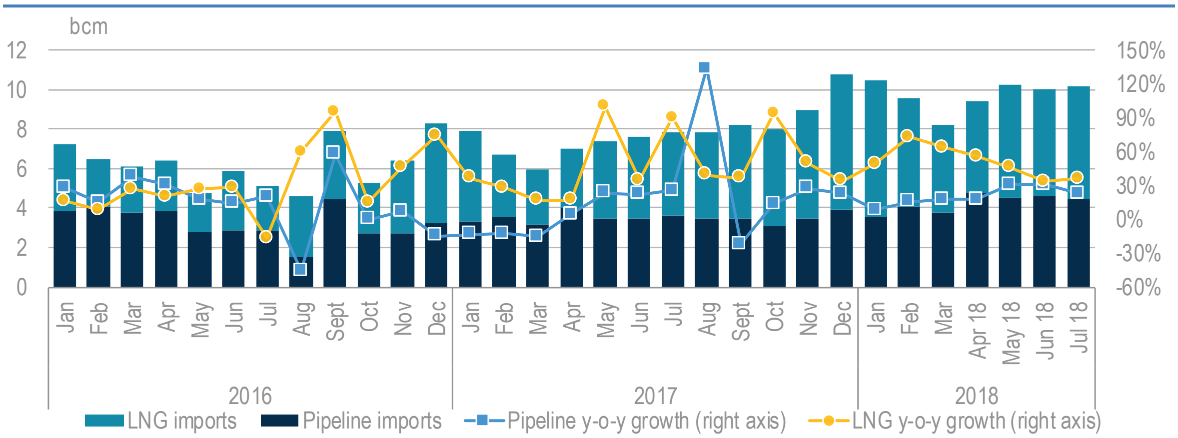
Supply from Uzbekistan is affected by the demand for gas in that country. Uzbekistan stopped winter gas flows to China during the first four months of 2017 in order to meet domestic demand. Flows started again in May 2017 with an average monthly volume of 0.45 bcm from May to December 2017. During the first quarter of 2018 volumes were low, with an average of 0.22 bcm per month.

Short-term LNG imports soared to meet rising demand

This situation left LNG to provide the incremental demand. In 2017 LNG imports totalled 52 bcm, 46% higher than in 2016, and China became the world's number two LNG importer after Japan, a position which Korea had held since 1994 (IEA, 2018).

The increase in LNG was four times the increase in pipeline imports. As a result, China's reliance on LNG has grown from 17% of total natural gas supply in 2016, to 22% in 2017, and 24% in the first half of 2018 (Figure 1.4).

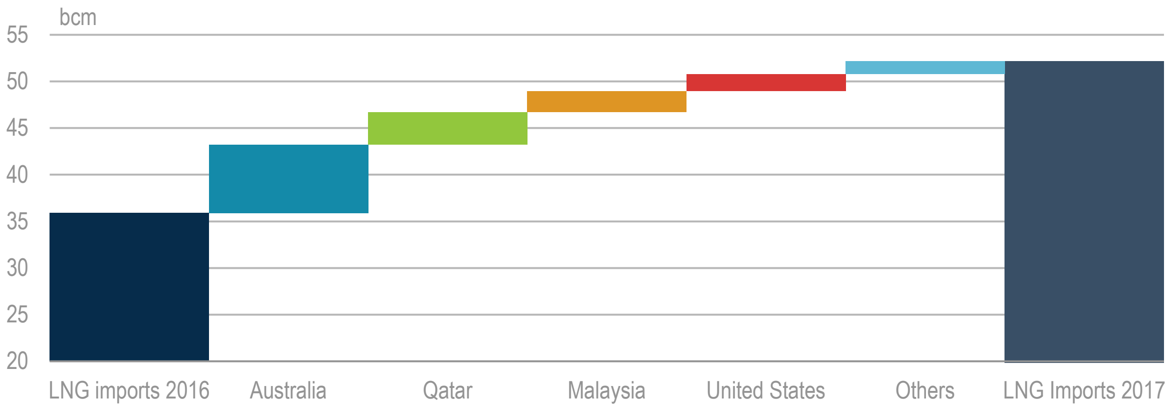
Figure 1.4 • Natural gas imports, China, 2016-18



Source: Data from Argus Media (2018a), *Argus Direct* (subscription required).

Australia supplied the largest share of the increase in LNG imports during 2017, providing 7.35 bcm mainly via long-term contracts, followed by Qatar (3.47 bcm) and Malaysia (2.24 bcm). The United States supplied 1.84 bcm more than it did in 2016 (Figure 1.5).

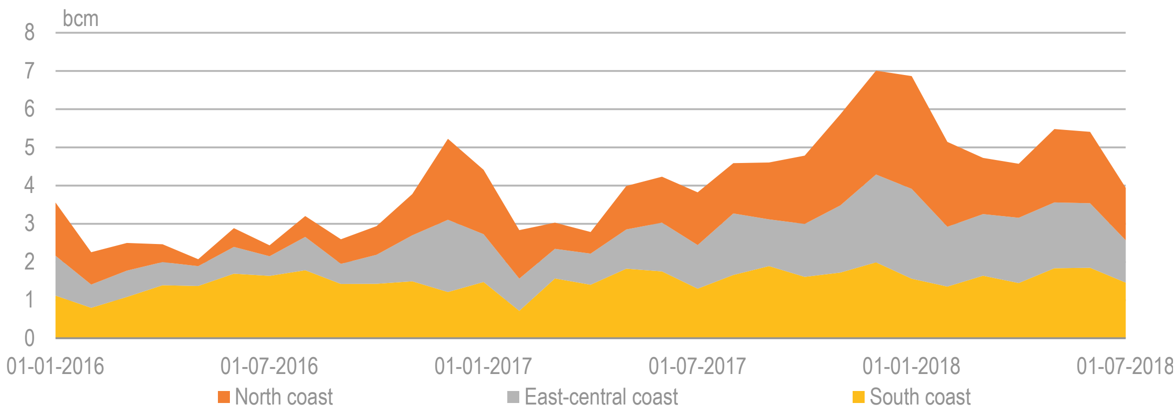
Figure 1.5 • Incremental LNG imports, China, 2016-17



Source: Data from Argus Media (2018a), *Argus Direct* (subscription required).

Regasification terminals located on the south coast delivered a total of 18.9 bcm during 2017, or 36% of total LNG imports (52 bcm), while terminals in the north delivered 17.6 bcm (34%) and those on the east-central coast of China 15.4 bcm (30%) (Figure 1.6).

Figure 1.6 • LNG regasification, China, 2016-18



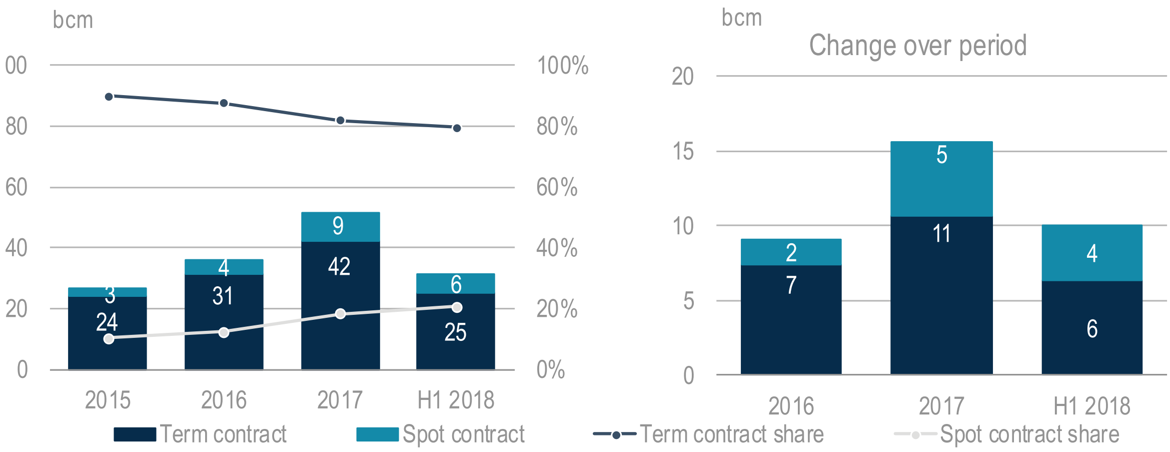
Source: ICIS (2018a), *ICIS LNG Edge* (subscription required).

In incremental terms, facilities in the north contributed 50% of the growth in LNG deliveries (or 8.1 bcm of 16 bcm), while east-central facilities contributed 34% (5.5 bcm) and terminals in the south only 15% of the incremental growth (2 bcm).

With regard to utilisation rates, north coast terminals operated at full capacity on average, some even working at 151% of their nameplate capacity. South coast terminals had a much lower average utilisation rate during 2017, at only 46%.

Spot LNG purchases experienced important y-o-y growth, increasing their volume from 4 bcm in 2016 to 9 bcm in 2017 (tripling their 2015 volume) (Figure 1.7). Their share of total contracted volumes increased to 18% in 2017 and to 21% during the first half of 2018. China National Offshore Oil Corporation (CNOOC) and China National Petroleum Corporation (CNPC) accounted for almost all of the spot purchases during 2017, at 95%. The remaining spot purchases came from other Chinese players such as Guanghui Energy, Beijing Gas Group, China Huadian and Shanghai LNG.

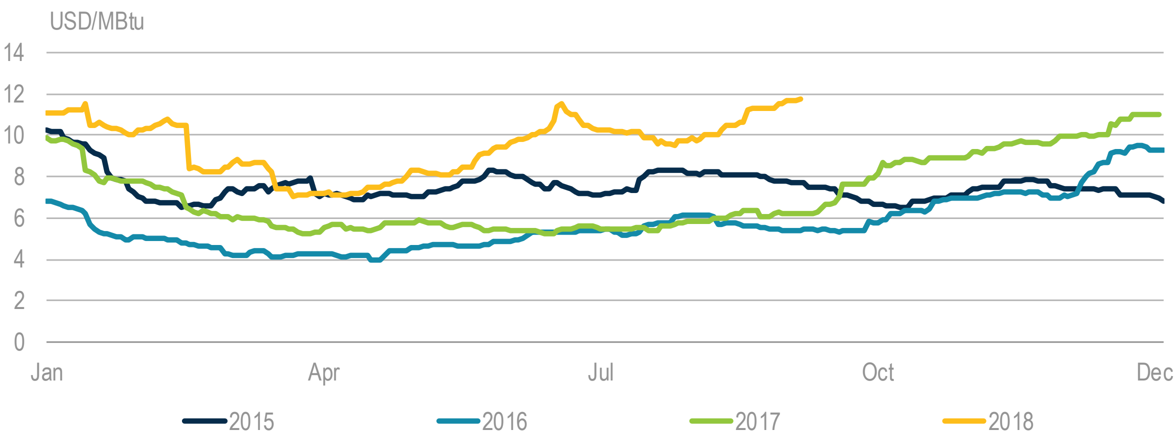
Figure 1.7 • LNG imports by type of contract, China, 2015-18



Source: ICIS (2018a), *ICIS LNG Edge* (subscription required).

During 2017, of all spot cargoes, 40% berthed at terminals along the north coast and 30% each along the east-central and south coasts. At the beginning of winter, in the last quarter, spot purchases rose again, with 80% heading to north and east-central coasts.

Figure 1.8 • Spot LNG import price, China, 2015-18



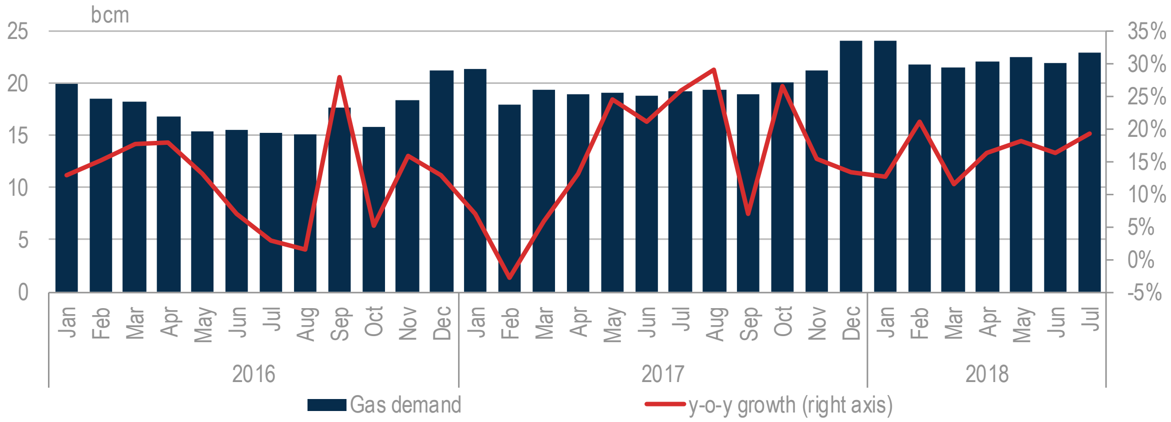
Source: ICIS (2018a), *ICIS LNG Edge* (subscription required).

China's spot LNG import price averaged USD 7.1 per million British thermal units (MBtu) in 2017, up 25% y-o-y. Prices peaked in December 2017 at around USD 11/MBtu (Figure 1.8). In the first half of 2018 the price averaged USD 9.1/MBtu, a 46% increase compared to the first half of 2017.

Handling the supply shortfall

Natural gas demand reached 237 bcm in 2017, reflecting close to 15% y-o-y growth, an astonishing rise compared to the 3% increase in global demand. Between May and August 2017 demand grew on average by 25% y-o-y, and by 16% on average y-o-y during November 2017 to February 2018 (Figure 1.9).

Figure 1.9 • Gas demand, China, 2016-18



Source: Data from Argus Media (2018a), *Argus Direct* (subscription required).

Supply allocation and substitution policies aimed at priority demand sectors

The stronger demand increase seen in northern China tested the ability of the Chinese gas infrastructure to deliver gas to the region, as gas system connections between southern and northern China are limited. While China's northern regasification terminals have been working above nameplate capacity, terminals in the south have been working at an average of around 46% (2017 data). State-owned companies had to develop solutions to bring natural gas from the south to the north in view of the lack of major pipelines connecting the regions.

Extraordinary measures were employed to improve gas supply:

- State-owned company CNOOC had to contract 100 trucks in December 2017 to transport LNG from its regasification terminals in the south, such as Zhuhai and Yuedong, to its industrial customers in the north. The trucks could transport 20 tonnes each. According to Reuters' calculations, delivering LNG by diesel trucks from Zhuhai to Baoding – a major city in the northern Hebei province struggling with gas shortages – would take about two days to cover the distance of 2 400 kilometres (km). Transport costs would be around CNY 50 400 (USD 7 455) per truck and the cargo's value would be around CNY 180 000 (USD 27 000). CNOOC's LNG had to be unloaded in the south because it has only one terminal in the north (Tianjin), which was already operating at full capacity (Reuters, 2017a).
- In December 2017 for the first time gas from provincial-level pipelines was injected into the trunk pipeline. Natural gas from the CNOOC Zhuhai LNG terminal (south) and South China Sea's production plant in Guangdong was injected into the CNPC west east pipeline (WEP) III in order to supply natural gas to north Guangdong (usually supplied by CNPC WEP III). By 12 December, CNOOC was injecting 7.25 million cubic metres per day (mcm/d) into CNPC's trunk pipeline in order to supply the Guangdong province. This allowed CNPC to allocate 7.25 mcm/d to supply natural gas to more than 1.5 million households in the north of China. In the NEA 2018 Energy Work Guidance document published in March 2018 this measure is referred as "south to north gas", alleviating bottlenecks (State Council of The People's Republic of China, 2018a).
- In January 2018 Sinopec delivered its first cargo of LNG transported by trucks from its regasification terminal in Beihai, Guangxi (south coast) all the way up to Zibo city in Shandong (north coast). The trucks travelled over 2 300 km (Reuters, 2018a).
- CNOOC also chartered two floating storage and regasification units (FSRUs) on a short-term basis to prepare for higher imports during winter (Reuters, 2017b).

Box 1.2 • China's north-south connection – infrastructure improvements

China has no major pipelines connecting the north to the south. Natural gas demand soared during the winter of 2017/18, especially in the northern regions due to heating needs. Chinese companies are implementing measures to prepare for this winter's demand:

- In August 2018, CNOOC brought into operation its ninth regasification terminal in Shenzhen Diefu (south coast), and, thanks to the agreement reached with CNPC, CNOOC will be able to deliver 17 mcm/d of supply capacity to the south so CNPC can divert the volumes to northern China this winter (CNPC, 2018a).
- Petrochina has committed to invest more than CNY 25.8 billion (USD 3.8 billion) to implement 33 interconnection projects starting in 2018-19, in order to optimise the pipeline system (national and regional) and solve the bottleneck problems. Since the beginning of this year, Petrochina has been working with Sinopec and CNOOC to connect the Guangdong LNG terminal to the WEP and connect Guangxi LNG terminal to the China-Myanmar pipeline to serve demand in the south (CNPC, 2018b).
- CNOOC announced in July 2018 that they will progressively provide third-party access to their terminals in the provinces of Guangdong and Zhejiang during the second half of 2018, allowing other NOC or private companies to unload their LNG.
- In August 2018, Sinopec announced various measures to reinforce winter supplies, such as renting 2 600 trucks to deliver LNG from the south to the north, increasing the purchase of spot cargoes, and improving its pipeline connection with CNPC and CNOOC pipelines.

Sources: CNPC (2018a), "CNOOC Shenzhen LNG receiving station officially put into operation'', http://center.cnpc.com.cn/bk/system/2018/08/02/001699768.shtml; CNPC (2018b), "Petrochina increases investment to promote national pipe network optimisation", http://news.cnpc.com.cn/system/2018/08/16/001701196.shtml.

As these actions were not sufficient to ensure adequate supply to northern China, the NDRC took demand-side measures in December 2017 by ordering state-owned companies to cut gas supplies to the industrial sector and divert them to the north of the country. German chemical group BASF declared force majeure on 12 December for production at its Chongqing plant as its supplier could not deliver natural gas (BASF, 2017). Natural gas-powered fertiliser plants also had to shut down in Sichuan and Yunnan (southwest China) since companies such as Petrochina started to reallocate the fuel to residential users in the north. China's largest fertiliser producer, Yuntianhua, had to close its facility in Yunnan (southwest China) on 11 December (Bloomberg, 2017a). In some parts of China, gas-fuelled vehicles had to face long lines for refuelling. In other cases, coal-fired power plants were permitted to restart to reduce gas consumption (See Box 1.3).

Box 1.3 • Huaneng Beijing Thermal Power Plant back in operation

Because of the tight supply of natural gas, on 7 December 2017 the Beijing Municipal Committee for Urban Management issued an urgent notice saying that the State Development and Reform Commission called for the immediate restarting of the coal-fired unit, Huaneng Beijing Thermal Power Plant, located in Gaobeidian village and with an installed capacity of 845 megawatts (MW) (Bloomberg, 2017b). This was to reduce the city's natural gas consumption and to alleviate the natural gas tension in the north of China. After more than six months of coal-free power generation (Beijing closed all coal-fired units in heating and power plants in March 2017), the Huaneng plant restarted operations during December.

Also during December 2017 the Ministry of Ecology and Environment told northern regions to allow coal burning in places where switching to gas or electric heating was not possible, in order to ease the natural gas shortfall. To ensure priority to residential natural gas users over industry, the NDRC ordered state-owned energy companies to cut supply to industrial users to save around 15 mcm/d (Reuters, 2018b). This was a particular setback for industrial customers who had just converted from coal-fired boilers to gas and now needed to interrupt production or switch to other fuels if possible.

Sources: Bloomberg (2017b), "China's anti-pollution efforts get a reality check", https://www.bloomberg.com/news/articles/2017-12-10/freezing-cities-force-china-to-ease-anti-pollution-curbs-on-coal; Reuters (2018b), "China's LNG prices drop as industrial users curbed, supply crunch eases", https://uk.reuters.com/article/us-china-lng-prices/chinas-lng-prices-drop-as-industrial-users-curbed-supply-crunch-eases-idUSKBN1ET10M.

Consequences of the natural gas shortage

The natural gas supply issues experienced last winter did not structurally challenge the fuel's role in China's energy mix and policy, but triggered several actions in the form of supply diversification, infrastructure development and policy framework.

Moves to develop and diversify the natural gas supply portfolio

In February 2018 Cheniere Energy announced that it had entered into two LNG sale and purchase agreements with Petrochina. According to the contracts, Petrochina will purchase 1.63 billion cubic metres per year (bcm/y) from Corpus Christi LNG, with some volumes starting in 2018 and the rest in 2023 up to 2043. However, uncertainties on trade policies emerged in early August when China threatened to impose a tariff of 25% on LNG imported from the United States. China announced on 18 September the imposition of a 10% tariff on US LNG from 24 September. In April 2018 CNOOC launched a tender for 32 LNG cargoes to be delivered from 2018 to 2022. In July 2018 Petrochina and ExxonMobil's Papua New Guinea LNG export terminal agreed a three-year deal of around 0.61 bcm/y (Platts, 2018a). In August, Petrochina advanced its conversations with Qatar to secure LNG supply, both in the short and long term, and in early September they signed a 22-year deal for around 4.6 bcm/y starting in 2018. The LNG will be deliverable to different regasification terminals such as Dalian, Tangshan (north coast) and Jiangsu (east-central coast).

To support this future development of LNG imports, new receiving terminals are expected in the short term. Three onshore LNG import terminals (Tianjin Nangang, Shenzen Diefu and Zhoushan) already started operations during the first nine months of 2018, while the Qidong expansion will come on line by the end of 2018. These new import terminals will add 14.3 bcm/y of LNG import capacity. By the end of this year, the country will have a total regasification capacity of 87.6 bcm/y. Thanks to the Tianjin Nangang terminal, the north coast's regasification capacity increased by 4.1 bcm/y (to 20.2 bcm/y). In addition, in June 2018 CNOOC and Hoegh signed a time charter for the FSRU Hoegh Esperanza for three years with a one-year extension, starting immediately. The FSRU will be utilised at the Tianjin LNG terminal (Hoegh, 2018). Other projects decided since the beginning of 2018 will help increase LNG import capacity further (see Box 1.4).

Box 1.4 • Recent developments in LNG terminals

Since the beginning of winter 2017 and up to the time of writing, construction of several projects has started. Petrochina and Beijing Enterprises Group announced the expansion of the Tangshan LNG terminal with the construction of four additional storage tanks. State-owned company CNOOC started the expansion of the Ningbo LNG terminal, adding another 4.1 bcm/y to its regasification capacity (Reuters, 2018c). CNOOC also started the construction of its Jiangsu Binhai LNG terminal (Platts 2018b) and in May 2018 the construction of the Zhangzhou LNG terminal located in Fujian province (each 4.1 bcm/y) (Interfax, 2018b). In June 2018 the company launched expansion of the Tianjin LNG terminal, adding another six LNG storage tanks to help meet demand in the northern region of the country (Reuters, 2018d). In April the NEA visited the Lianyungang site (Jiangsu) to speed up Sinopec's project there (Lianyungang Development and Reform Commission, 2018). In late July Sinopec received Shandong Provincial Development and Reform Commission approval for expansion of its Qingdao LNG facility. Sinopec is also planning to keep pursuing the development of three new LNG terminals: in Wenzhou (Zhejiang province), in Nantong (Jiangsu) and in Longkou (Shandong). Sinopec aims to reach 60 bcm/y of regasification capacity by the end of 2023 through the expansion of its current three terminals (Qingdao, Tianjin and Beihai with a current capacity of 12.3 bcm/y) (Reuters, 2018e).

Among the private operators, Guanghui has initiated construction of its Qidong LNG expansion project (0.8 bcm/y). It appears that construction of the peak storage and transport station jointly developed by GCL, Hangzhou Gas and Jiaxing Gas in Jiaxing Pinghu (Zhejiang province) is also under way (1.4 bcm/y). Zhongtian Energy also began construction of its LNG terminal in Jiangyin during 2018 (Jiangyin, 2018).

China is starting to develop inland LNG receiving and storage terminals in order to keep expanding the LNG market. In July 2018 private companies Guanghui Energy and China Huadian Corporation announced their intention to build an inland LNG terminal in Yueyang city (Hunan province), with a capacity of 2.72 bcm/y. The terminal is due to be built in three phases: the first phase is expected to be ready by December 2020 and will have a capacity of 0.68 bcm/y. The LNG will be sourced from Guanghui's LNG terminal in Qidong (Jiangsu province).

In September 2018 ExxonMobil signed a preliminary deal with Guangdong Yuedian Group, as well as the local governments of Guangdong and Huizhou, to build a petrochemical complex and invest in an LNG terminal in Huizhou.

Sources: Reuters (2018c), "Petrochina, Beijing firm doubling LNG storage in Caofeidian as demand rises", www.reuters.com/article/us-china-lng-expansion/petrochina-beijing-firm-doubling-lng-storage-in-caofeidian-as-demand-rises-idUSKBN1D60VM; Platts (2018b), "CNOOC to expand China's LNG import capacity by 6 million mt/year by 2021", www.spglobal.com/platts/en/market-insights/latest-news/natural-gas/070518-cnooc-to-expand-chinas-lng-import-capacity-by-6-million-mtyear-by-2021; Interfax (2018), "CNOOC starts work on Zhangzhou LNG terminal", http://interfaxenergy.com/gasdaily/article/31103/cnooc-starts-work-on-zhangzhou-lng-terminal; Reuters (2018d), "CNOOC to build 6 storage tanks in Tianjin LNG terminal expansion", https://af.reuters.com/article/commoditiesNews/idAFL3N1T31VE; Lianyungang Development and Reform Commission (2018), "The National Energy Administration came to investigate LNG receiving station", www.lyg.gov.cn/lygsfzhggwyh/nyc1/content/7f82cc52-23dd-4c01-9669-033786de2062.html; Jiangyin Government (2018), "Jiangyin's first new energy terminal settled in Lingang Development Zone", www.jiangyin.gov.cn/lgjjkfq/a/201805/8s35l6nuq0j9.shtml; Reuters (2018e), "Sinopec to increase LNG spot cargoes purchase, expand terminal capacity", https://af.reuters.com/article/commoditiesNews/idAFL3N1VP38S.

Besides the Power of Siberia 1 pipeline (38 bcm/y), which is scheduled to start operation by the end of 2019, Gazprom and CNPC had resumed talks by the close of 2017 on the proposed 30 bcm/y Power of Siberia 2 pipeline. According to China Daily News, a subsidiary of CNPC has started to seek additional gas supply to feed the pipeline between Myanmar and China. CNPC has been importing gas from the Daewoo International fields in Myanmar since 2013 via a 30-year contract, and is now looking to identify new gas deposits as well as following up new gas fields developed by Daewoo International and other companies. The firm is also considering building an LNG terminal located at the starting point of the China-Myanmar pipeline in order to feed gas into the pipeline (Reuters, 2018f).

Increasing market liquidity and responsiveness with the development of trading hubs

The Shanghai Petroleum and Natural Gas Exchange (SHPGX) was launched in 2015 and officially opened in November 2016 as a step further towards market-oriented reform of the gas sector. At the end of 2017, it was announced that China would launch its second gas trading exchange in Chongqing (location of China's largest shale gas development) in order to develop a benchmark gas price for Asia.

Since September 2017, and due to the seasonal natural gas shortage, liquidity in the Shanghai exchange has increased. In January 2018 CNOOC listed cargoes at up to CNY 5 100 per tonne (t), or USD 15.5/MBtu, for delivery in January and February 2018. In April 2018 the company sold 90 000 t of LNG for delivery in July and September from the Ningbo LNG terminal in Zhejiang (SHPGX, 2018). According to the news, 18 bidders participated in the auction, with 60 000 t for July delivery sold for around CNY 3 380/t (USD 500/t or USD 10.30/MBtu) and the rest for November delivery sold for around CNY 4 200/t (USD 620/t or USD 12.80/MBtu). By contrast, according to Platts, Japan/Korea Marker (JKM) ICE settlement prices for LNG cargoes stood at USD 7.95/MBtu for July delivery and USD 9.25/MBtu for November delivery (excluding 10% VAT, port fees and handling fees) (Platts, 2018c). It is expected that the auctions on the SHPGX will help avoid natural gas shortages.

Developing infrastructure with a focus on underground storage

The shortages experienced over the past winter shed light on the lack of sufficient infrastructure to deliver gas to the colder regions of China during annual peaks in demand. New supplies, such as the Power of Siberia pipelines, should help alleviate the situation, as should improved links between southern and northern China. To that end, Petrochina intends to invest more than CNY 25.8 billion (USD 3.8 billion) to implement 33 interconnection projects between 2018 and 2019 in order to optimise the pipeline system (national and regional) and solve the bottleneck problems. In addition, Petrochina has been working with Sinopec and CNOOC to connect the Guangdong LNG terminal to the WEP and connect Guangxi LNG terminal to the China-Myanmar pipeline.

One obvious shortcoming in China's gas system is the level of working gas storage capacity. China's underground gas storage (UGS) capacity accounted only for 3% of its annual consumption, far below the level of other countries. The 25 existing UGS facilities (Map 1.1), with a designed capacity of 41.5 bcm but a working capacity of only 10 bcm according to the NEA, are far from sufficient to ensure gas supply is reliable as demand continues to grow.

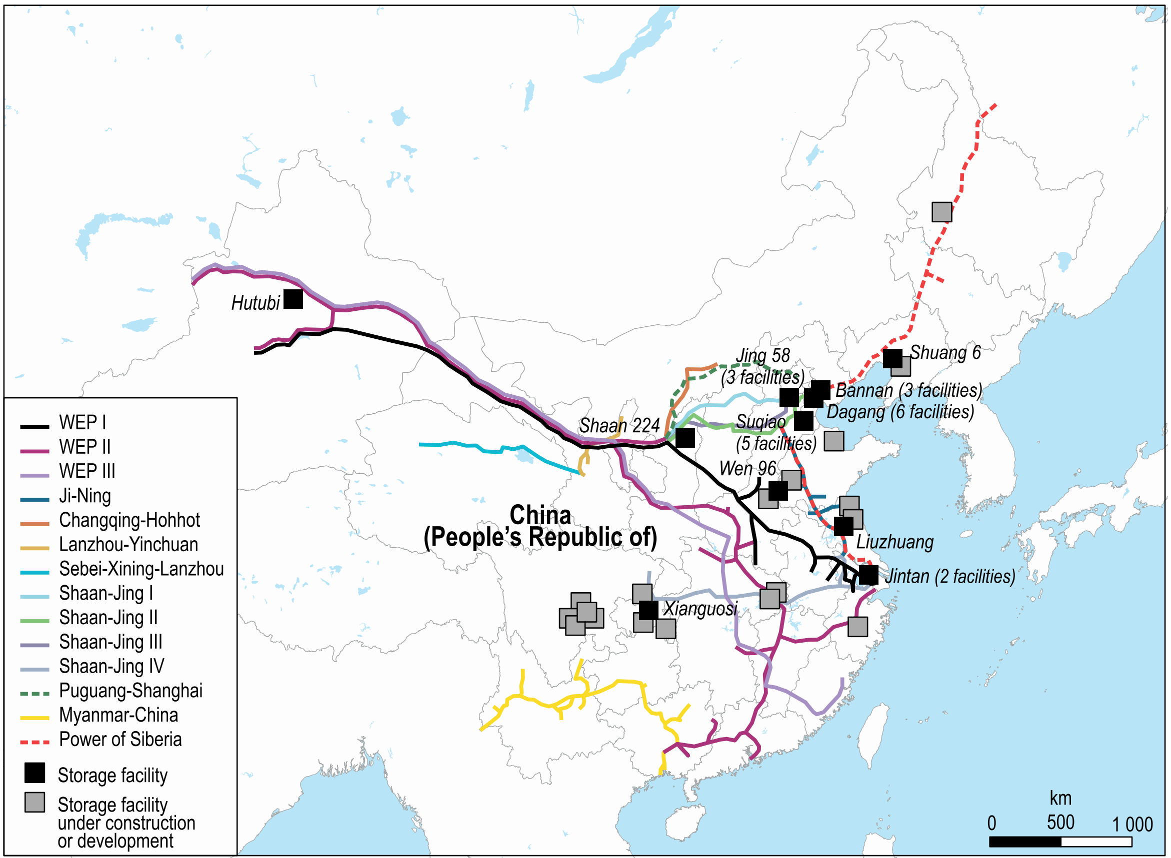
CNPC, owner of 23 of the 25 UGS facilities, supplied a record of 7.4 bcm of natural gas last winter, a 21% jump from the previous year, to ease the pressure of peak gas demand in winter. The company plans to supply an additional 700 mcm this winter. In April 2018 the company started gas injection operations at all its 23 facilities in order to be able to guarantee the gas supply during the coming winter (China Daily, 2018). It is also currently building the Chuzhou gas storage facility in the city of Huai An (Jiangsu province) – work started in May 2018 (CNPC, 2018c). Moreover, the company is planning to build eight new UGS facilities with a peak capacity of more than 57 mcm/d, representing total planned investment of over CNY 21 billion, or USD 3.1 billion. The construction of these eight new UGS facilities, all in the southwest region, can be roughly divided into three stages (CNPC, 2018d):

- The first stage consists of converting the depleted gas fields in Tongluoxia (already under way) and Huangcaoxia into gas storage. The two gas fields are close to the backbone network and Chongqing City. The total cost of both facilities is CNY 5.3 billion (USD 830 million) and they are due to be completed by 2022, ensuring an annual supply of 1.28 bcm of gas.
- The second phase comprises converting gas fields in Moujiaping, Shengongshan, Xinglongchang, Zhaigouwan and Wanshunchang. These UGS facilities are close to gas production sources and the pipeline network and are aimed at guaranteeing gas demand in Chengdu (Sichuan province).
- The third phase is strategic gas storage. The primary objective is the reconstruction of gas storage in the Shapingchang gas field located near Chongqing city, a facility designed to have a high peak load capacity.

Additionally, another branch of Petrochina announced in March 2018 that they would accelerate the construction of a further six new UGS facilities. They will be located in Daqing Shengping (Heilongjian province), Pingdingshan (Henan), Huai An (Jiangsu), Liaohelei 61 (Liaoning), Dagang Lujuhe (Tianjin) and Zhejiang Baiji (Zhejiang). Daqing Shengping will be the first volcanic rock gas storage facility in the world, will receive volumes from the Sino-Russian pipeline and will play an important role in meeting peak demand in the northeast provinces. The facility is due to be in operation by 2025 (CNPC, 2018e).

Sinopec, owner of the other two existing UGS facilities, is expected to open its third facility by the end of 2018. With a working gas capacity of 4 bcm, and a designed capacity of 10.4 bcm, the facility is being constructed in the depleted Wen 23 gas field in the Zhongyuan oilfield, Henan province. It will supply gas to northern cities during the winter heating season (Interfax, 2017; Sinopec, 2018). Sinopec also reported last year that it was conducting preliminary works on the Huangchang salt caverns and Guanghua sandstone reservoir in the Jianghan oilfield (Hubei province); according to the findings, the 40 potential cavities at Huangchang could have a total storage capacity of 5.2 bcm, while the Guanghua reservoir could hold 3.45 bcm (Sinopec, 2017).

Map 1.1 • Natural gas demand, China, 2016-18 gas storage and trunk pipelines, China, 2018



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.

Note: WEP = West-East Gas Pipeline.

CNPC is therefore looking to develop UGS facilities in northern China, such as the Daqing facility in Heilongjian, which will store the Sino-Russian piped gas to these regions. Most of its future developments are located in Sichuan and Chongqing in southwestern China, which were among the earliest places to produce domestic natural gas in China; these provinces have relatively better geological conditions and a much better pipeline infrastructure network. They are also close to the main areas of natural gas consumption. The company is looking to develop other facilities that could supply gas to the central coast of China, in Zhejiang and Jiangsu provinces.

As for Sinopec, besides the facility under construction in Henan province, which is due to supply the central coast of China, the company is looking to develop further UGS facilities in Hubei.

While these projects together will significantly increase China's storage capabilities, it faces limits to the development of UGS capacity. Unlike other countries, such as the United States, China does not have an ample supply of cheap storage options in the form of depleted oil fields and underground salt caverns. Additionally, China's government keeps tight control over gas prices. In the United States and Europe, whenever winter prices rise relative to summer, the incentive is created to invest in new storage to take advantage of seasonal arbitrage. A more liberal gas-pricing regime in China might draw more companies into the storage market (Bloomberg, 2018a).

In April 2018 the NDRC published a new policy to promote gas storage and peak-shaving mechanisms (State Council of People's Republic of China, 2018b). The document reiterates some of the gas reserve requirements for gas suppliers published in 2014 and lays out a road map for China to achieve a reasonable peak-shaving capability by 2020. As of the end of 2017 the available working capacity of China's UGS facilities only amounted to just 3% of total gas consumption, significantly lower than the international average of 12-15%. The tank capacity of its LNG regasification terminals amounted to 2.2% of national consumption (about 9% of LNG turnover in the country), while in Japan and Korea it stands at 15%. The government identified the lack of gas storage capacity as the major impediment to gas market development and the fundamental cause of the gas shortage during recent winters. To improve the situation, the NDRC policy quantifies storage targets for three types of gas market participant. By 2020, gas storage capacity should amount to:

- local government – storage capacity equivalent to no less than three days of average daily consumption
- city gas companies – storage capacity equivalent to no less than 5% of annual gas consumption
- gas supply companies – storage capacity no less than 10% of annual contracted sales volume.

The document also sets out a nationwide gas peak-shaving mechanism, with four layers of supply and demand measures to support gas market balance:

- primary measure – large-scale UGS facilities and LNG storage at receiving terminals
- secondary measure – emergency LNG storage
- supplementary measure – upstream fields, alternative energy and other supplies
- supportive measure – interconnection of the pipeline system.

In this document the government also defines the responsibility of each player in the gas sector:

- pipeline enterprises are responsible for emergency response besides performing their responsibilities under pipeline service contracts
- city gas enterprises bear the responsibility of meeting peak-hour demand
- local government is responsible for co-ordination and implementation.

The government is encouraging all kinds of investment entities to participate in the construction and operation of gas storage facilities, including gas suppliers, pipeline operators, city gas providers, large users and independent third parties. The document also encourages gas storage facility operators to obtain reasonable revenues by providing gas storage services, or to benefit from natural gas seasonal price differentials.

The government's storage targets are not technology specific and can be met with underground storage, LNG terminal storage, small-scale emergency LNG or compressed natural gas station storage, and demand management contracts.

New policy guidelines for natural gas targets

In December 2017 the government published its plan for heating in northern China, shifting the clean air campaign from "coal to gas" to "dispersed coal to clean coal". The initiative, announced by the NDRC, the NEA and 10 government agencies, is a 5-year plan (2017-21) to convert Chinese cities to clean heating during winter (Table 1.1) (NDRC, 2017).

The plan includes measures that will increase natural gas demand by 23 bcm/y by 2021. The switching of coal-fired to gas-fired boilers in 12 million households increases demand by 9 bcm/y, and the newly built and reconstructed gas-fired co-generation plants (additional capacity of 11 GW) by 7.5 bcm/y. The 50 000 t/h of steam generated at newly built and renovated gas-fired boilers will add a further 5.6 bcm/y, while the 1.2 GW of additional capacity in the form of gas-fired distributed heat adds another 0.9 bcm/y (NDRC, 2017).

Table 1.1 • Natural gas heating development target for "2+26'' cities

Northern regions	2019	2021
Overall objectives	Clean heating rate to reach 50%, replacing 74 million tonnes of bulk coal used in low-efficiency and small coal-fired boilers	Clean heating rate of 70%,replacing 15 million tonnes of coal
	All new users should use high-efficiency equipment, while the users of old equipment should gradually upgrade	
"2+26" area goals	Clean heating rate in the "2+26 cities should be over 90%, while in rural areas it should be 40%	All urban districts should have clean heating systems, and all coal-fired boilers under 35 steam tonnes should be demolished; rural areas should reach 60% efficiency
Other regional goals	Clean heating rate in cities should reach at least 60% (20% in rural areas)	Clean heating rate in cities should reach at least 80% and all coal-fired boilers in the cities under 20 steam tonnes should be demolished; rural areas should reach 40% efficiency

Note: the "2+26" cities are located in Beijing-Tianjin-Hebei and surrounding areas.
Source: NDRC (2017), *Natural Gas Heating Development Target for '2+26' Cities*.

In mid-2018, as part of the "blue sky defence war", the State Council unveiled a three-year action plan with further targets to lower emissions in urban areas (Box 1.5). Then, the Ministry of Ecology and Environment launched a one-year inspection programme to assess compliance with anti-pollution measures (Box 1.6).

Box 1.5 • Winning the battle for blue sky

In June 2018 the State Council released a three-year action plan to win the battle for "blue sky". The plan focuses on the Beijing, Tianjin and Shanghai areas, and the key cities of Hebei, Henan, Shaanxi, Shanxi, Shandong, Jiangsu, Zhejiang and Anhui. The implications for gas demand are complex, as it looks on the one hand to develop gas storage, but prevents development of gas-fired co-generation plants on the other.

The government has set 2020 targets to reduce SO2 and NOx emissions by at least 15% from 2015 levels. Regarding particular matter, PM 2.5 is targeted to fall by at least 18% in cities with low air quality standards. The ratio of days with good air quality should reach 80% annually, and the percentage of heavily polluted days should decrease by 25% or more from 2015 levels.

By 2020 the share of coal in China's energy consumption should decrease to less than 58%. Coal consumption in Beijing, Tianjin, Hebei, Shandong and Henan should decrease by 10% compared to 2015 levels, and decrease by 5% in the Yangtze River Delta. By 2020 over 55% of coal consumption should be for electricity generation, up from 43% in 2015. The government is trying to concentrate the use of coal in the power sector since coal-fired power plants have undertaken many upgrades over the past decade and they have reached the same emissions standards as gas-fired plants.

Aware of the gas supply shortage during the winter of 2017/18, the government continues to push infrastructure development forward, especially gas storage systems. By 2020, natural gas is expected to account for 10% of China's energy consumption. New gas projects are to be prioritised in the form of a coal-to-gas switch in urban cities and severely air polluted areas. However, the new policy announced a halt to new gas-based co-generation plants and gas use as a feedstock for chemical projects. Moreover, the plan specifies the orderly development of new natural gas-fired peaking power stations and other interruptible gas use.

Clean coal is seen as a tool for reducing air pollution in the heating sector. Distributed coal boilers in the Beijing-Tianjin-Hebei region, the Yangtze River Delta and some parts of Shaanxi province should be eliminated by 2020. Coal-fired units that have not been upgraded to environmental, and safety standards with a capacity of below 300 megawatts (MW) should be phased out. Additionally, by 2020 all coal-fired boilers and small-scale plants located within less than 15 km of a co-generation plant

(300 MW and above) should be shut down. These measures are aligned with the Clean Heating Plan's goal to reduce dispersed coal and substitute it with other fuels such as gas and electricity, and also clean coal.

The plan encourages the improvement of energy efficiency, looks to speed up clean and renewable energy (by 2020 non-fossil energy is to account for 15% of total energy consumption and curtailment of hydropower, wind and solar should be solved) and ban any further capacity for iron, coking coal, aluminium, cement and glass in the specified geographical areas. Regarding transport, by the end of 2020 the production of new energy vehicles is to reach 2 million units and sales of new energy or clean energy vehicles is to reach 80% of all sales. The plan also looks to develop rail freight transport with a target of increasing freight volume by 30% in 2020 compared to 2017 (with even bigger growth for other regions, such as a 40% increase in Beijing-Tianjin-Hebei).

As for natural gas, new gas-fired co-generation plants have been halted. The plan looks to promote the use of gas vehicles that meet the national emissions standards (although no further detail is given), and promote the use of new energy or clean energy carriers such as electricity and natural gas. Industrial furnaces and kilns are encouraged to use clean energy such as electricity and natural gas, or to source heat from surrounding thermal power plants.

Source: State Council of People's Republic of China (2018d), *The State Council issues a three-year action plan to win the battle for the blue sky*.

In August 2018 the NEA published the 2018 National Natural Gas Development Plan (State Council of People's Republic of China, 2018c). In the document, the government enumerates different solutions to solve the problems that emerged during the rapid adoption of natural gas, especially during 2017-18, pointing out the lack of production, supply and storage capacity that led to insufficient natural gas being available to keep up with demand. Even the Chinese government acknowledged that the lack of a market mechanism for natural gas was a major problem during the supply shortage, which is why the National Natural Gas Development Plan stresses the need to improve market mechanisms as well as to keep broadening supply diversity.

Box 1.6 • The intensive supervision programme for key areas

On 7 June 2018 the Ministry of Ecology and Environment issued the "Program for intensive supervision of the key areas of the blue sky defence war of 2018-2019" (MEE, 2018a). Although air quality is improving in the key geographical areas, pollution is still heavy in the industrial zones. The Beijing-Tianjin-Hebei region is still one of the worst for air quality in China.

The programme began on 11 June 2018 and concludes on 28 April 2019. The ministry is arranging around 200 inspection teams for the "2+26" cities and other main cities covered by the programme, each team consisting of 3-4 people. The main work of the supervision programme is to see whether the enterprises have put in place anti-pollution measures, to check coal-fired boilers and to verify implementation of emergency measures for heavy pollution. The scope of the supervision will be the "2+26" cities (Beijing-Tianjin-Hebei and surrounding areas) and a further 11 cities in Shanxi, Henan and Shaanxi provinces and the Yangtze River Delta region (Shanghai, Zhejiang, Jiangsu and Anhui). The inspection of coal-fired boilers will take place during the first phase of the programme, 11 June to 5 August 2018. The results of the supervision programme are updated daily on the ministry's web page. For example, on 4 August the 200 inspection teams supervised 210 districts in different cities in Hebei province (MEE, 2018b). The document lists 110 problems, revealing company names and the types of problems found, e.g. the need to eliminate coal-fired boilers, failure to implement dust control measures, pollution control facilities not installed.

Sources: MEE (2018a), *Interview with the person in charge from the Ministry of Ecology regarding the supervision of key areas in the blue sky defence war from 2018-2019*; MEE (2018b), *Progress of the intensive supervision work in the key areas of the Blue Sky defence war in 2018-2019 during the 4th of August*".

In order to achieve balanced growth of natural gas utilisation, the government proposes the following measures:

- Accelerate the development of a competitive market mechanism for exploration and development by promoting joint ventures between central and local entities, leaving taxes to the local regions and reducing economic constraints on exploration and development activities.
- Strengthen construction and interconnection of natural gas infrastructure, such as pipelines and regasification terminals.
- Establish a predictive and early warning mechanism for natural gas supply and demand, especially forecast demand during the winter heating period.
- Further diversify natural gas supply sources – importing countries, channels, contract models, contract duration; develop multilateral co-operation with key natural gas exporting countries.
- Implement a price mechanism for natural gas, for residential and non-residential consumers; provide subsidies to low-income groups conducting “coal to gas” in northern rural areas.
- Increase gas storage capacity, with targets for 2020 as detailed above.

On 5 September 2018 the State Council issued an order on natural gas for both local governments and companies (State Council of People’s Republic of China, 2018e). The objectives are to improve energy security, increase gas supply and storage capacity. The key points of the document are already reflected in the 2018 National Natural Gas Development Plan, but in the order, the target for domestic production of natural gas by the end of 2020 is set at 200 bcm/y.

Gas security events in Europe during winter 2017/18

European markets experienced several tight supply episodes last winter, which illustrated the resilience of its integrated natural gas networks and provided opportunities to apply the latest emergency policy measures as enacted by the revised 2017 EU Security of Gas Supply Regulation.

12 December 2017 – the “perfect storm” in Europe

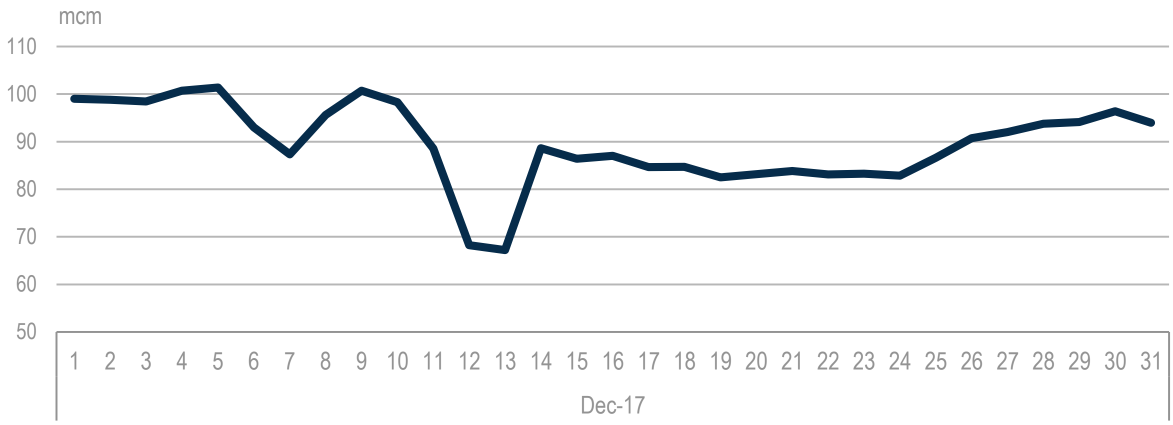
On 12 December 2017 Europe’s oil and gas infrastructure suffered from a series of individual technical disruptions affecting fuel production and transport facilities. The combination of co-ordination between industry stakeholders (suppliers and system operators), demand response to price spikes in downstream markets and emergency policy measures enabled any physical shortage to be avoided in spite of major technical issues.

North Sea oil and gas production output affected by pipeline shutdown

The North Sea Forties Pipeline System (FPS) was shut on 11 December following the discovery of a hairline crack in the pipe at Red Moss near Netherly, just south of Aberdeen. The crude carried by the pipeline represented nearly 40% of total UK liquids in 2017 (about 400 000 barrels per day). Pipeline owner INEOS declared force majeure on 13 December after announcing an estimated two to four week requirement to bring the pipeline system back into service. The pipeline is also a major route for bringing natural gas produced offshore to the United Kingdom; flows into the St Fergus terminal on 13 December decreased by 32% compared to flows on the 11th (Figure 1.10). The FPS returned to full capacity on 30 December.

On the same day, Gassco, the Norwegian transmission system operator, announced that flows would be trimmed from Troll, Europe’s largest offshore gas field, due to a power outage on the Troll-A platform alongside detection of a gas leak, which led to complete shutdown. The bulk of Norway’s production came back online on the following day, with Norwegian gas flows to the United Kingdom as well as to Germany, France and Belgium increasing substantially.

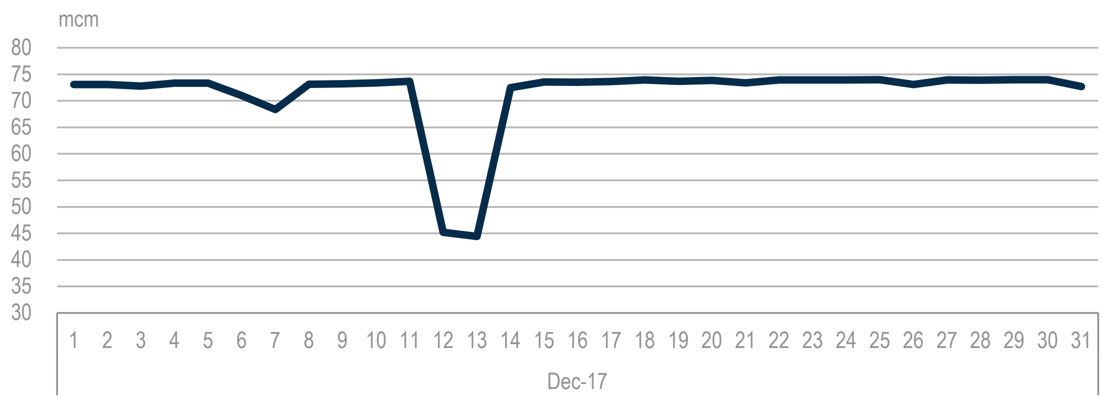
Figure 1.10 • Natural gas flows at the St Fergus gas terminal, United Kingdom, December 2017



Source: National Grid (2018a), *Data Item Explorer*.

Entry flows through the Langeled pipeline bringing Norwegian gas to the United Kingdom's Easington terminal decreased by 39% on the 12 December (Figure 1.11), and resumed normal levels on the 14th.

Figure 1.11 • Natural gas flows from the Langeled pipeline, United Kingdom, December 2017



Source: National Grid (2018a), *Data Item Explorer*.

Technical problems on the Balgzand Bacton Pipeline (BBL) linking the Netherlands to the United Kingdom were reported early in the afternoon of 12 December and caused capacity reductions for a couple of hours before being solved around 16:30.

The planned restrictions on withdrawals of cushion gas from the decommissioned Rough underground storage facility ended a day earlier than expected, and the facility was able to bring gas into the system.

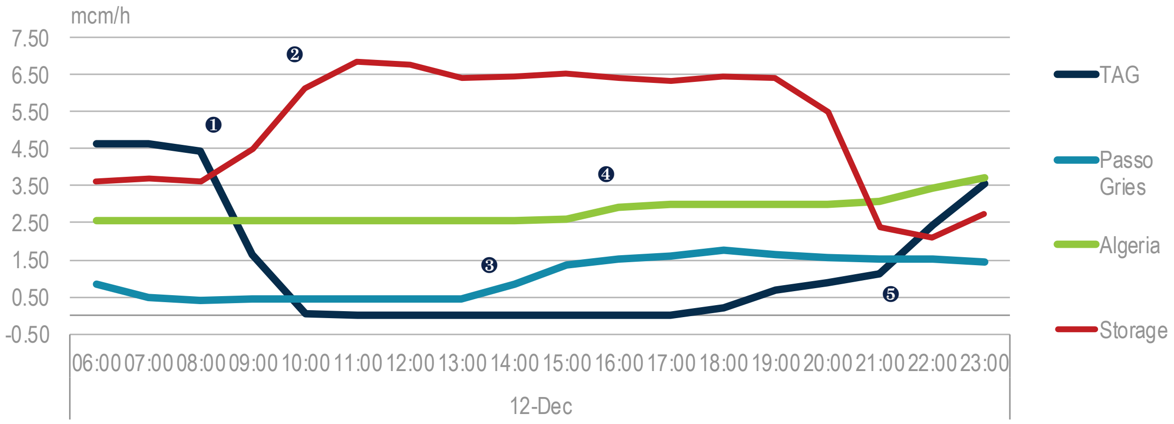
On the National Balancing Point, the United Kingdom's natural gas trading hub, prices surged to 95 pence per therm (up 40%) for spot transactions during the day. The Transmission System Operator (TSO) National Grid stated that supplies were ample to meet demand, which reached high levels in response to a recent cold snap. At the end of 12 December, the day-ahead closing price settled at an increase of 5% over the previous day and 17% over the Friday, 8 December.

This increase in prices was high enough on one hand to increase electricity generation from coal power plants, and on the other to increase imports via the BBL and IUK (Interconnector UK) pipelines, which connect the country with the Dutch and Belgian markets respectively.

Accident at the Baumgarten terminal affects Southern Europe

In the morning of the same day an explosion and fire occurred in Austria at the Baumgarten site – an important transit point for Russian gas bound for Italy. The facility, which transports the equivalent of about 10% of European gas demand, suspended operations.

Figure 1.12 • Natural gas supply sources to the Italian network, 12 December 2017



Notes: TAG = Trans Austria Gas pipeline; mcm/h = million cubic metres per hour.
Source: Snam Rete Gas (2017a), *Operating Data*.

As shown in Figure 1.12, flows through the Trans Austria Gas (TAG) pipeline – connecting Baumgarten to Italy – started to plummet between 08:00 and 09:00 and had stopped entirely by 11:00.

Since the TAG pipeline flows represented 43% of Italian imports during the first 11 months of 2017, its interruption led the Italian Minister of Economic Development to declare a state of emergency based on the three-level crisis management process defined in the 2017 update to the EU Security of Gas Supply Regulation.

The incident occurred during a period of cold weather in Europe. Parts of northern Italy were on red alert after a weekend of freezing rain and snow.

Italy declared Emergency Level (the third and highest crisis level) to ensure supply to priority users such as residential customers, enabling it to use different extraordinary measures such as allowing coal and oil power plants to operate at maximum capacity. However, Snam Rete Gas, the Italian TSO, did not have to resort to any emergency interventions (e.g. interrupting supply to industrial users or taking direct control of storage operations). Slovenia – also depending on Austrian gas transit – declared Early Warning status (the first crisis level).

The reactivity of gas storage was key to maintaining the supply of gas volumes required by the market. Withdrawals from storage sites started to rise almost immediately after the accident, i.e. from 3.63 mcm/h at 08:00 to 6.85 mcm/h by 11:00.

On 12 December, Snam announced that shippers were allowed to schedule volumes higher than the booked capacities for alternative supply sources at the Mazara del Vallo and Gela entry points for Algerian and Libyan gas supplies respectively (Snam, 2017b). Snam also initiated temporary measures to increase transit capacity through the Passo Gries connection point with Transitgas, whose pipeline connects Italy to northern Europe via Switzerland.[1] However, it should

[1]Capacity from Transitgas was partially reduced to 85% due to maintenance work on the upstream TENP pipeline connecting the Netherlands and Belgium to Switzerland through Germany (Fluxys, 2017).

be noted that gas supplies through Passo Gries only started to ramp up after 14:00, from 0.45 mcm/h to a peak of 1.75 mcm/h at 18:00.[2]

Flows from Algeria started to rise only after 15:00, as increasing volumes through the long-distance pipelines takes time. Algerian volumes rose by a mere 0.43 mcm/h to a peak of 3 mcm/h at 19:00. Supplies from Libya remained broadly flat.

At almost 20:00, Snam confirmed that Austria had authorised the resumption of gas transit operations, resuming Russian gas flows though the TAG pipeline (Snam, 2017d). Capacity at the Baumgarten hub was restored and flows to Italy, Germany and Hungary almost returned to normal on the same day.

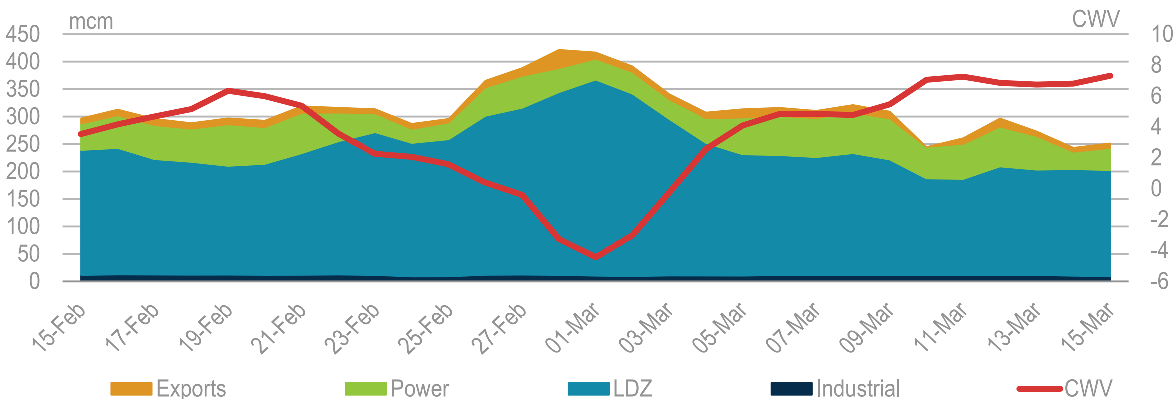
Day-ahead gas prices on Italy's Punto di Scambio Virtuale (PSV) reached a maximum of EUR 65 per megawatt hour (MWh) (more than doubling from the previous day), while day-ahead power prices reached EUR 110.98/MWh (Snam, 2017c), returning to pre-blast levels the following day.

As flows from Austria were restored, Slovenia lifted its Early Warning on 12 December and Italy its Emergency on 15 December.

Cold spell during February 2018 – The "Beast from the East"

Between 24 February and 4 March 2018, the United Kingdom and Ireland suffered a cold wave named the "Beast from the East", responsible for unseasonably low temperatures and heavy snowfall[3]. According to National Grid, 1 March was the seventh-coldest day in its 58-year weather record history and triggered the highest gas demand in seven years (National Grid, 2018b).

Figure 1.13 • UK gas demand, 15 February–15 March 2018



Source: National Grid (2018a), *Data Item Explorer*.

As shown in Figure 1.13, demand from the distribution network (or local distribution zones [LDZ], serving primarily households and commercial entities) rose the most significantly, by over 100 mcm/d from 243 mcm/d on 24 February to 357 mcm/d on 1 March as the composite weather variable (CWV)[4] dropped to -4.44 from an average of 2.8 through February.

[2] Gazprom Export issued a statement on 12 December, which stated "the company is working on redistribution of gas flows" (Gazprom Export, 2017).

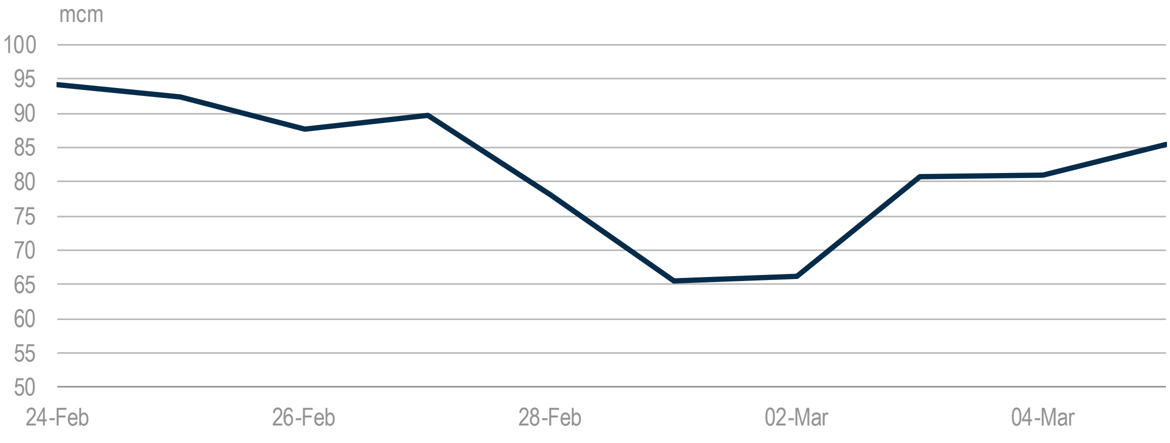
[3] This cold snap also affected continental markets, leading Sweden and Denmark to declare Early Warning status by the end of February 2018 for more than two weeks.

[4] The Composite Weather Variable (CWV) is a single measure of daily weather and is a function of actual temperature, wind speed, effective temperature and seasonal normal effective temperature (Gasgovernance, 2014).

Meeting rapidly climbing natural gas demand was challenged by the fact that the severe weather conditions caused a number of outages on certain key elements of supply infrastructure:

- Due to issues at the BBL station in Bacton, flows from the Netherlands to the United Kingdom were restricted during 27 and 28 February. The receiving capacity of the Bacton terminal was reduced due to outages at all the subterminals – by 5 mcm/d on 28 February at Bacton Shell, by 1.5 mcm/d at Bacton Perenco between 28 February and 1 March, and by 2 mcm/d at Bacton SEAL (Shearwater-Elgin area line) between 28 February and 1 March.
- Gas flows through the Barrow terminal, receiving offshore production from the Irish Sea, decreased from 5.82 mcm on 27 February to an average of 1.7 mcm/d between 28 February and 3 March due to technical issues.
- Norway's Kollsnes gas processing plant reported a reduction of 16 mcm/d (or 11% of its capacity) from 28 February to 2 March due to process problems caused by cold weather.
- The receiving capacity of the SEGAL pipeline was reduced by 8 mcm/d (~25% of its capacity) between 28 February and 3 March due to the loss of Modules 2 and 3 at the Mossmorran natural gas liquids fractionation plant in Scotland.
- Altogether, severe weather conditions and outages in the North Sea resulted in a decrease of gas flows to the St Fergus terminal (receiving both domestic offshore production as well as Norwegian imports) of over 25%, from almost 90 mcm on 27 February to 65 mcm on 1 March, reducing the availability of gas in the United Kingdom and further tightening the market (Figure 1.14).
- Due to unplanned technical issues at South Hook LNG terminal, the regasification terminal was not available on 1 March between 05:25 and 07:25. Send-out flows from the terminal did not return to pre-outage levels given the already low inventory levels, decreasing from 17.65 mcm on 28 February to 6 mcm on 1 March.
- The Rough closed storage facility has been supplying the gas market as the cushion gas is gradually removed. However, on 1 March gas outflow was reduced from 6 mcm to 1.4 mcm as a result of a 12-hour outage (Bloomberg, 2018b).

Figure 1.14 • Natural gas flows at the St Fergus Gas terminal, 24 February–9 March 2018

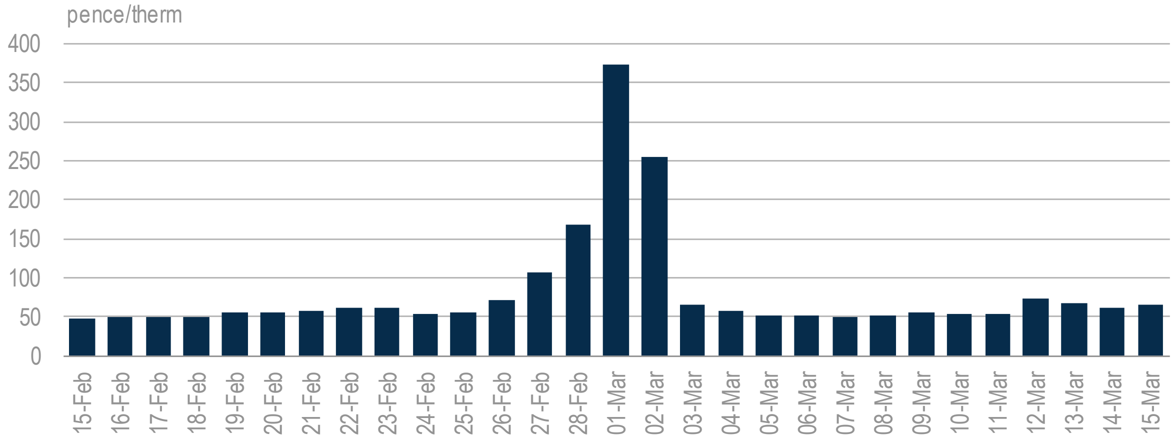


Source: National Grid (2018a), *Data Item Explorer*.

Impact on the market

Soon after the announcement of the unplanned outage at the South Hook terminal on 1 March, National Grid issued a Gas Deficit Warning at 05:47, with the supply deficit forecast to be around 45 mcm that day (ICIS, 2018b). The large supply-demand imbalance could have caused the linepack[5] to fall below the normal operating range (National Grid, 2018c). This was the first Gas Deficit Warning issued since the winter storms of 2010. As a result of the tight market situation, gas prices in the United Kingdom soared on 1 March to a 20-year high, above 370 p/therm (USD 50/MBtu).[6]

Figure 1.15 • UK SAP, 15 February–15 March 2018



Source: National Grid (2018a), *Data Item Explorer*.

The market reacted by optimising both the demand and supply side:

- Exports to Ireland were cut from 14.6 mcm on 27 February to 11.8 mcm on 1 March.
- The power sector reduced its gas burn from 58 mcm on 27 February to 38 mcm on 1 March, with gas further losing its price competitiveness vis-à-vis other supply sources. Electricity imports rose by over 60% between 28 February and 3 March. As a result, electricity prices soared to reach a 10-year high.
- Industrial gas consumers were asked to scale back gas consumption (Bloomberg, 2018b). According to National Grid data, deliveries to industrial consumers decreased by around 2 mcm/d between 27 February and 1 March. This was probably due to the fact that industrial consumers with flexible spot-indexed contracts took minimum levels of gas amidst the record-breaking price levels.

The supply side also reacted quickly:

- Flows from the continent through the BBL and the IUK pipelines rose by 150% from 32 mcm on 28 February to 80.3 mcm on 1 March.[7]
- Norwegian deliveries to Easington through Langeled rose by ~20% from 63 mcm on 28 February to 75 mcm on 1 March.
- Rough storage facility returned about 5 mcm to the market on 2 March.

Simultaneously, weather conditions also started to improve, as shown by the CWV rising from -15.4 on 1 March to -11.3 on 5 March. This naturally reduced heating demand and thus gas consumption by households and commercial entities.

The UK cold snap demonstrated the importance of having highly liquid and well-interconnected gas hubs from a supply security perspective. However, it should be highlighted that the availability of

[5] Linepack: Natural gas occupying all pressurised sections of the pipeline network. If pressure goes beyond or under a certain level, the pipeline system can be damaged.

[6] The system average price (SAP) reported by National Grid stood at 372 pence/therm.

[7] As the "battle" intensified for limited gas volumes, within-day prices at the Dutch TTF hub reportedly rose to EUR 120/MWh (Timera Energy, 2018).

Rough as a storage site – with a deliverability rate of around 40 mcm/d – could have mitigated the price volatility experienced in the United Kingdom due to the visit by the "Beast from the East".

The cold snap also demonstrated to role of coal-fired generation as back-up capacity during high-demand periods. The share of coal in the power generation mix climbed to an average of 27% between 27 February and March – whilst averaging just 7% through 2017.

Box 1.7 • Gas storage developments in the United Kingdom

The United Kingdom is the second-largest European gas market after Germany, with a gas demand of almost 82 bcm in 2017. Yet, gas storage capacity is only a fraction of that, currently standing at 1.3 bcm or 1.6% of the country's annual gas consumption. This is much lower than the EU average, approximating at 20% of gas consumption in 2017.

Due to the low seasonal price spreads, maintenance costs and the low integrity of the wells, the operator Centrica decided in June 2017 to stop operations at the Rough facility. Rough, a 32-year-old facility, used to provide around 70% of the country's total gas storage capacity (previous gas storage was 4.5 bcm or 6% of annual demand), and could meet 10% of daily peak winter demand for almost three months.

This year Centrica aims to extract approximately 1.6 bcm of cushion gas from Rough (of the 4 bcm remaining by the end of 2017). The question now is what the United Kingdom will do to replace the facility in order to avoid price volatility.

A number of new gas storage and expansion projects have recently been announced:

- Storengy's UGS facility in Stublach is due to see its capacity increase by 74 mcm in October 2018 and by a further 37 mcm by January 2019. However, additional compressors would be needed in order to increase the rate of extraction. According to Storengy (2018), once fully developed the facility will have a capacity of approximately 450 mcm, enough to supply 270 000 homes for 12 months.
- Halite Energy, the firm behind the GBP 660 million Preesall storage facility, said in January 2018 that the project was one year behind schedule. The company obtained permission for the facility in 2015. Although Halite has permission to drill 19 caverns in the salt strata, just 9 will be created and are due to come on line between 2020 and 2025 (LEP, 2017). The facility is intended to bring another 600 mcm of storage to the system.
- A further project, the Keuper Gas Storage Project, plans to provide up to 19 cavities. In March 2017 the project by INEOS received its Development Consent Order from the Secretary of State for Business, Energy and Industrial Strategy (INEOS, 2018).

The proposed Islandmagee gas storage facility in Northern Ireland would provide critical security of supply and flexibility to the Irish market. The facility, awarded Project of Common Interest status by the European Union, expects to have an injection capability of 12 mcm/d of gas and a maximumwithdrawal capability of 22 mcm/d. Islandmagee Storage Limited plans to build up to eight caverns, capable of storing up to 500 mcm (capital expenditure of GBP 308 million). In April 2018 the developers of the project raised GBP 925 000 in order to commence and complete front-end engineering design work. According to InfraStrata (2018), the facility is expected to provide over 25% of the United Kingdom's natural gas storage (based on UK capacity at January 2018). The project could be ready by H2 2022 and able to generate income until 2062.

Sources: Storengy (2018), Stublach Site", www.storengy.com/countries/unitedkingdom/en/our-site.html; LEP (2017), "Construction on Halite's £660 million gas project in Wyre to start early next year", www.lep.co.uk/news/construction-on-halite-s-660-million-gas-project-in-wyre-to-start-early-next-year-1-8845540; INEOS (2018), "Keuper Gas Storage Project", www.kgsp.co.uk; InfraStrata (2018), "Annual General Meeting Presentation January 2018", www.infrastrata.co.uk/images/stories/Presentations/infrastrata-agm-presentation-31-01-2018-v10.pdf.

Ukraine's gas crisis on 1 March 2018

In December 2017 the Arbitration Institute of the Stockholm Chamber of Commerce (SCC) ruled on the Gazprom-Naftogaz Ukrainy gas supply contract. SCC required the Ukrainian side to pay Gazprom USD 2.02 billion for incurred underpayments and to restart gas purchases from the Russian company – halted since 25 November 2015. SCC also lowered the annual contract quantity from 52 bcm to 5 bcm (the take-or-pay level remaining at 80%, meaning 4 bcm per annum) for 2018 and 2019.

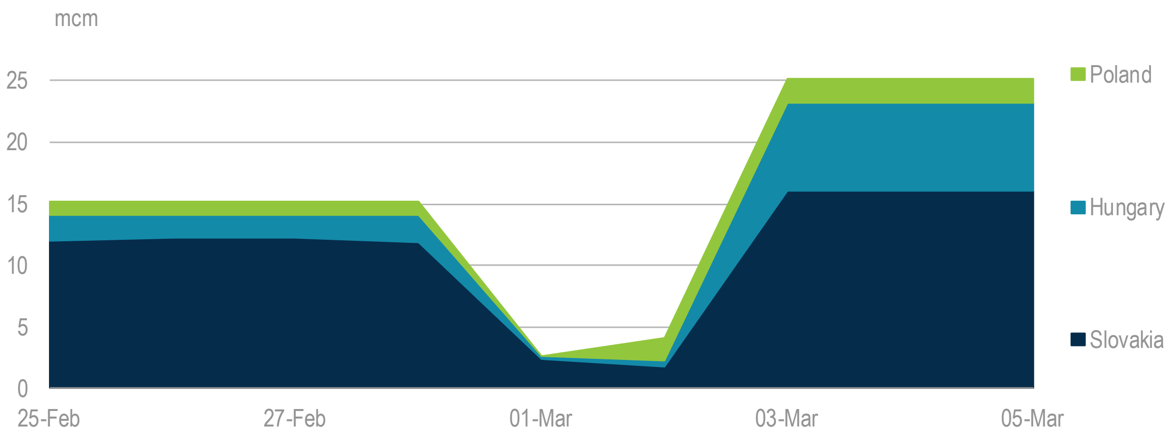
In the aftermath of the ruling, Gazprom and Naftogaz held several rounds of negotiations and agreed to restart gas supplies to Ukraine on 1 March 2018.

As shown in Figure 1.8, in the hope of receiving the agreed gas supplies from Gazprom, Ukraine reduced reverse flows from the European Union from 15 mcm on 28 February to 2.7 mcm on 1 March.

However, these gas deliveries never actually restarted. The SCC issued a ruling on the Gazprom-Naftogaz Ukrainy transit contract on 28 February 2018 and imposed a fine of USD 4.63 billion on Gazprom for not respecting the terms of the long-transit contract.

Gazprom management stated that the company would seek the termination of both contracts, making it impossible to start gas deliveries to Ukraine on 1 March 2018 – despite already agreeing to supply 18.393 mcm on that day (Ukrtransgaz, 2018a).[8]

Figure 1.16 • Reverse flows from the European Union to Ukraine, 25 February-10 March 2018



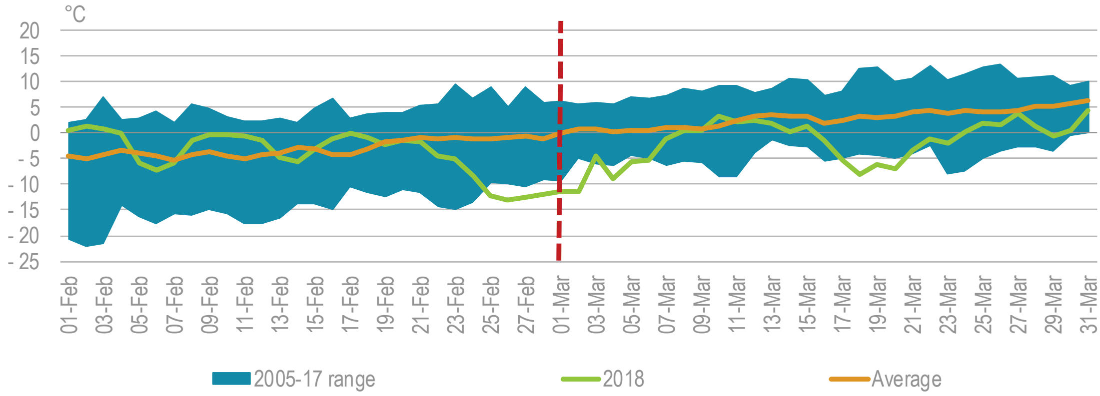
Source: ENTSOG (2018), *Transparency Platform*, https://transparency.entsog.eu/.

With the flows from the Russian Federation not materialising, Ukraine needed again to ramp up imports from the European Union to cover its demand needs – accentuated by the cold snap the country was experiencing, with temperatures in Kiev falling well below the 2005-17 historical range (Figure 1.17).

However, reverse flows from the European Union rose substantially only on 3 March. At the same time, Ukrainian gas producers were not able to increase deliveries, which remained broadly flat in the range between 56 mcm/d and 57 mcm/d. Gas withdrawals from Ukraine's large underground storage sites also remained relatively unresponsive to the market situation – actually decreasing slightly from 111 mcm on 1 March to 109.5 mcm on 2 March. This is mainly due to the fact that by the end of the winter, storage sites were only 32% full, which significantly decreased their deliverability rate. Hence, there was no immediate response from the supply side to Gazprom's decision to not restart gas exports to Ukraine.

[8] Gazprom eventually returned the prepayment that Naftogaz had made for March supplies.

Figure 1.17 • Temperatures in Kiev in February-March, 2005-18



Source: Raspisaniye Pogodi Ltd (2018), *Weather Archive*.

According to the Ukrainian Minister of Energy, the situation created a gas deficit of about 20 mcm/d. Several demand-side measures needed to be taken in line with the country's Rules for the Security of Natural Gas Supply:

- **Some thermal power plants** needed to switch to fuel oil. According to the Ukrainian Energy Minister, this measure could save about 15 mcm/d of gas.
- The population using **autonomous gas heating** was asked by Naftogaz Ukrainy, if possible, to reduce room temperatures by 1°C during the day and 2°C at night in the period 2-4 March (Ukrtransgaz, 2018b).
- Work at **kindergartens, schools and higher educational institutions** was suspended until 6 March inclusive.
- **Industrial consumers** were asked to review their production plans to consume less natural gas.

According to Naftogaz Ukrainy, these measures helped to reduce gas demand in Ukraine's major cities by 14%, or 25 mcm, on 2 March compared to the previous day (Naftogaz, 2018; RBC, 2018).

Reverse flows ramped up most quickly from Poland; however, they were rather limited in volume (2 mcm/d on 2 March). Deliveries from Hungary increased from 0.5 mcm/d to 7 mcm/d, and from Slovakia from 1.8 mcm/d to 16 mcm/d the following day.

On 3 March 2018 the Ukrainian President stated that "critical situation is resolved" as the country was able to increase reverse flows from the European Union, demonstrating the importance of gas interconnectors from the perspective of supply security (KyivPost, 2018).

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2. Update on LNG market flexibility metrics

The global natural gas market is expected to continue growing at an annual rate of 1.6% and to pass the 4 trillion-cubic-metre mark by 2022. Liquefied natural gas (LNG) is expected to account for 30% of that demand growth, with trading volume set to surpass 500 billion cubic metres (bcm) by 2023 (IEA, 2018).

At the same time, following the first production from the Sabine Pass LNG terminal in 2016, the United States will shift from its role of emerging LNG producer to one of being a main exporter of LNG, by constantly providing shipments to the global market. US LNG projects, which are mostly brownfield, are observed to take a minimum of 3.5 years from final investment decision (FID) to first shipment; hence the wave of US LNG projects that achieved FID during 2012-16 are now starting to produce. While South America and Europe (to a lesser extent) still remain natural destinations for US LNG cargoes given the close proximity of these markets, in 2016-17 almost half of total US LNG volumes were shipped to more attractive markets in Asia, mainly driven by growing demand from new buyers in the region.

The buyers of this US LNG are mostly contracted under free on board (FOB) terms, where the buyer has the responsibility for transport and mostly has discretion to choose the destination of the cargo. These contracted volumes with destination flexibility, which were signed during the period 2012-16, are now starting to flow into the market. In a separate move, the Japan Fair Trade Commission (JFTC) released its review into LNG contracts in June 2017, concluding that destination clauses are likely to violate Japan's Antimonopoly Act (JFTC, 2017). Restrictions on diversion are considered by the commission as highly likely to be a violation of antimonopoly law. As the JFTC declared its intention to continue to monitor the LNG market, those negotiating new contracts with the Japanese market are likely to be treading carefully.

The *Global Gas Security Reviews* have been following the transition of the LNG market towards flexibility by analysing LNG supply availability, seller and buyer behaviour (with the emergence of portfolio players), and the evolution of destination flexibility in LNG contracts. This chapter updates previous years' analysis using the same metrics, with the addition of new and deeper analysis of the growing role of portfolio players and implementation of LNG contracts with flexibility in the market, based on market forecasts provided by the latest *Market Report Series: Gas 2018* (IEA, 2018).

Similar to the previous years' reports, the analysis conducted here is based on the detailed contractual positions of importers and exporters and their actual traded volumes, using the International Energy Agency (IEA) internal LNG contract database. No specific assumptions are made on existing contract renewals unless publicly and explicitly stated by the contracting parties. Such volumes are hence considered to be "uncontracted" upon expiry. While the data are neither perfect nor complete, the results obtained should be robust and consistent with the developments observed across LNG markets.

2017 LNG supply availability – LNG plant capacity analysis

In the course of the past studies in the *Global Gas Security Review* series, reports have found that a plant's LNG production capacity often differs from the actual volume exported, sometimes with large gaps. The reliable availability of LNG supply is affected by unexpected and unscheduled events in addition to planned maintenance activities. The *Global Gas Security Reviews* observe the actual availability of LNG from each plant and the gap with its designed nominal production capacity ("nameplate capacity") to analyse the overall availability of LNG supply and thus the flexibility of producers to supply extra LNG in the case of a tight market. The analysis is based on the tracking of plant capacity that is offline ("offline capacity") and its share of total LNG export capacity.

An LNG plant is designed to run at its maximum designed capacity to produce the final product; however, the plant may be forced to shut down (go "offline") due to several factors and hence production to halt. Production eventually restarts once normal conditions return, initially at a slow production rate ("ramp-up"). This report categorises the most common factors affecting the capacity of an LNG production facility, on top of planned maintenance, as follows:

Weather: The weather factor is observed during unusually severe weather conditions that affect loading activities. Such conditions include, but are not limited to, cyclones, hurricanes and storm force winds. For analysis purposes, the report includes the unplanned stoppage of loading activities, while the plant is fully operational, into the category of weather-related offline capacity. Such cases are often related to adverse weather conditions at the loading port, with several days of offline status caused by the arrival of a cyclone or hurricane requiring evacuation of the workforce from offshore facilities.

Technical: LNG plants are complex sites designed to operate for long periods, and thus they regularly undergo maintenance that is planned well in advance. Yet, unexpected technical problems can emerge and cause unplanned shutdowns. Such cases often happen and may occur during the restarting period after shut-down at an existing facility or during the ramp-up phase at a new project. These unplanned offline cases can be shorter or longer in period depending on the extent of the problem and the scale of repair work, which often requires additional equipment and workforce. They may typically last from days to weeks, and sometimes for months and years.

Security: Several LNG facilities are located in politically unstable regions where unrest is frequent and security is poor. This can (occasionally or periodically) result in the evacuation of personnel and the partial or total shutdown of the LNG facility. In the worst cases, the export plant itself can be damaged due to direct attacks or collateral damage.

Lack of feedstock gas: Most of the world's LNG is produced from feedstock natural gas ("feedgas") from dedicated gas fields, and LNG facilities are sized to match the expected levels of production less whatever is required for domestic consumption. However, if production declines and/or domestic demand increases, a shortage of feedgas can occur and LNG production will be affected. This is by far the most common factor limiting actual production at existing LNG facilities.

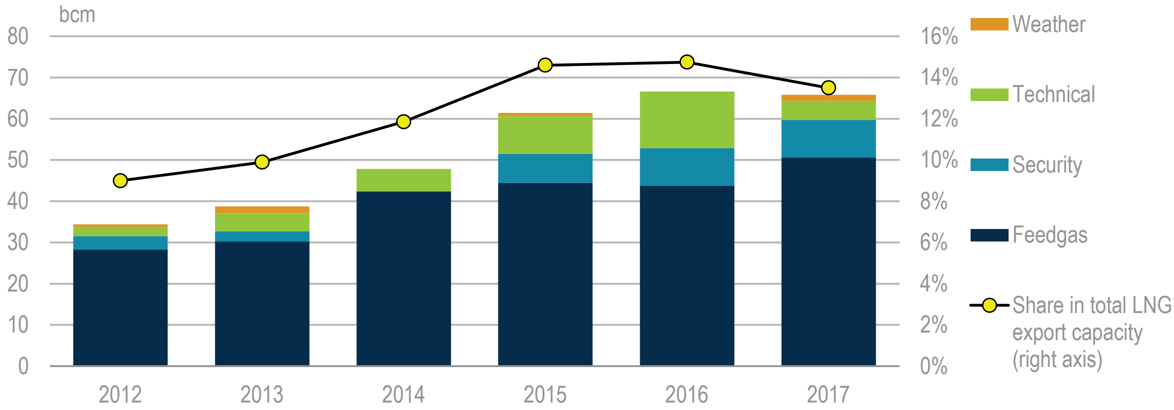
2017 – A year of improvement in plant reliability

Overall available capacity, meaning total capacity including that subject to planned maintenance, showed a slight increase in 2017 at 87%, up from 85% in 2016. This was due mainly to an improvement in unplanned maintenance for technical reasons, which freed almost 10 bcm of capacity for the LNG market.

Lack of feedgas worsened in 2017 and was responsible for 77% of unplanned capacity unavailability, dwarfing the security factor, which accounted for 14% and in 2017 only affected Yemeni production (Figure 2.1). Weather was a minor factor.

Using a definition of available capacity that deducts capacity subject to planned and unplanned shutdowns from total nameplate capacity, it is evident that availability varies by region (Figure 2.2). In the Africa region, Algeria, Angola and Nigeria recovered from technical issues and resumed smooth operations, which added over 7 bcm of additional available LNG to the market compared with the previous year. Despite the lack of gas supply in Egypt showing a slight recovery in 2017, it remained the most affected by offline capacity in the region.

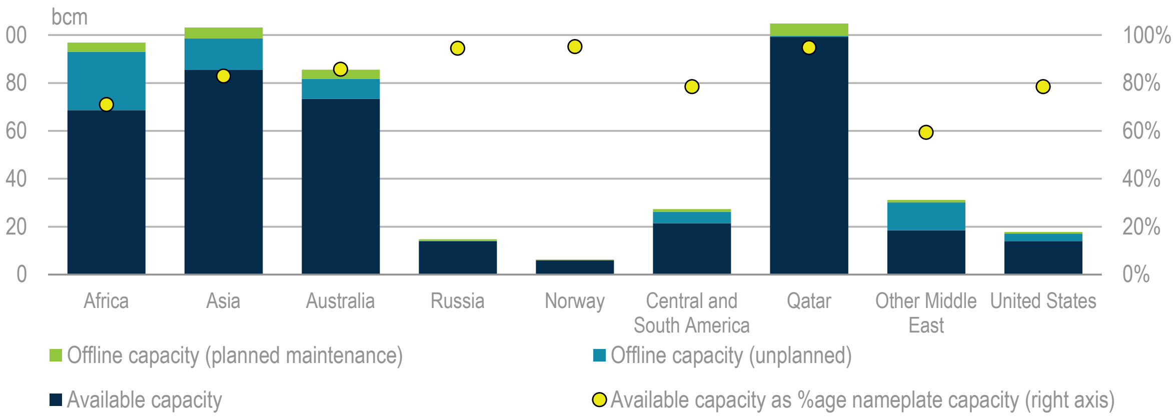
Figure 2.1 • LNG capacity offline (unplanned) by factor, 2012-17



Source: IEA analysis based on ICIS (2018), *ICIS LNG Edge* (subscription required).

By contrast, Qatar, which supplies slightly less than one-third of global LNG, continued to demonstrate the highest availability at 95%. The Russian Federation and the Asia region added nameplate capacity at Yamal LNG and Petronas LNG Train 9 respectively, and they increased their availability by 4.3 percentage points and 0.1 percentage points, respectively.

Figure 2.2 • LNG offline capacity and available capacity by region or country, 2017



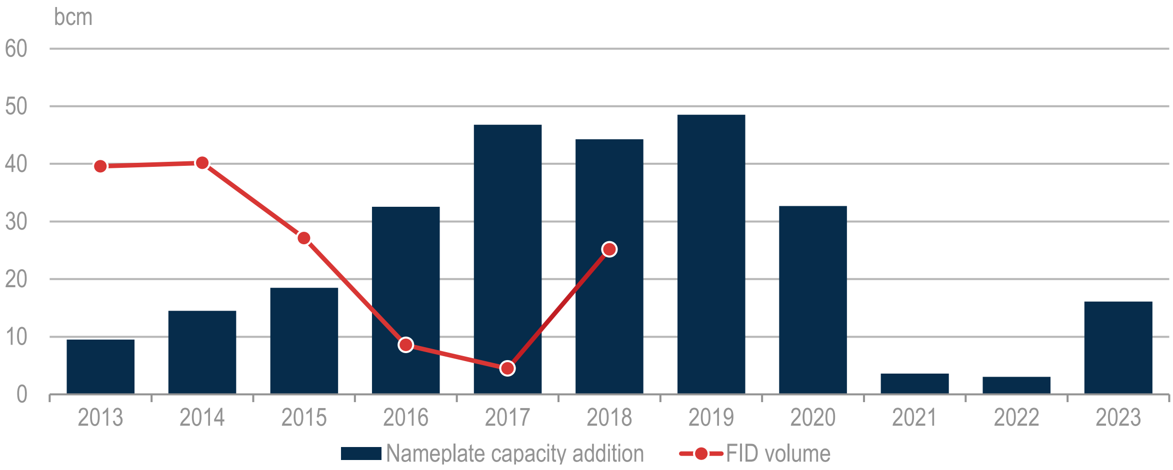
Source: IEA analysis based on ICIS (2018), *ICIS LNG Edge* (subscription required).

Capacity increase often causes unplanned teething problems

During 2017 Australia and the United States added around 35 bcm of nameplate LNG capacity. In Australia the new nameplate capacity is in the form of expansion at Gorgon LNG and commissioning of Wheatstone LNG, while in the United States is mainly from expansion at Sabine Pass LNG. While the nameplate capacity increased, Australia actually showed a slight decrease in the share of available capacity, from 90% to 86%. The new Wheatstone LNG project was in the commissioning phase, which often reveals unforeseen teething problems. The project required unexpected technical adjustment during this phase, which reduced capacity availability.

In contrast, LNG production in the United States saw improved capacity availability while increasing nameplate capacity, from 61% in 2016 to 82% in 2017. The lower rate of available capacity in 2016 was also associated with the ramp-up of the first train at the Sabine Pass LNG project. The increase in capacity in 2017 was mainly due to expansion at this plant, resulting in US capacity availability increasing by 17.6 percentage points. Observation shows that increases in technically related unplanned stoppages are often associated with the newly added capacity, especially greenfield projects and the ramp-up of the first train, and supply disruption can therefore be expected during this first phase of production. Globally, the wave of new LNG capacity additions is expected to peak in 2019 at nearly 50 bcm, with more than 30 bcm to be added in 2020. These new capacity volumes may therefore face unplanned output restrictions for technical reasons, notably in the United States where more than half of the total of about 150 bcm of new volume from 2018 will be located (Figure 2.3).

Figure 2.3 • FID volume, 2013-18, and LNG export capacity additions, 2013-23



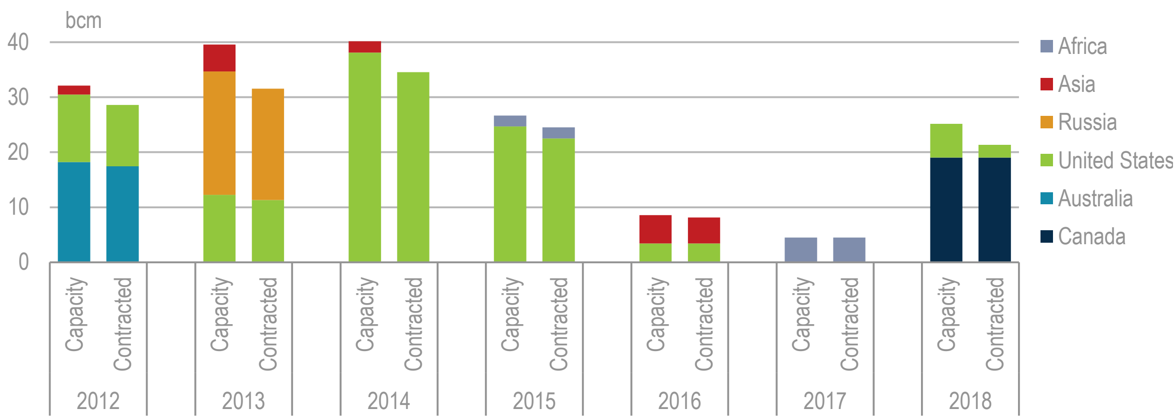
Notes: Nameplate capacity for projects with FID at the time of writing, using commissioning years according to project companies' official planning and assuming that one FID will result in an additional 5 to 6 bcm per year (bcm/y) for each US project to be commissioned by the end of the forecast period, excluding assumptions on unannounced delays and ramping-up rates of newly commissioned facilities. LNG Canada is included in 2018 FID volume but not in nameplate capacity addition as its first gas target is expected before 2025.

Source: IEA analysis based on ICIS (2018), *ICIS LNG Edge* (subscription required).

Smaller number of FIDs increases risk of a tighter market

Due to the lack of FIDs taken in recent years, annual LNG capacity additions are expected to significantly decrease from 2021. Until recently, market conditions suggested that the capacity under construction would create an oversupply in the short run, with markets not likely to balance before 2023.

Figure 2.4 • Capacity versus contracted volumes for projects obtaining FID, 2012-18



Note: For the purpose of the analysis, the figure only takes account of the contracted volume at the time of the FID; the uncontracted volume may be marketed later.

Source: IEA analysis based on ICIS (2018), *ICIS LNG Edge* (subscription required).

Under these circumstances, buyers have been reluctant to enter into the long-term deals that have traditionally underpinned the financing of new projects. As shown in Figure 2.4 above, the practice of obtaining a legally binding contract (LNG sale and purchase agreement [SPA]) at the time of FID continues; however, the capacity volume of projects achieving FID has declined since 2014 due to buyers' reticence. At the time of writing, two projects have taken FID in 2018:

- In the United States, with the expansion of the Corpus Christi LNG project in the form of Train 3, which is 55% contracted. All contracted volumes are on a FOB basis and thus the project does not need to secure shipment, and the uncontracted volume (less than 3 bcm) is expected to be sold to portfolio players once the facility enters production under the same shipping arrangements (FOB).
- In Canada, with the development of two trains from the LNG Canada project to deliver about 19 bcm per annum confirmed on 1 October 2018, with first gas expected before 2025 (Reuters, 2018a).

The current absence of major capacity additions beyond 2020[9] also illustrates the risk of a tighter market caused by the aforementioned potential technical issues associated with the ramp-up of new trains, in addition to any unplanned maintenance of operating projects. Feedback from US projects, operating and under construction, indicates that the average lead time for developing a brownfield liquefaction plant, including expanding the trains, takes a minimum of 3.5 years from FID to completion for "traditional" projects with trains of up to 5 million tonnes per year (6.8 bcm). As it would require such projects to achieve FID within less than two years for them to be operational before the end of 2023, close monitoring of the market is required to assess future capacity availability and the risk of tightness.

Reflecting the oil price recovery and surge in demand for LNG from the People's Republic of China (hereafter "China") and other emerging Asian buyers, several projects in different regions are currently being considered as the next FID candidates, and some of them could achieve FID in the near future. US projects at different stages of development pre-FID could be amongst the most likely candidates, as they do not require integrated upstream investment and most of them are converting existing regasification terminals into exporting liquefaction terminals.

Utilisation analysis: Improvement in maintenance activities

Once the effectively available capacity is known, it is possible to look at the 2017 export volumes and compute the following factors:

Load factor – the ratio of the actual output in a given year against the plant's nameplate capacity.

Utilisation factor – the ratio of the actual output to the potential maximum output of the facility adjusted to account for both planned outages (maintenance) and unplanned outages (lack of feed gas, technical problems, or weather).

This latter factor looks particularly relevant from a security of supply viewpoint – it shows how much more output could have been made available to the market had the demand for the additional gas been present. Hence, the report analyses the historical trend in the utilisation factor retrospectively from 2012 (Figure 2.5).

2017 shows recovery from teething problems and maintenance activities

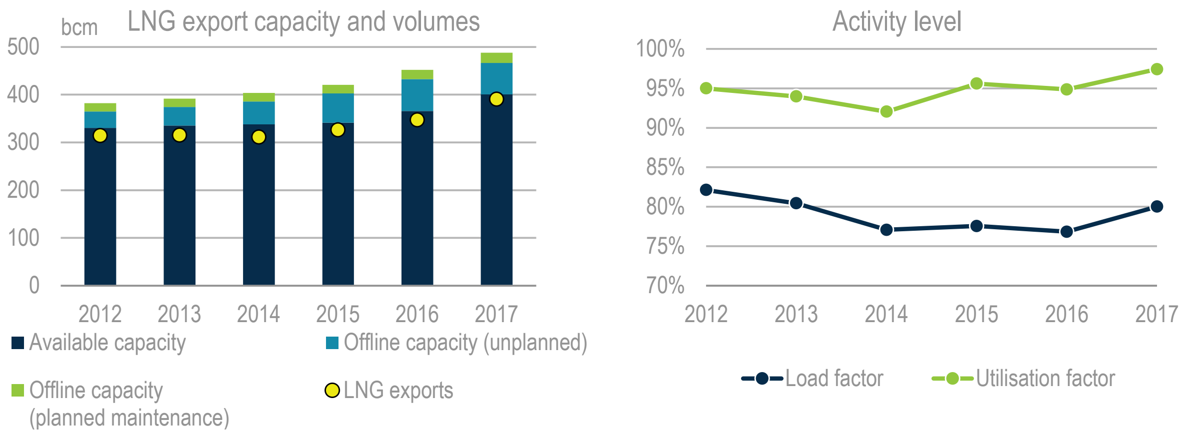
Total liquefaction capacity increased by around 8% during 2017, mainly in Australia and the United States, whereas output increased by around 12% on account of projects commissioned in 2016 starting to demonstrate smooth operations, plus a recovery in the performance of

[9] Based on final investment decisions as of October 2018.

African exporters. As such, the load factor rose to almost 80% in 2017 (Figure 2.5), almost the same level as in 2013 when only a small number of new projects came online and ramp-up disruption was limited.

At the same time, the utilisation factor also rose from 95% to 97%. The slight increase was due to an improvement in unplanned technical maintenance. This improvement added additional capacity of almost 11 bcm to the potential output, which helped supply the market with LNG while commissioning of new capacity was under way. As relatively similar additional volumes are expected to become available in 2018-19 (Figure 2.4), the volumes added by projects commissioned in 2016-17 are likely to compensate for any technical issues during the initial ramp-up at new capacity in the coming years.

Figure 2.5 • LNG offline capacity, available capacity, LNG exports and utilisation factor, 2012-17



Source: IEA analysis based on ICIS (2018), *ICIS LNG Edge* (subscription required).

The gap between average load and utilisation factors (80% and 97% respectively for 2017) shows how relevant such disruption is to LNG plant performance. Despite the increase in supply totalling more than 45 bcm, the utilisation factor showed an increase during 2016-17. This illustrates that the anticipated market oversupply did not happen in 2017, for two reasons: first, newly expanded plant production underperformed due to technical issues associated with ramp-up lasting longer than expected (unplanned offline capacity); and second, extra demand, including from the emerging Asian market, absorbed the gradually increasing export production volumes from both new and existing projects.

Recovery observed in African and US projects

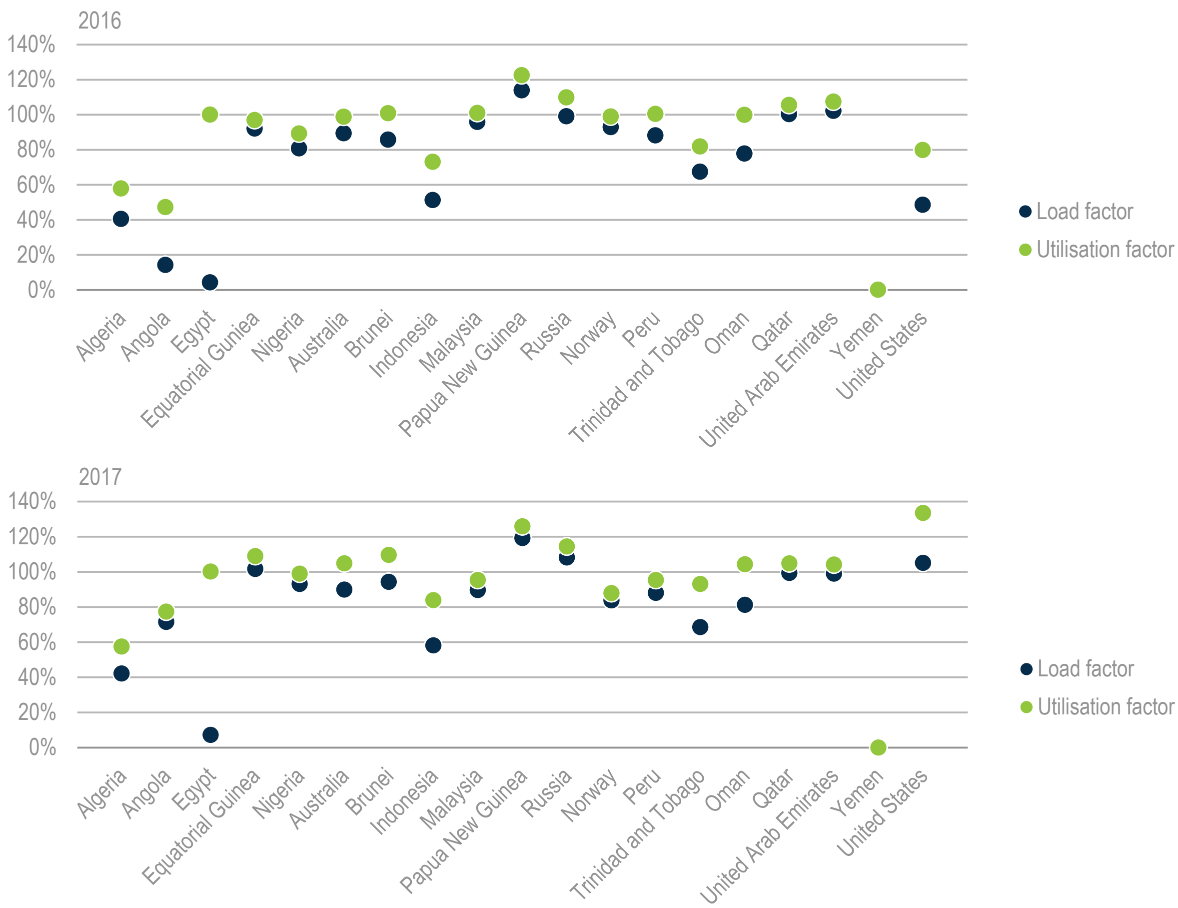
Most existing LNG-producing countries demonstrated a higher productivity rate in 2017, and thus an improved load factor. Production fully recovered in Angola and slightly recovered in Egypt in 2017, with less planned maintenance activity observed compared to the previous year (Figure 2.6).

Egypt was the only country showing a large difference between its load and utilisation factors. One of Egypt's two LNG projects came back online in 2017 with the partial recovery of the Idku terminal due to feedgas availability for exports. However, the exported volume itself was small, at slightly above 1 bcm.

Other than Angola and Egypt, countries that demonstrated improved utilisation factors were the United States, and Trinidad and Tobago. US projects ramped up smoothly during 2017, which improved its utilisation factor, whereas Trinidad and Tobago showed an improvement in feedgas supply issues compared to 2016.

Australia, Brunei, Equatorial Guinea, Papua New Guinea, Qatar and the United Arab Emirates continued to demonstrate their ability to produce and export close to or above their nameplate capacity.

Figure 2.6 • LNG export activity level by country in 2016-17



Notes: Supplies from Libya went offline in 2011 and are now not included in the worldwide nameplate capacity; factors above 100% indicate that observed production was above its nameplate (or designed) capacity, a feature often observed in liquefaction plants.
Source: IEA analysis based on ICIS (2018), *ICIS LNG Edge* (subscription required).

2017 LNG market flexibility – Portfolio player analysis

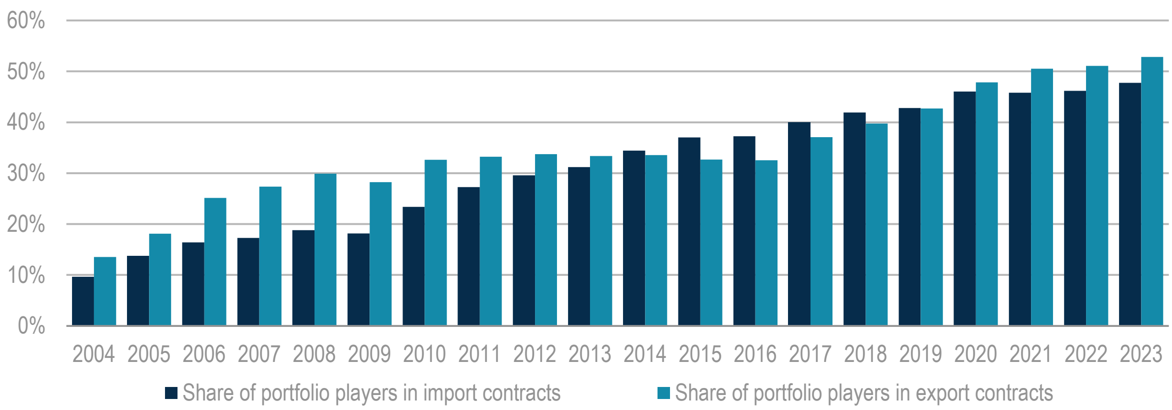
LNG plants have limited ability to provide extra availability to the market in the case of urgent need. As shown from analysis in the first issue of the *Global Gas Security Review 2016* (IEA, 2016), LNG supply flexibility derives from uncontracted or destination-free cargoes, by diversions, reloads, and portfolio players.

Portfolio players procure a mix of LNG supplies from various projects and sellers, and then resell to various customers according to their requirements. Portfolio players sell much of this via term contracts, but are also active in selling spot cargoes. Therefore they have both sell (export) and buy (import) contracts available to manage their own cargoes, providing a wider range of flexibility to their customers. Such flexibility is often valued at a premium, as the LNG projects themselves have limited uncontracted or excess capacity volumes to provide flexibility. The requirement for greater flexibility in term contracts has increased along with the rapid increase in the number of LNG buyers in the recent years (IEA, 2017), and the actual number of transactions using contracts with flexibility has also increased.

Global portfolio players as a major supply source

Customers have demanded more flexible terms in their contracts, particularly with respect to destination. With soft market conditions, shorter durations have become increasingly favoured. The willingness of portfolio players to offer flexibility and their ability to take risk on open positions is helping them gain market share. The share of LNG contracted volumes signed and executed by portfolio players for both export and import has shown a steady increase, and is expected to reach 50% of the total LNG contracted export volume by 2021 (Figure 2.7).

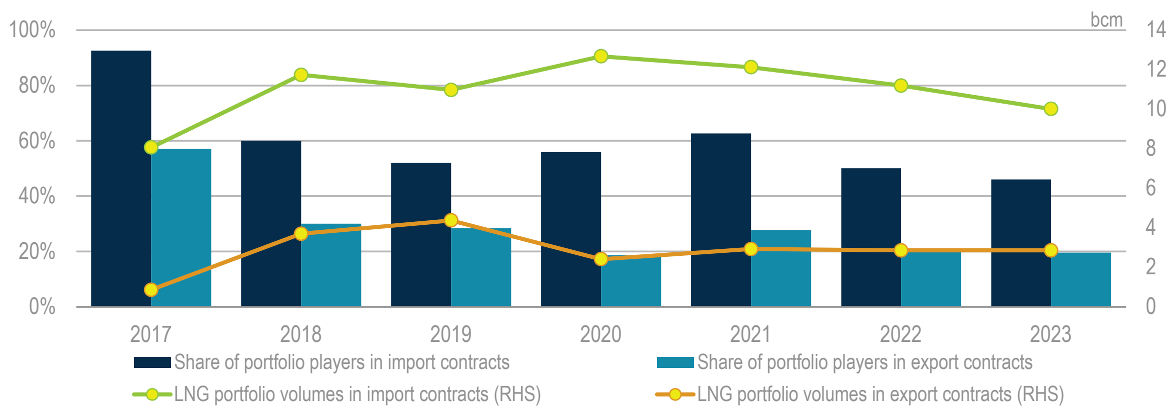
Figure 2.7 • Share of portfolio players in LNG market by volume of LNG, 2004-23



Note: The figure only shows term contract commitment at the time of writing; portfolio players' positions are balanced by short-term sales and purchases as well as by future term sales or purchases for the coming years.
Source: IEA analysis based on ICIS (2018), *ICIS LNG Edge* (subscription required).

As the volume of contracts increases, contract portfolios themselves are becoming more complex. From year 2020 onward the trend shows that portfolio players are committed to sell more LNG than the amount they have contracted to secure for their own portfolio they have more export contracts than import contracts (Figure 2.7).

Figure 2.8 • Share of portfolio players in LNG market, new contracts signed in 2017



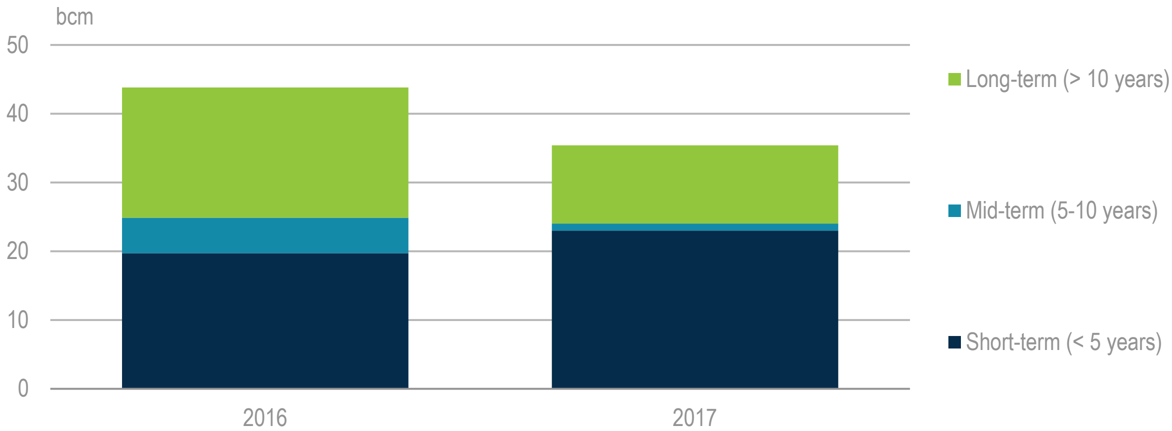
Note: The share represents the exact increment of annual quantity of each new contract signed in 2017.
Source: IEA analysis based on ICIS (2018), *ICIS LNG Edge* (subscription required).

Portfolio players have tended to balance their portfolios closer to the committed supply commencement date. In 2017, portfolio players contracted a total of 35 bcm/y of new importing and exporting contracts altogether (at maximum supply obligation volume per annum), at an average duration of three years, to balance the volumes of their supply portfolio for the upcoming years. As a result, portfolio players are, as a group, the most active in the short- and medium-term contract market, accounting for over half the import contract volumes for the next few years. Figure 2.8 below shows the share of portfolio players in all the LNG contracts signed during 2017. For the purpose of analysis, the share represents the increment of annual contract quantity (ACQ). The figure indicates that portfolio players accounted for 90% of the newly signed importing (sourcing) contracts with a duration of less than a year. The share decreases for contracts lasting between one and two years, indicating that the portfolio players may intend to take the same action in subsequent years, that is, to source the required cargoes at the last minute to convert into a "long" position to meet their supply obligations.

Shorter, smaller volumes sourced, creating more flexibility

In 2017, the volume of LNG signed and executed by portfolio players was estimated at around 35 bcm (on the basis of maximum volume per contract per annum), which was 8 bcm less than the volume signed in 2016, at 44 bcm. The analysis shows that in 2016 portfolio players signed larger volumes mainly with a long duration, while in 2017 they signed contracts for a lower volume of LNG with a shorter duration. In 2017 short-term contracts accounted for 65% of all contracts signed, a 17% increase on the previous year (Figure 2.9).

Figure 2.9 • Contract volumes newly signed by portfolio players, both import and export, 2016 and 2017



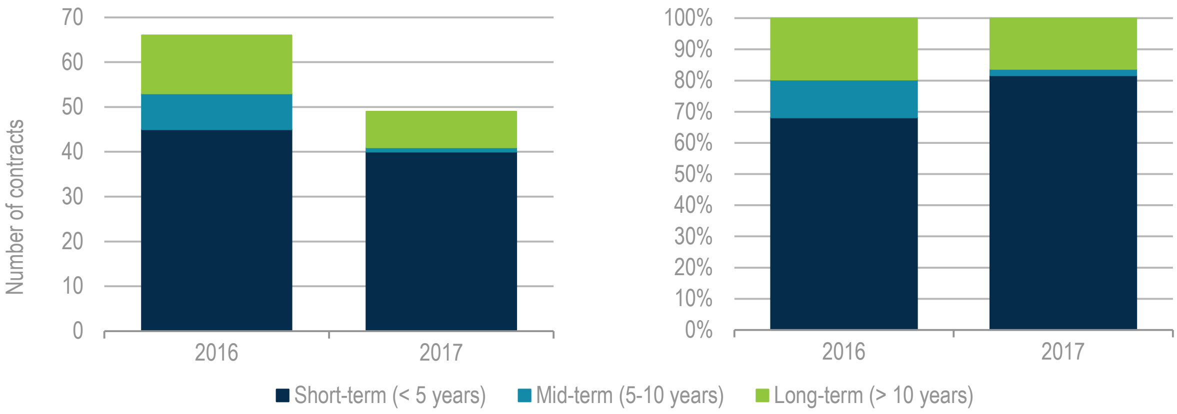
Note: Volume represents maximum annual quantity per annum for the duration of the contracts.
Source: IEA analysis based on ICIS (2018), *ICIS LNG Edge* (subscription required).

For the purpose of analysis, this report considers the sell and purchase agreements (SPAs) that are reportedly legally binding, and thus does not include reported heads of agreement (HOAs) or memorandums of understanding (MOUs). Furthermore, this report defines a contract as "short-term" where it has a duration of less than five years. Short-term contracts include multiple cargoes contracted for less than a year ("strip cargoes") but not one-off spot-trade contracts. Contracts between five and ten years' duration are defined as "mid-term", and contracts with a duration of longer than 10 years are categorised as "long-term".

Almost 50 contracts are estimated to have been signed and executed by portfolio players in the course of 2017 as per publicly available information. This was 26% lower than the number of contracts signed in 2016. All durations declined, although the decrease was greater for mid- and long-term contracts. As a result, the number of short-term contracts accounted more than 80% of all the LNG contracts signed and executed by portfolio players in 2017 (Figure 2.10).

Of the short-term contracts signed in 2017, the average duration was one year, and almost 30% of the volume was sourced for the buyers' portfolio, which means the buyers intend to resell the sourced volume to other customers. These data indicate that, for 2017, portfolio players used short-term contracts both to meet their supply obligations under the term deals they have in place with their respective customers, and to serve sudden extra demand from the market. The cargo destination of the contracts varied from traditional markets such as Japan, to emerging markets such as China, India, Jordan, Pakistan and Puerto Rico, with an urgent requirement from Egypt. This illustrates the growing role of portfolio players, who are procuring greater volumes in smaller individual quantities for shorter durations, hence improving the flexibility offered to the LNG market, to meet traditional buyers' demand fluctuations and emerging markets' urgent requirements.

Figure 2.10 • Number of newly signed contracts by portfolio players, both import and export, 2016 and 2017



Source: IEA analysis based on ICIS (2018), *ICIS LNG Edge* (subscription required).

Portfolio players supplement LNG plant availability

The more flexible primary supply sources, which provided shorter contracts at short notice, were projects in Angola, Indonesia, Qatar and the United States. Those projects were able to provide a total of around 8 bcm at short notice in 2017. Even though the length of contract negotiation periods varies, the contracts signed during 2017 for short duration are considered to be used for an urgent requirement (e.g. shortage of domestic gas, gas-fired plant construction delay, impact of policy implementation in China), and the suppliers were able to provide such extra volume quickly. Further detail is available on the largest sources of short-notice primary supplies.

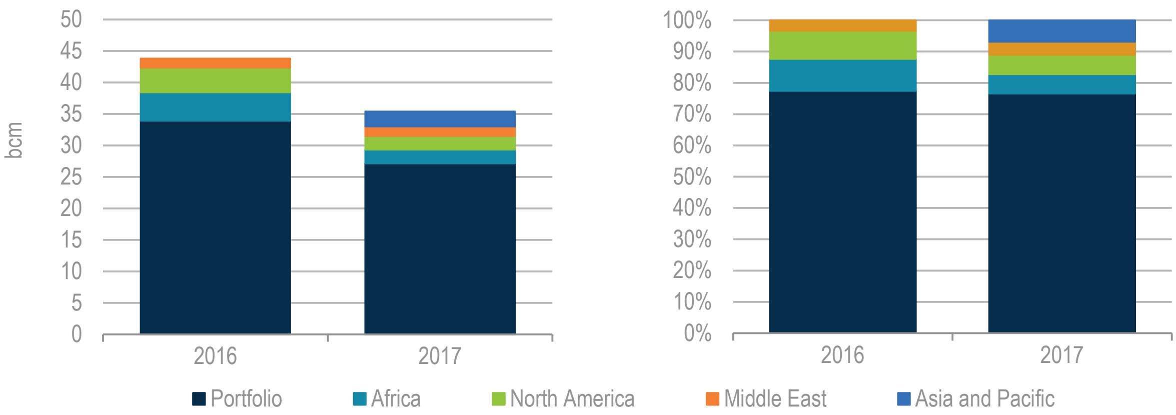
After recovering from technical issues experienced since start-up in 2013, Angola has been operating and producing smoothly since mid-2016, producing almost 70% of its nameplate capacity in 2017. The project has several term contracts in place; however, almost all of the produced volume was sold via single sales tenders in 2017, and sold to the most valuable market at the time of the tenders. This is believed to be possible because the project's sales term contracts are understood to have wide flexibility, including the seller's option to supply, or the buyers' option to accept the volume, divert, or not to take. Hence, the project has an ability to provide urgent cargoes in cases where the market is more attractive than the contracts currently in place.

Indonesian LNG cargoes were mostly contracted on a strip basis, which means multiple cargoes were sold within a year, or over the course of a few years. This indicates that the Indonesian project was performing well enough to sell additional production as strip deals – which normally require commitment a couple of months in advance. Qatari LNG was sold to portfolio players on a short-term basis, ostensibly to cover the upcoming portfolio players' supply obligations.

US-sourced volumes were contracted on a long-term basis from a project undergoing front-end engineering design, for potential support for the future FID of this project.

Figure 2.11 shows the LNG volume sourced by portfolio players under contracts signed in the year of the contract commencement date. This means that the volume is considered to be sourced to meet an immediate requirement. While the abovementioned sources – Angola, Indonesia, Qatar and the United States – were able to provide urgent cargoes to meet the immediate needs of portfolio players, the data show that more than 70% of urgent requirement volumes were sourced from other portfolio players. The primary sources of such LNG, sold by other portfolio players, consisted of more than 30 contracts with an incremental volume of more than 25 bcm. This means that, as the previous analysis showed, most LNG projects have limited incremental volumes available to respond to supply disruption or urgent demand. Instead, portfolio players are providing prompt, flexible and variable-duration contracts to meet the market's requirement.

Figure 2.11 • Origin and volume of LNG sourced by portfolio players contracted for the same year, 2016 and 2017



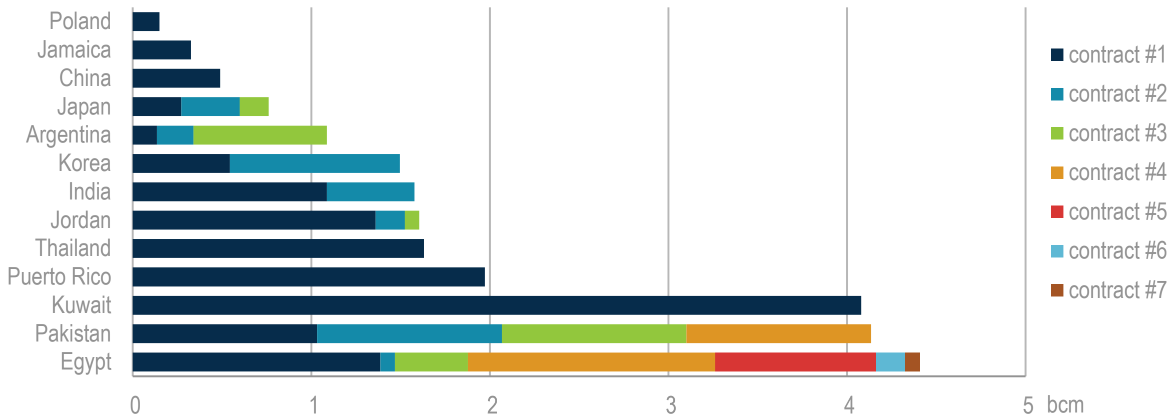
Source: IEA analysis based on ICIS (2018), *ICIS LNG Edge* (subscription required).

Where do portfolio cargoes go to?

The final destination of the volumes sourced from portfolio players and then resold by portfolio players was mostly the emerging LNG-consuming countries (Figure 2.12). The largest volume was sourced for Egypt through tenders, with 7 contracts in place for a total of more than 4 bcm of prompt requirements. Similar requirements were observed from other emerging LNG-importing countries such as Pakistan (4 contracts; 4 bcm), Jordan (3 contracts; 1.5 bcm), and Argentina (3 contracts; 1 bcm). Portfolio players are thus providing not just volume flexibility, but also security of supply to countries with less experience of importing LNG and urgent requirements.

Traditional LNG importing countries such as Japan and Korea, together with Pakistan and Kuwait, also signed import contracts for portfolio supply volumes with a longer duration – more than ten years' contract duration. For these longer-term contracts, the volumes were sourced from portfolio players who have equity volume ("equity lifting") from LNG projects where they are one of the partners. Those volumes sourced directly from primary sources by portfolio players are considered more reliable because they allow buyers to make better long-term supply forecasts, compared to the volumes sourced from secondary or third sources with short supply notices. Elsewhere, Argentina, Egypt and Jordan sourced LNG for limited periods to meet their urgent requirements in 2017.

Figure 2.12 • LNG contracts sourced from and resold by portfolio players by final destination, volume and number, 2017



Source: IEA analysis based on ICIS (2018), *ICIS LNG Edge* (subscription required).

As the proportion of portfolio players increases in the LNG market, so does the complexity of the offer, varying by origin of the LNG, contract duration, volume, option to supply or take the volume, and final destination. In this way the LNG market is further transforming the range of flexibility on offer to meet the specific needs of particular customers. As the volume of trade is set to increase along with the number of participants – namely an increase in the number of importing countries and portfolio players – the flexible market provided by portfolio players, who can supplement the rigidity of LNG plants' physical performance, is set to be the new norm.

How LNG contracts have evolved

Destination clauses in LNG contracts have been receiving close attention from competition authorities in the past two years. In June 2017 the JFTC, Japan's anti-monopoly regulator, released its review of the LNG trade in Japan (IEA, 2017). As a result of the survey, the JFTC requested that LNG sellers eliminate competition-restraining clauses or business practices. The actions, practices or provisions that are likely to be in violation of antimonopoly law in Japan, as identified by the JFTC, include: stipulating destination clauses; restricting diversions; and providing profit share clauses. Even though the cases of violation vary by means of transport and may be free on board (FOB) or delivered ex-ship (DES), the JFTC requested that LNG sellers neither provide nor adopt such competition-restraining clauses in a new or revised LNG contracts. It also requested that LNG sellers at least review existing contract conditions for competition-restraining business practices. The JFTC confirmed that it would keep monitoring the LNG market to vigorously enforce Japan's anti-monopoly law.

Following the JFTC report, the Korea Fair Trade Commission began researching the legality of destination clauses in LNG contracts in August 2017. In June 2018, the European Commission also opened a formal investigation into destination clauses to assess if Qatar Petroleum's long-term LNG supply agreements with European importers in the European Economic Area have violated EU antitrust rules (European Commission, 2018).

Analysis of contract flexibility

Analysis of LNG contracts signed since 2014 (Table 2.8) shows an evolution in the development of flexibility. For the purpose of analysis, "short-term" is defined as a contract with duration of up to one year.

Two observations stand out:

- **More short-term contracts with fixed destination.** The share of short-term contracts increased significantly in 2017 after a drop in 2016, and accounted for almost a quarter of overall contracted volumes signed last year – without taking into consideration spot transactions. These short-term contracts cover both SPAs and tenders. A growing number of contracts were signed to meet the specific requirements of a given LNG importer, mainly via tenders. The tendered cargoes are specified for delivery to terminals identified by the buyer during the agreed delivery dates, i.e. they have a fixed destination. Most of these contracts were for prompt execution: out of 23 short-term contracts, 14 started delivery transactions immediately after being signed.
- **Lack of long-term contracts.** The average contract duration dropped to 4 years in 2017, compared to 9 in 2016 and 16 for contracts signed before 2014. This was a consequence of the development of short-term contracts and a lack of new long-term supplies available on the market. Average contract volumes remained stable at 1.0 bcm/y.

Table 2.8 • Contract evolution by volume, before 2014, 2015-17

	Signed before 2014	Signed in 2015	Signed in 2016	Signed in 2017
Short-term (up to 1 year)	8%	16%	2%	24%
Flexible destination	39%	41%	42%	22%
Average contract duration (y)	16	10	9	4
Average contract volume (bcm/y)	1.7	1.0	1.2	1.0

Notes: Short-term excludes single spot transactions; y = year.
Source: IEA analysis based on ICIS (2018), *ICIS LNG Edge* (subscription required).

However, it should also be noted that LNG sourcing has also evolved. In the absence of new FIDs for large projects (only one FID in 2017), most of the contracted volumes were sourced from secondary sellers – i.e. portfolio players and over-contracted buyers. As described in the previous edition of this report (IEA, 2017), portfolio players have been the main buyers of primary LNG supply from liquefaction projects over recent years, which resulted in most of them building a net selling position. These long-term (usually flexible) volumes are resold by portfolio players to secondary buyers, with lower exposure to volume and duration but without destination flexibility. About 70% of contracts signed in 2017 had portfolio players as sellers.

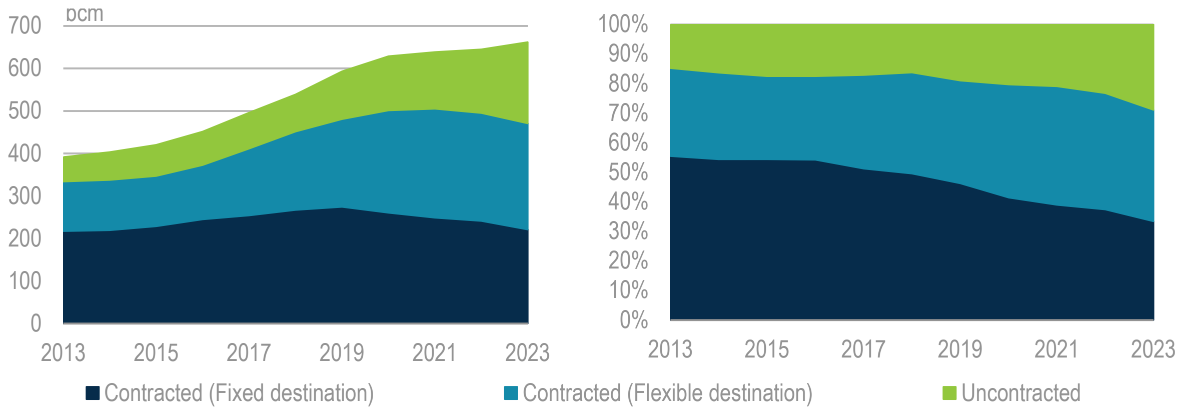
The tendency observed for contracts signed in 2017, with shorter duration and a decline in destination flexibility, highlights the development of secondary markets where sellers (mainly portfolio players) procure from the primary market in smaller volumes with shorter durations, to sell to secondary buyers (usually end users new to the LNG market or with an urgent need for cargoes). The emergence of this secondary market is made possible by the existence of primary sourcing via long-term contracts without destination clauses, which enables flexible reselling to end users.

The need for flexible destination contracts remains essential to ensure future market growth from smaller or emerging users who do not have access to primary sourcing from liquefaction projects. The need for access to longer-term flexible supply is expanding to new entrants such as commodity traders, as highlighted by the 15-year supply agreement signed by Vitol with Cheniere in September 2018 (Reuters, 2018b).

Medium-term flexibility outlook

Even though 2017 showed a decrease in the number and volume of signed contracts with destination flexibility, the overall trend of a gradual increase in destination flexibility is seen continuing in the coming years. Figure 2.13 presents an analysis on the assumption that expiring contracts are not renewed and with no specific assumption on any contracts yet to be signed (SPA contracts only). On such a basis, there would be a total net reduction of above 50 bcm with fixed destination clauses by 2023 due to the expiry of legacy contracts which see their net volume decrease from 2020. Over the same time period, LNG export contracts with flexible destination would add about 134 bcm, mostly from the United States. As a result, at the time of writing, the currently uncontracted volume would reach around 200 bcm by 2023, or almost a third of total supply. Those uncontracted LNG volumes – coming either from new projects or from the expiry of existing contracts – could well be contracted with flexible destinations and, in the case of contracts destined for Japan, the JFTC request has to be taken into consideration for newly signed contracts. Long-term contracts currently in place with Japan and expected to expire by 2023 total almost 50 bcm. Future negotiations therefore need to be carefully monitored to see if the trend towards greater flexibility is reinforced over a medium-term outlook.

Figure 2.13 • LNG export capacity contracted by destination flexibility, 2013-23



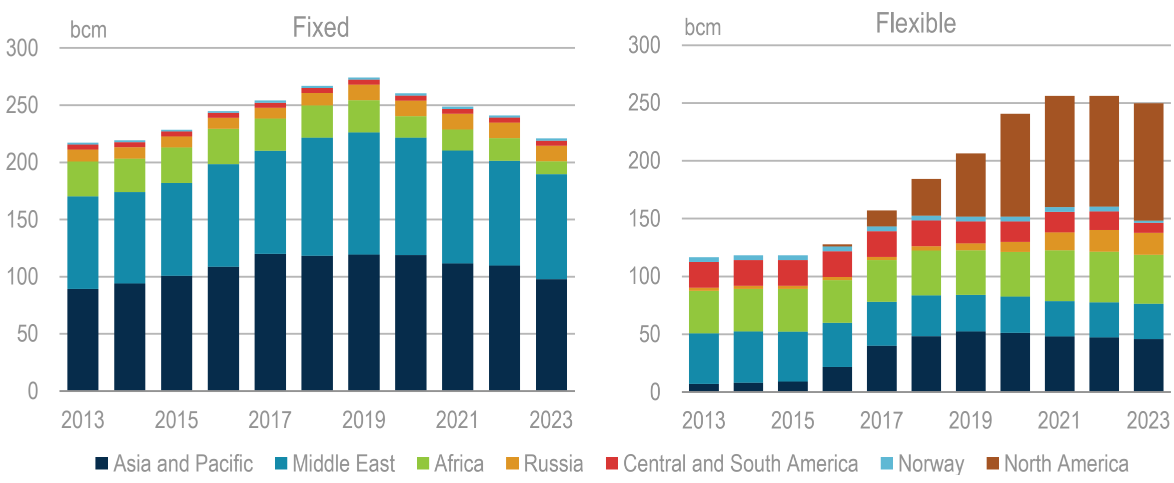
Source: IEA analysis based on ICIS (2018), *ICIS LNG Edge* (subscription required).

United States provide the bulk of destination flexibility

Figure 2.14 shows a breakdown by region and country of all contracted volumes from current LNG exporting capacity. While fixed destination contracts are set to decrease, peaking in 2019, destination flexibility is anticipated to increase steeply and to outnumber fixed destination volumes by 2021. The main contributor to destination flexibility is the United States, which is ramping up projects that sell LNG on a FOB basis and without destination restrictions, followed by Australia, whose volumes are sold mostly to the portfolio players. Altogether, by 2021, almost 60% of LNG cargoes from the Asia and Pacific and North America regions will have no destination restrictions.

More than 50 bcm/y of fixed destination exporting contracts are expected to expire in the coming 2-3 years, mostly from the Asia and Pacific and Middle East regions, then delivering to the Asia and Pacific region. Those contracts have the potential to be renewed or replaced by new contracts with flexible destinations, supplemented by the availability of increasing capacity from the United States and other regions that are demonstrating the capability to provide greater freedom of destination flexibility compared to previous decades.

Figure 2.14 • LNG export contract volumes with fixed and flexible destination by region and country, 2013-23



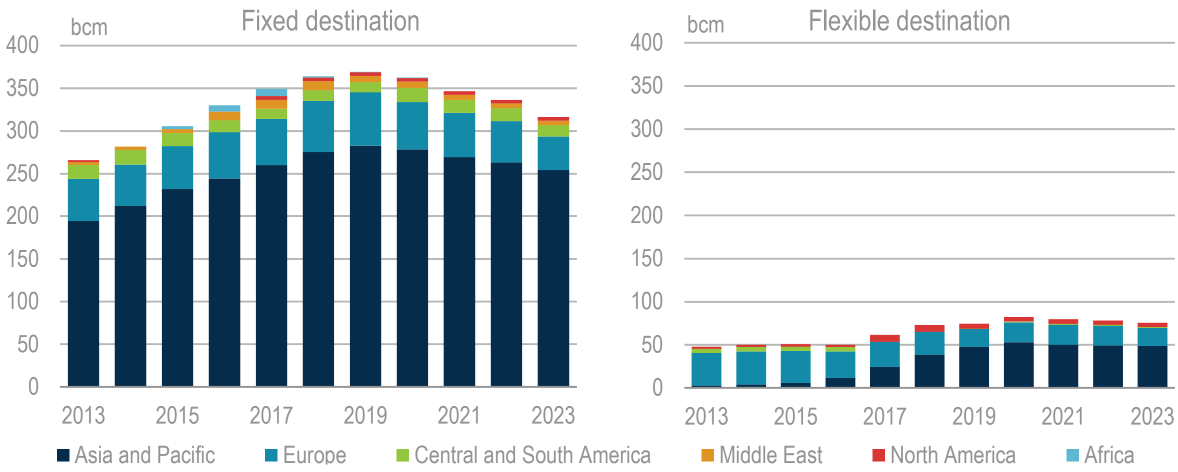
Note: Mexico is classified under North America.
Source: IEA analysis based on ICIS (2018), *ICIS LNG Edge* (subscription required).

Fixed destination remains dominant in Asia and Pacific

From the customers' perspective, analysis shows that importers maintain their dependence on LNG purchases under fixed destination contracts. This is considered to be due to existing long-term contracts with fixed destinations still being in place, and because of importing countries' ongoing requirement for a certain amount of cargoes to act as baseload supply for energy security purposes.

Figure 2.15 shows that in the peak of year 2019, 83% of importing contract volumes have fixed destinations, with the Asia and Pacific region accounting for 77% of fixed destination contracts. However, the gradual increase in flexible destination contracts is also expected in the same region with the expiry of legacy contracts and potential replacement with flexible North American contracts under short-, medium- and long-term contracts. The volume of contracted flexible destination LNG in the Asia and Pacific region is expected to show a net increase of 14 bcm (23%) between 2017 and 2023.

Figure 2.15 • LNG import contract volumes with fixed and flexible destination by region, 2013-23



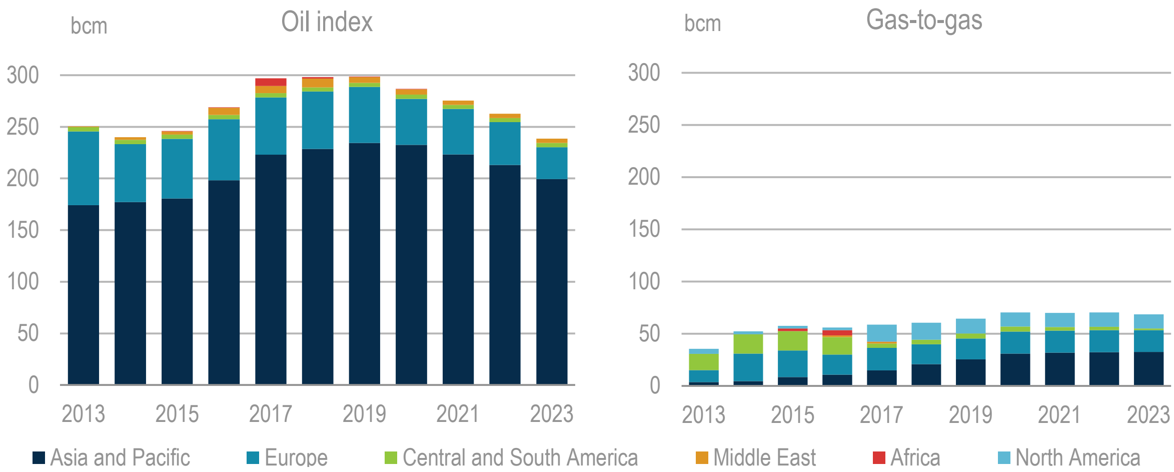
Note: Mexico is classified under North America.
Source: IEA analysis based on ICIS (2018), *ICIS LNG Edge* (subscription required).

Importing contracts with destination flexibility may have layers of destinations. For example, under FOB contracts, where the buyers have responsibility for transport, a fixed main (or primary) importing country or terminal(s) is likely to be firstly specified. In the second layer, the diversion option, or the right to divert to another country or other terminal(s) in case of overcapacity, is specified. Under DES contracts, where the seller has responsibility for and control of transporting the LNG using its own fleet, diversion is likely to be possible only under the condition that the diversion of the seller's vessel would not negatively impact its fleet operations. As the number of LNG importing countries and territories is expected to grow from the current 41 to 46 by 2023 (IEA, 2018), the trend for importers is toward greater contract diversification, driven by emerging Asian buyers including China. These LNG importers are likely to continue to prefer having a certain amount of contracts with a fixed destination, while also seeking certain flexibility (or options) to remove destination clauses in other contracts in their supply portfolio.

Medium-term price indexation outlook

The analysis of LNG contracts by price mechanism – addressing the split between oil-indexed and gas-to-gas pricing, by export and import, by region and country – shows a recent trend towards gas-to-gas indexation in LNG export and import contracts since the first US LNG shipment in 2016. Over 75% of oil-indexed LNG is delivered to Asia and Pacific, with Europe accounting for most of the rest (Figure 2.16).

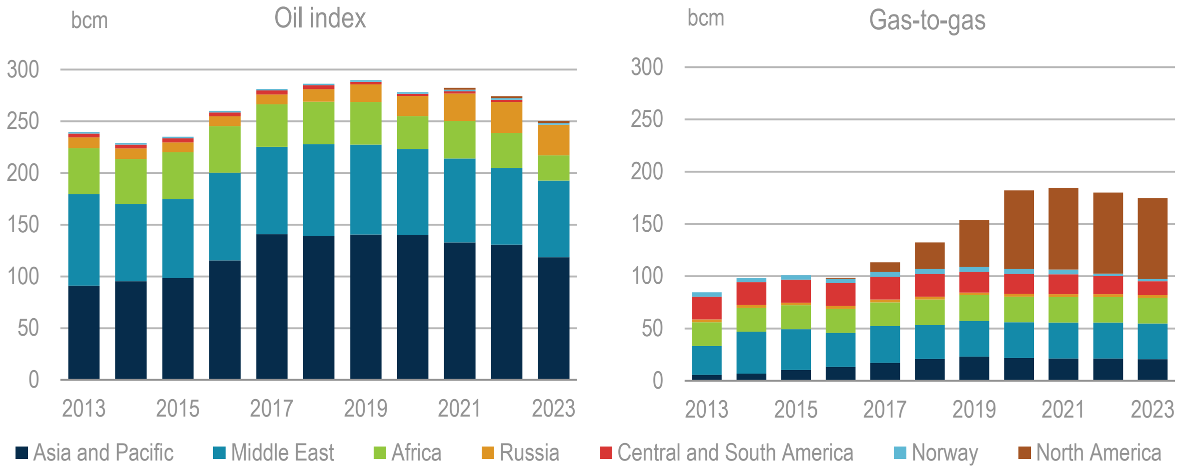
Figure 2.16 • LNG import contract volumes with oil index and gas-to-gas pricing by region and country, 2013-23



Note: Mexico is classified under North America.
Source: IEA analysis based on ICIS (2018), *ICIS LNG Edge* (subscription required).

This report also expects a further decline in the share of the oil-linked pricing mechanism in export contracts (Figure 2.17). The largest decrease in oil-indexed pricing is observed in the Asia and Pacific region (down by 22 bcm between 2017 and 2023), followed by Africa (down by 17 bcm). The decreasing oil-indexed volume, associated with the expiry of existing contracts, is to be replaced by gas-to-gas-indexed contracts gradually from 2017. The gas-to-gas pricing mechanism is driven by Henry Hub-priced LNG exports from the United States. As the US export volume expands, gas-to-gas-priced LNG contracts from the United States are expected to account for more than 40% of all export contracts priced in this way by 2023, compared to less than 10% in 2017, and to become the dominant source of all gas-to-gas-priced import contracts in the Asia and Pacific region.

Figure 2.17 • LNG export contract volumes with oil index and gas-to-gas pricing by region and country, 2013-23



Note: Mexico is classified under North America.
Source: IEA analysis based on ICIS (2018), *ICIS LNG Edge* (subscription required).

In spite of the steady growth of gas-to-gas-priced volumes for export contracts (which almost double between 2016 and 2021), oil indexation remains the major component of price determination for export volumes (Figure 2.16). This is even more the case for import volumes (Figure 2.17) with a growing share of Asian gas-to-gas indexed imports, but which although remains marginal compared with the region's total LNG imports. The short- to medium-term growth of uncontracted volumes (Figure 2.13), mainly linked to US LNG development, can provide opportunities to increase the share of gas-to-gas pricing in LNG import contracts in the future, but will not challenge the dominance of oil indexation in the near future – which can be all the more problematic for buyers in case of higher crude oil prices.

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3. Timeliness of LNG to compensate for unplanned supply imbalances – An empirical assessment

Analysis of LNG readiness

Liquefied natural gas (LNG) is playing an increasingly important role in meeting countries' natural gas demand, either as part of diversified gas supply portfolios that include domestic production or pipeline imports, or as the main source of natural gas supply (IEA, 2017). Trade in LNG grew from 230 billion cubic metres (bcm) in 2007 to over 390 bcm in 2017, whilst the number of importing countries more than doubled from 16 to 38 over the same period.

With an increasing number of countries relying on LNG to meet their growing gas demand, it is important to assess the readiness and timeliness of LNG sources to cover for potential supply disruption and/or surges in demand.

For the purpose of analysing the timeliness of LNG supply, this report classifies LNG importers' exposure by assessing the ability of the given gas market provide additional LNG supply in a timely manner.

This ability in turn will depend upon the availability of alternative sources of gas supply in the form of:

- spare capacity in domestic production
- pipeline import options
- availability of seasonal storage
- additionally available LNG volumes, and
- the diversity of the gas and LNG import portfolio.

The *Global Gas Security Review 2017* defined four types of buyer, depending on the respective share of LNG in their natural gas supply and of long-term contracts within their LNG supply. To assess the importance of LNG for importing countries, this year's *Global Gas Security Review* takes a slightly different approach,[10] using the first of last year's metrics, but a different second metric:

- **LNG as a proportion of gas consumption** – this metric describes the extent to which the gas supply portfolio relies on LNG. A low percentage would indicate the availability of other supply options, such as domestic production and/or pipeline imports.
- **Gas import diversity** – the second metric measures the diversity of a given country's gas import portfolio. It is calculated using the Herfindahl-Hirschman index (HHI), which in this case shows the market concentration of suppliers (here gas exporting countries) in a given import market. A low HHI indicates low market concentration, meaning greater import diversity.

Based on these two metrics, four groups of LNG importing countries can be distinguished:

- exposed LNG importers
- diversified LNG importers

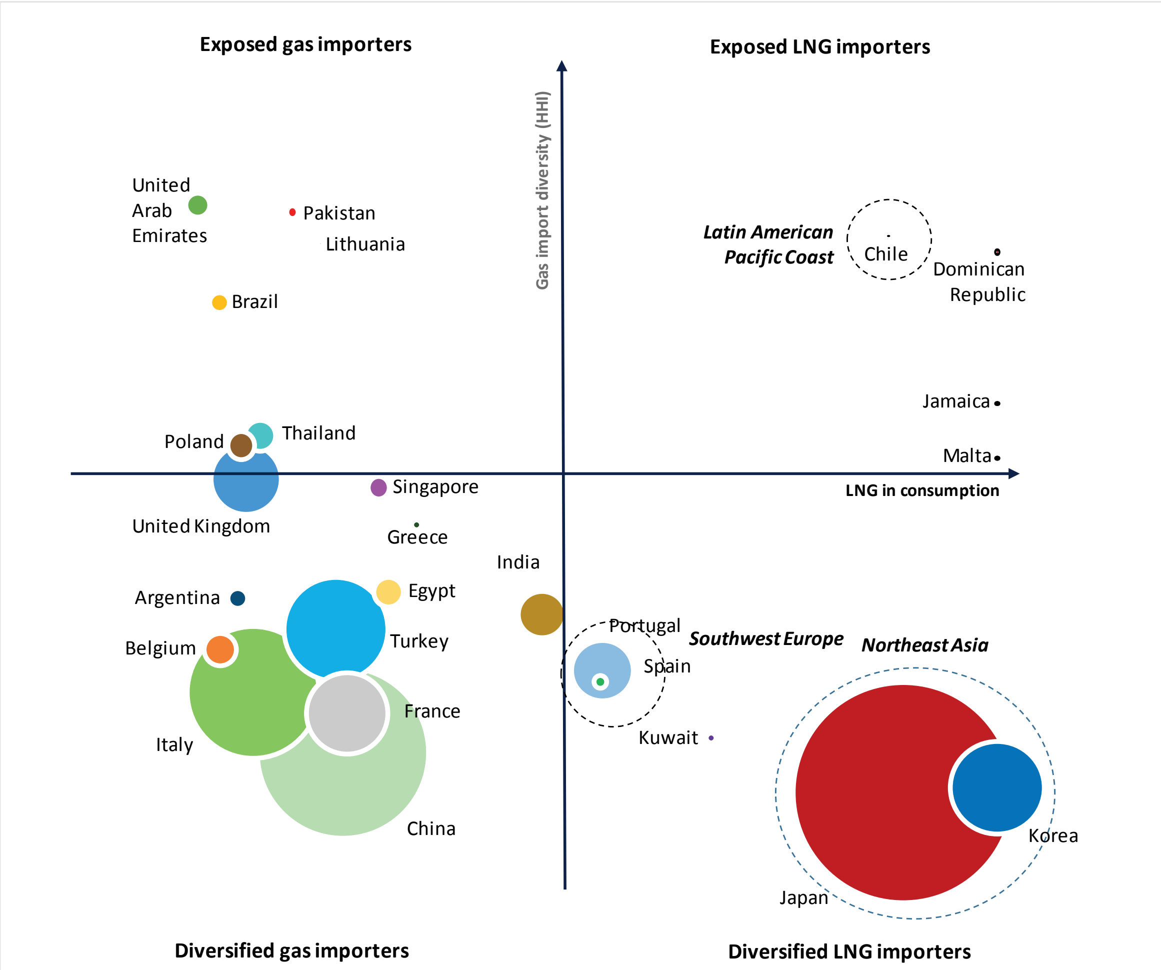
[10] The analysis of the *Global Gas Security Review 2017* provided a typology of LNG buyers based on the share of LNG in total gas supply and the share of long-term contracts in the LNG supply, which showed the development of shorter-term oriented and more price-sensitive importers (IEA, 2017). This year's analysis focuses on buyers' supply portfolios' diversity (or lack of) and related exposure in case of supply disruption.

- diversified gas importers
- exposed gas importers.

This segmentation should not be regarded as a rigid distinction between classes of buyer, but rather as a guiding framework that shows the diversity of the LNG demand market.

The chart in Figure 3.1 shows the segmentation of LNG importers into four types: the horizontal axis indicates the share of LNG in gas consumption (LNG dependency); the vertical axis shows their gas import diversity (HHI); and the bubble size represents the size of net gas imports in 2017.

Figure 3.1 • LNG buyer types and clustering based on 2017 imports



The first group ("Exposed LNG importers" in Figure 3.1) are those countries with a high percentage of LNG in their gas consumption, due to low domestic production and/or low pipeline imports, and a high HHI. Typically these markets started to import LNG recently (less the case for Chile that has been importing LNG for almost a decade) and do not currently have a diversified import portfolio.

The traditional LNG markets ("Diversified LNG importers"), such as Japan, Korea, Portugal or Spain, show a different picture in that respect. These countries started to import LNG decades ago and, while relying heavily on LNG to meet their gas needs, have by now achieved a well-balanced, diversified LNG import portfolio. One should note that historically these countries relied on a handful of projects there were available to produce and export LNG. However, they have been able to benefit from the growing diversity of LNG exporting countries and the emergence of new midstream players (such as portfolio players and trading houses).

The third segment of LNG importers ("Diversified gas importers") comprises countries characterised by a low share of LNG in gas consumption and a high diversity of gas import sources. France, Italy and Belgium are typical of this category, with LNG complementing piped imports from Algeria, Norway and the Russian Federation. The People's Republic of China (hereafter "China") also stands in this category, with domestic gas production covering over 60% of the country's needs in 2017 and about 20% being supplied by pipeline from Central Asia and Myanmar. However, China's exposure to potential LNG supply disruption is set to increase in the next few years, given that its widening import gap will be met mainly by LNG in the near future, with Russian pipeline supplies not ramping up until the early 2020s (IEA, 2018a). China already has a great diversity of LNG supplies and it can be presumed that this strategy will be sustained in the future both for commercial and security of supply reasons.

The fourth category ("Exposed gas importers") is defined by markets where LNG accounts for only a small share of gas consumption and which rely heavily on a few supply sources. A further distinction could be made between countries with relatively high domestic production (such as the United Arab Emirates or Thailand) and those relying primarily on pipeline imports and/or domestic production, but only from a limited number of suppliers (such as Lithuania).

Three geographical clusters emerge from the analysis as being particularly sensitive to LNG as a source of supply and hence as a marginal source in the case of disruption or imbalance:

- Northeast Asia (Japan and Korea), with important LNG trade volumes and a high level of LNG supply diversity.
- Southwest Europe (Spain and Portugal), with lesser yet still sizeable volumes and supply diversity.
- Latin American Pacific Coast (mainly Chile, with Colombia to follow if the proposed project on the Pacific Coast goes ahead), with more limited trade and diversity of LNG supply sources.

These clusters are composed of mature natural gas markets, which have developed a range of instruments to mitigate the impact of supply shortfalls – including short term LNG but also infrastructure and downstream flexibilities. As a result, these markets have successfully managed supply imbalances in the past, and can be seen as benchmarks for new and future importers relying on LNG as a main source of natural gas supply and flexibility.

Methodology and supply source typology

To assess the relative exposure to LNG as an incremental source in case of a supply disruption, this year's analysis focuses on the timeliness of alternative LNG supplies, i.e. the time frame required to bring additional volumes of LNG in the case of an unexpected supply-demand gap.[11]

Additional LNG supplies have been sorted into four different categories:

- **Uncontracted LNG** refers to sales that are not sold under short-, medium- or long-term contracts but instead on the spot market. By being uncontracted, these volumes are fully flexible and can be directed to the most profitable markets.

[11] For the purpose of analysis, which will assess the availability of alternative or additional LNG cargoes to the disrupted market, the report purposefully makes the following assumptions: an LNG sale and purchase agreement is in place; ship-shore compatibility, including Ship Inspection Report Programme (SIRE) inspections and terminal use agreements, are in place; import approval has been secured from respective authorities; LNG specifications and any other technical and regulatory conditions that the LNG importers are required to meet and clear have been attained.

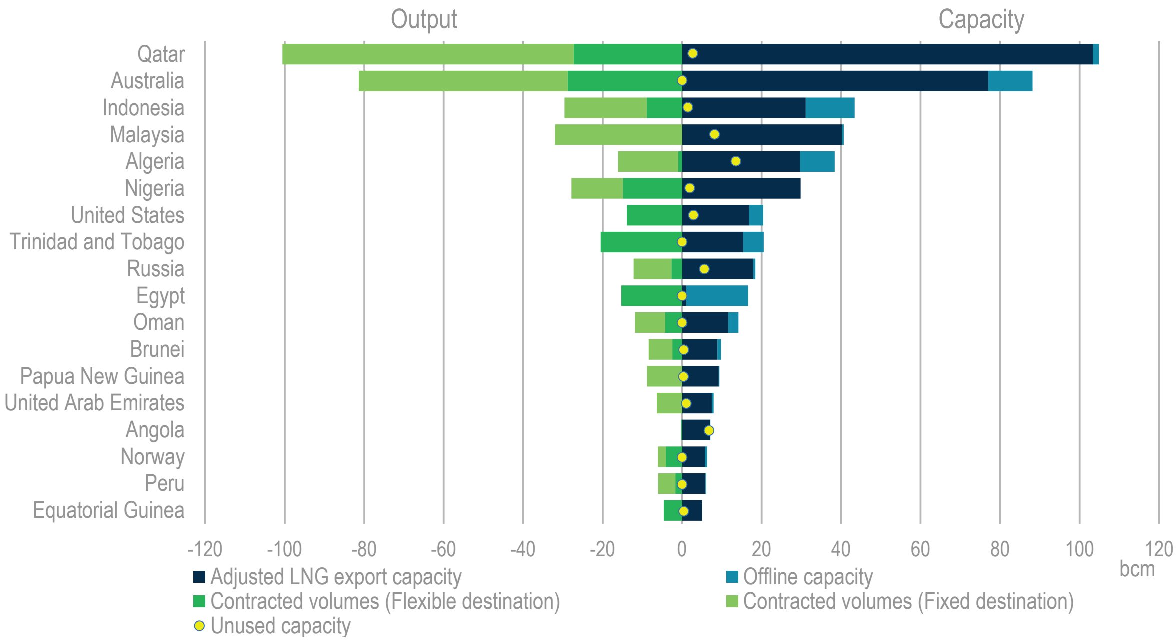
- **Flexible-destination LNG** refers to short-, medium- and long-term contracts that are either taken as free on board (FOB) at the liquefaction plant or where the buyer has flexibility in destination.
- **Fixed-destination LNG** refers to contracts with delivered ex-ship (DES) terms and/or with a destination clause.

- **LNG at sea refers to all volumes** – without regard to their contractual terms – which are already heading to their initial destination point.

Figure 3.2 shows that contracted LNG with a fixed destination still accounts for the majority of output, whilst flexible-destination LNG amounted to approximately 150 bcm in 2017. Unused LNG capacity (the difference between net capacity and output) stood at a mere 34 bcm due to the high share of contracted volumes and partly to some capacity being offline. The majority of the unused capacity was located in Algeria, Angola, Malaysia and the Russian Federation.

An additional source of supply considered in the analysis is LNG at sea (including both flexible and non-flexible cargoes), which in principle could be diverted – provided that commercial restrictions can be overwritten by emergency situations.

Figure 3.2 • LNG contracted volumes and export capacity in 2017



Source: IEA analysis based on ICIS (2018), *ICIS LNG Edge* (subscription required).

Figure 3.3 shows that LNG volumes at sea amounted to 14.3 bcm per day (bcm/d) in 2017, with a majority (70%) bound for Asian markets.

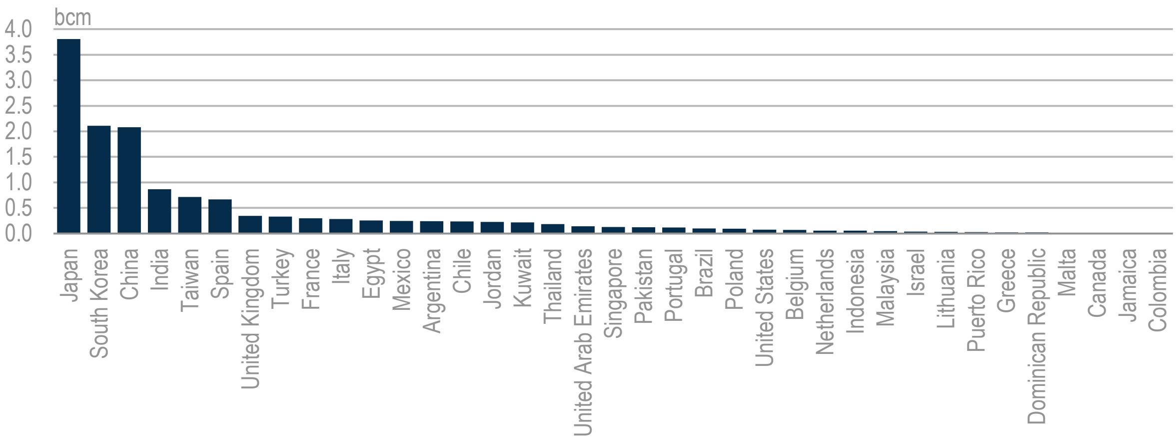
This is based on traded LNG volumes totalling 391 bcm in 2017. To calculate average LNG volumes at sea by destination country, all traded LNG volumes in 2017 have been aggregated by route from their origin country to their respective destination market. To calculate the LNG volumes on one route in a given day the following formula was used:

$$\frac{\text{annual LNG trade volume per route}}{365} \times \text{average shipping time per route}$$

Average shipping time associated with each route has been calculated under the following assumptions: (1) shortest routes are given preference; (2) the vessels' average speed is 16 knots

(29.63 kilometres per hour);[12] (3) entire operation of both loading and offloading takes one day each (note that no time has been allowed for berthing and unberthing); and (4) regarding LNG at the liquefaction plant, LNG is assumed to be already liquefied and available inside the tanks.

Figure 3.3 • Average LNG volumes at sea by destination country



Source: IEA analysis based on ICIS (2018), *ICIS LNG Edge* (subscription required).

If a cargo is to be diverted to a new destination, it will require additional time. The average additional diversion time is estimated as follows.

If the new destination market is in the same region as the initial destination market, the average diversion time is calculated in the following way:

$$\text{original shipping days (from origin to destination)} - \frac{\text{average shipping days per laden voyage}}{2}$$

If the new destination market lies in a different region than the initial destination market, the average diversion time will equal:

$$\text{original shipping days (from origin to destination)} + \frac{\text{average shipping days per laden voyage}}{2}$$

When assessing potential LNG volumes at sea, volumes that were already being delivered to a certain country are not considered as potential additional LNG supply for that country.

In respect of potential LNG cargoes, the analysis assumes that 0.08 bcm represents one cargo, and that export plants will not send cargoes with volumes lower than 0.08 bcm (for security, technical and economic reasons).

Timeliness of additional LNG sourcing – regional case studies

Northeast Asia

The Northeast Asian market (which consists of Japan and Korea) heavily relies on LNG imports. This mature market, with demand of over 170 bcm in 2017, is served by a diversified portfolio of suppliers built up over decades. The Japanese and Korean markets both experienced demand shock in the aftermath of the 2011 Great East Japan Earthquake (which significantly affected Japanese energy supply with the shutdown of all nuclear power stations), the

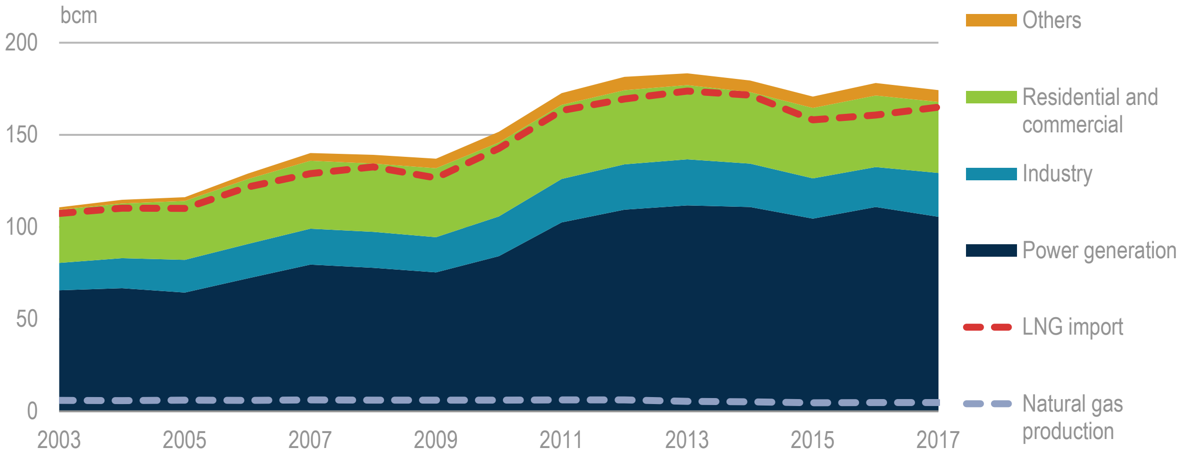
[12] Maximum average laden speed observed in 2013; see Chapter 4, Figure 4.8.

Kumamoto Earthquake of 2016, and two strong earthquakes that occurred in a region home to nuclear power plants in Korea in 2016 and 2017 respectively. The IEA has therefore been closely monitoring the security of gas supply in the region by assessing: the robustness of emergency response (IEA, 2016a); LNG infrastructure and flexibility in supply volumes and contracts (IEA, 2016b); emergency policy measures and co-ordination mechanisms and LNG import typologies (IEA, 2017).

Natural gas supply and demand

The power generation sector is the main component of natural gas demand, currently accounting for over 60% of the market's total gas demand, and with a compound average growth rate of 4% over the last decade (Figure 3.4).

Figure 3.4 • Northeast Asia natural gas demand by sector and supply, 2003-17



Source: IEA (2018b), *Natural Gas Information* (database).

The residential and commercial and industrial sectors follow the power sector, accounting for 22% and 14% of natural gas demand respectively. Almost 95% of the gas supply of 170 bcm is met by LNG imports.

In 2017, Northeast Asia imported LNG from a total of 22 countries (Figure 3.5), of which 60% or almost 100 bcm was from three countries – Australia, Malaysia and Qatar. Over 65% of total LNG imports came from within the Asia and Pacific region.[13]

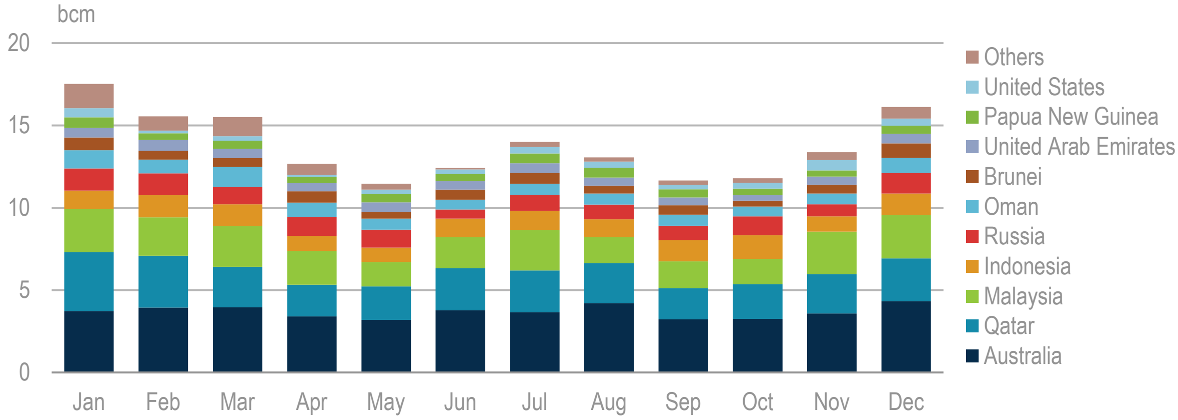
Seasonality is observed across monthly demand, with a little over 6 bcm in seasonal variance. The months of peak demand are in the northern hemisphere winter (December to March), with another slight demand increase in the summer (July and August). These increases are due to higher residential heating need (both power generation demand and direct heating devices) in winter and air conditioning (power generation demand) in summer.

In the absence of underground storage facilities, variability in consumption needs is met by flexibility in LNG imports and, to a lesser extent, by storage in LNG tanks at receiving terminals or in specific storage facilities. LNG storage capacity has been increasing since LNG imports began in the late 1960s, mainly by converting oil import and storage terminals into LNG import terminals. Over 20 bcm of LNG storage capacity and 360 bcm of LNG send out capacity are currently installed in total, with an average utilisation rate of 54%. The average conceals a wide variation,

[13] For the purpose of regional analysis, Russian LNG from the Sakhalin II project is categorised as Asia and Pacific supply volume.

with storage terminals located near cities more highly utilised (one over 140%) while those in smaller markets are lightly used (one has an utilisation rate of 20%).

Figure 3.5 • Northeast Asia LNG imports by source, 2017



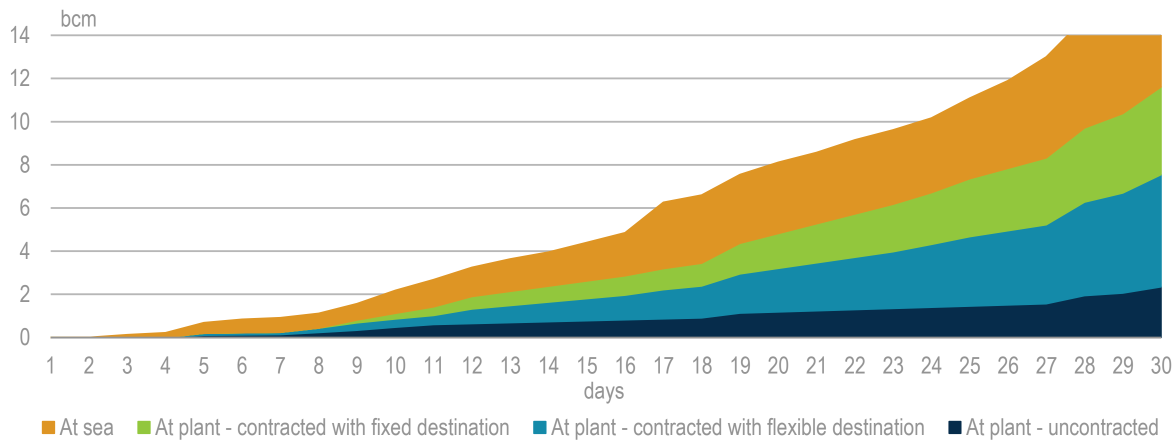
Source: IEA analysis based on ICIS (2018), *ICIS LNG Edge* (subscription required).

Timeliness of unplanned LNG sourcing

Currently the average LNG shipping duration from exporting plants located in the Asia and Pacific region is in the range of 3 to 13 days for laden voyage to the Northeast Asian market (including offloading time). Qatar and the US Gulf Coast are 17 and 25 days for a laden voyage from the region, respectively.

Thus, in theory, the Northeast Asian market could receive an urgent additional LNG cargo within three days after the unplanned need has been identified. However, physically and contractually available LNG is difficult to source in a timely manner. The Northeast Asian market imported more than 170 bcm of LNG in 2017 (or an average of 15 bcm per month), accounting for nearly 45% of global LNG trade. This illustrates that nearly half of the LNG at sea is already heading to the Northeast Asian market with the final destination determined, which limits the number of available and nearby alternative supplies.

Figure 3.6 • Theoretically available LNG volumes for Northeast Asia

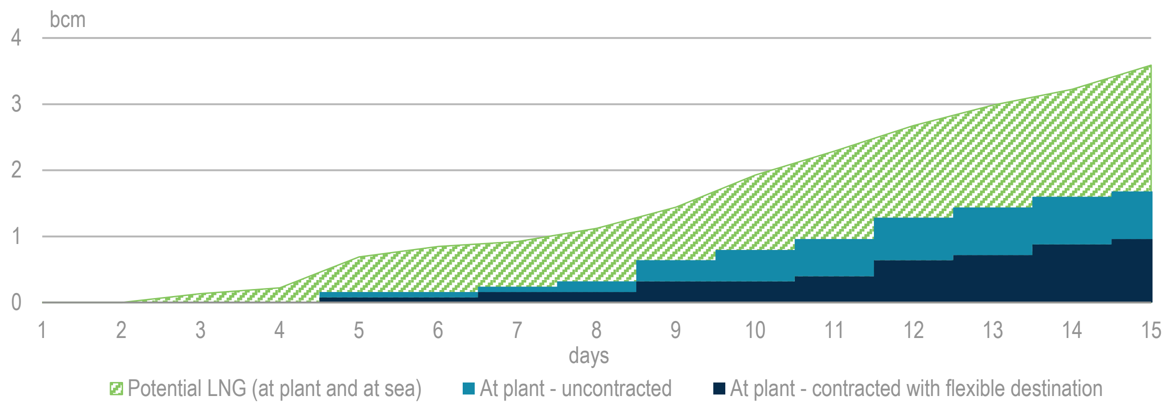


Source: IEA analysis based on ICIS (2018), *ICIS LNG Edge* (subscription required).

Figure 3.6 shows the cumulative LNG supply over one month that can be diverted to Northeast Asia, taking into account the time needed to reach this market. LNG cargoes already at sea, which account for most of the volume and appear to be the closest source of supply, are nonetheless less likely to be diverted at short notice as they are already bound for a destination as per contractual agreement, even though short-term swaps or diversions can be envisaged (if permitted by the contracting parties). The fact that LNG is still at the liquefaction plant does not necessarily mean it can easily be classified as divertible to Northeast Asia – especially for volumes contracted with fixed destinations.

LNG supply more likely to be divertible to the Northeast Asian market are the volumes contracted with flexible destinations, as well as the uncontracted volumes. Figure 3.7 focuses on these specific sources and their availability and timeliness over the first 15 days on a cargo-by-cargo basis.

Figure 3.7 • Potential additional LNG cargoes for Northeast Asia, 2017



Source: IEA analysis based on ICIS (2018), *ICIS LNG Edge* (subscription required).

The analysis shows that the potential for additional supply remains limited, reflecting the lack of spare capacity margin at most liquefaction plants (Chapter 2) and the fact that most of the Pacific Basin export plants are principally contracted to Northeast Asia already. As a consequence, the two first additional cargoes from uncontracted capacity and contracted LNG with flexible destination would not arrive before 5 days (and two others on the 7th day). Other potential sources (at sea or contracted with fixed destination) could arrive sooner (3 days minimum) provided that they can be redirected.

Southwest Europe

LNG supply is of particular importance to the Southwest European gas market (Spain and Portugal), which has almost no domestic production and is less interconnected than Northwest European countries.

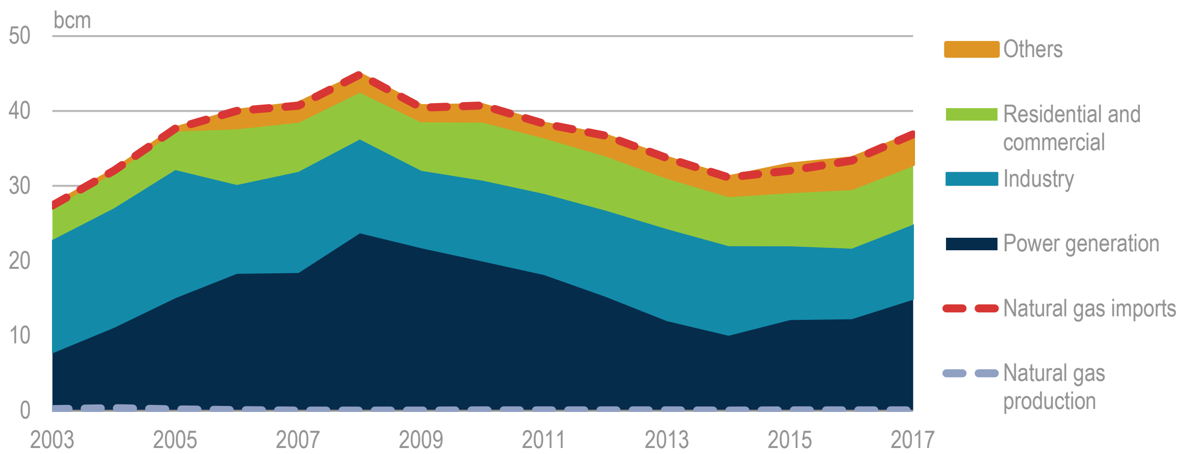
Natural gas supply and demand

Portugal and Spain consumed 37 bcm of natural gas in 2017, which accounted for approximately one-fifth of the peninsula's total primary energy supply in 2016. As shown in Figure 3.8, power generation accounted for the largest share of gas consumption at almost 40% in 2017.

Natural gas plays a key role in balancing the Spanish and Portuguese power systems, which both rely heavily on variable renewables and most importantly on hydropower. The share of hydropower in total power generation – depending to a large extent on precipitation – has varied between 9% and 18% through the last decade, impacting on flexible thermal generation (including gas-fired power plants). Consequently, the share of gas-fired generation in the power mix varied between 13% and 33% through the period 2006 to 2016.

Combined demand from the industrial and other sectors (including the energy sector) accounted for 37% of total consumption in 2017, mainly driven by oil refineries as well as the chemical and petrochemical sectors.

Figure 3.8 • Southeast Europe natural gas demand by sector and supply, 2003-17

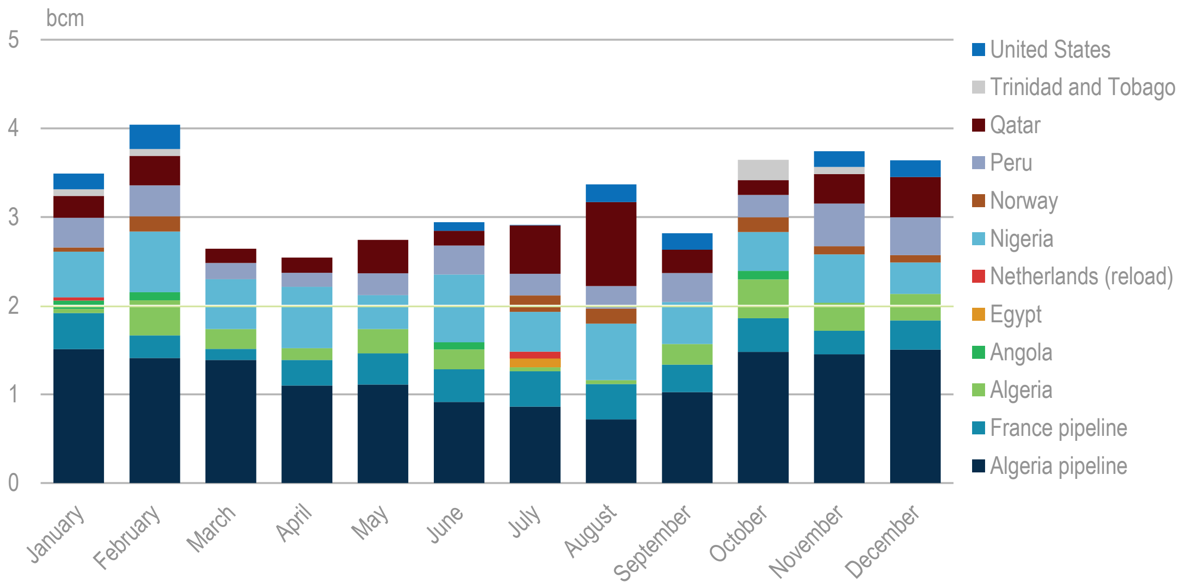


Source: IEA (2018b), *Natural Gas Information* (database); IEA analysis based on ICIS (2018), *ICIS LNG Edge* (subscription required).

Residential and commercial demand accounted for 22% of total gas consumption. This contrasts with Northwest European markets where it typically accounts for over 40%, as heating requirements for Spanish and Portuguese buildings are usually limited by mild temperatures through the heating season.

This seasonality has two components: one is driven by gas distributed to the residential and commercial consumers, which peaks during the heating season, while the other reflects gas-to-power demand peaking throughout the summer, and is largely driven by cooling degree days.

Figure 3.9 • Gas imports to Southwest Europe in 2017



Sources: ENTSOG (2018), ENTSOG Transparency Platform; ICIS (2018), *ICIS LNG Edge* (subscription required).

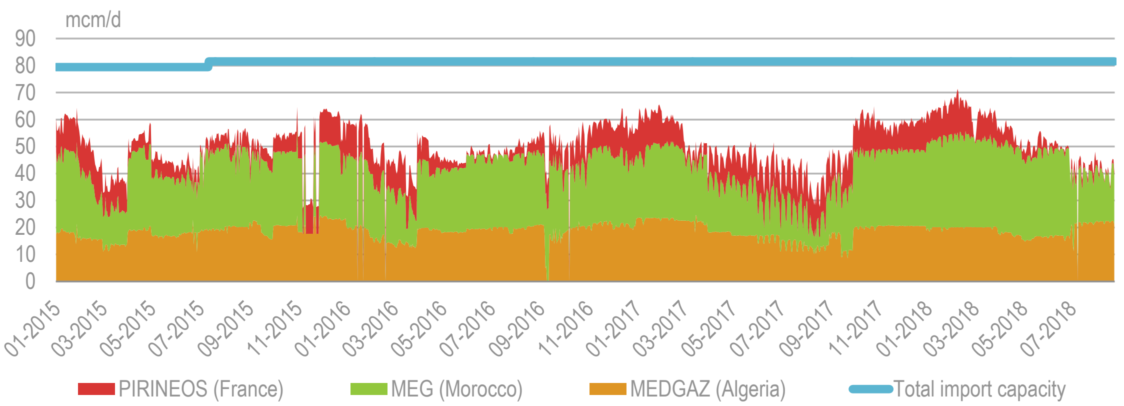
Gas production on the Iberian Peninsula is virtually non-existent – in 2017 it amounted to 0.035 bcm. Hence, both Portugal and Spain are entirely reliant on gas imports. LNG imports started in 1969 when the Barcelona LNG terminal began operating with two tanks. Spanish LNG import capacity continuously increased through the 1970s and 1980s in parallel with the country's gasification plan launched in 1975. Today Spain's LNG import capacity stands at 62 bcm per year (bcm/y).[14] Portugal's LNG terminal in the Port of Sines became operational only in 2004 (with a regasification capacity of 5.26 bcm/y).

The first import pipeline into Spain became operational in 1993, at Larrau, opening the way for gas imports from Northwest Europe through France. The Maghreb–Europe gas import pipeline, bringing Algerian gas to Spain and Portugal via Morocco, entered commercial service in November 1996 with an initial capacity of 8.5 bcm/y, increased to a current capacity of 14 bcm/y. In 1996, the first gas interconnection between Spain and Portugal was established at Badajoz (with an entry capacity of 4 bcm/y into Portugal and with a reverse capacity of 2 bcm/y), allowing Algerian gas to reach the Portuguese market. Medgaz, the second gas pipeline bringing Algerian gas to the Iberian Peninsula, became operational in March 2011 with a capacity of 8 bcm/y – currently at 9 bcm/y. A second, bidirectional interconnection with France, the Adour pipeline, began operation in December 2015, bringing total import capacity from France to 7 bcm/y.

LNG accounted for 52% of total gas imports (or 20.25 bcm) into the Iberian Peninsula in 2017, with cargoes supplied by 11 different export countries. Almost one-third of LNG imports arrived from Nigeria, followed by Qatar (21%), Peru (21%) and Algeria (18%).

Pipeline imports (18.35 bcm in 2017) are largely dominated by Algeria, with a share of almost 80% (Figure 3.9). When combined with its LNG export volumes, Algeria's share reached 44% of total gas supplies to the Iberian Peninsula.[15] In June 2018, Naturgy (previously Gas Natural Fenosa) and Sonatrach signed an agreement to renew the gas procurement contracts between Algeria and Spain to 2030, representing more than 40% of Naturgy's import portfolio (Naturgy, 2018). Pipeline imports via France bring gas volumes to the Iberian Peninsula from Northwest Europe, including supplies from Norway and the Netherlands.

Figure 3.10 • Natural gas pipeline import flows and capacity, Southwest Europe, 2015-18



Source: ENTSOG (2018), ENTSOG Transparency Platform.

[14] Not including the El Musel terminal, which is currently mothballed.

[15] It should be noted that imports from Algeria are limited by Spain's Royal Decree 1766/2007. This stipulates that in the case that the sum of all supplies of natural gas for national consumption from a given country exceeds 50% of total imports, direct suppliers and consumers holding supplies of more than 7% of national annual consumption must limit their supplies from the country to less than 50% of the total.

As shown in Figure 3.10, spare capacity in import pipelines is rather limited during the peak demand periods of the heating and cooling seasons. Furthermore, there might be limitations around upstream production capacity or export capability. For instance, Algeria's Hydrocarbon Law No. 05-07 gives priority to meeting the needs of the national market, both in liquid hydrocarbons and in natural gas, meaning that exports might be potentially restricted in order to meet domestic requirements.[16]

Spain has four underground gas storage sites with a combined working gas capacity of 2.8 bcm/y and with an aggregated maximum withdrawal capacity of about 20 mcm/d. Portugal's underground storage capacity is 0.32 bcm/y with a maximum withdrawal capacity of 6 mcm/d. During high demand periods, spare withdrawal capacity averages around half of maximum withdrawal capacity.

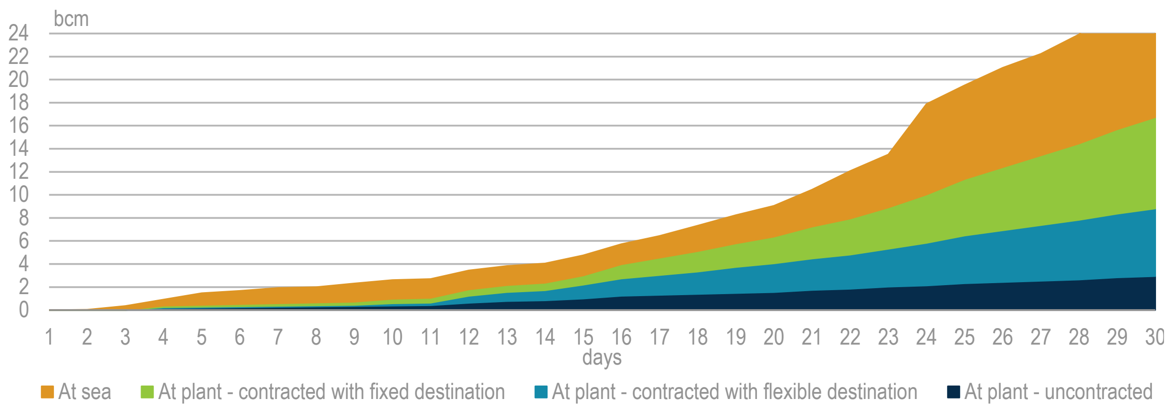
In addition, Spain has about 2 bcm/y of extra storage capacity in LNG tanks and Portugal's terminal at Sines has a storage capacity of 0.23 bcm/y.

Timeliness of unplanned LNG sourcing

The relative proximity of the Iberian Peninsula to major LNG producers (such as Algeria, Nigeria, Norway and Qatar), as well as to the key trading routes of the Atlantic Basin, results in quicker deliverability of additional LNG volumes when needed by the market.

Figure 3.11 shows the total theoretically available additional LNG that could be brought to the Southwest European gas market in the case of an unplanned supply shortfall.

Figure 3.11 • Theoretically available LNG volumes for Southwest Europe



Source: IEA analysis based on ICIS (2018), *ICIS LNG Edge* (subscription required).

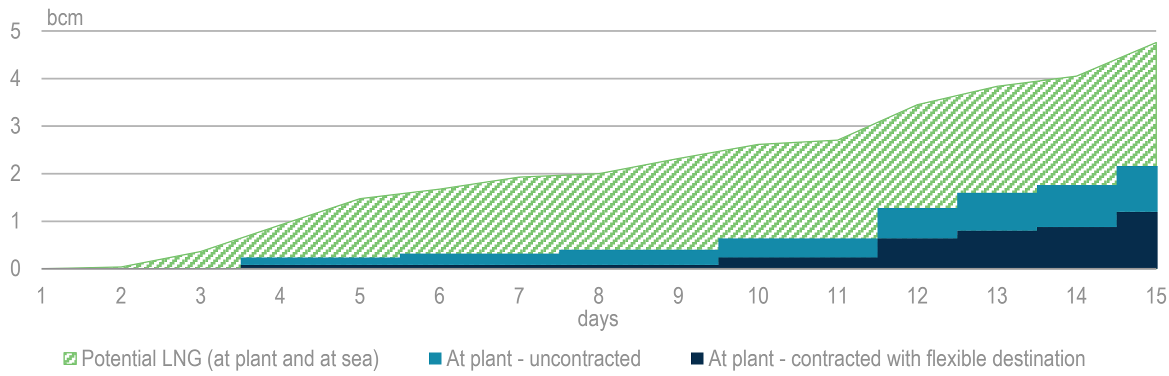
Southwest Europe could start receiving extra LNG volumes from the third day after submitting an interest in purchasing additional cargoes (Figure 3.11). This is mainly due to its proximity to other European LNG buyers (such as France and Italy), from where LNG cargoes could theoretically be redirected.

If cargoes at sea or with a fixed destination could not be diverted, the Iberian gas market would need four days to receive up to three additional cargoes by purchasing uncontracted or flexible volumes of LNG directly from an LNG supplier (Figure 3.12). One cargo would be sufficient to cover approximately one day of average daily gas consumption on the Iberian Peninsula.

[16] *Loi n° 05-07 du 19 Rabie El Aouel 1426 correspondant au 28 avril 2005 relative aux hydrocarbures*

It should be noted that the Iberian gas market benefits not only from its geographical proximity to LNG suppliers and trade routes, but also from the evolving regulatory framework of the European Union, which prohibits territorial sales restrictions. The European Commission has been pursuing lengthy negotiations since 2000 with the European Union's largest LNG and pipeline gas importers to eliminate destination clauses from import contracts.[17] This has in turn made most LNG volumes contracted to Europe divertible.

Figure 3.12 • Timeliness of LNG supply to Southwest Europe



Source: IEA analysis based on ICIS (2018), *ICIS LNG Edge* (subscription required).

Moreover, LNG terminals in France, Belgium and the Netherlands, as well the Isle of Grain terminal in the United Kingdom, have reloading capabilities. This is a more time-consuming and costlier solution; however, it provides commercial flexibility in those cases where the original buyer does not have a contractual right to divert cargoes and/or profit-sharing agreements in place. Hence, in practice LNG could be re-exported to Iberia from France and Northwest Europe. Under the best technical conditions, assuming that an LNG transhipment on a vessel berthed in Fos Cavaou (in south of France) were sent to and regasified in Barcelona, the timing could be lowered to three to four days.

South American Pacific Coast

The following analysis focuses on Chile, as Colombia's only LNG terminal is located on the Caribbean Coast and a second import terminal on the Pacific Coast has yet to be confirmed. Around 52% of Chile's gas supply is used for power generation and the country is highly dependent on LNG imports, in particular from Trinidad and Tobago, which provided 82% of LNG supply in 2017.

Chile's natural gas market has been dominated by imported LNG since its two LNG import terminals came into operation in 2009 and 2010, following Argentina's reduction in natural gas exports to Chile in 2008. Chile's indigenous production stood at around 1.2 bcm in 2016 and 2017, or around 20% of total consumption, which amounted to approximately 5.2 bcm. Since domestic production only supplies the far south, and due to the lack of pipeline connection with its neighbours, Chile is considered a virtual island in terms of natural gas supply.

In 2016 Chile started exporting natural gas to Argentina. However, in July 2018 the Argentinian Energy Minister said Argentina would begin exporting natural gas to Chile from October 2018 – first flows were delivered on 28 September (El Tribuno, 2018). The gas is due to be sourced

[17] Agreements have been reached with Statoil and Norsk Hydro (now both part of Equinor) in July 2002, with Nigeria LNG in December 2002 and with Algeria's Sonatrach in July 2007 (European Commission, 2002a, 2002b, 2007).

principally from the Vaca Muerta shale gas formation (Neuquen basin) through the Andes to the central Biobio region.

Natural gas supply and demand

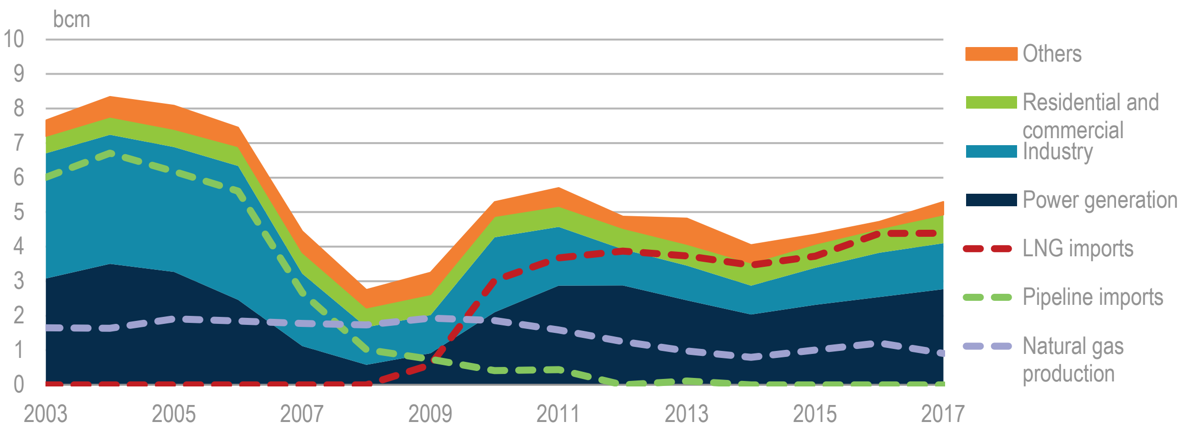
The share of natural gas in Chile has been declining in the past decade: its share of total primary energy supply fell from 21% in 2006 to 12% in 2016, while its share of electricity generation stood at 16% in 2016 compared with 20% in 2006 (IEA, 2018c).

Domestic gas production supplies an isolated network in the Magallanes region in the far south. Production volumes have been declining, from around 1.75 bcm per year during the 1990s, to 0.8 bcm in 2014 and up again to 1.2 bcm in 2016.

Domestically Chile lacks good infrastructure connections between its three markets: north, central and south. Consumption by sector differs across the three regions. In the far north, gas is supplied by the Mejillones LNG terminal and is mainly used for power generation. Additionally, some large mining customers directly import LNG from the terminal. In the central and southern regions, natural gas is supplied via the Quintero LNG terminal and is consumed by both industry and households. As for the Magallanes region in the far south, power generation, residential heating and the methanol production industry are all supplied by the limited domestic production. Total final consumption is concentrated in the Region Metropolitana of Santiago (63% of total final consumption in 2015), while Magallanes accounts for 23% and the central region of Valparaiso for 11%. Moreover, two floating storage and regasification units are proposed for the Biobio region and another for the Atacama region.

During 2015-17, around 52% of Chile's natural gas consumption was used for power generation, with industry consuming around 25% (Figure 3.13).

Figure 3.13 • Chile natural gas demand by sector and supply, 2003-17



Source: IEA (2018b), *Natural Gas Information* (database); IEA analysis based on ICIS (2018), *ICIS LNG Edge* (subscription required).

Natural gas imports from Argentina started in 1997 and volumes increased significantly until a peak in 2004, when natural gas demand reached 8.3 bcm and Argentina supplied 6 bcm. In 2004 Argentina began restricting natural gas exports due to higher domestic demand during winter. In 2008 total natural gas supply plummeted to 2.5 bcm due to Argentina's cut in natural gas exports to Chile. In response, the country decided to build two fast-track LNG terminals, the Quintero LNG plant in the central region (2009) and the Mejillones LNG plant in the far north (2010). Trinidad and Tobago has been the main source of Chile's LNG, accounting for 82% of total imports in 2017, with the United States (East Coast) supplying 15%, Equatorial Guinea 2% and Qatar 1% (Figure 3.14).

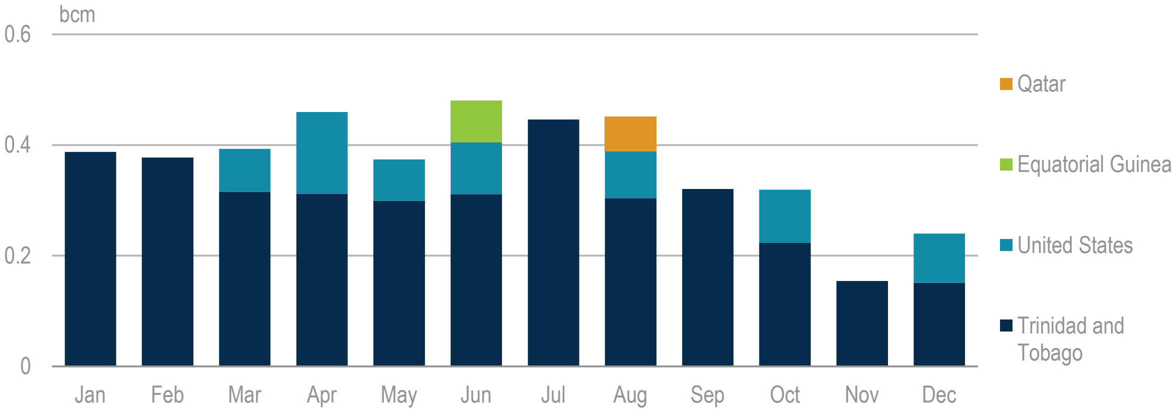
Before the expansion of the Panama Canal, completed in 2016, LNG imports were reliant on Trinidad and Tobago to an even greater extent, at 92% of total imported volumes during 2014-15.

Gas demand peaks both in autumn (March-May), when hydro reservoirs are low and combined-cycle gas turbines are used to fill the gap in electricity generation, and in winter (June-August) because of high heating demand.

As regards storage, Chile lacks specific underground natural gas storage facilities due to the country's geology and seismicity, and therefore the country's total storage capacity is 521 000 cubic metres (m^3) of LNG (or an equivalent of 312 mcm under gaseous form), located at the Quintero LNG plant (334 000 m^3 LNG) and the Mejillones LNG plant (187 000 m^3 LNG).

Chile currently has four LNG supply contracts with Total, Naturgy (formerly Gas Natural Fenosa) and Shell, totalling around 6 bcm/y. Aside from the contract with Shell, all the contracts have more than 14 years remaining before expiry. In 2017, 96% of the volumes received were via term contracts, with 4% from spot transactions (two cargoes from Petrobras, of which one was from Trinidad in April and the second from Qatar in August).

Figure 3.14 • LNG imports to Chile in 2017



Source: IEA analysis based on ICIS (2018), *ICIS LNG Edge* (subscription required).

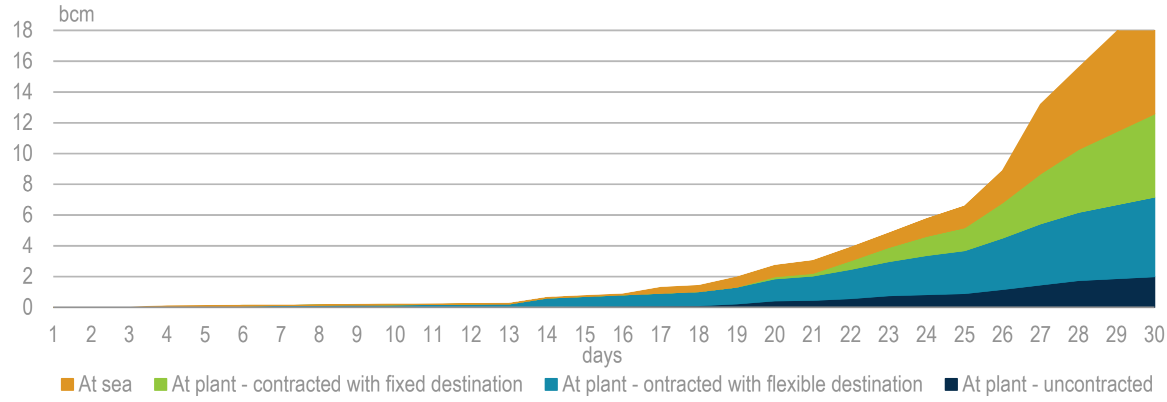
Timeliness of unplanned LNG sourcing

The closest source of LNG to Chile is Peru, at three days' delivery time. With the expansion of the Panama Canal, LNG cargoes from Trinidad and Tobago could arrive in 11 days. For cargoes coming from the US Gulf Coast, Chile would have to wait 12 days. Cargoes coming from Equatorial Guinea would need just under 18 days, and 23 days for cargoes coming from Qatar.

Figure 3.15 shows that Chile is a remote market from major LNG supply routes, even including less divertible sources of supply such as LNG already at sea or contracted LNG with a fixed destination.

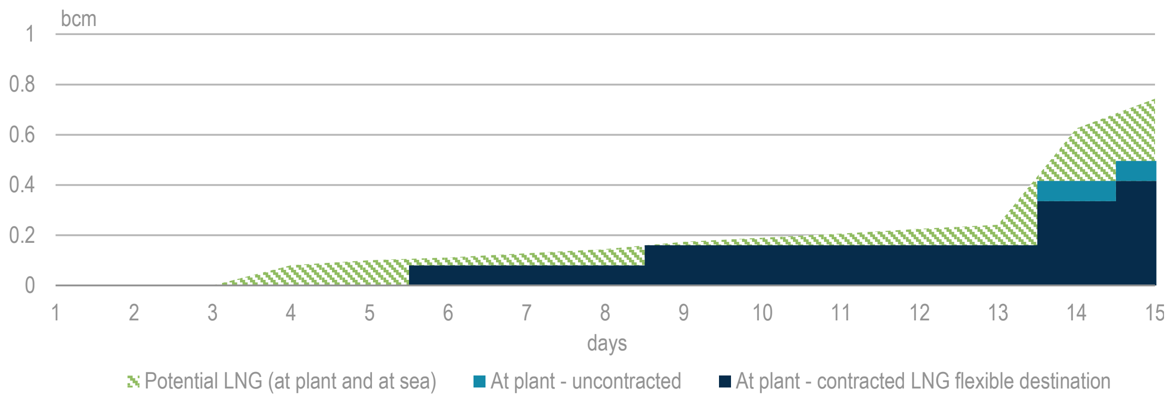
Figure 3.16 focuses on the most probable sources of additional LNG for diversion to Chile – LNG at the liquefaction plant contracted with flexible destinations and uncontracted capacity at the liquefaction plant. The analysis shows that Chile could receive its first additional cargo on the 6th day from Peru. However, if such a cargo is already loaded and can be diverted, it could be received in four days.

Figure 3.15 • Potential additional LNG volumes for Latin American Pacific Coast



Source: IEA analysis based on ICIS (2018), *ICIS LNG Edge* (subscription required).

Figure 3.16 • Timeliness of LNG supply to Chile



Source: IEA analysis based on ICIS (2018), *ICIS LNG Edge* (subscription required).

Conclusion

The analysis carried out on the time required to source additional volumes of LNG demonstrates that – despite the improving situation on contractual flexibility – securing additional LNG on the market cannot be seen as an immediate solution to compensate for unexpected additional supply needs. This analysis shows that the first additional LNG volumes would typically need several days at least to be shipped to the market requesting additional volumes of gas.

Hence, it is advisable for markets relying on LNG to complement their sourcing arrangements with the capability to respond to short-term requirements, enabling them to mitigate the impact of gas deficit situations. Actions could include:

- Developing underground and/or LNG storage capacity.
- Maintaining gas storage stocks above peak season demand levels so that unexpected short-term demand can be met.
- Strengthening the gas grid via the construction of both interstate and regional interconnectors, as well as the development of linepack18 management capabilities.
- Strengthening the power grid by building up electricity interconnectors.

[18] Defined as the short-term storage of natural gas by compression in transmission and distribution networks.

- Enabling fuel-switching in the power sector by maintaining a diverse generation mix that can partly replace gas-fired power plants.
- Facilitating short-term increases in power imports.
- Initiating demand response, contractual arrangements with major industrial gas consumers that enable midstream utilities to reduce and/or interrupt gas supplies in situations of emerging gas deficit.
- Improving building heating efficiency and expanding deployment of renewable heating systems.

The markets analysed in the case studies have already implemented most (if not all) of these capabilities and are committed to further strengthen them in the future. This includes developing new gas and power interconnectors in Southwest Europe, implementing market reforms in Northeast Asia or investing in new pipeline capacity in Chile.

However, emerging gas markets – still in the early development phases of their gas infrastructure and regulatory framework – should focus not only on the upstream aspects of natural gas security of supply, but also on the development of downstream capabilities (such as interconnectivity and storage) as well as a the implementation of regulations fostering the transparent and non-discriminative functioning of the gas market.

The gradual elimination of destination clauses from LNG import contracts would certainly quicken the deliverability of LNG volumes to the markets where they are needed. This should be accompanied by the development of liquid regional LNG hubs that provide the right price signals to buyers and sellers. Moreover, a number of LNG players see the benefits of having a flexible supply-demand portfolio underpinned by an increasing number of swap and option agreements, providing new options for markets with short-term requirements. Such agreements complement other forms of operational and contractual flexibility – such as swapping LNG cargoes among offtakers of a same liquefaction plant according to the schedule defined by the plant's Annual delivery program (ADP), or upward flexibility clauses existing in long-term contracts.

However, the commoditisation of LNG – similar to crude oil – might well be hindered by a number of physical constraints (such as the availability of spare LNG production capacity and LNG carriers), high market entry costs and the general preference towards long-term contracts due to the capital-intensive nature of LNG projects.

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4. Could LNG shipping become an issue for security of natural gas supply?

Once seen as a set of "floating pipelines" supporting long-term sales and purchase agreements, the liquefied natural gas carrier (LNGC) fleet is being affected by changes in the liquefied natural gas (LNG) market, with increasing demand for flexibility in supply and contracts of shorter duration. Such changes challenge the traditional LNG shipping business model, with greater uncertainty in medium-term fleet development and availability, and potential impacts on shipping price levels and volatility.

LNG remains a niche shipping market

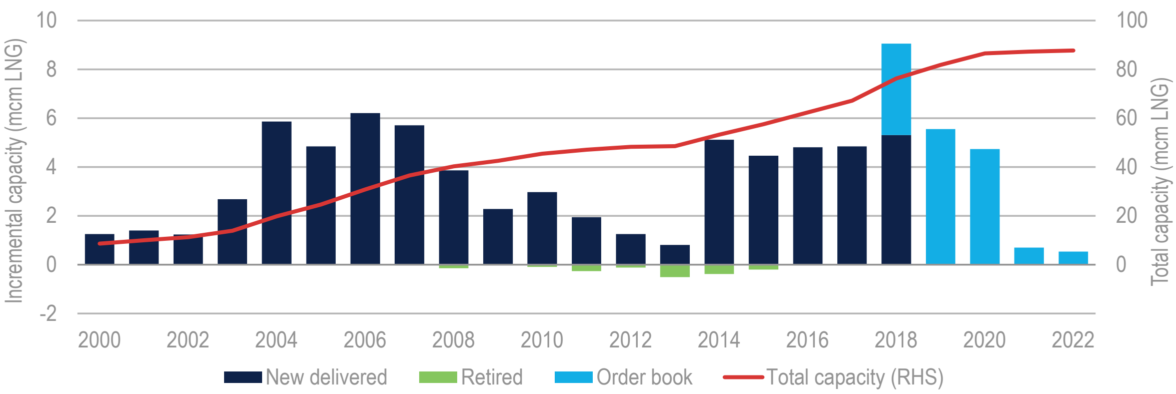
Global LNG trade has experienced strong growth in volume over the past decade, with a compound annual average growth rate of 5.6% over the past ten years, more than twice that of global international seaborne trade, which stood at 2.5% over the same period (UNCTAD, 2017).

However, with 391 million tonnes (Mt) traded in 2017 and 467 active vessels[19] as of mid-2018, LNG remains a niche market within global seaborne trade, which amounted to 10.7 billion tonnes in 2016 (UNCTAD, 2017) (BRS, 2018). After experiencing two successive periods of strong investment in the mid-2000s and early 2010s, orders for new-build LNGCs have dropped since 2016 as the LNG market entered a period of demand uncertainty, confronted with the prospect of ample supply and lower natural gas prices compared to the high benchmark of the early 2010s.

LNGC fleet growth is driven by LNG investment decisions

The global LNGC fleet is relatively young, with vessels less than 10 years old accounting for 49% of tonnage and 47% of the vessel count respectively. Most recent vessels were built in conjunction with the wave of investment in liquefaction capacity that occurred in the late 2000s (Figure 4.1).

Figure 4.1 • LNGC fleet capacity development, 2000-22



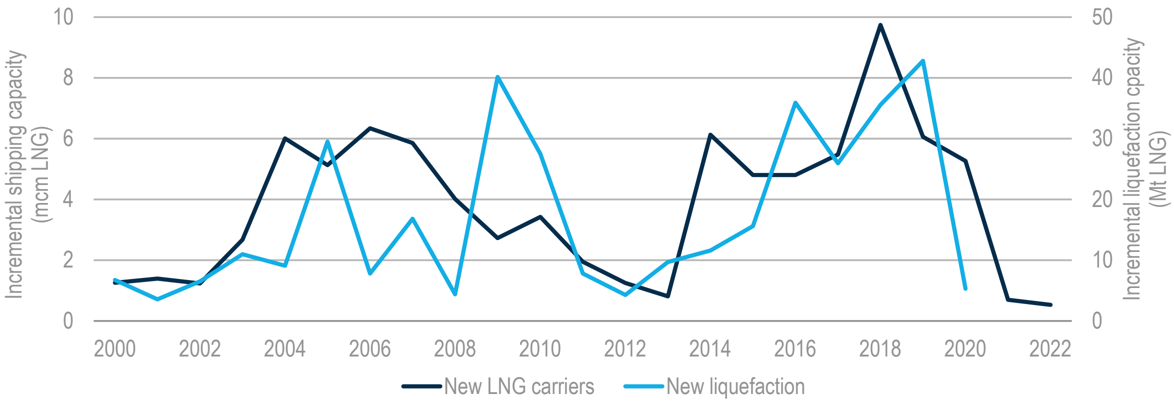
Notes: Excludes FSRUs and FSUs; mcm = million cubic metres.
Source: IEA calculations, based on data from ICIS (2018), *ICIS LNG Edge* (subscription required).

[19] Excluding 31 floating storage and regasification units (FSRUs) and floating storage units (FSUs), which can be used as regular LNG carriers – even though this is not their original purpose.

The LNGC fleet grew at an average of 6.7% per year over the past decade in tonnage terms, whereas the average growth in terms of vessel numbers stood at 5.4% per year, a discrepancy that can be explained by the increase in average vessel size during the same period. The tonnage growth is higher than that experienced in the global merchant fleet, which grew by 5.7% per year (or 6.9% by number of vessels).

Figure 4.2 shows that the LNGC fleet has grown in parallel with new LNG supply investment decisions, with both capacity addition curves showing the same trends over recent years, as LNGCs were traditionally dedicated to a specific supply project or even route and ordered or chartered to match the commissioning of new supply capacity.

Figure 4.2 • LNG liquefaction and carrier fleet capacity additions per year, 2000-22



Note: Excludes FSRUs and FSUs.
Source: IEA calculations, based on data from ICIS (2018), *ICIS LNG Edge* (subscription required).

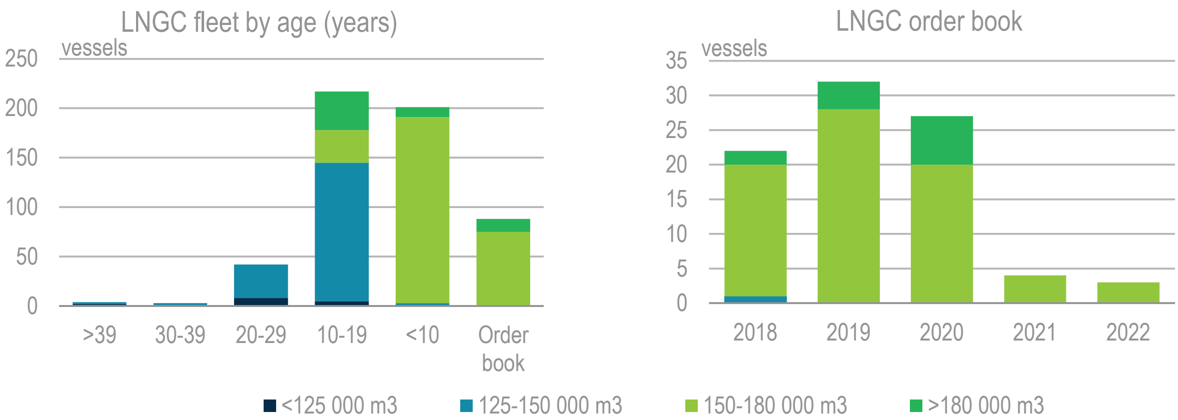
A relatively young fleet with increasing standard vessel size

The average size of LNGCs has grown over time (Figure 4.3) with the development of trade and the increase in travel distances, from the first Medmax carriers of below 75 000 cubic metres (m^3) in the early stages of the trade's development in the 1970s, to around 130 000 m^3 in the early 2000s, and to the current average of 174 000 m^3. Specific classes of bigger carriers, known as Q-Flex and Q-Max (around 210 000 m^3 and 260 000 m^3 respectively) were built in the mid to late 2000s specifically for the needs of Qatar's LNG exports.

The average age of the LNGC fleet is 9.2 years using a tonnage-weighted average, which is similar to that of the global merchant fleet. Using a number of vessels-weighted average, at 10.5 years the age of the LNGC fleet is significantly lower than the global fleet, which is 19.9 years (UNCTAD, 2017). Contrary to most types of merchant vessels, the LNGC fleet has a consistent distribution and is not characterised by a discrepancy between very large recent ships and small old ones (serving a secondary market mainly in developing economies, reflecting the unwritten rule of age limits between 15 and 20 years in the main international shipping markets). This consistency reflects the higher technical complexity and resulting higher build costs of LNG vessels compared to most other carriers (see following section on fleet chartering).

The LNGC order book as of mid-2018 amounted to 104 vessels and 15.3 mcm of LNG, or an increase of 29% to the total fleet tonnage. Most of the vessels under construction are due for delivery in 2018 and 2019 (with some deliveries deferred to 2019 and 2020, see Figure 4.3), corresponding to orders placed in or before 2015 when the LNG market was still experiencing tight supply with high price levels. The number of new orders placed with shipyards has fallen since 2015 – orders rebounded in 2017 compared to the lows of 2016, but remain at about half the average level observed in the past decade.

Figure 4.3 • LNG fleet overview by age and size

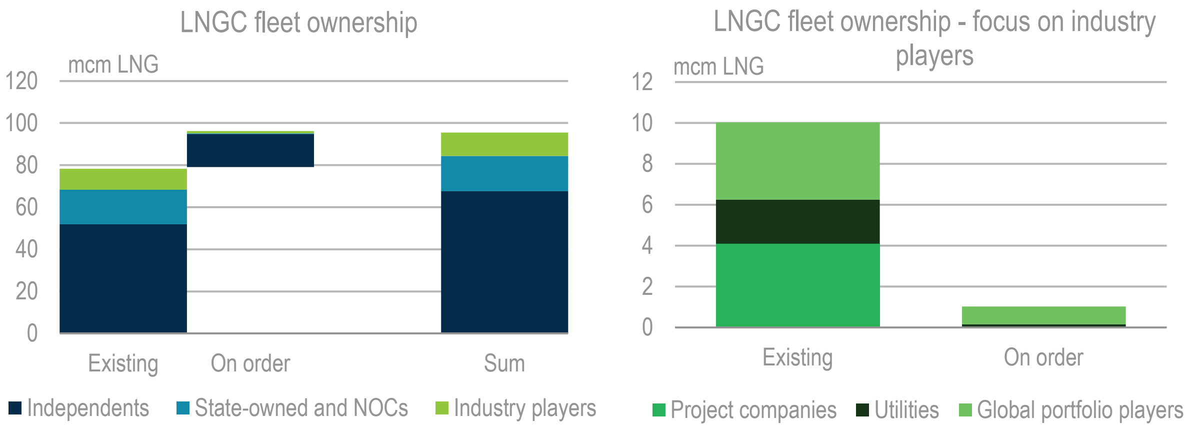


Note: Excludes FSRUs and FSUs.
Source: IEA calculations, based on data from ICIS (2018), *ICIS LNG Edge* (*subscription required*).

LNG industry and national oil companies still own a third of the fleet

The LNGC fleet is mainly owned and operated by independent shipping companies, i.e. they have no commercial interest in the LNG trade itself. These account for two-thirds of existing fleet capacity. This is much lower than for the crude oil tanker fleet, where independents own over 85% of global tonnage. However, independents account for over 90% of the LNGC capacity on order (Figure 4.4). Six major shipping companies control about half of the independently owned fleet – GasLog, Kawasaki Kinsen Kaisha (K Line), Maran Gas Maritime, Mitsui OSK Lines (MOL), Nippon Yusen Kaisha (NYK) and Teekay Shipping.

Figure 4.4 • LNG fleet ownership by type of company



Note: Excludes FSRUs and FSUs.
Source: IEA calculations, based on data from ICIS (2018), *ICIS LNG Edge* (*subscription required*).

Parties with LNG trade-related activity account for the remaining third of the LNGC fleet's current capacity, with an overwhelming majority held by either state-owned companies or national oil companies (NOCs). Among these, Qatar's Nakilhat plays a dominant part with 55 wholly or jointly owned LNGCs, mainly dedicated to shipping Qatar's LNG to its different customers. A more detailed view of the remaining industry players' share (Figure 4.4) shows the importance of project companies (special purpose companies operating LNG export infrastructure) and global portfolio players (trading on both the buying and selling side). Altogether, the non-state-owned industry players (including LNG export project companies) own 13% of the existing fleet capacity – compared with less than 3% for the crude oil fleet.

Fleet chartering is dominated by long-term contracts

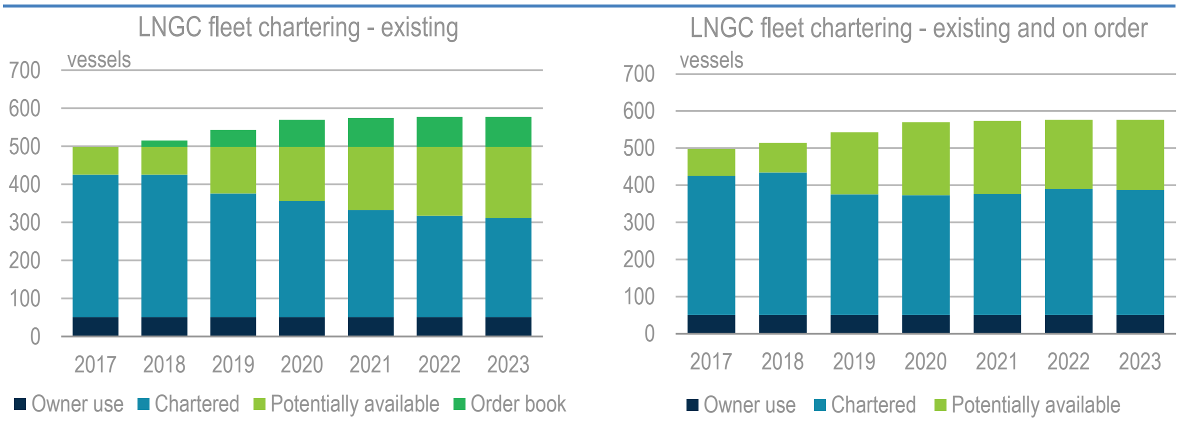
LNGCs are expensive vessels compared to other classes of commercial ships, owing to the higher level of technical complexity required to handle and re-liquefy their cargo. According to market quotes, orders for new-build vessels during the first half of 2018 were secured at an average of USD 180 million – this is about 10% less than price levels observed before 2016 when shipyard order books were full, although still above twice the cost of a new very large crude carrier (VLCC) oil tanker and about a third of its cargo capacity.

Because of this capital intensity, long-term chartering has long been the rule for the LNGC market, not only in relation to the vessels' utilisation, but also for the initial decision to invest in new-build capacity. New-build orders have usually been linked with long-term chartering contracts and/or utilisation of the vessel by its future owner as part of its own fleet. Some speculative (or "open") orders were taken in the mid-2010s as a result of market tension in the aftermath of the Great Japan Earthquake of 2011, yet these remain exceptions to the rule of ensuring long-term chartering prior to an investment decision.

LNGC charter durations are traditionally long, typically from 10 to 20 years with options to extend to up to 30 years as well as options to buy the vessel upon contract expiry. This is to be put in the context of the traditional structure of the LNG industry, configured around long-term supply purchase agreements and limited flexibility – where LNGCs were usually dedicated to a project or even to a single route.

Such patterns have been challenged in recent years by the transformation of the LNG market, with the development of commercial flexibility and shorter-term transactions leading to an increase in subchartering for short durations or even by voyage; nonetheless, the LNG shipping market remains dominated by long-term charters. The chartering fleet replacement rate thus remains moderate over the next five years (see Figure 4.5): half of the current fleet is less than 10 years old, and almost 90% of the fleet is less than 20 years old.

Figure 4.5 • LNG fleet chartering, based on current fleet and order book, 2017-23



Note: Excludes FSRUs and FSUs.
Source: IEA calculations, based on data from ICIS (2018), *ICIS LNG Edge* (subscription required).

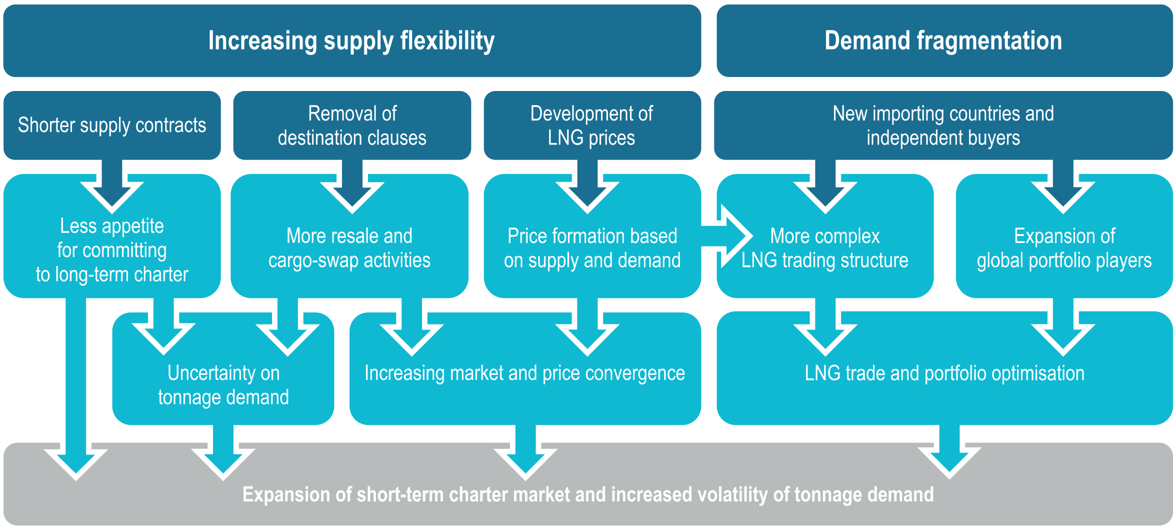
The proportion of LNGCs available for chartering (excluding subchartering of vessels already under contract) accounted for about 14% of the fleet in 2017, and could rise to a maximum of 38% of the existing fleet or 33% of the existing and on-order fleet by 2023 should any of the expiring charters not be renewed.

However, this contractual view may differ from operational outcomes that reflect overall fleet flexibility. The development of subchartering opportunities has created additional flexibility for short-term LNG buyers while optimising the potential long portfolio position of primary charterers – the LNGC market is still far from being as liquid as the oil tanker market. It should be noted that some charters could be considered as proxies for direct ownership (especially for NOCs) and could therefore be assumed as highly likely to continue after expiry.

Recent changes in LNG trade have shaken the shipping market's foundations

Changes experienced in global LNG trade over the recent past have had repercussions on the shipping market. The development of a buyers' market for LNG, prompted by the building up of supply capacity ahead of demand, led to LNG importers increasingly needing greater liquidity and flexibility. These requirements were realised in the form of shorter supply contract durations made possible by the development of short-term and spot transactions, the removal of destination clauses allowing for more cargo resales and swaps, and the introduction of more variety in LNG pricing.

Figure 4. 6 • Changes in LNG trade and impacts on LNG shipping market



Source: IEA from MOL (2017), *Shipowners' Way Forward – How to Reach a Sustainable Future*, presentation to the 3rd International LNG Congress, 16-17 October 2017.

This increasing flexibility in LNG supply, combined with the fragmentation of LNG demand enabled by the multiplication of new buyers, led to the development of much more complex market structures and optimisation strategies. This situation also resulted in lower visibility of demand for LNG suppliers, and consequently, for LNG shipping requirements (Figure 4.6).

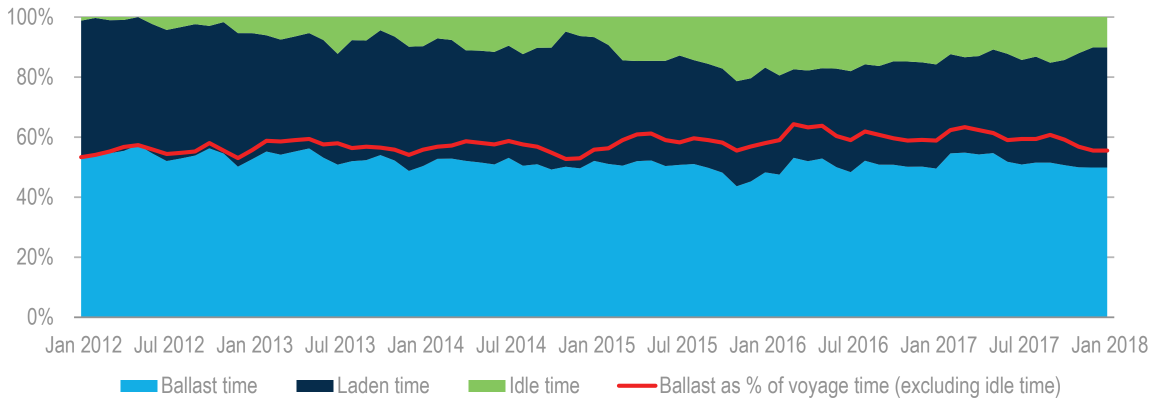
These changes in LNG trade resulted in three main impacts on the LNGC shipping market:

- lower average fleet use and increased volatility in tonnage demand
- growing unpredictability from the emergence of short-term chartering
- short-term charter rates showing stronger volatility and seasonality.

Fleet utilisation becoming more volatile

LNGC fleet utilisation rates reached an all-time high in 2012. They then fell as market pressure eased with the delivery of new vessels from the second wave of capacity investment triggered by the 2011 Fukushima nuclear incident (see Figure 4.1). As a consequence, the average proportion of time spent outside voyage time (referred to as "idle time"), which was almost zero in 2012, increased progressively as new-build capacity was being added. It reached an annual average of 17% in 2016 before slightly recovering in 2017 at 13% (see Figure 4.7).

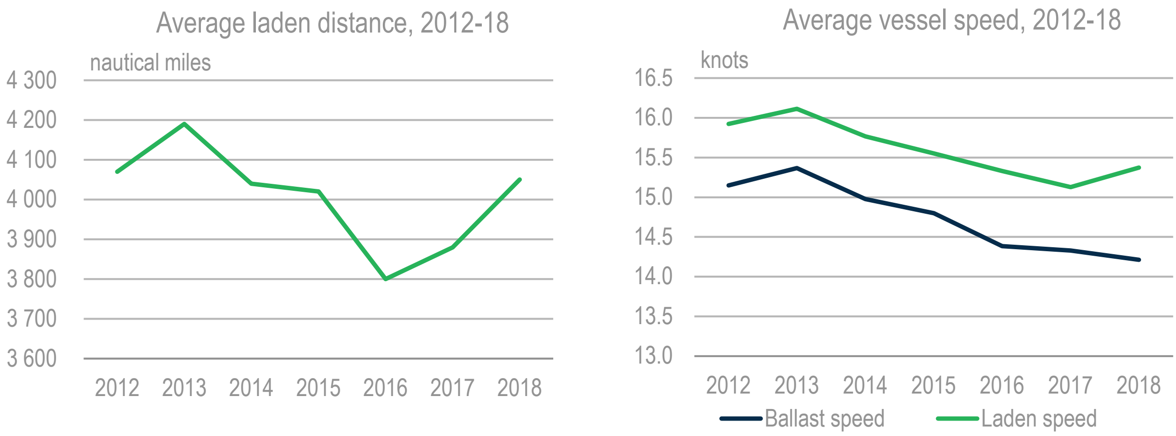
Figure 4.7 • Evolution of average voyage and idle time of the LNGC fleet, 2012-17



Source: IEA calculations, based on data from ICIS (2018), *ICIS LNG Edge* (subscription required).

Idle time increased at the expense of laden voyage time (with cargo), which fell from an average of 44% of total time in 2012 to a nadir of 33% in 2016, recovering to 35% in 2017 owing especially to the intensification of LNG trade in Asia over the final months of the year. It is worth noting that average annual ballast time (without cargo) remained stable over the period at slightly above 50% of total time, which implies an increase in the proportion of ballast time within total voyage time (i.e. outside of idle).

Figure 4.8 • Evolution of average voyage distance and speed of the LNGC fleet, 2012-18



Note: For vessels above 125 000 m^3.
Source: IEA calculations, based on data from ICIS (2018), *ICIS LNG Edge* (subscription required).

Ballast time thus increased from an average 55% of voyage time in 2012 to above 60% in 2016 and 2017. This can be explained by the average decrease in LNG shipping market tension over recent years, prompting charterers to optimise voyage costs by lowering speed or taking longer routes to avoid canal costs. The practice of lowering speed, also referred to as "slow steaming", is commonly used in maritime transport as a means of fuel saving. In the case of LNGCs, although the design speed of recent vessels is about 20 knots, the fleet average is significantly less (see Figure 4.8) taking into account the potentially important performance gap between the youngest vessels and the older ones. The average speed decreased by 3% for laden voyage between 2012 and the first half (H1) of 2018, and by 6% for ballast voyage.

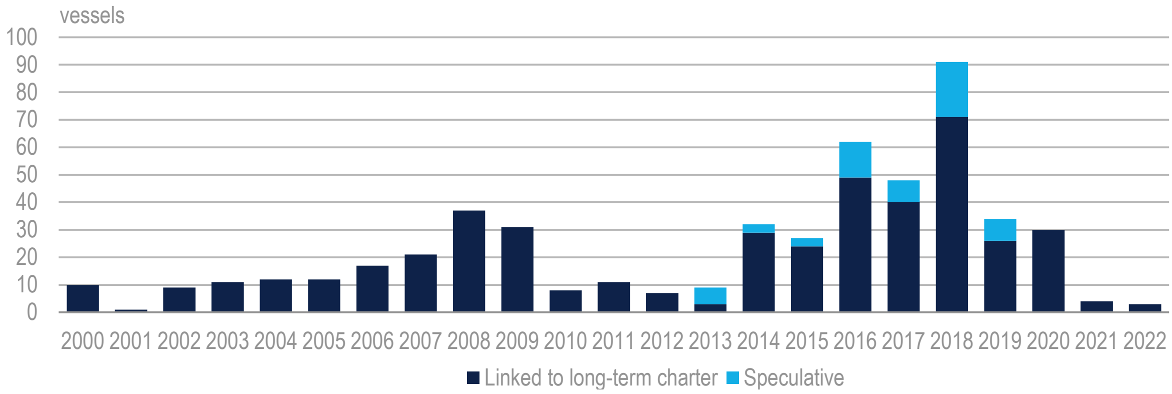
This enabled a reduction in the number of idle days, which could otherwise have risen even higher, especially taking into account the structural decrease in voyage distance over the same period (Figure 4.8). The average laden distance decreased by 14% between 2013 and 2016, recovering slightly in 2017 and H1 2018, although still 7% below the 2013 level.

Short-term charter market expanding

The increased availability of LNG, combined with greater market activity from short-term buyers, led to the expansion of short-term charter contracts (i.e. less than three years). This development towards a more flexible LNG shipping market was also made possible by the concomitant increase in available shipping capacity.

One of the main drivers of this change has been the emergence of speculative orders in the shipyards, a previously unknown behaviour for LNGC owners. This differs from traditional LNGCs built as "project vessels", owned via a special-purpose vehicle and financed by way of project financing, attached to a long-term charter, and often dedicated to a specific liquefaction project. Most speculative vessels were ordered in 2011-12, when spot charter rates jumped with LNG spot prices in the aftermath of the Fukushima accident. These orders resulted in the delivery of speculative vessels from 2013, with the bulk of deliveries between 2016 and 2018 (Figure 4.9).

Figure 4.9 • LNG commissioning per year and type of order, 2000-22



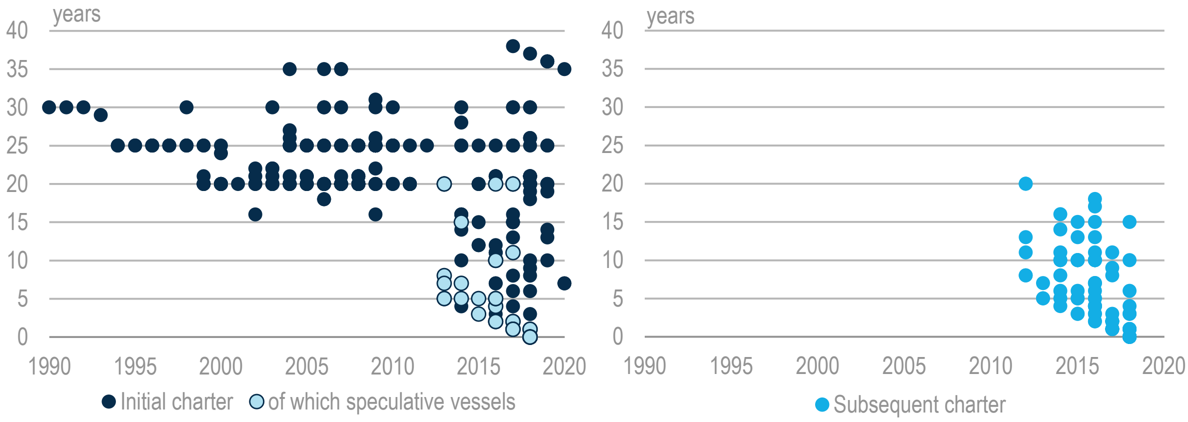
Note: Excludes FSRUs and FSUs.
Source: IEA calculations, based on data from ICIS (2018), *ICIS LNG Edge* (subscription required).

Even though they represent a minority of deliveries, speculative orders accounted for 20% of newly built LNGCs delivered between 2013 and 2018 (compared to none in the previous years). The presence of these unchartered vessels contributed to providing flexibility, but also to the imbalance in the shipping market and a fall in charter rates.

The second recent factor contributing to the development of short-term chartering is the expiry of initial long-term charters for older vessels. This secondary market appeared in the early 2010s and applies mainly to less-efficient steam turbine vessels, which are usually chartered at a discount compared to more modern dual- or tri-fuel diesel electric (DFDE or TFDE) propulsion vessels.

This shift in trend can be observed in the reported charter duration by vintage, as shown in Figure 4.10. For initial charters (i.e. newly built vessels), the industry's norm was previously between 20 and 25 years, moving to 16 years for the last five years (2013-18). While this is not a radical change, as charters for 20 years and over are still signed, it shows a visible evolution in chartering. Speculative vessels are a main contributor to this evolution, with an average charter duration of less than seven years. The subsequent charter market for second-hand vessels displays the same trend in a more visible way, with most of transactions signed for less than 12 years, and the average duration sliding from 13 years in 2012 to three years in 2017 (and less than two years for transactions during the initial months of 2018).

Figure 4.10 • Evolution of LNGC charter duration by date of signature



Note: Excludes FSRUs and FSUs.
Source: IEA calculations, based on data from ICIS (2018), *ICIS LNG Edge* (subscription required).

The third factor owes to the charterers' own management of their shipping portfolios. Major LNG buyers or midstreamers – such as global portfolio players – have developed short-term optimisation of their fleet management to avoid the opportunity cost arising from idle chartered vessels. This includes greater recourse to subchartering for entire or even partial voyages (such as backhauling – i.e. using part of the ballast leg to transport LNG to intermediate destinations) as well as swaps to net trades and reduce voyage time.

Charter rate volatility and increasing seasonality

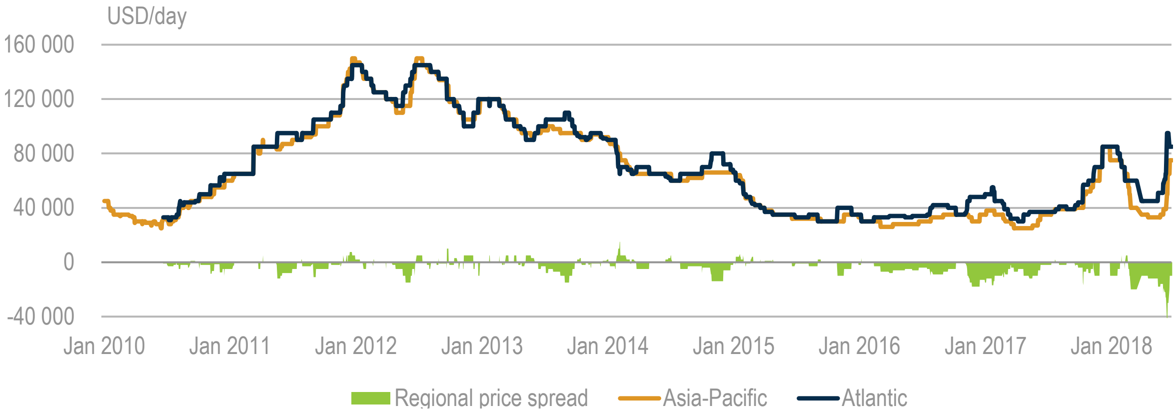
As previously mentioned, the LNGC fleet is mainly chartered under long-term contracts, which usually have limited flexibility: the long-term charter price is usually flat; contrary to LNG or pipeline contracts there is usually no price review clause; and any option for early termination of the charter would usually suppose the upfront payment of the total remaining charter value. Hence no sizeable structurally short-term fleet is available to provide for a liquid LNGC spot market, in contrast to other segments of maritime trade.

It is understood that as of mid-2018 fewer than 20 LNGCs are unchartered and available at short notice, down from around 35 at the end of the 2017/18 winter season. This does not include some overcapacity hidden in charterers' portfolios, which is likely to be subchartered to third parties. The sum of these components provides a degree of shipping capacity likely to be traded in short-term transactions.

LNGC spot charter rates reflect the availability of these idle vessels relative to demand (Figure 4.11) with a steep increase in the aftermath of the Fukushima accident caused by the sharp increase in LNG trade with limited short-term vessel availability. The size of this balancing market expanded over time and led to excess shipping capacity, with charter rates reaching their lowest levels in 2016. Spot chartering rates have experienced stronger seasonal patterns over the past two years, especially with the surge in LNG imports into the People's Republic of China (hereafter, "China") last winter. More recently, rates recovered sharply in July 2018 with the unexpected return of LNG reloads from northwest Europe, attracted by the prospect of higher margins in the Asian market, causing a sudden tightening of the shipping fleet availability. This led to a strong increase in regional price spreads between Atlantic and Pacific basins, as observed during the previous winter.

Even if the short-term trade were to develop further and the increasing volatility in shipping rates indicated the growth of spot activity as a balancing market, LNGC chartering is far from being a liquid market. Transactions are still ruled by bilateral, over-the-counter negotiations, and charter rates are quotes provided by a limited number of brokers and not a price signal resulting from an organised marketplace.

Figure 4.11 • Evolution of regional spot charter rates for LNGCs, 2010-18



Source: IEA calculations, based on data from ICIS (2018), *ICIS LNG Edge* (subscription required).

Liquidity and transparency hence remain limited in this nascent spot trading. In spite of several attempts to provide a standardised contractual framework, the market still lacks a globally used common reference for trade, seen as the first step towards market liquidity and commoditisation. As a consequence, currently no LNGC freight index is available to act as a transparent reference for pricing – and eventually price hedging. The Baltic Exchange, which provides benchmark indexes for global shipping rates, announced in January 2018 its intention to develop a specific LNGC index in partnership with brokers, based on the assessment of potential reference trading routes (Reuters, 2018).

Could shipping become a weak link in the LNG supply chain?

Global natural gas trade has grown by more than 40% over the past 15 years, with an increasing role played by LNG, which saw its share of the trade increase from 22% to 35% over the period. By 2023, interregional traded volumes are expected to account for 31% of total natural gas consumption,[20] with LNG standing at 505 billion cubic metres (bcm) or almost 40% of total trade (IEA, 2018).

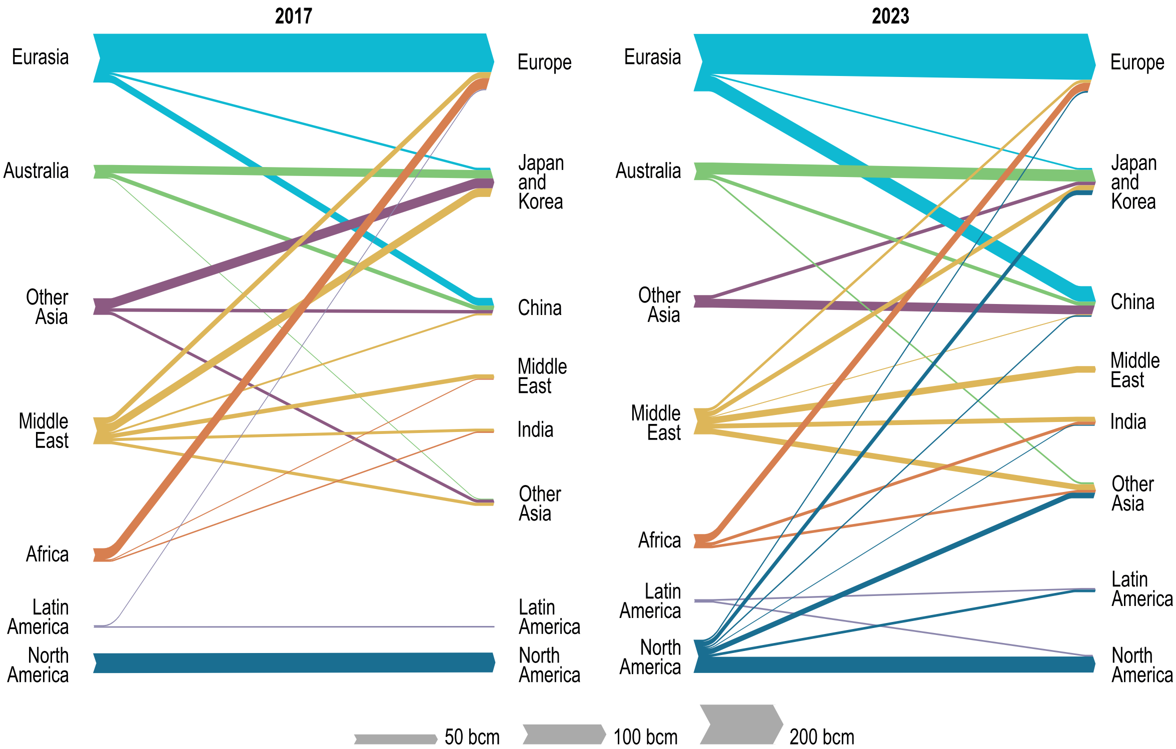
LNG trade keeps expanding and diversifying

Global gas trade flows are expected to change significantly over the period to 2023, as shown in Figure 4.12. The trade flow picture, currently dominated by a limited number of major links, is expected to evolve towards growing interregional trade and interdependence between buyers and sellers, enabled by the development of LNG.

[20] Trade figures reflect volumes traded between regions and therefore do not include all intraregional trade flows.

Asia, already the main focal point of LNG trade, sees its position reinforced by the emergence of major new buyers such as China and India, as well as experiencing greater intraregional diversification. China and emerging Asian markets are expected to account for over 90% of LNG trade growth over the next five years. Other developments are expected in Europe, where LNG imports contribute to the replacement of depleting domestic production, and in Latin America as a seasonal complement to power generation needs.

Figure 4.12 • Main natural gas flows, 2017 and 2023

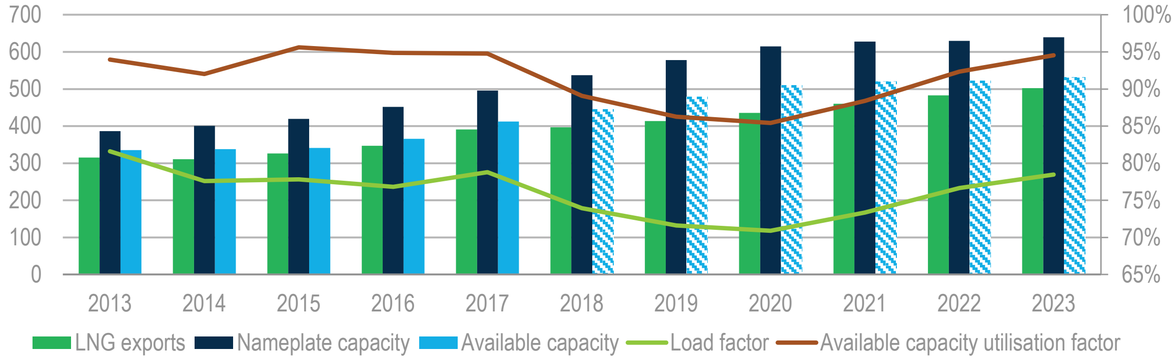


Source: IEA (2018), *Market Report Series: Gas 2018*.

On the supply side, the Middle East's traditional position as the single global LNG balancing supplier is increasingly challenged by the strong development of export capacity in North America, Australia and the Russian Federation. The current wave of LNG export projects adds some 140 bcm of liquefaction capacity between 2018 and 2023, increasing global capacity by almost 30%. Half of that expansion (70 bcm) takes place in the United States. Nearly all the new liquefaction capacity should be operating by 2020. This could result in looser LNG market conditions, especially between 2019 and 2020 when the bulk of new liquefaction capacity begin operations – assuming that these new projects are commissioned according to their current schedule and no additional unplanned maintenance is required. This loose market could be short-lived owing to the dynamic growth in emerging Asian markets. Without new investment, the average utilisation rate of liquefaction is likely to return to its pre-2017 level by 2023 (Figure 4.13).

Owing to the long lead time of such projects, investment decisions need to be taken in the next few years to ensure adequate supply beyond 2023. The confirmation by LNG Canada on 1 October 2018 (LNG Canada, 2018) to develop two processing trains for an estimated 19 bcm per annum export capacity is a positive sign towards ensuring the sustainable growth of the global LNG market.

Figure 4.13 • LNG trade and liquefaction utilisation rate, 2013-23



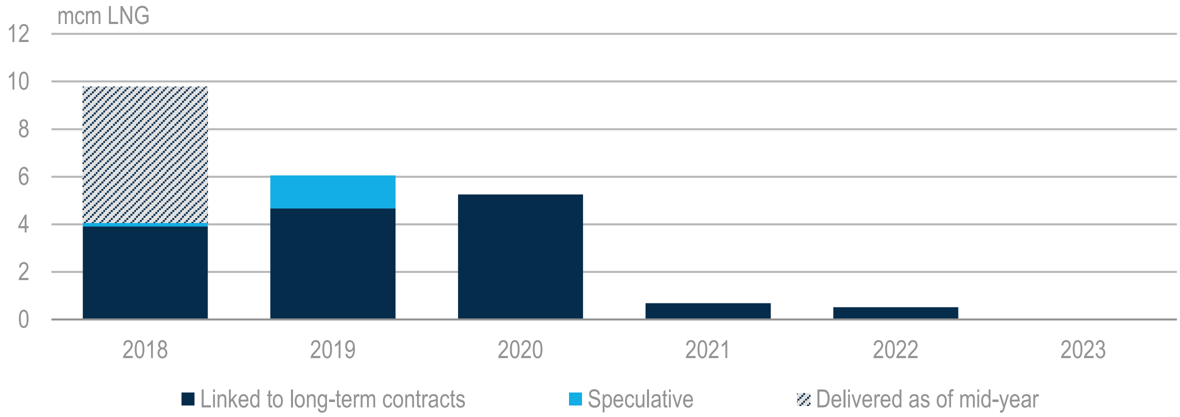
Notes: Load factor = the ratio of the actual output in a given year against the plants' nameplate capacity; available capacity utilisation factor = the ratio of the actual output to the potential output of the facility, adjusted to account for both planned outages (maintenance) and unplanned outages (lack of feed gas, technical problems, or weather).

Source: IEA (2018), *Market Report Series: Gas 2018*.

Towards a tight LNG shipping market?

In the same way that the pattern of final investment decisions (FIDs) for liquefaction projects built a "wave" of LNG capacity development in the first half of this decade, orders for new LNG vessels multiplied up to the point of creating bottlenecks in the shipyards. This led to the current strong level of new deliveries, which reaches its peak in 2018 with over 50 carriers due to be delivered totalling almost 10 mcm of LNG carrying capacity, or about 13% year-on-year increase in the total LNGC fleet tonnage. This new-build wave ebbs after 2018, with about another 11 mcm of new carrying capacity to be delivered in 2019-20, and almost no deliveries thereafter (Figure 4.14).

Figure 4.14 • LNGC new deliveries and order book, 2018-23

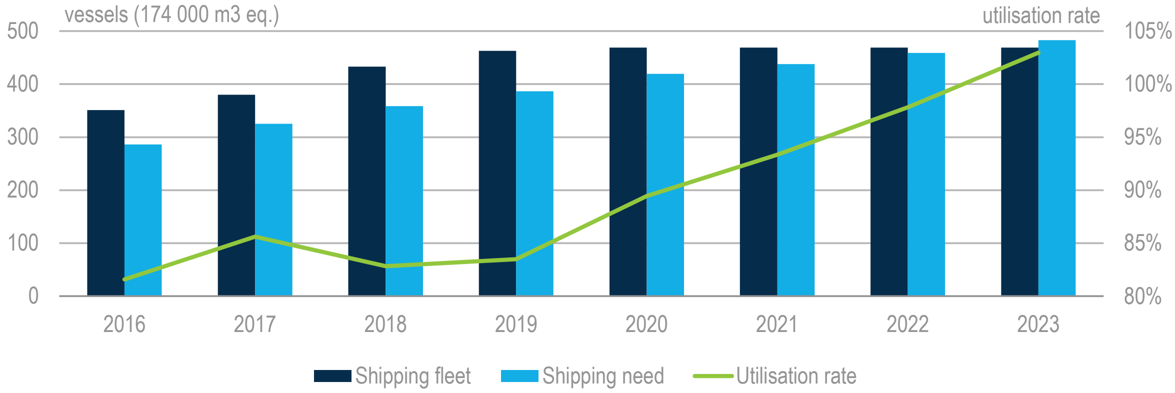


Note: Excludes FSRUs and FSUs.

Source: IEA calculations, based on data from ICIS (2018), *ICIS LNG Edge* (subscription required).

Considering that LNGC construction takes between two and three years, fleet capacity is expected to remain almost flat in 2021 (and possibly 2022) unless new orders are placed in the coming months. This absence of available shipping capacity in a fast-growing LNG market could be a serious issue for flexibility and security of supply, even earlier than the liquefaction tightening mentioned above.

Figure 4.15 • LNG shipping balance and utilisation rate, 2016-23



Notes: Shipping assumptions: average size = 174 000 m^3; availability = 345 days (95%); average speed = 15 knots growing to 16 knots from 2020; port days = 2.5 days per voyage for loading and offloading; round trips= 100% for fixed volumes, 75% for flexible volumes; available shipping fleet includes existing LNGCs and those under construction, but does not include floating LNG, FRSU or FSU vessels, and does not assume scrapping of existing vessels.
Source: IEA calculations, based on LNG trade forecast from IEA (2018), *Market Report Series: Gas 2018*.

This review analyses the impact of LNG market growth on shipping needs based on the latest IEA medium-term LNG trade forecast (IEA, 2018). The resulting shipping balance (Figure 4.15, expressed in standard vessel equivalent) shows that after strong growth in shipping capacity in 2018 and 2019, leading to stagnation of the fleet utilisation rate, this rate then rapidly increases to reach above 90% from 2020 and exceed 100% by 2023. However, tensions are likely to materialise before reaching full utilisation, and it can be assumed that under the forecast assumptions the LNGC market could become tight as soon as 2020.

This forecast assumes a simplified view of the LNGC market and therefore tends to underestimate several limits to vessel availability:

- *Lack of fungibility*: in spite of its limited size compared with other areas of seaborne trade, LNG shipping is technically not a single market but rather an aggregation of submarkets depending on geographical basins, vessel size, technology and fuel. Accessibility to ports and canals is another discriminating factor, with restrictions applying according to width, water depth or height.
- *Portfolio barriers to fleet optimisation*: the shipping need forecast assumes by default that cargoes can be shared and pooled, such as in a pipeline. Such optimised used of LNG vessels faces several limitations:
  - Most charterers have shipping portfolios with long-term charters and are not always eager to subcharter when they have unused capacity for fear of missing optimisation opportunities and owing to the market's lack of cargo pooling.
  - The technical ability to share a cargo and perform partial loading and offloading is often limited by technical considerations, such as the risk of high-impact pressure on the tank surface created by liquid movement inside the tank – also known as "sloshing".
  - The lack of co-ordination between short-term trade requirements and technical specifications/vessel location (as explained in the previous section) can result in vessels being idle in a tight market.
- *Ageing vessel management and regulatory framework*: while the average age of an LNGC is 10 years, ship owners usually keep even the oldest vessels in good condition due to their high construction and replacement costs. As these vessels grow older the competitiveness gap with new-build LNGCs will increase, causing price spreads and the potential emergence of submarkets for less-efficient vessels. Keeping the oldest vessels in the market (provided that

they are still fit for purpose) will help alleviate risks of tonnage shortage; however, the availability of these oldest vessels may be challenged as major importing countries adopt more stringent port regulations.

Such risk factors could result in a tighter LNG shipping market happening sooner, especially in winter when most buyers compete for spot LNG cargoes. Additional LNGC orders are therefore needed in the short term in order to avoid shipping scarcity issues. During the first six months of 2018 some 26 firm orders have been placed (LNG Journal, 2018), helped by more attractive yard pricing. This may prove insufficient to keep the global LNGC market in balance, taking lead times into consideration – the earliest a new build can now be delivered is 2021.

The impacts of a tight LNGC market would be higher and more volatile spot charter rates, as well greater risk of vessels being unavailable in the short term, especially in the Atlantic Basin where LNG prices are usually less attractive than in the Pacific. LNGC availability and volatility in charter rates could therefore become a medium-term concern for the security of natural gas supply. To mitigate this risk – and in addition to investment in new-build capacity – further liquidity and transparency are required to alleviate some of the inflexibilities in the current LNGC trade, as discussed above.

Box 4.1 • Could LNG shipping follow the same path as the crude oil tanker market?

In the aftermath of shocks to the global energy system in the 1970s and 1980s, the crude oil shipping market went through a series of structural changes as patterns of crude oil trading altered (Mabro, 1984). The spot market, which served as a residual market for crude oil trade in the 1950s and 1960s, shifted toward becoming a marginal market with growing importance in price formation in the late 1970s, and became a major market in the early 1980s. By 1985, spot volume was estimated to account for over half of international crude oil trade, while spot and spot-related transactions (including variable price contracts, barter trade, netback pricing deals, etc.) were thought to account for 80 to 90% of internationally traded crude oil (World Bank, 1989).

The tanker market followed a similar pattern with the development of shorter charters, enabled by significant overcapacity – the average tanker utilisation rate almost halved between 1973 and 1988 (Clarksons, 2015). With such ample shipping supply, ownership was no longer a strategic issue for the oil majors, who vertically de-integrated their activities to optimise their portfolios and divested from non-core business activities such as shipping, thus switching to chartering on the spot market or with short-term contracts. This move was further incentivised by the threat of reputational risk in the aftermath of the 1989 Exxon Valdez oil spill. The current share of non-state-owned oil companies in tanker fleet ownership is understood to be below 3% (Intertanko, 2011).

Could LNG shipping follow the same path towards a liquid and globalised market? While initial changes observed in the recent past may point in this direction, challenges remain to be overcome:

- Even if LNG trade were to enjoy strong growth rates, it is still far from reaching the critical mass of major seaborne commodities. This relates to the cost of entry to the LNG supply chain, with higher development costs for export and import terminals traditionally leading to contractual barriers to flexibility, which are progressively being challenged by the emergence of spot trading. This also led to a de facto limitation on the number of players, although the situation is improving with the emergence of new buyers and resellers.
- Beyond the cost of terminals, LNGCs remain expensive vessels compared to other classes of carrier, both in terms of building and maintenance, due to their higher technical complexity. For example, a new-build crude oil tanker from the VLCC class (with a cargo capacity corresponding to about three new-build LNGCs) had an estimated price in early 2018 of around USD 80 million (Teekay, 2018), compared with about USD 180 million for an LNGC. This cost differential also impacts the dynamics of fleet turnover: the crude oil tanker fleet has experienced average annual delivery and scrappage growth rates of 5.6% and 1.8% respectively since 2000, with the strongest scrappage rates observed during the initial months of 2018 (Sea News, 2018), thus contributing to the tanker fleet turnover.
- Financing structures also differ – as for most shipping, tanker financing mainly relies on bank loans using the vessel as collateral, with debt financing remaining consistent over time in spite of the cyclical nature of shipping markets. The financial crisis of 2008 and the enforcement of stronger norms under the Basel III framework led to a gradual reduction of

banks' exposure to the shipping industry. The role of export credit agencies has increased as an alternative source of debt finance, as standalone finance or as collaborative financing schemes in partnership with commercial banks. Some ship owners also opt for recourse to capital markets – an opportunity to issue debt with long maturities and a fixed interest rate.

Sources: Mabro (1984), *On Oil Price Concepts*; World Bank (1989), *The New Era of Petroleum Trading*, in World Bank Technical Papers Series; Clarksons (2015), *A Tanker Statistic You May Not Know*, in Clarksons Research Blog; Intertanko (2011), *Key Tanker Figures (2011) at a Glance*; Teekay (2018), *Tanker Insights – Newbuilding Prices Finding Support*; Sea News (2018), *Global Crude Tanker Shipping Market Overview*.

The shipping oversupply experienced in 2015-16 led to initiatives such as the development of pooling among ship owners – the Cool Pool was established in 2015 by Dynagas, GasLog and Golar LNG and pooled together a fleet of 18 modern vessels (built between 2010 and 2016) (The Cool Pool, 2018). A further step would be the development of organised markets, a strong driver to spur greater transparency and liquidity beyond existing bilateral deals. The Baltic Exchange initiative to develop an LNGC price index is a positive sign for the development of such organised markets (Reuters, 2018). Comparison with the crude oil tanker market, which went through similar structural changes in the 1980s, provides some insight, but also highlights the fundamental differences between the two markets (see Box 4.1).

For the LNG shipping market the issue of vessel availability will remain crucial, particularly should a sellers' market develop where ship owners would have fewer incentives to accept speculative short- to medium-term charters. Owners may become more exposed to revenue and cost recovery risks, as the current flat rate with cost pass-through long-term charter pricing structure cannot be applied as is to shorter periods. This may also have consequences for financing schemes, as it could become difficult to apply traditional project financing structures to vessels on shorter-term contracts. Lenders are therefore likely to become more exposed to risks relating to refinancing and residual value, as the loans would extend beyond the initial chartering contract duration.

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Glossary

Regional and country groupings

Africa

Algeria, Angola, Benin, Botswana, Cameroon, Congo, Democratic Republic of Congo, Côte d'Ivoire, Egypt, Eritrea, Ethiopia, Gabon, Ghana, Kenya, Libya, Morocco, Mozambique, Namibia, Nigeria, Senegal, South Africa, Sudan, United Republic of Tanzania, Togo, Tunisia, Zambia, Zimbabwe and other African countries (Burkina Faso, Burundi, Cape Verde, Central African Republic, Chad, Comoros, Djibouti, Equatorial Guinea, Gambia, Guinea, Guinea-Bissau, Lesotho, Liberia, Madagascar, Malawi, Mali, Mauritania, Mauritius, Niger, Reunion, Rwanda, Sao Tome and Principe, Seychelles, Sierra Leone, Somalia, Swaziland and Uganda).

ASEAN

Brunei Darussalam, Cambodia, Indonesia, Laos, Malaysia, Myanmar, the Philippines, Singapore, Thailand and Viet Nam.

Caspian region

Armenia, Azerbaijan, Georgia, Kazakhstan, Kyrgyz Republic, Tajikistan, Turkmenistan and Uzbekistan.

China

Refers to the People's Republic of China, including Hong Kong.

FSU/non-OECD Europe

Albania, Armenia, Azerbaijan, Belarus, Bosnia and Herzegovina, Bulgaria, Croatia, Cyprus,[21,22] Lithuania, the Former Yugoslav Republic of Macedonia, Georgia, Gibraltar, Kosovo, Kyrgyzstan, Malta, the Republic of Moldova, Montenegro, Romania, Russian Federation, Serbia, Tajikistan, Turkmenistan, Ukraine and Uzbekistan.

European Union

Austria, Belgium, Bulgaria, Croatia, Cyprus,[23,24] Czech Republic, Denmark, Estonia, Finland, France, Germany, Greece, Hungary, Ireland, Italy, Latvia, Lithuania, Luxembourg, Malta, Netherlands, Poland, Portugal, Romania, the Slovak Republic, Slovenia, Spain, Sweden and the United Kingdom.

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[21] Note by Turkey: The information in this document with reference to "Cyprus" relates to the southern part of the Island. There is no single authority representing both Turkish and Greek Cypriot people on the Island. Turkey recognises the Turkish Republic of Northern Cyprus (TRNC). Until a lasting and equitable solution is found in the context of United Nations, Turkey shall preserve its position concerning the "Cyprus issue".

[22] Note by all the European Union Member States of the OECD and the European Union: The Republic of Cyprus is recognised by all members of the United Nations with the exception of Turkey. The information in this document relates to the area under the effective control of the Government of the Republic of Cyprus.

[23] Note by Turkey: The information in this document with reference to "Cyprus" relates to the southern part of the Island. There is no single authority representing both Turkish and Greek Cypriot people on the Island. Turkey recognises the Turkish Republic of Northern Cyprus (TRNC). Until a lasting and equitable solution is found in the context of United Nations, Turkey shall preserve its position concerning the "Cyprus issue".

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Latin America

Argentina, Bolivia, Brazil, Chile, Colombia, Costa Rica, Cuba, the Dominican Republic, Ecuador, El Salvador, Guatemala, Haiti, Honduras, Jamaica, Netherlands Antilles, Nicaragua, Panama, Paraguay, Peru, Trinidad and Tobago, Uruguay, Venezuela and other Latin American countries (Antigua and Barbuda, Aruba, Bahamas, Barbados, Belize, Bermudas, British Virgin Islands, Cayman Islands, Dominica, Falkland Islands (Malvinas), French Guyana, Grenada, Guadeloupe, Guyana, Martinique, Montserrat, St. Kitts and Nevis, Saint Lucia, St. Vincent and the Grenadines, Suriname and Turks and Caicos Islands).

Middle East

Bahrain, the Islamic Republic of Iran, Iraq, Jordan, Kuwait, Lebanon, Oman, Qatar, Saudi Arabia, the Syrian Arab Republic, the United Arab Emirates and Yemen.

Non-OECD Asia

Bangladesh, Brunei Darussalam, Cambodia, Chinese Taipei, India, Indonesia, the Democratic People's Republic of Korea, Malaysia, Mongolia, Myanmar, Nepal, Pakistan, the Philippines, Singapore, Sri Lanka, Thailand, Viet Nam and other Asian countries and territories.[25] Excludes China.

North Africa

Algeria, Egypt, Libya, Morocco and Tunisia.

North America

Canada, Mexico and United States.

OECD

Includes OECD Europe, OECD Americas and OECD Asia Oceania regional groupings.

OECD Americas

Canada, Chile, Mexico and United States.

OECD Asia and Pacific

Australia, Japan, Korea and New Zealand.

OECD Europe

Austria, Belgium, Czech Republic, Denmark, Estonia, Finland, France, Germany, Greece, Hungary, Iceland, Ireland, Italy, Latvia, Luxembourg, Netherlands, Norway, Poland, Portugal, Slovak Republic, Slovenia, Spain, Sweden, Switzerland, Turkey and United Kingdom. For statistical reasons, this region also includes Israel.[26]

South America

Argentina, Bolivia, Brazil, Chile, Colombia, Ecuador, Falkland Islands (Malvinas), French Guyana, Guyana, Paraguay, Peru, Suriname, Uruguay and Venezuela.

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[25] Individual data are not available and are estimated in aggregate for: Afghanistan, Bhutan, Cook Islands, Fiji, French Polynesia, Kiribati, the Lao People's Democratic Republic, Macau (China), Maldives, New Caledonia, Palau, Papua New Guinea, Samoa, Solomon Islands, Timor-Leste, Tonga and Vanuatu.

[26] The statistical data for Israel are supplied by and under the responsibility of the relevant Israeli authorities. The use of such data by the OECD and/or the IEA is without prejudice to the status of the Golan Heights, East Jerusalem and Israeli settlements in the West Bank under the terms of international law.

Acronyms, abbreviations and units of measure

Acronyms and abbreviations

ACQ	annual contract quantity
BBL	Balgzand Bacton Pipeline
CNOOC	China National Offshore Oil Corporation
CNPC	China National Petroleum Corporation
CWV	composite weather variable
DES	delivered ex-ship
DFDE	dual-fuel diesel electric
FID	financial investment decision
FOB	free on board
FPS	Forties Pipeline System
FSRU	floating regasification and storage unit
FSU	floating storage unit
HOA	heads of agreement
HHI	Herfindahl-Hirschman index
H1	first half
H2	second half
IEA	International Energy Agency
IUK	Interconnector UK
JKM	Japan/Korea Marker
LDZ	local distribution zones
LNG	liquefied natural gas
LNGC	liquefied natural gas carrier
MOU	memorandum of understanding
NDRC	National Development and Reform Commission
NEA	National Energy Administration
NOC	national oil company
SAP	system average price
SCC	Stockholm Chamber of Commerce
SHPGX	Shanghai Petroleum and Natural Gas Exchange
TAG	Trans Austria Gas pipeline
TFDE	tri-fuel diesel electric
TSO	transmission system operator

UGS	underground gas storage
VLCC	very large crude carrier
WEP	west east pipeline
y-o-y	year-on-year

Units of measure

bcm	billion cubic metres
bcm/d	billion cubic metres per day
bcm/y	billion cubic metres per year
GW	gigawatt
km	kilometre
mcm	million cubic metres
mcm/d	million cubic metres per day
mcm/h	million cubic metres per hour
MBtu	million British thermal units
Mt	million tonnes
Mtoe	million tonnes of oil equivalent
MW	megawatt
MWh	megawatts per hour
m^3	cubic metre
t	tonne
t/h	tonnes per hour

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Global Gas Security Review 2018

Meeting Challenges in a Fast Changing Market

Today's natural gas markets are being reshaped by major emerging liquefied natural gas (LNG) buyers, led by the People's Republic of China and the rising production and exports from the United States. This transformation, driven by growing markets and supplied by fast-changing LNG trade, brings its share of security-related challenges as was highlighted by China's supply shortfall over the last winter.

Supply flexibility remains a key prerequisite to ensuring continued global gas trade development and security. Yet priorities in terms of flexibility differ between long-term traditional buyers, who seek the removal of destination clauses, and new emerging buyers more focused on procuring short-term supply, usually for prompt delivery.

The International Energy Agency's third edition of the *Global Gas Security Review* provides an in-depth analysis of recent security-related issues and lessons learned.

The report shows the most recent trends in LNG flexibility, based on a detailed assessment of contractual data. It examines the impact of the growing role of emerging LNG buyers and of the development of market liquidity on trade and new contracts. And, this year, it includes a special focus on short-term LNG deliverability as well as shipping fleet availability, two important factors in assessing gas security of supply around the world.