International Energy Agency
Secure Sustainable Together

Global Gas Security Review

How is LNG Market Flexibility Evolving?

2017

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INTERNATIONAL ENERGY AGENCY

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Foreword

As recent events have demonstrated, the security of natural gas supplies cannot be taken for granted. From cold spells in southern Europe, to hurricanes in the Gulf of Mexico, to diplomatic tensions among Gulf countries, energy security is impossible to ignore even with the current state of abundant global supplies.

The current natural gas market may appear comfortable, with production growth currently outpacing demand and fast developing LNG trade unlocking new markets and putting competitive pressure on prices. In this vision of a buyer's market, security of supply may not appear to be an immediate concern.

But understanding risks is part of the International Energy Agency's mission. While the IEA was founded to address oil security, our mission has broadened along with the global nature of the energy system. Energy security today means much more than it did in the 1970s, as it encompasses a more globalised natural gas market and the changing nature of power markets.

In its second year, the *Global Gas Security Review* is a response to the mandates on natural gas security that the IEA Secretariat received from its member countries during the 2015 IEA Ministerial and from the Group of Seven (G7) in 2016 under Japanese presidency. With this second edition, we have enhanced our analysis and assessment of LNG markets as part of our broader effort to improve market and data transparency, and to support greater resilience in global gas markets. Alongside an analysis of latest policy developments, we update our assessment of the level of flexibility provided by LNG supply and consider how this matches the flexibility needs of different types of LNG buyers.

The report underscores that the transformation of gas markets from regional systems to a more interconnected and globalised network is leading to greater interdependence among regions and to new interactions with other fuels. It is also likely to bring new challenges in terms of security of supply. Faced with multiple risks arising from tight markets, weather-related issues, and political tensions, it is crucial that energy policies and policymakers remain ready to respond.

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Executive Director

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Acknowledgements

Global Gas Security Review 2017 was prepared by the Gas, Coal and Power Markets Division (GCP) of the International Energy Agency (IEA). The analysis was lead and co-ordinated by Jean-Baptiste Dubreuil, senior gas analyst. Willem Braat, Jaime González-Puelles, Volker Kraayvanger, Minoru Muranaka and Rodrigo Pinto Scholtbach are the authors, with contributions from Jean-Baptiste Dubreuil and Tomoko Uesawa.

Keisuke Sadamori, Director of the IEA Energy Markets and Security (EMS) Directorate, and Peter Fraser, Head of GCP, provided expert guidance and advice.

Valuable comments, data and feedback were received from within the IEA from Sylvia Beyer, Tord Bjorndal, Aad van Bohemen, Amos Bromhead, Carlos Fernández Alvarez, Tim Gould, Lucie Girard, César Alejandro Hernández, Paul Simons, Johannes Trueby and Laszlo Varro. Special thanks go to Ian Cronshaw for his advice throughout the process.

Timely and comprehensive data from the Statistical Division were fundamental to the report.

Special thanks go to Justin French-Brooks for editing the report and to Therese Walsh for overseeing the editing process.

The IEA Communication and Information Office (CIO), particularly Rebecca Gaghen, Astrid Dumond, Jad Mouawad, Katie Russell and Bertrand Sadin provided essential support towards the report’s production and launch.

The review was made possible by assistance from Tokyo Gas, Uniper, Enagás, and the Ministry of Economic Affairs of the Netherlands.

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Executive summary

Natural gas, the cleanest and the least carbon-intensive fossil fuel, is expected to play a key role in the transition to a cleaner and more flexible energy system. In the central scenario of the International Energy Agency's (IEA) *World Energy Outlook*, natural gas is the only fossil fuel that will maintain its share in the energy mix of the coming decades, mainly supported by policies to reduce air pollution and greenhouse gas emissions.

The currently oversupplied gas market and low price environment have resulted in renewed growth of natural gas use for power generation and industrial activities in mature gas economies as well as in newly developing gas markets. However, such a comfortable situation does not prevent security of supply concerns and issues, as shown over the past year through different events.

The IEA launched the first annual *Global Gas Security Review* (*GGSR*) in 2016 to identify and analyse some critical elements such as physical production flexibility of the LNG infrastructure and flexibility in contractual arrangements. This year's report updates the major findings regarding these two crucial elements of global gas security and aims to deepen analysis by introducing additional concepts and metrics to develop a more comprehensive assessment of global gas security of supply.

Security of supply remains a live issue

This report highlights several recent events, ranging from physical shortages and supply emergencies to potential supply threats, which have occurred since late 2016. On the importers' side, southern European countries experienced stressed situations in natural gas and power markets during the winter of 2016-17, which led to triggering emergency response mechanisms in several countries. Although no gas or power outages were experienced in any of the affected countries, prices rose sharply and some demand-side measures had to be adopted, showing that even in mature and well-interconnected markets, unexpected shocks can still put strong pressure on physical balancing. On the exporters' side, the recent examples of the diplomatic tensions between Qatar and several Gulf countries, and of Hurricane Harvey in the United States, proved to be more threats than real supply issues since they did not have actual consequences on LNG output level. Nevertheless, they did show that supplying countries, however important and reliable, are still exposed to high impact, low probability events with potentially substantial consequences for global gas supply.

Such incidents remind us that security of supply cannot be taken for granted. Governments should always be aware that unexpected events can lead to rapid changes in energy market conditions and, thus, should continue efforts to develop robust security of supply policies, including emergency response.

Volume flexibility in LNG infrastructure is improving gradually

One measure of supply security that was examined in *GGSR 2016* is the question as to what extent the LNG export capacities were actually able to increase production in case of major supply disruptions or demand shocks. This year's report finds that the situation is gradually improving. A combination of capacity increase from new plants, a slight decrease in off-line capacity, and slower demand expansion result in lower liquefaction utilisation rates: 96% in 2015, 95% in 2016, and an anticipated 87% for 2017 — thus increasing the potential for LNG supply response in case of tightness. It has to be noted, however, that despite the increased liquefaction capacities relative to LNG demand, upswing LNG production capacities remain modest.

LNG trade flexibility keeps on improving

LNG contracts flexibility appears as an important determinant of the resiliency of the global gas system. This report's updated analysis of new signed contracts shows clear evidence of contractual structures becoming less rigid – this trend is evidenced by the growing share of flexible destination contracts as well as by the decrease in duration. The current well-supplied market is obviously the driver behind such a trend, providing opportunities to achieve more flexible market arrangements and new pricing systems that reflect regional supply and demand balance.

Building upon the analytical framework in *GGSR 2016*, this year's report tries to identify how contract flexibility would develop over the next five years. Looking forward, the pool of legacy export contracts with fixed destination and long duration can be expected to shrink as these expire, and would be replaced by more flexible contracts. As for new sources of supply, the development of US exports emerges as a major source of additional contractual flexibility. Global portfolio players also appear as flexibility providers with increasing open-selling positions – even though those would be more transitory than structural given that portfolio players are expected to secure more long-term outlets. Finally, the emergence of new players such as trading houses has granted additional flexibility and contributed to market diversification towards new, less credit worthy, importing actors than that of most of those served by traditional suppliers.

Significant policy developments in gas security of supply

Recent updates on energy policies show the importance of gas security of supply concerns, calling for frameworks ensuring co-ordinated actions among different stakeholders to provide timely and adequate response to gas security of supply issues and emergencies.

The European Union's Security of Gas Supply Regulation introduces regional co-operation between member states sharing similar supply risk exposure. This solidarity mechanism aims to foster cross-border actions among neighbouring states in case of severe situations impacting protected customers, and it initiates an exchange on gas supply contracts information in order to better assess the overall internal market supply situation.

Japan's emergency policy measures for natural gas include a gradual three-step response process at individual company, industry, and cross-industries levels involving co-ordinated downstream supply, upstream supply, and demand-side measures. The 2016 Kumamoto Earthquake provided an illustration on how such emergency response policies to regional gas disruption were co-ordinated at industry level as well as with state agencies and ministries.

Despite becoming one of the world's largest exporters of natural gas, Australia's Energy Market Operator concluded that the country may not have enough gas available to the domestic market to meet increasing needs of natural gas for power generation as early as 2018. The Australian government introduced the Australia Domestic Gas Security Mechanism to address this issue, which would – if activated – ensure availability of supply for domestic end users by placing requirements on LNG exporters. In October 2017, an agreement was announced between the Australian government and the LNG exporters to ensure that sufficient gas would be available through 2019, leading the government to defer triggering the mechanism at this time.

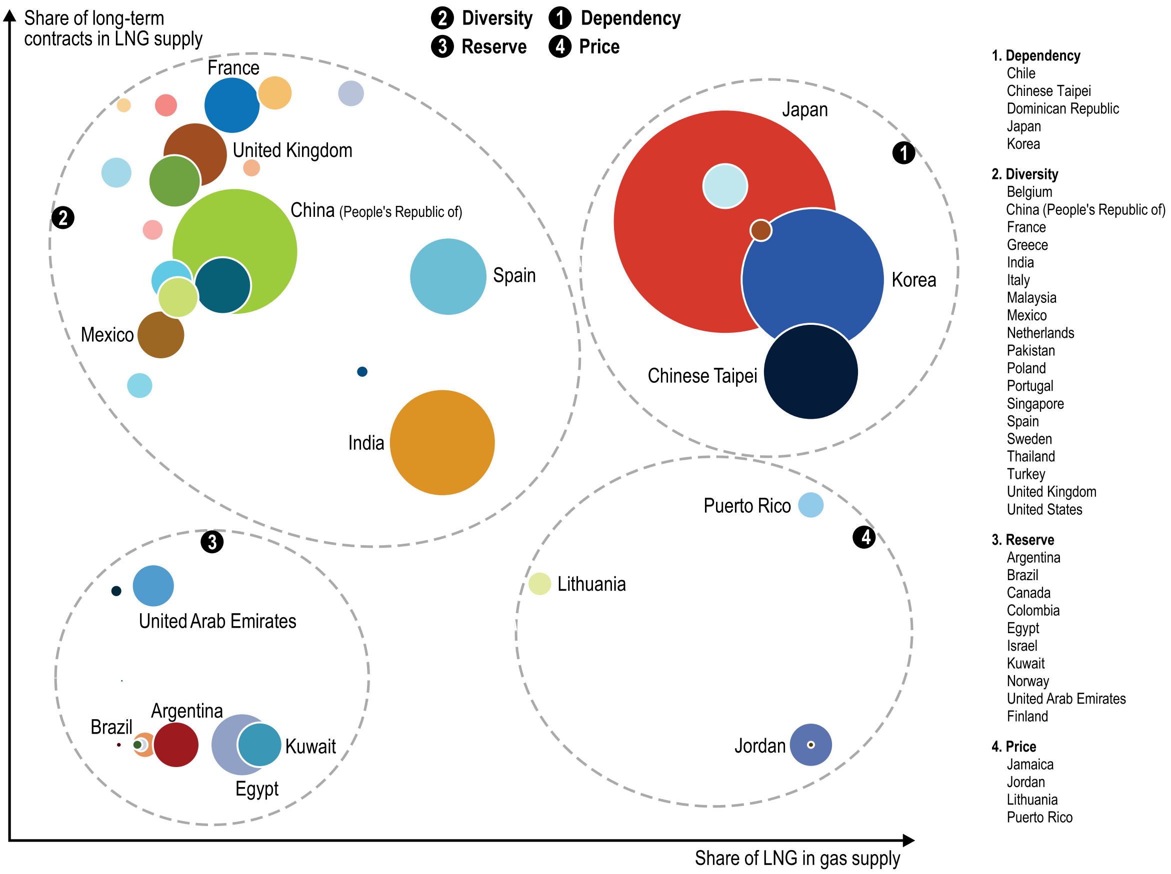
The June 2017 ruling by the Japan Fair Trade Commission against destination clauses in LNG contracts, as well as the similar ongoing inquiry by the Korea Fair Trade Commission, appear as important policy steps to increase flexibility and ensure more market resilience in case of supply issues.

Assessing LNG flexibility needs with an analysis of types of LNG buyers

LNG market expansion to an increasing number of countries and territories – 38 with LNG import terminals in 2016, growing to 47 by 2022 – is accompanied by greater differentiation among buyers, according to their domestic market requirements. In this report, an analysis of types of LNG buyers is presented in which the procurement strategies of the different players are analysed.

This approach defines four types of buyers, depending on their respective shares of LNG in natural gas supply and of long-term contracts within LNG supply. It ranges from markets almost fully dependent on LNG supplies (Type 1) to new importers where short-term supply is the rule and consumption is driven by fuel competitiveness (Type 4).

Figure ES.1 • LNG buyers types and clustering based on 2016 imports



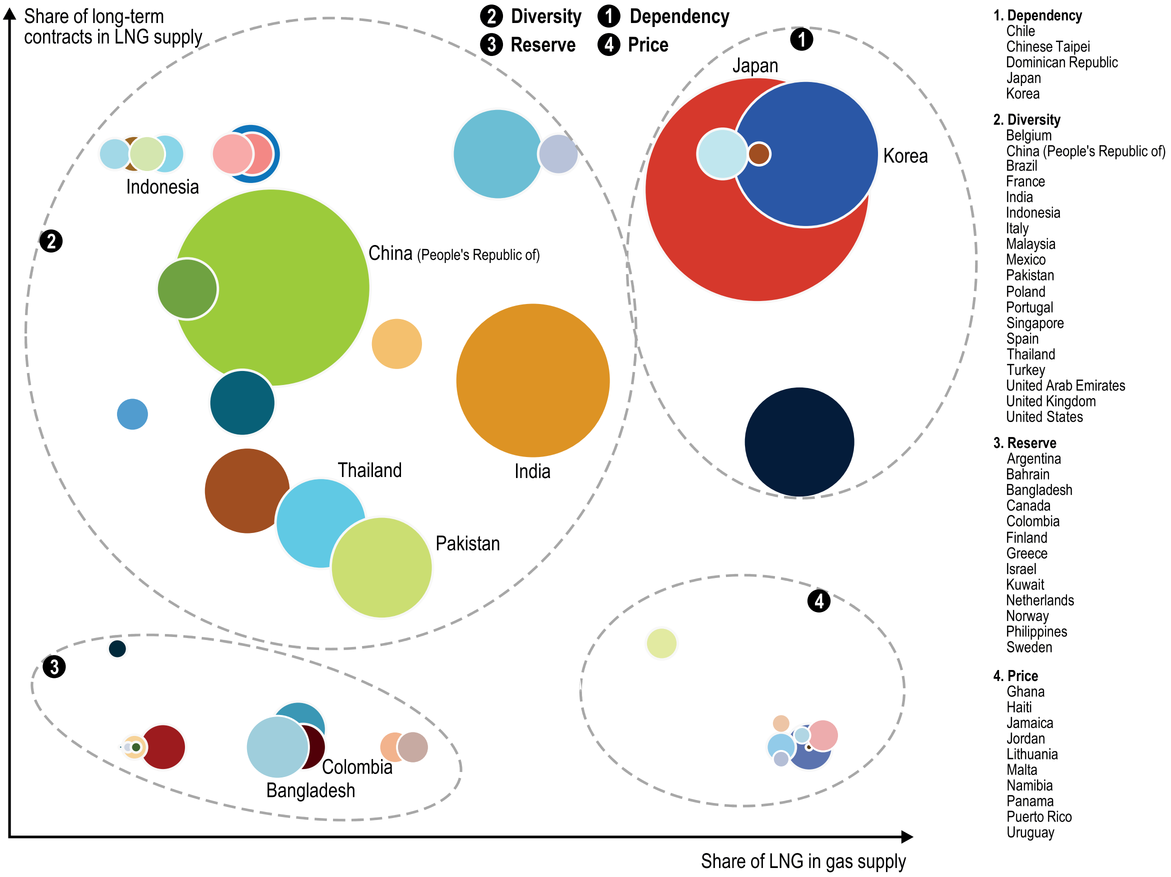
Source: IEA (2017), *Natural Gas Information 2017* (database), www.iea.org/statistics; IEA (2017b), *Market Report Series: Gas 2017*, www.iea.org/bookshop/741-Market_Report_Series:_Gas_2017; ICIS (2017), *ICIS LNG Edge*, www.icis.com/energy/liquefied-natural-gas/lng-edge (subscription required).

The picture emerging from this approach provides a fair illustration of the ongoing transitions in natural gas markets: the 2016 version displays a still quite conventional view of the LNG markets with mature importers accounting for the largest share of volumes and being either highly dependent (Type 1 *"Dependency"* including Japan, Korea and Chinese Taipei) or using LNG as part of a wider supply portfolio approach (Type 2 *"Diversity"* including European countries and Mexico), in contrast to fragmented new importers which are mainly price sensitive (Type 3 and 4), and with the major gas developing economies (People's Republic of China, India) in between.

Increasing markets' interdependence will bring new security of supply challenges

By contrast, the projected types for 2022 appear less clustered, with more volumes, more importers and a higher share of emerging economies. Import dependency rises as a whole as LNG grows and sees its market share expanding in several new importing countries. Demand is also expected to require more flexibility, especially for power generation where integration of a growing share of intermittent renewable production sources would increase profile volatility.

Figure ES.2 • LNG buyers types and clustering based on 2022 imports forecast



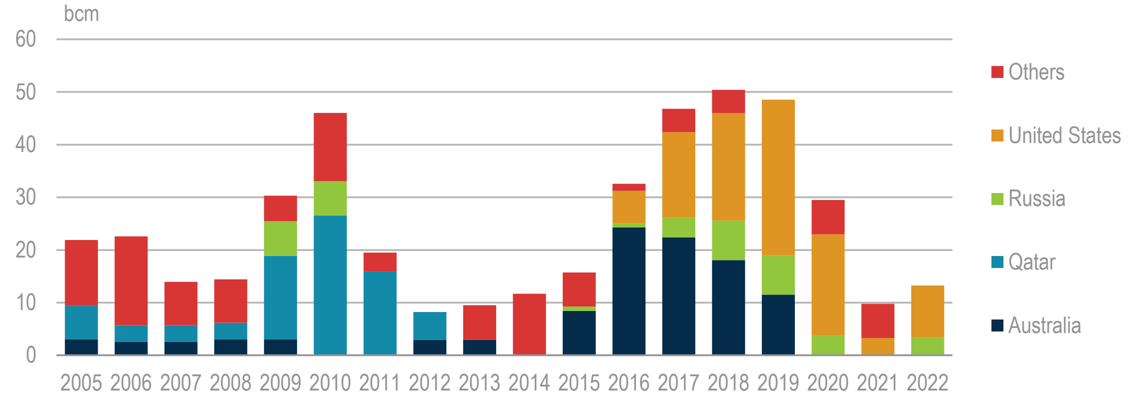
Source: IEA (2017), *Market Report Series: Gas 2017*, www.iea.org/bookshop/741-Market_Report_Series:_Gas_2017; ICIS (2017), *ICIS LNG Edge*, www.icis.com/energy/liquefied-natural-gas/lng-edge (subscription required).

The global gas market is reshaping to a more fragmented and interconnected structure, with greater needs for flexibility. At the same time, the LNG overcapacity is expected to ebb, with an anticipated retightening of the supply demand balance. This changing environment of increased interdependence between markets is likely to bring new security of supply challenges to both mature and new importers that will require adapted policy responses.

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

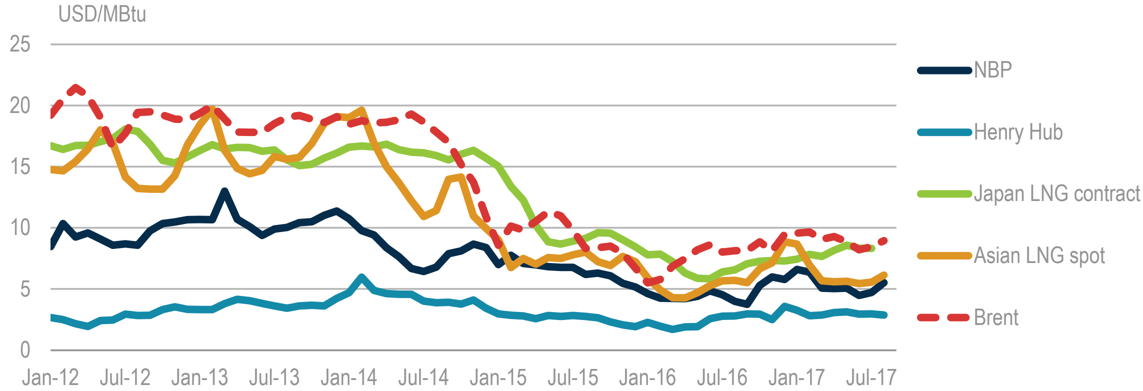
Global natural gas markets are in the midst of a second wave of expansion in the supply of liquefied natural gas (LNG). 2016 saw the leading edge of this wave with over 30 billion cubic metres (bcm) of LNG liquefaction capacity added. Nearly 200 bcm of further liquefaction capacity is due to be added by 2022 (Figure 1.1), led by the United States and Australia, countries which, with Qatar, will by then account for the majority of LNG supply capacity.

Figure 1.1 • Incremental liquefaction capacity, 2005-22



This expansion in supply will exceed expected growth in LNG demand, which is forecast to be closer to 100 bcm over the same period (IEA, 2017a). Even accounting for unavailability of supply (see next section), LNG markets are not expected to rebalance before the mid-2020s. For now, LNG prices remain low (Figure 1.2), only one final investment decision (FID) for new liquefaction facilities has been taken in 2017, and demand, while growing robustly, is not keeping pace with the addition of supply.

Figure 1.2 • Gas price development, 2012-17



Note: NBP = National Balancing Point (United Kingdom).

Sources: NBP, Henry Hub, Japan LNG contract and Brent data: Bloomberg Finance LP; Asian LNG spot data: ICIS (2017a), *ICIS LNG Edge*, www.icis.com/energy/liquefied-natural-gas/lng-edge (subscription required).

As highlighted in the first *Global Gas Security Review* (IEA, 2016a), even well-supplied and flexible markets can suffer from temporary tight market situations. Under those circumstances, appropriate energy policies and infrastructure remain crucial to ensure security of supply.

In the case of natural gas markets, limited liquidity together with the lack of adequate gas storage (both in terms of working gas volumes and withdrawal rates) in many countries could delay market response to potential supply or demand shocks by up to several days, even in a broader global context of oversupply (IEA, 2016a). The market's ability to rebalance – from the supply side – will be dependent on its capacity to: a) increase production; b) increase pipeline or LNG imports; or c) use gas storage. The limitations and time needed for each of these options to materialise should be carefully addressed, case by case, to avoid a false sense of comfort.

Yet events over the last 12 months have also shown that natural gas security of supply cannot be taken for granted and remains a live issue, in spite of a loose overall supply environment.

- In January 2017, a cold snap and delays in LNG shipments led to gas supply emergencies in southern Europe.
- In April 2017, the government of Australia announced the introduction of a Domestic Gas Security Mechanism in relation to certain exporters of LNG.
- In June 2017, several neighbouring countries broke off diplomatic relations with Qatar, currently the world's largest exporter of LNG.
- In August 2017, Hurricane Harvey hit Texas, causing major risk of oil and gas production capacity shut-ins and associated threats to LNG exports.

This first chapter reviews the main gas security of supply-related issues over the past year – all of them related to LNG.

Electricity and gas security events in southern Europe during winter 2016/17

Southern European countries experienced stressed situations in natural gas and power markets during the winter of 2016/17 (EURELECTRIC, 2017), when a rapid increase in both gas and power demand took place due to lower than expected temperatures, at a time when global LNG markets were briefly constrained and significant non-gas-fired power generation units were offline. Despite the overall abundance of natural gas supply, the cold spell that struck the region tested the ability of markets to react in a timely fashion to unanticipated events.

Since mid-2016, LNG spot prices had been rising steadily in several regions underpinned by increasing Asian LNG demand. Unexpected LNG shortages in major exporting countries, such as Algeria, worsened the situation in early 2017. The temporary shutdown of several nuclear reactors in France boosted natural gas demand for power generation in that country, as well as electricity and gas imports from neighbouring countries.

Despite the fact that no power or gas outages were experienced in any of the affected countries, prices for both commodities rose sharply (see Figure 1.5 and Figure 1.9), and recent European events should be considered as a reminder that security of supply cannot be taken for granted, even in apparently well-supplied markets.

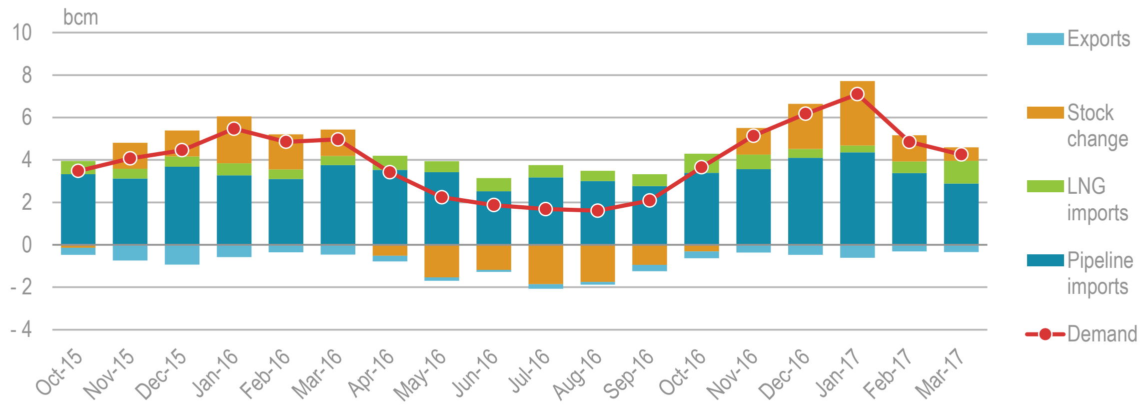
France

In January 2017, monthly natural gas demand hit a seven-year high of more than 7 bcm (Figure 1.3). This represented a 30% increase with respect to the previous year, mainly driven by low temperatures, but also due to a doubling of deliveries for electricity and heat generation.

The increase in natural gas demand for generation followed the decision of the French nuclear authority – the Autorité de Sûreté Nucléaire (ASN) – to carry out safety reviews in all nuclear power plants in France after finding anomalies concerning the carbon content of the steel in the reactor under construction at Flamanville. The investigation took several months and affected as many as 22 of the 58 nuclear reactors in France (ICIS, 2016).

As Figure 1.3 shows, the country was able to handle the upturn in gas demand by increasing pipeline imports and the use of natural gas in storage by 33% and 37% year-on-year (y-o-y), respectively. Thanks to the ample availability of gas in storage and pipeline interconnections with neighbouring countries, no issues arose at a national level. However, the country faced some regional issues that threatened local gas security of supply.

Figure 1.3 • Natural gas supply and demand balance in France



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

Congestion in the south east

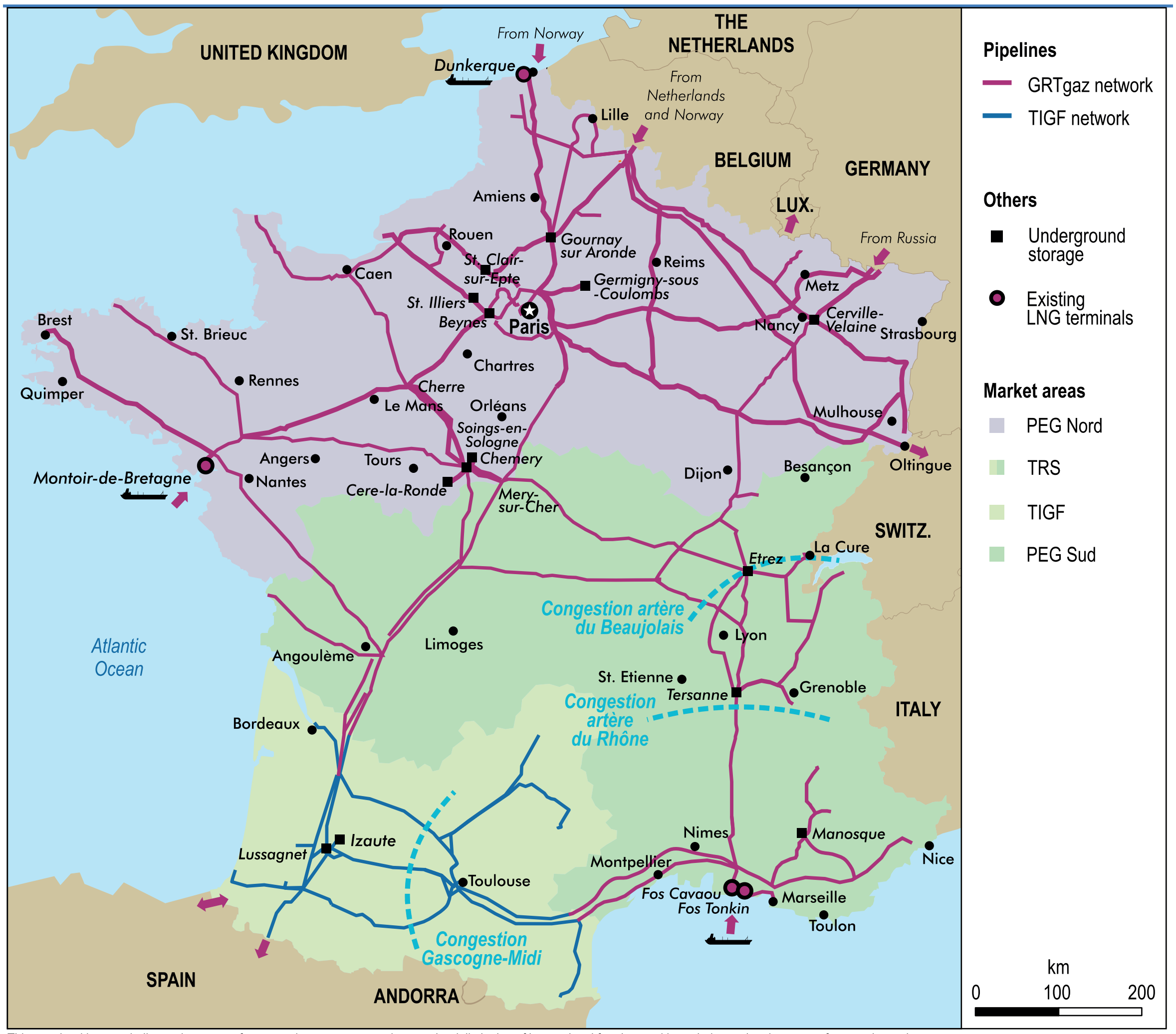
The natural gas market in France is structured around two main north-south transmission corridors – the west corridor and the east corridor – interconnected by cross pipelines (Map 1.1).

High-pressure infrastructure in the country belongs to two networks operated by separate transmission system operators (TSOs), GRTgaz in the north and southeast regions and Transport et Infrastructures Gaz France (TIGF) in the southwest region. After more than a decade of consolidation, the country has reduced the number of market areas from eight in 2004 to only two, the Point d'Échange de Gaz Nord (PEG Nord) and the Trading Region South (TRS) – the latter having been created after the merger between PEG Sud and TIGF in 2015. Furthermore, the country is strengthening internal infrastructure to create a single marketplace by 2018 (IEA, 2016b).

Despite having well-developed gas infrastructure, the GRTgaz network has experienced congestion in the north-to-south link between PEG Nord and PEG Sud in recent years (IEA, 2016b). When these bottlenecks occur simultaneously with Gascogne-Midi congestion in TIGF, the northern and southwestern regions remain well supplied by pipeline imports from several European countries and two regasification terminals – Montoir-de-Bretagne and Dunkerque LNG – while the southeast region becomes virtually isolated. When this happens, the southeast market relies critically on LNG imports at Fos-sur-Mer terminals (Fos Cavaou and Fos Tonkin) and natural gas storage facilities at Etrez, Manosque and Tersanne (fast withdrawal but limited working gas volume salt caverns).

Despite the local TSO being fully aware of the vulnerability and in the process of remedial action, such a congestion event took place during last winter, triggering numerous local alerts between mid-December and the end of January (GRTgaz, 2016).

Map 1.1 • Natural gas transmission network in France



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.

As represented in Map 1.1, bottlenecks appeared simultaneously in the "artère du Rhône" and in the "artère du Beaujolais" transmission lines. At that time, shippers had two alternatives to deliver gas to the southeast region: a) increase sendout from the Fos LNG terminals; or b) increase gas withdrawals from the Etrez, Manosque and Tersanne storage facilities.

Box 1.1 • French government to increase flexibility in gas storage obligations

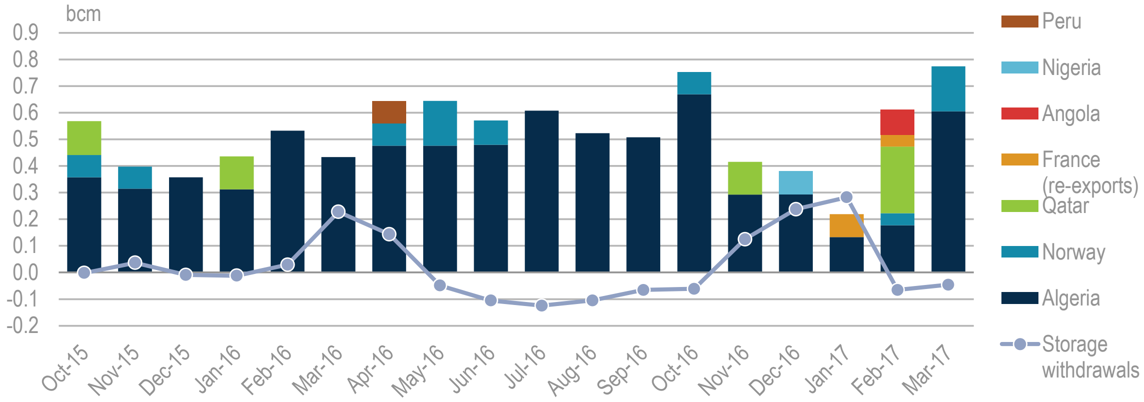
According to a ministerial order published on 5 August 2017 in France's official journal – the *Journal officiel de la République française* (JORF) – gas suppliers will have more alternatives to fulfil their storage obligations from winter 2017/18 onwards.

Under the new rules, shippers will be able to use LNG storage together with foreign storage sites and facilities to account for up to 50% of their obligations – while previous regulations required the use of domestic underground gas storage (UGS) only. Nevertheless, the new alternatives must not be simultaneously used by other EU countries to address security of supply. Additionally, suppliers must ensure enough transport capacity to ship the stored volumes to the French system.

Source: ICIS (2017b), "French government redraws suppliers' gas storage obligations", *ICIS LNG Edge*, https://lngedge.icis.com/news/article/10131583 (subscription required).

Given the high LNG prices in the region and the unavailability of the liquefaction plant at Skikda in Algeria (the major LNG supplier to southeast terminals in France, Figure 1.4) most shippers decided to increase natural gas withdrawals from the salt caverns. This decision reduced gas stocks in the region pushing them to the lowest level in five years (GRTgaz, 2016). In order to avoid potential supply disruptions later in the winter, GRTgaz issued market guidelines and requested shippers to increase their LNG imports at Fos Cavaou and Fos Tonkin terminals near Marseille, even if they were already fulfilling market obligations.

Figure 1.4 • LNG imports and natural gas storage withdrawals in southeast France



Notes: LNG imports account only for the deliveries to Fos Cavaou and Fos Tonkin regasification terminals; natural gas storage withdrawals consider the withdrawals from Manosque, Tersanne and Etrez underground storage facilities.

Sources: LNG imports: ICIS (2017a), *ICIS LNG Edge*, www.icis.com/energy/liquefied-natural-gas/lng-edge (subscription required); natural gas storage withdrawals: GRTgaz (2017), *Smart GRTgaz*, http://www.smart.grtgaz.com/en/flux_physiques/PITS.

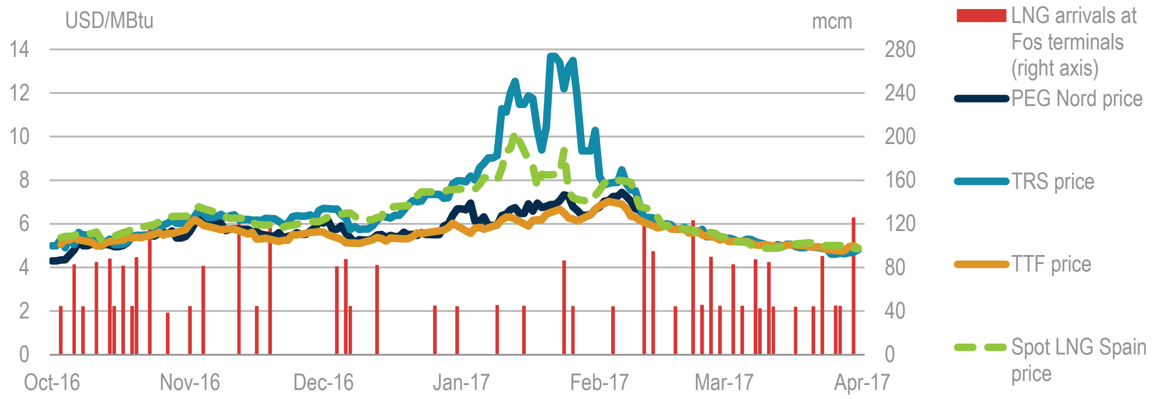
In an effort to tackle January's tight situation in the southeast region, LNG was shipped from Montoir-de-Bretagne LNG terminal in northwest France to Fos Cavaou LNG terminal in the southeast (Figure 1.4). The first cargo departed 18 January and arrived at the Fos Cavaou LNG terminal five days later. The second LNG re-export cargo left in late January and took four days to arrive at Fos Cavaou LNG terminal in early February. A shipment from Qatar, which left on 28 January, took two weeks, arriving at the Fos terminal on 11 February.

Hence, most of the volumes needed in January did not reach the destination region until February, spending an average voyage time of eight days. The time taken for those cargoes to reach southeast terminals highlights the importance of timeliness of supply, even when the volumes are shipped within the same country.

The congestion described above also had a direct impact on natural gas spot prices in France during winter 2016/17. The spread between prices in the north (PEG Nord) and in the south (TRS) grew steadily up to USD 6.8 (United States dollar) per million British thermal units (MBtu) by 22 January. As Figure 1.5 shows, during this period prices in the northern region remained aligned with major continental hubs such as the Dutch Title Transfer Facility (TTF), while prices in the south were above the LNG spot price in Spain, which became the benchmark for southeast gas supply. This divergent trend was not reversed until a significant amount of additional LNG volumes were delivered to southeast terminals in late February. Mild temperatures also contributed to lower natural gas withdrawals from storage facilities with no need for further demand side measures.

Events experienced in France during the winter of 2016/17 are a good example to show that even well-supplied markets cannot always provide either rapid or cheap responses to supply or demand shocks when interconnection capacity is inadequate.

Figure 1.5 • Natural gas spot prices in France versus TTF and LNG spot price in Spain, winter 2016/17



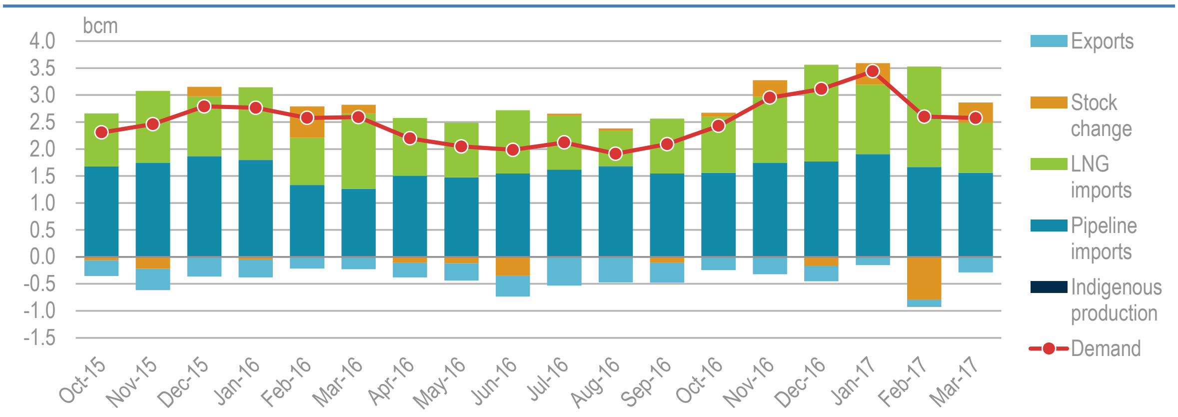
Sources: Natural gas prices in France: Bloomberg Finance LP; other prices: ICIS (2017a), *ICIS LNG Edge*, www.icis.com/energy/liquefied-natural-gas/lng-edge (subscription required).

Spain

Spain is a traditional natural gas consumer and the fuel plays a major role in its energy mix. In 2016, natural gas represented 21% of total primary energy supply (TPES) (IEA, 2017b) and 19% of electricity production as a complement to its large renewable generation portfolio (IEA, 2017c). Indigenous production is negligible, so the country relies on natural gas imports via pipeline and LNG to supply domestic demand.

At the beginning of 2017, conventional demand for natural gas rose by 21% y-o-y, underpinned by low temperatures (Enagás, 2017a). On top of that, the associated growth in electricity demand coincided with lower renewables output and greater demand from France (see previous section), increasing natural gas demand for heating and power generation by 42% y-o-y in January. Altogether, demand grew to a five-year record that totalled 3.4 bcm in January 2017 (Figure 1.6).

Figure 1.6 • Natural gas supply and demand balance in Spain

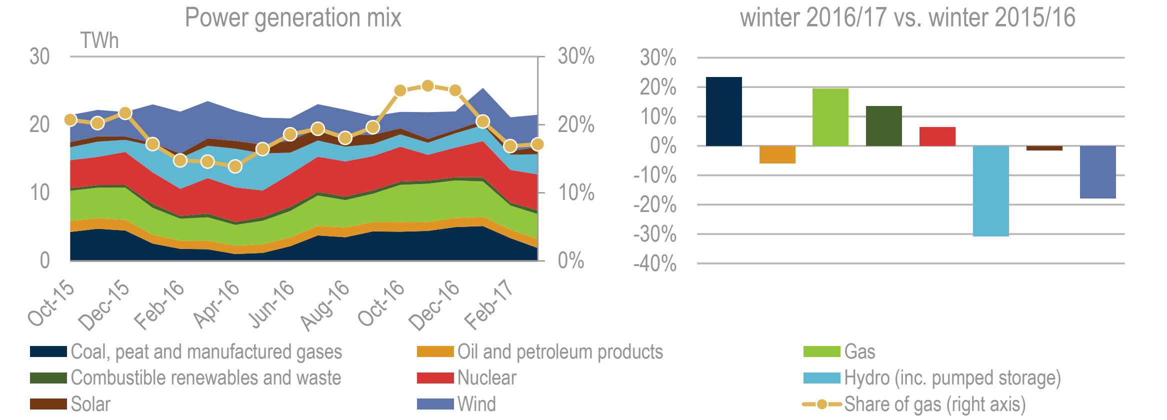


Source: IEA (2017b), *Natural Gas Information* (database), www.iea.org/statistics/.

Spain has a well-diversified and well-balanced power generation mix as shown in Figure 1.7, with flexibility provided by hydro and a modern gas-fired fleet. The significant share of renewable energy sources makes the consumption of natural gas for electricity production largely dependent on weather conditions and competition with other fuel prices. During the winter of 2016/17,[1] weak rainfall and low wind speeds reduced significantly hydro and wind generation by 31% and 18% respectively, i.e. nearly 11 terawatt hours (TWh) less throughout the season compared to the previous year. To fill the gap left by those sources, combustible fuels increased production by more than 9 TWh overall, of which half was from natural gas, representing an increase in gas consumption of around 0.7 bcm.

While coal was the fastest-growing fuel in relative terms (up 23%), natural gas experienced the highest growth in absolute terms. As a result, gas-fired generation became the major source of power generation in Spain during winter 2016/17 with an average share of 22%, followed by nuclear power (21%), coal (18%) and wind (18%).

Figure 1.7 • Power generation mix in Spain



Source: IEA (2017c), *Electricity Information* (database), www.iea.org/statistics/.

As discussed above, the basic alternatives to meet the increase in gas demand experienced in January from the supply side were: a) to increase production; b) to increase pipeline or LNG imports; or c) to increase the use of gas stocks. In the case of Spain, only the second was viable. Nevertheless, well-designed markets that provide appropriate price signals also contribute to match supply and demand during stress periods (without increasing supply) as high supply prices may discourage demand – reducing consumption to match available supplies.

Timeliness of security of supply in Spain

Spain has virtually no gas production (0.05 bcm in 2016 [IEA, 2017b]) and limited operational underground storage capacity distributed among four different sites: Gaviota, Serrablo, Yela and Marismas. According to Enagás, the Spanish TSO, the country had 5.5 bcm of UGS capacity in 2016, nearly 50% of which was occupied by cushion gas, leaving 2.8 bcm of working gas capacity (Enagás, 2017b).

Additionally, the country has mandatory strategic stocks in place equivalent to 20 days of the firm sales in the previous natural gas year. Shippers are obliged to maintain their corresponding strategic stocks; however, the government is responsible for its use as they are reserved for major emergencies such as failure of infrastructure, import disruptions due to geopolitical issues, force majeure and adverse meteorological phenomena (Platts, 2017). By the end of last year, strategic stocks in Spain represented 1.5 bcm.

[1] The winter season in Europe starts 1 October and ends 31 March.

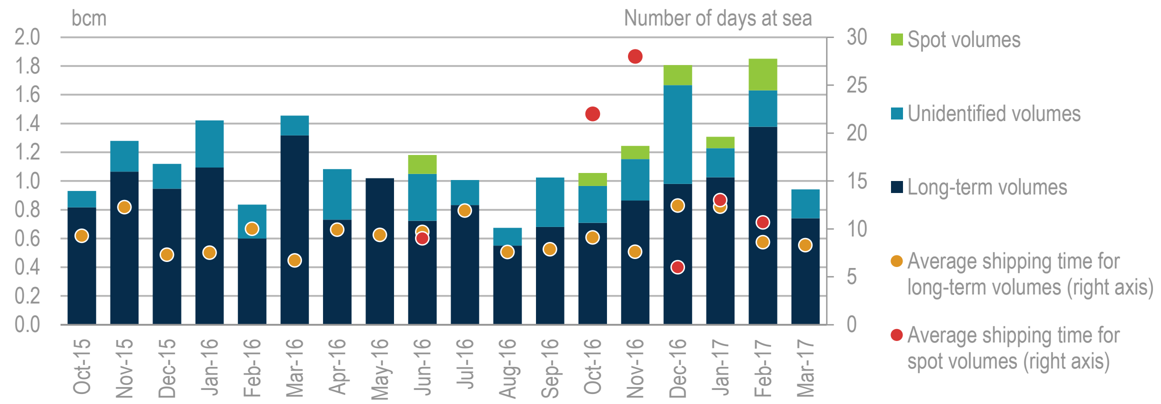
This means that the remaining operational underground gas storage (UGS) capacity that the country had to face the January cold spell was around 1.3 bcm. Of this capacity, only 0.2 bcm were actually being used by shippers by the end of December 2016. Hence, the amount of operational gas in storage at the beginning of the year – representing less than 1% of annual demand – was too low to provide flexibility to the system.

In addition to its UGS capacity, the country has 25 LNG tanks distributed among six operating regasification terminals. In total, LNG tanks add 1.5 million tons of LNG storage capacity (Enagás, 2017b),[2] equivalent to 2 bcm of extra storage capacity albeit at a significantly higher cost. In 2016, average use of LNG storage capacity was 37%, while by the end of the year LNG stocks accounted for nearly 0.9 bcm (including cushion gas).

Therefore, the only viable alternative for the country to meet the upturn in demand was to increase imports (up 10% y-o-y) and to a lesser extent reduce pipeline exports (down 22% y-o-y) (Figure 1.8). As pipeline imports from major suppliers were already high (Algerian imports were close to full capacity and imports from France were hitting two-year record levels [Platts, 2017]), LNG imports became the last option to fulfil winter demand. As a consequence, LNG volumes increased by 17% compared to the previous winter.

On a monthly basis, February LNG imports hit a five-year record, accounting for slightly more than 1.8 bcm. However, this figure contrasts with natural gas demand, which fell by 24% compared to the previous month, down to 2.6 bcm. The increase in LNG imports together with the decrease in gas demand left around 1 bcm of "extra" supply looking for a market that ended up being stored (Figure 1.6).

Figure 1.8 • LNG imports on sales basis in Spain and average shipping time



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

The explanation for this mismatch between LNG imports and gas demand is once again related to timeliness of supply. As Figure 1.8 shows, an important share of the volumes imported last winter was negotiated on a spot basis. Due to the unexpected nature of the increase in demand and the shortfall at the Skikda LNG plant in Algeria, shippers could not provide enough LNG volumes through long-term contracts and were forced to draw on the spot market to meet demand. As Figure 1.8 highlights, spot volumes usually take longer to reach final destination than term volumes. Accordingly, average shipping time for LNG volumes rose from 9 days in winter 2015/16 to 12 days in winter 2016/17 (up 33%). As a consequence, extra LNG volumes arrived after the

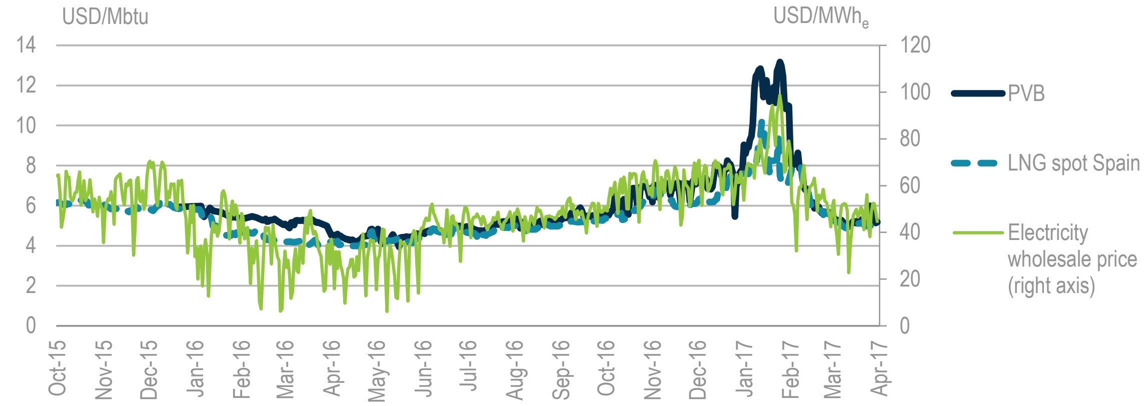
[2] The Spanish TSO, Enagás, reports 3 316 500 cubic meters (cm) of LNG storage capacity in total.

demand peak. That situation caused a significant increase in gas stocks by the end of February (Figure 1.6), which is quite abnormal during winter.

The low liquidity of the recently implemented Spanish gas market and its dependency on LNG imports became evident from the spot prices observed at the Spanish natural gas hub, Punto Virtual de Balance (PVB). As Figure 1.9 shows, gas prices soared above LNG spot prices last winter, taking almost one month to return to previous levels regardless of the broader context of oversupply. Until the tight situation eased late in February, Spanish wholesale gas prices soared driven by the country's need to rapidly increase natural gas supply. In addition, as highlighted before, gas-fired generation was fundamental to meet the upturn in electricity demand during the same period owing to the shortfall in hydro and wind generation (Figure 1.7). Consequently, the Spanish wholesale electricity market also reflected the increase in natural gas spot prices reaching 98.8 USD/MWh by January 25. At that time, natural gas spot prices also peaked at 13.2 USD/Mbtu.

On top of fuel prices, third-party access (TPA) fees also represent a relevant share of the variable costs of underused power generation plants since low utilisation rates discourage generators from booking long-term transport capacity. Instead, generators draw on the secondary market to reserve short-term capacity on demand with the consequent higher cost — which is ultimately reflected in their variable generation costs and therefore in spot electricity prices.

Figure 1.9 • Natural gas and electricity spot prices in Spain



Sources: Natural gas price: MIBGAS (2017), *Resultados del Mercado*, www.mibgas.es/aplicaciones/datosftpGAS/datosftp.jsp?path=//datos_GAS//AGNO_2017//XLS/; LNG price: ICIS (2017a), *ICIS LNG Edge*, www.icis.com/energy/liquefied-natural-gas/lng-edge (subscription required); electricity price: OMIE (2017), *Market results*, OMIE, Madrid, www.omie.es/files/flash/ResultadosMercado.swf.

In order to improve the transparency and liquidity of the Spanish natural gas market, which has been traditionally based on bilateral agreements negotiated over the counter (OTC), the government is currently supporting the development of the Iberian Gas Market (MIBGAS), a trading platform for different products to be delivered at the PVB and other local points of the gas system. However, MIBGAS is still at an early stage of development; it started operations in December 2015, with limited volumes been negotiated at the time of writing. Thus, total traded volume in August 2017 amounted to 994.4 GWh (i.e. 0.09 bcm), representing 4% of the total national demand (MIBGAS, 2017).

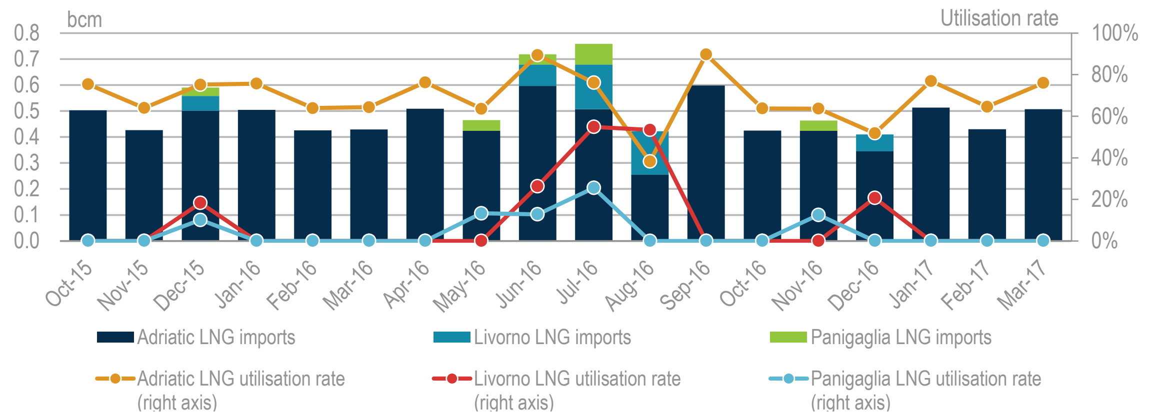
Italy

Italy is the third-largest gas consumer in Europe after Germany and the United Kingdom, and natural gas plays a dominant role in its energy mix, representing around 40% of the country's

TPES (IEA, 2017b). In 2016, roughly 8% of country's demand was met by domestic production, while 83% corresponded to pipeline imports, mainly from the Russian Federation (hereafter, "Russia") and northern Europe.

Italy has 15.5 bcm of LNG importing capacity distributed between three operational LNG regasification terminals (IEA, 2016c): two offshore facilities near Rovigo (Adriatic LNG) and Tuscany (Livorno LNG), and another onshore facility in Liguria (Panigaglia LNG). However, LNG only accounted for slightly more than 6 bcm, or 9%, of natural gas supply in 2016. Adriatic LNG accounts for almost 90% of these imports and has an average load factor of 68%. Livorno and Panigaglia are lightly used (Figure 1.10) (Panigaglia being limited to small cargoes of 70 000 cm maximum), with gas originating from Algeria under long-term contract. Qatar is the dominant LNG supplier, with around 90% market share as per its long-term contract with Italian utility Edison.

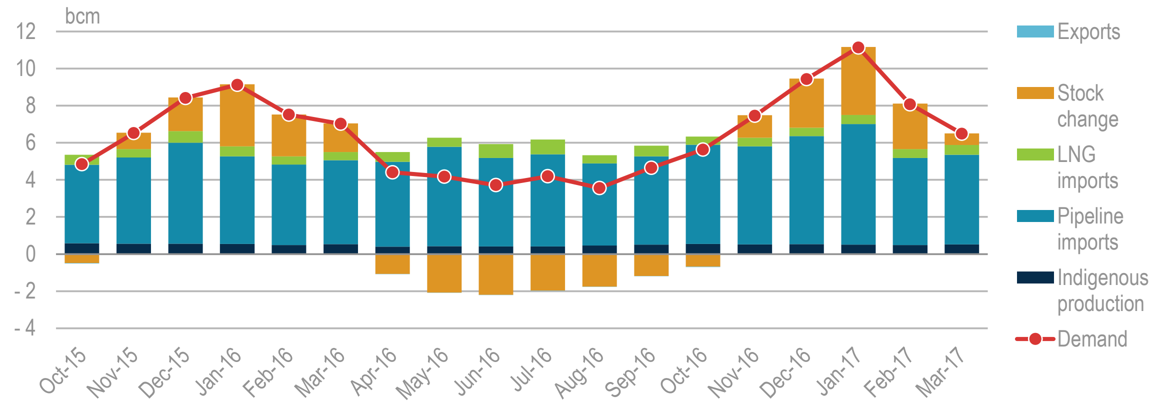
Figure 1.10 • Italian LNG imports and utilisation rate by regasification terminal



Source: ICIS (2017a), *ICIS LNG Edge*, www.icis.com/energy/liquefied-natural-gas/lng-edge (subscription required) and IEA analysis.

In addition, during winter 2016/17 the country used its vast underground storage capacity of nearly 16 bcm, with stock drawdown providing over 30% of peak winter demand, to balance seasonal demand (Figure 1.11).

Figure 1.11 • Natural gas supply and demand balance in Italy



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

Like other southern European countries, Italy faced a severe cold spell last winter that started on 7 January, affecting in particular the southern part of the peninsula. As a result, in January natural gas demand rose by 22% y-o-y to 11.1 bcm. The significant increase in demand was mainly driven by households and led to 11-year record highs.

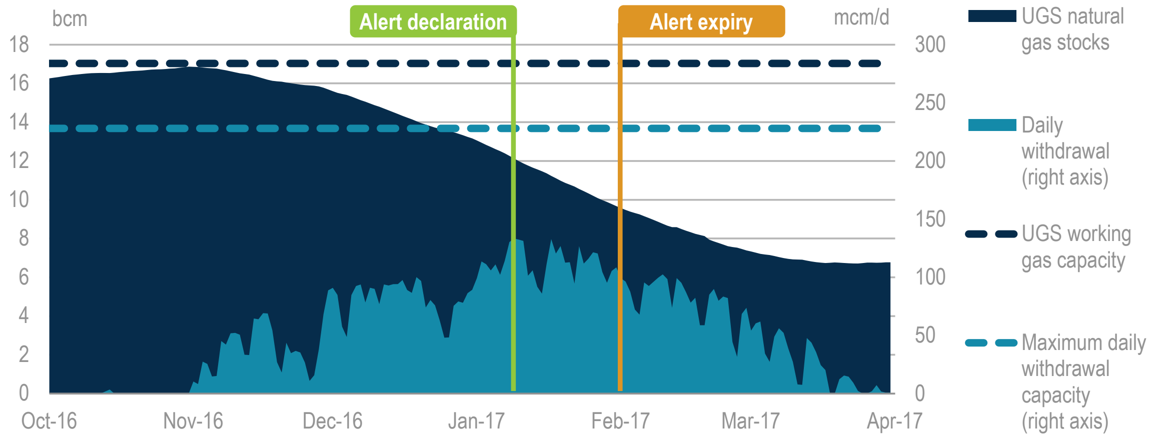
To handle the rise in January demand, the country raised its pipeline imports by 38% y-o-y, mainly from Russia but also from both northern Europe and North Africa, representing a monthly increase of nearly 2 bcm compared with the same period the previous year. LNG imports were steady y-o-y, accounting for just 0.5 bcm. On top of that, natural gas withdrawals from underground storage grew by 9% y-o-y, up to 3.7 bcm, so that more than one-third of Italy's demand during the first month of the year was met by gas stocks.

The large increase in withdrawals from natural gas underground storage forced the Italian government to declare an alert level on 9 January. At that time, shippers were encouraged to increase their imports using contract flexibility or spot purchases to prevent an early depletion of domestic storage. The alert level remained in place until 1 February, when the expected decrease in natural gas demand (down 27% in February) allowed the government to lift the alert.

Emergency declaration criteria

According to the Italian Emergency Procedure, the alert level was triggered when daily withdrawal volumes from UGS surpassed the contractual withdrawal threshold booked by shippers. This meant that the utilisation level of shippers' contractual capacity was actually above 100%; however, it did not necessarily mean that natural gas stocks were under stress. In fact, as Figure 1.12 shows, gas stocks were at 71% of total capacity when the alert level was declared on 9 January. Hence, the country had 12 bcm of underground stored gas stocks – including strategic stocks – to face the remaining winter months. To put this figure into perspective, it is equivalent to 83% of remaining demand in February and March.

Figure 1.12 • Natural gas stocks and withdrawal rate at Italian UGS, winter 2016/17



Source: GIE (2017), *AGSI+ Transparency Platform* (database), https://agsi.gie.eu/#/.

Furthermore, when the extra volume withdrawn was rebalanced after a reduction in withdrawal rates and the alert level was lifted, natural gas stocks amounted to 10 bcm, i.e. 21% below the existing stocks when the alert level was declared.

However, daily withdrawals were at their highest level when the alert was declared (9 January), reaching 133 million cubic metres (mcm) per day. Still, this amount only represented around 60% of the maximum daily withdrawal capacity.

While Italy experienced isolated daily price spikes at the Italian natural gas hub – Punto di Scambio Virtuale (PSV) – during last winter; unlike other European countries Italy was able to rapidly increase pipeline imports and withdrawals from underground gas storages limiting the duration of the peaks. For the same reason, the reported impact of last winter events in Italian forward prices has been little (Platts, 2017).

The natural gas events in Italy in early 2017 highlighted not only the value of gas storage in handling unexpected increases in demand, but also the relevance of defining appropriate metrics and procedures to declare alert levels, in order to reflect real market emergencies.

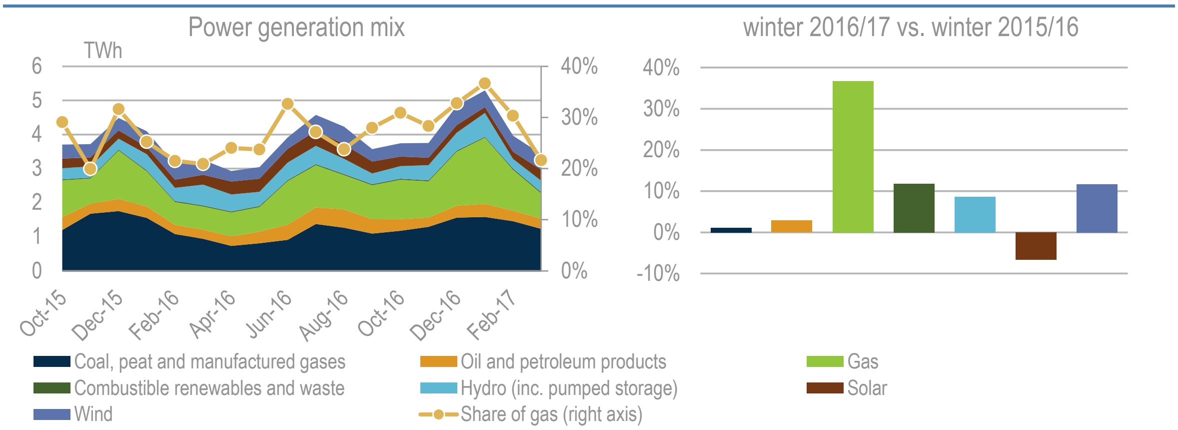
Greece

Greece is a relatively young natural gas market as the fuel only became part of the energy mix in 1996. However, gas has played a growing role in its power mix since then, accounting for almost 30% of generation in 2016. Last year's natural gas demand totalled 4 bcm, 68% of which were deliveries for electricity and heat generation.

From the supply side, the country is 100% dependent on LNG and pipeline imports. As Greece has no underground storage capacity (the exploitation of the nearly depleted gas field of South Kaval in northern Greece is being investigated [IEA, 2017a]) and its LNG storage capacity is limited (two LNG tanks of 65 000 cm each, amounting to 0.08 bcm [DESFA, 2017b]), the country also relies on imports to balance the system during high demand periods.

The sharp cold spell faced by southern European countries last winter led to a significant increase in Greece's natural gas and power demand. In the case of power generation, the rise in demand (up by 12% compared with the same period the previous year) was mainly covered by gas-fired generation surging by 37% (2.1 TWh) compared with winter 2015/16, accounting for 31% of overall power generation during the winter (Figure 1.13).

Figure 1.13 • Power generation mix in Greece

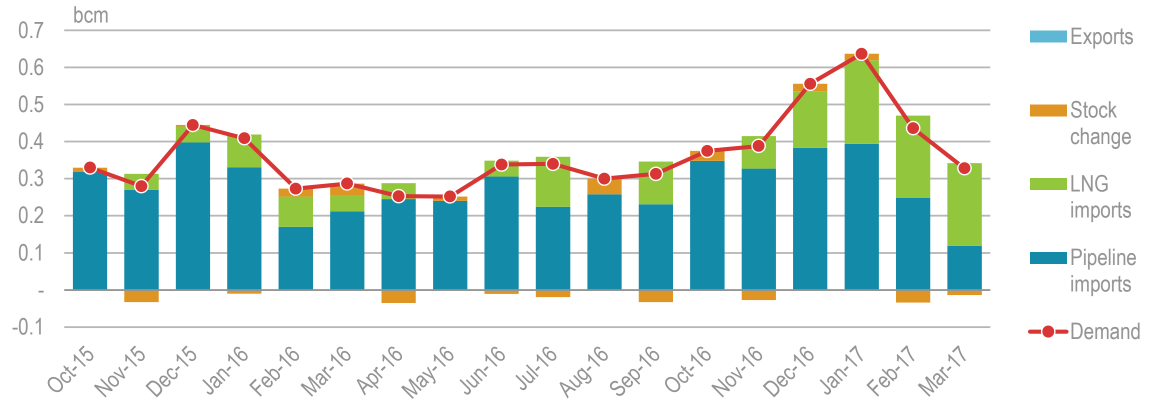


Source: IEA (2017c), *Electricity Information* (database), www.iea.org/statistics/.

On top of its major role in power generation, conventional natural gas demand also rose by 32% (or 1.1 bcm) throughout the season compared with the previous winter. Due to exceptionally high demand for both domestic supply and gas-fired power generation, total natural gas demand hit an all-time monthly record of 637 mcm in January 2017 (Figure 1.14), some 40% above the previous high.

As described above, the country has virtually no storage capacity. Therefore, the increase in gas demand had to be met by increased LNG and pipeline imports. Accordingly, as Figure 1.14 shows, LNG imports soared by 156% y-o-y to meet January demand while pipeline imports rose 19% y-o-y, accounting for 225 mcm and 394 mcm respectively.

Figure 1.14 • Natural gas supply and demand balance in Greece



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

The unpredicted increase in gas demand triggered the declaration of two consecutive alert levels to safeguard national gas and power supply.

The first crisis started on 19 December with the declaration of an early warning state and lasted 13 days until business as usual resumed on 31 December. The early warning was declared after a sustained increase in gas demand for seven days in a row. The delay of an Algerian LNG cargo due to bad weather conditions in late December tightened the situation, leading to the alert declaration on 21 December.

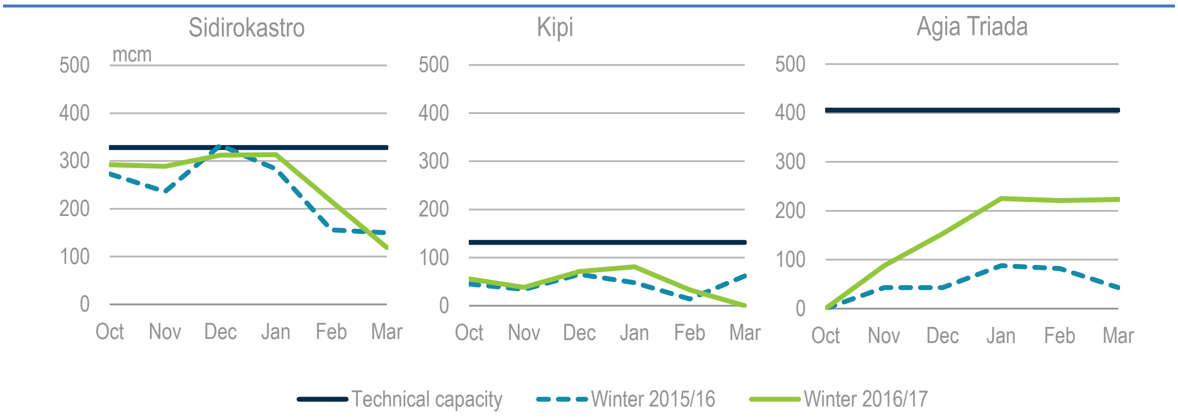
The second crisis started on 9 January and finished on 13 February, 36 days later. In this case, the tight situation was also due to exceptionally high demand (Figure 1.14).

During Greece's gas crisis, the market was not able to rebalance itself and the government needed to implement several measures according to the provisions of the Greek Emergency Plan.

Handling the gas crisis

As noted above, the only viable alternative to meet the rise in gas demand was to increase pipeline and LNG imports.

Figure 1.15 • Greek natural gas monthly imports by entry point, winter 2016/17



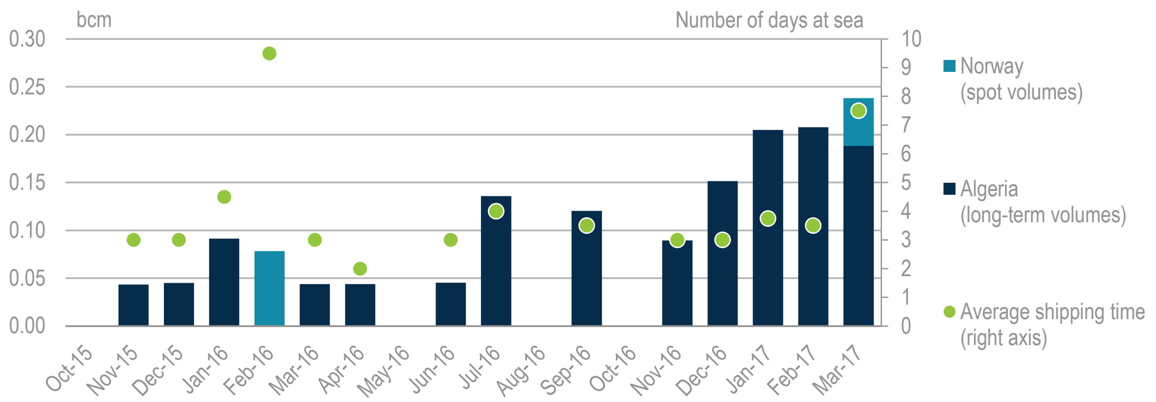
Source: IEA (2017b), *Natural Gas Information* (database), www.iea.org/statistics/; DESFA (2017a), *National Natural Gas System: NNGS Operation Report for Year 2016*, www.desfa.gr/?page_id=3310&lang=en.

Greece's natural gas system has three entry points with an annual import capacity of 10.5 bcm (DESFA, 2017a):

- **Sidirokastro**, which has 4.0 bcm of import capacity and serves as the entry point for Russian pipeline volumes via Bulgaria.
- **Kipi**, which brings Turkish pipeline gas into the country with a maximum import capacity of 1.6 bcm.
- **Agia Triada**, which offers an additional 4.9 bcm of import capacity and enables the entry into the system of LNG volumes imported at Revithoussa LNG terminal. Historically, these volumes have been long-term contracted to Algeria.

Given that pipeline imports from Bulgarian and Turkish border entry points could not be significantly increased in absolute terms, the last option left was to increase LNG imports through Agia Triada (Figure 1.15). Consequently, LNG imports tripled compared to the previous winter. In order to achieve this significant increase, the country benefited from its long-term contract with Algeria. In addition, one extra spot cargo was delivered from Norway's Snohvit LNG plant, arriving in Greece 12 days later, on 19 March. As Figure 1.16 shows, spot volumes had a significant impact on average shipping time for LNG imports. Accordingly, average shipping time in March – with one spot cargo – almost doubled the average time required for LNG imports compared to January, when no spot cargoes were delivered (Figure 1.16).

Figure 1.16 • LNG imports by sales basis in Greece and average shipping time



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

The relevant difference between the time needed for spot and long-term contracted LNG volumes to be delivered should be carefully assessed and analysed to avoid a false sense of comfort in countries with significant spare LNG importing capacity during periods of abundant supply.

During the Greek crisis, the increase in LNG imports was not enough to tackle the rapid demand growth in a timely fashion. Therefore, the country needed to adopt several demand-side measures to avoid forced interruptions of supply. These measures included:

- Requesting interruptible gas customers to reduce their consumption by at least 40%.
- Approving standard contracts for demand-side management.
- Fuel switching of gas-fired power generation plants to diesel oil where possible.
- Increasing hydropower generation.
- Voluntary management of gas-fired power plants according to TSO's guidance.
- Exercising interruptible electricity contracts.

Thanks to the adoption of these demand-side measures, together with the increase in LNG imports, no gas or electricity outages took place during the crisis.

However, supplied natural gas demand during the crisis was below previously forecast demand. This means that without the reduction in consumption provided by demand-side measures the country could have experienced forced interruptions of supply.

Thus, Greek events highlight once again that an abundance of supply – especially LNG – in the market, together with spare importing capacity, are not enough by themselves to prevent temporary tight situations.

Electricity and gas security events in Australia

In September 2016 and more recently in February 2017, Australia experienced electricity security events that provide insights into both electricity and gas security. The September 2016 event entailed a state-wide electricity blackout in South Australia and in February 2017 electricity load shedding was initiated by the Australian Energy Market Operator (AEMO) in South Australia and New South Wales.

Black system event in South Australia – September 2016

The black system event in South Australia took place on 28 September 2016. That day, a series of events in the electricity infrastructure led to the disruption of electricity supply to around 850 000 electricity customers in South Australia.

In the afternoon, during a severe storm, major damage to key transmission lines led to the disconnection of approximately 450 MW of wind generation at that moment, equal to about a quarter of the South Australian electricity demand at that time [next to 330 MW of gas generation, 430 MW of other wind generation, approximately 615 MW of imports from Victoria and about 50 MW of solar photovoltaic (PV) supply]. A sudden increase in demand on the interconnector with Victoria, already operating at close to capacity, triggered an automatic protection mechanism which took the interconnector offline. This disconnection led to the loss of approximately 900 MW of supply from Victoria and, in the absence of significant and very rapid load shedding, the total electricity system collapsed. The black system event lasted about 26 hours, although in certain areas network problems persisted due to damage to the transmission network, and load was restored progressively over the next days. The South Australian market remained disconnected from the National Electricity Market (NEM) until 11 October while special procedures to manage power system security were implemented by AEMO.

Load-shedding events in South Australia and New South Wales – February 2017

On 8 February 2017 in South Australia, and two days later in New South Wales, strong heatwaves occurred. In the New South Wales event, lower than forecast wind generation, coupled with forced outages at some gas-fired power plants, in combination with sharply higher than expected residential power demand (mainly for air-conditioning) led to necessary load shedding. In both cases, the unavailability of gas-fired electricity generation capacity led to the forced downward adjustment of electricity demand. On 10 February, the lack of gas supply, due to low pressure in a gas supply pipeline, prevented the start-up of a 600 MW gas-fired power plant.

Impact on gas security

These events have brought significant attention to the power system's response to extreme circumstances, in the light of ongoing changes in Australia's generation mix to higher levels of renewable energy sources, and the critical role of gas in both power security and pricing in South Australia specifically.

The state's energy system relies entirely on renewables and gas-fired power generation and imports from Victoria, notably since South Australia's last coal-fired units closed in 2016 and its main gas-fired power plants were mothballed. Moreover, South Australia has to deal with lower baseload power imports from Victoria (where the largest coal plant, Hazelwood, closed in March 2017).

The increasing short-term interdependency of gas and power security, the possibility of reliability shortfalls in 2018 in New South Wales, Victoria and South Australia at regional level (see AEMO, September 2017), and a projected rise in variable energy sources (gas, wind and solar PV) mean that managing short-term variations in production and demand has become a core priority for the states concerned and AEMO as market and system operator of the NEM. Reliability and security are now high on the agenda of governments and regulatory institutions. AEMO has recently highlighted the increasing tightening of the domestic gas supply-demand balance and its potential impact on the electricity generation system:

- Declining gas production may result in insufficient gas being available to meet the projected demand for gas from gas-fired power plants from the summer of 2018/19, potentially resulting in electricity supply shortfalls between 2019 and 2020 (projected to occur in Victoria, New South Wales and South Australia).
- Such shortages would affect cost and reliability of electricity supply, to an extent that would breach the NEM reliability standard. Moreover, gas can support the system integration of variable renewable energy sources, along with battery storage and pumped hydro.
- However, the economics of gas-fired power plants are being challenged by high gas prices and tight supply. Hence, maintaining system security is becoming more challenging, which is increasing the risk of supply shortfalls in both gas and electricity. AEMO notes that the risk of short-term interruptions to electricity demand is likely to increase should gas-fired generation be unavailable due to difficulties in sourcing gas.

Increased gas production and alternatives to gas-fired power would mitigate the risk of gas supply shortfalls. However, new gas developments are expensive and increasingly challenged by social acceptability, with moratoria in Victoria, New South Wales and South Australia.

In order to address this issue, the Australian government is considering extending the powers of AEMO to procure and enter into commercial contracts with existing gas-fired power generators. In June 2017 the Australian government introduced draft legislation with obligations on gas producers and LNG companies to supply the domestic market in the event of a shortfall by ministerial decision – this aspect is further detailed in chapter 3.

Impact of the Qatar diplomatic crisis

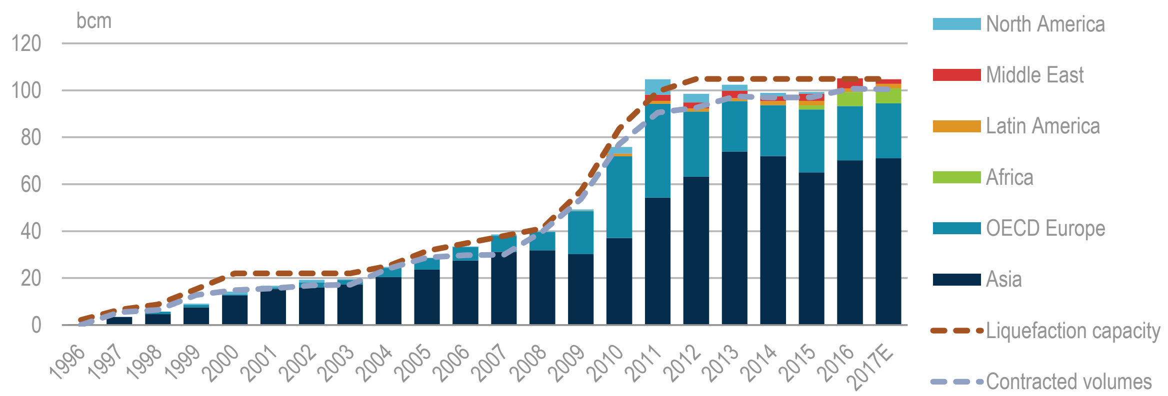
Qatar is the world's largest producer and exporter of LNG, producing around 100 bcm in 2016, and is also a major pipeline gas exporter to the United Arab Emirates and Oman, exporting 17 bcm there in 2016. At the beginning of June 2017, several countries broke off diplomatic relations with Qatar, including three fellow Gulf Cooperation Council (GCC) members, Saudi Arabia, the United Arab Emirates and Bahrain, as well as Egypt. The GCC also includes Kuwait and Oman, but they have not suspended relations with Qatar. To isolate Qatar economically and politically, those countries deciding to break off relations took multiple measures, which included a ban on receiving Qatari vessels; this ban may result in natural gas and oil supply disruptions. This section discusses the impacts of the crisis on global gas markets.

Qatari natural gas production and export

Qatar has an estimated 25 trillion cubic metres (tcm) of gas reserves, 14% of the global total. The small peninsula has the third-largest conventional gas reserves after Russia and Iran, nearly all of which are located in the offshore North Field, part of a structure that extends into Iran, where it is known as South Pars. Qatar early on recognised the value of developing its natural gas reserves and started exporting it as LNG in 1996 (Figure 1.17) and by pipeline to the United Arab Emirates in 2002.

After sending out the first LNG cargo to Japan in 1996, Qatar kept investing in LNG facilities and expanding its export capacity. Massive capacity additions from 2009 to 2011 have made Qatar the world's largest LNG exporter, with 105 bcm export capacity, and it has supplied around 30% of global LNG since 2011. By pipeline, Qatar's export to the United Arab Emirates averaged 17 bcm per year between 2010 and 2016. It has also exported via pipeline to Oman since 2008, with a volume of 2 bcm per year since 2010.

Figure 1.17 • Qatari LNG export volumes, liquefaction capacity and contracted volumes, 1996-2017

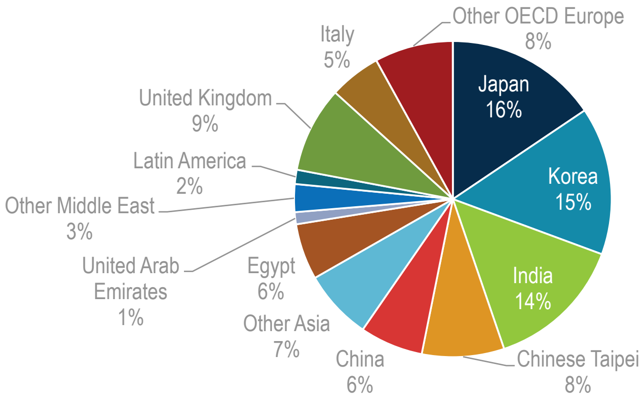


Note: LNG export volumes in 2017 are estimates based on the actual volume traded by July 2017.

Sources: IEA (2017b), *Natural Gas Information* (database), www.iea.org/statistics/; ICIS (2017a), *ICIS LNG Edge*, www.icis.com/energy/liquefied-natural-gas/lng-edge (subscription required).

More than 90% of Qatar's LNG production is committed as part of supply purchase arrangements signed between 2011 and 2017. Each year since 2011, Qatar has offered significant flexibility to the global LNG market with its uncontracted supply capacity of around 10 bcm per year and destination-free contracts of around 30 bcm per year. Some of these flexible volumes were shipped to meet unexpected demand around the world, as was the case after the 2011 Great East Japan Earthquake. The International Energy Agency (IEA) *Global Gas Security Review 2016* (IEA, 2016a) indicated that Qatar has been the major provider of flexible LNG supply since 2011.

Figure 1.18 • Destination of Qatari LNG exports in 2016



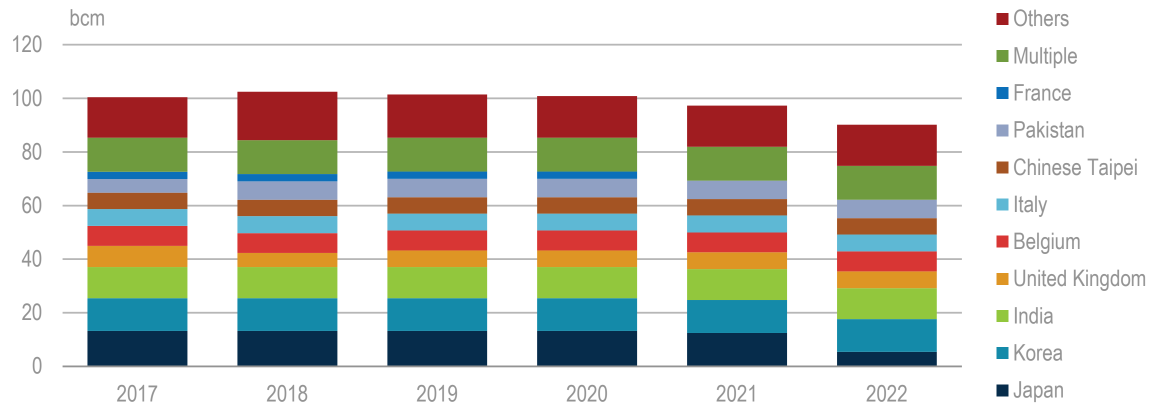
Source: ICIS (2017a), *ICIS LNG Edge*, www.icis.com/energy/liquefied-natural-gas/lng-edge (subscription required).

From the beginning of the Qatari LNG export history, the main destination has been Asia followed by Europe, although at the time of FIDs, volumes were destined in equal share to Asia, Europe and (then importing) North America. Since 2011, two-thirds of Qatari LNG has been exported to Asia and one-quarter to Europe. The United Arab Emirates started importing Qatari LNG from 2010, with Egypt following suit from 2015. Qatar has proven highly credible in terms of the load factor of its liquefaction facilities. Since 2011, Qatar has operated its LNG export facility at close to full load, accounting for 30% of the global LNG trade. By doing so, it has met not only its term contract obligations, but also provided flexible spot volumes to sustain the global LNG market. In 2016, the traditional five Asian LNG importers, Japan, Korea, India, Chinese Taipei and the People's Republic of China, accounted for 60% of Qatar's LNG exports (Figure 1.18). In Europe, because of lower LNG demand, import volumes from Qatar were around half their 2011 level, at 23 bcm in 2016. LNG exports from Qatar to Egypt and the United Arab Emirates comprised 63% and 31% of those countries' total LNG imports and 18% and 1.8% of domestic gas consumption, respectively, in 2016.

As described earlier, Qatar has more than 90% of its LNG production volumes committed under term contracts. More than half of its contracted volumes are assigned to Asian importers, such as Japan, Korea, India and Chinese Taipei, and one-third of them are with European countries such as the United Kingdom, Belgium, Italy and France (Figure 1.19).

The Qatari LNG supply portfolio includes markets which are heavily dependent on LNG, notably Japan, Korea and Chinese Taipei, and these account for around 30 bcm of contracts with Qatar. By 2022, around 10 bcm of contracts will expire and most of these are with Japan. Because of Japan's over-contracted position, these contracts appear unlikely to be renewed in their current form. Moreover, Qatar Petroleum reaffirmed its commitment to invest in a planned expansion of the North Field, announcing plans to ramp up LNG production by 30% by 2022-24, reaching total liquefaction capacity of around 135 bcm per year. In total, Qatar might have around 45 bcm of capacity available in the market. Contracts signed by other traditional LNG exporters, such as Australia, Indonesia and Malaysia, totalling around 100 bcm per year, will also expire by 2022. These contract expiries will take place when the global LNG market faces a situation of significant oversupply in the coming years due to the second big wave of new liquefaction capacities in Australia and the United States. Therefore, Qatar will be seeking to obtain new deals in a very competitive market and, if it meets customers' demands for various flexibilities, its new business deals would enhance overall gas security of supply, not only with upward volume flexibility, but also with destination flexibility.

Figure 1.19 • Qatari LNG contract volumes by destination, 2017-22

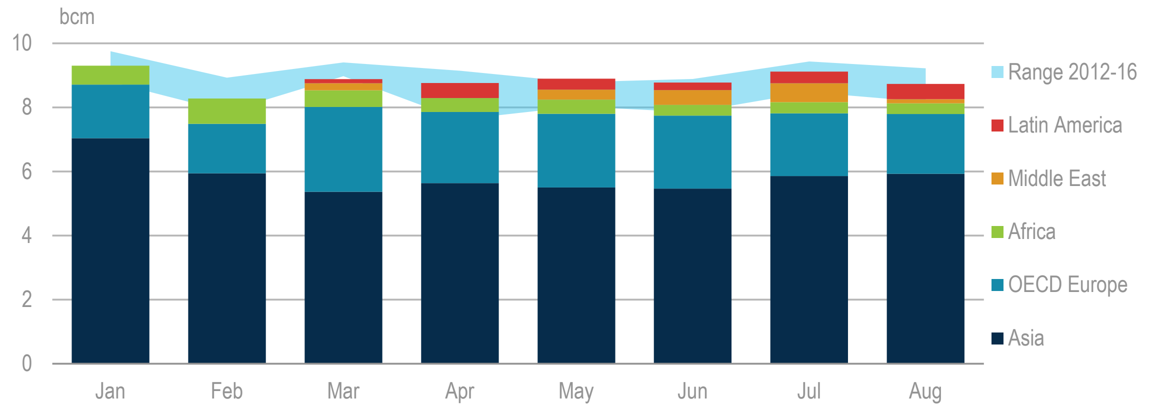


As Qatar is the world's largest LNG exporter, the impact of any possible export disruption on the global LNG market could be significant.

Evolution of Qatari LNG exports since the tension started

After the tension started, the IEA observed the impact of the Qatar diplomatic crisis on the global LNG market to meet its natural gas security mandate given at the IEA Ministerial meeting in 2015. Comparing the range of monthly LNG export volumes seen in the past five years, Qatar has continued to export its LNG within the range. Qatari LNG flows to major markets in Asia and Europe appear to be unaffected (Figure 1.20). Most of the Qatari LNG cargoes for Europe go through the Suez Canal in Egypt, but the passage of Qatari-flagged or Qatari-owned vessels through the Suez Canal is not expected to be affected since Egypt is bound by international maritime law to allow free passage of seaborne vessels. To date, supplies to Europe via the Suez Canal appear unaffected.

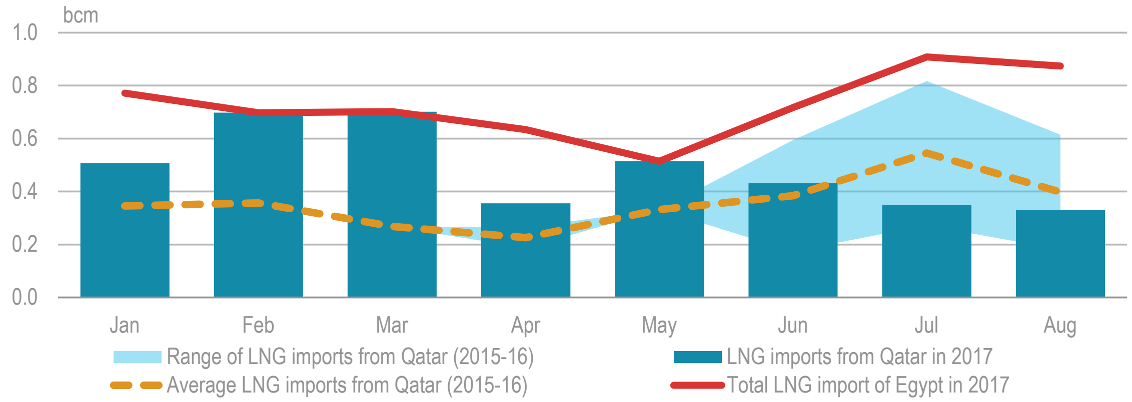
Figure 1.20 • Monthly Qatari LNG export volumes by region, 2012-17



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

Egypt has banned Qatari-flagged or Qatari-owned vessels from its ports, but has continued to import LNG from Qatar under short-term contracts with third-party traders such as Glencore and Gunvor, which charter non-Qatari vessels. In the first five months of 2017, significantly increased Qatari volumes arrived, but from June, LNG coming from Algeria, Angola and Nigeria increased (Figure 1.21).

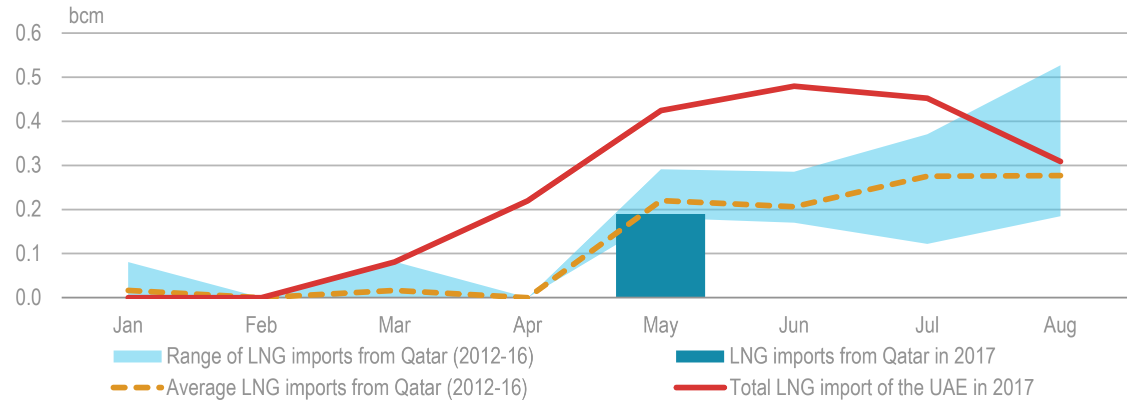
Figure 1.21 • Egyptian LNG imports, 2015-17



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

The United Arab Emirates has one long-term contract, for 1 bcm of Qatari LNG per year, with Shell. Under this contract, around a dozen shipments are expected each year and in fact the country received 11 contracted cargoes in 2016. However, in 2017, it had received only two cargoes by the end of May, and none subsequently at the time of writing (Figure 1.22). Over the past five years, Shell has delivered contracted Qatari LNG to the United Arab Emirates with vessels chartered by Qatargas, and this could be the reason why there have been no LNG imports from Qatar since June 2017. To meet demand since then the United Arab Emirates have increased imports from Algeria, Angola and the United States. In addition to LNG imports from Qatar, the country also imports pipeline gas from Qatar via the Dolphin pipeline. The Dolphin pipeline accounted for 20% of its gas consumption in 2016, 15 bcm out of 75 bcm, and there has been no sign of any supply interruption to date.

Figure 1.22 • United Arab Emirates LNG imports, 2012-17



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

Impact of the Hurricane Harvey on the US gas market and beyond

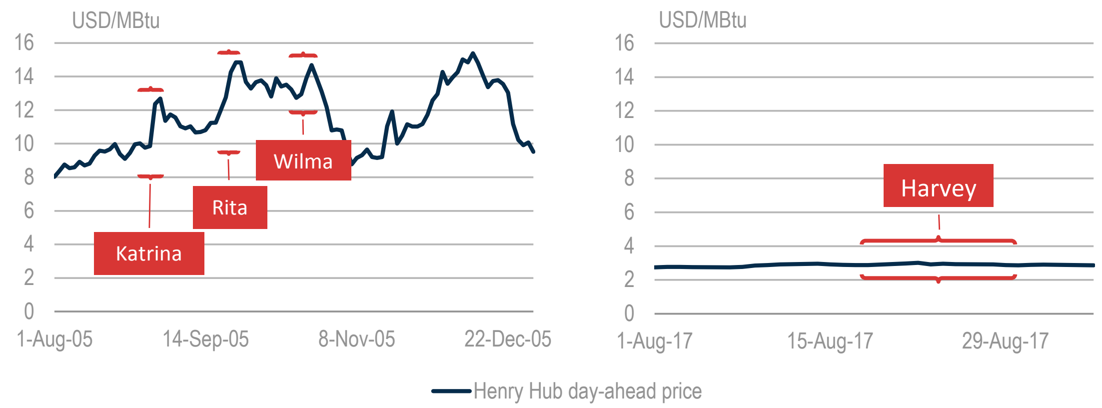
On 25 August 2017 Hurricane Harvey hit Texas, the heart of the US oil and gas industry, as a category 4 hurricane with winds of 209 kilometres per hour, making it the strongest storm to strike the state since 1961.

Unprecedented levels of rainfall and flooding continued during the following days, forcing mass evacuation of Houston, the fourth most populous city in the United States, causing casualties and devastation in the affected region. Companies evacuated personnel from offshore and onshore gas production facilities in the Gulf Coast region, which produced around 150 bcm, or 20%, of yearly US gas production in 2016. This leads to the question of how Harvey affected security of gas supply both to Mexico and the global market, given that the United States started to export LNG in February 2016.

Harvey's arrival reminded the region of Hurricanes Katrina, Rita and Wilma 12 years ago, which had significant consequences in terms of production shut-ins, resulting in price spikes between late August and October 2005 (Figure 1.23). At that point in time, the surge of US shale gas had not started – natural gas was consumed in the Gulf Coast or transported to other demand areas in the United States. Offshore gas production in the Gulf of Mexico had a significant share of total US production (17%), which resulted in significant impacts for the US gas market when the hurricanes forced operators to repeatedly shut-in production. Severe damage to infrastructure (power, pipeline and storage) exacerbated the disruption. The surge of US shale gas has diversified production in the country and shifted gas flows, as virtually all incremental US production in the subsequent years has come from the Marcellus and Utica plays in the Appalachian Basin (Ohio, Pennsylvania and West Virginia currently amount to around 220 bcm annually).

In contrast to 2005, Henry Hub spot prices were very stable when Harvey disrupted production. Although up to half of Eagle Ford onshore gas production was shut in for a few days and offshore production saw a peak loss of around 26%, US gas production was much more robust. This reflected the shale gas revolution, which has created a second production pillar in the Northeast of the United States. New pipeline capacity connects the Appalachian Basin not only with Canada and the Midwest, but also with the Atlantic and Gulf coasts to supply these regions with highly competitive shale gas. Furthermore, in the aftermath of Hurricane Harvey, gas demand has been lower than normal as (industrial) gas demand decreased due to shut-ins of gas processing plants and/or damage to the infrastructure.

Figure 1.23 • Henry Hub spot prices during Hurricanes Katrina, Rita, Wilma and Harvey

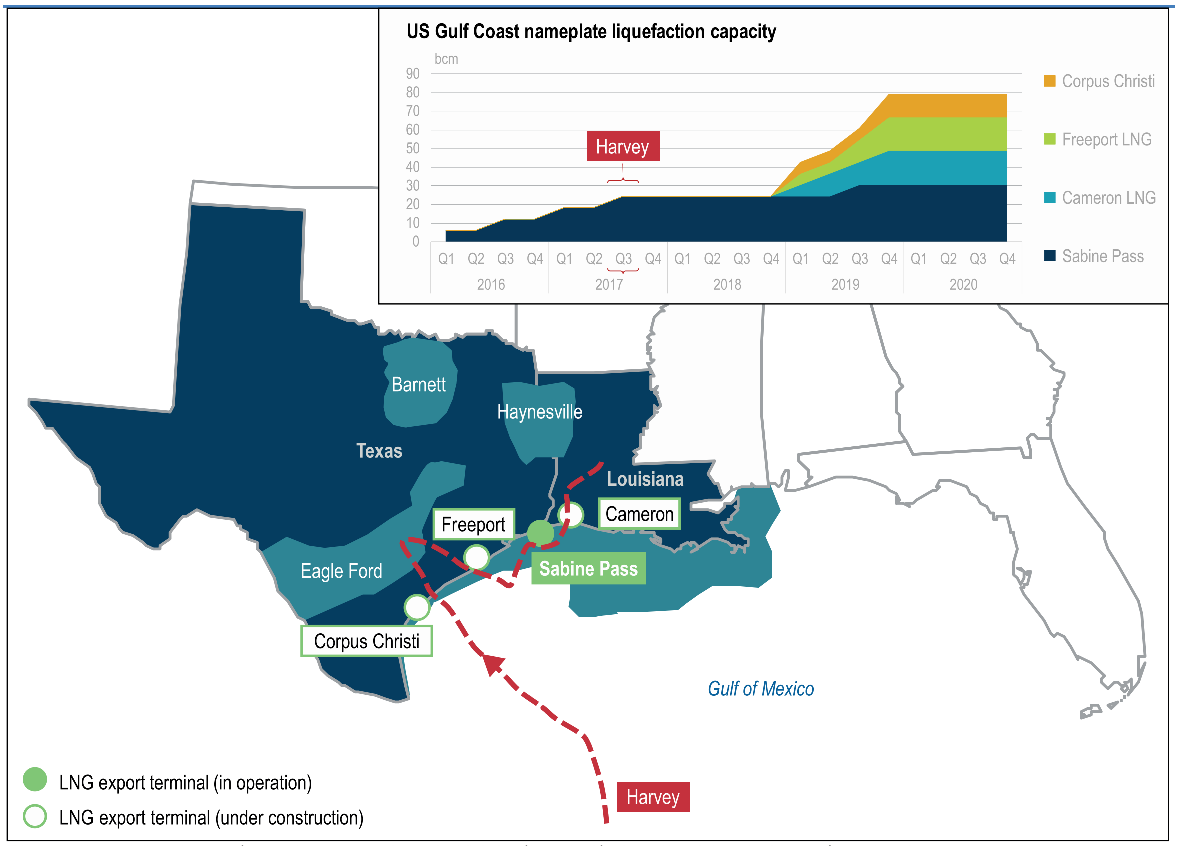


Source: Bloomberg Finance LP.

In addition, lower temperatures led to lower gas-fired power production used for air-conditioning in commercial and residential buildings. However, the Sabine Pass LNG export terminal was closed for some two weeks, still the only liquefaction terminal on the Gulf Coast. Additional liquefaction terminals (Cameron LNG, Freeport LNG and Corpus Christi Liquefaction) will start operation at the end of this decade and may even increase the significance of the Gulf Coast as a link between the US and global LNG markets (see Map 1.2).

Almost all US LNG capacity currently under development will be located in an area from western Louisiana to Corpus Christi in Texas, totalling 80 bcm (in addition, Cove Point LNG and Elba Liquefaction will add a further yearly liquefaction capacity of 10 bcm). Clearly, the Gulf Coast is vulnerable to disruption, potentially for weeks at a time. During Hurricane Harvey, the Sabine Pass terminal stopped loading LNG vessels for 12 days. In the meantime 10 LNG vessels were waiting in the Gulf of Mexico to be loaded. This number could increase substantially in the future with liquefaction capacity ramping up in the Gulf Coast (one LNG vessel represents a volume of around 0.1 bcm) resulting in a delay of cargoes for the relevant LNG importers.

Map 1.2 • US Gulf Coast increasingly connected to the global LNG market



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.

Sources: EIA (2017a), *Natural Gas Consumption by End Use* (database), www.eia.gov/dnav/ng/ng_cons_sum_dcu_SLA_a.htm; EIA (2017b), *Natural Dry Gas Production* (database), www.eia.gov/energyexplained/data/U.S.%20dry%20shale%20gas%20production.xlsx; ICIS (2017a), *ICIS LNG Edge*, www.icis.com/energy/liquefied-natural-gas/lng-edge (subscription required).

As 2005 has shown, multiple destructive hurricanes are possible during the peak hurricane season, which usually lasts from August through October. Importers relying on US cargoes during this period would be particularly affected if they cannot source gas from other supply sources or implement demand-side measures. For instance, US LNG is becoming an increasingly important source for markets in Latin America.

Chile, for example, is heavily dependent on LNG imports: they represented 4.4 bcm in 2016, of which US LNG accounted for 17% or 0.76 bcm. Pipeline imports from Argentina have virtually dropped to zero since June 2015 and Chile even started to re-export gas to Argentina from its regasification terminals. Indigenous production only has a share of 23% of yearly supplies

(1.2 bcm). Against this backdrop, an interruption of LNG supplies would directly affect gas consumers, with gas-fired power generation, for instance, accounting for around 50% of total gas demand and being closely connected to the LNG industry.

Particularly in the northern part of Chile, other thermal power production (primarily coal) would need to fill the gap in case gas-fired power production were to suffer from interrupted LNG supplies. The United States has shown that its flexible market in both gas and power can ride out severe disruptions; however, exports could be heavily affected for weeks or potentially longer, both for LNG and pipeline exports to Mexico.

Due to a declining national gas production and a soaring demand in the power sector, by 2022, about half of Mexican gas needs will be sourced from the Texas/Gulf region, and the connection between the United States and Mexico will be even stronger as new pipeline capacity of around 40 bcm will be added to the existing 100 bcm (see Map 1.3). During Hurricane Harvey, Mexico's Control Centre for Natural Gas (CENAGAS) implemented demand-side measures and requested end users to decrease their consumption for six days in order to protect the integrity of the system. In addition, capacity at the LNG terminals Madero and Manzanillo was used in order to balance interrupted supply from the US border. Mexico's increasing dependency on US pipeline gas will make security of supply measures indispensable in the instance of hurricanes once again affecting US imports.

Map 1.3 • Gas pipeline connections from the US to Mexico

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

Source: EIA (2016), *"New U.S. border-crossing pipelines bring shale gas to more regions in Mexico"*, www.eia.gov/todayinenergy/detail.php?id=28972.

This is not the first time that the natural gas system in Mexico is affected by events in the US: The explosion of a Kinder Morgan gas processing plant in Texas in July 2016 and resulting constraints of relevant pipeline segments connecting the US with Mexico led to gas shortages in Mexico and elucidated how vulnerable Mexico currently is to interruptions of US gas imports. Hence, security of supply will be needed to be carefully assessed, in particular to address the issue on how Mexico will be able to mitigate interruptions like those caused by Hurricane Harvey or the ones seen in summer 2016.

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2. Update on LNG market flexibility metrics

The market for liquefied natural gas (LNG) is growing in volume, with nearly 200 billion cubic metres (bcm) of liquefaction capacity additions anticipated by 2022, in suppliers, with the emergence of Australia and the United States, and in new markets, with 47 countries and territories expected to import LNG by 2022 compared to 38 in 2016. The emergence of the United States as a major player in global LNG trade is beginning to have a major impact both in terms of the volumes of LNG available to the market, and also in respect of the flexible conditions under which LNG is made available to the market. The sale of gas free on board (FOB), the absence of destination clauses, pricing formulas based on gas-to-gas competition, and the scalability of new investments in both liquefaction (with modular trains) and regasification (with floating storage and regasification units [FSRUs] – see Box 4.2 in chapter 4) offer growing flexibility that can improve global gas security.

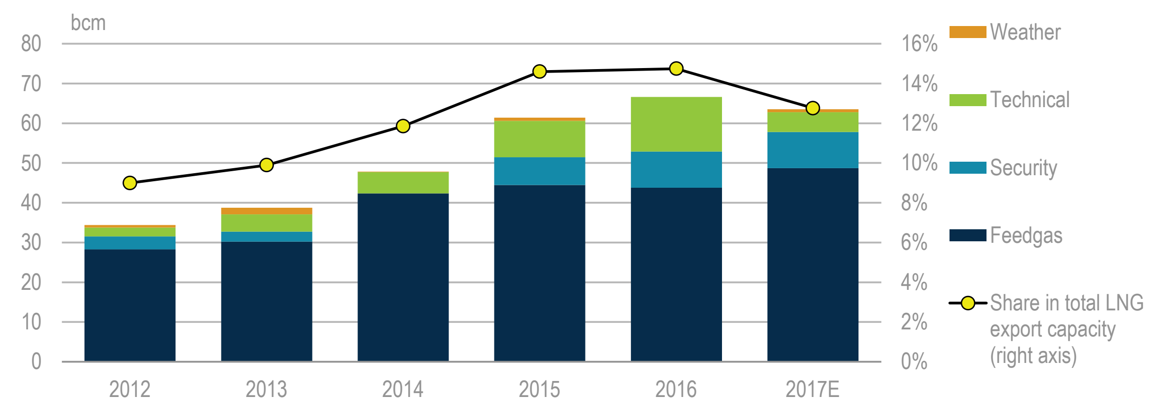
Yet this shift in LNG markets remains gradual. New contracts are still entered into with destination clauses, oil indexation pricing formulas and with limited reliance on spot trade. In this transitional context, the evolution of flexibility needs to be monitored with specific metrics to properly assess market evolution and the resulting gas security provided by such flexibility.

Last year's report examined two key metrics to help assess LNG flexibility: flexibility provided by liquefaction infrastructure with available capacity, and contract flexibility, as in the ability of contracting parties to supply additional LNG or shift the destination of LNG delivery. This chapter provides an update of last year's analysis on both metrics, and puts contract flexibility in perspective of medium-term market evolution, based on market forecast provided by the latest IEA *Gas 2017* report (IEA, 2017).

Similar to last year's report, the analysis conducted in this book is based on detailed contractual positions of importers and exporters and their actual traded volumes, based on the International Energy Agency (IEA) internal LNG contract database. No specific assumptions were made on existing contract renewals – unless publicly and explicitly stated by the contract parties. Such volumes are hence considered as "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.

Analysis of 2016 LNG supply availability

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



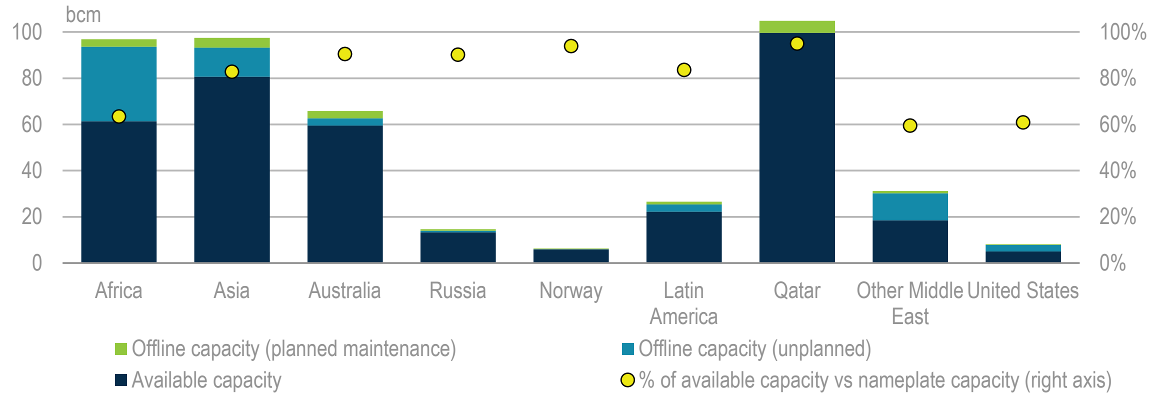
Source: IEA analysis based on ICIS (2017), *ICIS LNG Edge*, www.icis.com/energy/liquefied-natural-gas/lng-edge (subscription required).

Overall capacity availability including planned maintenance, at 81% in 2016, is at the same level as the previous year, but remains significantly lower than the 86% recorded in 2012. Looking at outages by cause, gas supply shortages are responsible for two thirds (66%), followed by technical issues (20%) and security (14%) (Figure 2.1).

Capacity availability varies by region (Figure 2.2). During 2016 it was particularly problematic in Africa, with only 63% availability due to lack of gas supply in Egypt and technical issues in Angola. Gas availability at Kenai, Alaska, also explains the relatively low figure (61%) for the United States. In the Middle East, Yemen LNG is still closed due to civil war. In Asia, 30% of Indonesian capacity was offline (more than half caused by feed gas issues). Australia had lower availability (90% in 2016 against 93% in 2015) owing primarily to the delays in ramping up production at Gorgon LNG.

By contrast, Qatar, which supplies 30% of the world's LNG, had 95% availability in 2016. The Russian Federation and Norway, with over 90%, fared nearly as well – albeit with one single operational plant in each of these two countries.

Figure 2.2 • LNG offline capacity, available capacity and availability factor by region and country in 2016



Source: IEA analysis based on ICIS (2017), *ICIS LNG Edge*, www.icis.com/energy/liquefied-natural-gas/lng-edge (subscription required).

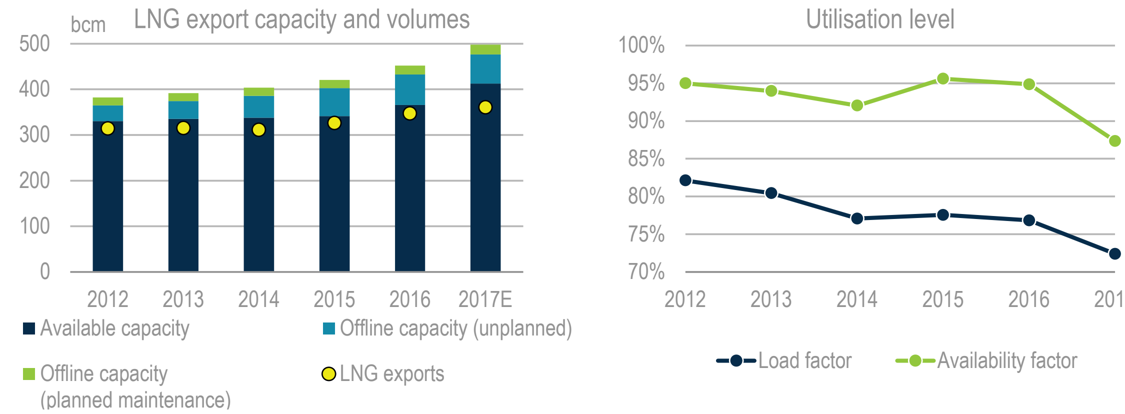
Once the effectively available capacity is known, it is possible to look at the 2016 export volumes and compute the following factors:

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

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.

Figure 2.3 shows that the trend in recent years, for offline capacity to increase at nearly the same rate as capacity being added, was not observed in 2016: the utilisation rate defined by the availability factor, which stood at 96% in 2015, almost stagnated at 95% in 2016, and is expected to decrease to 87% for 2017. This can be explained by a combination of factors, with increasing new capacity development rate (13% y-o-y expected for 2017 against 7% in 2016 and 1% in 2015) in parallel with more modest trade growth (4% expected for 2017, against 6% in 2016 and 5% in 2015). As further capacity growth in the coming years is mostly expected to come from private operators in Australia and the United States, the industry will need to operate with a high availability factor to cover its short-run marginal costs in a low gas price environment. This ability of the industry to return to high levels of availability seen in the past can, in turn, enhance supply security by providing fewer unexpected supply outages.

Figure 2.3 • LNG offline capacity, available capacity, LNG imports and availability factor, 2012-17

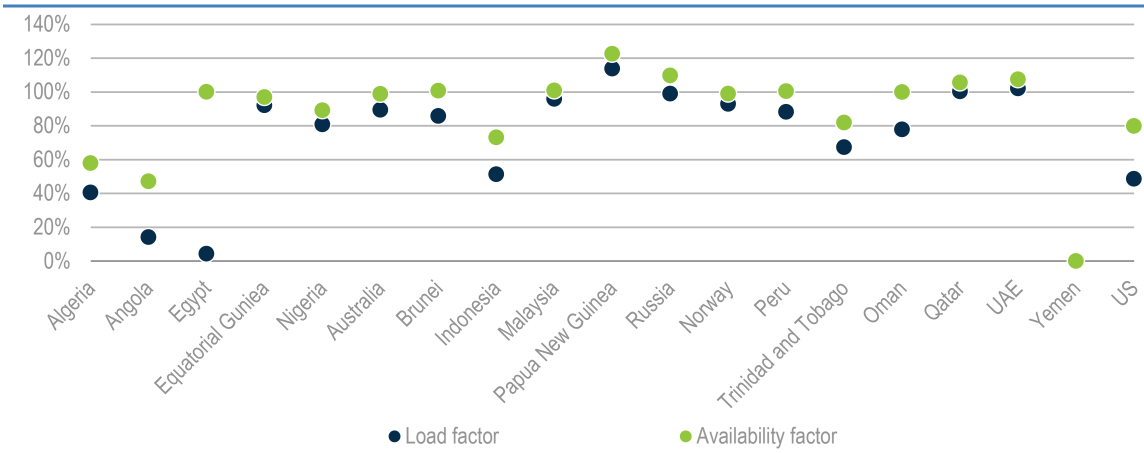


Source: IEA analysis based on ICIS (2017), *ICIS LNG Edge*, www.icis.com/energy/liquefied-natural-gas/lng-edge (subscription required).

The gap between average load and availability factors (77% and 95% respectively for 2016) shows how relevant these disruptions are to LNG plant performance. The high availability factor shows that – as for last year's report – LNG production had limited ability to increase output to respond to a demand shock despite the increase in supply of over 30 bcm. The extent to which the availability factor changes over the coming years, as supply capacity expands more rapidly than demand, will be monitored closely. On a country basis (Figure 2.4),[3] two countries – Egypt and Angola – exhibit major differences between their load and availability factors:

- Egypt exported 0.7 bcm in 2016, accounting for 100% of its available capacity (the Damietta plant is still closed).
- Angola resumed exports in the first half of 2016 after a two-year shutdown, but its single plant was shut again for scheduled maintenance for another two months.

Figure 2.4 • LNG export utilisation level by country in 2016



Note: Papua New Guinea actually produced above its nameplate capacity, which explains the 115% load factor.
Source: IEA analysis based on ICIS (2017), *ICIS LNG Edge*, www.icis.com/energy/liquefied-natural-gas/lng-edge (subscription required).

[3] Supplies from Libya went offline in 2011 and are now not included in the worldwide nameplate capacity.

Impacts of 2016 supply issues

Following this broad view of 2016, the analysis focuses on four countries – Algeria, Angola, Egypt and Yemen – which exhibited the lowest load factors in 2016, plus Australia. While Australia did not suffer from supply issues in 2016, the delay to the start-up of the Gorgon LNG plant led to reduced output for 2016. Table 2.1 provides a breakdown of output for these countries between contracted and uncontracted deliveries, compared with nameplate capacity and contracted volumes.

Table 2.1 • Impact of LNG supply issues in four countries plus delays in Australia (in bcm unless stated)

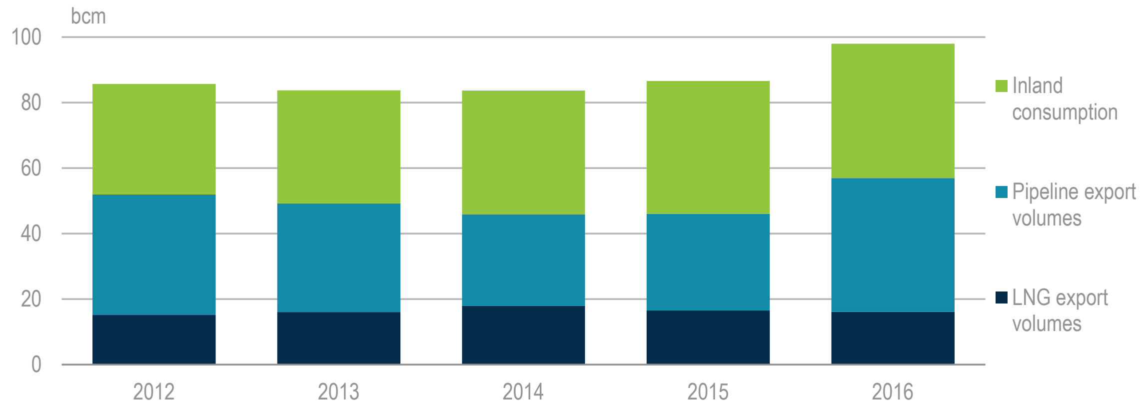
	Algeria	Angola	Australia	Egypt	Yemen
Nameplate capacity (bcm)	**38.4**	**7.1**	**65.8**	**16.6**	**9.1**
Of which contracted	19.9	0.0	53.4	15.3	9.1
2016 deliveries	**15.5**	**1.0**	**58.8**	**0.7**	**0.0**
Of which contracted	14.6	0.0	51.1	0.5	0.0
Of which spot	0.9	1.0	7.7	0.2	0.0
Share of contracts delivered (%)	**73%**	**N/A**	**96%**	**3%**	**0%**

Note: N/A = not applicable.
Source: IEA analysis based on ICIS (2017), *ICIS LNG Edge*, www.icis.com/energy/liquefied-natural-gas/lng-edge (subscription required).

The results from Table 2.1 demonstrate the different situations experienced by these countries:

- Angola had no contracted volumes yet as of 2016, partly owing to repeated technical issues since start-up in 2013.
- Yemen and Egypt experienced difficulty, as most of their supply is contracted, but few (in the case of Egypt) or no (for Yemen) deliveries took place.

Figure 2.5 • LNG export, pipeline export and inland consumption in Algeria, 2012-16



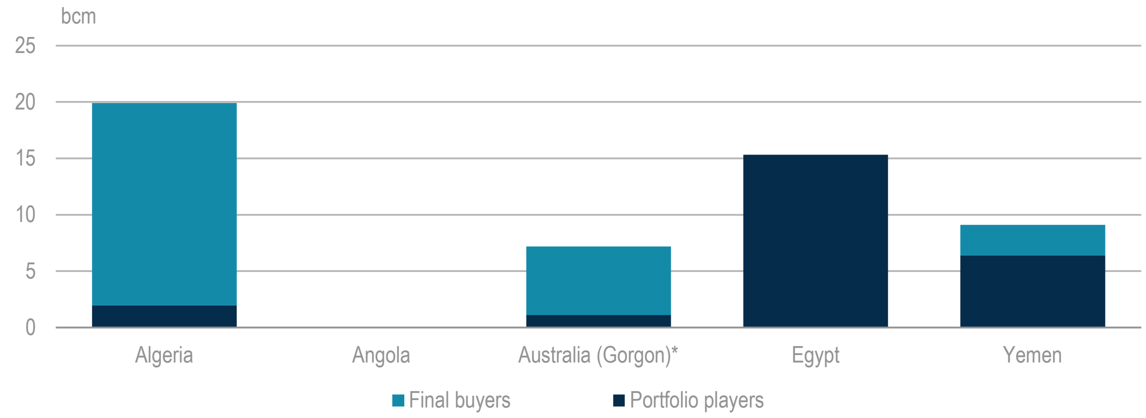
Source: IEA (2017), *Natural Gas Information* (database), www.iea.org/statistics/.

- With Algerian LNG exports further declining (down 5.7% in 2016 against 2015, after a fall of 4.6% in 2015 versus 2014), actual LNG export volumes under contract were below contractual requirements. The closure of Skikda LNG plant for maintenance in January 2017 has also had some impacts on southern European gas balancing, as discussed in Chapter 1. The situation is actually more complex, as Sonatrach, the state-owned energy company, has proved increasingly flexible when renegotiating its pipeline gas contracts (Eni, 2016), resulting in a sharp rise in its pipeline exports in 2016 (perhaps to compensate for previous years' lower volumes; see Figure 2.5). If Algeria also wishes to increase its contracted LNG exports, Sonatrach will most probably need to align with its competitors and offer similar contract flexibility.

- For Australia, the main disruption was related to delays with commissioning the Gorgon facility. While contracts may not have been affected (depending on the contract effective date), it may well have forced customers who expected to take delivery of LNG from Gorgon in 2016 to seek other supplies.

Despite these issues, the global oversupply situation resulted in buyers being able to find alternative sources of supply, without causing physical or price tensions. To better understand buyers' response, Figure 2.6 provides a breakdown of sales per type of buyer (portfolio players and final buyers).

Figure 2.6 • LNG contracts with portfolio players and final buyers for selected countries/projects in 2016



* 2016 volumes according to assumed contract start-up dates.

It appears that portfolio players were mainly exposed to 2016 supply issues from Egypt and Yemen. In principle, portfolio players are more likely to mitigate such supply issues, as they aggregate supplies from various sources/projects in order to serve their various customers. For final buyers, contracting with portfolio players provides some security against force majeure risks, and can be seen as an alternative to diversifying their own bilateral supply portfolio to mitigate risks.

LNG market flexibility – technology and participants

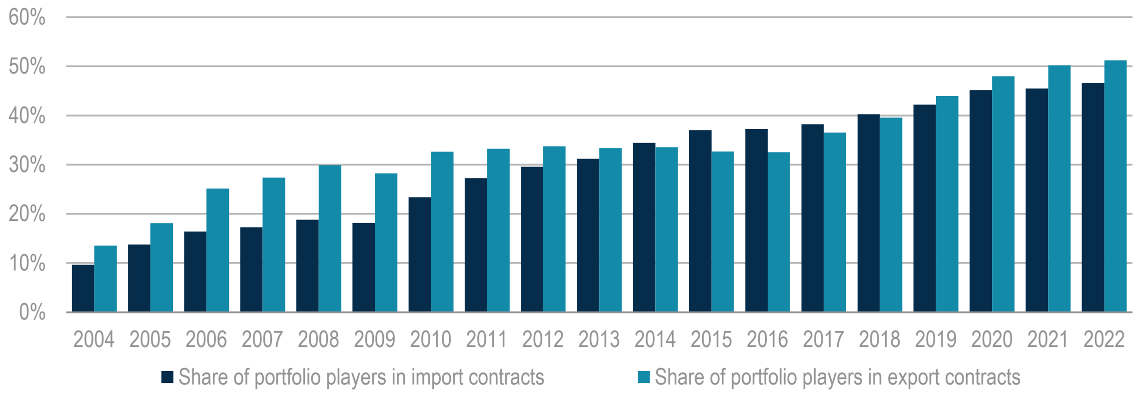
This desire for increased flexibility on the demand side of the LNG market makes it more difficult to raise capital for very large, long lead time and capital-intensive liquefaction projects. It thus encourages developers to seek out new liquefaction technology that offers, at perhaps a slightly higher unit cost of production, a more flexible technology. Two of the most recent LNG developments are indicative of this investment shift. The Coral project in Mozambique uses the new floating LNG (FLNG) technology and is due to supply around 4.5 bcm annually when it is brought into service. The newly sanctioned US project at Elba Island is a two-phase project with ten small modular liquefaction facilities: six trains for the first phase in 2018; and four trains for the second phase by 2019. Similar small-train modular technology may be deployed in other potential projects, such as Tellurian's 35 bcm Driftwood LNG project near Lake Charles (composed of 20 modules).

The *2016 Global Gas Security Review* (IEA, 2016) found that, even if LNG production was mostly operating at high availability (the average availability rate for liquefaction plant is 95%), the flexibility of the LNG market came from uncontracted LNG supplies, diversions including reloads, and aggregators (known in the LNG market as portfolio players).

Portfolio players, as discussed in last year's report, aggregate supplies from various sources/projects that they resell to various customers. By acting as a counterparty to LNG developers, portfolio players take on the risk of being able to find a buyer for their LNG. For final customers, relying on portfolio players to supply LNG helps mitigate force majeure risks.

Portfolio players currently account for more than a quarter of the LNG market, but their impact on flexibility is complex. As part of their own risk mitigation strategy, they try to buy with destination flexibility while selling with limited flexibility to their customers. The share of portfolio players is expected to grow substantially over the coming years (Figure 2.7).

Figure 2.7 • Share of portfolio players in LNG market, 2004-22



The recent arrival of trading houses on this market is also worth noting. Thanks to a more liquid market, traders are entering the LNG space, providing additional flexibility and contributing to market diversification towards new importing actors with weaker credit worthiness than most of those served by traditional suppliers.

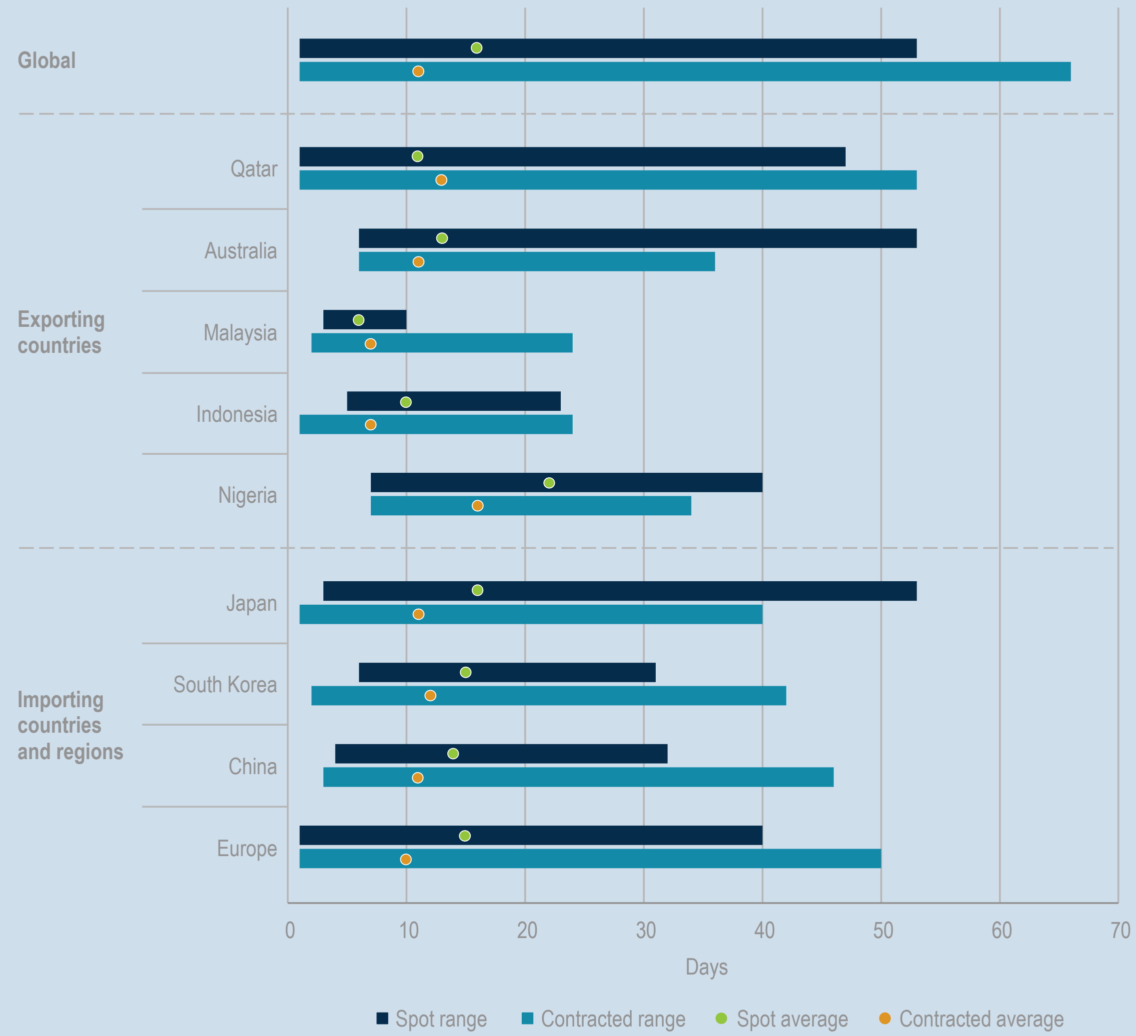
The development of LNG trade and increasing number of LNG carriers at sea would also account for extra flexibility available for the market, although appropriate timeliness of supply could remain an issue (Box 2.1).

Box 2.1 • LNG shipping time and LNG on the water

As noted in *Global Gas Security Review 2016* (IEA, 2016), "In the event of a supply disruption or a demand shock, LNG trade flows would rapidly shift so that gas can reach the regions that needed it most". In respect of volume and destination, flexibility of LNG trade has been increasing over recent years. However, as seen in the case of southern Europe in the period between late 2016 and early 2017, LNG does not shift instantaneously from market to market. Account needs to be taken of the time necessary to negotiate the procurement of additional volumes with sellers, increase LNG production at the liquefaction facilities in some cases, and to ship LNG from export terminals to the destination.

In 2016, one interesting finding on the shipping time between LNG export terminals and import terminals is that spot volumes took longer to reach their destination – five days longer on average – than contracted volumes (Figure 2.8). Buyers and sellers tend to enter into long- or medium-term contracts with the players that are located geographically closer, to obtain a higher netback for the seller and a lower cost for the buyer. In fact, import patterns are largely split regionally between the Atlantic Basin and the Pacific Basin. On the spot market, buyers have to find what is available even if the distance is much further. Particularly in the current environment of low shipping rates, shipping costs as a share of the whole LNG import cost are relatively low and this could also allow the buyers to choose spot cargoes at the further distances. On the import side, LNG cargoes to all major consumers took longer for spot volumes than contracted ones, while on the export side, LNG cargoes from almost all exporters, except for Qatar and Malaysia, took longer for spot LNG delivery than contracted volumes. Qatar's major importers, such as Japan, Korea and European countries, and Malaysia's major importer, Japan, procure much less spot volume from these two exporting countries; other importerscloser by do so instead. In a crisis situation, some buyers will currently have to procure uncontracted LNG and should expect this time difference. As the spot market becomes larger and has more liquidity, or spot cargo chartering rates become higher, the difference in shipping time between spot cargoes and cargoes under contract might become shorter.

Figure 2.8 • Shipping time analysis for LNG cargoes



Source: IEA analysis based on ICIS (2017), *ICIS LNG Edge*, www.icis.com/energy/liquefied-natural-gas/lng-edge (subscription required).

From a different point of view, LNG volumes already at sea could be thought of as one of the instruments to be used in the case of LNG supply disruption or sudden demand increase. In 2016, the average LNG shipping time was 12 days, and given that total LNG traded volumes last year were 353 bcm this means there were an average of 12 bcm of LNG at sea. Traditional LNG importers, such as Japan, Korea and European countries, have a high share of contracted volumes, with average shipping dates of around 10 days, and this indicates that, on average, 3% (10 days/365 days) of all contracted volumes for these markets is always at sea at any one time. Most of these volumes are shipped with a fixed destination, but some remain flexible and in principle can be redirected. As the share of flexible destination contracts increases, this arrangement can be expected to occur more frequently and enhance security of supply.

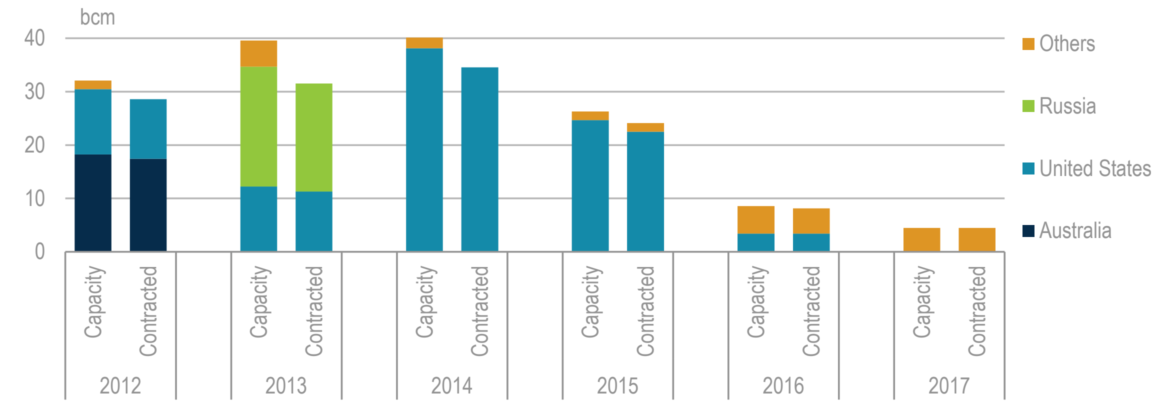
Moving towards a more flexible LNG market?

As the LNG market is growing in volume and diversity of players, contracting strategies are expected to increase in importance to enable the mitigation of uncertainties. Buyers will look for competitiveness and flexibility, both of destination and of quantity.

Continuing need for long-term contracts to secure new FID

For a liquefaction plant to obtain final investment decision (FID), binding long-term contracts covering most of the output (85% on average in 2009-16) have been required as commercial guarantee to finance the investment. As shown in Figure 2.9 below, this trend has continued with 95% of the volumes contracted in 2016, and 100% for the only FID taken so far in 2017, Coral FLNG in Mozambique. In the current well-supplied market environment, it looks clear that risk must be shared between upstream developers and off-takers. Note that Eni, the developer of the Coral facility, chose to contract all 4.6 bcm of its capacity to BP, a portfolio player, rather than trade the LNG directly itself.

Figure 2.9 • Capacity versus contracted volumes for projects obtaining FID, 2012-17



Recent signed contracts show an increasing share of flexible volumes

Following on from the analysis of contractual structures in *Global Gas Security Review 2016* (IEA, 2016), this report provides an update on all contracts signed in 2016. The analysis confirms the previously observed trends (Table 2.2).

First, the share of flexible destination contracts has continued to increase as a trend over the recent past, accounting for almost 42% of newly signed volumes in 2016. Second, the average contract length is decreasing for both fixed and flexible destination contracts – the reduction is more important for fixed destination than for flexible. Third, average quantities (expressed in

ACQ) have stabilised between 2015 and 2016, but remain substantially below values for contracts signed before 2014.

Table 2.2 • Contract evolution by 2016

	Destination flexibility	Average ACQ (bcm)	Average duration (y)	Share with destination flexibility
Signed before 2014	Fixed	1.52	15	60.6%
	Flexible	2.13	17	39.4%
	Total	**1.71**	**16**	**100.0%**
Signed in 2015	Fixed	0.83	7	59.5%
	Flexible	1.23	15	40.5%
	Total	**0.96**	**10**	**100.0%**
Signed in 2016	Fixed	1.14	8	58.1%
	Flexible	1.26	12	41.9%
	Total	**1.19**	**9**	**100.0%**

Notes: ACQ = annual contractual quantity; y = year.

Medium-term flexibility outlook

The desire for flexibility on the part of both supply and demand is a key driver for understanding how markets are changing and how these changes might affect security of supply. As contracts remain the essential link between LNG supply and demand, the evolution of contractual terms has to be closely monitored to properly understand ongoing market changes. For this purpose, LNG sales are split into different categories:

- **Contracted** sales are split in between short term (less than two years), medium term (between two years and five years) and long term (more than five years). Another distinction is made between **flexible destination** – referring to short-, medium- or long-term contracts that are either taken FOB at the liquefaction plant or where the buyer has flexibility in destination – and **fixed destination**, which refers to contracts with delivered ex ship (DES) terms and/or with a destination clause.
- **Spot** or **uncontracted** refers to sales that are not sold under short-, medium- and long-term contracts. By being uncontracted, these volumes are fully flexible and can be directed to the most profitable markets.

With limited new uncontracted supply scheduled to come on stream over the next few years, opportunities for more flexibility would hence come from the contracts themselves. In fact, a greater proportion of new contracts have flexible terms (i.e. no destination clauses), encouraged by both the innovative business models of the US suppliers and policies in the consuming countries and territories. Expiring “legacy” long-term contracts would also provide an opportunity to renegotiate terms towards more flexibility.

Flexible destination contract share to increase substantially up to 2022

The recent evolution observed in new signed contracts, with a growing share of flexibility, impacts mainly future LNG volumes – indeed since 2010, the share of LNG contracted volumes without destination clauses in total trade has hardly changed, being 34% in 2016 (Figure 2.10). This share should increase dramatically to 53% by 2022.

Figure 2.10 • LNG export contract volumes by destination flexibility, 2012-22

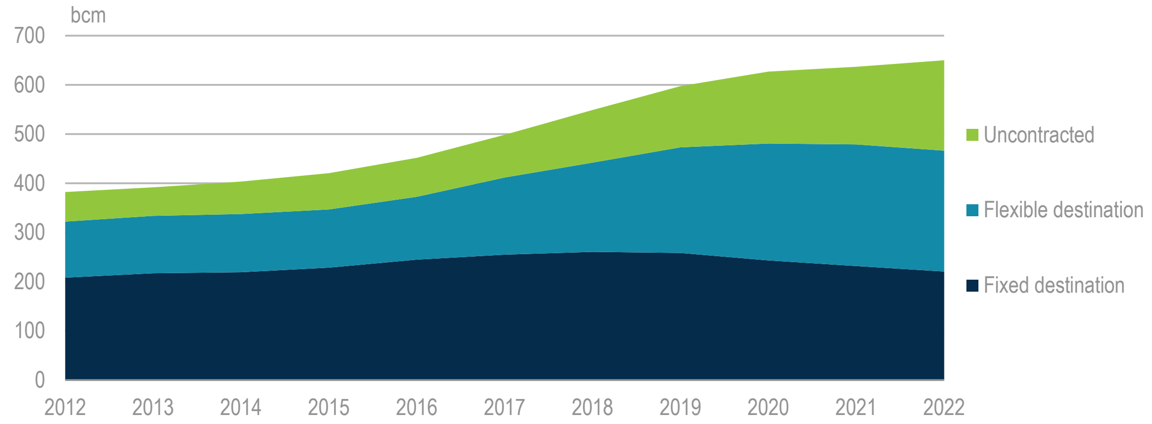
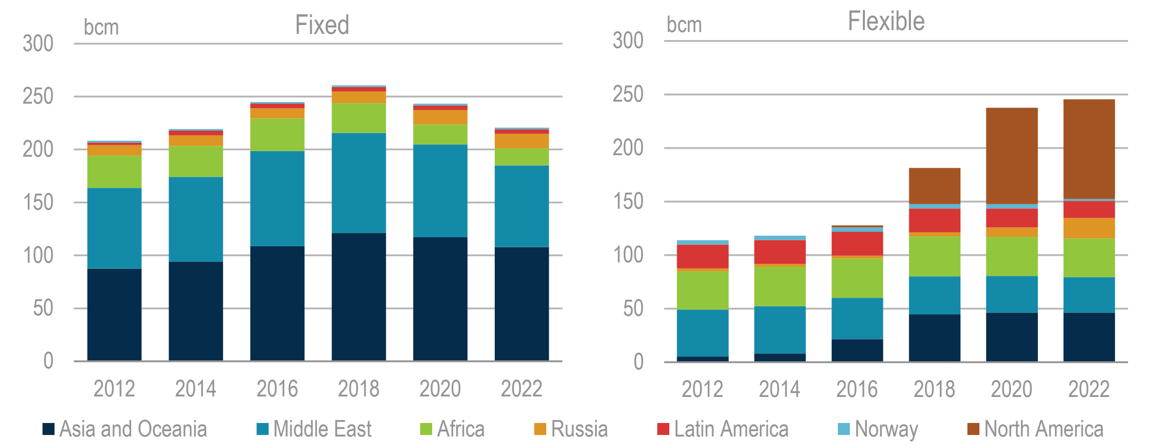


Figure 2.10 is built all things being equal – taking that expiring contracts are not renewed and without any specific assumption on future contracts yet to be signed. On that basis, by 2022 there would be a net reduction of 24 bcm of annual supply with fixed destination clauses, whereas some 118 bcm/y of destination-free LNG contracts would be added. At the time of writing, on an export basis some 69 bcm/y of inflexible contracts would expire between 2017 and 2022, while 38 bcm/y would be added – mostly in 2017 and 2018. On an import basis, 115bcm/y of inflexible contracts would expire over the same period, while 76 bcm/y of new contracts would be added – again mostly in 2017 and 2018. Renegotiations for those expiring contracts – which could be replaced by shorter ones – need to be carefully monitored to see if the above trend towards more flexibility in the medium-term future is reinforced or not.

US exports will provide a major contribution to flexible contracted volumes

From an exporting country viewpoint, the analysis shows that an average 38% of contracted volumes were flexible in 2016. Asian exporters appeared to be the least flexible (12%), while US volumes were fully flexible. As shown previously with newly signed contract analysis, flexible volumes have grown slowly over recent years, yet remained roughly constant as a share of total volumes. This is beginning to change: by 2022, flexible volumes would double to 247 bcm, led by 93 bcm from North America – and mostly the United States (see Figure 2.11 below).

Figure 2.11 • LNG export contract volumes with fixed and flexible destination by region and country, 2012-22

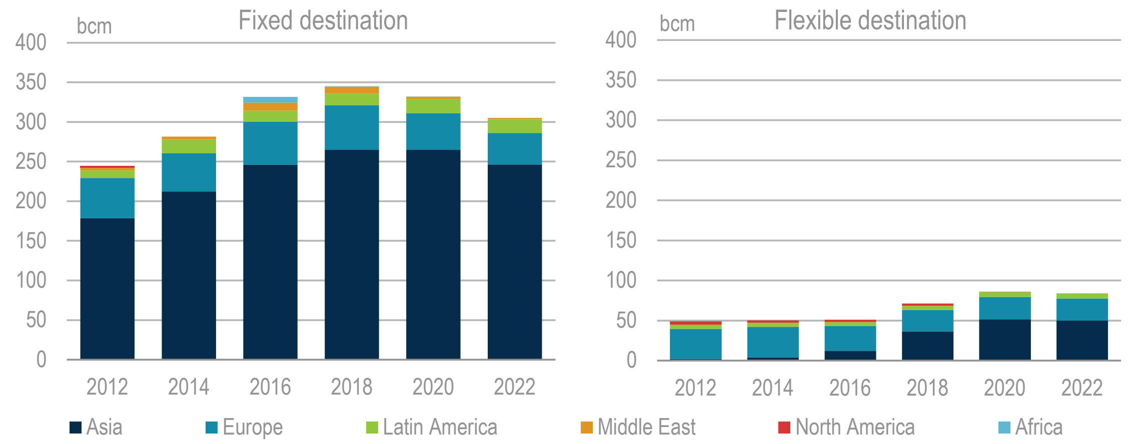


While the United States is the major contributor to the pool of flexible LNG contracts, the current pool of inflexible export contracts can be expected to shrink as contracts expire. The two regions from where most of the contracts (fixed and flexible) are expiring over the coming years are the Middle East (-18 bcm/y) and Africa (-15 bcm/y). The two countries seeing the most contracts expiring in the 2016-22 period are Malaysia (-16 bcm/y, all fixed) and Algeria (-13 bcm/y fixed and -2bcm/y flexible).

Fixed destination to remain a dominant feature, especially for Asian buyers

From the customers' perspective, the share of flexible contracts for importers, at 13% in 2016, is less than half that of exporters – the difference between the two is explained by the portfolio players (see next section). Although the volume of flexible destination contracts almost doubles between 2016 and 2022, it would still account for a minority of currently known import contracts for 2022, with a share of 22% of volumes (Figure 2.12).

Figure 2.12 • LNG import contract volumes with fixed and flexible destination by region, 2012-22



Volumes imported by Asian buyers have currently very limited flexibility, just 5% for 2016; this situation is expected to improve owing to the abovementioned expiry of legacy contracts and development of flexible North American contracts.

The expected growth in flexible imports is happening mainly in Asia. Inflexible volumes are also expected to decrease both in Asia and Europe. Other importing regions – Africa, Latin America and the Middle East – are currently relying on short-term and spot supplies, which are expected to prevail in the near future.

The Asian trend has to be further split between the People's Republic of China and India adding contracted volumes, and Japan, which is currently over-contracted in LNG and is consequently not expected to renew all of its existing inflexible contracts due to expire in the coming years. The recent June 2017 ruling from the Japan Fair Trade Commission highlighting the competition issues raised by flexibility restrictions in LNG contracts – and the subsequent similar enquiry by the Korea Fair Trade Commission (see Box 2.2 below) – are likely to further reinforce this push for increased flexibility among traditional Asian buyers.

Box 2.2 • Japan Fair Trade Commission ruling (2017)

In June 2017, the Japan Fair Trade Commission (JFTC), Japan's anti-monopoly regulator, released its review of the LNG trade, aimed at ensuring fair competition in LNG trades (JFTC, 2017). It stated that competition-restraining clauses or business practices should be eliminated from new or revised LNG contracts, and LNG sellers should review such clauses or business practices in existing contracts. The commission stated that providing destination clauses is likely to violate Japan's Antimonopoly Act. Also, the restrictions on diversion are considered by the commission as highly likely to be a violation of antimonopoly law. The market study shows that 22% of long-term FOB gas contracts have strict restrictions on resale to third parties and 48% of the contracts require the consent of the seller to divert the cargo to a destination other than Japan. Concerning the obligation to pay for contracted volumes even if the customer does not need the LNG, the JFTC stated that in itself such a take-or-pay clause does not pose a competition problem. Only in the case that the seller unilaterally imposes take-or-pay clauses, making use of a bargaining position "superior" to that of the buyer and without offering sufficient negotiation, is such conduct likely to be in violation of the Antimonopoly Act.

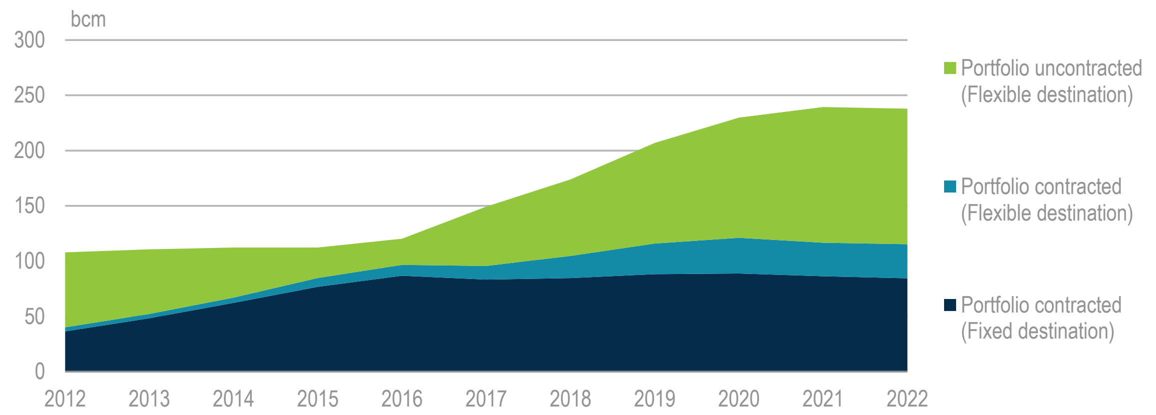
The market study by the JFTC can be considered an important step in the policy of the Japanese government to create more liquidity in a market that has been dominated by a few suppliers. The ruling will also play an important role in future negotiations with suppliers and could result in an increasing number of cargoes being traded by Japanese "buyers". The JFTC declared that it would continue monitoring the LNG market and would take "strict actions" against any violations of the Antimonopoly Act of Japan.

In July 2017, Japan and the European Union signed a Memorandum of Co-operation on promoting and establishing a liquid, flexible and transparent global LNG market (METI, 2017). Under the memorandum, the parties will exchange experience and undertake joint activities to spread best practices to improve the functioning of the global LNG market, including information on flexibility in LNG contracts. They will also enhance their co-ordination in international fora and between organisations in the area of energy, in particular regarding responses to unexpected gas market disruptions. By involving all LNG producers and consumers in joint activities, they aim to promote the liquidity, transparency and flexibility of the global LNG market, to ensure competitive LNG supplies and improve the resilience of the international market and its capacity to respond to emergencies.

Following these events, the Korea Fair Trade Commission also started researching the illegality of destination clauses in the LNG contracts. Together with the current oversupplied market condition, this action might extend to other LNG importers, and potentially improve flexibility in the global LNG market more quickly.

Portfolio players faced with increasing (currently) open selling positions

Figure 2.13 • LNG import contract volumes with portfolio players, 2012-22



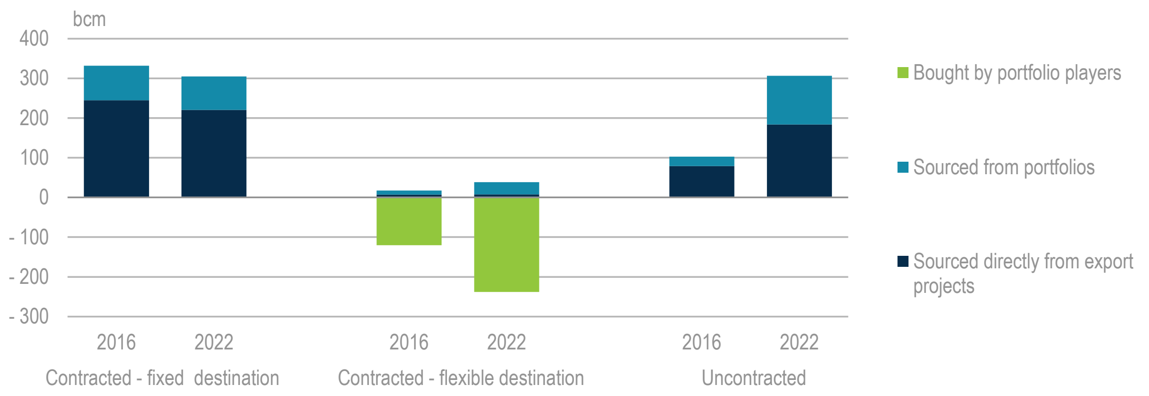
As previously mentioned in Chapter 1, portfolio players provide security of supply to their customers by mitigating the impacts of potential supply disruptions, as may occur in a direct exporter to importer contract. However, this usually comes at a cost of less flexibility in destination, as portfolio players tend to buy flexible volumes from exporters and sell with fixed destination to their customers. As Figure 2.13 shows, flexible volumes only accounted for 28% of total portfolio players' sales in 2016, out of which 20% are provided by uncontracted open positions, which leaves only 8% to contracted sales with effective flexible destination.

While the current picture shows an expanding share of uncontracted volumes for the portfolio players up to 2022, the expectation must be that this uncontracted share will shrink and be replaced by contracted volumes as portfolio players close their open positions. The question, from a customer and security of supply perspective, is whether much of these new contract volumes will be free of destination clauses.

LNG market flexibility increases, for both structural and more temporary reasons

Figure 2.14 below summarises the evolution of contractual structure and flexibility input by type of provider for the medium-term period, based on current information.

Figure 2.14 • LNG supply evolution per type of contract, 2016-22



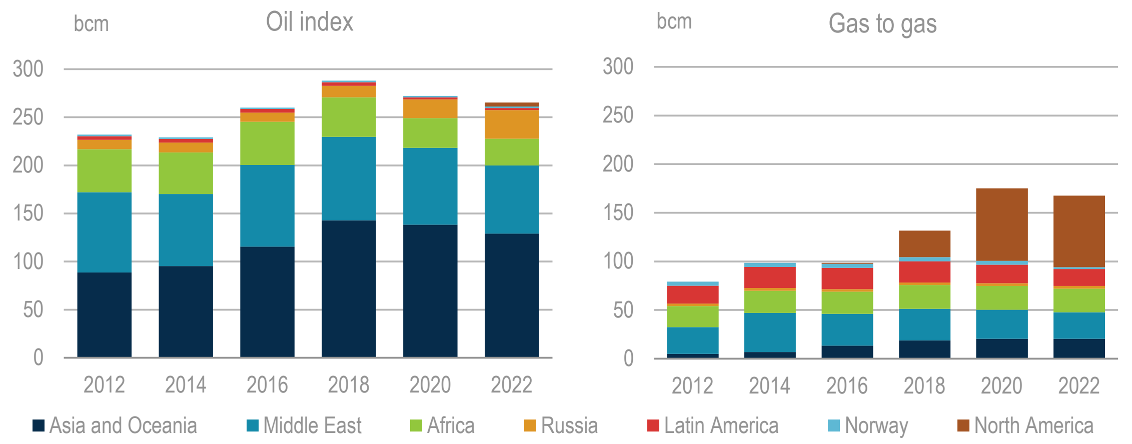
- Contracts with a fixed destination are expected to decrease, with some additions from new projects but whose contribution would be more than counterbalanced by the expiry of legacy contracts, which are counted as uncontracted (at least currently). The respective shares of export countries and portfolio players as suppliers of fixed contracts are not expected to change, marked by the dominance of the former group.
- Flexible contracted volumes are expected to double, mainly owing to the development of US exports, which emerges as a major source of additional contractual flexibility. Most of these flexible volumes are bought by portfolio players (as shown in Figure 2.14) who then resell them, mainly with fixed destination. However, the amount of flexible contracted volumes sold through portfolios is expected to increase substantially.
- Currently uncontracted volumes remain a significant question for the coming years. Based on current figures, they are expected to triple to around 300 bcm/y by 2022, with a 60/40 split between export countries and portfolio players. The first category is mainly composed of volumes under expiring contracts, while the second encompasses a strong proportion of open positions taken by portfolio players from new exporting projects. In both cases, these uncontracted volumes may be more transitory than structural for their sellers, who are actively looking to secure more long-term outlets. The oversupplied

market environment would probably add competitive pressure on sellers to market such volumes in the coming years, with buyers looking for the most competitive options, at least until the supply-demand gap closes and the LNG market retightens.

Oil indexation decreases in exports, but maintains its share in contracted exports

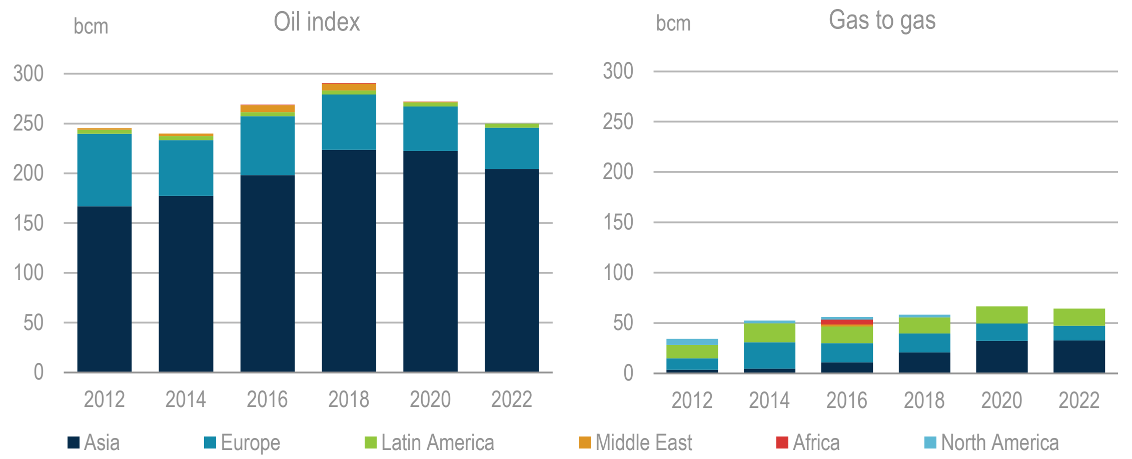
This analysis looked at the split between oil-indexed and gas-to-gas pricing in contracts in the different exporting and importing regions. The share of oil indexation in export contracts is expected to decrease, thanks mainly to the emergence of Henry Hub-priced US LNG volumes (Figure 2.15).

Figure 2.15 • LNG export contract volumes with oil index and gas to gas by region and country, 2012-22



Imports are also moving towards more gas indexation but at a slower pace (Figure 2.16), with Asia, the largest buyer, only moving down from oil indexation of 78% in 2016 to 69% in 2022. This discrepancy is explained by several factors, including the abovementioned open uncontracted volumes (some of which being gas indexed) as well as some other gas-indexed volumes being bought by portfolio players and resold under oil-indexed formulas.

Figure 2.16 • LNG import contract volumes with oil index and gas to gas by region, 2012-22



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3. Security of supply policy update: Regulatory frameworks of the European Union, Japan and Australia

Policy frameworks ensure co-ordinated actions among stakeholders in times of security of supply concerns and emergency situations. Against the backdrop of political tensions, natural disasters or tight markets, the European Union, Japan and Australia are three examples where appropriate mechanisms were developed and recently updated in order to enhance the robustness of security of supply. All described frameworks facilitate the exchange of necessary information and enable the mitigation of supply constraints across relevant stakeholders (and even countries based on the latest revision of the EU security of supply regulation). However, updates and adjustments to existing frameworks – also triggered by regular gas supply simulations – need to be carried out to ensure that policy frameworks are compatible with relevant characteristics of a country or region (e.g. ability to diversify supplier base or means of transport [liquefied natural gas (LNG) versus pipeline]) that can change over time.

The European Commission's update to the Security of Gas Supply Regulation

At EU level, Regulation 994/2010 is the principal legislation with respect to security of supply. In force since December 2010, it is a consequence of the Russian Federation-Ukraine gas dispute in 2009 and establishes a framework to co-ordinate security of gas supply issues between natural gas transmission system operators, EU member states (and their competent authorities) and the European Commission.

The regulation establishes two main indicators, ensuring that each member state proves that it can satisfy total gas demand in case the single largest element of its gas infrastructure is not available **(infrastructure standard)** and that relevant natural gas system operators can supply protected customers even under severe weather conditions **(supply standard)**. Moreover, competent authorities of each member state have to prepare one assessment and two plans, which elucidate how supply and infrastructure standards are met **(risk assessment)**, how supply risks are mitigated **(preventive action plan)** and what measures need to be undertaken in case of a severe gas supply disruption **(emergency plan)**.

Crisis management and information exchange are structured on the basis of three crisis levels (Table 3.1), including the role of the European Commission and member states in case an emergency is declared.

In May 2017, the European Council and the European Parliament reached agreement on the draft version of the updated Security of Gas Supply Regulation, which revises the existing regulation EU 994/2010. The update was triggered by stress tests during 2014, which demonstrated that national security of supply policies should also take into account the situation of neighbouring states.

Table 3.1 • Crisis levels according to the EU security of supply regulation

<table>
<tr><th colspan="2">Phase</th><th>Description</th><th colspan="2">Measures</th></tr>
<tr><td>Phase 1</td><td>Early warning</td><td>Defines a situation where an event may occur that is likely to result in significant deterioration of the supply situation.</td><td rowspan="3">Relevant information must be provided to the Commission and the competent authorities of the member states directly connected to the relevant crisis. This includes details of what actions are required. In the event of an emergency, the member state must notify the Commission's Emergency Response Coordination Centre.</td><td></td></tr>
<tr><td>Phase 2</td><td>Alert</td><td>Triggered when a supply disruption or exceptionally high gas demand occurs and results in significant deterioration of the supply situation. However, the market is still able to manage the disruption or demand without the need to resort to non-market measures.</td><td></td></tr>
<tr><td>Phase 3</td><td>Emergency</td><td>Declared where there is a significant supply disruption, exceptionally high gas demand or other significant deterioration of the supply situation. All relevant market measures have already been implemented, but the supply of gas is still insufficient to meet the remaining gas demand so non-market measures have to be introduced especially to safeguard gas supply to protected customers.</td><td>Competent authority shall follow the pre-defined actions according to its emergency plan.
Transmission system operator: Capacity at interconnection points to a neighbouring member state that has declared an emergency has priority.
The system user of the prioritised capacity shall promptly pay fair compensation to the system user of the firm capacity.
Member states may decide to prioritise the gas supply to certain critical gas-fired power plants over the gas supply to protected customers in case the lack of gas supply to critical gas-fired power plant:
• Results in severe damage in the functioning of the electricity system.
• Hampers the production and/or transport of gas.</td></tr>
</table>

Source: European Council (2017), Regulation of the European Parliament and of the Council concerning measures to safeguard the security of gas supply and repealing Regulation (EU) No 994/2010, http://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CONSIL:PE_22_2017_INIT&rid=10.

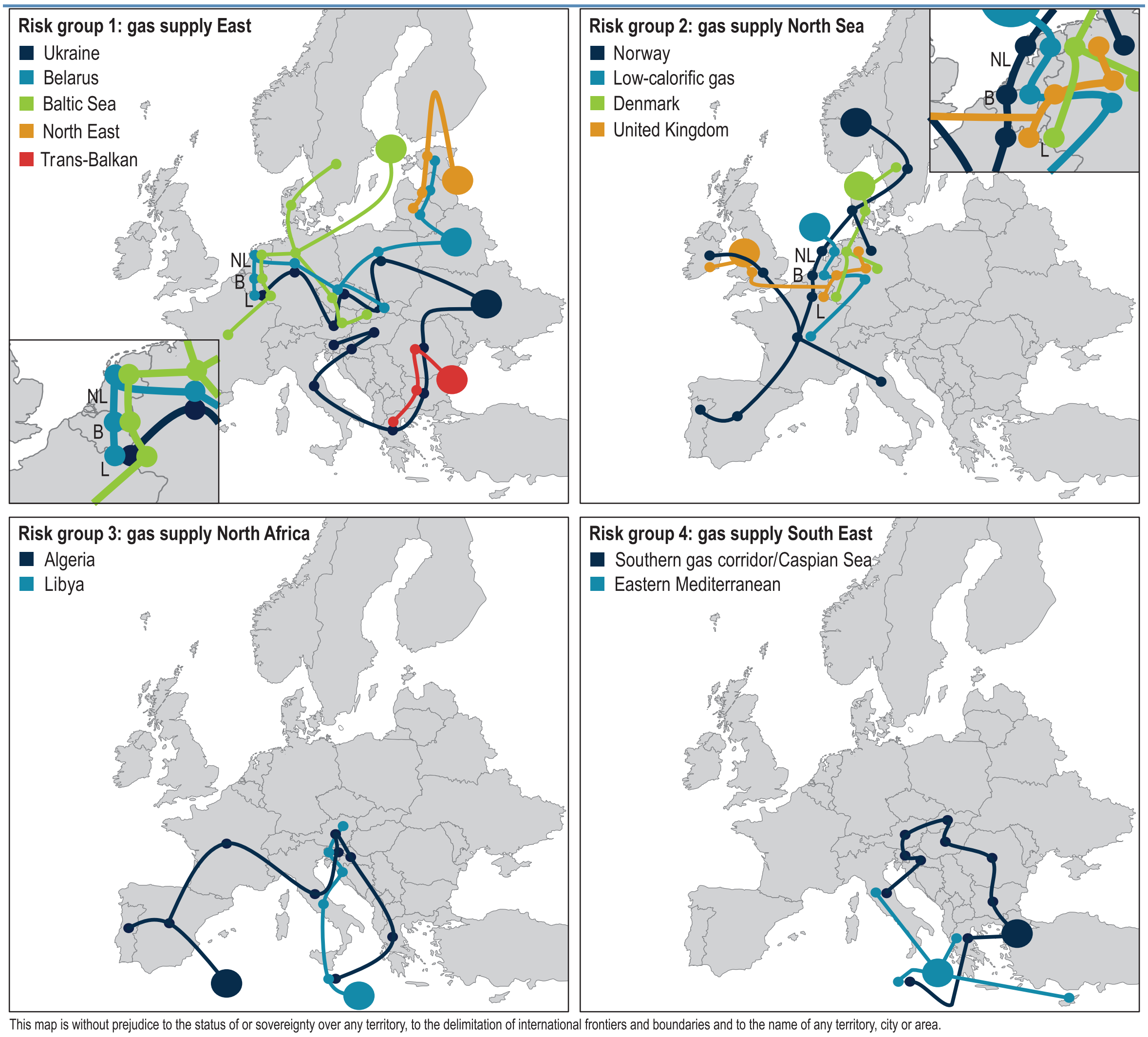
This led to new provisions under which member states will:

- Co-operate on tasks related to security of gas supply-related tasks within four risk groups (see Map 3.1).
- Provide supplies to neighbouring states under a solidarity mechanism.
- Co-operate on the exchange of specific gas supply contract information, which is needed to better assess the overall gas supply situation.

On 13 September, the European Parliament approved the updated Security of Gas Supply regulation. The final decision of the Council is outstanding and expected at the end of October.

Following this, the regulation will come into force 20 days after the text has been published in the official journal of the European Union.

Map 3.1 • Risk groups according to the revised EU security of supply regulation



Note: NL = Netherlands, B = Belgium, L = Luxembourg.

Source: EU (2017a), Regulation of the European Parliament and of the Council concerning measures to safeguard the security of gas supply and repealing Regulation (EU) No 994/2010, http://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CONSIL:PE_22_2017_INIT&rid=10.

The risk groups in Map 3.1 are defined on the basis of their main gas supply sources and transport corridors. This enables relevant member states to define preventive and emergency measures more effectively and efficiently, ensures a consistent response to supply issues and reduces negative spill-over effects that an insulated national approach to security of gas supply could have on neighbouring countries. Member states within the four risk groups are organised with respect to a specific security of gas supply issue. For example, under Risk Group 1, Belgium, Germany, France and the Netherlands jointly co-operate on low-calorific gas-related issues, and Denmark, Germany, Luxembourg, the Netherlands and Sweden jointly co-operate on Denmark-related supply issues.

With the revised 2017 Security of Gas Supply Regulation and the repeal of Regulation (EU) No 994/2010, a new phase in the implementation of gas security of supply measures will start. The solidarity guideline on legal, technical and financial arrangements for application of solidarity – yet to be finalised as this report is written, and to be introduced in December 2017 – is intended to address severe shortages in the supply of protected customers (households and, under special circumstances, essential social services and district heating). It enables member states to indicate that cross-border actions are needed and as a result, other member states countries can be called upon will be identified within the relevant risk groups to help the requesting member state. Member states, or their relevant gas authorities, are supposed to enter into bilateral agreements that specify the conditions under which such an appeal can be done.

It is for the first time that an obligation to provide solidarity to other member states is introduced in an EU regulation; however there are several prerequisites for solidarity to work properly. For instance, it is necessary that cross-border access to infrastructure is maintained operational even in an emergency situation. Moreover, the arrangements between the relevant member states or gas authorities have to ensure that countries that provide emergency supply will be compensated in a fair manner.

In order to better assess overall gas supply situations, national gas utilities will co-operate more closely with the relevant member states on the exchange of gas supply contract information. Competent national authorities now require companies to automatically provide contract information that is considered relevant for the national market's security of gas supply. However, access to this information is limited with several exclusions, for example price-related information. Additional information can be requested in a reasonable manner and in a defined framework by the European Commission if the information is critical to security of supply for a member state, the region or the European Union.

Japan: Emergency policy measures and co-ordination mechanisms

Since the 2011 Great East Japan Earthquake, Japan has been putting additional effort into enhancing the robustness of its energy security of supply policy, including emergency response (IEA, 2016).[4] Japan's gas security policy consists of a mix of strategies and instruments involving diversification of the long-term LNG supply contract portfolio to enable greater contractual flexibility, procurement of additional LNG from spot markets, and the use of existing commercial LNG stocks in industry.

The Gas Business Act sets the rules for market activity and stipulates the actions required to secure natural gas supply capacity (Government of Japan, 1954). "Gas retailers" (defined as companies that "supply gas via pipelines") have the obligation to hold sufficient supply capacity to meet their customers' requirements. If they are not able to fulfil such obligations, the Minister of Economy, Trade and Industry (METI) has the competence to order the gas retailers to take other necessary measures to secure supplies (see next section). The same act stipulates that gas utilities are required to develop and submit plans for their supply of gas and the installation and operation of gas facilities for each new fiscal year. The plans are evaluated by METI.

Three levels of co-ordination for emergency measures

In the case of disruption to LNG imports, the main domestic importing companies (electricity companies and gas utilities) each deploy several actions according to the phase and gravity of the

[4] This chapter is based on the gas resiliency assessment of Japan done by the IEA in July 2016; see www.iea.org/publications/freepublications/publication/gas-resiliency-assessment-of-japan.html.

disruptive event, as described in Table 3.2. To reflect the recommendation of the gas resiliency assessment of Japan done by the IEA in July 2016, Japan Gas Association established the guideline for the large scale natural gas supply disruption including the framework such as emergency management organization among the city gas industry.

Table 3.2 • Japanese emergency policy measures, natural gas

Phase	Measures		
	Supply side		Demand side
	Downstream	Upstream	
Phase 1	Co-ordination at individual company level: 1. Use stocks on-hand. 2. Reschedule cargoes (with co-contractor, etc.). 3. Find new LNG supplier. 4. Fuel switching for electricity generation.	1. Co-ordination with LNG-producing countries to procure additional supply (at company and government level). 2. Consult Japanese companies with upstream interests regarding diversion of LNG cargoes (government and JOGMEC).	
Phase 2	Co-ordination at industry level: 1. Share LNG stocks among companies. 2. Transfer electricity among power companies.		
Phase 3	Co-ordination across industries.		1. Request voluntary efforts among consumers to save electricity/gas. 2. Legal restrictions on power usage.

Note: JOGMEC = Japan Oil, Gas and Metals National Corporation.
Source: Japanese Ministry of Economy, Trade and Industry (METI).

The emergency response measures are taken based on co-ordination at three levels: at individual company level, industry level and cross-industry level. Emergency response procedures, as undertaken following the 2011 Great East Japan Earthquake and the earthquake in Kumamoto in 2016, demonstrated that a co-ordination process at all three levels is an effective way to react rapidly in response to a disruptive event.

Box 3.1 • The Kumamoto Earthquake of 2016 and the co-ordination mechanisms

The Kumamoto Earthquake in 2016 illustrates how emergency response to regional gas disruption is co-ordinated at industry level as well as with the government.

The Kumamoto Earthquake affected the southern part of Japan, and interrupted gas distribution to over 100 000 households in the area. Immediately after the earthquake, the emergency response team of the Japan Gas Association (JGA) was established to provide mutual aid in support of the emergency response team of Saibu Gas, the local city gas utility. Several other regional companies dispatched staff to Kumamoto to work as part of the JGA rescue team, providing restoration services such as pipeline repair, temporary city gas supply, and gas valve leak testing. In total, 2 676 support staff from 22 other city gas utilities were dispatched and able to restore gas supply in 15 days.

The METI emergency response team provided instructions to the JGA emergency response team as well as to the electric power and oil industry. Instruction included effective use of mobile gas generators, reinforcement of the JGA rescue team, identification of key facilities such as hospitals and welfare facilities, and confirmation of need for priority supply. The electric power industry was instructed to increase the number of high-voltage power generator vehicles to provide emergency power distribution, and the oil industry was directed to carry out priority fuel supply to those vehicles.

In Phase 1, where co-ordination is conducted at the individual company level, the use of in-house LNG stocks and fuel switching would be the first measure taken by most power companies. Additionally, a reallocation of the main power companies' gas imports can be done based on position swaps with project partners. They can also procure additional LNG either from the spot market or from their contractual flexibility as per Upward Quantity Tolerance (UQT). Upstream supply measures can also apply, such as temporary reallocation of shipping schedules.

In Phase 2, co-ordination takes place at industry level. Companies would be required to pool their LNG stocks through domestic pipelines to accommodate mutual need.

In Phase 3, co-ordination would be conducted at cross-industry level, implying monitoring of demand response. To provide the necessary flexibility, gas companies could reduce deliveries to their customers with interruptible contracts, with the exception of priority customers such as hospitals, welfare institutions and government offices. Mobile air-mixed propane gas generators could also be used as temporary supply to priority consumers. These facilities can be considered as robust security backup capacity, as Japan holds some 1.5 Mt of liquefied petroleum gas (LPG) reserves and industries are required by law to hold an equivalent of 50 days of import volume.

Through Phase 1 to Phase 3, as the upstream measure, the government of Japan could also request Japanese companies who have upstream interests to divert LNG cargoes to Japan.[5]

As a last resort, mandatory demand restrictions could be introduced. The government of Japan has the authority to issue an order to electricity retailers and/or large electricity consumers to restrict the use of electricity by limiting power usage or peak load when it is deemed necessary to resolve supply shortage.

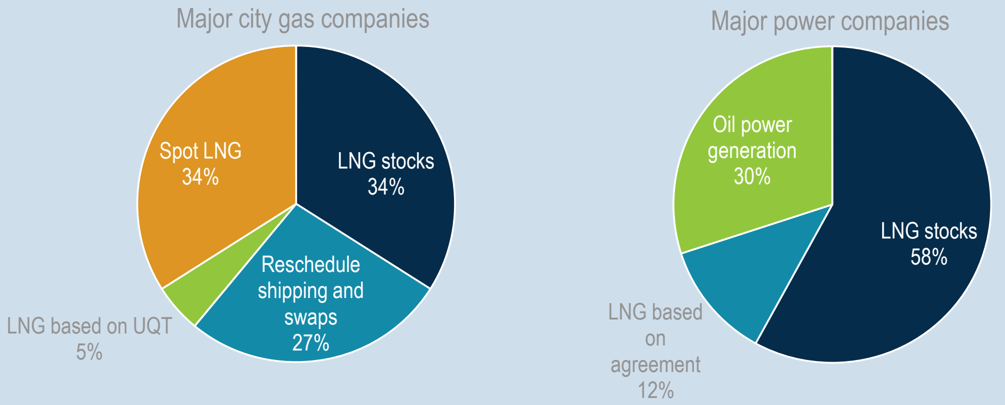
Box 3.2 • Emergency response of major Japanese utilities and city gas companies

In 2016, during a security of supply workshop in Japan, the IEA conducted a simulation exercise to look at, among other matters, the composition of the emergency measures of the main utilities and gas companies. The exercise highlighted the importance of the LNG spot market to replace the lost volumes, representing around 35% of the emergency measures package of the major city gas companies together (Figure 3.1). Such a high share stresses the importance of the availability of stable and flexible LNG supply-demand structures to be able to perform spot and short-term transactions rapidly. In this context, further easing of destination restrictions and increased flexibility in contractual arrangements prove necessary developments to increase spot market recourse in case of a disruption.

In addition to the spot market, gas companies also have the possibility of swapping contracted LNG together with the option of diverting cargos; this measure can eventually deliver around 30% of the volumes needed to replace the LNG losses. The simulation demonstrated that, in the case of a larger impact, city gas companies would import 5% of the needed volumes based on the agreed flexibility within existing contracts (UQT clause). For the individual electricity company, the share of additional LNG sourced on the basis of agreements is much higher, namely 12% (Figure 3.1).

[5] In relation to this, it is important to mention that the government is supporting Japanese enterprises to secure oil and gas upstream interests in order to achieve a 40% ratio of self-development by 2030.

Figure 3.1 • Illustrative emergency response of the major city gas and power companies



Source: Japanese Ministry of Economy, Trade and Industry (METI).

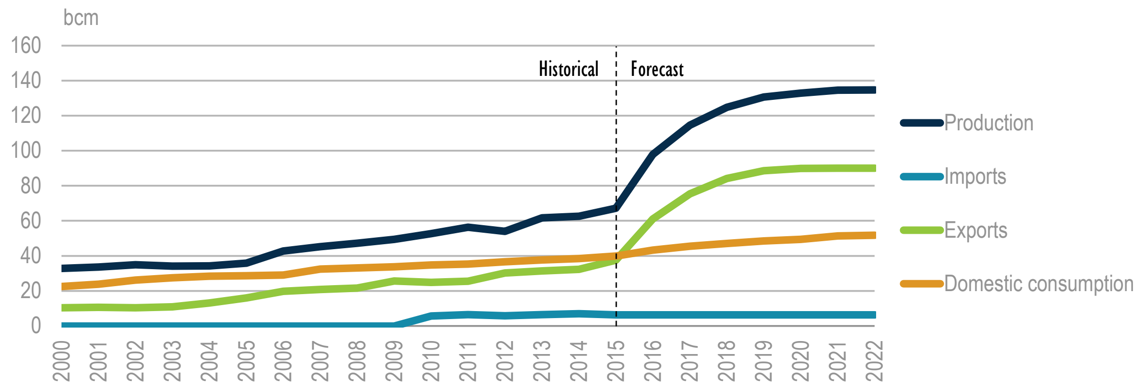
The emergency exercise showed the importance of (operational) LNG stocks to alleviate the impact of a disruption for both power and city gas companies, providing respectively 58% and 34% of replacement for lost volumes.

Fuel switching would then account for 30% of the power companies' response. The earthquake in 2011 highlighted among other factors the critical role played by ageing oil-fired power generation plants as backup capacity. This oil-fired capacity supported the Japanese power system and helped avoid major effects of the electricity supply shortage.

Australia

In recent years, the wave of new LNG liquefaction projects has put Australia in the spotlight with strong growth in gas production and LNG exports, as seen in Figure 3.2. As a consequence of this development, Australia has experienced strong increases in its domestic – wholesale and retail – gas prices (described in the IEA *Gas 2017* report [IEA, 2017a]) and short-term power and gas shortages in the eastern and south-eastern markets in 2016 and 2017, as described in chapter 1. The combination of these power and gas shortages highlights the increasing interaction between the gas and electricity markets in Australia and the associated challenges, a trend also being seen in a number of other countries.

Figure 3.2 • Gas balance Australia, 2000-22



Note: bcm = billion cubic metres.

Source: Historical data: IEA (2017b), *Natural Gas Information* (database), http://www.iea.org/statistics/.

Reacting to these energy supply security concerns, the Australian government implemented a new gas security mechanism to complement and speed up ongoing gas market reforms towards 2020, proposed under the lead of the Council of Australian Governments (COAG) Energy Council. The new gas security policy is based upon an adequacy assessment, notably by the 2017 *Gas Statement of Opportunities* report of the Australian Energy Market Operator (AEMO) and consultation of all gas market participants. The new policy provides for the Minister for Resources and Northern Australia to enact LNG export restrictions under the Australian Domestic Gas Security Mechanism (ADGSM).

The Australian Domestic Gas Security Mechanism

AEMO has warned that without increases in Australian domestic gas production or a rapid increase in non-gas-fired power generation capacity, potential gas supply shortages may occur on the basis of the projected demand for gas-fired power generation between 2019 and 2024.

The ADGSM is in effect from July 2017 and is a temporary measure intended to cover the period of LNG export projects ramp up until the end of 2022. The framework allows the Australian government to intervene if needed to ensure sufficient delivery of natural gas to the domestic market. In short, if supply-demand market dynamics point towards insufficient supply of gas to the domestic market, the mechanism calls for partial and temporary restriction of LNG exports in order to ensure enough gas is available for the domestic market.

The need for a domestic gas security mechanism was driven by rapid changes in the East Coast gas market in Australia, a region where most of the population lives and most industry is located. Until recently, all LNG was exported from stranded gas deposits in the north and west of Australia, and not connected to the East Coast gas market. However, three new LNG projects have been built in Queensland, now effectively connecting the East Coast market to global gas markets, at a time when many long-term, relatively cheap legacy contracts were expiring. Despite assurances from project developers that the plants would be supplied from dedicated coal bed methane production areas, because of moratoria and regulatory restrictions in some States this could not be the case for all export plants, causing real fears of gas shortages and price spikes in the East Coast market.

The ADGSM is structured to follow a last resort approach based on a three-step process of declaration, consultation and determination. The first step lies with the Minister for Resources and Northern Australia to issue a declaration of intent before 1 October to determine if the following year risks a shortfall of gas. The second step requires the consultation of relevant stakeholders (market bodies, government agencies, potentially affected industry). The gas market conditions of the upcoming potential shortfall year will be assessed by these stakeholders. If, after this consultation, the Minister for Resources and Northern Australia decides that the following year is indeed a shortfall year, step three is the determination of LNG export controls for that year.

Export controlled volumes are determined on the basis of the Total Market Security Obligation (TMSO), which is the amount of gas needed from the LNG export projects to supply the domestic market. Following the TMSO calculation, the "net market position" of each LNG export project is assessed to determine whether it should be subject to an export volume restriction. Each project's net market position is either contributing to or subtracting from the domestic gas supply-demand balance (and excludes production from the gas fields which are dedicated specifically to LNG export projects). The TMSO is allocated on a pro-rata basis across all LNG projects in net-deficit, the allocation being termed the Exporter Market Security Obligation (EMSO). For plants subject to an EMSO, the Minister grants export permissions in the form of either an Unlimited Volume Permission (i.e. no export volume restriction) for those LNG projects not connected to domestic markets experiencing supply shortfalls, or an Allowable Volume Permission (i.e. export volume restriction) to ensure those LNG projects connected to domestic markets experiencing a shortfall meet their EMSO (Australian government, 2017). In October 2017, major East Coast LNG exporters agreed to dedicate additional supply to the domestic market for the next two years, thus saving the government from issuing the declaration of intent as required in the ADGSM mechanism. A formal Heads of Agreement was signed by the Prime Minister and representatives from the three East Coast LNG exporters. The agreement reached meant that the forecast shortfall of gas for the domestic market would be provided by the LNG exporters on reasonable terms and that any uncontracted gas would be first offered to the domestic market.

Medium-term policy and developments in the Australian gas market

Aware of the structural changes to the Australian gas market, the COAG Energy Council released a comprehensive gas market reform package in August 2016, the most recent of a series of energy market reports dating back more than two decades (COAG Energy Council, 2016). It comprises 4 priority areas and 15 reform measures to realise a liquid wholesale gas market where efficient and transparent price signals provide for investment and new gas supply. It includes measures to reform the gas spot markets and concentrate trading on two primary hubs, increase available gas supply in the domestic market, reduce barriers to competition, provide easier access to and optimise the allocation of transport capacity and enhance transparency as well as consumer information.

The Australian Consumer and Competition Commission (ACCC) is conducting several inquiries into gas and electricity prices – an Interim Report of the gas inquiry 2017-20 was published in September 2017 (ACCC, 2017) – looking at gas supply arrangements, gas production, demand and transport with a view to improving transparency of the gas market in Australia. The ACCC has the power to compel energy undertakings to provide market data. Australia Energy Market Commission (AEMC) rule changes provided for the introduction of a Gas Bulletin Board, which has moved the market towards more transparency with regard to gas capacity. On 1 August 2017, a new commercial arbitration framework for pipeline access entered into force. While it may provide for more information, it is unlikely to lead to more third-party access or freeing up of capacity, which is currently not available on key market interconnections across the East Coast. The ACCC is going to review the arrangements in the future.

With the eastern market being considered the most vulnerable to potential gas supply shortages, the connection of the eastern with the northern network via the Northern Gas Pipeline is expected to be completed by 2018. This connection would assist in reducing supply constraints in the eastern market, stimulate competition and enable increased gas production in the northern region. The expansion of the South West Pipeline in Victoria will facilitate the necessary injection in the Iona underground storage plant to avoid future shortfalls (AEMO, 2017a). Storage in Australia remains relatively low compared to consumption, with seasonal swings being met by production variations. As gas-fired power generation becomes more important for power security, it is unclear how sharp variations in gas supply will be met. Building other new infrastructure would improve the market situation and new transmission pipelines are being planned in Australia.

Gas and power system security

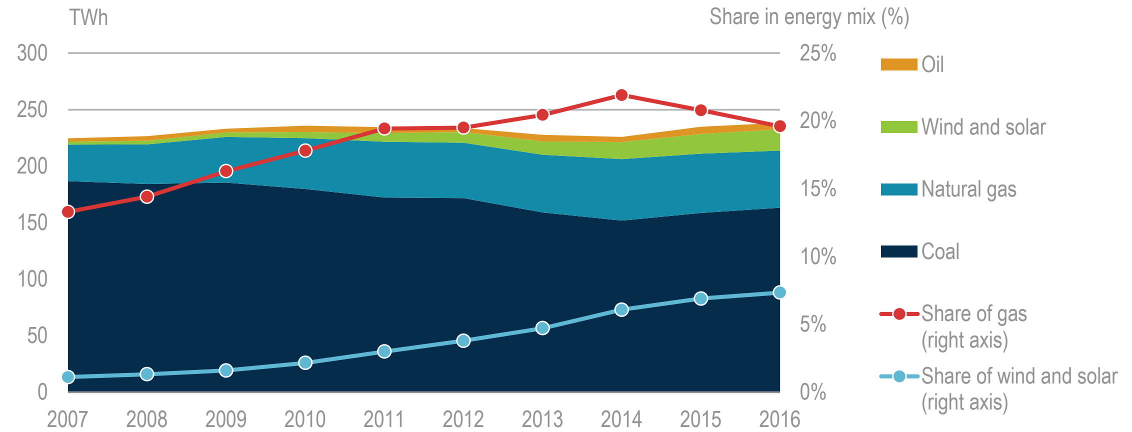
In the Australian power sector, gas will need to play a critical role as renewable power increases and coal power plants close. Figure 3.3 shows that in the last ten years, the share of gas-fired power in the power generation mix has risen from around 15% to over 20%, with significant regional variations. Variable renewables (wind and solar photovoltaics) have increased from 2% of generation in 2010 to 7% in 2016, with further increases anticipated for end of 2017, taking the share to well over 15%. Among the south-eastern states, South Australia is most reliant on natural gas in electricity generation, where gas accounted for more than 50% of local power generation next to a share of renewables of 42% as recently as 2015/16. [6] The rapid rise in renewables, plus the rising price of gas, saw this share fall to 38% two years later (Australian Government, 2016). Many gas-fired plants were mothballed.

The increasing dependency of Australia's power system on gas may have an important impact on the reliability of gas and electricity supply to customers. The reliance of the power system on gas-fired power generation is increasing because old coal plants are closing and intermittent renewable generation is growing. On the supply side, this may lead to shortfalls in the supply of gas to gas-fired power generation units should demand for gas-fired power generation rise sharply (for example with heat waves). In turn, this would increase the need to switch from gas to other sources to maintain a reliable electricity supply. However, the switching potential is decreasing. Recently, 2.4 gigawatts (GW) of coal-fired capacity have closed, including one unit of 1.6 GW at only six months' notice. A further 2 GW seems likely to close by 2022.

In response to this issue, natural gas producers and pipeline operators made a commitment to the Commonwealth Government to make gas supply available to electricity generators during peak NEM periods in 2017. The Gas Supply Guarantee mechanism has been developed by industry to facilitate the delivery of these commitments.

While the ADGSM is intended to provide means to manage the risks to the annual domestic energy balance, the Gas Supply Guarantee mechanism is directed to short-term deliverability and supply issues for GPG, and as such is most appropriate to address operational risks or major unplanned events, such as an unplanned outage of a major coal-powered unit. (AEMO,2017a).

Figure 3.3 • Power generation by fuel type in Australia, 2007-16



Note: TWh = terawatt hour.
Source: IEA (2017c), *Electricity Information* (database), www.iea.org/statistics/.

This will tighten the electricity supply-demand balance and markedly reduce the gas-to-coal switching potential. In the longer term, after 2025, AEMO assumes that the strong growth in renewables will decrease the reliance on gas-fired power generation as installed renewable power capacity has projected (not committed) growth totalling 20 GW over the next ten years (AEMO, 2017b; 2017c).

[6] Australian data is presented in fiscal years, ending 30 June.

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4. LNG buyer types

This liquefied natural gas (LNG) buyer analysis defines four types of buyers – Dependent, Diversity, Reserve and Price – based on their LNG gas supply dependency and on the share of long-term contractual commitments. On the basis of the clustering of LNG buyers, several characteristics can be attributed to an LNG buyer type. This clustering will help to understand the markets in which future LNG import growth is likely to take place.

The LNG buyer types should not be regarded as a rigid distinction between classes of buyers, but rather as a guiding framework that shows the diversification of the LNG demand market. It provides direction as to which LNG buyer segments future demand growth is expected to take place in.

The four LNG buyer types range from markets with a high dependence on LNG with low price sensitivity, to markets where LNG is regarded as a (new) energy supply option where it competes with other fuels in the energy mix or covers (temporary) increases in energy demand.

The two primary defining metrics are:

- **LNG supply dependency**: the first metric defines whether an LNG buyer has a diversified gas supply portfolio in which other gas supply options, such as domestic production or pipeline imports, are available. This describes the extent to which the gas supply portfolio is dependent on LNG.
- **LNG buying commitment**: the second metric measures the share of long-term contractual LNG commitments versus the share of short-term and spot LNG purchases. This gives an indication of the level of LNG import volume and price flexibility that is suitable for the nature of a market's demand.

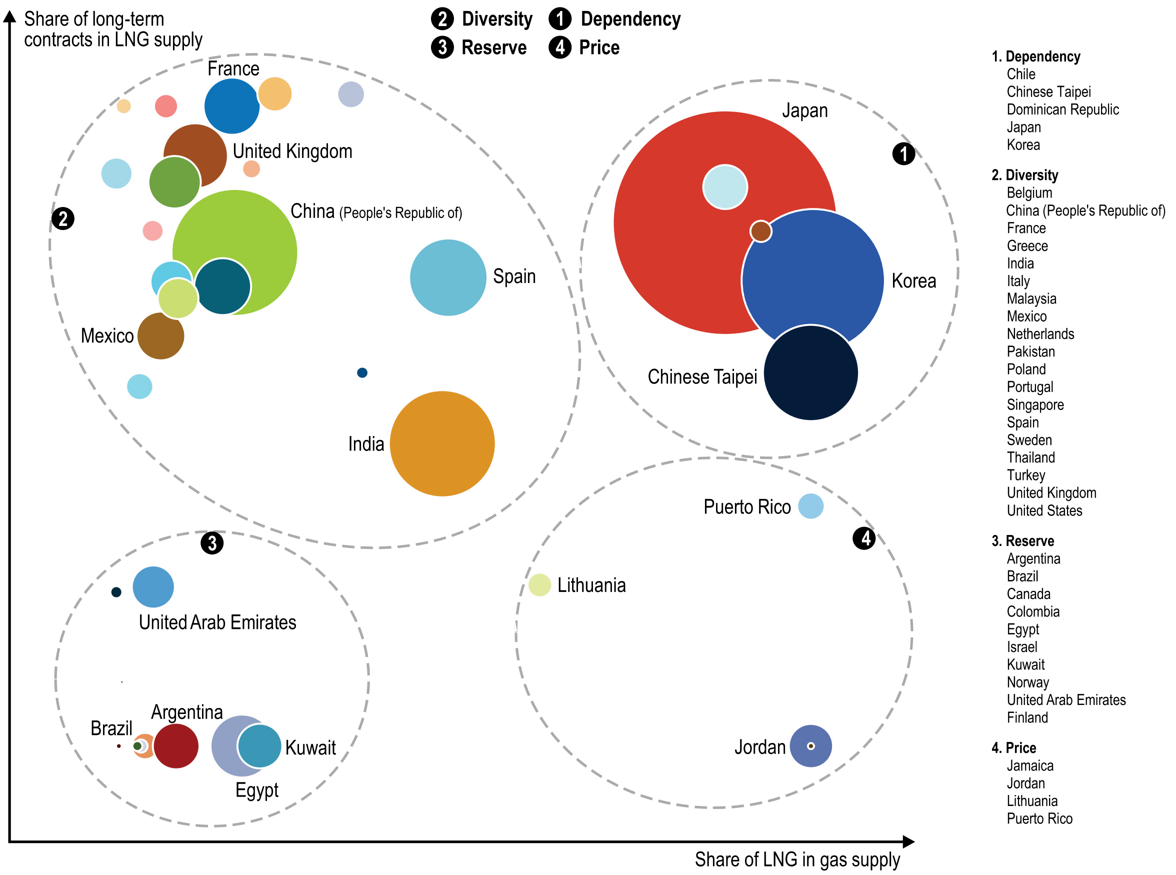
The four LNG buyer types may overlap when certain gas market characteristics are similar and are not used to define the LNG buyer types. Buyers are not bound to one type over time as their energy system and energy supply portfolio evolves. The chart in Figure 4.1 shows the segmentation of the LNG buyers into four types; the horizontal axis indicates the share of LNG in the gas supply mix (LNG dependency); the vertical axis shows the share of long-term contracts in total LNG volumes; and the bubble size represents the size of LNG imports in 2016.

This clustering allows for the attribution of several characteristics to the four LNG buyer types to guide the description of the LNG buyer markets in terms of:

- share of gas in the energy supply mix
- share of gas in the power supply mix
- security of LNG supply strategy
- price sensitivity of LNG demand
- appetite for LNG contract commitment and destination clauses.

The first three characteristics are based on quantitative analyses of buyers' energy market structure, as summarised in Figure 4.2.

Figure 4.1 • LNG buyer types 2016

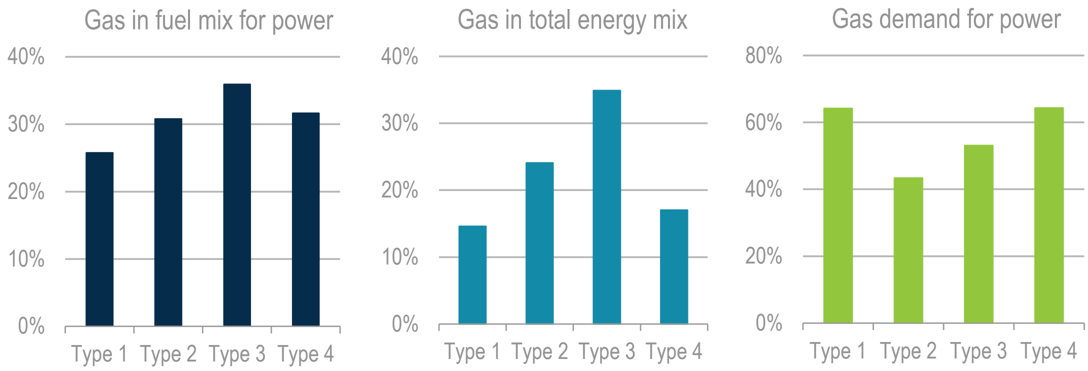


Note: Based on 2016 data.

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

The different buyer types are described in the following sections. Each buyer type is also exemplified by a type representative country.

Figure 4.2 • LNG buyer types characteristics



Notes: Based on 2015 data; gas demand for power (third graph) is the share of gas demand for the power generation sector of the total gas demand.

Source: IEA (2017b), *Market Report Series: Gas 2017*, www.iea.org/bookshop/741-Market_Report_Series:_Gas_2017; IEA (2017c), *World Energy Balances 2017* (database), www.iea.org/statistics.

Type 1: Dependent

This type consists of buyers which are almost fully dependent on LNG supplies because alternative gas supplies are non-existent or limited. Securing continuous supply is of high importance, which is reflected by the almost 80% average share of long-term LNG contracts. Japan, Korea and Chinese Taipei form the top three out of five in this type, with almost 180 billion cubic metres (bcm) of LNG imports. Together they represented more than half of global LNG imports in 2016. Japan, as the world's largest LNG importer, can be described as exemplary for this LNG buyer type.

Of all LNG importers, the share of gas in the total primary energy demand mix is the lowest in Type 1, on average 15%. This implies that the energy system of LNG importers relies to a lesser extent on gas when the gas supply structure is undiversified.

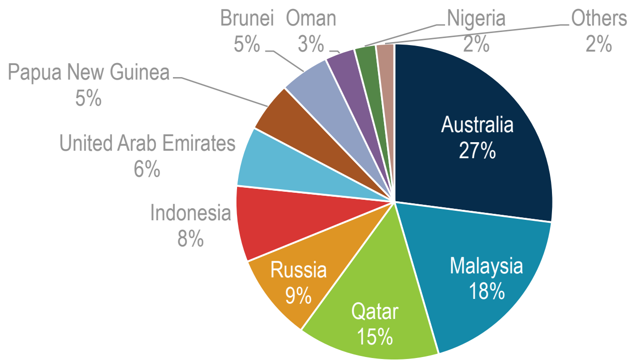
A similar relationship can be observed on the dependency of the power generation system on gas. Again, for Type 1 this is the lowest at 26%. Year-on-year differences in power generation by gas and other fuels can shift this percentage significantly in all LNG buyer type groups. Type 1 is also characterised by a high share of total gas demand used by the power sector – on average 64% – while 17% and 18% are used by the industrial and residential sectors respectively. Gas is therefore generally used for baseload and peak power generation and to a lesser extent for seasonal residential demand.

Considering the focus on securing supplies through long-term commitments, Type 1 LNG demand is considered to be less price-sensitive in the short term. As a share of long-term contract commitments come to an end, shorter-term commitments are likely to increase, all things being equal. On a volumetric base, Type 1 is expected to decrease its overall LNG imports by 12 bcm by 2022. The balance between long-term and short-term contracts is likely to remain related to the gas demand structure: long-term commitments with fixed destination clause match with guaranteed demand, while shorter-term commitments are linked to more variable demand.

Japan

Japanese gas consumption, the fifth-largest in the world in 2016, is predominantly met by LNG imports, making Japan the world's largest LNG consumer. In 2016, import dependency reached almost 98%, and the country's total LNG imports amounted to 117 bcm with well-diversified import sources. These volumes were imported from 17 countries, including re-exported volumes from France, Singapore and Korea – see Figure 4.3.

Figure 4.3 • LNG suppliers to Japan, 2016

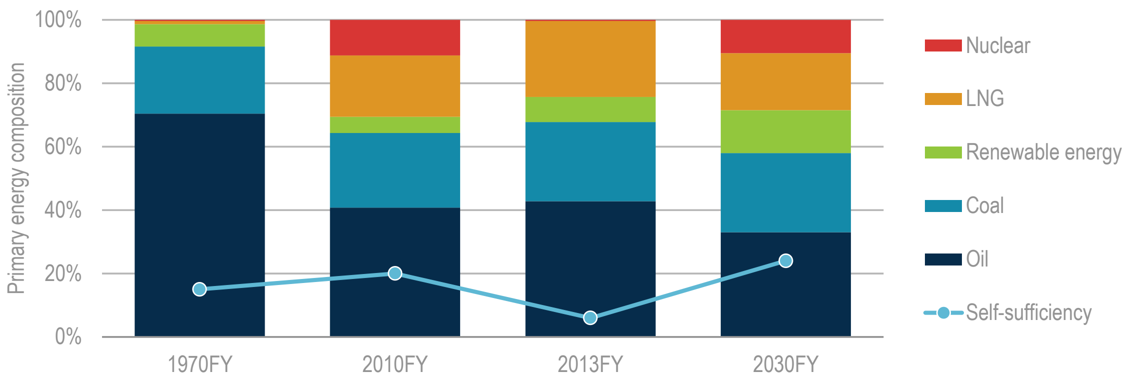


Source: ICIS (2017), *ICIS LNG Edge*, www.icis.com/energy/liquefied-natural-gas/lng-edge (subscription required).

Natural gas plays a crucial role in Japan's primary energy mix, particularly after the 2011 Great East Japan Earthquake. As a consequence, the closure of all nuclear power plants – which accounted for 25% of power generation in 2010 – resulted in a substantial increase in the use of gas in the power sector, from 28% in 2010 to the highest level of 42% in 2014.

According to the *Long-Term Energy Supply and Demand Outlook* prepared by the Japanese government in July 2015 (METI, 2015), the share of natural gas in the country's primary energy supply in 2030 is projected to decline from the current 24% in 2016 to around 18% (Figure 4.4), similar to the situation before the earthquake. The gradual restarting of nuclear power plants and the further deployment of renewable sources are considered by the government of Japan to be key factors for overall energy security, as greater diversification of power sources would contribute to improved resilience of response measures in case of emergency and would decrease overall natural gas import dependency.

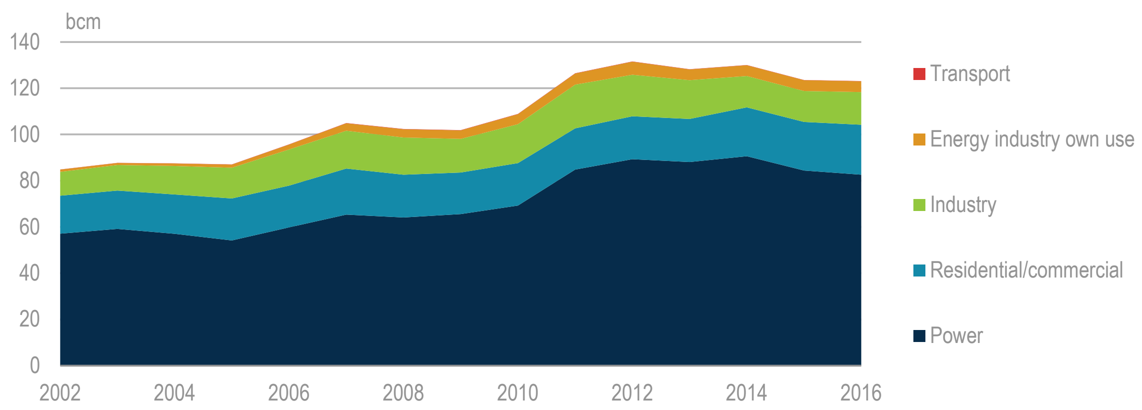
Figure 4.4 • Long-term primary energy supply outlook for Japan, 1970-2030



Note: FY = fiscal year (1 April to 31 March).
Source: METI, *Long-Term Energy Supply and Demand Outlook*, www.meti.go.jp/english/press/2015/pdf/0716_01a.pdf.

Gas-fired power generation, which provided around 40% of Japanese electricity in 2016, is likely to become a growing source of flexibility to electricity systems as the share of intermittent renewable energy increases. In 2016, the power generation sector was the largest user of natural gas in Japan, accounting for around 67% of the country's total gas demand. The industrial sector and the residential sector constituted 11% and 18% respectively, while energy sector own use and commercial/other accounted for the remaining 4% (Figure 4.5).

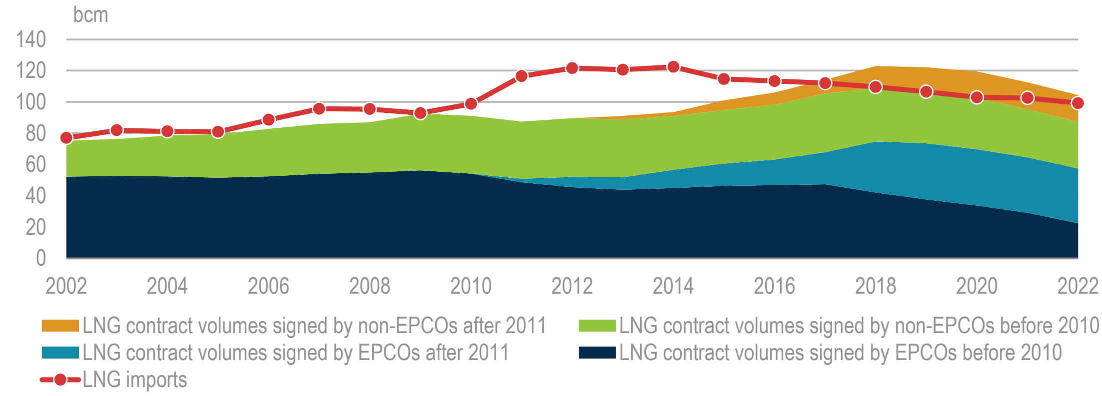
Figure 4.5 • Natural gas consumption in Japan by sector, 2002-16



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

LNG supply security is directly linked to electricity security in Japan, as demonstrated by the dominant share of the power sector in natural gas consumption. Japan has typically procured almost all its LNG supply under term contracts (Figure 4.6). After the 2011 earthquake, Japan also procured LNG from the spot market to bridge the gap between its domestic needs and contracted volumes. To secure their future gas needs, Japanese companies signed new contracts after 2011, led by the 10 large electricity power companies (EPCOs). However, as discussed in *Gas 2017* (IEA, 2017b), gas consumption for power generation is expected to decline from 83 bcm to 62 bcm between 2016 and 2022, assuming that 17.5 gigawatts (GW) of nuclear capacity, around one-third of the capacity operating in 2010, has restarted by 2022, and annual growth in renewable energy generation of around 5%. Japan reached a turning point in 2016 when its LNG demand started to lag behind its long-term contracted volumes. The coming years' decreasing demand trend would result in a significant over-contracted position, leading to a surplus peak of around 25 bcm in 2018, which would then gradually shrink to around 5 bcm by 2022.

Figure 4.6 • LNG contracted volumes and LNG imports in Japan, 2002-22



Source: LNG imports 2002-15: IEA (2017b), *Natural Gas Information 2017 (*database), www.iea.org/statistics/.

An important instrument to manage this potential oversupply is destination flexibility of LNG, that is, the ability to divert agreed volumes to other markets where LNG is needed. Such an adjustment could contribute substantially to a more liquid LNG market worldwide. Making use of the opportunities offered by a well-supplied LNG market, the Japanese government together with the main Japanese LNG buyers (the major utilities and gas companies) have been increasing pressure on suppliers to agree to more contractual flexibility and increase the liquidity of the LNG trade through measures including further elimination of destination clauses. Furthermore, the aim of the government to develop an LNG trading hub in Japan can be considered an important instrument in achieving this aim. Another important step has been the decision of Japan's Fair Trade Commission to end unfair restrictions in LNG contracts (Box 2.2).

Despite the expectation of important structural changes, as more flexible contracts and new price formulas are negotiated by Japanese LNG buyers during the years to come, the country will remain the most exemplary country ofType 1. Looking ahead, gas import dependency will remain the highest worldwide, with LNG as the primary source of the country's gas mix. Out of the approximately 100 bcm expected to be imported in 2022, 60% will be consumed by the power sector; as a consequence, LNG will maintain a key position in the power fuel mix and will continue to be linked to electricity security of supply in the country. With expiry of long-term contracts and the expected increase in contractual flexibility during the years to come, the main LNG buyers in Japan are likely to explore the most appropriate ratio of spot/short-term contracts and long-term (but flexible) contracts to enhance their supply security resilience in the long term. In this search for the right balance, the need to sign new long-term contracts, for example as an instrument for buyers to avoid volatility, will be undoubtedly an important consideration for the future portfolio composition of Japan's largest LNG importers.

Type 2: Diversity

This type consists of countries with a diversified gas supply portfolio including domestic production, pipeline imports and less than one-fifth LNG imports on average. A large number of European LNG importers are in this group, forming a well-diversified and well-connected trade region. One of Europe's larger LNG importers, the United Kingdom, is described below as example country. Although the share of LNG in the supply portfolio remains relatively low on average, 80% of LNG contracts are long-term commitments. Domestic production is maximised in most countries, which leaves variability in pipeline and LNG supplies. In total, 19 countries are found in this group and together represent 37%, or 128 bcm, of global LNG imports.

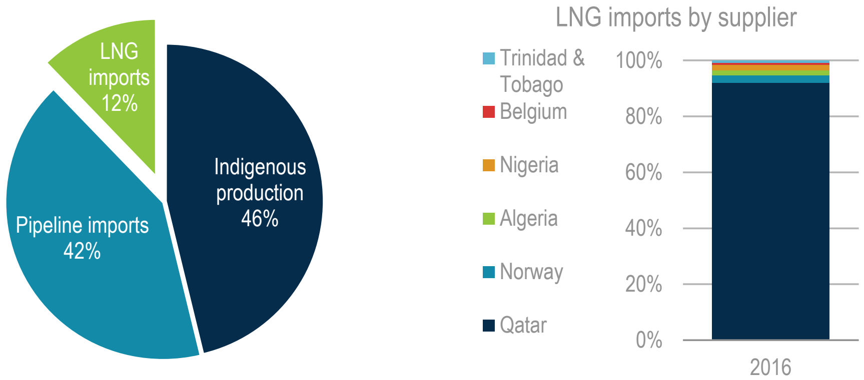
Gas has a one-quarter share of the total energy mix on average and provides one-third of power generation fuel. The total gas demand segmentation in this LNG buyer type is also the most diversified of the LNG buyer types: the power segment accounts for 43% (the lowest of all buyer types), industry for 31% and residential for 25%. This implies a relatively stable base of gas demand, as industry and residential experience less competition from other fuels in the short term.

LNG commitments are characterised by a high share of long-term contracts, in combination with redirecting or reloading of LNG shipments and an increasing share of shorter-term commitments. Redirecting or reloading is mostly done in EU member state countries, where LNG has no national market destination clause and operates in a highly competitive market. LNG may not be needed to meet a country's annual gas demand, but may be necessary to supply seasonal or peak demand. Supply capacity from the range of gas supply sources is generally sufficient to meet demand. LNG is therefore regarded as one, but not necessarily the only, security of supply option in the gas supply portfolio. Demand for LNG remains price sensitive because it competes with other sources of supply, while on the demand side other fuels compete with gas in the power generation segment.

United Kingdom

The United Kingdom began to diversify its gas supply portfolio with Algerian LNG in the 1960s and 1970s; however, the country still had a very high share of domestic production at that time.

Figure 4.7 • UK gas supply portfolio and LNG imports by supplier, 2016

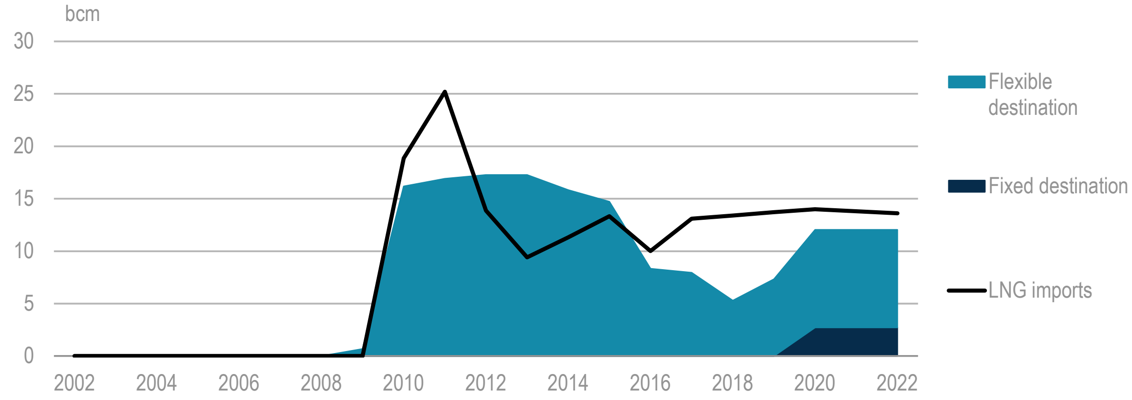


Sources: IEA (2017a), *Natural Gas Information 2017* (database), www.iea.org/statistics/; LNG imports: ICIS (2017), *ICIS LNG Edge*, www.icis.com/energy/liquefied-natural-gas/lng-edge (subscription required).

Pressure to diversify supply sources increased when domestic production began to decline after it peaked in the year 2000 at 115 bcm. In 2016, domestic production commanded a share of 46% and gas imports 54%. Of gas imports, the larger share comes via pipeline and originate from Norway, the Russian Federation and the Netherlands. LNG is mostly imported from Qatar on a long-term basis (see Figure 4.7).

As a large part of the United Kingdom's contracted portfolio is flexible, Qatari imports shifted away from the country during 2011 and 2014 due to price spikes in the Pacific Basin (see Figure 4.8); however, the gap in the supply portfolio was closed by increased pipeline imports. This illustrates that LNG imports to the United Kingdom can be volatile, but at the same time it shows that the portfolio is well-diversified and capable of importing more pipeline gas once LNG is heading to higher-priced markets. Flexibility of gas imports will be even more important against the backdrop of the decision to close Rough storage, the largest seasonal storage facility in the United Kingdom (see Box 4.1).

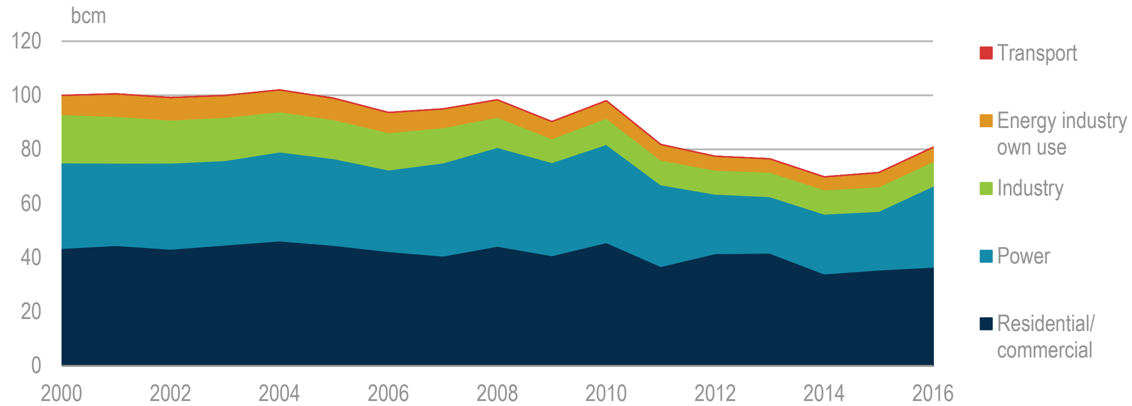
Figure 4.8 • LNG contracted volumes and LNG imports in the United Kingdom, 2002-22



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

In the United Kingdom, gas-fired power generation has been the main driver of incremental gas consumption. This development has been recently supported by the introduction of a carbon price floor, which increased costs of coal-fired power generation and led to coal plant closures, a trend which will continue based on the policy to phase out all coal plants in the United Kingdom by 2025.

Figure 4.9 • Natural gas consumption in the United Kingdom by sector, 2000-16



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

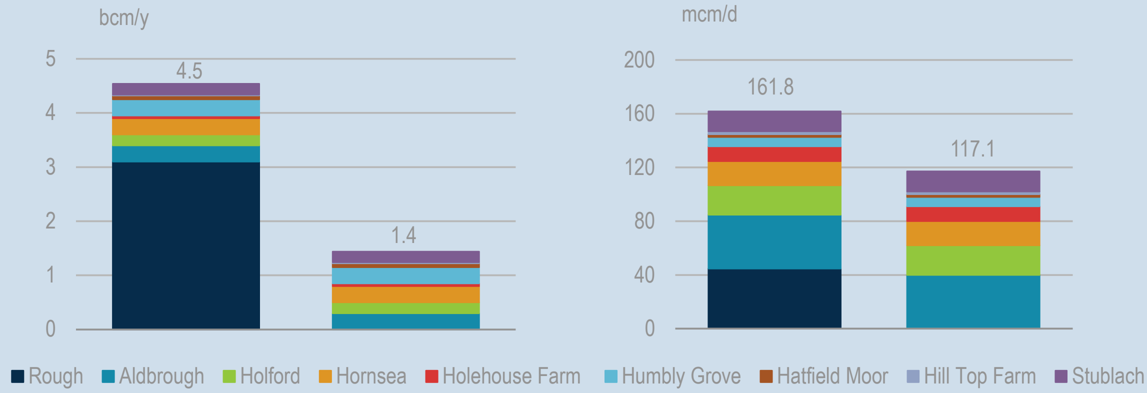
In relation to overall gas demand, residential and commercial use is the major consumer with a share of around 45%, followed by power generation with a share of 37%. The use of gas in industry has been fairly stable and is not expected to increase above the current share of around 18% (including energy industry own use) (Figure 4.9).

Box 4.1 • Regional focus North West Europe: Does the closure of the Rough storage site affect UK security of gas supply?

On 20 June 2017, Centrica Storage announced it would close its Rough storage site – the largest and only seasonal storage facility in the United Kingdom. Operating at full capacity (peak output 44.7 million cubic metres per day [mcm/d], working gas capacity 3.1 billion cubic metres per year [bcm/y]), the offshore storage site could meet around 10% of UK daily winter peak demand and account for around two-thirds of total storage capacity. Centrica's decision was the result of a review initiated following technical issues identified a year earlier that forced the operator to stop injections; it therefore could not use the asset at full capacity during the winter of 2016/17. The review showed that some facilities (e.g. wells) were too old and no longer fit for purpose, and that replacing these facilities was not commercially feasible given the economics of seasonal storage (Centrica Storage, 2017).

Aside from Rough, the United Kingdom's total storage capacity consists of eight salt cavern storage facilities. These eight facilities have higher injection/withdrawal rates, which allows for year-round injection and withdrawal and are better matched to the demands of a gas-dominated power sector. Rough's future unavailability will reduce the country's working gas capacity from 4.5 bcm to 1.4 bcm and peak output from 162 mcm/d to 117 mcm/d (Figure 4.10). This raises the question: does the closure of Rough create a security of supply issue for the United Kingdom during winter?

Figure 4.10 • UK working gas capacity (left) and peak output (right) with and without Rough



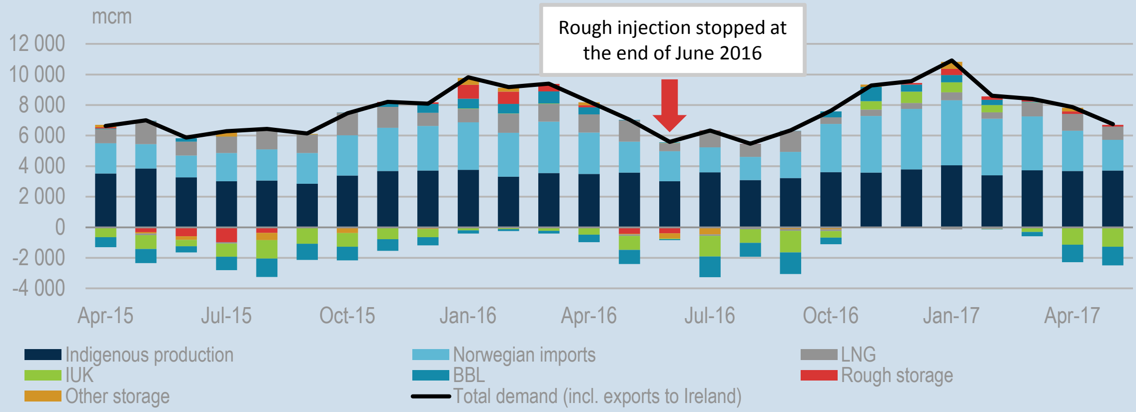
The UK gas supply is well diversified, with other flexible supply sources that could be drawn upon to balance Rough's unavailability.

- The first potential option is mid-term storage alongside the two interconnectors (Interconnector UK [IUK] and Balgzand Bacton Line [BBL]) that connect the United Kingdom with Belgium and the Netherlands, as these currently provide important flexibility, either as an outlet for surplus supplies in summer or to meet demand in winter (Figure 4.11).

- A second option is LNG – up to now mainly from Qatar – due to idle regasification capacity (only 20% of 50 bcm/y was used in 2016).

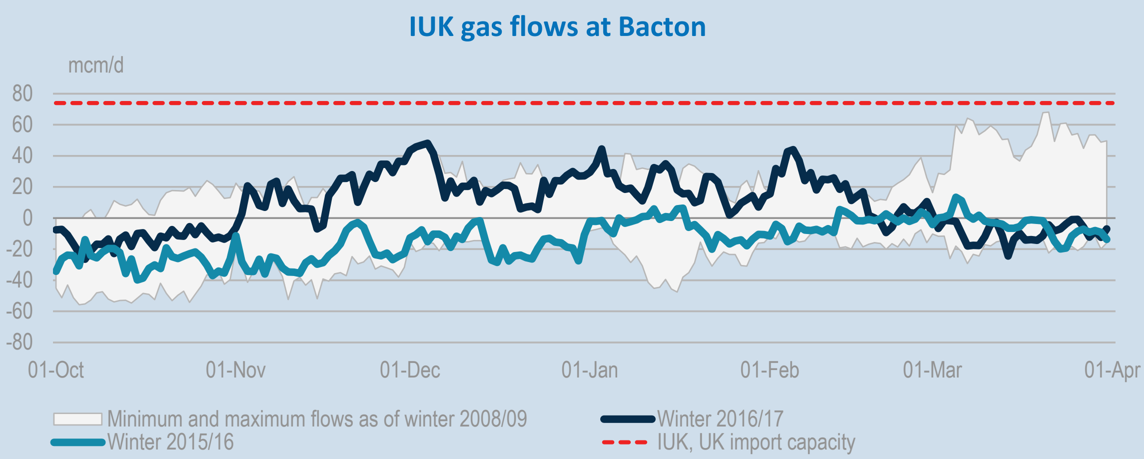
- Finally, pipeline imports from Norway and UK indigenous production provide most of the baseload supply, so Norway – already a major supplier of flexibility through the Langeled pipeline (Easington entry point) – is a third option. Norway has the flexibility to shift gas between the United Kingdom and the continent, and to increase production from flexible fields (mainly Oseberg and Troll) if National Balancing Point (NBP) prices give sufficient incentive. UK domestic production peaked in 2000, making gas imports an increasingly important pillar for the country's gas supply. However, the North Sea Cygnus gas field, which started production in December 2016, is likely to offset declines in other ageing gas fields, stabilising UK production for the upcoming winter 2017/18.

Figure 4.11 • UK supply/demand balance, April 2015–May 2017

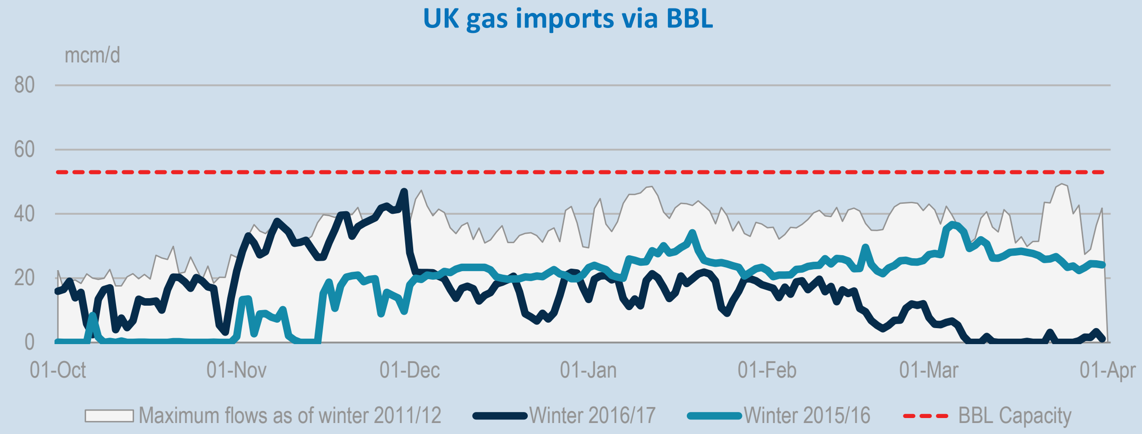


Last winter, provided a rehearsal of the impact of Rough's unavailability as Rough was operating at reduced capacity. Injection had to be stopped at the end of June 2016 and the site could only be filled to around 40%, which also reduced the peak delivery rate. During the winter of 2016/17, IUK and mid-term storage offset Rough's partial unavailability (BBL flows decreased at the end 2016, after Centrica's import contract with Gasterra expired). In combination with increased supplies from Norway, additional demand experienced at that time (an increase of 10% compared to the previous winter season, mainly due to higher gas-fired power production [up 29%]) was balanced throughout the season. For the upcoming 2017/18 winter, Rough will still contribute to UK gas supplies as Centrica envisages withdrawing cushion gas during winter 2017/18 (around 0.9 bcm). But once Rough is completely out of service, the country has surplus supply capacity to fill the gap, with IUK and/or BBL the likely sources. In winter 2016/17, IUK maximum flow into the UK was 48 mcm/d versus 74 mcm/d import capacity; BBL maximum flow was 47 mcm/d versus 53 mcm/d import capacity in the same period (Figure 4.12).

Figure 4.12 • IUK and BBL gas flows



Note: above zero indicates UK imports; below zero indicates UK exports.



However, NBP prices need to rise above continental gas hub levels in order to attract additional Norwegian imports. Based on spare capacity during winter 2016/17, St Fergus can take more additional volumes than Easington (Norwegian imports via Langeled pipeline [entry Easington] were temporarily reaching maximum capacity in the previous winter) (Figure 4.13). LNG volumes offer a much larger amount of spare capacity, which are likely to also be filled with US volumes contracted as of 2019 (Figure 4.14).

Figure 4.13 • Norwegian monthly import flows and relevant capacity

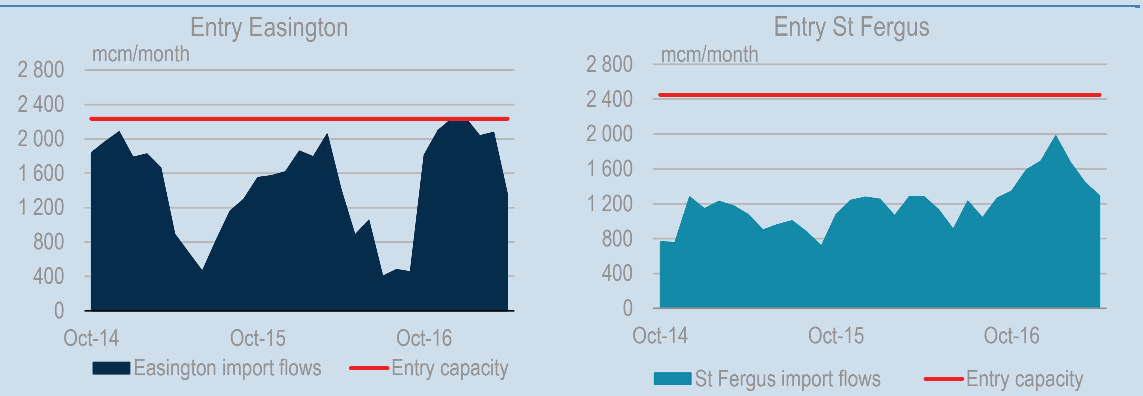
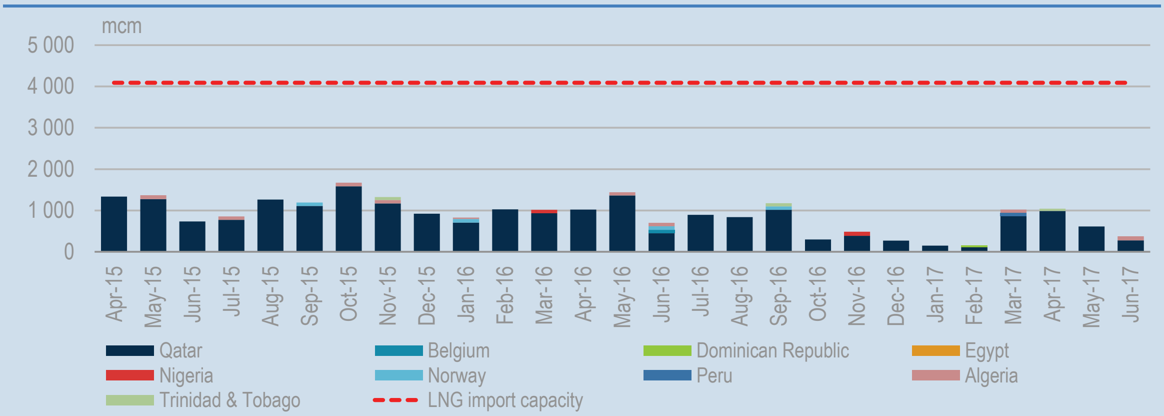


Figure 4.14 • LNG monthly import flows and total regasification capacity



Should these supply options be available, Rough's closure will not result in a security of supply issue during a normal winter for the United Kingdom– according to the gas security assessment made by system operator National Grid in its 2016/17 Winter Outlook report, supply capacity would be sufficient to cope with unavailability of Rough storage during a cold winter (1 in 20). Rough's unavailability, however, will also mean that flexibility during summer (injection of imported volumes) will be more difficult to manage; IUK, the only interconnector with physical export capacity to the continent, is already heavily used (NBP prices in 2016 and 2017 already reacted, dropping below summer prices of the previous seasons). Additionally, other outlets such as exports to Ireland are expected to decrease as Ireland's Corrib gas field started production in December 2015 and is therefore likely to result in lower gas imports from the United Kingdom.

Sources: BBL (2017), Historical Flow (database), www.bblcompany.com/operational-data/historical-flow?startdate_Day=1&startdate_Month=01&startdate_Year=2011&enddate_Day=31&enddate_Month=12&enddate_Year=2013&unit=m3%28n%29; Centrica Storage (2017), Cessation of Storage Operations at Rough, www.centrica.com/news/cessation-storage-operations-rough; ENTSOG (2017), Transparency Platform (database), https://transparency.entsog.eu/#/?loadBalancingZones=false; DUKES (2017), Statistics on supply and demand for natural gas (database), www.gov.uk/government/uploads/system/uploads/attachment_data/file/632530/DUKES_4.4.xls; IEA (2017a), Natural Gas Information 2017 (database), www.iea.org/statistics; Interconnector UK (2017), Operational Data (database), www.interconnector.com/operational-data/historical-data/data-downloads/; National Grid (2017), Storage and LNG Operator Information (database), www2.nationalgrid.com/uk/Industry-information/gas-transmission-operational-data/supplementary-reports/; National Grid (2016), 2016/17 Winter Outlook report, http://www2.nationalgrid.com/UK/Industry-information/Future-of-Energy/FES/Winter-Outlook/; National Statistics (2017), Energy Trends (database), www.gov.uk/government/statistics/gas-section-4-energy-trends.

Type 3: Reserve

Similar to Type 2, Type 3 countries have a diversified gas supply portfolio in which LNG accounts for only 10%. However, and in contrast with Type 2, the low rate of long-term LNG contracts (6% as an average compared to 80% for Type 2) implies a relatively short-term balancing of demand and supply, which is caused by several factors. LNG demand can be triggered by a relatively strong price-sensitive demand for gas in power generation and industry. Gas demand can also be dependent on a strong variability in power generation from other fuels. For example, in a country like Brazil power generation is highly dependent on hydropower, which can be unavailable in a dry season, thus leading to fuel switching as observed in recent years. Brazil is described in more detail in the following section. This group has 10 countries, accounting for 25 bcm of LNG imports in 2016, although 5 countries together accounted for only 1 bcm of these.

A number of these countries are characterised by a move to commissioning floating storage regasification units (FSRUs) in the recent past. This is the case for Argentina, Brazil, Colombia, Egypt, Kuwait and the United Arab Emirates. FSRUs are a less capital-intensive investment, especially if the unit is chartered, and allow for more flexible utilisation (with possible chartering periods of five years) than permanent onshore LNG regasification units. This is reflected in the high use of short-term contracts (see Box 4.2).

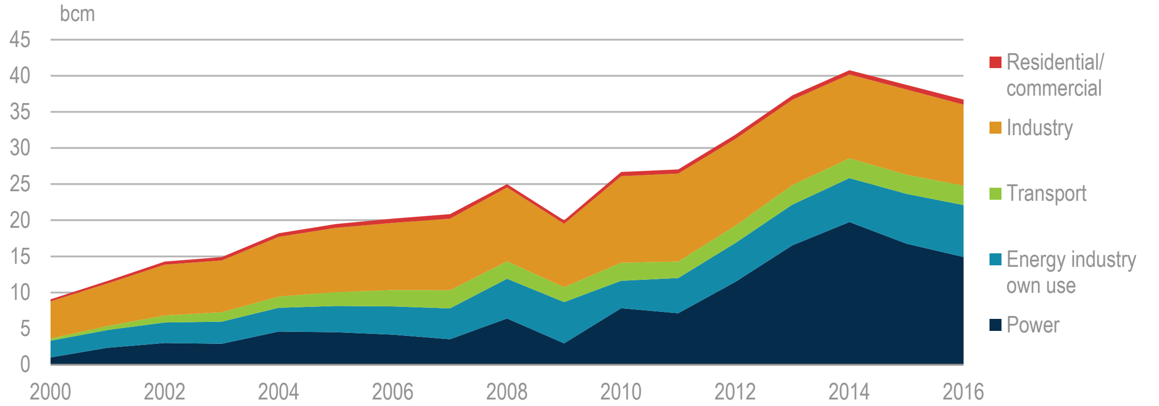
Countries within this group can be split into two subcategories:

- Countries that use LNG mainly to provide balance for a variable gas demand structure (e.g. Brazil), or to balance a short-term change in supply or demand, as in Egypt. Faced with a strong decline in production while demand continued to grow, Egypt had to resort to LNG imports; however, it is expected to ramp up production to resume its role as a net exporter in a few years' time, as the Zohr field is developed.
- Countries, such as the United Arab Emirates or Kuwait, which have used LNG to diversify their gas supply structure or because no pipeline import infrastructure alternative is available. Such countries could be expected to become Type 2 LNG buyers if they invest in more long-term onshore receiving terminals.

Brazil

Brazil is the second-largest gas market in Latin America, only surpassed by Argentina. Industry has traditionally been the main gas consumer in the country, with power generation also accounting for significant volumes (Figure 4.15). However, weak rainfall in the region – especially between 2012 and 2015 – has increased natural gas demand for power generation in recent years due to the country's high dependency on hydro generation. Hence, the severe drought recently experienced has boosted the natural gas share of power generation from 5% in 2011 to 14% in 2015. The growth in gas-fired generation has allowed the country to compensate for the significant decrease in hydro generation from 81% to 62% of overall production during the same period.

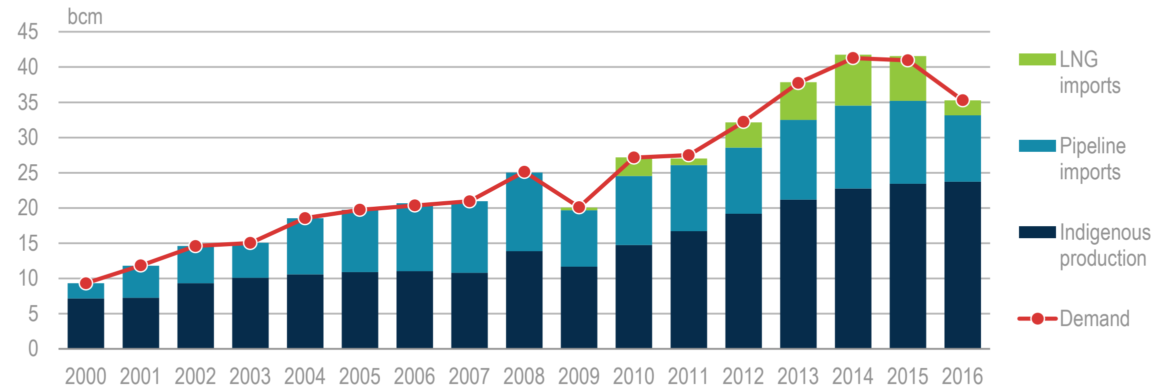
Figure 4.15 • Natural gas consumption in Brazil by sector, 2000-16



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

The increasing role of gas-fired generation in the power generation mix has pushed natural gas demand beyond Brazil's traditional supply sources, i.e. indigenous production and pipeline imports, mainly from Bolivia via the GASBOL pipeline.

Figure 4.16 • Natural gas supply and demand balance in Brazil, 2000-16



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

In order to diversify its natural gas supplies, the country decided to move to LNG and installed different FSRUs, to benefit from the flexibility that these solutions provide if the country's natural gas importing needs soften in the future. Accordingly, Brazil chartered three FSRUs consecutively and started importing LNG in 2009 (Figure 4.16). The new terminals were commissioned as follows:

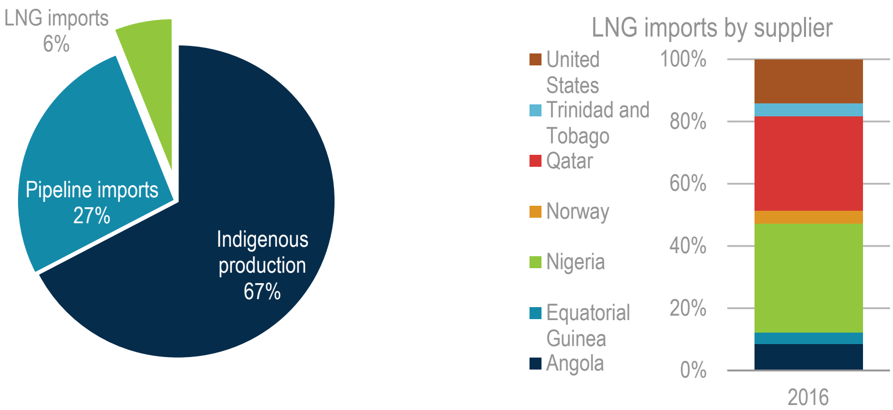
- Pecém in Q2 2009
- Guanabara Bay in Q3 2009
- Bahía in Q1 2014.

However, owing to the decrease in LNG imports during 2016 – a result of the recovery in hydro generation – and the low utilisation rate of the Guanabara Bay terminal, Petrobras announced in December its intention to end the charter of Golar Spirit FSRU (located at Guanabara Bay) one year in advance of its original plan. Subsequently, the company relinquished the vessel to owner Golar in June 2017.

The fact that Petrobras was able to end its charter agreement prematurely illustrates the flexibility that this kind of facility can provide, which would not have been possible with conventional onshore facilities.

In 2016, LNG imports represented 6% of natural gas supply in Brazil, while domestic production was responsible for 67%, the remaining 27% being met by pipeline imports from Bolivia (Figure 4.17). In aggregate, natural gas supply accounted for 35.3 bcm while LNG imports amounted to 2.1 bcm. Nigeria and Qatar were the main LNG suppliers, together accounting for 66% of total LNG deliveries.

Figure 4.17 • Brazil gas supply portfolio and LNG imports by supplier, 2016

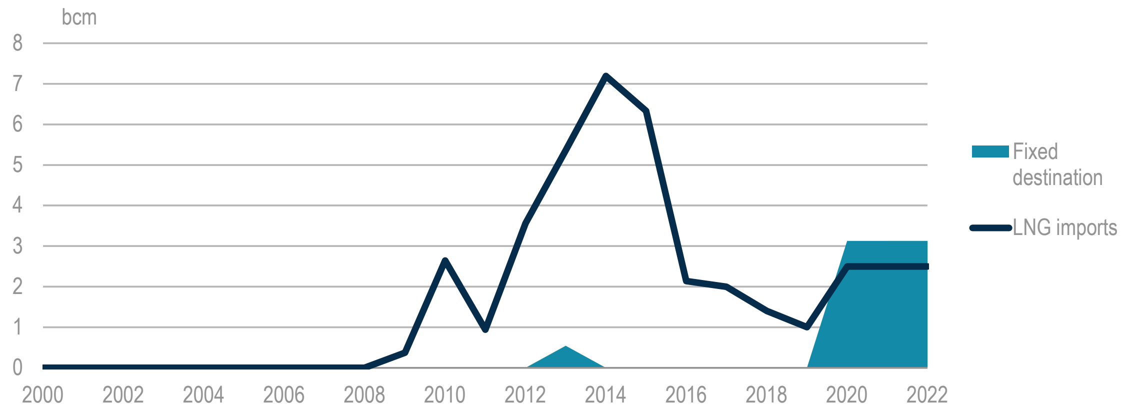


Sources: IEA (2017a), *Natural Gas Information 2017* (database), www.iea.org/statistics/; LNG imports: ICIS (2017), *ICIS LNG Edge*, www.icis.com/energy/liquefied-natural-gas/lng-edge (subscription required).

Given the uncertainty of natural gas demand and its dependency on hydropower availability, all the cargoes received in 2016 were negotiated on a spot basis (Figure 4.18). However, the recent "Gas to Grow" policy announced by Brazil will promote access to essential gas infrastructure and could support LNG demand in the long term (IEA, 2017b).

While the contribution of natural gas to power generation is expected to shrink in favour of growing renewable capacity, this would increase the flexibility requirements that must be met by gas-fired generation. Consequently, several projects have been called upon to provide the required flexibility in the future via integrated solutions, known as LNG-to-wire, which combines combined-cycle gas turbines with dedicated FSRUs. The first wave of these projects is expected to come on line by 2020 and would include long-term LNG supply contracts (of 25 years), as reflected in Figure 4.18.

Figure 4.18 • LNG contracted volumes and LNG imports in Brazil, 2000-22



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

Type 4: Price

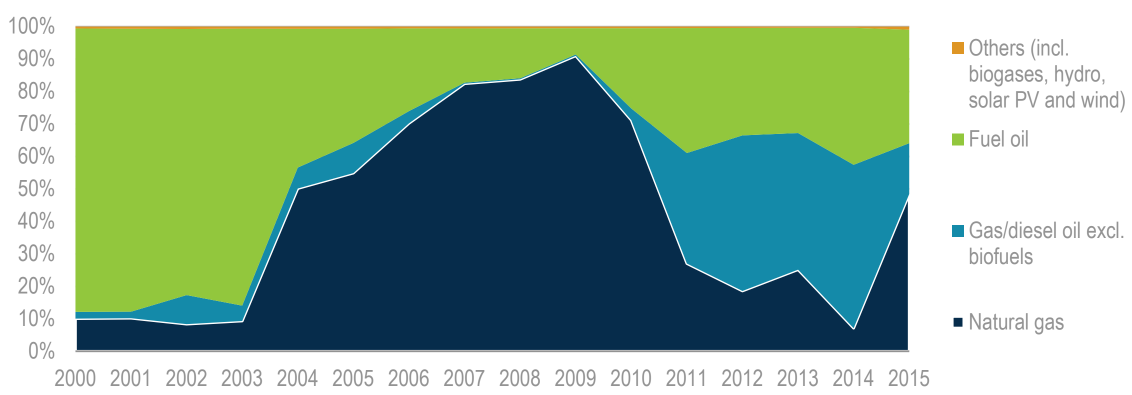
This group consists only of new players: Jordan, Puerto Rico, Lithuania and Jamaica. In Type 4,LNG is playing the role of dominant gas supply source, and is mainly purchased on a spot basis or under short- and medium-term contracts (Jordan, Puerto Rico and Jamaica). LNG is typically regarded as a cheap fuel in competition with other fuels, as in Jordan, which made a significant switch from oil to gas for power generation since the country started importing LNG in 2015, increasing the share of natural gas in its power mix from 7% in 2014 to 48% in 2015.

Other countries, such as Lithuania, which has a more balanced gas demand for power generation, industry and the residential sector, regard LNG mainly as a way to diversify gas supplies.

Jordan

Jordan is an illustrative example of the new wave of LNG importers that do not need natural gas to meet their energy demand, but which have recently decided to move to this fuel to create more competition in the power sector, taking advantage of low spot LNG prices.

Figure 4.19 • Power generation mix in Jordan by fuel, 2000-15



Note: PV = photovoltaic.
Source: IEA (2017d), *Electricity Information 2017* (database), www.iea.org/statistics/.

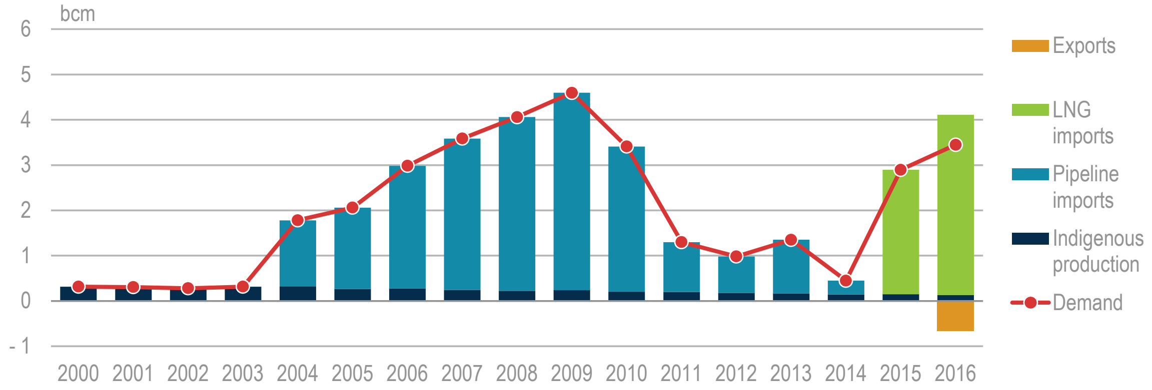
Power generation has been the only consumer of natural gas in Jordan since the country started domestic production in 1989. However, due to its limited gas reserves, natural gas represented less than 15% of its power mix until 2004 (Figure 4.19).

In 2004 the country started importing natural gas from Egypt through the Arab Gas Pipeline (Figure 4.20), allowing gas-fired generation to become the dominant contributor to its power generation mix, accounting for slightly more than 90% by 2009.

At that time, natural gas was mainly supplied by Egypt, with domestic production being responsible for just 5% of supply. In aggregate, natural gas accounted for 41% of total primary energy supply (TPES) in 2009 (IEA, 2017a; IEA, 2017c).

However, frequent disruptions to Egyptian natural gas supply through the Arab Gas Pipeline owing to terrorist attacks during 2010, and the subsequent sharp rise in Egyptian gas demand in 2011, reduced Egyptian gas exports to Jordan by 93% in 2014 from a peak of 4.4 bcm in 2009 (Figure 4.20). The decline in Jordan's natural gas imports forced the country to switch gas-fired generation to fuel oil and gas/diesel oil, reducing the gas share in the power generation mix to 7% by 2014 (Figure 4.19). This change caused an important increase in Jordan's energy bill, raising the cost of consumed energy from JOD 2 603 million in 2010 to JOD 4 480 million in 2014 (MEMR, 2015).

Figure 4.20 • Natural gas supply and demand balance in Jordan, 2000-16



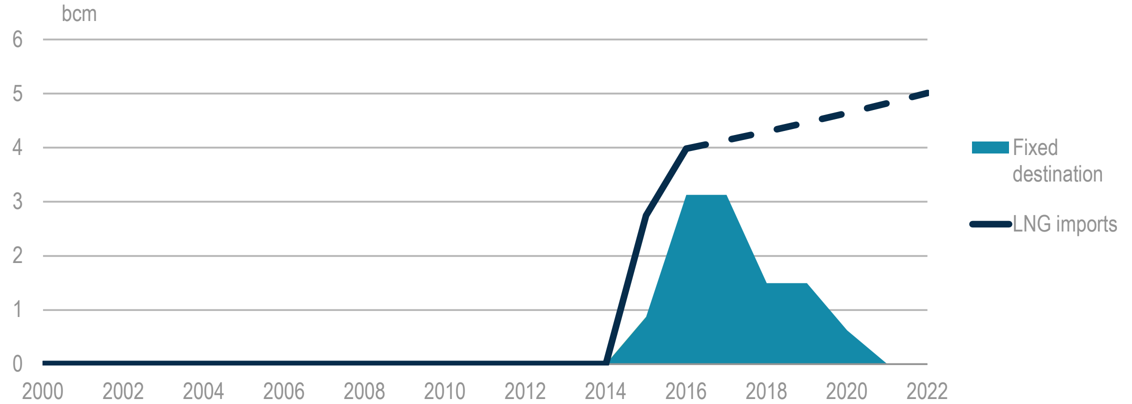
Sources: IEA (2017a), *Natural Gas Information 2017* (database), www.iea.org/statistics/; IEA analysis based on Argus (2017), "Egypt, Jordan and Pakistan import more LNG", www.argusmedia.com/news/article/?id=1401989.

To find more competitive supply for power generation and benefit from the abundance of cheap LNG in the market, the country decided to develop a new regasification terminal. Due to the uncertainty about future availability of competitive Egyptian or Israeli pipeline imports and the urgency to access new supply as soon as possible, the country opted to lease an FSRU as the best option to fulfil its requirements in a timely and cost-effective way.

Thus, Jordan awarded Golar LNG a five-year charter agreement to install the FSRU Golar Eskimo in the port of Aqaba, in the Red Sea. The terminal started importing LNG by mid-2015 (Figure 4.20) through spot and medium-term agreements, providing flexibility to slow LNG imports whenever spot prices increase or cheaper pipeline supplies become available. Accordingly, National Electric Power Company of Jordan (NEPCO) signed two contracts with Shell, one five-year sale and purchase agreement for the supply of 1.5 bcm/year from mid-2015 up to 2020, and another two-year contract for the delivery of 1.6 bcm/year starting in 2016 (Figure 4.21). On top of these contracts, Jordan also imported additional spot LNG cargoes and is expected to maintain this trend in the coming years, unless cheaper alternative supplies (possibly pipeline gas) become available.

While the contracts signed with Shell have fixed destination clauses that could threaten Jordan's future flexibility, their short length together with country's under-contracted situation (Figure 4.21) grant Jordan the ability to lower its LNG imports rapidly if market developments point towards it.

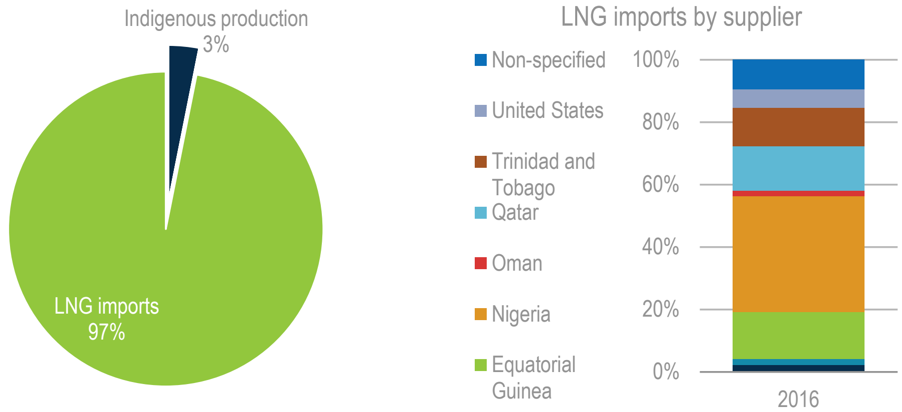
Figure 4.21 • LNG contracted volumes and LNG imports in Jordan, 2000-22



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

In 2016, Jordan's LNG imports amounted to 4 bcm, representing 97% of its natural gas supplies (Figure 4.22). However, only 40 out of the 48 LNG cargoes delivered to the country were used by domestic consumers (Figure 4.20), while the other 8 cargoes were regasified and exported to Egypt through the Arab Gas Pipeline (Argus, 2017) according to an agreement between Egypt and Jordan to share FSRU Golar Eskimo spare capacity (LNG World News, 2016).

Figure 4.22 • Jordan gas supply portfolio and LNG imports by supplier, 2016



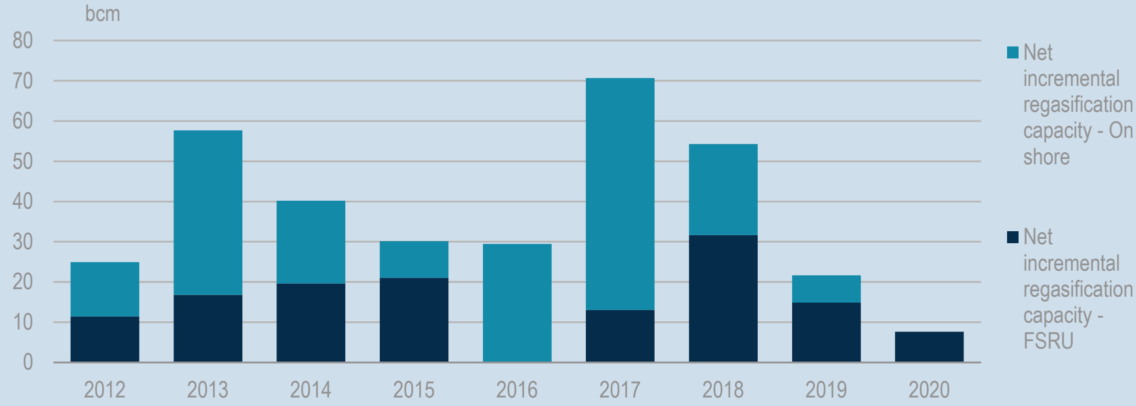
Sources: IEA (2017a), *Natural Gas Information 2017* (database), www.iea.org/statistics/; LNG imports: ICIS (2017), *ICIS LNG Edge*, www.icis.com/energy/liquefied-natural-gas/lng-edge (subscription required).

In the longer term, Jordan's government is planning to reduce the share of natural gas in its primary energy mix from 35% in 2016 to 30% by 2020, and 8% by 2025. This reduction will mainly be driven by Jordan's aim to start using nuclear energy for power generation (MEMR, 2017).

Box 4.2 • FSRUs

FSRUs have opened the door to LNG for a range of additional markets recently, mostly identified as Type 3 or Type 4, which import LNG to meet short-term gas demand when the LNG price is competitive with other fuels. FSRUs have been attractive for these markets because of lower initial investment cost, shorter installation period (around 18 months for FSRUs versus more than 5 years for onshore conventional regasification terminals) and more flexibility in length of commitment than onshore regasification facilities. The most recent countries to invest in FSRUs are Lithuania (Type 4) in 2014, Egypt (Type 3) and Jordan (Type 4) in 2015, and the United Arab Emirates (Type 3) in 2016.

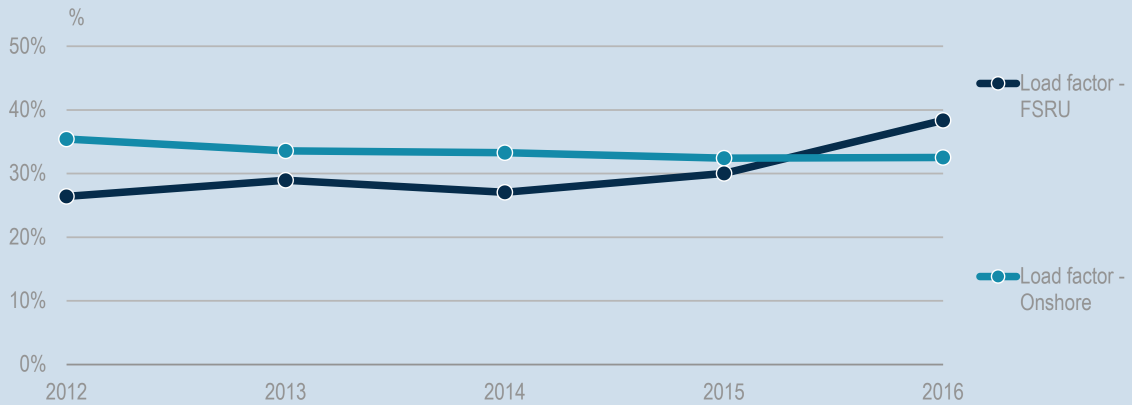
Figure 4.23 • Incremental regasification capacity: conventional vs FSRU (2012-20)



Since the world's first FSRU starting operation in the United States in 2005, 24 FSRUs are now in operation. Globally, FSRUs account for 18.5% of the total number of regasification terminals and 10% of regasification capacity. In the coming years, more than 60 bcm of new FSRU capacity is expected to come online and around two-thirds of this addition is due to take place in Type 3 and Type 4, such as Ghana, Bangladesh and Uruguay (Figure 4.23).

Since 2015, backed by low LNG prices, the volume of LNG received by FSRUs has grown. The load factor of FSRUs has also grown year on year and in 2016 exceeded that of onshore regasification terminals (Figure 4.24). This is a good example of the price sensitivity of Type 3 and Type 4. Although each of these markets is much smaller than traditional large LNG buyers, such as Japan and Korea, their aggregated LNG import volumes in 2016 accounted for 41.5 bcm, equal to 12% of global LNG demand, together the third-largest market after Japan and Korea.

Figure 4.24 • Load factor for FSRUs vs conventional regasification terminals (2012-16)



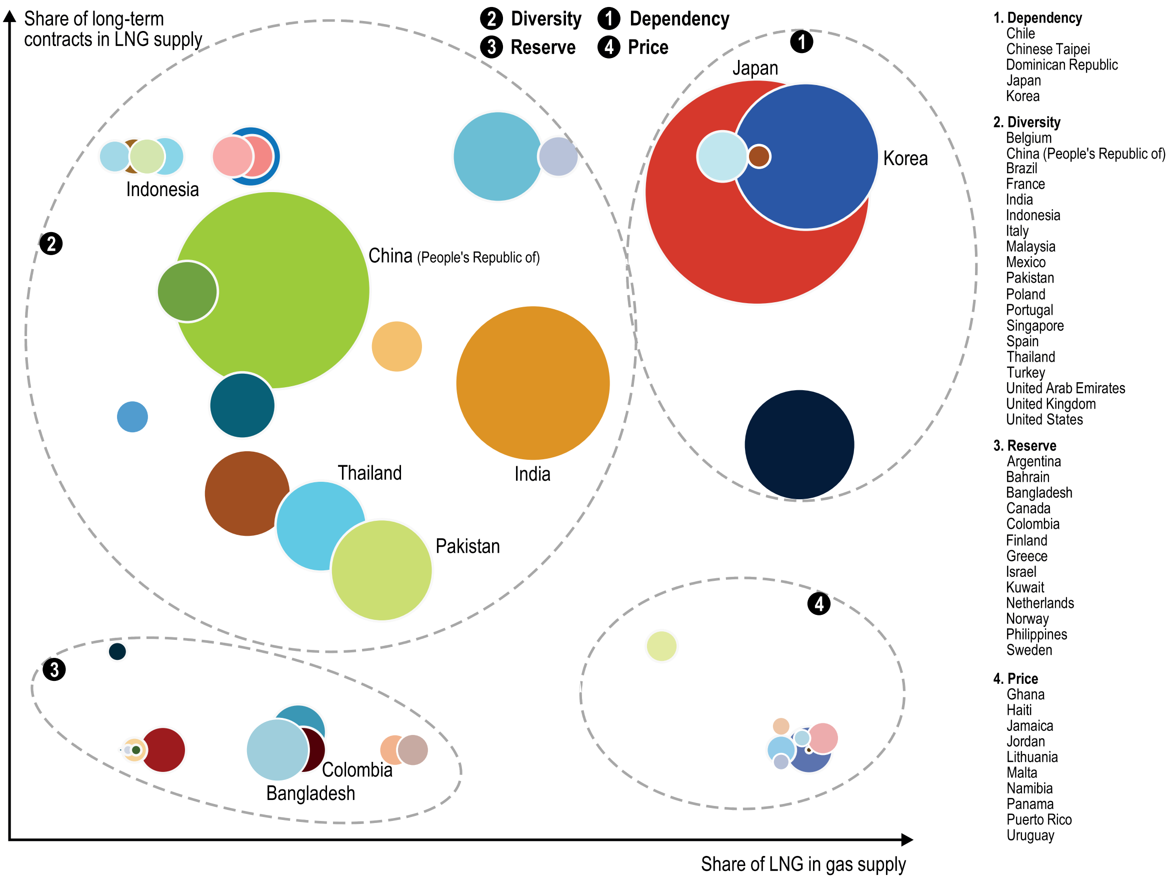
Source: ICIS (2017), *ICIS LNG Edge*, www.icis.com/energy/liquefied-natural-gas/lng-edge (subscription required).

As an instrument of security of supply, in recent years FSRUs have played an important role in overcoming the shortfall in gas production or meeting emerging gas demand quickly. In terms of number of importers and also aggregated volumes, the share of the LNG market met by FSRUs is expected to expand mainly in Type 3 and Type 4. Given the nature of these markets, the demand for LNG may increase as the market expands or decrease in response to higher LNG prices. Therefore, flexibility in the global LNG market will become more important for the timely and adequate response to potential fluctuations in LNG demand among these markets.

Increasing diversification of the LNG buyer market by 2022

Global LNG imports are expected to grow from around 355 bcm in 2016 (including re-exports) to over 460 bcm in 2022. Taking the 2016 position in the types' matrix as a starting point, a number of buyers move their position towards a higher share of LNG in their natural gas supply, and nine new countries are expected to enter the LNG market over this period.[7] The buyer types provide insight into the groups in which LNG demand is expected to grow. With this, the interaction between flexible LNG sellers and buyers can be better understood. Figure 4.25 shows the LNG types for 2022 on the basis of expected supply and demand (from the *Gas 2017* report) and contractual information as of September 2017 (IEA, 2017b).

Figure 4.25 • LNG buyer types 2022



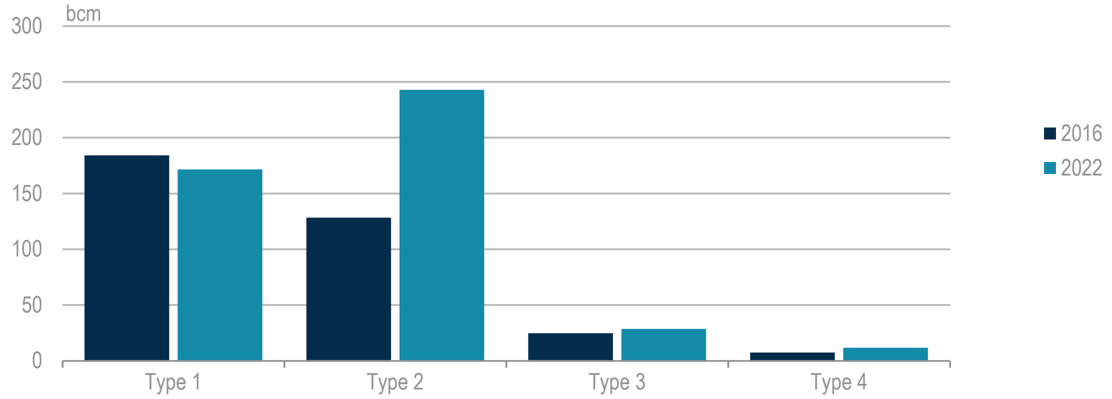
Source: IEA (2017b), *Market Report Series: Gas 2017*, www.iea.org/bookshop/741-Market_Report_Series:_Gas_2017; ICIS (2017), *ICIS LNG Edge*, www.icis.com/energy/liquefied-natural-gas/lng-edge (subscription required).

[7] Nine countries (Bahrain, Bangladesh, Ghana, Haiti, Namibia, Panama, Philippines and Uruguay) are expected to start import LNG by 2022, while Egypt's imports will probably decrease to zero in the coming years.

The first observations are an increase in LNG demand in most countries and territories, notably expected in the People's Republic of China (hereafter, "China"), India, Thailand and Pakistan. Although these types do not support a rigid distinction between LNG buyers, Figure 4.25 displays a more dispersed distribution of LNG buyers over the metric. This indicates that buyers will increasingly show characteristics that are typically attributed to more than one type.

Second, ten new players are expected to enter the market as Type 3 and 4 LNG buyers, although the expected LNG imports for these two groups only increase by 11 bcm. Third, a number of buyers move towards the high and low range on the vertical axis (share of long-term contracts). This is explained by two trends: on the one hand, those moving to the upper range are (close to) over-contracted because the long-term contract volumes are higher than the expected LNG import volumes; on the other hand, because a number of contracts end between 2016 and 2022, and for which no new long-term contracts have been signed yet, a number of buyers automatically move to a low share of long-term contracts in LNG imports by 2022. As can be seen in Figure 4.25, Type 1 and 2 still rely mostly on long-term contracts for their 2022 LNG supply, albeit at a lower level than in 2016. The coming years will show whether these volumes will be long-term contracted or whether LNG buyers will rely on medium- and short-term commitments or the spot market. Figure 4.26 summarises the volume of imports for the four LNG buyer types for 2016 and 2022.

Figure 4.26 • LNG buyer type imports in 2016 and 2022



Type 1 Dependent

The top two importers of 2016, Japan and Korea, both Type 1 players, show a fall in LNG imports between 2016 and 2022 (down 17 bcm/y). This goes together with an upward shift towards an over-contracted position, which indicates that the total of long-term contracts signed in the past has been overestimating, from today's perspective, the gas demand expected by 2022.

Type 2 Diversity

Chinese LNG imports are expected to grow by 41 bcm/y by 2022, accounting for more than one-third of the growth among Type 2 countries. This will place China as the second-largest LNG importer by 2022. A high share of its 2022 LNG imports are now already committed under long-term contracts. India is expected to become the third-largest LNG importer by 2022, moving from 26 bcm/y in 2016 to 48 bcm/y in 2022. So far, about half of its expected LNG imports are secured under long-term contracts.

A number of Type 2 portfolio importers, notably European players, find their expected LNG imports already fully committed in long-term contracts, as shown in Figure 4.25.

India and Spain both move marginally to the right, away from the Type 2 cluster, indicating an increasing reliance on LNG for their gas supply. Several countries, including Thailand and Pakistan, have not yet signed new long-term contracts in proportion to the expected growth in LNG imports, as shown by a drop on the vertical axis in Figure 4.25. This points in the direction of a share of their LNG imports being guaranteed (and committed under long-term contracts) and part likely being met by short-term contracts.

Type 3 Reserve

As for the Type 3 cluster, growth in volumes per country is expected and a number of new LNG importers are expected to emerge in this cluster, notably Bangladesh, the Philippines and Colombia, which together account for 14 bcm per year growth in LNG imports. Generally speaking, this group of countries is likely to remain, to a certain extent, reliant on short-term contracts and this makes their LNG demand more price sensitive. One peculiarity in this group is Egypt, accounting for over one-third of Type 4 LNG imports in 2016 and expected to revert back to being an LNG exporter by 2022.

Type 4 Price

An increasing number of small and most likely price-sensitive players are coming to the market over the coming years. These are typically found in the Type 4 cluster. Relatively low LNG volumes are likely to be used in competition with other fuels in some markets, making their demand more price sensitive. Although the total volumes are limited, these pockets of growth emerge in an oversupplied market. In the case of a significant supply or demand shock, these buyers are more likely to decrease LNG imports on the basis of price (and only when their energy systems permit a decrease in LNG supplies).

Increasing market interdependence will bring new security of supply challenges

In conclusion, the LNG buyer clusters that exist today are not likely to remain as they are. The LNG buyer market is likely to become more diversified with an increasing share of LNG imports by emerging economies. At the same time, LNG overcapacity is expected to ebb, with an anticipated progressive retightening of the supply-demand balance – although the growth of LNG demand is not expected to be sufficient to rebalance the LNG market before 2022, the end of the forecast period.

A number of existing LNG importers are likely to increase the diversity of their LNG supply portfolio – finding a balance between long-term and short-term commitments. With a number of big players, such as India, Pakistan and Thailand, close to the centre of the LNG buyer metric, it is not fully clear yet how their LNG buying commitment and policy will develop over the coming years. The integration of a growing share of intermittent renewable production sources in the power system is expected to drive more LNG demand to meet flexibility requirements.

As more importers join the LNG market, they inherently become more vulnerable to market events beyond their own traditional trading region. A better understanding and adaptation of LNG buying strategy and gas security policy among both buyers and suppliers would increase the resilience of the global LNG market.

For individual buyers, it is important to understand in which direction their market is moving; when they rely more on LNG for their gas supplies, a greater need for a robust gas security policy may be appropriate. In the case of markets likely to increase reliance on short-term commitments, an energy system policy that fosters proper demand response and power system fuel-switching capabilities – to deal with an LNG demand or supply shock – will be needed to safeguard reliable and affordable energy supply.

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Appendix

Table A.1 • Adjusted liquefaction capacity and offline capacity by type (bcm)

Country	Capacity and Offline reasons	2012	2013	2014	2015	2016	2017E
Africa	**Nameplate capacity**	**77.2**	**83.8**	**93.6**	**96.8**	**96.8**	**96.8**
	Adjusted capacity	**59.5**	**60.5**	**61.2**	**60.2**	**61.4**	**68.4**
	Feedgas	**13.6**	**15.5**	**24.2**	**25.4**	**26.1**	**23.8**
	Security	**0.8**	**2.5**	**-**	**-**	**-**	**-**
	Technical	**0.2**	**2.1**	**5.0**	**7.8**	**6.2**	**1.1**
	Weather	**-**	**-**	**-**	**0.3**	**-**	**-**
	Planned maintenance	**3.1**	**3.2**	**3.2**	**3.2**	**3.2**	**3.6**
Algeria	Nameplate capacity	25.8	28.9	35.2	38.4	38.4	38.4
	Adjusted capacity	18.1	20.1	25.6	28.4	26.8	27.8
	Feedgas	6.8	7.8	8.2	8.2	10.1	8.2
	Security	-	-	-	-	-	-
	Technical	-	-	-	-	-	1.0
	Weather	-	-	-	0.3	-	-
	Planned maintenance	1.0	1.1	1.3	1.5	1.4	1.5
Angola	Nameplate capacity	-	3.5	7.1	7.1	7.1	7.1
	Adjusted capacity	-	3.4	2.0	-	2.1	6.6
	Feedgas	-	-	-	-	-	-
	Security	-	-	-	-	-	-
	Technical	-	-	5.0	7.1	4.8	0.1
	Weather	-	-	-	-	-	-
	Planned maintenance	-	0.2	0.1	-	0.1	0.3
Egypt	Nameplate capacity	16.6	16.6	16.6	16.6	16.6	16.6
	Adjusted capacity	9.3	9.3	0.5	-	0.7	1.0
	Feedgas	6.8	6.8	16.1	16.6	15.9	15.6
	Security	-	-	-	-	-	-
	Technical	-	-	-	-	-	-
	Weather	-	-	-	-	-	-
	Planned maintenance	0.5	0.5	-	-	-	-
Equatorial Guinea	Nameplate capacity	5.0	5.0	5.0	5.0	5.0	5.0
	Adjusted capacity	4.8	4.8	4.8	4.8	4.8	4.8
	Feedgas	-	-	-	-	-	-
	Security	-	-	-	-	-	-
	Technical	-	-	-	-	-	-
	Weather	-	-	-	-	-	-
	Planned maintenance	0.3	0.3	0.3	0.3	0.3	0.3
Nigeria	Nameplate capacity	29.8	29.8	29.8	29.8	29.8	29.8
	Adjusted capacity	27.4	22.9	28.3	27.0	27.0	28.3
	Feedgas	-	1.0	-	0.7	0.1	-
	Security	0.8	2.5	-	-	-	-
	Technical	0.2	2.1	-	0.7	1.3	-
	Weather	-	-	-	-	-	-
	Planned maintenance	1.4	1.2	1.5	1.4	1.4	1.5

Notes: 2017 numbers are estimated based on the data until the end of September 2017; Outage volumes by feedgas, security, technical and weather were calculated based on *ICIS LNG Edge*; Outage volumes by planned maintenance were IEA estimation.

Source: IEA analysis based on ICIS (2017), *ICIS LNG Edge* (see Reference section in Chapter 1).

Table A.2 • Adjusted liquefaction capacity and offline capacity by type (bcm) (continued)

Country	Capacity and Offline reasons	2012	2013	2014	2015	2016	2017E
Asia Oceania	**Nameplate capacity**	**121.1**	**124.0**	**125.9**	**139.0**	**163.3**	**189.3**
	Adjusted capacity	**103.0**	**104.8**	**105.7**	**116.8**	**140.1**	**160.4**
	Feedgas	**11.6**	**11.6**	**14.6**	**14.6**	**12.3**	**18.3**
	Security	**-**	**-**	**-**	**-**	**-**	**-**
	Technical	**0.5**	**0.4**	**-**	**1.3**	**3.4**	**1.4**
	Weather	**0.6**	**1.7**	**-**	**0.1**	**-**	**0.7**
	Planned maintenance	**5.4**	**5.5**	**5.6**	**6.1**	**7.4**	**8.4**
Australia	Nameplate capacity	30.1	33.0	33.0	41.5	65.8	88.2
	Adjusted capacity	28.1	29.5	31.4	38.4	59.5	76.1
	Feedgas	-	-	-	-	-	6.0
	Security	-	-	-	-	-	-
	Technical	-	0.3	-	0.9	3.2	1.4
	Weather	0.5	1.7	-	0.1	-	0.7
	Planned maintenance	1.5	1.6	1.7	2.0	3.1	4.0
Brunei	Nameplate capacity	9.8	9.8	9.8	9.8	9.8	9.8
	Adjusted capacity	9.3	9.3	8.8	8.8	8.3	8.4
	Feedgas	-	-	0.5	0.5	1.0	1.0
	Security	-	-	-	-	-	-
	Technical	-	-	-	-	0.1	-
	Weather	-	-	-	-	-	-
	Planned maintenance	0.5	0.5	0.5	0.5	0.4	0.4
Indonesia	Nameplate capacity	46.2	46.2	43.5	43.4	43.4	43.7
	Adjusted capacity	32.4	32.8	27.9	27.6	30.4	30.7
	Feedgas	11.6	11.6	14.1	14.1	11.4	11.4
	Security	-	-	-	-	-	-
	Technical	0.5	0.1	-	0.2	-	-
	Weather	0.1	-	-	-	-	-
	Planned maintenance	1.7	1.7	1.5	1.5	1.6	1.6
Malaysia	Nameplate capacity	35.0	35.0	35.0	35.0	35.0	38.2
	Adjusted capacity	33.2	33.2	33.2	33.2	33.2	36.3
	Feedgas	-	-	-	-	-	-
	Security	-	-	-	-	-	-
	Technical	-	-	-	-	-	-
	Weather	-	-	-	-	-	-
	Planned maintenance	1.7	1.7	1.7	1.7	1.7	1.9
Papua New Guinea	Nameplate capacity	-	-	4.7	9.4	9.4	9.4
	Adjusted capacity	-	-	4.5	8.7	8.7	8.9
	Feedgas	-	-	-	-	-	-
	Security	-	-	-	-	-	-
	Technical	-	-	-	0.2	0.2	-
	Weather	-	-	-	-	-	-
	Planned maintenance	-	-	0.2	0.5	0.5	0.5

Notes: 2017 numbers are estimated based on the data until the end of September 2017; Outage volumes by feedgas, security, technical and weather were calculated based on *ICIS LNG Edge*; Outage volumes by planned maintenance were IEA estimation.

Source: IEA analysis based on ICIS (2017), *ICIS LNG Edge* (see Reference section in Chapter 1).

Table A.3 • Adjusted liquefaction capacity and offline capacity by type (bcm) (continued)

Country	Capacity and Offline reasons	2012	2013	2014	2015	2016	2017E
Middle East	**Nameplate capacity**	**136.0**	**136.0**	**136.0**	**136.0**	**136.0**	**136.0**
	Adjusted capacity	**124.9**	**127.1**	**127.2**	**120.1**	**118.1**	**117.6**
	Feedgas	**1.7**	**1.7**	**2.1**	**2.5**	**2.5**	**2.5**
	Security	**2.4**	**-**	**-**	**7.0**	**9.1**	**9.1**
	Technical	**0.4**	**0.5**	**-**	**-**	**-**	**0.6**
	Weather	**-**	**-**	**-**	**-**	**-**	**-**
	Planned maintenance	**6.6**	**6.7**	**6.7**	**6.3**	**6.2**	**6.2**
Oman	Nameplate capacity	14.1	14.1	14.1	14.1	14.1	14.1
	Adjusted capacity	11.8	11.8	11.4	11.0	11.0	11.0
	Feedgas	1.7	1.7	2.1	2.5	2.5	2.5
	Security	-	-	-	-	-	-
	Technical	-	-	-	-	-	-
	Weather	-	-	-	-	-	-
	Planned maintenance	0.6	0.6	0.6	0.6	0.6	0.6
Qatar	Nameplate capacity	104.9	104.9	104.9	104.9	104.9	104.9
	Adjusted capacity	99.3	99.1	99.6	99.6	99.6	99.0
	Feedgas	-	-	-	-	-	-
	Security	-	-	-	-	-	-
	Technical	0.4	0.5	-	-	-	0.6
	Weather	-	-	-	-	-	-
	Planned maintenance	5.2	5.2	5.2	5.2	5.2	5.2
United Arab Emirates	Nameplate capacity	7.9	7.9	7.9	7.9	7.9	7.9
	Adjusted capacity	7.5	7.5	7.5	7.5	7.5	7.5
	Feedgas	-	-	-	-	-	-
	Security	-	-	-	-	-	-
	Technical	-	-	-	-	-	-
	Weather	-	-	-	-	-	-
	Planned maintenance	0.4	0.4	0.4	0.4	0.4	0.4
Yemen	Nameplate capacity	9.1	9.1	9.1	9.1	9.1	9.1
	Adjusted capacity	6.4	8.7	8.7	2.0	-	-
	Feedgas	-	-	-	-	-	-
	Security	2.4	-	-	7.0	9.1	9.1
	Technical	-	-	-	-	-	-
	Weather	-	-	-	-	-	-
	Planned maintenance	0.3	0.5	0.5	0.1	-	-

Notes: 2017 numbers are estimated based on the data until the end of September 2017; Outage volumes by feedgas, security, technical and weather were calculated based on *ICIS LNG Edge*; Outage volumes by planned maintenance were IEA estimation.

Source: IEA analysis based on ICIS (2017), *ICIS LNG Edge* (see Reference section in Chapter 1).

Table A.4 • Adjusted liquefaction capacity and offline capacity by type (bcm) (continued)

Country	Capacity and Offline reasons	2012	2013	2014	2015	2016	2017E
North America	**Nameplate capacity**	**2.0**	**2.0**	**2.0**	**2.0**	**8.2**	**24.4**
	Adjusted capacity	**0.6**	**0.6**	**0.6**	**0.6**	**5.0**	**20.9**
	Feedgas	**1.4**	**1.4**	**1.4**	**1.4**	**1.4**	**2.0**
	Security	**-**	**-**	**-**	**-**	**-**	**-**
	Technical	**-**	**-**	**-**	**-**	**1.6**	**-**
	Weather	**-**	**-**	**-**	**-**	**-**	**0.3**
	Planned maintenance	**-**	**-**	**-**	**-**	**0.3**	**1.1**
United States	Nameplate capacity	2.0	2.0	2.0	2.0	8.2	24.4
	Adjusted capacity	0.6	0.6	0.6	0.6	5.0	20.9
	Feedgas	1.4	1.4	1.4	1.4	1.4	2.0
	Security	-	-	-	-	-	-
	Technical	-	-	-	-	1.6	-
	Weather	-	-	-	-	-	0.3
	Planned maintenance	-	-	-	-	0.3	1.1
Latin America	**Nameplate capacity**	**26.6**	**26.6**	**26.6**	**26.6**	**26.6**	**26.6**
	Adjusted capacity	**24.7**	**25.3**	**25.0**	**24.4**	**22.2**	**21.8**
	Feedgas	**-**	**-**	**-**	**0.5**	**1.4**	**2.0**
	Security	**-**	**-**	**-**	**-**	**-**	**-**
	Technical	**0.6**	**-**	**0.2**	**-**	**1.8**	**1.6**
	Weather	**-**	**-**	**0.1**	**0.4**	**-**	**-**
	Planned maintenance	**1.3**	**1.3**	**1.3**	**1.3**	**1.2**	**1.1**
Peru	Nameplate capacity	6.1	6.1	6.1	6.1	6.1	6.1
	Adjusted capacity	5.7	5.7	5.7	5.4	5.3	5.6
	Feedgas	-	-	-	-	-	-
	Security	-	-	-	-	-	-
	Technical	-	-	-	-	0.5	0.2
	Weather	-	-	0.1	0.4	-	-
	Planned maintenance	0.3	0.3	0.3	0.3	0.3	0.3
Trinidad and Tobago	Nameplate capacity	20.5	20.5	20.5	20.5	20.5	20.5
	Adjusted capacity	19.0	19.5	19.3	19.0	16.9	16.2
	Feedgas	-	-	-	0.5	1.4	2.0
	Security	-	-	-	-	-	-
	Technical	0.6	-	0.2	-	1.3	1.4
	Weather	-	-	-	-	-	-
	Planned maintenance	1.0	1.0	1.0	1.0	0.9	0.9

Notes: 2017 numbers are estimated based on the data until the end of September 2017; Outage volumes by feedgas, security, technical and weather were calculated based on *ICIS LNG Edge*; Outage volumes by planned maintenance were IEA estimation.

Source: IEA analysis based on ICIS (2017), *ICIS LNG Edge* (see Reference section in Chapter 1).

Table A.5 • Adjusted liquefaction capacity and offline capacity by type (bcm) (continued)

Country	Capacity and Offline reasons	2012	2013	2014	2015	2016	2017E
Eurasia	**Nameplate capacity**	**19.3**	**19.3**	**19.3**	**20.1**	**20.9**	**24.7**
	Adjusted capacity	**17.7**	**17.1**	**18.2**	**19.1**	**19.1**	**23.2**
	Feedgas	-	-	-	-	-	-
	Security	-	-	-	-	-	-
	Technical	**0.7**	**1.3**	**0.2**	-	**0.8**	**0.2**
	Weather	-	-	-	-	-	-
	Planned maintenance	**0.9**	**0.9**	**1.0**	**1.0**	**1.0**	**1.2**
Norway	Nameplate capacity	6.3	6.3	6.3	6.3	6.3	6.3
	Adjusted capacity	5.3	4.7	5.8	5.9	5.9	5.9
	Feedgas	-	-	-	-	-	-
	Security	-	-	-	-	-	-
	Technical	0.7	1.3	0.2	-	0.1	-
	Weather	-	-	-	-	-	-
	Planned maintenance	0.3	0.2	0.3	0.3	0.3	0.3
Russian Federation	Nameplate capacity	13.1	13.1	13.1	13.9	14.7	18.4
	Adjusted capacity	12.4	12.4	12.4	13.2	13.2	17.3
	Feedgas	-	-	-	-	-	-
	Security	-	-	-	-	-	-
	Technical	-	-	-	-	0.7	0.2
	Weather	-	-	-	-	-	-
	Planned maintenance	0.7	0.7	0.7	0.7	0.7	0.9
Total	**Nameplate capacity**	**382.3**	**391.8**	**403.5**	**420.6**	**451.8**	**497.8**
	Adjusted capacity	**330.5**	**335.4**	**337.9**	**341.2**	**365.9**	**412.4**
	Feedgas	**28.3**	**30.2**	**42.4**	**44.5**	**43.8**	**48.7**
	Security	**3.2**	**2.5**	-	**7.0**	**9.1**	**9.1**
	Technical	**2.3**	**4.3**	**5.4**	**9.1**	**13.8**	**5.0**
	Weather	**0.6**	**1.7**	**0.1**	**0.8**	-	**0.9**
	Planned maintenance	**17.4**	**17.7**	**17.8**	**18.0**	**19.2**	**21.7**

Notes: 2017 numbers are estimated based on the data until the end of September 2017; Outage volumes by feedgas, security, technical and weather were calculated based on *ICIS LNG Edge*; Outage volumes by planned maintenance were IEA estimation.

Source: IEA analysis based on ICIS (2017), *ICIS LNG Edge* (see Reference section in Chapter 1).

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,[8,9] 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,[10, 11] Czech Republic, Denmark, Estonia, Finland, France, Germany, Greece, Hungary, Ireland, Italy, Latvia, Lithuania, Luxembourg, Malta,

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[8] 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".

[9] 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.

[10] 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".

Netherlands, Poland, Portugal, Romania, the Slovak Republic, Slovenia, Spain, Sweden and the United Kingdom.

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.[12] 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 Oceania

Australia, Japan, Korea and New Zealand.

[11] 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.

[12] 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.

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.[13]

South America

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

Acronyms, abbreviations and units of measure

Acronyms and abbreviations

ACCC	Australian Consumer and Competition Commission
ACQ	annual contractual quantity
ADGSM	Australian Domestic Gas Security Mechanism
AEMC	Australian Energy Market Commission
AEMO	Australian Energy Market Operator
ASN	Autorité de Sûreté Nucléaire (France)
BBL	Balgzand Bacton Line
CENAGAS	Control Centre for Natural Gas (Mexico)
COAG	Council of Australian Governments
DES	delivered ex ship
EMSO	Exporter Market Security Obligation (Australia)
EPCO	electricity power companies
FID	final investment decision
FLNG	floating LNG
FOB	free on board
FSRU	floating storage and regasification unit
FY	fiscal year
GCC	Gulf Cooperation Council
GIE	Gas Infrastructure Europe
GIIGNL	International Group of Liquefied Natural Gas Importers
IEA	International Energy Agency
IUK	Interconnector UK
JFTC	Japan Fair Trade Commission
JGA	Japan Gas Association
JOD	Jordanian Dinar
JOGMEC	Japan Oil, Gas and Metals National Corporation
JORF	Journal Officiel de la République Française
LNG	liquefied natural gas
LPG	liquefied petroleum gas
METI	Minister of Economy, Trade and Industry (Japan)

[13] 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.

MIBGAS	Iberian Gas Market
NBP	National Balancing Point
NEPCO	National Electric Power Company of Jordan
N/A	not applicable
OTC	over the counter
PEG Nord	Point d'Échange de Gaz Nord (France)
PSV	Punto di Scambio Virtuale (Italy)
PV	photovoltaic
PVB	Punto Virtual de Balance (Spain)
TRS	Trading Region South (France)
TIGF	Transport et Infrastructures Gaz France
TMSO	Total Market Security Obligation (Australia)
TPA	third-party access
TPES	total primary energy supply
TSO	transmission system operator
TTF	Title Transfer Facility (Netherlands)
UGS	underground gas storage
UQT	Upward Quantity Tolerance
USD	United States dollars
y	year
y-o-y	year-on-year

Units of measure

bcm	billion cubic metres
bcm/yr	billion cubic metres per year
cm	cubic metre
GW	gigawatt
MBtu	million British thermal units
mcm	million cubic metres
mcm/d	million cubic metres per day
MW	megawatt
tcm	trillion cubic metres
TWh	terawatt hour

This document and any map included herein are 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.

IEA PUBLICATIONS,
International Energy Agency
Website: www.iea.org
Contact information: www.iea.org/aboutus/contactus

Cover design: IEA.
Photo credits: © Graphic Obsession
Typeset in France by IEA, October 2017

IEA/OECD possible corrigenda on: www.oecd.org/about/publishing/corrigenda.htm

Global Gas Security Review 2017

How is LNG Market Flexibility Evolving?

Natural gas markets are changing at a rapid pace, moving from regional integration to a more globalised and interdependent market. This transformation is creating new security-related concerns, which remain alive despite the current state of oversupply in the gas market.

The International Energy Agency's second annual *Global Gas Security Review* offers an extensive assessment of recent gas balancing issues and related policy developments linked to security of supply, as well as lessons learned from recent events.

This year's edition also updates the liquefied natural gas (LNG) flexibility metrics that were developed in last year's report. Our latest data shows a continuing improvement in supply and contractual flexibility, which are expected to develop in the near future, along with the growing diversification of market participants and a lasting situation of oversupply.

To improve the risk assessment of importing countries, the report introduces a new typology of LNG buyers as a tool to measure market exposure, and related security of supply issues per type of buyer, as well as provides a measure of future LNG market evolution.