

Global Gas Security Review 2019

International
Energy Agency

A low-angle, upward-looking photograph of an industrial facility, likely a gas processing plant. The image shows a complex network of white metal walkways, railings, and large pipes. A prominent feature is a long, arched walkway that recedes into the distance, creating a strong sense of perspective. The sky is bright blue with scattered white clouds. In the lower-left corner, there are yellow safety railings. The overall composition is clean and industrial, emphasizing the scale and complexity of the infrastructure.

September 2019

Abstract

Global natural gas demand is growing strongly, supported by abundant and diversified sources of supply. Liquefied natural gas (LNG) remains a key enabler of international trade development with double-digit growth three years in a row, and with future growth potential supported by another wave of investment decisions in LNG export facilities throughout the world.

Much of the growth in LNG consumption is occurring in countries where LNG competes with other sources of natural gas and fuels, meaning LNG importers want more flexibility. The development of LNG spot trading, the growing share of destination-free supply contracts, and the rise of portfolio players as key buyers are all signs that the LNG market is responding to these increasing demands.

The International Energy Agency's fourth edition of the *Global Gas Security Review* provides a detailed overview of these recent global market trends as well as specific regional analyses for major importing markets.

This year's report focuses on three topics. It first provides an update on LNG market flexibility metrics based on a detailed assessment of recent contractual activity. It analyses the evolution of flexibility in LNG supply procured by traditional Asian buyers for their domestic markets, and how this flexibility could contribute to improving security of supply for fast-growing markets elsewhere in Asia. Finally, this year's report includes a focus on north-western Europe's gas security challenges as a major source of domestic supply (the Groningen field in the Netherlands) is phased out.

Foreword

Energy security is once again making headlines. As the leading energy organisation responsible for energy security, the International Energy Agency (IEA) remains central to the international system to safeguard the security of oil supply.

When I became Executive Director four years ago, I recognised that we needed to broaden our definition of energy security in order to meet new challenges. The integration of renewable energy sources into our electricity systems had become a priority for policymakers. But the world's increasing reliance on natural gas also needed more attention.

Last year was a golden year for natural gas – global demand grew a remarkable 4.6%, with liquefied natural gas (LNG) consumption growing at a double-digit rate for the third year in a row. Natural gas is increasingly used to substitute coal – saving over 500 million tonnes of CO₂ emissions since 2010. In many jurisdictions, power systems are becoming more reliant on natural gas generation to meet peak demand as the contributions from coal or nuclear power decline.

This year marks our fourth *Global Gas Security Review* report. This year's report updates our outlook for LNG investment and contracting, and the news is positive. The year 2019 has already set a record for final investment decisions in new LNG liquefaction facilities – and the year is not over yet. More contracts are destination flexible than before. A greater share of developments depend on different financing approaches – a requirement we had identified two years ago in our *World Energy Outlook* as necessary for a new gas order to emerge.

Yet recent events caution us against complacency on energy security. As gas markets go global, and electricity security becomes more tied to gas security, we need an all-fuels perspective to ensure that governments can carry out their energy transitions safely and securely. As the global energy authority, the IEA remains ready to provide support with data, analysis and real-world solutions.

Dr Fatih Birol

Executive Director

International Energy Agency

Executive summary

The drive for flexibility

Demand for natural gas – and particularly for liquefied natural gas (LNG) – is growing strongly. Gas consumption rose by an estimated 4.6% in 2018, its highest annual growth rate since 2010. LNG demand is growing even more quickly, with double-digit trade growth three years in a row. The commissioning of over 50 million tonnes per annum (Mtpa) of liquefaction capacity during 2018 (equivalent to 72 billion cubic metres per year [bcm/y]) enabled LNG trading to grow by 10%, to reach 420 bcm/y.

In LNG markets, buyers are demanding more LNG on terms that are more flexible. The willingness of US LNG exporters (the main source of LNG supply growth in the medium term) to provide LNG on a destination-free basis, the rise of portfolio players as key buyers and the emergence of equity lifting as a significant business model are all signs that the LNG market is responding to these increasing demands. As a result, the share of destination-free contracts has been growing since 2015 to reach a share of 40% of total LNG delivered during 2018. Moreover, the volume of LNG spot trading transactions has expanded by almost 60% since 2015 to above 100 bcm/y, accounting for nearly a quarter of global LNG trade.

The flexibility of the global gas market in the coming years will continue to be crucial, as natural gas plays a critical role in the energy transition towards a cleaner and more sustainable energy system. This year's *Global Gas Security Review* addresses three issues. First, it monitors the progress in global LNG contractual flexibility by providing an update on the LNG market flexibility metrics. Second, the report analyses the flexibility mechanisms used by traditional major LNG importers in Asia. While these importers may experience little or no growth, their considerable imports may be an important source of potential flexibility for growing markets elsewhere in Asia. Finally, this year's report weighs the challenges facing north-western Europe regarding gas supply security and assesses the importance of its "gas flexibility" as a major source of production – the Groningen field in the Netherlands – is phased out.

Driven by portfolio players, LNG contracting activity rebounded to its highest level in five years...

LNG contracting activity rebounded in 2018 to reach its highest level in five years, with a total of 123 bcm/y of concluded contracts. Much of this increase relates to the development and financing of new liquefaction projects.

Portfolio players continued to be key to this increased activity and have been involved in all liquefaction projects that have taken final investment decision (FID) during 2018, accounting for 45% of contract volumes. This increased activity can be attributed to the desire of portfolio players to rebuild their portfolios so they can provide market flexibility and match long-term supply with the anticipated growth in LNG demand.

The equity-lifting model is gaining popularity in the project financing structures of liquefaction projects. This model allows offtakers/partners to have access to the project's LNG volumes proportionate to their equity stake and, as such, secures both the economic viability of the project and the volumes contracted under long-term agreements. Equity lifting has enabled some of the

largest LNG liquefaction projects to reach FID, hence ensuring that additional LNG can contribute to a balanced global gas market and security of supply. LNG Canada, Greater Tortue FLNG and Golden Pass LNG all use this model.

... underpinned by longer, larger and more flexible contracts

New projects continue to be underpinned by long-term contracts. Long-term deals have dominated recent LNG contracting, reaching a share of 74% in 2018 and 92% in 2019 so far. Moreover, large contracts (over 4 bcm/y) and medium-sized contracts (2–4 bcm/y) increased significantly, representing 56% and 82% of the total volumes signed in 2018 and 2019 (to date) respectively. This is in contrast to the previous three years when the majority of deals were for volumes under 2 bcm/y.

Most of the recent growth in demand for LNG in Asia comes from a new group of “emerging” buyers. The profiles of these emerging buyers are different from those of traditional buyers: they are both less dependent on LNG as a source of gas supply and more sensitive to price. Consequently, flexibility is more highly valued despite the continued reliance on long-term deals.

Notably, longer-term contracts do not necessarily mean less flexibility. Destination flexibility is becoming a common feature in contracts of all durations. In 2018, 58% of volumes contracted and linked to a project that had already taken FID had no fixed destination, reaching 89% of volumes so far in 2019. This is in addition to other forms of flexibility built into these contracts, which enable buyers to adjust the volume and timing of deliveries.

Innovation in LNG contracting to enhance regional security of supply...

The growth in the Asian LNG market is being driven by newer importers, whereas demand from traditional buyers is expected to be stagnant. Most of these traditional buyers import LNG through sale and purchase agreements (SPAs). LNG SPAs, in practice, have clauses providing both the seller and the buyer with a certain level of flexibility in relation to their respective commercial commitments to volumes, destination, delivery programme and transport.

In general, long-term contracts allow for more commercial flexibility since contracted volumes are managed over the course of multiple years. The buyers’ obligation to take LNG cargoes or sellers’ obligation to deliver LNG may be compensated by “make-up” and “carry forward” cargoes in the following contract year(s). Such flexibility in volume has been evolving in a diverse way with increased variability in size and timing. Buyers can call upon volumes on a full-cargo basis at the time of requirement. Similarly, unwanted cargoes can be diverted and resold in other markets at the time an adjustment is needed.

Practical experience shows that the flexibility mechanisms embedded within the LNG SPAs can be better exploited through regional co-operation, parties benefiting from the synergies that stem from short shipping distances. In addition, greater contract flexibility is being implemented as new procurement strategies emerge, including the creation of joint ventures, joint procurement with other markets and expanded reloading capabilities.

...means traditional buyers could become a larger source of additional flexibility for the Asian LNG market

By creatively utilising such tools, traditional Asian buyers are able to become LNG sellers in the secondary market, providing intraregional flexibility of supply to emerging buyers. It is estimated that 15 bcm/y of volumes contracted to traditional Asian LNG buyers are currently considered to be flexible in destination. This destination-flexible volume would cover up to 15% of the forecast LNG demand of emerging Asian LNG buyers, if the whole amount were to be supplied.

For example, Japanese importers are now investing in their infrastructure, primarily for reloading, in order to serve the growing Asian market. Furthermore, they are actively developing their trading capabilities and fostering new LNG demand in the Asia Pacific region by entering the distribution and LNG bunkering businesses. The harmonisation of regulations related to receiving ports and regasification facilities could facilitate intraregional trade and hence improve security of supply.

The transformation of the broader energy system in north-western Europe...

The import requirements of north-western Europe are expected to increase by one-fifth (or almost 40 bcm/y) in the next five years, as indigenous gas production enters a phase of rapid decline, whilst domestic consumption is set to remain flat. The phase-out of the Groningen field, producing low-calorific natural gas (L-gas), will require the expansion of conversion facilities in the Netherlands, able to transform imported high-calorific gas (H-gas) into L-gas.

The gas supply challenges come at a time when natural gas will become increasingly important for electricity security. The north-western European power system is expected to undergo a profound transformation, with an increasing share of variable renewables in the electricity mix and the announced retirement of 45 gigawatts of nuclear and coal-fired power generation in the next five to six years. Consequently, gas-fired power generation will play a progressively more important role in the balancing of the power system, driving up the overall short-term flexibility requirements of the gas system. Gas will provide nearly all the “thermal swing” required to meet high-energy demands – whether provided by gas or electricity – during a cold period.

...calls for the further enhancement of downstream gas flexibility

In this context, the need to enhance the system flexibility of north-western Europe’s gas infrastructure calls for a regional approach. This could be pursued by developing additional import capacity, improving midstream interconnectivity and harmonising gas storage regulation. Strengthening the flexibility of the north-western European gas system would also reinforce the region’s position within the global gas market, as internal flexibility tools allow timely and cost-efficient responses to changing global supply–demand dynamics.

The importance of Europe’s flexible energy system to the global gas market was demonstrated during past supply and demand shocks. The fuel switching capacity of the European power system played a crucial role in making additional LNG volumes accessible to the Japanese market in the

aftermath of the Great East Japan Earthquake in March 2011 and the consequent shutdown of nuclear power reactors.

Over the medium term, the role of the Asian power sector (where abundant switching potential also exists) could increase by offering flexibility to global energy markets via the intermediation of destination-free flexible LNG cargoes – with Europe as a potential outlet. The rising interdependence between regional markets should provide the incentive for both Asian and European market players, as well as regulators, to enhance co-operation towards a more flexible global gas market.

Findings and recommendations

Key findings

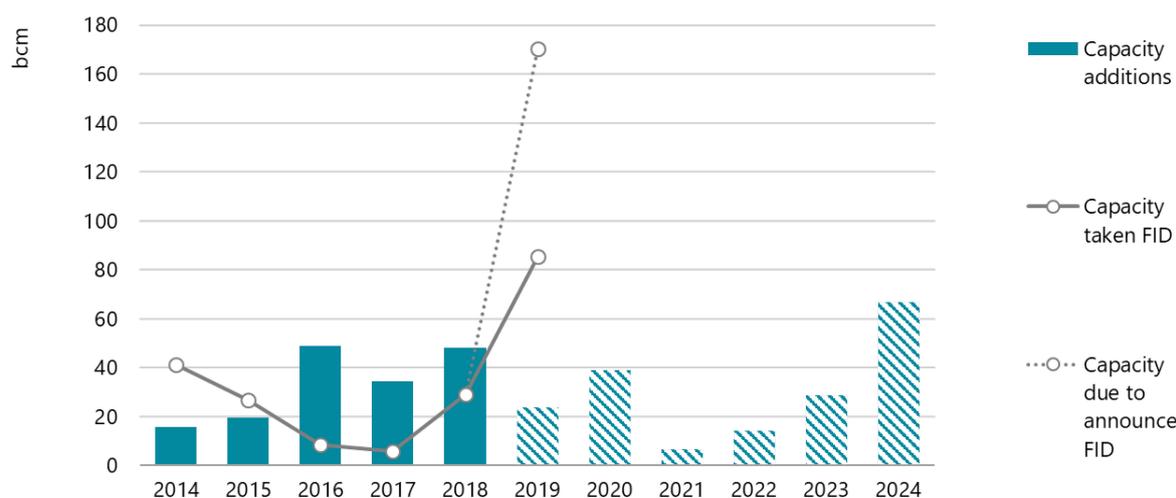
- **Global gas markets continued to consolidate and evolve towards greater flexibility**, driven by the increasing role of portfolio players, transforming business models, contracting trends and growing downstream flexibility requirements.
- **LNG contracting activity rebounded to reach its highest level in five years in 2018**, mostly resulting from newly sanctioned liquefaction projects. The contracting actions of market participants, especially portfolio players, have ensured that most contracts concluded in 2018 are destination-flexible.
- **Contract flexibility is evolving to further strengthen security of supply in Asia**. Long-term contracts involving traditional buyers can provide more operational flexibility than is generally recognised. Volume options, including diversions, open up the potential for increased co-operation via intra-regional trade between LNG buyers.
- **In north-western Europe, rapidly declining domestic production and increasing import requirements, coupled with growing volatility in gas demand, signify an emerging need to further enhance the system flexibility of the region's downstream gas infrastructure.**

Update on LNG market flexibility metrics

Liquefied natural gas (LNG) contracting activity rebounded to reach its highest level in five years in 2018, mostly resulting from newly sanctioned liquefaction projects. 2018 and 2019 to date have seen a step change in investment activity compared to recent years:

- After two years of low activity, several new projects took final investment decision (FID) in 2018: Corpus Christi LNG train 3, LNG Canada, Greater Tortue FLNG 1 and Tango FLNG.
- Investment momentum has continued into the current year. 2019 to date has already seen the most natural gas liquefaction capacity ever sanctioned in a single year.

Figure 1. Additions to global liquefaction capacity (2014–24) and FID volume (2014–19)



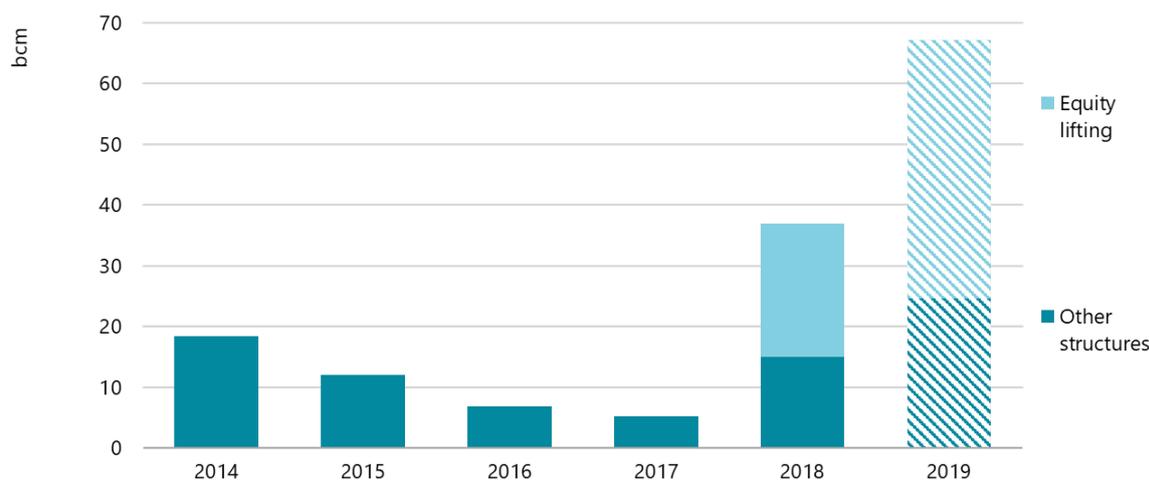
Note: Capacity additions are based on the announcements of developers and only include the capacity of projects that had taken FID by the time of writing this report.

Source: IEA analysis based on ICIS (2019), *ICIS LNG Edge*, <https://lngedge.icis.com/> (subscription required).

A record-setting capacity of over 170 billion cubic metres (bcm) of natural gas liquefaction is due to take FID in 2019, far surpassing 2005’s previous record of 70 bcm.

Growing adoption of the equity offtake marketing structure has contributed to this recent boost in contracting activity and project sanctioning. In an equity offtake (or equity-lifting) model, partners have access to LNG market volumes according to their equity stake, reducing the need for long-term sale and purchase agreements (SPAs) to secure a project’s funding. Since this approach couples financing and offtake for prospective projects, developing under this model can accelerate the FID process.

Figure 2. FID-enabling contracts by signing year and structuring model (2014–19)



Note: 2019 data reflect contracts signed up to the time of writing.

Source: IEA analysis based on ICIS (2019), *ICIS LNG Edge*, <https://lngedge.icis.com/> (subscription required).

After 2017, a shift to the equity-lifting model among FID-enabling deals appeared to accelerate FID timelines with a novel approach to financing.

With more projects using an equity offtake model in 2018, long-term contracts (concluded contracts longer than ten years linked to projects that have already taken FID) grew by more than 55 bcm between 2017 and 2018. Large contracts (more than 4 bcm/year) and medium-sized contracts (between 2 bcm/y and 4 bcm/y) also increased (by almost 41 bcm), representing 56% of the total volumes signed in 2018.

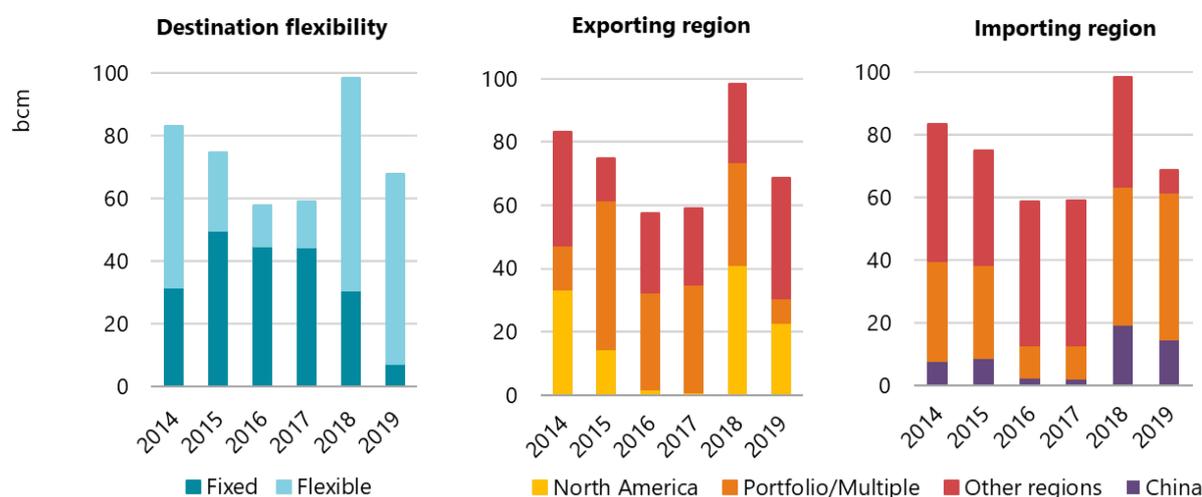
Activity from market participants known as portfolio players has a major role in creating the flexibility to accommodate consumer preferences. Even though yearly contracted portfolio sales (exporting contracts) have been falling since 2015, they still accounted for 33% of concluded contracts linked to FID projects. Because the total volumes from this contracting activity outpace the volumes from expiring contracts, the market volumes portfolio players are obligated to supply increase at a steady pace in the medium term. This market share of total export contracts held by portfolio players is set to reach an all-time high by 2024 (54% of total export volumes).

Portfolio player activity has also had implications for importing regions. In 2018 contracts without a specific destination represented the largest share of contracting activity: these made up almost 45% of all concluded contracts linked to FID projects. During 2019 so far, this share is 68%. Portfolio players are responsible for a large share of deals developed during 2018 and 2019 to date, chiefly to rebuild their portfolios. Signed under flexible destination terms, these contracts provide the main source of volumes needed to cover their position. 2018 also exhibited a shift in the strategy of trading companies, signing long-term and larger contracts instead of relying exclusively on short-term and spot deals. Just as with exports, the import volume share for portfolio players is projected to continue growing, increasing from 42% in 2018 to 48% in 2024.

Overall market flexibility has continued to improve, driven in some cases by contract commitments in North America:

- Among export contracts, North America is the main source of 2018's newly signed commitments. Of all 2018 concluded contracts associated with FID projects, 42% originate in North America. This is mostly due to the development of new LNG projects in the United States and Canada.
- Destination flexibility is increasingly common: the number of contracts concluded with destination flexibility in 2018 was higher than in previous years. Still, many legacy contracts have destination clauses, meaning destination-flexible contracts do not yet represent the majority of market volumes.

Figure 3. Concluded LNG contracts by destination flexibility, exporting region and importing region (2014–19)



Notes: Data relate to contracts concluded and linked to projects that have already taken FID, as well as contracts concluded sourced from a portfolio. Data from 2019 include only the information available at the time of writing. In the exporting region chart, the *Other regions* category comprises Africa, Asia Pacific including People's Republic of China ("China"), Eurasia, Europe, Middle East, and Central and South America. In the *Importing region* chart, the *Other regions* category comprises Africa, Asia Pacific excluding China, Eurasia, Europe, Middle East, and Central and South America.

Source: IEA analysis based on ICIS (2019), *ICIS LNG Edge*, <https://lngedge.icis.com/> (subscription required).

A strong move to destination-flexible contracts is apparent as North America emerges as the key exporter and portfolio players as key buyers.

Some buyers with new and increasing demand for natural gas, particularly in Asia, still need to secure their supply and are actively signing new contracts. For example, the People's Republic of China (hereafter, "China") is rapidly expanding its imports, and among import contracts to single destinations China was the most popular destination in 2018 and so far during 2019. Of all FID project contract volumes, China's contracts represented 20% in 2018 and 22% in 2019 to date. Driven by air quality policy measures and gas shortages seen in the winter of 2017/18 (IEA, 2018), Chinese buyers are seeking to reduce their exposure to supply risk and winter spot LNG price volatility. This willingness to contract reflects their interest in long-term supply protection.

Other contractual elements such as contract indexation have also seen further development. Gas contracts have increasingly been signed or renegotiated to include hub gas price indexation, reducing the historically predominant links to oil. North American export contracts constitute a large proportion of export contracts with gas-to-gas indexation that exist in the market today. During 2018 and 2019, diversification behaviour evolved further with the onset of new pricing structures based on the destination market and the use of the gas.

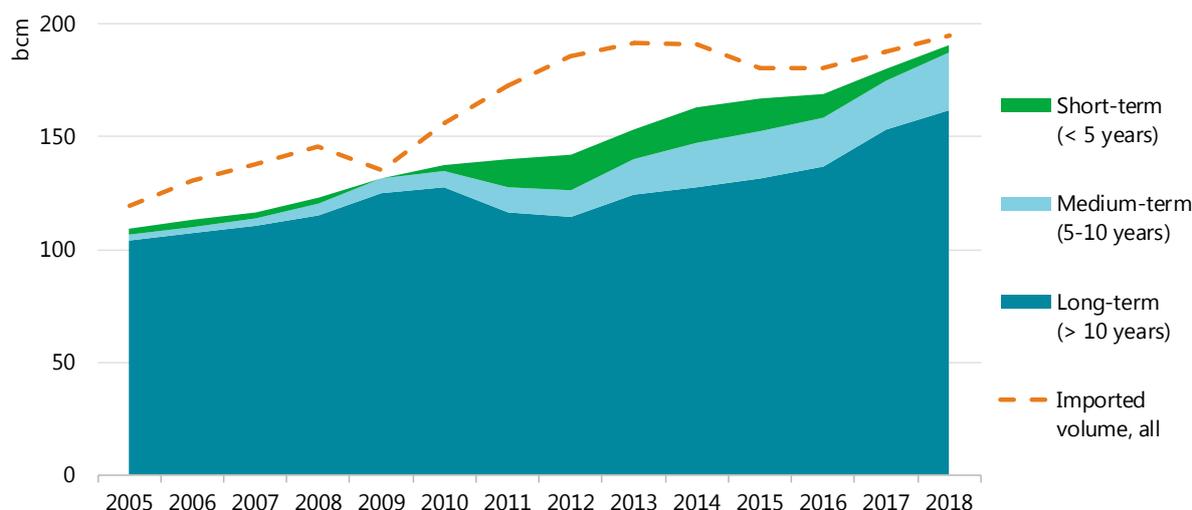
LNG supply security in Asia: An opportunity for traditional buyers

The structure of the Asian LNG market is undergoing a major shift. Demand from traditional LNG buyers, namely Japan and Korea, is likely to be flat or decline gradually depending on use in power generation. However, with or without a decline, these traditional buyers will still account for over 180 bcm/y of LNG purchases by 2024, or 60% of Asian LNG demand. Creating measures

to secure robust sources of LNG supply and meeting uncertainty of demand have been key objectives for these buyers.

Given the uncertainty in the demand level, buyers have been seeking greater flexibility in their supply contracts. The average duration of a contract in the traditional Asian LNG buyers' portfolio is 20 years.

Figure 4. Structure of term contracts among traditional Asian LNG buyers and volume of LNG imports (2005–18)



Note: Short-term contracts (< 5 years) do not include spot transactions.

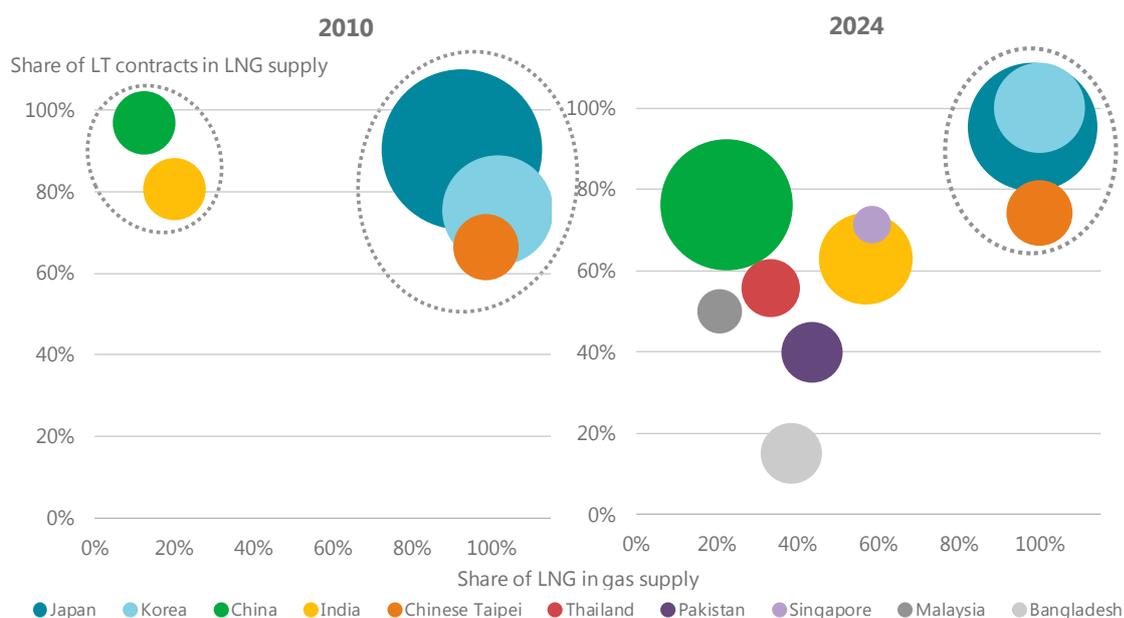
Sources: IEA analysis based on data from ICIS (2019), *ICIS LNG Edge*, <https://lngedge.icis.com/> (subscription required); imported volume data from GIIGNL (2019), *GIIGNL Annual Report 2019*, https://giignl.org/sites/default/files/PUBLIC_AREA/Publications/giignl_annual_report_2019-compressed.pdf.

Over 85% of LNG procurement by traditional Asian buyers is via long-term contracts to secure stable supply.

Options have become the tool of choice for increased flexibility. For example, cargoes can be increased in frequency to align with expected growth in demand (tranche option). A cargo can be sourced to meet a sudden increase in demand during a tight market (call option). At times of low demand, a cargo can be diverted to another market (diversion option) and be sold to such market without the risk of the cargo remaining unsold on the spot market (put option). This is a major improvement on the historically predominant demand adjustment mechanism, whereby a certain percentage of the annually contracted volume can be adjusted after the closure of the contract year, with the obligation carried forward.

Emerging Asian buyers are also seeking increased contractual flexibility. Most of the future growth in the Asia region is set to come from these non-traditional emerging buyers, namely Bangladesh, China, India and Pakistan. They are less dependent on LNG, with domestic gas production and pipeline imports available to them. However, ever-growing gas demand is quickly surpassing domestic production, meaning that more LNG is needed. This is creating a situation where LNG is required, but it has to compete on pricing with competition from domestically produced or pipeline imported natural gas.

Figure 5. Evolution of Asian LNG buyer types (2010–24)



Note: LT = long-term.

Sources: IEA analysis based on data from ICIS (2019), *ICIS LNG Edge*, <https://lngedge.icis.com/> (subscription required); 2024 is based on LNG forecast import data from IEA (2019a), *Market Report Series: Gas 2019*, <https://webstore.iea.org/market-report-series-gas-2019>.

The growth of LNG demand among emerging buyers will be strongly affected by the pricing of the competing fuels.

Expansion of LNG import capability is an urgent requirement to meet unpredictable levels of demand growth. This is where comprehensive contract flexibility becomes essential. In 2018 emerging Asian LNG buyers were overcontracted compared to actual imported volumes by 180%. Flexibility in their contracts allowed these excess contracted volumes to be managed.

Figure 6. LNG import volumes and percentage covered by contracts, emerging Asian economies (2014–24)



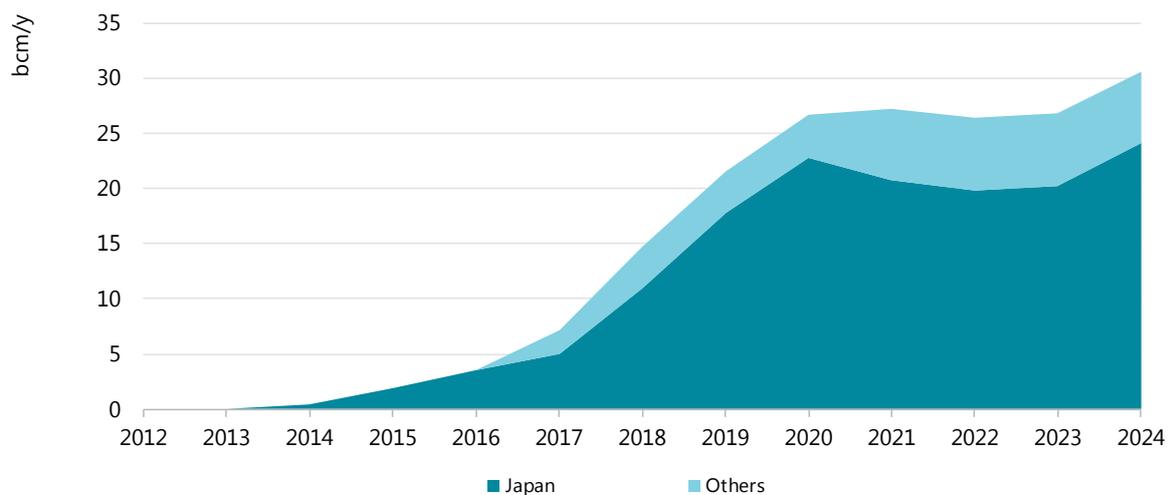
IEA, 2019. All rights reserved.

Emerging LNG buyers have on average 80% of their demand secured by contracts. However, the unavailability of imports or affordability mismatches may cause sudden supply and demand imbalances.

The analysis shows that these emerging Asian LNG buyers are at an immature state in respect of long-term commitment to LNG over the coming years, reflecting their sensitivity to price and the ongoing development of their importing infrastructure.

One of the solutions could be in the form of traditional Asian LNG buyers, who can provide supplies of LNG using the flexibility in their contracts. It is estimated that 15 bcm/y of LNG contracted to traditional Asian LNG buyers can currently be considered destination-flexible. This destination-flexible volume would cover up to 15% of forecast LNG demand among emerging Asian LNG buyers.

Figure 7. LNG volumes contracted to traditional Asian LNG buyers with flexible destination (2012–24)



Sources: IEA analysis based on data from ICIS (2019), *ICIS LNG Edge*, www.icis.com/explore/services/analytics/lng-market-intelligence-solution/ (subscription required); 2024 is based on LNG forecast import data from IEA (2019a), *Market Report Series: Gas 2019*, <https://webstore.iea.org/market-report-series-gas-2019>.

LNG contracted to traditional Asian buyers with a flexible destination could cover up to 15% of LNG demand from emerging Asian LNG buyers, potentially providing them with extra flexibility.

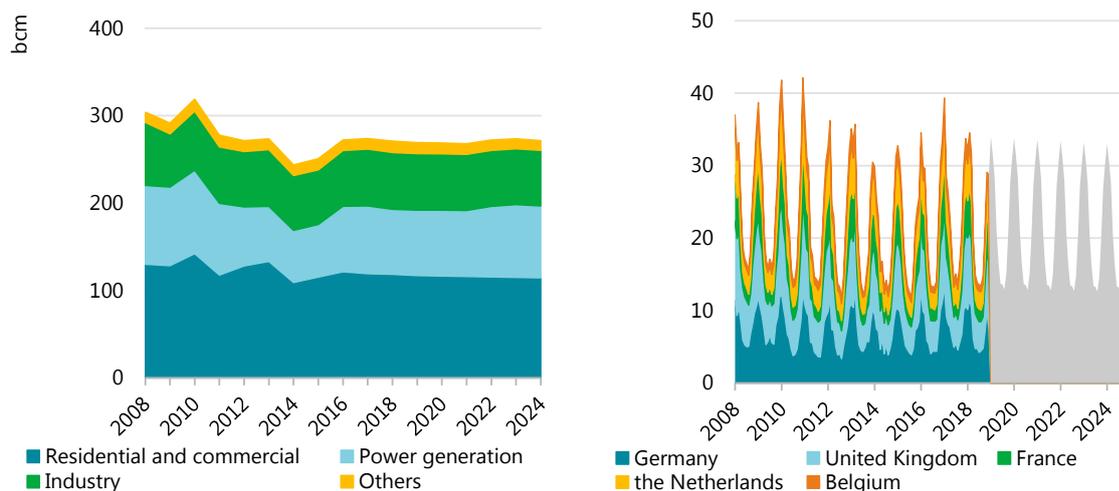
Japanese buyers are expanding their LNG networks to implement contractual flexibility. Examples include the formation of joint ventures and jointly procuring contracts with other market participants. Also, the enlargement of receiving infrastructure is being observed in Japan, with additional loading capabilities at LNG terminals. This will enable these Japanese buyers to have an LNG outlet during fluctuations in demand, by reloading LNG onto another LNG vessel, into smaller-scale ISO containers, or onto LNG bunker supply vessels. All such operations are enabled by the greater flexibilities that traditional Asian buyers have secured, thanks to ample additional supply and the emergence of portfolio players.

This additional layer of supply security in the Asian LNG market, over and above traditional suppliers and global portfolio players, also contributes to the operational robustness of the fast-growing yet immature emerging buyers. The traditional Asian LNG buyers' contractual flexibilities and implementation capabilities can further increase trading flows regionally and interregionally, serving new demand set to appear in other markets.

North-western Europe’s gas flex: Still fit for purpose?

The inherent flexibility of the north-western European natural gas system has played a crucial role in the development of a liquid, tradable and well-integrated regional gas market, where security of supply is ensured by adherence to market rules and the strong seasonality of demand is satisfied with adequate physical natural gas supply.

Figure 8. North-western Europe’s gas demand by sector (2005–24) and by month (2005–18)

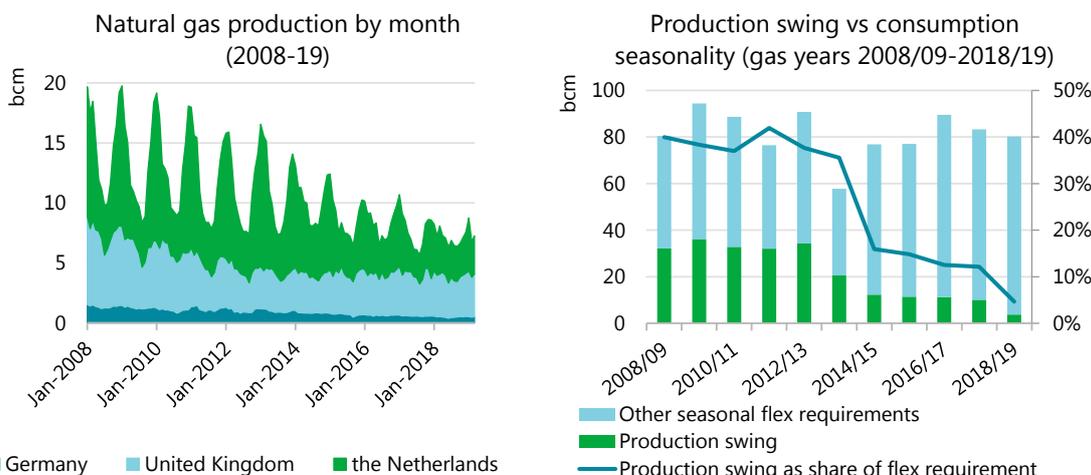


Source: IEA (2019b), *Natural Gas Monthly Statistics*, www.iea.org/statistics/monthly/#gas.

North-western European natural gas demand is characterised by a pronounced seasonal pattern, driven by the heating needs of the residential and commercial sectors.

However, rapidly declining domestic production and increasing import requirements have gradually eroded this flexibility in the past five years. The proportion of winter gas requirements met by production swing has fallen from 40% to below 5%.

Figure 9. Natural gas production and flexibility requirement in north-western Europe (2008/09–2018/19)

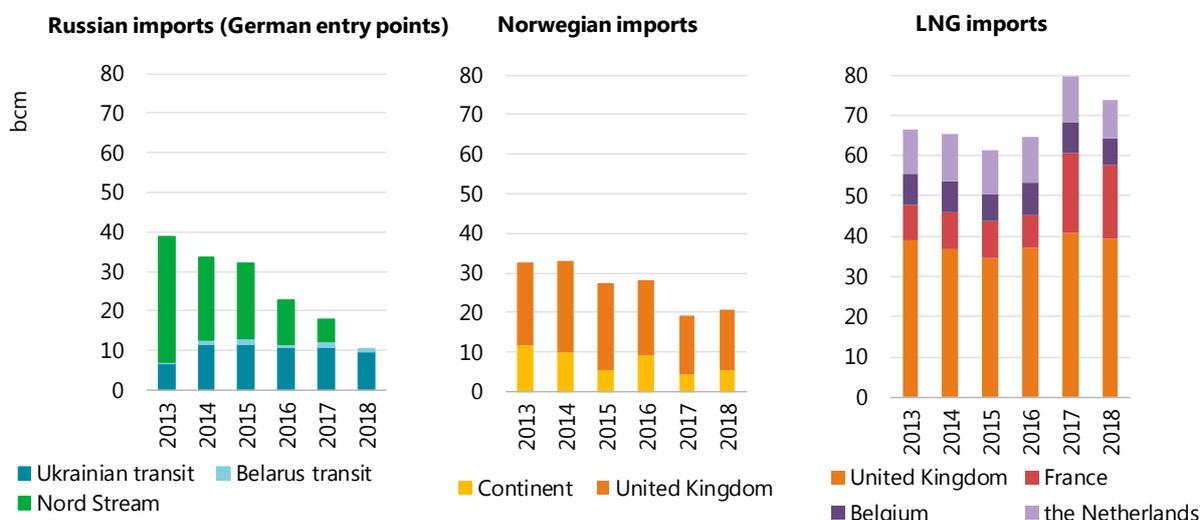


Source: IEA (2019b), *Natural Gas Monthly Statistics*, www.iea.org/statistics/monthly/#gas.

European natural gas production has halved over the past decade, while its seasonal production swing fell by 90% during the same period, increasing the call on other sources of flexibility.

Spare import capacity via Norwegian and Russian pipelines directly servicing north-western Europe fell to close to zero during the past two heating seasons.

Figure 10. Annual spare import capacity into north-western Europe by origin of imports (2012–18)

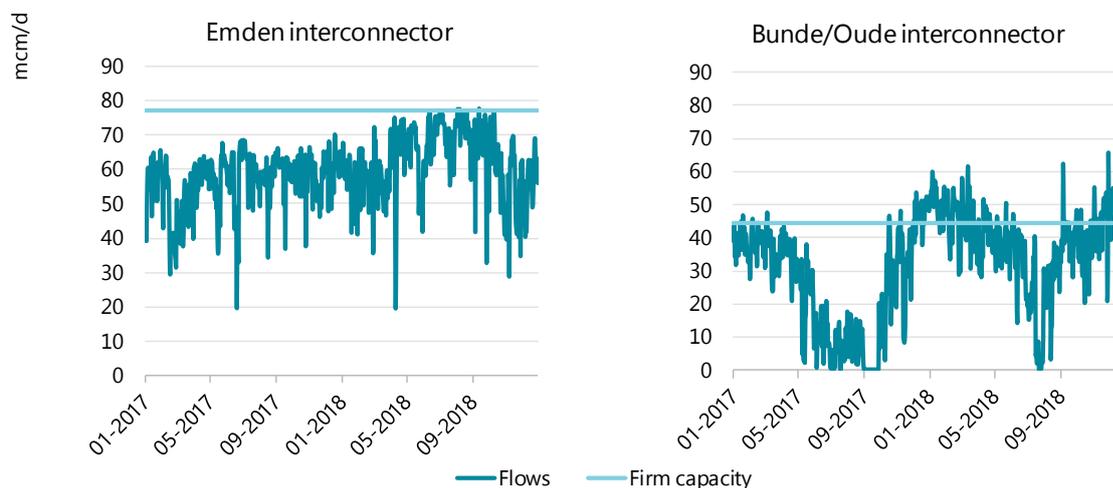


Source: IEA (2019c), *Gas Trade Flows*, www.iea.org/gtf/.

Spare pipeline import capacity to north-western Europe has more than halved since 2013, falling from 70 bcm/y to just above 30 bcm/y, while spare regasification capacity has risen by 10% to above 70 bcm/y.

Gas interconnectors from Germany to the Netherlands are becoming saturated as a result of the evolving supply outlook in the Netherlands.

Figure 11. Interconnector flows to the Netherlands (2017–18)



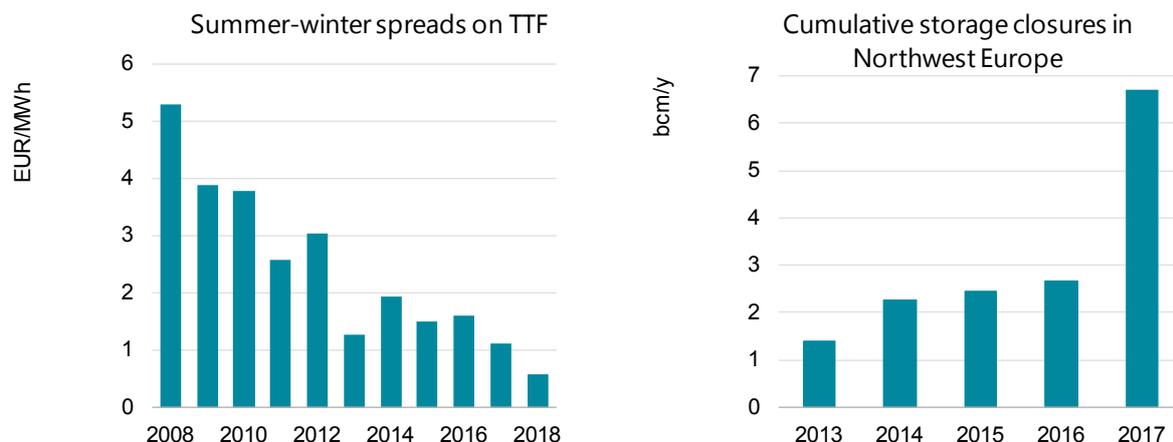
Note: mcm/d = million cubic metres per day.

Source: ENTSOG (2019), *Transparency Platform*, <https://transparency.entsog.eu/>.

The utilisation of interconnectors feeding into the Dutch natural gas grid is saturated during periods of high demand, hence limiting the availability of spare capacity.

Deteriorating storage economics has led to the closure of 5 bcm of storage capacity since 2013.

Figure 12. Spread between summer and winter gas prices on TTF (2008–18) and gas storage closures in north-western Europe (2013–17)



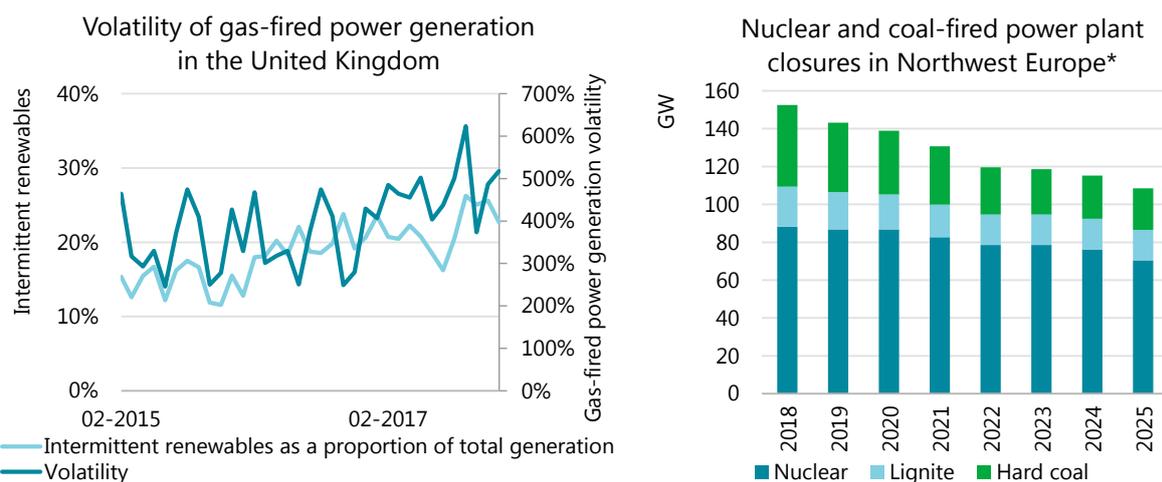
Notes: MWh = megawatt hour; TTF = Title Transfer Facility.
 Source: Bloomberg Finance LP (2019), Bloomberg Terminal (subscription required).

Seasonal spreads on the TTF have more than halved since 2012 to an average below EUR 1.5/MWh, insufficient to cover the operating costs of some storage sites and leading to the closure of over 5 bcm of storage capacity since 2013.

The flexibility of the north-western European gas system could further decline amidst the increasing import requirements of the region, expected to grow by 40 bcm/y by 2024, primarily due to declining domestic production. Moreover, the challenging storage economics coupled with the expiry of long-term storage contracts could lead to the retirement of further storage capacity in the region.

In the medium term, the north-western European power system is expected to undergo a profound transformation, with an increasing share of intermittent renewables in the electricity mix and the announced retirement of 45 GW of nuclear and coal-fired power generation in the next five to six years.

Figure 13. UK volatility in gas-fired power generation (2015–17) and announced power plant closures in north-western Europe (2018–25)

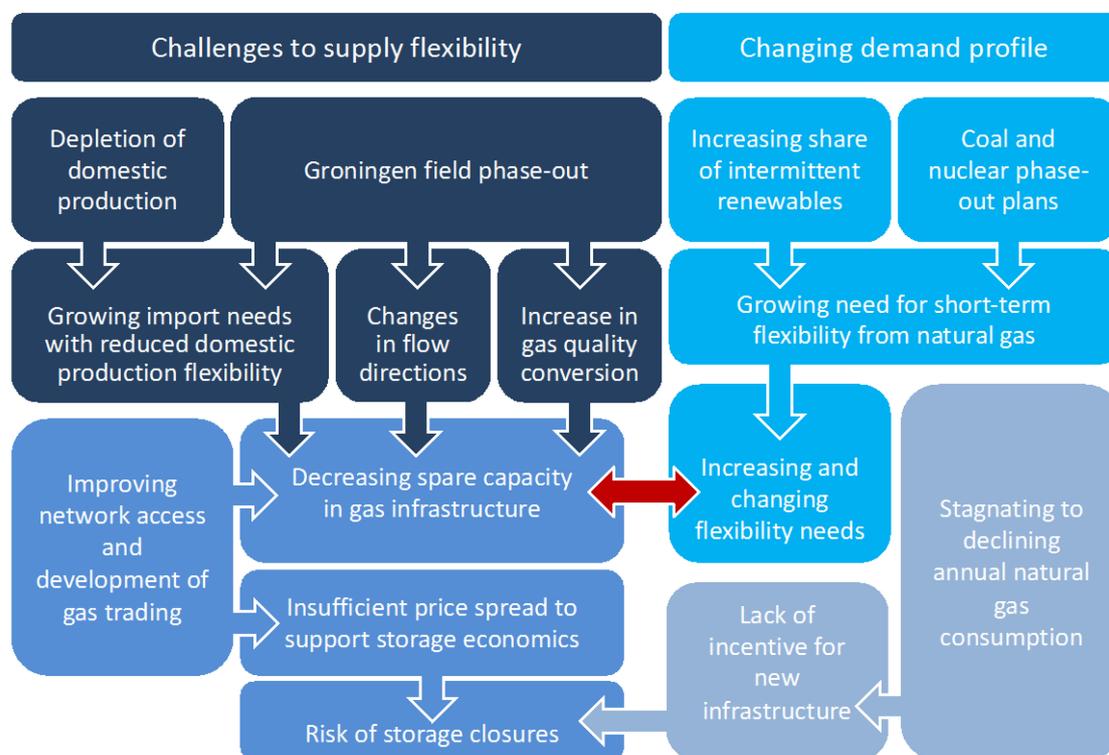


* Based on announcements by governments and companies.
 Sources: Share of renewables: IEA (2019), *Monthly Statistics*, www.iea.org/statistics/monthly/; gas-fired power generation: ENTSO-E (2019), *Transparency Platform*, <https://transparency.entsoe.eu/>.

The growing share of intermittent renewables, coupled with declining coal-fired and nuclear power generation, is set to increase the volatility of gas-fired power generation.

As a consequence, gas-fired power generation will play an increasingly important role in the balancing of the power system, i.e. as a backup to variable renewables and to meet peak demand. This in turn could drive up the volatility of gas-to-power demand and hence the overall short-term flexibility requirements of the gas system.

Figure 14. North-western Europe's changing gas flexibility landscape



IEA, 2019. All rights reserved.

While the flexibility of gas supply is decreasing, the call for flexibility in north-western Europe's gas system might increase over the medium term when considering the broader energy complex.

In this context, the need to enhance the systemic flexibility of north-western Europe's gas infrastructure should be considered using a regional approach and include:

- Development of additional import capacity to meet both incremental import requirements (pipeline and LNG) and the need to further diversify supplies (via LNG).
- Improvement of midstream interconnectivity, in particular on the border between Germany and the Netherlands, via either new interconnectors or the reconfiguration of existing exit/entry capacities.
- Harmonisation of gas storage regulation, with the eventual development of support mechanisms to prevent further storage site closures.

Strengthening the flexibility of the north-western European gas system would also reinforce the position of the region within the global gas market, as internal flexibility tools allow a timely and cost-efficient response to changing global supply–demand dynamics.

This has been clearly demonstrated during the first half of 2019, when north-western Europe has been able to profit from a loose global LNG market by increasing LNG imports in a counterseasonal

fashion, exploiting existing synergies between spare regasification and storage capacity. Consequently, trading on the TTF soared to record levels, with an increasing number of market players hedging their LNG positions on the Dutch hub.

This indicates that if TTF continues to be supported by a strong and flexible natural gas grid, it could further reinforce its position as a global gas price benchmark and hence the role of north-western Europe in the global LNG trade.

Technical analysis

1. Update on LNG market flexibility metrics

Introduction

Each year the *Global Gas Security Review* has been assessing the growth in flexibility of the liquefied natural gas (LNG) market by analysing LNG supply availability, seller and buyer behaviour, and the evolution of destination flexibility in LNG contracts. This chapter focuses on the most recent LNG contracting trends, analysing the implications of a new wave of liquefaction investment for future flows and pricing methods. It also updates previous years' analysis of the growing role of portfolio players and implementation of LNG contracts with flexibility in the market, as well as examining the changing contract strategy of trading houses.

Similar to previous years' reports, the analysis conducted here is based on the detailed contractual positions of importers and exporters and their actual traded volumes, using the International Energy Agency (IEA) internal LNG contract database. No specific assumptions are made on existing contract renewals unless publicly and explicitly stated by the contracting parties. Hence, such volumes are considered to be "uncontracted" upon expiry.

Update on LNG contract trends

LNG contracting activity rebounded in 2018, reaching its highest level (in terms of total volume) in five years. Contracts totalling 123 billion cubic metres (bcm) were concluded, with around 57% of them signed as firm.¹ For the purpose of analysis, this chapter focuses on concluded contracts linked to projects that have already taken FID.² These contracts also grew in 2018, reaching 98 bcm, an increase of more than 39 bcm over the previous year. Much of this contracting activity relates to the development and financing of new liquefaction projects. Different deal structures, such as the equity-lifting model used by LNG Canada, are being exercised to facilitate the process of reaching FID. In the equity-lifting model, offtakers/partners have access to marketable LNG volumes according to their equity stake. Such structures reduce the need for long-term SPAs to secure the project's financing.

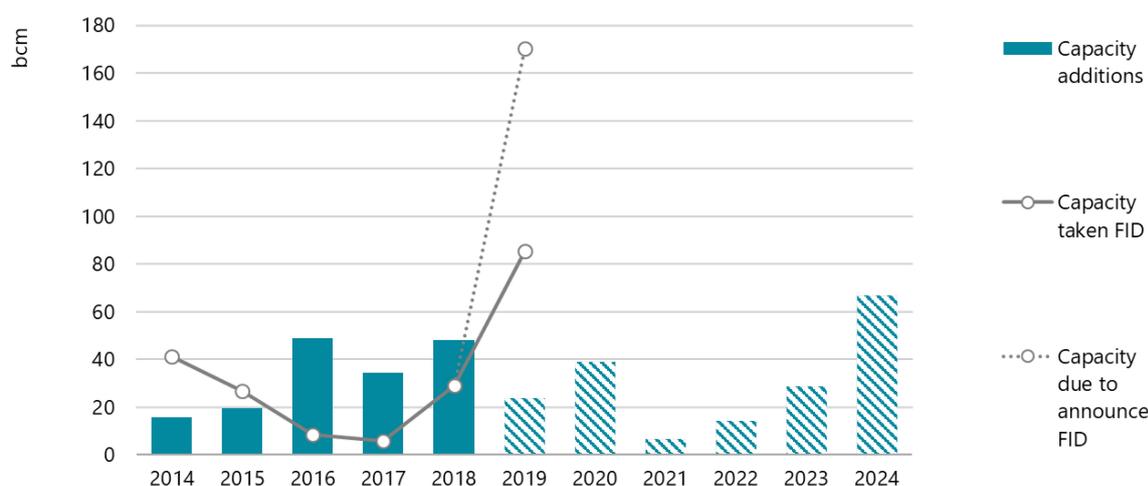
¹ Defined as concluded sale and purchase agreements (SPAs) and entitlement equity operations associated with a project that has taken final investment decision (FID) during the year.

² Sales from portfolios are also included.

Liquefaction activity: New wave of investment gaining momentum

Liquefaction investment activity also rebounded in 2018 (Figure 15), with several new projects taking FID, after two years of low investment activity. The LNG Canada project alone, with its 19 bcm capacity, surpassed all the capacity sanctioned in 2016 and 2017 combined. During 2018 approximately 30 bcm of new capacity was sanctioned (Corpus Christi LNG train 3, LNG Canada, Greater Tortue FLNG 1, Tango FLNG), with North American projects representing 86% of the total. At the time of writing, projects amounting to 85 bcm (Sabine Pass LNG train 6, Golden Pass LNG trains 1–3, Calcasieu Pass, Mozambique LNG trains 1 and 2, Arctic LNG 2) have already taken FID in 2019, the most capacity ever sanctioned in a single year.

Figure 15. Additions to global liquefaction capacity (2014–24) and FID volume (2014–19)



Note: Capacity additions based on developers' announcements and include only the capacity of the projects that have taken FID at the time of writing this report.

Source: IEA analysis based on ICIS (2019), ICIS LNG Edge, <https://lngedge.icis.com/> (subscription required).

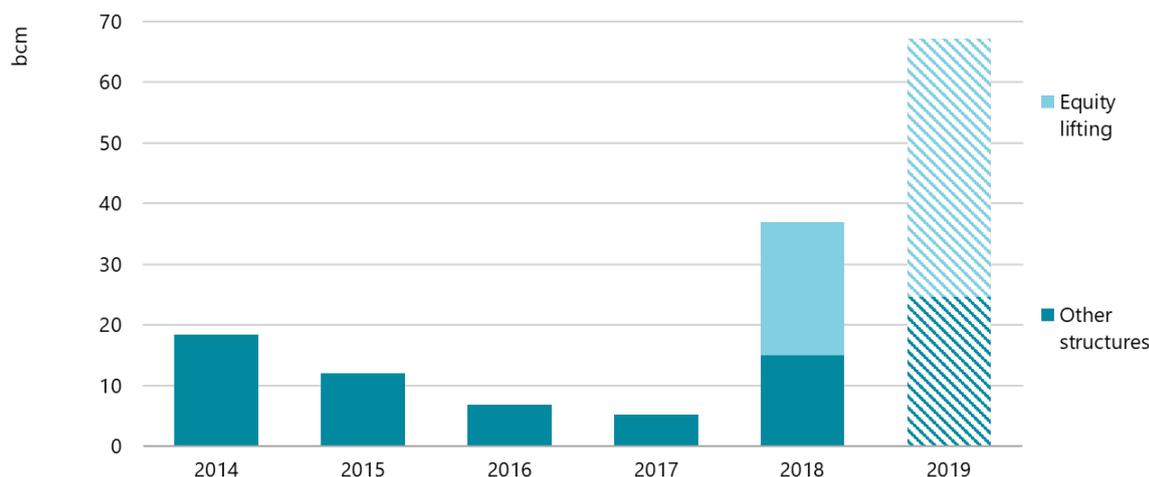
A record-setting capacity of over 170 bcm of natural gas liquefaction is due to take FID in 2019, far surpassing 2005's previous record of 70 bcm.

Much more could be coming. If only considering the projects most likely to announce FID during 2019 (those projects that have already completed front-end engineering and design [FEED] and are expected to come online before the end of 2024), 2019 FID volumes could exceed 160 bcm (IEA, 2019). Even if most do not proceed, the total has already surpassed the 2005 peak of almost 70 bcm. US sellers continue to push for additional capacity to enable them to bring extra volumes into Asian and European markets. Alongside the United States (Driftwood LNG), countries such as Mozambique (Rovuma LNG) and especially Qatar (Qatargas V–VIII) have ambitious plans to develop new liquefaction facilities (IEA, 2019).

Between 2020 and 2022, annual LNG capacity additions are expected to decrease from 2018 levels based on the current status of investment decisions (Figure 15). Despite this reduction, capacity additions between 2020 and 2024 are set to be over 17 bcm higher than during 2012–17. Considering all FIDs taken in 2018 and 2019, by the end of 2024 the LNG market is expected to see a wave of new liquefaction capacity coming online. These confirmed projects could represent capacity additions of more than 105 bcm by 2024.

One of the reasons for the boost in contracting activity in 2018 and 2019 has been the implementation of equity-lifting structures (Figure 16). This model has been used in the past (e.g. Snøhvit LNG or Gorgon LNG) with slightly different terms and structuring, but 2018 and 2019 have seen a resurgence with multiple large-capacity projects reaching FID as result of the advantages it offers in current market conditions.

Figure 16. FID-enabling contracts by signing year and structuring model (2014–19)



Note: 2019 data reflect contracts signed up to the time of writing.

Source: IEA analysis based on ICIS (2019), *ICIS LNG Edge*, <https://lngedge.icis.com/> (subscription required).

After 2017, a shift to equity-lifting contracts among FID-enabling deals was seen to accelerate FID timelines with a novel approach to financing.

In the equity-lifting model, offtakers/partners have access to the project's LNG volumes proportionate to their equity stake (Ledesma and Fulwood, 2019). Under other traditional offtake models, financing is sought once offtake has been secured using long-term contracting with third parties. In contrast, the equity model secures both the economic viability of the project and the volumes contracted under long-term agreement. This accelerates the process and timeline by which projects reach FID. LNG Canada, Greater Tortue (Mauritania and Senegal), Golden Pass LNG (United States), and the Russian Federation's (hereafter, "Russia") Arctic LNG 2 have been the first examples of the use of this model. Mozambique's Rovuma LNG has also announced plans to develop under an equity-marketing model.

Export source and import destination: Flexible gas gaining ground

North American projects have been the main source of new contracts. In 2018, 42% of newly contracted gas volumes³ involved LNG originating in North America (Figure 17), mostly due to the development of new LNG projects in the United States and Canada. In 2019 to date, Eurasia represents the largest source of newly contracted gas (35%) thanks to the Arctic LNG 2 project in Russia. Africa was also an important source due to the Greater Tortue and Mozambique LNG projects, accounting for 11% of gas contracted in 2018–19 linked to new projects.

Market participants known as "portfolio players" are a major component of the contract data presented in Figure 17, as they concluded contracts in which the exporting region is not specified.

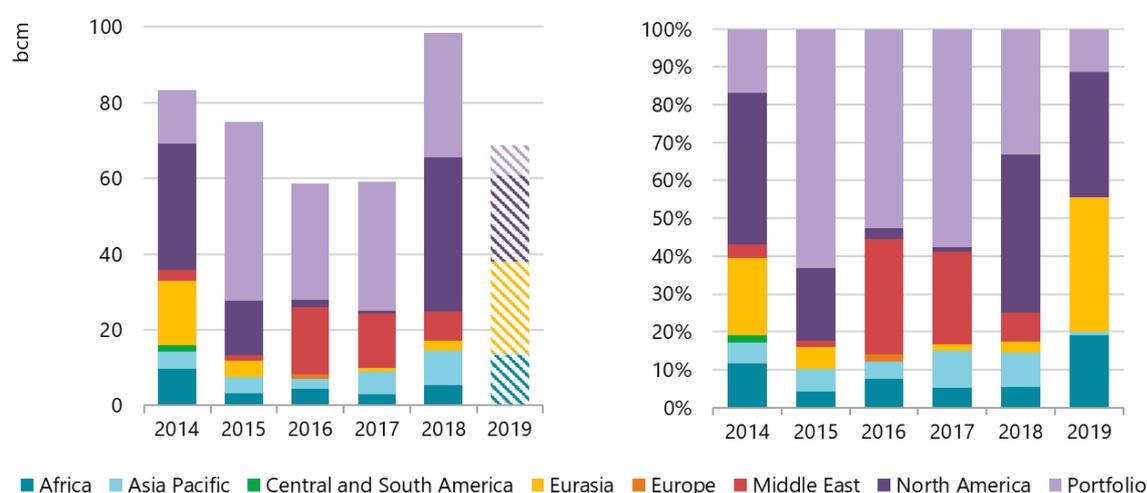
³ Sales from portfolios are also included.

The total volume of sales contracts signed each year by portfolio players has fallen since 2015. This is because most of the volumes in their portfolios have already been sold through term contracts or spot deals, reducing the opportunity to resell and increasing the need to expand their portfolio volumes.

The contracts that portfolio players sign with buyers obligate them to supply incremental volumes for future delivery, meaning that the total market volume supplied via portfolio players is increasing. This trend is analysed in detail later in this section.

During 2018 contracts to supply LNG sourced from a portfolio accounted for 33% of contracted volumes linked to post-FID projects. This market share is well below the level of 2015, when contracts associated with a portfolio represented 63% of volumes. The smaller 2018 share is mostly due to the increased volume from contracts signed to export gas from North American projects (Figure 17), although portfolio contracted volumes also decreased by 2 bcm from 2017 to 2018.

Figure 17. Contracts signed each year by contract exporting region and with no identified region (2014–19)



Notes: Contracts concluded and linked to projects that have already taken FID; sales from portfolios are also included; Portfolio category stands for contracts in which the origin is a portfolio player (i.e. not linked to any specific region); 2019 data only include the information available at the time of writing.

Source: IEA analysis based on ICIS (2019), *ICIS LNG Edge*, <https://lngedge.icis.com/> (subscription required).

Contracting activity by exporting region in 2018 shows growth in North American volumes, while export volumes from portfolio players remain an important contribution to deal activity.

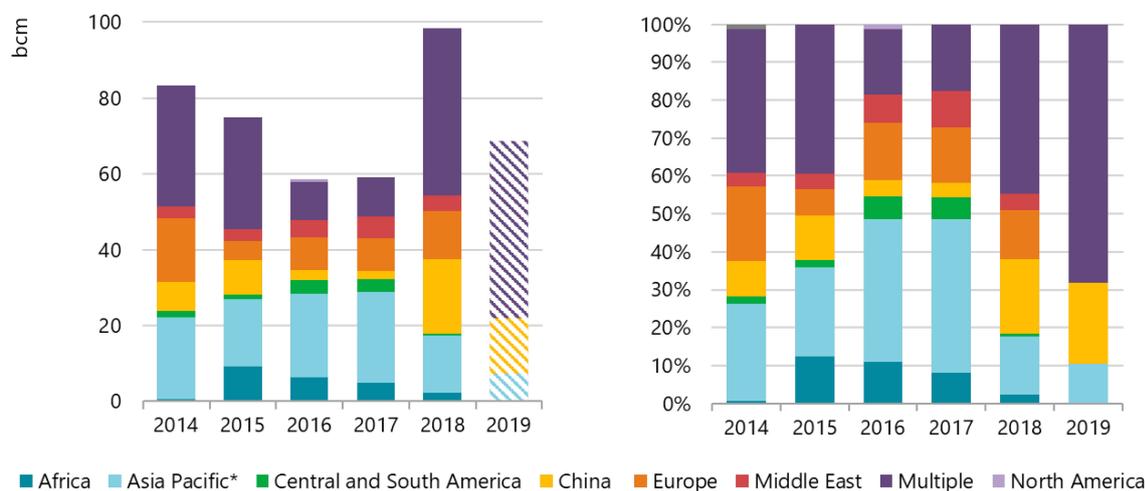
As for the destination of LNG in contracts signed during 2018, agreements without a specific destination represented the largest share, representing 45% of all volumes linked to post-FID projects (Figure 18). During 2019 to date, their share has increased to 68%. Portfolio players are one of main counterparties in multiple-destination contracts, responsible for a large share of deals developed under the equity-lifting model during 2018 and 2019 to date. These contracts provide them with the main source of volumes needed to cover their positions.

Trading houses, such as Trafigura, Vitol and Gunvor, have emerged as a new buyer of multiple-destination LNG. The year 2018 exhibited a shift in the strategy of trading companies – they increasingly sign long-term contracts instead of relying exclusively on short-term and spot deals to cover their positions. This change in their strategy is a manifestation of the gradual consolidation of the global LNG market. Following a trend previously set by portfolio players, trading houses are trying to take advantage of all the synergies that ensuring a long-term supply can provide,

maximising the business opportunities available to them. Additionally, LNG offers them the possibility of diversifying away from mature and low-growth markets, such as crude oil (Bloomberg, 2019a).

Among contracts with a specific destination, the People's Republic of China (hereafter, "China") was the most popular destination in 2018 and has been so far during 2019, surpassing other traditional buyers. In 2018, China accounted for 20% of all contract volumes signed and linked to a project that had already taken FID and 21% in the year to date. Environmental policies in China aimed at reducing air pollution have driven substantial growth in gas demand since 2017, mainly forcing coal-to-gas switching in the residential and industrial sectors. After the gas shortages in the winter of 2017/18 (IEA, 2018), Chinese buyers have signed long-term contracts for 34 bcm/y to reduce their exposure to supply risk and the high spot LNG prices in winter. Chinese buyers signing equity-lifting arrangements during 2018–19 is a clear reflection of a readiness for the protection provided by long-term contracts. In 2018–19, portfolio players were the main source of these new contracts, accounting for more than 45% of the concluded Chinese contracts, followed by Russia (17%), Qatar (14%), Canada (9%), Mozambique (6%), the United States (5%) and Papua New Guinea (4%).

Figure 18. Contracts signed each year by contract importing region (2014–19)



Notes: Contracts concluded and linked to projects that have already taken FID; sales from portfolios are also included; multiple category stands for agreements without a specific destination; 2019 data only include the information available at the time of writing; Asia Pacific* does not include China.

Source: IEA analysis based on ICIS (2019), *ICIS LNG Edge*, <https://lngedge.icis.com/> (subscription required).

Import contracts signed by China outpaced those of other direct destinations in 2018, representing 20% of all contract volumes signed.

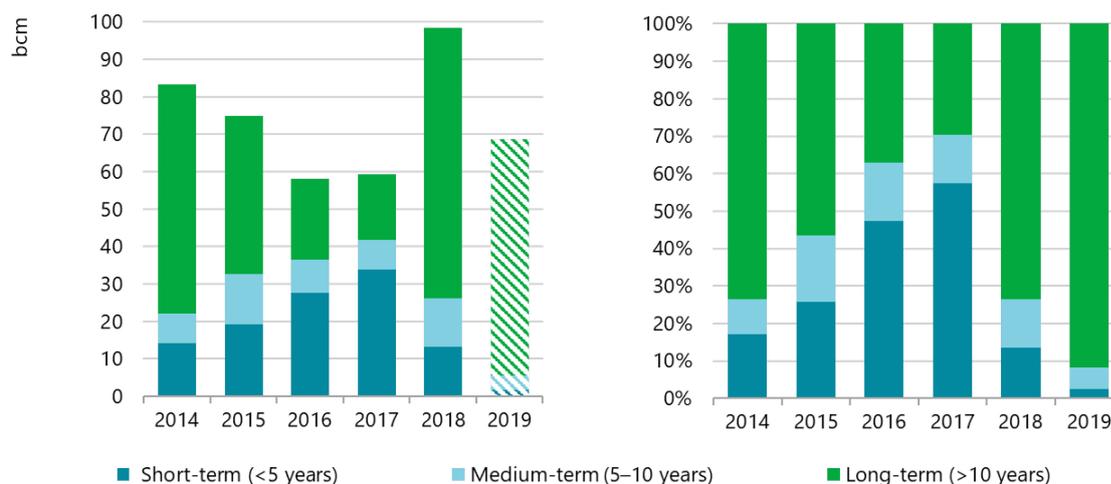
Longer and larger contracts do not mean less flexibility

The number of long-term contracts (concluded contracts of more than ten years linked to projects that have already taken FID), which had fallen to very low levels in 2017, grew substantially in 2018 to more than 72 bcm. As a result, long-term deals have dominated recent LNG contracting, reaching a share of 74% in 2018 and 92% in 2019 so far (Figure 19). Developers of new projects have made more long-term LNG available to the market. Seeing strong demand growth (global LNG trade is forecast to grow by 26% during 2018–24) and the need to secure their own long-term supply (together with the impacts associated with an increase in spot market exposure and LNG spot price volatility during the winter heating season), buyers have the appetite for longer-term contracts. Both portfolio players and emerging Asian buyers have been

very active in the long-term market. Long-term contracting by trading houses represents a shift in their strategy, which had relied primarily on short-term and spot deals.

Apart from this increased interest in long-term contracts, medium-term contracting activity has increased due to legacy contracts being renewed on different terms and new projects signing shorter SPAs to increase interest among potential offtakers and therefore accelerate FID timelines. By contrast, short-term contract volumes fell last year and have been very low to date in 2019.

Figure 19. Contracts signed each year by duration (2014–19)



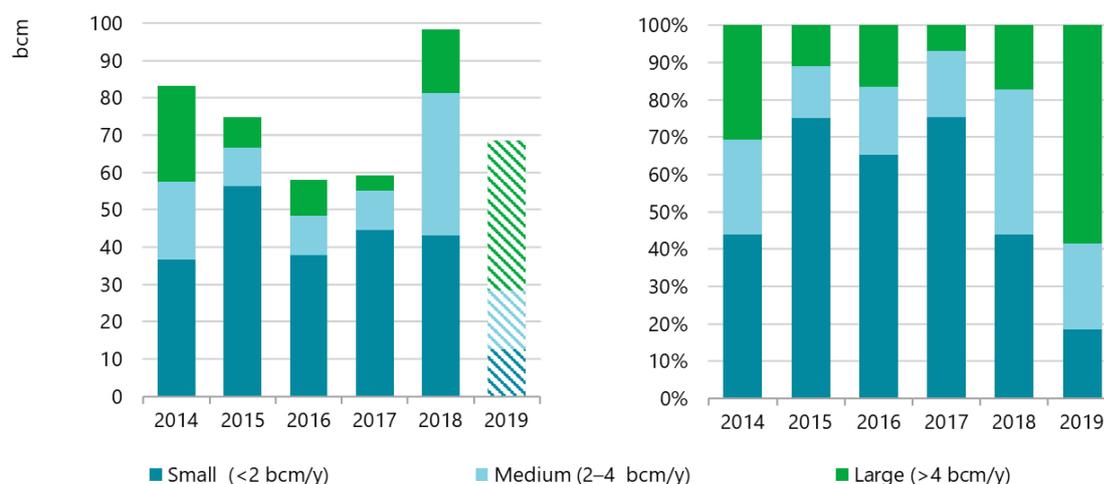
Notes: Contracts concluded and linked to projects that have already taken FID. Sales from portfolios are also included. Data from 2019 include only the information available at the time of writing.

Source: IEA analysis based on ICIS (2019), *ICIS LNG Edge*, <https://lngedge.icis.com/> (subscription required).

Long-term contracts became the dominant form of LNG contracting in 2018, as new FIDs found willing customers wishing to secure supply and avoid price risks.

New liquefaction investments also influenced the LNG volumes in contracts signed during 2018 (Figure 20). Large contracts (more than 4 bcm/y) and medium-sized contracts (2–4 bcm/y) increased significantly (by almost 41 bcm), representing 56% of the total volumes signed in 2018, in contrast with the previous three years when the majority of deals were for volumes under 2 bcm/y. Large contracts were mostly signed at year-end when liquefaction projects took FID. During 2019 so far, large contracts alone represent around 58% of contracted volumes. In 2018, the volumes sold through small contracts decreased slightly by 1 bcm/y compared to 2017, showing that there is still market interest in signing small contracts.

2018 LNG contract data show a positive correlation between size and duration. There is no single short-term contract larger than 2 bcm/y. Approximately 70% of the 2018 long-term LNG contracts are greater than 2 bcm/y. Despite this correlation, it is also remarkable that 30% of long-term contracts are smaller than 2 bcm/y, reflecting portfolio players reselling activity.

Figure 20. Contracts signed each year by volume (2014–19)

IEA, 2019. All rights reserved.

Note: Contracts concluded and linked to projects that have already taken FID. Sales from portfolios are also included. 2019 data include only the information available at the time of writing.

Source: IEA analysis based on ICIS (2019), *ICIS LNG Edge*, <https://lngedge.icis.com/> (subscription required).

Medium-sized and large contracts rebounded in 2018 thanks to new projects, although small contracts still play a significant role in contracting activity, accounting for over 56% of contracted volumes.

Portfolio players and flexibility

While long-term contracts are still crucial for securing the funding for new liquefaction facilities (and even for exploration and production), customers increasingly require greater flexibility in volumes and destinations. Portfolio players procure a mix of LNG supplies from various projects and sellers, and resell to customers according to their requirements. They sell much of this via term contracts, but are also active in selling spot cargoes. Therefore, they have both sell (export) and buy (import) contracts available to manage their own cargoes and optimise their return, thereby providing a wide range of flexibility for their customers. Such flexibility is often valued at a premium, as the LNG projects themselves typically have limited uncontracted or excess capacity volumes to provide flexibility (IEA, 2018). This kind of market player has become increasingly important as the number of LNG buyers has grown significantly in recent years. Some of the new buyers experiencing significant growth have a different profile than traditional buyers such as Japan and Korea. Thanks to their reselling activity, portfolio players are able to tailor deals that meet the requirements that these new consumers require.

The number of companies selling LNG from their portfolios has grown substantially since 2010, with progressively more traditional companies creating their own portfolio and becoming portfolio players. National companies that have traditionally sold their gas production through long-term agreements tied to specific projects, for example Gazprom, signed export contracts for LNG sourced from their portfolio of projects in 2018 and 2019, i.e. with no fixed source.

This section analyses portfolio player contract trends. For the purpose of this analysis, the only contracts considered are those that have been sourced for or from portfolios, i.e. excluding contracts that have been sourced directly from named projects.

In 2018, export volumes supplied by portfolio players represented 40% of total export volumes. Based on current contracts, this share is expected to grow to over 54% of total export volumes by 2024 (Figure 21). Import volumes attributable to portfolio players are also projected to continue growing, increasing from 42% in 2018 to 48% in 2024.

Figure 21. Portfolio players' volumes and market share of import and export contracts (2012–24)



Note: It is assumed that expiring contracts are not renewed, with no specific assumption on any contract yet to be signed.

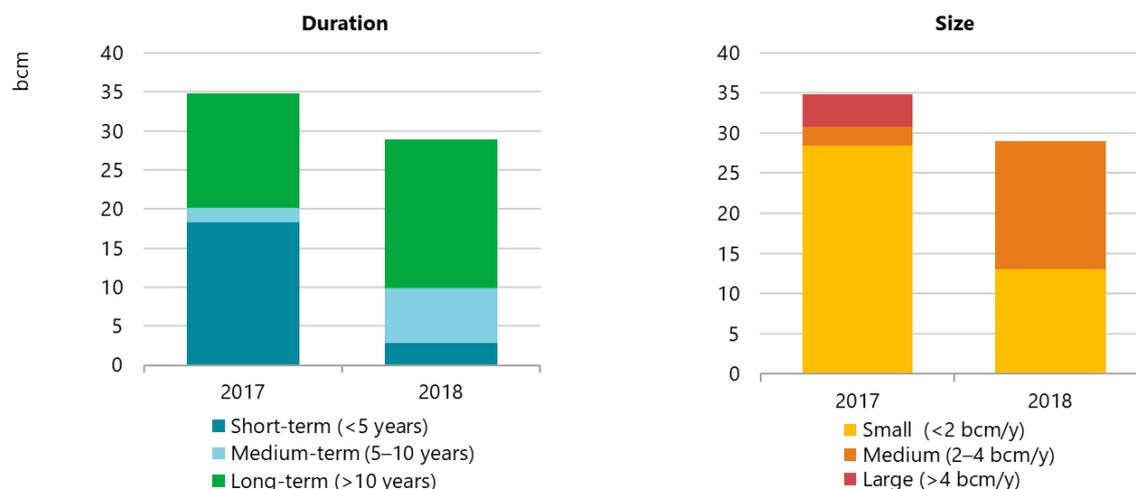
Source: IEA analysis based on ICIS (2019), *ICIS LNG Edge*, <https://lngedge.icis.com/> (subscription required).

Portfolio player contracted volumes account for an increasing share of the market due to their contracting activity associated with the higher pace of FIDs being taken, as reflected in their share of export contracts increasing to 54% by 2024.

Contract data show that from 2018 portfolio players have contracted to sell more LNG than they have contracted to secure for their own portfolios (i.e. the volume of export contracts exceeds that of import contracts). Portfolio players have reduced their total export volumes via new contracts from 2015 levels. During 2018 volumes associated with newly concluded contracts for LNG exports from portfolio players decreased by 17% compared with the previous year (Figure 22). This reduction was even more dramatic when analysing the number of contracts in 2018. The number of concluded contracts for LNG sourced from portfolio players fell by more than 50% compared to 2017 levels, mainly because of a 90% reduction in short-term agreements. Despite this important decrease, portfolio players' concluded export contracts still represent 33% of all contracts linked to projects that have already taken FID.

Concluded contracts for LNG to be supplied by portfolio players have increased in length and contract volume. During 2017, low-volume contracts (less than 2 bcm/y) represented 82% of the concluded contracts for LNG to be provided by portfolio players. In 2018, this share was only 45%. Contrary to expectations, portfolio players' activity and increased participation have not meant the end of long-term contracts. Long-term contracts (more than ten years) for LNG to be supplied by portfolio players increased by almost 30% compared to 2017 levels, representing 66% of new contracts in 2018 (Figure 22).

Figure 22. Duration and size of contracts signed for LNG to be supplied by portfolio players (2017 and 2018)



Source: IEA analysis based on ICIS (2019), *ICIS LNG Edge*, <https://lngedge.icis.com/> (subscription required).

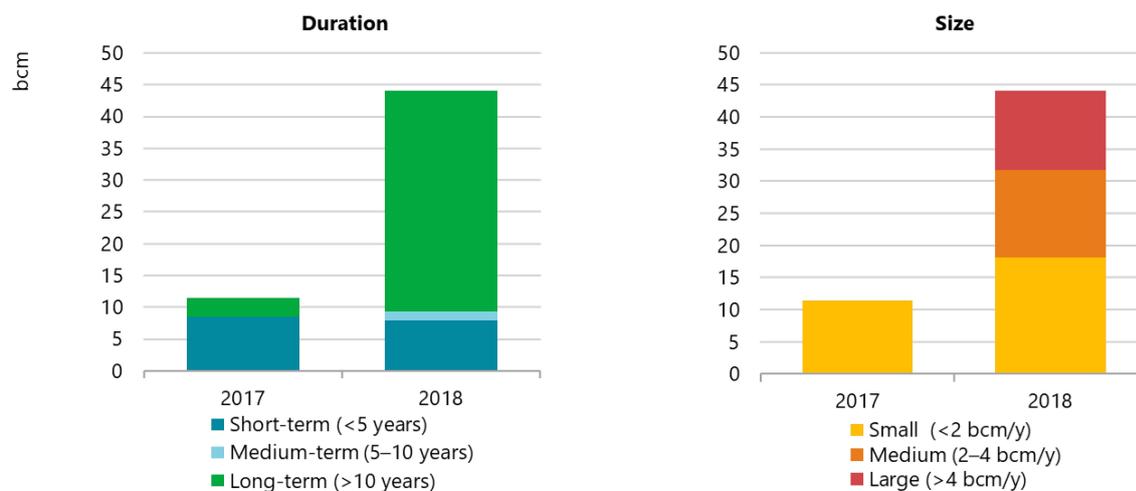
The volume of long-term portfolio player export contracts increased by almost 35% in 2018, representing 66% of contracts they signed that year despite a year-on-year decrease of 17% in overall portfolio player export contracts.

During 2018 and 2019 so far, portfolio players have been focusing on rebuilding their portfolios by increasing the total volume of import contracts signed, in order to compensate for the gap between volumes committed and the volumes available in their portfolios in the long term. These contracts alone accounted for the 45% of new contracts linked to projects that have already taken FID. In lieu of signing SPAs, portfolio players have taken equity stakes in projects, having been offered equity-lifting schemes such as the one used by LNG Canada. In one way or another, at least one portfolio player participated in all liquefaction projects that have taken FID during 2018 and the year to date.

This rebuilding process clearly reflects features of the import contracting activity conducted by portfolio players. In 2018, most of the new contracts for LNG to be supplied to portfolio players were long-term agreements (more than ten years) (Figure 23). Regarding volume, contracts larger than 2 bcm/y represented almost 59% of the total volume signed by portfolio players and linked to projects that have already taken FID. This is a large and rapid change from the past – during 2017, 100% of the contracts concluded were for less than 2 bcm/year.

Most contracted volumes sourced for portfolio players came from North America (53%), followed by the Middle East (13%), Africa (8%), and Russia (6%). These longer and larger contracts are intended to provide available volumes for portfolio players to use in the coming years, when many of the projects with which they are connected come online.

Figure 23. Duration and size of contracts signed for LNG to be supplied to portfolio players, 2017 and 2018



Source: IEA analysis based on ICIS (2019), *ICIS LNG Edge*, <https://lngedge.icis.com/> (subscription required).

The almost fourfold increase in the volume of portfolio player import contracts is nearly all in respect of long-term contracts, pursued for the rebuilding of portfolios.

Analysis of contract flexibility

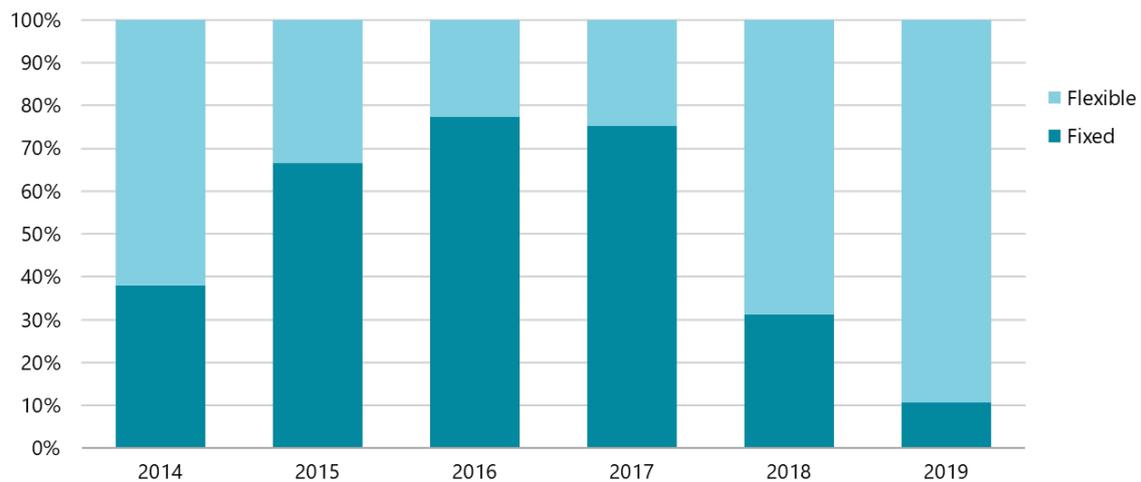
One way to assess flexibility on the LNG market is by analysing the share of contracts with destination clauses. Destination restrictions have an important impact on market liquidity, limiting demand response to price signals.

Unlike the current process of rebuilding portfolios, 2016 and 2017 exemplified how a period of low FID activity can affect the flexibility of contracts signed. In these two years, most contracting activity by portfolio players involved reselling the volumes in their portfolios through fixed-destination contracts. As highlighted in previous sections, 2018–19's new wave of liquefaction investment is accompanied by flexible contracts with greater volumes and longer terms. The share of contracts signed with a flexible destination increased to 69% last year, becoming the majority of all deals signed (Figure 24). That share has increased to 89% of volumes so far in 2019.

Volumes flowing into the market under flexible conditions are increasing. This results from the increasing role of portfolio players and new capacity coming online, contracted with terms and conditions that differ from legacy projects.

Figure 25 presents an analysis that assumes expiring contracts are not renewed and with no specific assumption on contracts yet to be signed (only including SPA and equity offtake contracts). Even though new contracts were mostly signed under flexible conditions, fixed destination contracts still accounted for the majority of the volumes in the market during 2018, representing 53% of the total volumes. Flexible destination volumes represented 33% of the total volumes traded in the market, while uncontracted capacity represented 14%. It is important to highlight that those uncontracted LNG volumes – coming either from new projects or from the expiry of existing contracts – could be available to be contracted under fixed or flexible terms.

Figure 24. Contracts signed each year by destination clause (2014–19)

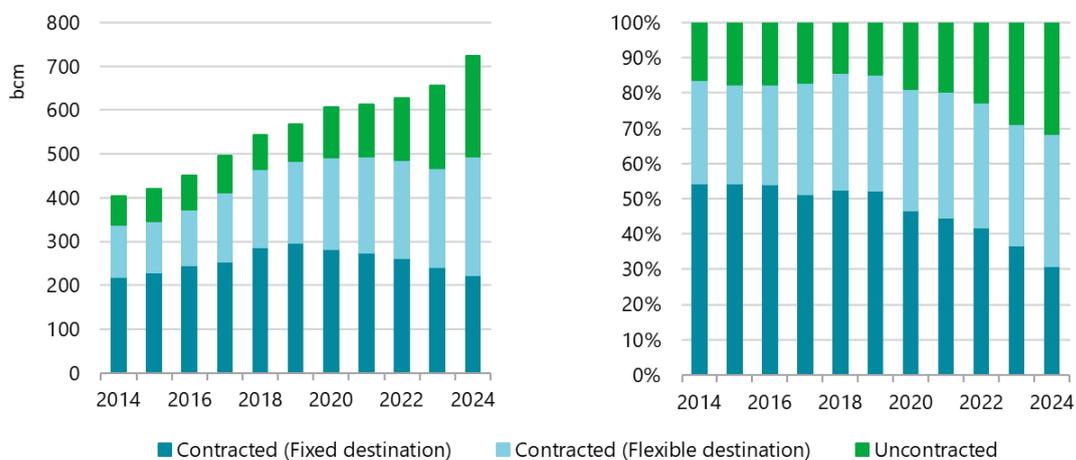


Notes: Based on the volumes of contracts concluded and linked to projects that have already taken FID. Sales from portfolios are also included. 2019 data include only the information available at the time of writing. Destination flexibility is determined using proprietary data based on *ICIS LNG Edge* supplemented with public data. Where data is unavailable, destination flexibility is interpreted from contract sales basis, agent profile, and market situation.

Source: IEA analysis based on ICIS (2019), *ICIS LNG Edge*, <https://lngedge.icis.com/> (subscription required).

Almost 70% of all contracts signed in 2018 have destination flexibility.

Figure 25. LNG export capacity by destination flexibility (2014–24)



Note: It is assumed that expiring contracts are not renewed, with no specific assumption on any contract yet to be signed. SPA and equity entitlement contracts only.

Source: IEA analysis based on ICIS (2019), *ICIS LNG Edge*, <https://lngedge.icis.com/> (subscription required).

Fixed destinations continue to account for the majority of volumes in the market, although this is forecast to fall as new contracting activity reflects increased destination flexibility until 2024, when flexible volumes represent the largest share of the market.

On the basis described above for Figure 25, the period 2018–24 would show a total reduction in fixed destination volumes of 63 bcm due to the expiry of legacy contracts. Over the same period, LNG export contracts with flexible destination would add about 92 bcm, mostly from the United States. At the time of writing, the currently uncontracted volume would reach around 229 bcm by 2024, or

almost a third of total export capacity, with contracted fixed destination clauses falling to roughly one-third, and contracted flexible destination accounting for the final third.

As already highlighted, an important share of this increase in destination flexibility is market driven. The activity of portfolio players, which are increasingly serving a more fragmented buyer pool, required flexible conditions.

Although emerging markets with increasing demands continue to secure volumes, buyers from markets that traditionally look to fixed destination contracts (Japan and Korea, for example) have also been pushing for greater flexibility in new LNG contracts. Many competition authorities have adopted cautious attitude to this kind of clause, either fighting to remove them from existing contracts or preventing any seller from including them in new contracts. As explained in last year's report, the Japan Fair Trade Commission, Korea Fair Trade Commission and European Commission have conducted several formal investigations into the legality of fixed destination contracts. Notably, these investigations explored whether traditional clauses included in supply contracts are anticompetitive and have the potential to violate national or regional antitrust laws.

While some competition authorities are more focused on avoiding fixed destination clauses in new contracts, the European Commission previously agreed to close its investigations once these clauses were erased from existing contracts and banned from the future contracting (e.g. Sonatrach investigation [European Commission, 2007]). Some of these inquiries have yet to conclude (IEA, 2018), complicating the task of anticipating the outcome and the implications for the LNG market. These authorities intend to continue monitoring the LNG market in order to protect the interests of their consumers.

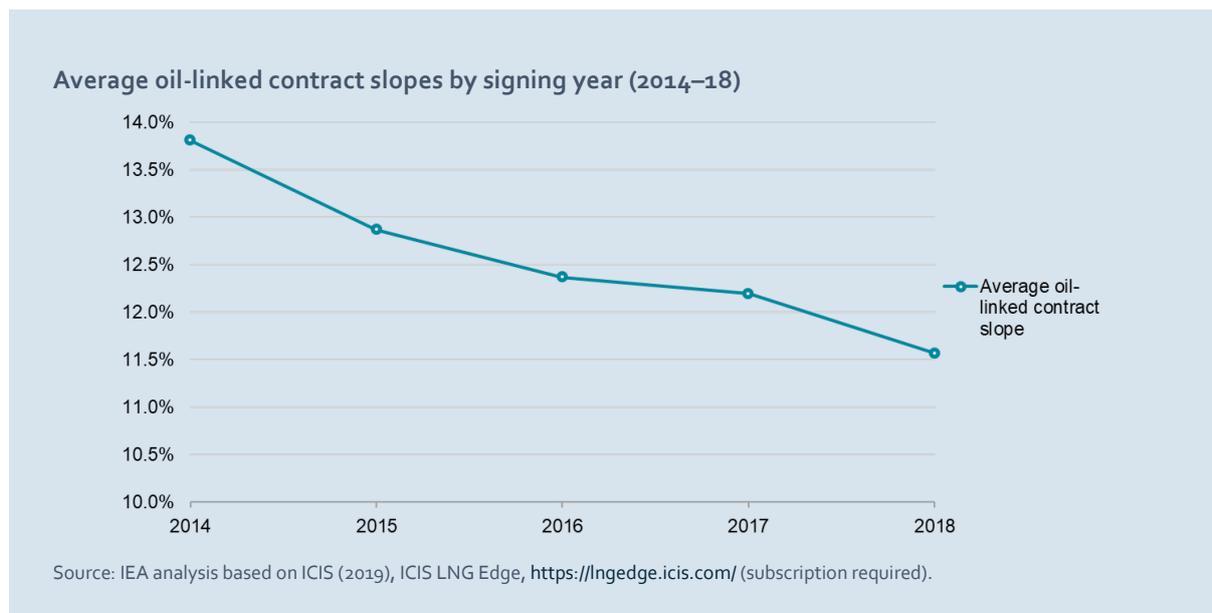
Pricing trends

The price of LNG has traditionally been indexed to the price of crude oil (either international crude prices such as Brent or West Texas Intermediate, or specific crude import prices such as Japanese Customs-cleared Crude or "Japanese Crude Cocktail" [JCC]).

Box 1. Oil-linked contract slopes

A contract slope establishes the degree of oil-to-gas indexation. It measures the extent to which the LNG price changes in response to changes in the oil price. For example, a slope of 16.67% is approximately oil parity. LNG has typically been priced at this level unless markets are extremely tight, or the features of the deal or the buyer profile could imply a higher risk for the seller. Oil-linked pricing formulas usually also include upper and lower limits (S-curves), thereby dampening the impact that oil price changes could have on the LNG price. Setting aside S-curves and other mechanisms, buyers prefer a flat slope in a context of high oil prices since it limits the impact on the price they have to pay. LNG producers and sellers prefer flat slopes at low oil prices to minimise the impact on cash flows.

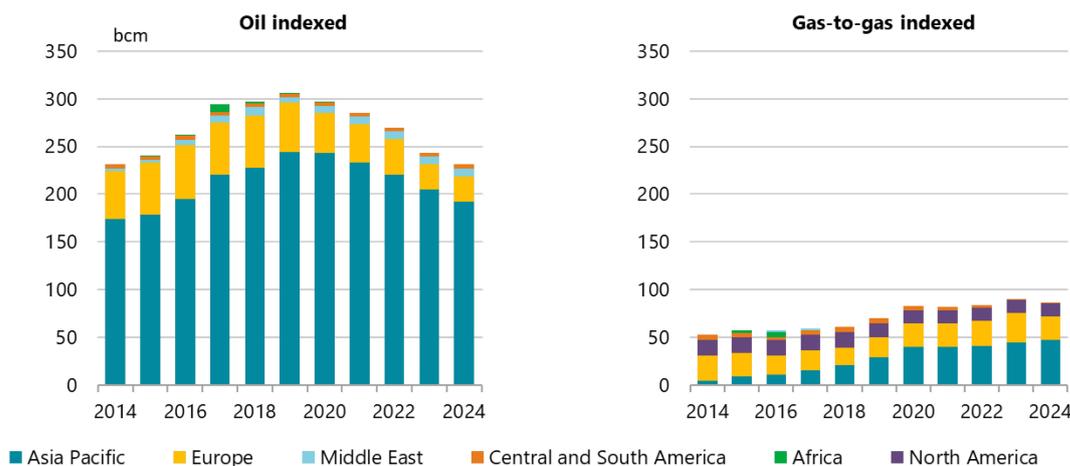
During 2018 and only for the contracts for which information is available, oil-linked contract price slopes remained mostly within the 11–12% range, continuing with the declining trend seen since 2014 (when the range was concentrated between 13% and 14%). Slope numbers are expected at least to remain within this range, as liquefaction capacity from Australia and the United States continues to come online until 2022 and additional liquefaction capacity has already taken FID.



Novel approaches to price linkages have started to gain momentum. Since the beginning of this decade, European gas contracts have increasingly been signed or renegotiated to include hub gas price indexation (even though this process has not been homogeneous among regions), reducing the historically predominant links to oil. Gas-to-gas indexation, preferably to liquid hubs, eliminates cross-commodity risk and aims to better mirror supply and demand fundamentals. However, lack of liquidity and price visibility on the physical market (and through associated derivative instruments) remain concerns.

The analysis of LNG contracts by price formula – addressing the split between oil-indexed and gas-to-gas pricing, by export and import, by region and country – shows a recent trend towards gas-to-gas indexation in both LNG export and import contracts since the first US LNG shipment in 2016. Gas hub-linked LNG contracts (especially to Henry Hub, but also to the Title Transfer Facility [TTF] or the National Balancing Point [NBP]) are gaining a larger share of contracts signed than in previous years, not only in Europe but also in Asia. Over 75% of oil-indexed LNG is delivered to the Asia Pacific region, with Europe accounting for most of the rest (Figure 26).

Figure 26. Oil indexed vs gas-to-gas indexed import volume (2014–24)



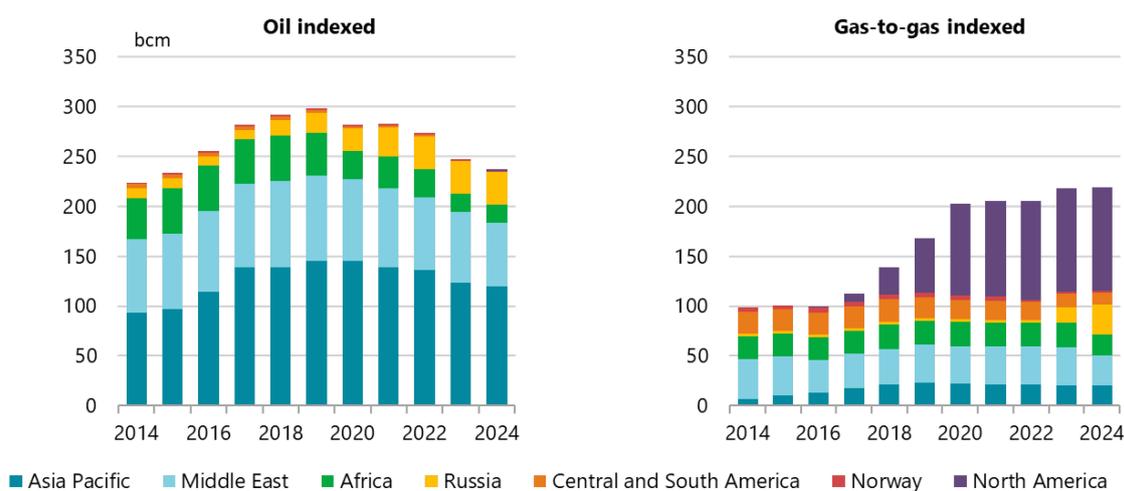
Note: Contracts not linked to a specific destination/origin have been excluded from the analysis.

Source: IEA analysis based on ICIS (2019), ICIS LNG Edge, <https://lngedge.icis.com/> (subscription required).

Recent import volumes slightly tend towards gas-to-gas indexation based on contracts signed in a variety of regions.

This report expects a further decline in the share of the oil-indexed pricing in export contracts (Figure 27). The largest decrease in oil-indexed pricing is observed in the Africa region (down by 27 bcm between 2018 and 2024), followed by the Middle East (down by 23 bcm). The decreasing oil-indexed volume is associated with the expiry of existing contracts gradually from 2017. The gas-to-gas pricing mechanism is mostly driven by Henry Hub-priced LNG exports from the United States. As the US export volume continues to rise with the growth in liquefaction capacity, gas-to-gas-priced LNG contracts from the United States are expected to account for more than 47% of all export contracts by 2024, up from less than 10% in 2017. These contracts are projected to become the dominant source of all gas-to-gas-priced import contracts in the Asia Pacific region.

Figure 27. Oil indexed vs gas-to-gas indexed export volume, 2014–24



Note: Contracts not linked to a specific destination/origin have been excluded from the analysis.

Source: IEA analysis based on ICIS (2019), ICIS LNG Edge, <https://lngedge.icis.com/> (subscription required).

North American volumes represent 47% of gas-to-gas-priced export contract volumes by 2024, increasing from a share of only 10% in 2017.

The steady decline in oil-linked contracts can be explained by both customer preference and the approach taken by portfolio players. Emerging Asian importers, expected to be the main driver of LNG growth in coming years, secure gas-to-gas-indexed US LNG to diversify their procurement portfolio. At the same time, long-term oil-indexed contracts still provide their main supply of gas. Portfolio players diversify with US LNG under gas-to-gas-indexed contracts, but then resell some of those volumes under an oil-indexed pricing formula. In 2018, 70% of the volumes supplied by portfolio players were oil-indexed, while 80% of the contracts sourced for portfolio players were gas-to-gas indexed. With this, portfolio players are trying to avoid Henry Hub as the price reference for exporting since the price dynamics in the United States have no correlation to competing energy sources in their domestic market.

During 2018 and 2019, the diversification behaviour evolved further with the onset of new pricing structures based on the destination market and the use of the gas:

- April 2019: Shell and Tokyo Gas announced the signing of heads of agreement partly using a coal-linked pricing formula, the first time this approach has been observed in LNG contracts. In addition to securing a long-term and stable supply, this deal is designed to maintain the competitiveness of gas against its main competitor in the power sector through a continuous benchmark against coal prices in the target market (Reuters, 2019).

- June 2019: Cheniere and Apache settled a long-term gas supply agreement, in which Apache will supply 1.16 bcm over the next 15 years to be marketed by Cheniere. The agreement uses an innovative LNG pricing structure based on international LNG indices, according to which Apache receives an LNG price net of a fixed liquefaction fee and additional costs incurred by Cheniere (Cheniere, 2019). In this price structuring system, the producer accepts international prices instead of relying on the Henry Hub price, whose dynamics are not totally aligned with LNG fundamentals (Bloomberg, 2019b).
- July 2019: Tellurian and Total announced an SPA in which the purchase price at the liquefaction terminal is linked to a destination market price, based on the Platts Japan Korea Marker (LNG World News, 2019). This pricing structure could force the offtaker to pay a higher price, depending on the spot market, but it dramatically reduces the market risk Total assumes since the structure includes a built-in profit margin. This agreement is similar to an earlier non-binding agreement that Tellurian signed with Vitol in 2018 (Platts, 2018; Reuters, 2018).

The growing availability of LNG is being facilitated by an increasing number of portfolio players and additional capacity due to come online in the coming years. The expansion of the market and new pricing structures have provided the opportunity for both sellers and buyers to adopt increased market flexibility, while also adapting to a more volatile environment.

References

- Bloomberg (2019a), "Commodity traders turn to LNG as big oil profits prove elusive", www.bloomberg.com/news/articles/2019-03-27/lng-grows-for-trading-houses-from-gunvor-to-trafigura-glencore.
- Bloomberg (2019b), "America's gas is hot in Shanghai. The price, not so much", www.bloomberg.com/news/articles/2019-04-03/american-gas-is-hot-in-shanghai-american-prices-not-so-much.
- Cheniere (2019), "Cheniere Corpus Christi Stage III and Apache sign long-term gas supply agreement indexed to global LNG prices", <https://chenierelng.gcs-web.com/node/20586/pdf>.
- European Commission (2007), "Commission and Algeria reach agreement on territorial restrictions and alternative clauses in gas supply contracts", http://europa.eu/rapid/press-release_IP-07-1074_en.htm.
- ICIS (2019), *ICIS LNG Edge*, <https://lngedge.icis.com/> (accessed 23/08/2019) (subscription required).
- IEA (International Energy Agency) (2019), *Market Report Series: Gas 2019*, IEA, Paris, <https://webstore.iea.org/market-report-series-gas-2019>.
- IEA (2018), *Global Gas Security Review 2018*, IEA, Paris, <https://webstore.iea.org/global-gas-security-review-2018>.
- Ledesma, David and Mike Fulwood (2019), "New players, new models", OIES, Oxford, www.oxfordenergy.org/wpcms/wp-content/uploads/2019/04/New-Players-New-Models.pdf?v=11aedd0e4327.
- LNG World News (2019), "Total kicks up investment in Tellurian's Driftwood LNG", www.lngworldnews.com/total-kicks-up-investment-in-tellurians-driftwood-lng/.
- Platts (2018), "Tellurian-Vitol LNG deal signals shifting balance of power", <https://blogs.platts.com/2018/12/11/tellurian-vitol-lng-deal-shifting-power/>.
- Reuters (2019), "Tokyo Gas, Shell sign LNG deal linked to coal pricing in rare move", www.reuters.com/article/us-lng-tokyo-gas-shell/tokyo-gas-shell-sign-lng-deal-linked-to-coal-pricing-in-rare-move-idUSKCN1RH0UB.
- Reuters (2018), "US LNG developer Tellurian strikes initial offtake deal with Vitol", www.reuters.com/article/lng-usa-tellurian/u-s-lng-developer-tellurian-strikes-initial-offtake-deal-with-vitol-idUSL8N1YB53D.

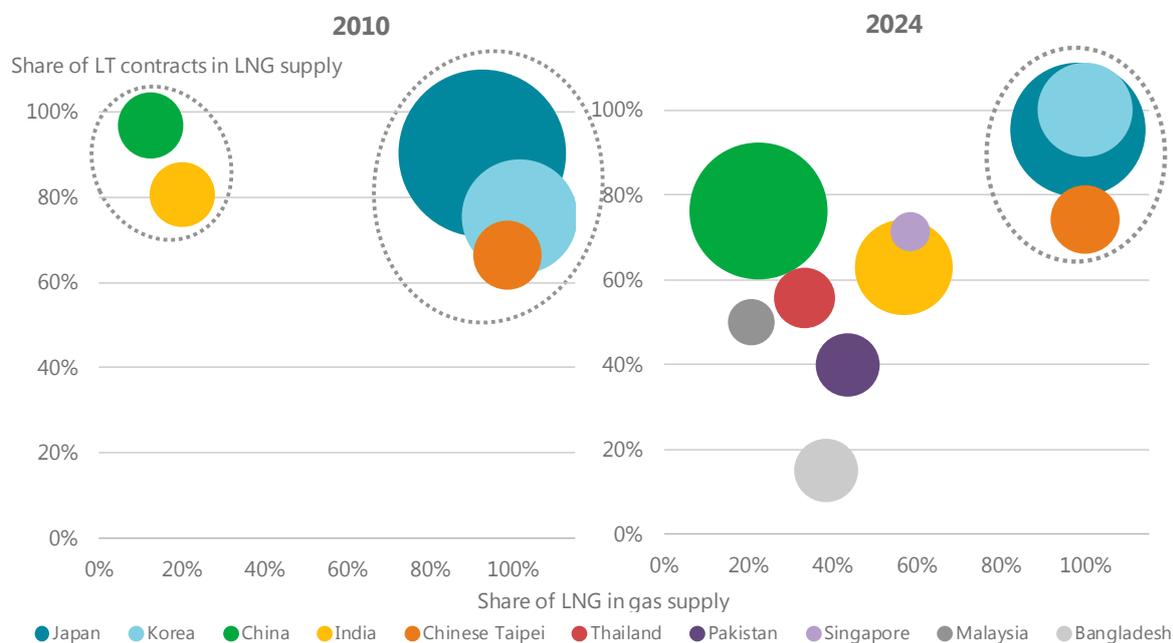
2. LNG supply security in Asia: An opportunity for traditional buyers?

Introduction

The structure of the Asian liquefied natural gas (LNG) market is undergoing a major shift. While traditional LNG buyers Japan and Korea are forecast to see flat or declining demand, non-traditional buyers⁴ China, India, Pakistan and Bangladesh are driving most of the future growth in this region. They are less dependent on LNG as a source of natural gas supply, but they expect to expand imports rapidly to meet ever-growing gas demand that is surpassing domestic gas production and pipeline imports.

The graphs in Figure 28 cluster Asian LNG buyers in groups according to two primary metrics: LNG supply reliance (share of LNG in natural gas supply); and LNG buying commitment (share of long-term contracts within LNG supply). Countries clustered on the right of each graph are LNG-dependent buyers, heavily reliant on LNG supplies because they have limited or non-existent alternatives. Such buyers are also characterised by a high share of long-term contracts within their LNG supplies, and this is forecast to remain the case over the next five years. The composition and size of this first cluster remains therefore unchanged in the medium term.

Figure 28. Evolution of Asian LNG buyer types (2010–24)



Note: LT = long term.

Sources: IEA analysis based on data from ICIS (2019), *ICIS LNG Edge*, <https://lngedge.icis.com/> (subscription required); 2024 is based on LNG forecast import data from IEA (2019), *Market Report Series: Gas 2019*, <https://webstore.iea.org/market-report-series-gas-2019>.

The traditional clustering of Asian LNG buyers gives way to a more diversified structure.

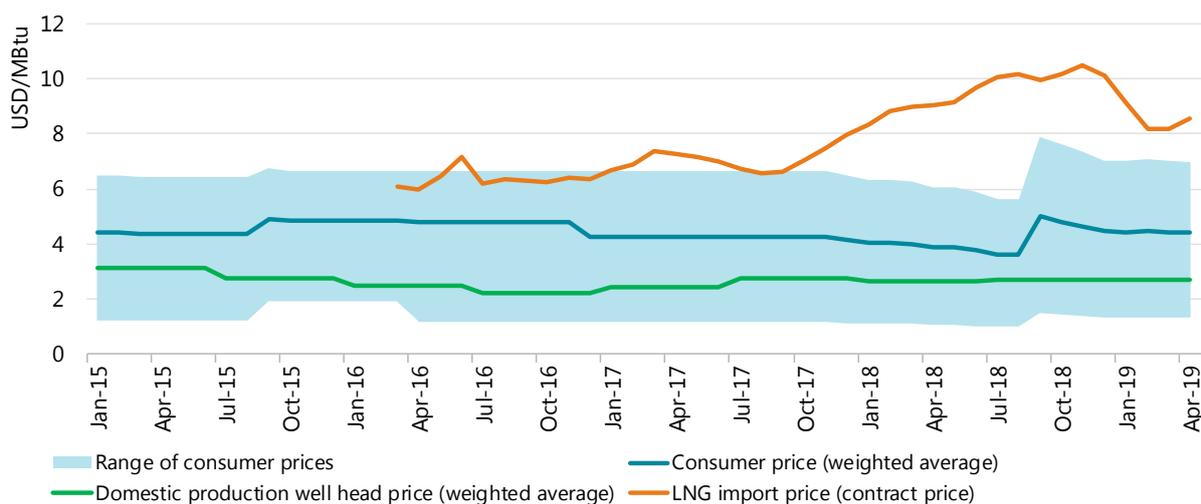
⁴ This typology of LNG buyers was introduced in the *Global Gas Security Review* (IEA, 2017).

Countries clustered on the left are more diversified buyers, with a more limited exposure to LNG as a share of gas supply due to the existence of domestic production and/or alternative pipeline import sources. These buyers also currently have a high share of long-term contracts within their respective LNG buying portfolios but, for most of them, their future growth in import needs has yet to be covered by additional long-term contracts, as shown by their position in the right-hand graph (2024) in Figure 28. The result is a simultaneous increase in the share of LNG in their gas supply and a decrease in the share of long-term contracts – based on contracts signed at the time of writing this report.

The subsequent supply gap could be bridged by a combination of additional long-term contracts and more short-term procurement. However, these emerging buyers are in general more price-sensitive than traditional buyers, and are thus more likely to opt for shorter-term supply options depending on the level of import prices. LNG, as an internationally traded commodity, naturally exposes the importing country to the globally traded price, which could be higher than the domestic reselling price. Therefore, this analysis is made on the basis that, for the medium term to 2024, the minimum demand for LNG is met through long-term contracts. The further increase in demand, which could be still supplemented by an increase in domestic production or pipeline imports, would be managed by a mixture of medium-term and short-term LNG contracts.

These emerging buyers are different from the traditional players. Japan and Korea have relied almost entirely on LNG for their natural gas supply and have been accepting long-term oil-linked contracts as the basis for the secure supply of gas. By contrast, many of the more recent entrants to the LNG market have their own gas production developed for domestic use and at lower prices. For example, Pakistan started importing LNG as an additional marginal source of gas supply in 2016. Its main source of LNG supply is a long-term contract with Qatar, using a pricing formula linked to the internationally traded oil price.⁵ As shown in Figure 29, the LNG contract price in Pakistan has been higher than that of the consumer price. The differential is USD 3 per million British thermal units (MBtu) on average since imports from Qatar began, and USD 5.6/MBtu at its peak.

Figure 29. Natural gas supply prices and average domestic consumer prices in Pakistan (2015–19)



Sources: OGRA (2019a), *Consumer Gas Prices*, www.ogra.org.pk/consumer-gas-prices; OGRA (2019b), *Well Head Gas Prices*, www.ogra.org.pk/well-head-gas-prices; OGRA (2019c), *Regasified LNG Notified Prices*, www.ogra.org.pk/lng-notified-prices.

The oil-indexed contracted LNG price has decreased the attractiveness of imported LNG.

⁵ Pakistan entered this LNG supply contract following a competitive tender. The awarded contract has a pricing formula reportedly linked to the three-month average of Brent crude oil prices with a slope of 13.37%.

Consequently, more diversified buyers have created a larger Asian LNG market by size. However, import volumes could depend on the prevailing price and these buyers are more reluctant to take on long-term commitments without the flexibility to resell or redirect cargoes depending on market conditions, given that alternative gas supplies would be a direct competitor to the imported LNG. These new buyers seek greater flexibility in the market and paradoxically can be an important source of supply security for the market – as prices rise, the volumes they take could drop. In addition, a lack of sufficient infrastructure for importing and transporting incremental quantities of gas necessitates flexibility in volume and delivery, and potentially affects the affordability of LNG.

The demand for greater flexibility is already becoming evident. Figure 30 shows LNG imports among emerging Asian economies, and the percentage of the total covered by term contracts. Most of the regional demand has been covered by contracted volumes during the initial years of importing LNG until 2018.

The year 2018 was the year that Bangladesh started importing LNG via a floating storage regasification unit (FSRU) as an intermediate solution until an onshore terminal could be completed. Delays in construction, however, meant that Bangladesh was only able to import one-third of its contracted volume in the first year, leading to an over-contracted situation for the emerging Asian economies as a whole in 2018. Beyond 2018, the proportion of future demand covered by term contracts progressively declines but is expected to be covered by contracts with ample flexibility or shorter contracts with higher affordability.

Figure 30. LNG imports into emerging Asian economies and proportion covered by term contracts (2014–24)



IEA, 2019. All rights reserved.

Notes: bcm = billion cubic metres; e = estimate.

Sources: IEA analysis based on data from ICIS (2019), *ICIS LNG Edge*, <https://lngedge.icis.com/> (subscription required); 2024 is based on LNG forecast import data from IEA (2019), *Market Report Series: Gas 2019*, <https://webstore.iea.org/market-report-series-gas-2019>.

Emerging Asian LNG buyers have on average 80% of their demand secured by contracts. However, affordability or the ability to import may cause a sudden supply and demand imbalance.

Where will this additional flexibility come from? *Global Gas Security Review 2018* (IEA, 2018) looked at the role of portfolio players, who are able to offer shorter-term and lower-volume contracts to help importers manage variation in demand. Most new LNG contracts for incremental supply are committed to traditional buyers (Japan and Korea in particular), and most of these are on a long-term basis. This year's report examines a significant and less appreciated source of flexibility – the

contractual arrangements of the traditional buyers themselves. Supply and demand imbalances are not a new phenomenon, and these longer-term contracts held by traditional buyers have more flexibility than might initially appear. Traditional importers in Japan, for example, foresee a business opportunity to use that flexibility to make some LNG available to the growing Asian market through diversion or reloading. Two facts underscore the potential: first, the almost half of LNG demand among emerging Asian LNG buyers in 2024 that has yet to be contracted, and second, the relative proximity of importers to one another in Asia.

This chapter now explores that flexibility and the potential for increased trade between traditional and non-traditional buyers of LNG in Asia to improve supply security in the region.

LNG flexibility in Asia

Flexibility in long-term contracts

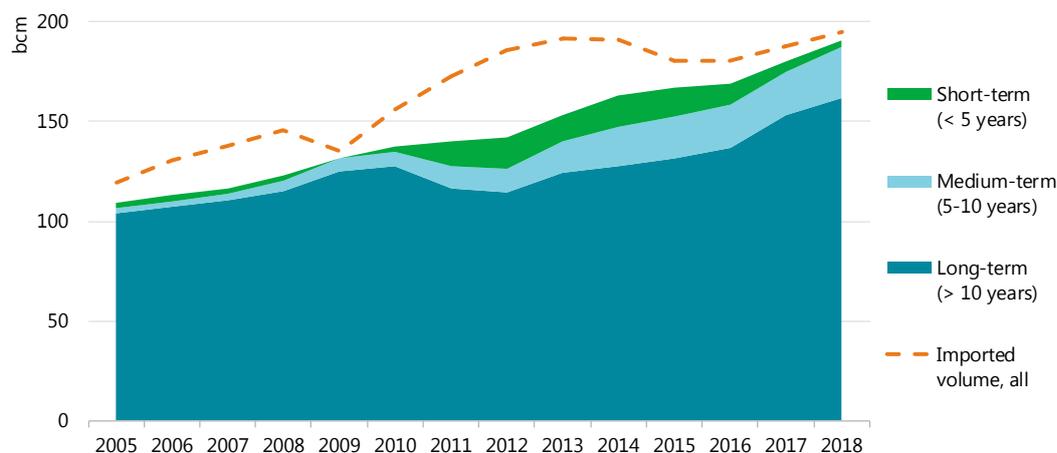
The need for flexibility varies according to the type of LNG buyer. For traditional buyers, their dependency situation naturally encourages a contractual need to focus on long-term stability and sustainability of procurement. This results in a high share of long-term contracts, with 95% of contracts in place in 2005 having a duration of over ten years (Figure 31).

The sudden increase in demand following the Great East Japan Earthquake in 2011 was largely met by spot markets and shorter-term contracts, with long-term contracts falling to less than 80% of the total in 2014. This was due to the sudden increase in LNG requirements to cover additional demand from power generation after the shutdown of nuclear capacity in Japan. This led the sellers (LNG projects) to sell their reserved excess volume⁶ through shorter-term contracts to supply this unforeseen demand. Trade flows from the Atlantic Basin to Asia also increased by 18% during the period. The share of shorter-term contracts (less than five years) increased from 2% in the late 2000s to 11% after the event, and the share of medium-term contracts (five to ten years) increased from an average of 4% to 13%. Following the easing of the situation and the arrival of new LNG production start-ups, the long-term contract share gradually increased to 85% by 2018, with most of the rest supplied under medium-term contracts (13%).

The analysis shows that even if long-term stability of LNG supply remains the priority for traditional Asian LNG buyers, their procurement strategy has shown a gradual shift toward shorter durations of up to ten years, as demand growth is modest (or in the case of Japan, decreasing) and the long-term demand for gas is less certain, especially for power generation. However, long-term contracts, with an average of 20 years' duration, still covered most demand volumes in 2018 (Figure 31).

⁶ LNG projects have reserved excess volumes to meet their supply obligations for the UQT (upward quantity tolerance) rights of the buyers, which are, in general, around 5–10% of the annual contracted volume in long-term contracts.

Figure 31. Structure of term contracts for traditional Asian LNG buyers and imported LNG volume (2005–18)



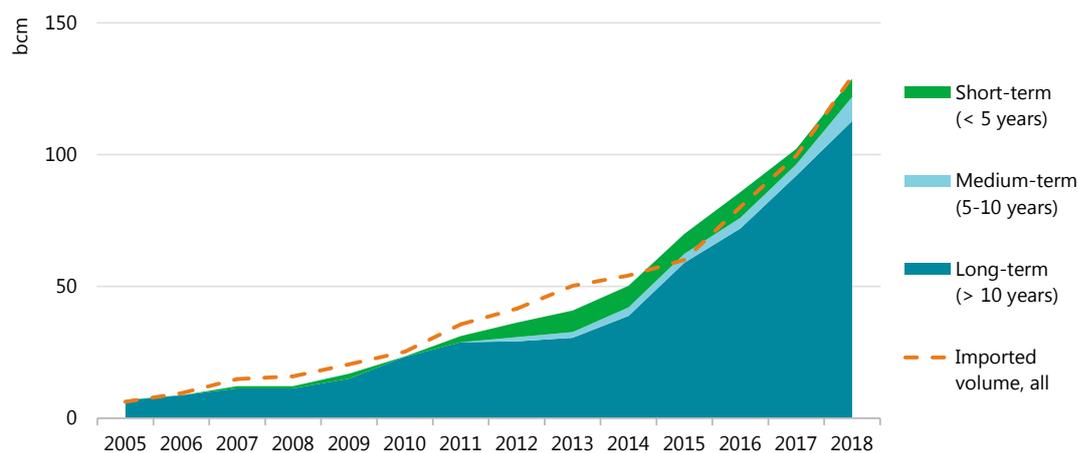
Note: Short-term contracts (< 5 years) do not include spot transactions.

Source: IEA analysis based on data from ICIS (2019), *ICIS LNG Edge*, <https://lngedge.icis.com/> (subscription required); imported volume data from GIIGNL (2019), *GIIGNL Annual Report 2019*, https://giignl.org/sites/default/files/PUBLIC_AREA/Publications/giignl_annual_report_2019-compressed.pdf.

Over 85% of LNG procurement for traditional Asian buyers is via long-term contracts to secure stable supply.

Long-term contracts have predominated among the other Asian LNG buyers as well. They accounted for over 90% of contracted volumes in India, China, Singapore, Malaysia, Pakistan and Bangladesh in 2018 (Figure 32), with the shares even higher in China and India. The reliance on long-term contracts can be explained by the need to develop import infrastructure (LNG receiving terminals and connection of pipeline networks).

Figure 32. Structure of term contracts in emerging Asian LNG buyers and imported LNG volume (2005–18)



IEA, 2019. All rights reserved.

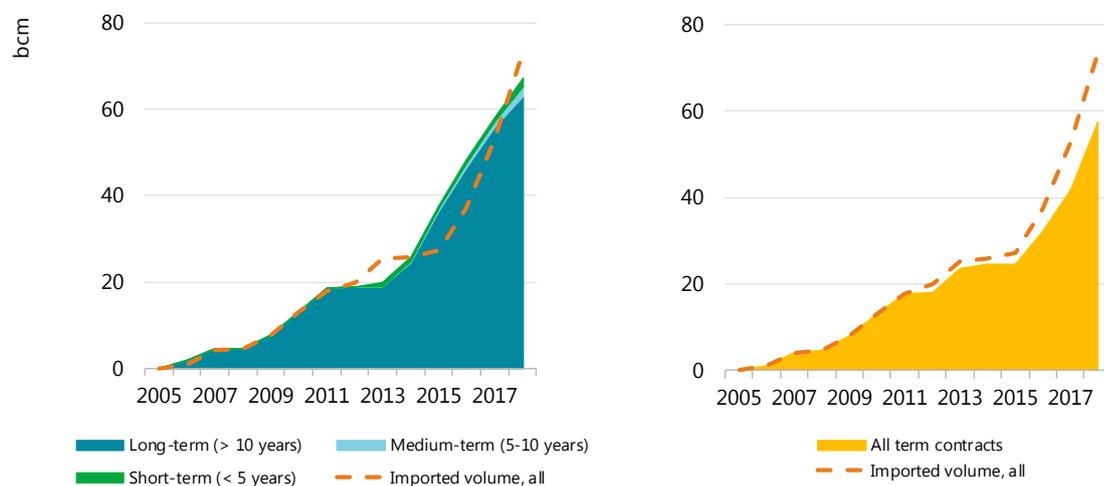
Note: Short-term contracts (< 5 years) do not include spot transactions.

Source: IEA analysis based on data from ICIS (2019), *ICIS LNG Edge*, <https://lngedge.icis.com/> (subscription required); imported volume data from GIIGNL (2019), *GIIGNL Annual Report 2019*, https://giignl.org/sites/default/files/PUBLIC_AREA/Publications/giignl_annual_report_2019-compressed.pdf.

LNG imports for emerging Asian buyers are generally aligned with contracted volumes, while other supply sources accommodate any eventual flexibility needs.

Interestingly, the contracted volumes in 2015–17 exceeded actual imported volumes, which required the buyers with flexibility rights embedded in the contracts to exercise those rights to manage the over-contracted volumes (Figure 33). Much of this over-contracted position can be attributed to China.

Figure 33. Structure of term contracts in China and imported LNG volume (2005–18)



Notes: Short-term contracts (< 5 years) do not include spot transactions; calendar years 2015–17 were over-contracted; the actual exercise of contractual rights and obligations is not publicly available information.

Source: IEA analysis based on data from ICIS (2019), *ICIS LNG Edge*, <https://lngedge.icis.com/> (subscription required); imported volume data from GIIGNL (2019), *GIIGNL Annual Report 2019*, https://giignl.org/sites/default/files/PUBLIC_AREA/Publications/giignl_annual_report_2019-compressed.pdf.

China has been exercising the flexibility in its term contracts to meet fluctuations in demand.

In 2013, China was under-contracted and additional short-term volumes had to be procured, most likely using flexibilities within existing long-term contracts with Malaysia, Qatar, Australia and Indonesia. The LNG may have been delivered to the new regasification terminals that commenced operation at Zhejiang Ningbo, Guangdong Zhuhai Jinwan LNG, Tianjin, and Tangshan LNG.⁷

In 2014, although China was technically over-contracted, delays in the commissioning of new LNG supply from Australia meant that in fact Chinese buyers sourced up to 18 bcm from the spot market to meet demand.⁸ China continued to rely on the spot market until the beginning of 2018, when policy-driven gas demand exceeded the contracted volume (Action Plan on Prevention and Control of Air Pollution [IEA, 2018]). China's position was eased by diversification of its gas portfolio into longer terms and development of new LNG receiving terminals and other infrastructure, such as pipelines and underground storage facilities.

With the predominance of long-term contracting in LNG sales, the flexibility embedded in these contracts is potentially an important resource for the Asian LNG market. Previous reports have examined destination flexibility, an attribute of particular importance to portfolio players, who have emerged as counterparties to many LNG projects. The next section examines the use of options in LNG contracts as a source of flexibility.

⁷ It is likely that the buyers exercised their rights to extra volumes in delivery at place (DAP) contracts. DAP contracts require the seller to make the LNG transport arrangements. Contracted projects with ample fleet and operational experience are likely to have made it possible to meet the buyers' requests to provide additional volumes and shipments.

⁸ Note: the contract arrangements between the Australian facilities and Chinese buyers are not publicly available, and hence the flexibility embedded in these contracts is not clear.

Options in LNG contracts

Traditionally LNG contracts have been commonly agreed with upward or downward quantity options within the contractual compensation scheme, to be exercised within the contract term (commonly known as “make-up” and “carry forward”, respectively). However, the allowance is small and limited due to the rigid production behaviour of the LNG plant. Cargo sizes also fall in a narrow range for a given vessel for safety reasons. This scheme allows compensation to be adjusted reflecting minor differences between actual delivered volumes versus contractually agreed volumes (MBtu against full-cargo basis).

For larger adjustments, sellers with the greater flexibility of portfolio pools are able to provide volume options in cargo sizes. This allows the buyer to request an additional cargo or cargoes under the same legal terms and conditions, or the seller to deliver greater or lesser volumes. The price to be paid in compensation will depend on the design of the option.

Examples of volume options include the following:

Volume tranche option – The buyer has multiple layers of contracted volume, so called “tranches”.

The buyer has the option to take several tranches of volume, one at a time with different periods between them. For example, an agreement may be made to sell a total volume of 3 million tonnes per annum (Mtpa) in tranches of a) 2.0 Mtpa, b) 0.5 Mtpa, and c) 0.5 Mtpa. The volumes can be delivered to the buyer with variable timing, for example, 2.0 Mtpa in the first year, and the remaining volumes to be delivered in the subsequent months or years. This type of delivery profile is suited to buyers with greater visibility of the large demand increments (or decreases). One example would be the process of an energy switch from coal to gas, where the volume tranches would accommodate the forthcoming increases in gas demand. Other examples would be an increase in gas demand from the expansion of a pipeline connection, or large new demand creation from the industrial sector.

Destination diversion option – The buyer has a right to nominate an alternative receiving terminal, including outside the buyer’s market.

This option is added to **DAP** (delivered at place) delivery, where the seller has the obligation to provide the transport. Under DAP delivery the destination port is nominated in advance to allow the seller to validate technical and operational deliverability for safe operation. Under the diversion option, the buyer has the right to nominate a new alternative terminal for prompt diversion. However, it is unlikely for a buyer to exercise this right frequently, as the operational and commercial hurdles of en-route diversion are high. The seller faces extra checks on the safety and compatibility of the nominated receiving terminal(s) prior to calling. In addition, the diversion could affect its fleet management, such as changes to voyage schedules.

The incremental costs for inspection and voyage days with extra fuel may be transferred to the buyer, depending on the terms and conditions. The buyer is still required to receive and pay for the LNG under the said LNG contract. As such, the buyer would need to ensure that the nominated terminal has the capacity to receive and send on for consumption the LNG delivery, or enter into a back-to-back sale and purchase agreement with the receiving terminal capacity owner for the resale of the received LNG.

For **FOB** (free on board) transactions, where the risk and title transfer to the buyer at the delivery point, the buyer has by nature the right to deliver the purchased LNG cargo to its preferred receiving terminal.

Call option – A party has the right to buy (“call”) an LNG cargo at an agreed price on or before a particular date. Typically, the buyer is able to ask for a full LNG cargo to be delivered within a few

months of notification at a pre-agreed price or according to a pre-agreed pricing formula. This option is valuable for the buyer who requires additional volume to meet a fluctuation in demand. Hence, the option is useful in the case a sudden demand surge raises the spot market price above the level of the pre-agreed call option price. Call option contracts also stipulate the range of acceptable LNG specifications and LNG sources, as sourcing LNG of the right specification from a supply portfolio or on the spot market may prove to be difficult.

Put option — A party has the right to sell (“put”) an LNG cargo to the contracted party at an agreed price on or before a particular date. The receiving party has an obligation to receive it. For Asian LNG buyers this option is useful when they have an unwanted cargo that they are not able to consume as originally planned. The destination of the unwanted cargo is usually pre-agreed, the nominated receiving terminals normally having a low utilisation rate. These have the physical capacity to accept an extra cargo throughout the year, and hence have higher availability. This also reduces the technical risk that the vessel or LNG specification does not match the receiving terminal’s requirements.

Valuation of options

The cost of options is determined by the contract framework, negotiated on a case-by-case basis and not publicly available. The negotiation is, however, assumed to result in a premium (or discount) compared to traditional or basic contractual conditions, as most of the options listed in the previous section imply additional (material or opportunity) costs for the party selling the option. For example, changes to an agreed delivery schedule within the contract year may incur extra costs for the transporter, by floating the vessel in open water for additional days (in the case of schedule deferment) or speeding up and hence consuming more bunker fuel than originally planned (in the case of schedule advancement). In a volume put option, where the option holder can sell an unwanted cargo at short notice, the LNG cargo may be priced at a discount to the market-traded price.

A destination diversion option for a DAP contract can also be valued at a premium. For the LNG seller, who bears the transport obligation, diversion of the unsold cargo to another destination may incur extra shipping and port charges. The technical compatibility of the vessel, and confirmation that the alternative terminal will be clear, must be ensured prior to the seller accepting the diversion request from the buyer, and any potential difference in tax regime may also need to be addressed. The seller and buyer, therefore, need to agree in advance on mitigation of such unforeseen additional costs, which depend on the destination requested by the buyer.⁹

Flexibility in Japanese LNG contracting

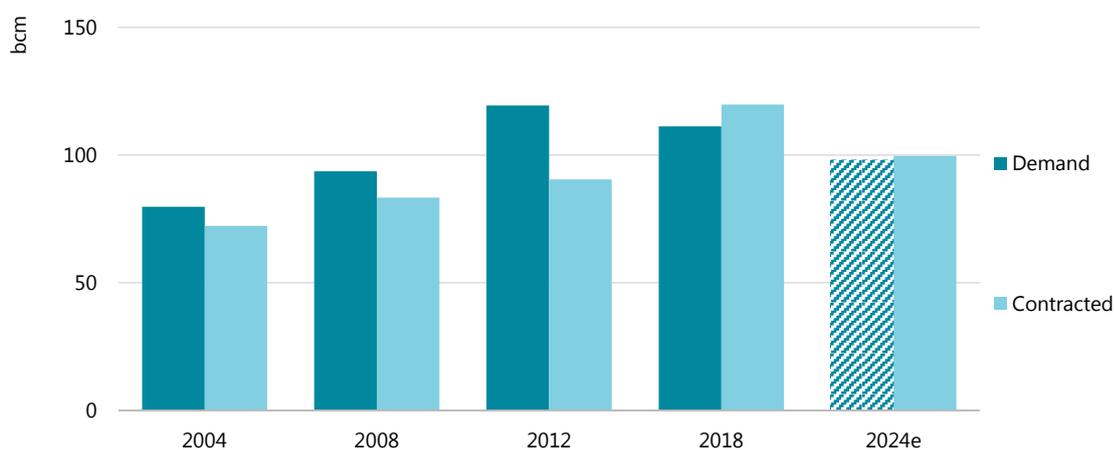
Japan has been importing LNG for 50 years and LNG currently meets over 97% of its natural gas requirements. Around 70% of it is used for power generation (around a third of Japan’s electricity supply), followed by residential and commercial use, and then industrial use. The country’s LNG procurement strategy, therefore, has to be aligned with its forecast natural gas demand and is particularly sensitive to the needs of the power sector.

Prior to the 2011 earthquake, LNG demand was only slightly larger than contracted supply, where around 90% of demand was met by term contracts and the remainder could be accommodated by additional deliveries from contracted suppliers (Figure 34). The nuclear plant closures following the earthquake resulted in a surge of LNG demand that far exceeded such contractual flexibility. In 2012 Japan experienced a shortage of nearly 30 bcm of contracted LNG, meaning that 25% of demand

⁹ The flexibility of destination diversion is designed to be used in the case of emergency. Hence, the price or pricing framework is considered and agreed in advance to avoid potential disagreement at the time of action.

was uncontracted, where buyers were exposed to the market volatility associated with sourcing urgent and prompt cargo deliveries. Since that time, contracted volumes have increased again and gas demand has decreased as nuclear plants have returned to service (currently nine plants representing 9 GW). Japan is now somewhat overcontracted. By 2024, with further nuclear restarts and contracts expiring, demand and supply of LNG are expected to be roughly in balance at around 100 bcm.

Figure 34. LNG demand and contracted volume, Japan (2004–24)



Source: IEA analysis based on data from ICIS (2019), *ICIS LNG Edge*, www.icis.com/explore/services/analytics/lng-market-intelligence-solution/ (subscription required); 2024 is based on LNG forecast import data from IEA (2019), *Market Report Series: Gas 2019*, <https://webstore.iea.org/market-report-series-gas-2019>.

The post-Fukushima demand surge for power generation use is expected to diminish as nuclear plants continue to restart.

The demand shock following the earthquake has helped to reshape the LNG market. More emphasis is placed on flexibility – in quantity and in destination deliverability outside the Japanese market. The emergence of a secondary market where portfolio players, among others, provide extra layers of flexibility to deliver is also expected to further offset the rigidity of the LNG value chain.

Japanese LNG buyers have also been evolving as regards procurement flexibility. They are now implementing this flexibility beyond the Japanese market with innovative measures. These innovations have been made possible through: their experience of LNG procurement over 50 years; a higher number of the strategic partners in the market; enhanced flexibility in LNG contracts; and ample LNG availability from diversified sources such as Australia and United States, and new supply sources to come from Canada and Mozambique. This section summarises the evolution of flexibility in LNG contracts and implementation, which is expanding into the market beyond Japan.

Innovation in contracting

Recently announced contracts provide evidence of innovative provisions extending into new supply contracts. In April 2019 Tokyo Gas¹⁰ signed a ten-year LNG contract with Shell that has a pricing formula partially indexed to coal. The LNG volume of 0.7 bcm/y will be sourced from Shell's global portfolio. Subsequently, Tokyo Gas agreed a joint procurement scheme with UK utility Centrica for LNG from Mozambique LNG for 20 years. The cargoes will be delivered under DAP (seller to arrange

¹⁰ A gas utility supplying 11 million natural gas customers, primarily in the Tokyo Metropolitan area.

transport) with no destination restrictions. Under the arrangement, Tokyo Gas and Centrica aim to share the total volume of 3.5 bcm/y and adjust it to meet their demand fluctuations. As both receiving terminals share similar distances in shipping days from Mozambique (20–25 days laden voyage), any disruption to the seller's shipping fleet schedule should be limited.

Expansion of LNG network

Japanese companies are also investing in their infrastructure, primarily for reloading, in order to serve the growing Asian market. Shizuoka Gas¹¹ converted its own Shimizu LNG Sodeshi Terminal into a reloading facility in 2016. It is targeting Southeast Asia as the most promising receiving market for reloaded LNG, and the terminal is equipped with technology that shortens the time taken for LNG reloading. Several reloaded cargoes have already been sold and delivered to other Asian markets.

Also in 2019 Shizuoka Gas made an agreement with Clean Energy, a subsidiary of Chinese Dalian Inteh holdings, for the sale of LNG in ISO tanks to the Chinese market. Each ISO tank is filled with 18 tonnes of reloaded LNG, transported by truck to a container exporting terminal, and then shipped to Dalian Port with a voyage four days.

Similarly, Saibu Gas¹² announced a new business to use its wholly owned Hibiki LNG terminal for reloading LNG for Russian producer Novatek. The terminal will be used for the transshipment (as an intermediate destination) of Novatek's LNG to the Asian market. Novatek operates Yamal LNG and Arctic 2 LNG. The Yamal LNG project, with a capacity of 2.2 bcm/y, has been delivering LNG to Europe and China since 2017. Arctic 2 LNG is planning to produce 2.7 bcm/y of LNG, starting in 2023. The projects aim to transport LNG to the Asian market via reloading terminals to reduce laden shipping time by half to 20 days via the Arctic Ocean ("eastward route"), from 40 days via the Suez Canal ("westward route"). On the eastward route, an LNG transshipment terminal is planned on the Kamchatka peninsula, and Saibu's Hibiki terminal will be an alternative for optimisation. The Hibiki terminal is able to accept and reload the LNG onto small, medium-sized and large LNG carriers, and is located near to the Chinese market. It is therefore suitable for meeting sudden demand fluctuations. Saibu Gas is planning to construct extra LNG tanks and a new loading facility, with FID expected in 2019 and operations due to commence in 2023.

Saibu Gas has also concluded a trial delivery by ISO tanks loaded at the Hibiki terminal. The ISO tanks were transported by truck to another container port in Japan and then by container ship to Lianyung in China. Saibu Gas also anticipates further opportunities in Southeast Asia.

Creating joint ventures

Institutional arrangements are also changing. JERA¹³ was formed by merging the fuel procurement operations of Tokyo Electric and Chubu Electric in 2015. In 2018 JERA further expanded its business by acquiring LNG trading businesses from EDF of France. These added 4 bcm/y of additional LNG to JERA's original portfolio of 48 bcm/y, of which 14 bcm/y (28%) have destination-free contracts. JERA also has acquired EDF's capacity access to an LNG receiving terminal in Europe, to which JERA aims to divert destination-free cargoes for demand optimisation. JERA also aims to gain a pricing advantage by optimising the market pricing differentials between Asian and European markets, utilising the financial risk management capability of EDF.

¹¹ A gas utility supplying natural gas to 0.3 million customers. LNG procurement volume is 1.8 bcm/y.

¹² A gas utility supplying natural gas to 0.9 million customers. LNG procurement volume is 0.7 bcm/y.

¹³ JERA procures LNG for Tokyo Electric and Chubu Electric. LNG is mainly used for power generation. LNG procurement volume is 48 bcm/y.

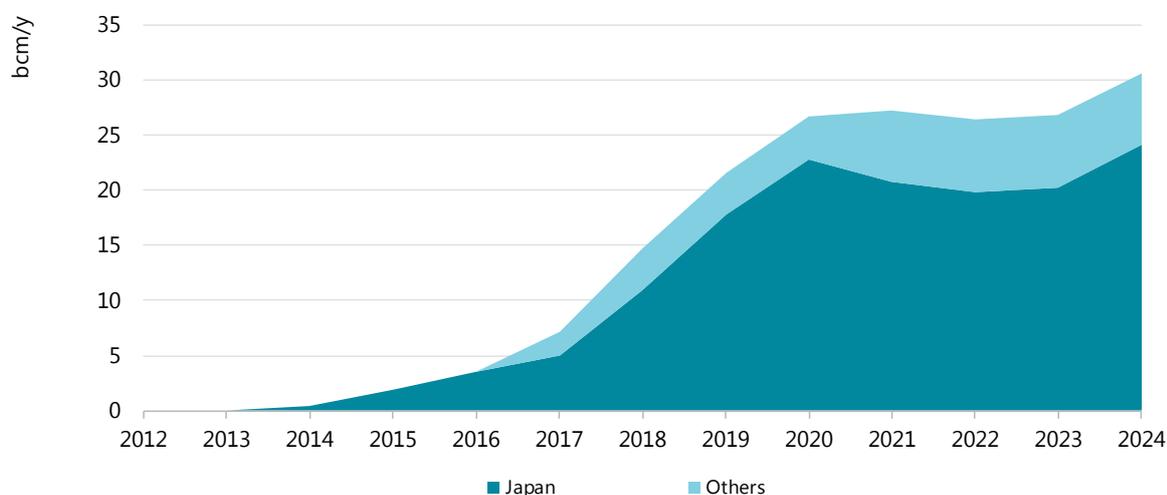
Expanding LNG outlets

JERA has been active in creating new LNG demand in the Asia Pacific region, which would eventually be helpful for managing the supply and demand balance within JERA's portfolio. In 2019 JERA started FSRU and gas distribution businesses in Eastern Australia with the Japanese trading company Marubeni. JERA is also in the process of launching an LNG bunkering business and currently has an LNG bunkering vessel under construction, due for delivery in 2020. JERA plans to source the LNG from its stockpile, to be reloaded at JERA's Kawagoe LNG receiving terminal (reloading facility currently under construction). Then the LNG bunker vessels will provide LNG fuel for Toyota's vehicle carrier vessels en route between Japan and the west coast of the United States.

Proximity and security of supply

IEA analysis shows that emerging Asian LNG buyers have the potential to experience uncontracted demand in the medium term, while also requiring volume optimisation due to limited receiving terminal capacity until new infrastructure is constructed or connected. One solution to this could be the flexible supply provided by the traditional Asian LNG buyers. These buyers have experience of market dynamics with 50 years of safe operational capability, using flexibilities in their long and short-term contracts to meet uncertain demand. Given their requirement to create new demand to absorb potential excess contracted volumes, they are well-positioned to provide a solution – currently 15 bcm/y of volumes contracted to traditional Asian LNG buyers are considered to be destination-flexible. This destination-flexible volume is expected to double to 31 bcm/y by 2024, which would cover up to 15% of forecast LNG demand for emerging Asian LNG buyers, if all are to be provided (Figure 35).

Figure 35. LNG volumes contracted to traditional Asian LNG buyers with flexible destination (2012–24)



Source: IEA analysis based on data from ICIS (2019), *ICIS LNG Edge*, www.icis.com/explore/services/analytics/lng-market-intelligence-solution/ (subscription required); 2024 is based on LNG forecast import data from IEA (2019), *Market Report Series: Gas 2019*, <https://webstore.iea.org/market-report-series-gas-2019>.

Flexible LNG from traditional Asian LNG buyers is set to cover up to 15% of LNG demand from emerging Asian LNG buyers, providing extra flexibility in the region.

This destination-flexible LNG volume would be seen to be suitable for diverting to emerging Asian buyers, where over 40% of demand growth is expected to originate in the coming years. The development of a market expected to see such robust demand growth would have a great impact on regional and global security of supply. Table 1 shows that Northeast Asian LNG buyers (Japan,

Korea, China) – and emerging LNG buyers – Southeast Asia (Singapore, Thailand) and South Asia (India, Bangladesh, Pakistan) – are all relatively close to one another (within four sea voyage days).

Table 1. Laden voyage days between major Asian LNG delivery ports

From \ To	Japan	Korea	China (north)	China (south)	Singapore	Thailand	India (east)	India (west)	Pakistan
Japan		2.6	3.4	4.4	7.6	7.7	11.7	14.6	15.1
Korea	2.6		1.8	3.2	6.5	6.6	10.6	12.9	14.0
China (north)	3.4	1.8		3.9	7.3	7.2	11.3	13.5	14.7
China (south)	4.4	3.2	3.9		4.1	4.2	8.1	10.4	11.5
Singapore	7.6	6.5	7.3	4.1		2.1	4.1	6.3	7.5
Thailand	7.7	6.6	7.2	4.2	2.1		6.2	8.4	9.6
India (east)	11.7	10.6	11.3	8.1	4.1	6.2		3.8	5.0
India (west)	14.6	12.9	13.5	10.4	6.3	8.4	3.8		1.3
Pakistan	15.1	14.0	14.7	11.5	7.5	9.6	5.0	1.3	



IEA, 2019. All rights reserved.

Notes: Durations only account for days at sea and do not include loading and offloading days. For the purpose of analysis, "Japan" refers to Tokyo Bay area, "Korea" to Pusan, "China north" to Tianjin, "China south" to Guangzhou, "Singapore" to Jurong, "Thailand" to Sriracha, "India (east)" to Chennai, "India (west)" to Mumbai, and "Pakistan" to Karachi.

Source: IEA calculation assuming an average speed of 16 knots, taking into account that the vessels would limit their maximum speed due to the close proximity to other buyer countries, based on distances from sea-distances.org.

Analysis shows that the nearest terminals can be reached within three voyage days, enabling fluctuations in supply and demand to be met promptly. The requirements of traditional buyers (highly dependent on LNG supply, yet with fluctuating demand) and of emerging buyers (LNG demand set to increase, but infrastructure immature and price sensitivity currently hindering the signing of long-term contracts) could be mutually beneficial for stronger regional security of supply. Traditional buyers, who already maximise their own use of the secondary market, can play a new role by becoming sellers of LNG in a secondary market that is at the stage of developing in the wider Asia region.

Contract flexibility and means of implementation – examples such as reloading, partnerships and ISO container loading – would bring interconnectivity between the parties to the region, with enhanced readiness to manage supply and demand disruption. Similar to the operational experiences of global portfolio players, traditional Asian LNG buyers can become sellers providing robustness to the operation of immature emerging market infrastructure.

Furthermore, as seen in traditional buyers expanding their LNG network beyond the region – accessing out-of-region terminals and using sourced LNG as bunker fuel – the LNG network and the security it brings are set to expand interregionally. Diversion or time-swapping optimisation are currently observed between bilateral buyers within the region, while reloading trade flows are mainly observed from Europe to Asia, where excess supply has been delivered to meet demand. Traditional Asian LNG buyers are well placed to further increase regional trading flows by selling LNG into markets where new demand is set to rise.

References

- GIIGNL (International Group of Liquefied Natural Gas Importers) (2019), *GIIGNL Annual Report 2019*, GIIGNL, Neuilly-sur-Seine, https://giignl.org/sites/default/files/PUBLIC_AREA/Publications/giignl_annual_report_2019-compressed.pdf.
- ICIS (2019), *ICIS LNG Edge*, <https://lngedge.icis.com/> (accessed 25/06/2019) (subscription required).
- IEA (International Energy Agency) (2019), *Market Report Series: Gas 2019*, IEA, Paris, <https://webstore.iea.org/market-report-series-gas-2019>.
- IEA (2018), *Global Gas Security Review 2018*, IEA, Paris, <https://webstore.iea.org/global-gas-security-review-2018>.
- IEA (2017), *Global Gas Security Review 2017*, OECD/IEA, Paris, <https://webstore.iea.org/global-gas-security-review-2017>.
- OGRA (Oil and Gas Regulatory Authority of Pakistan) (2019a), *Consumer Gas Prices*, www.ogra.org.pk/consumer-gas-prices.
- OGRA (2019b), *Well Head Gas Prices*, www.ogra.org.pk/well-head-gas-prices.
- OGRA (2019c), *Regasified LNG Notified Prices*, www.ogra.org.pk/rlng-notified-prices.

3. North-western Europe's gas flex: Still fit for purpose?

Introduction

North-western Europe's natural gas infrastructure has been a key enabler of a well-integrated and tradable regional gas market.¹⁴ The high level of interconnectivity, spare import capacity, local production capabilities and availability of storage capacity have all contributed to providing flexibility – both in space and time – to the natural gas grid, facilitating the development of liquid and tradable gas markets. Meanwhile, security of supply is reinforced by adherence to market rules.

The import requirements of north-western Europe are expected to increase by almost 40 billion cubic metres per year (bcm/y) in the next five years, as indigenous gas production enters a phase of rapid decline while domestic consumption is set to remain flat. Moreover, the direction of natural gas flows within the region is expected to gradually change, mainly driven by the decline in natural gas production in the Netherlands. This raises the question of north-western Europe's gas infrastructure adequacy for future market conditions, i.e. its ability to accommodate greater natural gas imports with different flow directions and profiles.

The flexibility of the region's gas grid is also gaining importance in the context of the profound changes in the European power sector. North-western Europe is set to phase out almost 45 gigawatts (GW) of coal-fired and nuclear baseload power generation capacity in the next five to six years. This means that the linkage between electricity security of supply and natural gas deliverability will become more intimate: gas-fired power generation has a growing role in ensuring the "thermal swing" as backup for the increasing share of intermittent renewables and in supplying a larger share of peak demand.

Moreover, the global natural gas market is becoming increasingly interlinked via flexible and divertible LNG cargoes, increasing the influence of events in distant markets on the European gas market. These rising interdependencies are further amplifying the importance of north-western Europe's "gas flexibility", ensuring that its gas markets can react in a timely manner to changing global supply–demand dynamics, without putting at risk domestic gas deliverability.

Gas flexibility toolkit

Natural gas consumption in markets with cold winters demonstrates a strong seasonal pattern, driven primarily by the heating needs of the residential and commercial sectors.

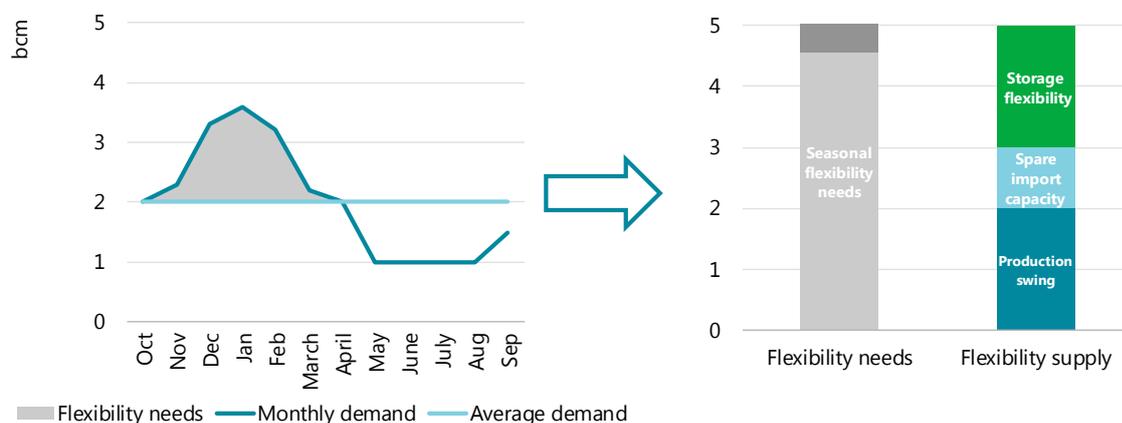
In addition, shorter-term variability of demand (volatility) is usually present, driven in the winter by the variation in temperatures and across the year by the fluctuating needs of the power sector (where gas-fired power plants play a balancing role in supporting intermittent renewables and meeting peak demand).

The need for flexibility to satisfy natural gas demand can be met through a combination of upstream and downstream flexibility tools, including a seasonal swing in domestic production, spare import capacity and storage (Figure 36). Moreover, spare capacity in downstream interconnectors is

¹⁴ Northwest Europe refers to Belgium, France, Germany, the Netherlands and the United Kingdom.

crucial so that gas flows can be redistributed efficiently and gas storage used to its optimum under stressed market conditions. In addition, linepack flexibility services, LNG storage and demand-side response can contribute to shorter-term variations in natural gas demand.

Figure 36. Simplified schematic of seasonal gas flexibility needs and supply balance in the northern hemisphere



IEA. All rights reserved.

The seasonal flexibility needs of natural gas demand are met through a combination of upstream and downstream supply flexibility, including production swing, spare import capacity and storage.

After initially analysing the evolving need for flexibility to meet north-western European natural gas demand, this chapter assesses the current state of the flexibility tools available to the system, including:

- **Upstream deliverability:** the evolution of indigenous gas production, addressing both volume changes and seasonal patterns.
- **Import capacity:** the position on annual and peak import capacity, seasonal swings and the timeliness of additional import volumes.
- **Midstream interconnectivity:** the evolution of utilisation rates, considering both annual averages and during peak demand.
- **Storage flexibility:** the evolving storage space in north-western Europe and its utilisation rates.

The assessment of these flexibility tools is crucial given the growing role that natural gas is expected to play in north-western Europe's energy system.

North-western Europe's gas demand: Seasonality and volatility

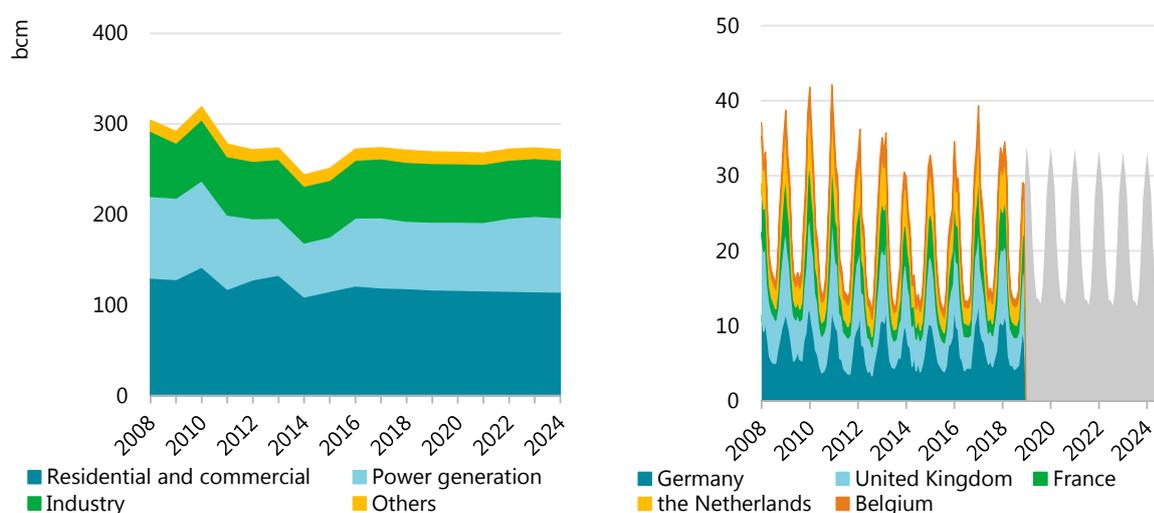
North-western European gas consumption stood at 271 bcm in 2018, just above half of total European gas demand. One characteristic of the north-western European natural gas system is the co-existence of a combined high-calorific gas (H-gas) and low-calorific gas (L-gas) market zones. L-gas has been produced since the early 1960s from the giant Groningen field in the Netherlands and a number of much smaller fields in Germany, and today has a market of around 55–60 bcm/y, concentrated in the Netherlands (25 bcm/y), north-western Germany (20 bcm/y),

Belgium and France (each 5 bcm/y). L-gas supply is supplemented by conversion of H-gas via conversion facilities (Figure 37). Production of L-gas is declining rapidly, and the consequences of this for the north-western European gas market is analysed below in detail.

The residential and commercial sectors accounted for 44% of north-western European gas consumption on average between 2005 and 2018, followed by power generation (27%) and industry (24%) (Figure 37). Each sector is characterised by different demand patterns and hence flexibility requirements.

The high share of the residential and commercial and the power sectors results in a strong seasonal pattern of natural gas demand, with almost two-thirds of total gas consumption occurring during the heating season.¹⁵

Figure 37. North-western Europe's gas demand by sector (2008–24) and by month (2008–24)



Source: IEA (2019a), Natural Gas Monthly Statistics, www.iea.org/statistics/monthly/#gas.

North-western European natural gas demand is characterised by a pronounced seasonal pattern, driven by the heating needs of the residential and commercial sectors.

The seasonal swing¹⁶ varies according to weather conditions and resulting temperatures (their impact on energy consumption being reflected in terms of heating-degree days). However, it averaged 80 bcm over the last decade, driving the flexibility requirements of the north-western European gas system. Residential and commercial gas demand is expected to decline only slightly over the medium term (at a rate of 0.6% per year to 2024), meaning that seasonality will remain a key characteristic of the region's gas consumption pattern.

In the power generation sector, natural gas is playing an increasingly important balancing role in the power system by supporting intermittent renewables and meeting peak demand. In 2018, gas-fired power generation accounted for almost one-fifth of total electricity production in north-western Europe. Over the medium term, the rapidly expanding renewable power fleet and the gradual retirement of 45 GW of nuclear and coal-fired power generation capacity by 2025 are expected to drive up the volatility of gas-to-power demand in north-western Europe.

¹⁵ In a gas year, the heating season refers to the period between 1 October and 31 March, whilst the summer (or injection) season refers to the period between 1 April and 30 September.

¹⁶ The difference in natural gas consumption between the heating season and the summer season of the gas year.

Gas demand from the industrial sector has a relatively flat profile when compared with the seasonality of the residential and commercial sectors or the volatility of gas-to-power. Some industrial consumers offer demand-side response (DSR) services through interruptible and/or dynamically priced gas supply contracts; however, their contribution to the overall flexibility of the European gas system remains rather limited.¹⁷

Current state of flexibility tools

Upstream deliverability

North-western European natural gas production has halved over the last decade, from almost 180 bcm in 2008 to just above 85 bcm in 2018. The Netherlands alone accounted for over half of this decline, followed by the United Kingdom (36%) and Germany (11%). Whilst in the United Kingdom and Germany the decrease in gas production is associated with the depletion of gas fields, in the Netherlands it has been largely driven by the production caps imposed on the giant Groningen field – accounting alone for almost 30% of total north-western European gas production over the last decade.

The Dutch authorities have imposed successive caps on the field beginning in 2014, following a number of earthquakes in the Groningen province. In combination with the depletion of the country's small fields (at a rate of 10% per year), this has led to the halving of Dutch gas production in the past five years, from above 80 bcm in 2013 to below 40 bcm in 2018, when the Netherlands became a net gas importer for the first time in its history.

Consequently, the region's import requirements have risen by 45% (or 60 bcm/y) over the past decade, increasing the utilisation rates of its import infrastructure and gradually changing the pattern of interconnector flows as well.

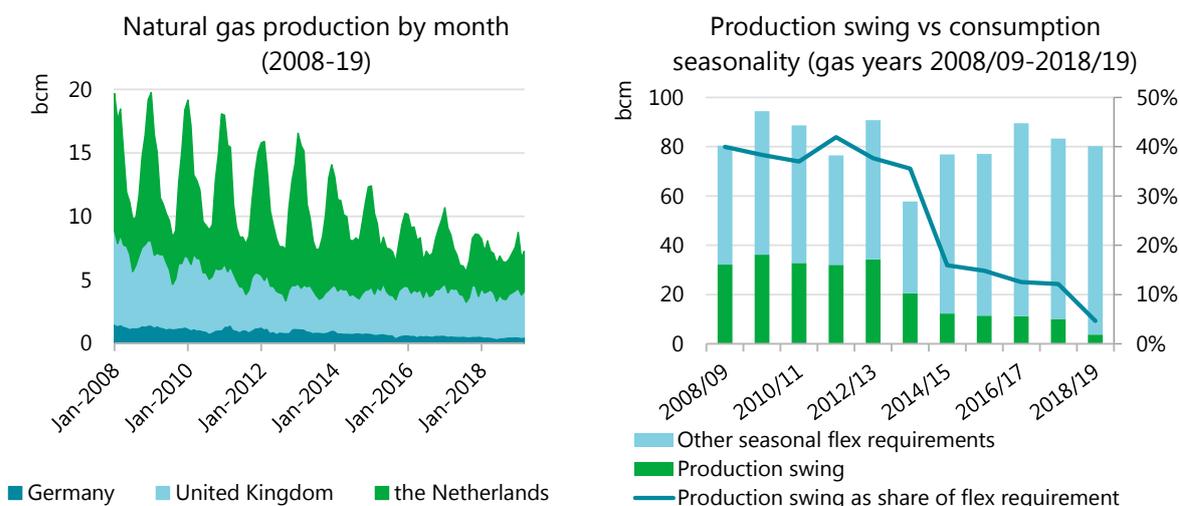
Most importantly, declining domestic production has been accompanied by a flattening of the seasonal profile of the region's gas production, which has traditionally been provided by the output flexibility of Groningen. Whilst in the gas year 2008/09 the seasonal swing¹⁸ in production was over 30 bcm, it fell to below 4 bcm in the gas year 2018/19.

Figure 38 shows that the rapidly shrinking production swing increased the role of other flexibility sources (such as storage, interconnectors and spare import capacity) in meeting the seasonality requirements of north-western European gas consumption.

¹⁷ In its 2018/19 gas DSR annual report, the National Grid reported zero DSR offers and trades (National Grid, 2019).

¹⁸ The difference between the natural gas output of the heating season and the summer season of the gas year.

Figure 38. Natural gas production and flexibility requirement in north-western Europe (gas years 2008/09–2018/19)



Source: IEA (2019a), Natural Gas Monthly Statistics, www.iea.org/statistics/monthly/#gas.

North-western European natural gas production has halved over the past decade, while its seasonal production swing fell by 90% during this period, increasing the call on other sources of flexibility.

In the medium term, natural gas production in north-western Europe is set to fall by a further 45%, driving up the region's import requirements by an additional 40 bcm/y by 2024. This will be largely driven by the Netherlands (accounting for 70% of the decline), as the Dutch government decided to phase out Groningen production by 2030 at the latest, following a 3.4 magnitude earthquake in January 2018.

Box 2. Natural gas conversion facilities in the Netherlands

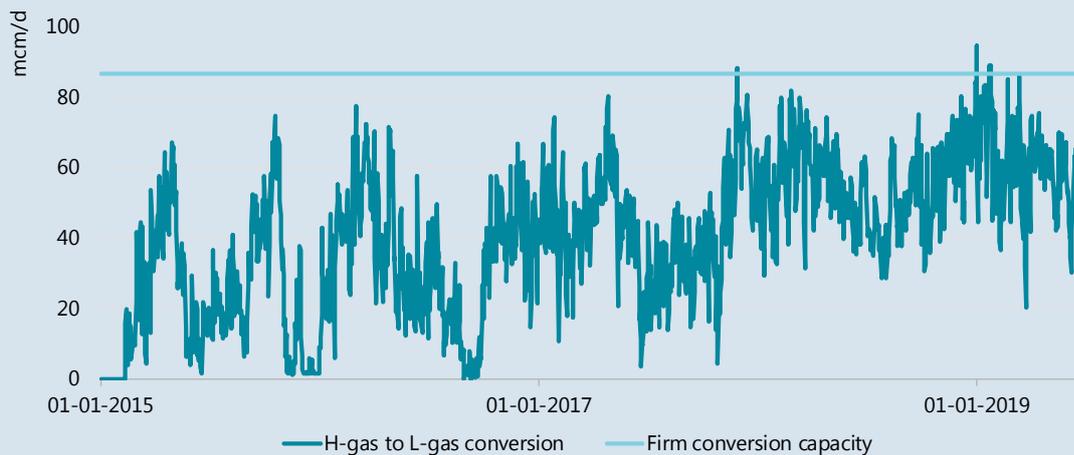
Natural gas from the Groningen field has a lower calorific value (35.17 megajoules per cubic metre) than the average for European natural gas, meaning that it cannot simply be replaced with other natural gas sources, such as imports. Natural gas with a higher calorific value needs to be converted to low-calorific gas, principally via nitrogen blending. The conversion facilities are an integral part of the Dutch gas transport system and are managed by the Dutch transmission system operator (TSO) (Gasunie Transport Services [GTS]). The conversion costs are "socialised", as they are incorporated within transmission tariffs.

In the last four years, conversion facilities have increasingly been substituting for Groningen gas production. Their output rose sixfold from 4.8 bcm in 2014 to almost 29 bcm in 2018, to account for over 60% of total L-gas supply in the Netherlands. In its latest annual report, Gasunie reported an average utilisation rate of 88% of firm capacity for 2018, meaning that very limited spare conversion capacity is available (Gasunie, 2019).

In fact, this high annual average utilisation rate disguises the country's high dependence on these facilities during the heating season. The majority of L-gas is destined for the residential and

commercial sectors (both in the Netherlands and the surrounding markets), resulting in a strong seasonal pattern of its consumption. This means that the utilisation rate of conversion facilities usually peaks during the heating season. Data from GTS suggest a utilisation rate above 93% of firm conversion capacity for the heating season 2018/19 – despite an unusually mild winter. As shown in the graph below, on numerous occasions conversion rates have tested the technical capacity limits of the facilities over the last two heating seasons. This led the Dutch TSO to ask market participants to adjust their high-calorific/low-calorific gas balance to reduce nitrogen usage (GTS, 2019).

H-gas to L-gas conversion in the Netherlands (January 2015–June 2019)



Note: mcm/d = million cubic metres per day.

Source: GTS (2019), "Dataport", http://dataport.gastransportservices.nl/default.aspx?ReportPath=%2fTransparency%2fQC_RQC-N2dump.

The commissioning of a new conversion facility in Zuidbroek in the first quarter of 2022, depending on the available import capacity, will be able to offset a reduction in Groningen gas production of 7 bcm/y.

In September 2019, the Dutch government issued a new plan, according to which the field could stop producing by mid-2022 –provided average weather conditions- and would be fully closed by 2026 at the latest. The government's proposal has to be approved by the Dutch parliament; if adopted, it would further increase north-western Europe's import requirements through the forecast period (Rijksoverheid, 2019). A more detailed description of the government's most recent phase-out plan is provided in Box 3.

In the United Kingdom, natural gas production is expected to decrease by 3.7% per annum as the North Sea fields continue to deplete. Moreover, in Denmark the Tyra field will be temporarily shut down between September 2019 and July 2022 due to redevelopment work. The field produced 3.65 bcm last year and accounts for approximately 90% of domestic Danish natural gas production. Its temporary closure will further weigh on the region's import requirements, as Denmark is expected to increase its gas imports via Germany during the redevelopment period.

Box 3. Accelerating Groningen's phase-out

In September 2019, the Dutch government announced a new phase-out plan for Groningen, according to which the field could stop producing natural gas by mid-2022, almost eight years earlier than previously planned. The production cap for the 2019/20 gas year is lowered to 11.8 bcm (Rijksoverheid, 2019).

The government's new plan leaves a four-year period, between mid-2022 and 2026, when the field could still produce and act as a "security buffer" to meet demand in a particularly cold winter.

In the revised phase-out plan, in addition to new conversion facility at Zuidbroek (Box 2), the government proposed a number of new measures to facilitate the implementation of a faster phase-out without disrupting the natural gas supply–demand balance in the Netherlands and north-western Europe.

These include:

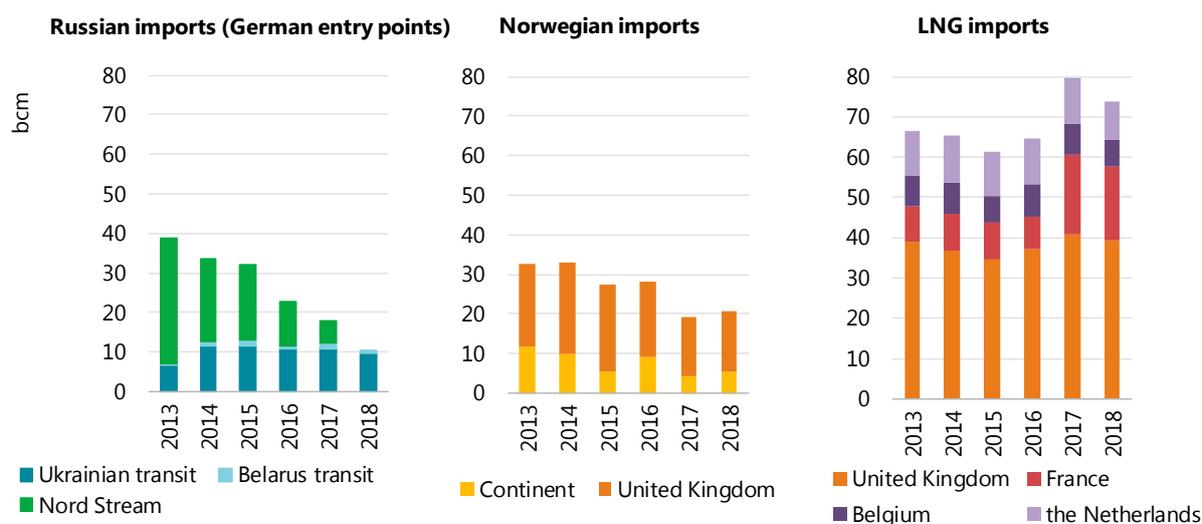
- Raising the utilisation rate of existing nitrogen conversion facilities to 100%.
- Expanding the Norg storage facility from 5 bcm/y to 6 bcm/y capacity to store additional L-gas.
- Amending the Gas Act to forbid the nine largest industrial gas consumers to use low-calorific gas after 1 October 2022. This bill is currently before the Council of State for advice.
- Gradually reducing low-calorific gas exports to Belgium, France and Germany, with an agreement that exports will cease by the gas year 2029/30.

Import capacity

North-western European natural gas production has continued to decline through the last decade, increasing its import dependency from 42% in 2008 to 70% in 2018, or by almost 60 bcm/y in volumetric terms. The share of imports needed to meet the region's natural gas demand during the heating season rose from 38% in the gas year 2012/13 to almost 55% in the gas year 2017/18.

Import requirements surpassed the region's natural gas production for the first time in 2012. Most of these additional imports have been sourced from Norway, Russia and the global LNG market via regasification terminals. Moreover, north-western Europe increasingly serves as a transit route for some of the gas volumes going to other markets in Central and Eastern Europe, as well as south-western Europe.

With the expectation that the region's import requirements are set to increase by an additional 40 bcm/y by 2024, it is important to assess the current state of the region's annual and peak spare capacity. Figure 39 shows the evolution of the annual spare import capacity of major import infrastructure servicing north-western Europe, by origin of imports, i.e. from Russia, Norway and LNG regasification terminals. When combined, total annual spare capacity amounted to almost 140 bcm in 2013 and decreased by over 30 bcm by 2018 to 105 bcm.

Figure 39. Annual spare import capacity to north-western Europe by origin of imports (2013–18)

Source: IEA (2019b), *Gas Trade Flows*, www.iea.org/gtfl/.

Spare import pipeline capacity to north-western Europe has more than halved since 2013, falling from 70 bcm/y to just above 30 bcm/y, whilst spare regasification capacity rose by 10% to above 70 bcm/y.

Annual spare import pipeline capacity has more than halved, decreasing from 70 bcm in 2013 to just above 30 bcm in 2018, as both Russian and Norwegian pipeline deliveries to north-western Europe have increased considerably during this period to compensate for the decline in domestic production. LNG import flows remained broadly flat, with most of the LNG trade driven by the Asia Pacific region during this period.

Norwegian natural gas pipeline flows into north-western Europe rose from 102 bcm in 2013 to almost 114 bcm in 2018. Over half of these additional export flows went to continental Europe, largely driven by the higher import requirements of the Netherlands.¹⁹ Consequently, annual spare export capacity from Norway to continental Europe decreased from 12 bcm in 2013 to an average of 5 bcm in 2017–18. Whilst there is still spare capacity in the Norwegian export pipelines servicing north-western Europe, flow data suggest that the two gas processing plants feeding those pipelines (Kårstø and Kollsnes)²⁰ have reached an average utilisation rate of 95% in recent years.

Norwegian gas export flows rose less significantly to the United Kingdom, by 5 bcm/y between 2013 and 2018, a reflection of UK domestic production actually increasing during this period. Consequently, the Norwegian spare export capacity available to the United Kingdom has decreased only slightly since 2013 and stood at 16 bcm in 2018. It can be argued that some of this spare capacity could serve the flexibility requirements of the rest of north-western Europe, given the interconnectivity between those markets.

Russian natural gas exports can reach the north-western European market via three main routes. The Eastern European transit corridor has been used since the early 1970s to export natural gas to the Federal Republic of Germany and later on to other north-western European countries. Natural gas needs to transit via Ukraine, Slovakia and Austria or the Czech Republic before reaching the German market. This route has been complemented by the Yamal pipeline corridor – running through Belarus and Poland to Germany – reaching its full capacity of 33 bcm/y in 2006. The Nord Stream pipeline, which directly connects Russia to Germany, started commercial operations in

¹⁹ According to CBS (Statistics Netherlands), the net imports of the Netherlands grew from -1 215 petajoules (PJ) in 2013 to 192.3 PJ in 2018, suggesting that the country became a net importer of natural gas for the first time in its history, whilst its import requirements grew by 35 bcm/y by 2018 (CBS, 2019).

²⁰ Kårstø and Kollsnes have a processing capacity of 90 mcm/d and 144.5 mcm/d respectively, equalling 85.6 bcm/y combined capacity.

October 2011 and reached its full operational capacity of 55 bcm/y at the end of 2012.²¹ This allowed some of the Russian exports destined for north-western European market to be rerouted from the Eastern European transit corridor, which consequently led to the gradual optimisation of the entry/exit capacities alongside the transit route. Today about 20 bcm/y of natural gas can reach Germany via Austria and the Czech Republic.²²

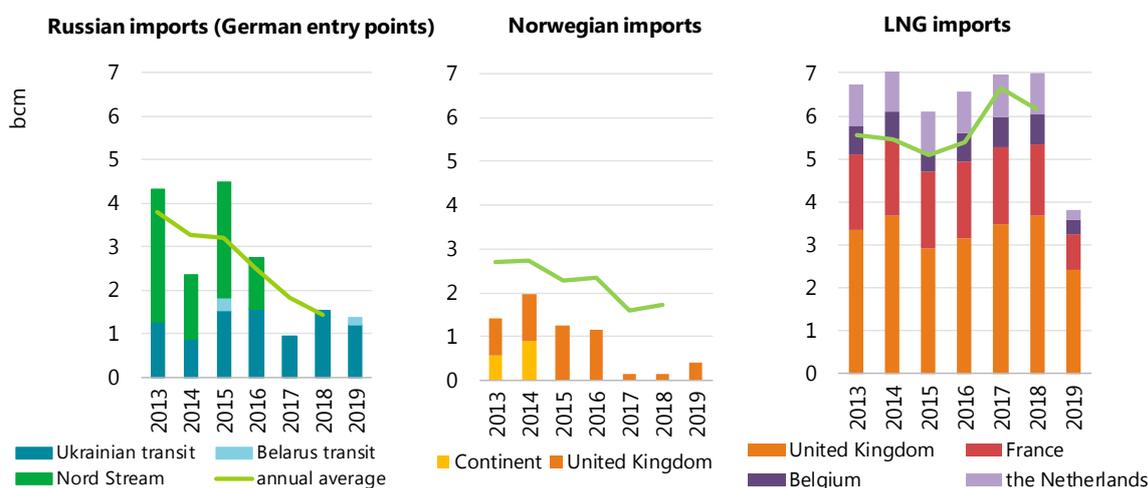
The utilisation rate of the Yamal pipeline averaged 95% between 2012 and 2018, leaving very limited spare capacity for any additional import flows. As shown in Figure 39, the spare capacity available in Nord Stream in 2013 (30 bcm) had virtually disappeared by 2018, when the pipeline’s utilisation rate reached 107%, meaning that flows have been above the firm technical capacity of the pipeline. This leaves the Eastern European corridor as the main source of Russian pipeline spare capacity available to north-western European markets, amounting to 10 bcm in 2018. Natural gas flow data suggest that this transit route is being used as a solution of last resort to meet peak demand during the heating season.

In contrast to the import pipelines, spare capacity in the LNG regasification terminals remained relatively abundant, averaging almost 70 bcm/y between 2013 and 2018. This is due to the somewhat limited increase in LNG imports to north-western Europe during the period, and to the expansion of capacity, with the commissioning of the Dunkirk terminal in northern France in 2016 with a regasification capacity of 13 bcm/y.

Given the strong seasonality of north-western European natural gas demand, it is important to consider spare capacity available during the heating season specifically.

Figure 40 shows the evolution of spare import capacity by origin of gas for the month of January (which usually experiences the highest monthly level of demand) between 2013 and 2019. The green line indicates the average monthly spare import capacity, while the bars show the spare capacity available in January of the given year.

Figure 40. Spare import capacity in January to north-western Europe by origin of imports (2013–19)



Source: IEA (2019b), *Gas Trade Flows*, www.iea.org/gtff/.

Spare pipeline capacity tends to be lower during the heating season, given their reactivity to seasonal demand. In contrast, spare capacity at regasification terminals shows a counterseasonal pattern.

²¹ However, regulatory access issues to the OPAL pipeline – an onshore continuation of Nord Stream – has limited the overall utilisation of Nord Stream until 2017 by ~15 bcm/y.

²² The Waidhaus entry/exit point is not considered, as it mainly serves to transit Nord Stream- and Yamal-sourced gas via the Gazela pipeline running through the Czech Republic back to southern Germany. As such, it does not serve the entry of additional import flows from the Eastern transit corridor.

For the month of January, spare import capacity in both Russian and Norwegian pipelines has been significantly decreasing since 2012, by over 80% by 2017. Norwegian export flows show a strong response to the seasonality of north-western European demand, with January's spare import capacity significantly lower compared with the annual monthly average. Significantly, since 2015 spare import capacity from Norway directly to north-western Europe has virtually disappeared for the month of January, partly driven by the higher natural gas import requirements of the Netherlands. Moreover, in both 2017 and 2018 Norwegian spare capacity available to the United Kingdom in January fell to below 0.2 bcm.

Russian export flows appear to show less sensitivity to demand seasonality. This can be explained by a number of factors, including:

- Gazprom's large underground storage facilities located in north-western Europe, which allow the company to optimise its export flows.
- The regulatory access issues surrounding the OPAL pipeline (which connects Nord Stream to the Central and Eastern European markets) until 2017.
- Oil indexation, which prevailed until recently in some of Gazprom's contracts (altering buyers' nominations).

Nonetheless, the spare capacity in Russian pipelines fell below 1 bcm in January 2017, with no spare capacity left in the pipelines directly servicing north-western Europe, i.e. Nord Stream and Yamal.

This leaves LNG regasification facilities as the main holders of spare import capacity, ranging between 6 bcm and 7 bcm in January during 2013–18. In January 2019, spare regasification capacity fell below 4 bcm due to a large LNG influx into Europe, as incremental LNG supply could not be absorbed by other regions. This in turn drove up the utilisation rates of European regasification terminals.²³ Nevertheless, 4 bcm per month (accounting for over 10% of gas demand) still represents, in principle, a considerable safety net in case of supply or demand shocks.

As highlighted in *Global Gas Security 2018*, timeliness remains a key issue when considering LNG imports. Last year's analysis showed that in a best-case scenario it would take several days to import an additional cargo of LNG. This also means that LNG cannot be considered as a sole and immediate remedy for short-term system balancing in case of supply disruptions or demand shocks.

More immediate solutions for short-term balancing require either spare import pipeline capacity or midstream interconnectivity and storage flexibility, or a combination of them.

Midstream interconnectivity

Given the limited spare import pipeline capacity that north-western Europe has available, it is important to assess the current state of interconnectivity between country-level markets. Spare capacity in interconnectors can mitigate the impact of supply/demand shocks by the internal redistribution of gas flows and the optimisation of gas storage usage.

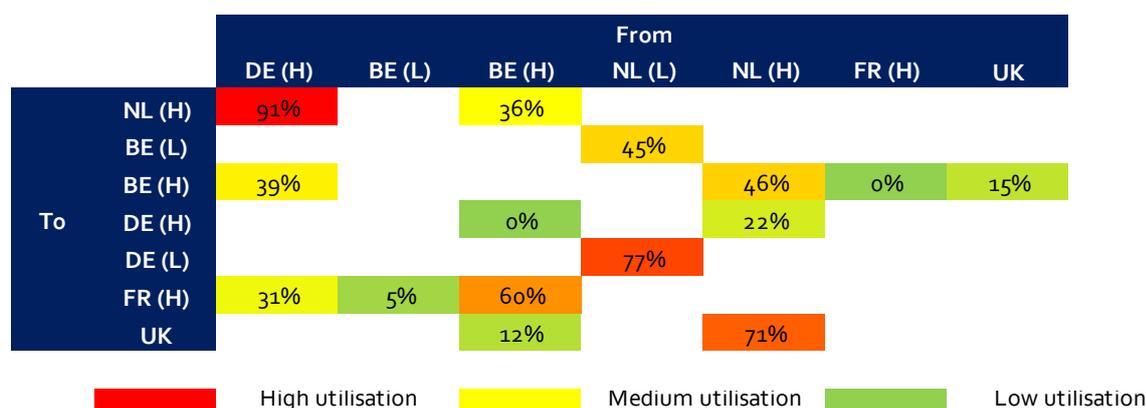
The evolving supply dynamics in the Netherlands and the United Kingdom have not only increased the overall import requirements of north-western Europe, but have also affected the volume and the pattern of flows within the region itself.

²³ For a more detailed discussion of recent LNG market trends, refer to IEA (2019c).

The most significant impact has been on the Netherlands, which became a net importer of natural gas in 2018. The Dutch “gas roundabout” remains at the heart of the north-western European gas system, with interconnections built to all its surrounding markets (Belgium, Germany and the United Kingdom).

Figure 4.1 provides a matrix of the utilisation rates for the interconnections in north-western Europe in January 2019.

Figure 4.1. Utilisation of interconnections in north-western Europe, January 2019



Notes: BE = Belgium; DE = Germany; FR = France; NL = The Netherlands; UK = United Kingdom; (H) = H-gas; (L) = L-gas.

Sources: IEA (2019b), *Gas Trade Flows*, www.iea.org/gtf/; *ENTSOG (2019)*, *ENTSOG Transparency Platform*, <https://transparency.entsog.eu/>.

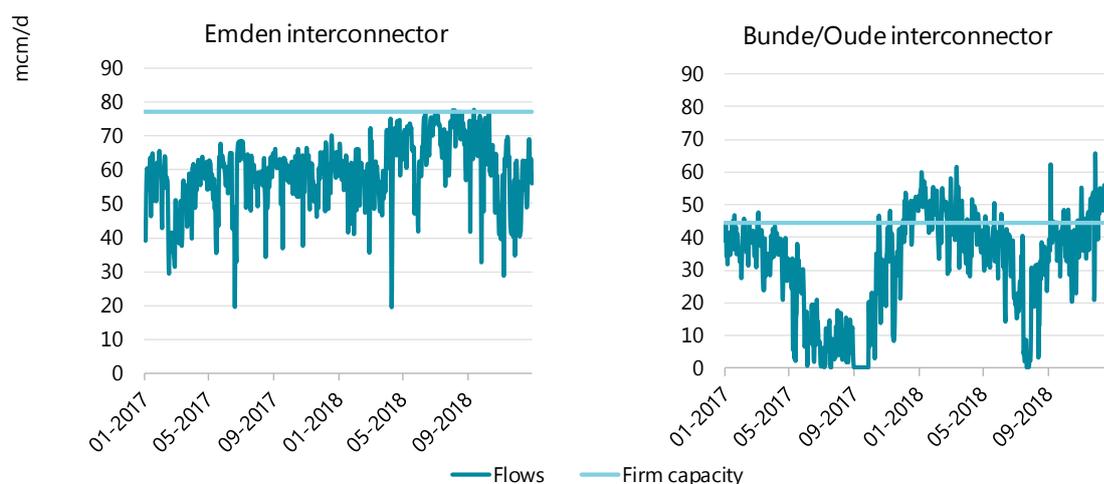
The utilisation rates of north-western Europe’s interconnection show in most cases few capacity constraints even during periods of high natural gas demand.

The matrix indicates that most of the interconnectors do not have capacity constraints, with the notable exception of the major exit/entry points between Germany and the Netherlands, where the 91% utilisation rate suggests low spare capacity available during the peak month of the heating season, while import needs are rising in the near future.

The Netherlands has three main entry points. Norwegian natural gas is imported via the Emden terminal in Germany, feeding into the Dutch gas grid via an interconnector. Russian imports to the Netherlands need to transit via Germany through the Bunde/Oude Statenzijl interconnection. The Dutch gas grid is also connected to a number of German gas storage facilities used to balance the gas market in the Netherlands. There are two import interconnectors with Belgium; however, one of them (Zelzate) is used by Belgian shippers to access storage sites located in the Netherlands. This is likely to remain the case in the medium term because, for geological reasons, Belgium is unlikely to develop any significant gas storage facilities. The second interconnector (Zebra) allows actual import flows from Belgium, but has a rather limited capacity of 4 bcm/y.

Altogether, the Netherlands has an import capacity of almost 50 bcm/y via these interconnections. Based on import flows²⁴ in 2018, their estimated annual spare capacity was over 10 bcm (equal to almost one-quarter of annual Dutch gas consumption). However, when considering the distribution of these import flows, the abundance of spare capacity becomes less apparent. As shown in Figure 4.2, both the Emden and Bunde/Oude interconnections have been running close to and even above their firm technical capacities, particularly during the heating season. This also means that spare capacity in interconnections cannot be taken for granted, especially during periods of high demand.

²⁴ Note that not all of these import flows are destined for the Dutch market. Some of them transit onto Belgium and France and others are converted into L-gas and then re-exported to meet the Netherlands’ L-gas export commitments to Belgium, France and Germany.

Figure 42. Interconnector flows to the Netherlands, 2017–18

Source: ENTSOG (2019), *ENTSOG Transparency Platform*, <https://transparency.entsog.eu/>.

The utilisation of interconnections feeding into the Dutch natural gas grid from Germany is saturated during periods of high demand, hence limiting the availability of spare capacity.

Considering the evolving natural gas production outlook in the Netherlands, as discussed in previous parts of this chapter, the country's import requirements are set to increase in the medium term and potentially drive up the utilisation rates of these interconnectors. This indicates a need to increase the capacity of certain entry points to the Dutch natural gas network.

The BBL pipeline – connecting the Netherlands and the United Kingdom – became bidirectional on 1 July 2019, enabling natural gas imports into the Netherlands with an annual capacity of 5 bcm/y. However, it is important to note that during the heating season the pipeline is unlikely to provide additional import flexibility to the Netherlands, as the BBL is expected to continue to work in a “Netherlands-to-United Kingdom” mode. This is primarily due to the fact that the United Kingdom has been increasingly relying on the gas storage capabilities of continental Europe since the closure of the Rough storage facility (which accounted for 70% of UK working gas storage capacity), explaining the relatively high utilisation rate of the pipeline during the heating season (71% in January 2019).

The interconnectors relaying Dutch L-gas to Germany also show a relatively high utilisation level (77% in January 2019), which is due to the high seasonality of L-gas demand, consumed primarily in the residential and commercial sectors. It is important to note that L-gas consumption is expected to decrease in Germany, due to the ongoing conversion of end-consumers to H-gas.²⁵ Consequently, the German TSO association (FNB Gas) foresees L-gas import requirements from the Netherlands halving by gas year 2024/25 and falling to zero by 2029/30 (FNB, 2019).

The evolution of the domestic production outlook in the Netherlands, and consequently the changing natural gas flow patterns, indicate the need to optimise the country's entry/exit capacity, primarily alongside the Dutch “gas roundabout”, which is set to remain at the heart of north-western Europe's gas system.

²⁵ According to FNB, over 150 000 L-gas devices were adapted to H-gas in 2018, with over 300 000 devices to be converted by the end of 2019. The target is to convert all the 5.1 million L-gas devices to H-gas by 2030 (FNB, 2019).

Storage capacity

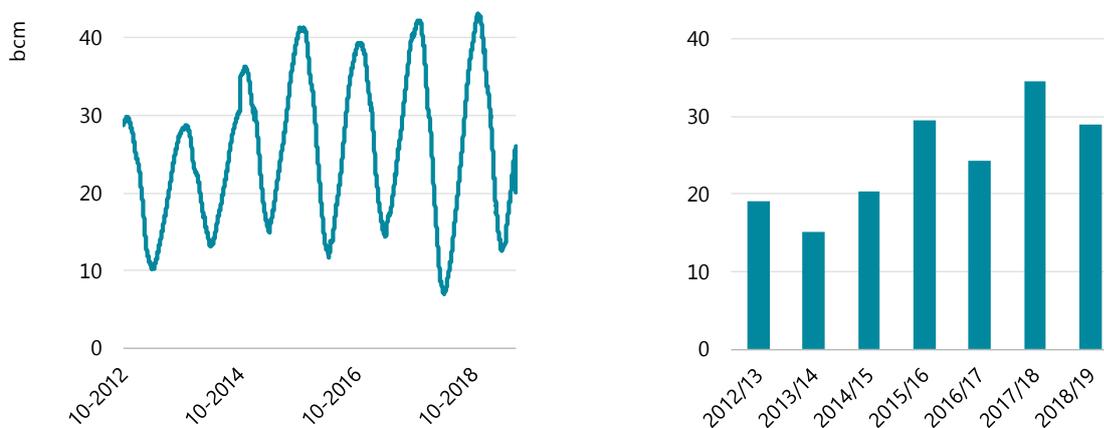
Because of the declining production swing and gradually eroding spare import pipeline capacity, since 2012 natural gas storage has become increasingly important to meeting north-western Europe's seasonal gas requirements.

North-western Europe has natural gas storage capacity of 50 bcm, equating to about one-fifth of the region's gas consumption in 2018. This is substantially lower compared to Italy or Central and Eastern Europe, where gas storage capacity accounted for 25% and 30% of gas consumption in 2018, respectively. About half of north-western Europe's storage is located in Germany (24 bcm), with France and the Netherlands both having 12 bcm. In the United Kingdom only 1.5 bcm of capacity has been left since the closure of the Rough storage facility in 2017 and Belgium has less than 1 bcm capacity. Hence, both countries rely on storage capacity located in neighbouring markets via interconnections.

About 60% of north-western Europe's underground storage sites are either aquifers or depleted fields, which are best suited for seasonal storage purposes. Almost 40% of all storage space is located in salt caverns, which offer much higher frequency cycling and hence are better positioned to respond to short-term market volatility.

The proportion of north-western Europe's gas demand that was met by gas storage during the heating season rose from an average of 14% between the gas years 2010/11 and 2013/14 to above 20% during the 2014/15–2017/18 period. This in turn increased the utilisation rate of natural gas storage facilities in north-western Europe, resulting in a widening storage swing.²⁶

Figure 43. Storage swing in north-western Europe (2012–19)



Source: GIE (2019), "AGSI+ Storage data", <https://agsi.gie.eu/#/>.

The utilisation rate of natural gas storage facilities in north-western Europe has been increasing amidst declining domestic production and shrinking spare import pipeline capacity.

Figure 43 illustrates that storage utilisation reached its peak in March 2018, when north-western Europe was hit by a late and particularly brisk cold spell baptised the "Beast from the East". Storage facilities were depleted to an average level of 15% (or below 8 bcm). Storage stocks decreased below 5% in France, whilst in Belgium they fell below 1%. The availability of natural gas storage located in the Netherlands and Germany²⁷ was therefore crucial to meeting the overall demand requirements of the region, whilst pushing the deliverability of storage sites to the limit (see Box 4).

²⁶ Storage swing refers to the difference in the quantity of natural gas in storage at the beginning of the gas year (1 October) and the end (31 March) when the heating season officially ends.

²⁷ Both Germany and the Netherlands had storage full at 25% at the beginning of March.

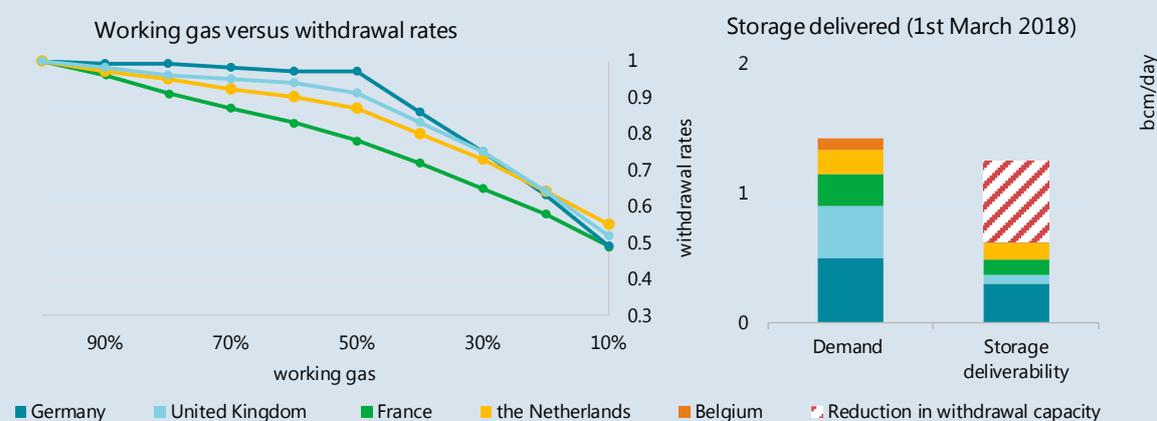
Box 4. Storage deliverability

Episodes similar to the “Beast from the East” demonstrate not only the security value of natural gas storage, but also its apparent abundance relative to other flexibility tools in the north-western European gas system, such as spare import pipeline capacity and production swing.

The withdrawal rates of gas storage sites tend to decline with the decreasing level of working gas in stock, given the lowering pressure level within the storage space. The deliverability of storage sites starts to decline once the volume of working gas volume falls below 50%.

This means that storage sites become less reactive (both in time and volume) to variations in demand by the end of the heating season, making the gas system particularly vulnerable to late cold snaps.

Storage deliverability in north-western Europe



Sources: Gaspool (2019), “Consumption data”, www.gaspool.de/en/services/balancing-group-manager/consumption-data/slpsyn/; ENTSOG (2018), “Winter Supply Outlook 2018/2019”, www.entsog.eu/sites/default/files/2018-10/SO0021-Winter%20Supply%20Outlook%2018-19_o.pdf; GIE (2019), “AGSI+ Storage data”, <https://agsi.gie.eu/#/>; ENTSOG (2019), *Transparency Platform*, <https://transparency.entsog.eu/>; National Grid (2019), “Data Item Explorer”, <http://mip-prod-web.azurewebsites.net/DataItemExplorer/Index>; NCG (2019), “Aggregated consumption data”, www.net-connect-germany.de/en-gb/Transparency-information/Aggregated-Consumption-Data.

The practical consequences of this phenomenon were clearly demonstrated during the visit of the Beast from the East. North-western European daily natural gas demand spiked at almost 1.5 bcm on 1 March 2018, whilst the depleted storage sites were able to operate only at about half of their total withdrawal capacity, falling from ~1.25 bcm/day to below 0.65 bcm/day. Nevertheless, storage facilities were still able to meet almost half of north-western Europe’s gas demand, demonstrating their value in security of supply during shock demand/supply events.

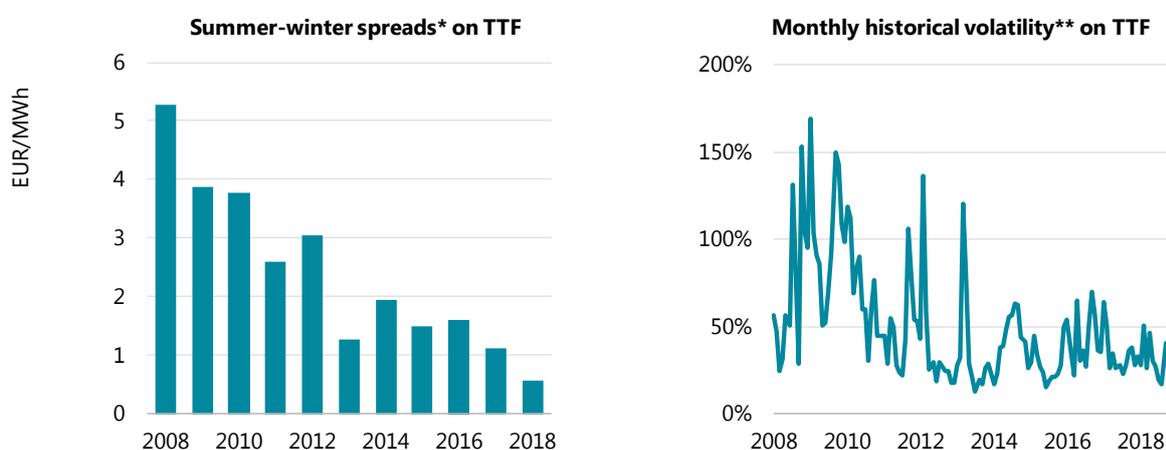
The low volumes of working gas eroded their capability to provide further gas supplies, which would have served as a security buffer through the stressed market conditions – during the same period, spare capacity in import pipelines servicing Germany was limited and outages in North Sea pipelines affected supplies to the United Kingdom. This led to a stressed market situation, with prices rallying on both the NBP and TTF to above USD 50/MBtu during 1 March 2018. A more detailed analysis of the Beast from the East and its consequences for the north-western Europe’s gas markets is provided in the Global Gas Security Review 2018 (IEA, 2018).

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

Despite the crucial role played by storage, almost 7 bcm of gas storage capacity has been either closed or mothballed in north-western Europe since 2011. This is primarily due to the deterioration of the market value of natural gas storage, which derives from the combination of seasonal spreads (the price difference between winter and summer contracts for gas deliveries) and short-term price volatility (the realised price variations of a given gas delivery contract over a given period). Storage operators in north-western Europe rely primarily on revenue streams from capacity auctioning, with bids usually mirroring the evolution of seasonal spreads.

As shown in Figure 44, summer–winter spreads on the TTF more than halved from an average of almost EUR 4 per megawatt hour (MWh) between 2008 and 2012, to an average below EUR 1.5/MWh since 2013, insufficient to cover the operating costs of some storage facilities. Moreover, during the same period short-term volatility has fallen from an average of 63% to 43%. If February and March 2018 are excluded (which had an unusually high volatility due to a late cold snap), average volatility over the period would be 36%.

Figure 44. Spread between summer and winter gas prices on TTF (2008–18) and gas storage closures in north-western Europe (2013–17)



* Annual average of rolling summer–winter spreads, based on TTF SUM1 contract and TTF WIN2 contract.

** Excludes February and March 2018 when volatility spiked at unusually high levels.

Source: Bloomberg Finance LP (2019), Bloomberg Terminal (subscription required).

Declining summer–winter spreads and short-term price volatility are eroding the market value of natural gas storage, weighing on the revenue streams of storage operators.

A number of factors explain why both summer–winter spreads and short-term volatility have been declining over the last decade, particularly:

- **Decreasing demand:** Natural gas consumption in north-western Europe fell by over 50 bcm/y between 2008 and 2015, with the power sector accounting for over half the decline.
- **Improving network access:** The implementation of regulations and network codes deriving from the Third Energy Package (including capacity auctioning, effective congestion management mechanisms, transparency requirements and obligations on reverse capacity) has improved the functioning of the gas network.
- **The development of trading:** North-western European hubs have rapidly evolved over the past decade, both in terms of traded volumes and liquidity. The larger number of market participants, with increasingly sophisticated trading capabilities, has slowly eroded the market rigidities from which seasonal spreads and volatility derive.

While seasonal spreads have been recovering in the first quarter of 2019, primarily driven by the decline in TTF summer contracts,²⁸ the forward curve at the time of writing suggests that they will average below EUR 2/MWh over the medium term. This is insufficient for any incentive to invest in natural gas storage. Further, it would not cover the operating expenses of some existing storage facilities.

Moreover, a number of long-term storage contracts are set to expire in the medium term, further weighing on the revenue streams of storage operators. In combination with the persistence of low seasonal spreads, this could lead to additional storage site closures in north-western Europe. One notable example is the Grijpskerk storage facility (with a capacity of 2.8 bcm) in the Netherlands, which has announced that it will close by the beginning of 2022, when the service contract between the operator Nederlandse Aardolie Maatschappij (NAM) and GasTerra expires.

The closure of additional storage sites could lead to wider seasonal spreads and higher short-term volatility, as seen in the United Kingdom since the closure of Rough. More importantly, this loss of capacity would be to the detriment of the overall capability of the gas system to deliver physical volumes to end consumers under stressed market conditions.

Considering the deteriorating economics of natural gas storage, in 2017 France introduced a support mechanism allowing storage operators to recover their operating expenses. In line with Law 2017-1839 (Legifrance, 2017), storage operators are entitled to additional revenues (from the tax recovered by the natural gas transmission network operators) if the auction revenue and regulated income of the gas storage operators are negative. If their auction revenue surpasses their regulated income, storage operators are obliged to return the surplus to grid users via the grid tariff. This mechanism allows storage operators to recover their operating expenses. Under the new regulatory regime, gas injections in 2018 rose by almost two-thirds year-on-year, to their highest level at least since 2013.

While storage regulation remains largely in the national domain, given the interconnectedness of the north-western European gas market, a regional approach towards storage support mechanisms would be beneficial both to overall market functioning and security of gas supply.

A transforming energy system

In the medium term, north-western Europe's power system is expected to undergo a profound transformation. Generation from intermittent renewables is set to expand by 30% by 2023, while around 45 GW of nuclear and coal-fired power plants, over 10% of the region's power generation in 2018, are expected to close by 2025 (Figure 45).

Consequently, gas-fired power generation will play an increasingly important role in the balancing of the power system by providing backup to variable renewables and meeting peak demand. This also means that the volatility of gas-to-power demand is expected to increase over the medium term.

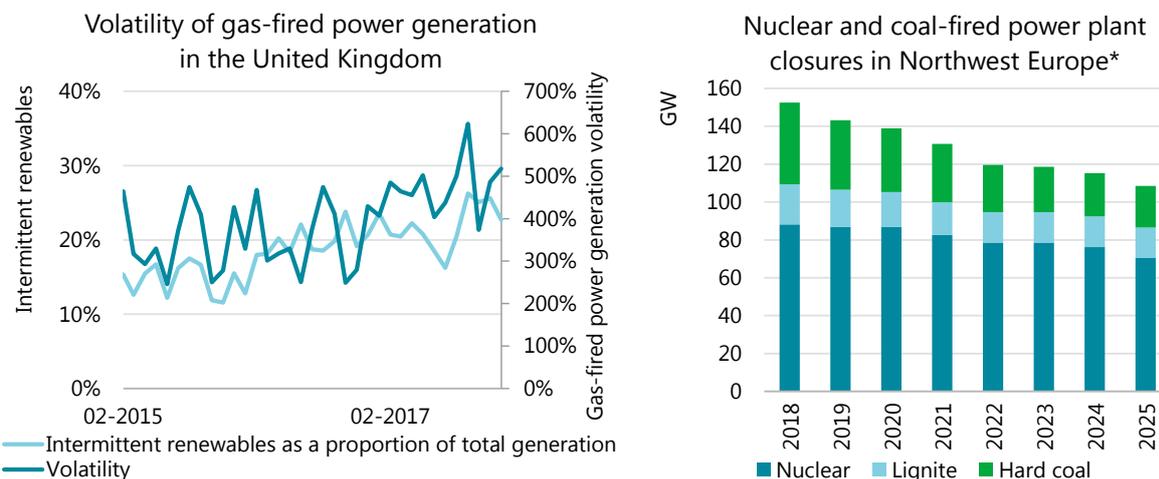
In turn, this would increase the natural gas system's requirement for short-term flexibility, enhancing the value of fast-cycling gas storage facilities, the role of interconnectors and the importance of peak spare import capacity.

This has been particularly visible in the United Kingdom, where the share of wind and solar rose from 15% in 2016 to 22% in 2018, whilst the share of coal-fired power generation halved from 10%

²⁸ Due to a relatively loose global LNG market and an unusually mild 2018/19 winter, leaving northwest Europe's storage stocks almost half full at the end of the heating season.

to 5%, as the introduction of a domestic carbon price floor in 2013 put coal at a disadvantage to gas in the power sector. Consequently, gas-to-power demand rose by 44%, up to 26 bcm in 2018, whilst the share of natural gas within the power mix rose from 27% in 2013 to almost 40% in 2018. During the same period, the volatility of gas-to-power demand increased from 346% to 471% (Figure 45).

Figure 45. UK volatility in gas-fired power generation and power plant closures in north-western Europe



* Based on announcements by governments and companies.

Sources: Share of renewables: IEA (2019d), *Monthly Statistics*, www.iea.org/statistics/monthly/; gas-fired power generation: ENTSO-E (2019), *Transparency Platform*, <https://transparency.entsoe.eu/>.

The growing share of intermittent renewables, coupled with declining coal-fired and nuclear power generation, is set to increase the volatility of gas-fired power generation.

The linkage between security of electricity supply and natural gas deliverability is becoming more intimate, especially during periods of high electricity demand. As highlighted in the *Global Gas Security Review 2018* (IEA, 2018), during the late cold snap in March 2018 (the Beast from the East), coal-fired power generation played a crucial role in supporting the power system in the United Kingdom, contributing approximately 25% of the country's power supply between 26 February and 3 March. Indeed, the combination of unseasonably low temperatures and outages affecting several critical elements of gas supply infrastructure translated into skyrocketing natural gas prices, which naturally limited the gas burn within the power sector and hence increased the call on coal-fired power generation.

In line with the emission limits set by the UK government, remaining coal-fired power generation plants will be shut down by October 2025. Consequently, if a scenario similar to the Beast from the East were to occur in a coal-free post-2025 winter, the call on gas-fired power generation would be higher, potentially increasing natural gas consumption by 10% (or 40 mcm/d)²⁹ during a cold snap. This indicates that the future development of the north-western Europe's gas infrastructure would benefit from taking into consideration the transformation of the power system and the role played by gas-fired power generation as a guarantor of electricity supply security.

The gradually disappearing switching potential between coal- and gas-fired power generation in north-western Europe will also increase the importance of having access to a diversity of pipeline gas imports as well as to flexible LNG from the global gas market.

²⁹ Considering an average electrical efficiency of 50% in the gas-fired power plant fleet.

In the aftermath of the Great East Japan Earthquake in March 2011 and the consequent shutdown of Japan's 57 nuclear power reactors, the switching capacity of the European power system played a crucial role in making additional LNG volumes accessible to the Japanese market.

Japan's surging natural gas demand translated into high LNG spot prices (averaging almost USD 15/MBtu between 2011 and 2014) and a wide premium to European hub prices (TTF was trading at USD 9/MBtu during the same period). This, in turn, attracted LNG cargoes originally destined for Europe towards Japan and even incentivised reloading activities at Europe's regasification terminals. Consequently, the share of gas-fired power generation in Europe fell from 45% in 2011 to 38% in 2014, whilst the share of coal-fired power generation rose from 50% to 58% during the same period.

In the future, the role of the Asian power sector – where abundant switching potential exists – could expand to providing flexibility to global energy markets via the redirection of destination-free flexible LNG cargoes, with Europe as a potential outlet. The rising interdependence between regional markets should provide the incentive for both Asian and European market players, as well as regulatory organisations, to enhance co-operation, resulting in a more flexible global gas market.

Strengthening the flexibility of north-western Europe's gas system would also reinforce the region's position within the global gas market, as internal flexibility tools allow timely and cost-efficient reactions to changing global supply–demand dynamics.

References

- Bloomberg Finance LP (2019), Bloomberg Terminal (subscription required).
- CBS (Statistics Netherlands) (2019), "Energy balance sheet; supply, transformation and consumption", <https://opendata.cbs.nl/statline/#/CBS/en/dataset/83140eng/table?ts=1566813862485> (accessed 5 June 2019).
- ENTSO-E (2019), *Transparency Platform*, <https://transparency.entsoe.eu/>.
- ENTSOE (European Network of Transmission System Operators for Gas) (2019), *ENTSOE Transparency Platform*, <https://transparency.entsoe.eu/>.
- ENTSOE (2018), "Winter Supply Outlook 2018/2019", www.entsoe.eu/sites/default/files/2018-10/SO0021-Winter%20Supply%20Outlook%202018-19_o.pdf.
- FNB (2019), "Netzentwicklungsplan Gas 2018–2028" [Gas Network Development Plan 2018–2028], www.fnb-gas.de/files/2019_03_20_nep-gas-2018-2028_final_1.pdf (accessed 2 July 2019).
- Gaspool (2019), "Consumption data", www.gaspool.de/en/services/balancing-group-manager/consumption-data/slpsyn/ (accessed 2 July 2019).
- Gasunie (2019), "Annual Report 2018", [www.gasunie.nl/en/about-gasunie/investor-relations/financial-information/\\$2450/\\$2442](http://www.gasunie.nl/en/about-gasunie/investor-relations/financial-information/$2450/$2442) (accessed 2 July 2019).
- GIE (Gas Infrastructure Europe) (2019), "AGSI+ Storage data", <https://agsi.gie.eu/#/> (accessed 2 July 2019).
- GTS (Gas Transport Services) (2019), "Dataport", http://dataport.gastransportservices.nl/default.aspx?ReportPath=%2fTransparency%2fQC_RQC-N2dump (accessed 2 July 2019).
- IEA (International Energy Agency) (2019a), *Natural Gas Monthly Statistics*, IEA, Paris, www.iea.org/statistics/monthly/#gas.
- IEA (2019b), *Gas Trade Flows*, IEA, Paris, www.iea.org/gtfl.
- IEA (2019c), *Market Report Series: Gas 2019*, IEA, Paris, <https://webstore.iea.org/market-report-series-gas-2019>.

IEA (2019d), *Monthly Statistics*, IEA, Paris, www.iea.org/statistics/monthly/.

IEA (2018), *Global Gas Security Review 2018*, IEA, Paris, <https://webstore.iea.org/global-gas-security-review-2018>.

Legifrance (2017), Loi n° 2017-1839, www.legifrance.gouv.fr/affichTexte.do?cidTexte=JORFTEXT000036339396&categorieLien=id (accessed 5 July 2019).

National Grid (2019), "Data Item Explorer", <http://mip-prod-web.azurewebsites.net/DataItemExplorer/Index>.

NCG (NetConnect Germany) (2019), "Aggregated consumption data", www.net-connect-germany.de/en-gb/Transparency-information/Aggregated-Consumption-Data (accessed 2 July 2019).

Rijksoverheid (2019), "Kamerbrief over gaswinningsniveau Groningen in 2019-2020" [Letter to the Parliament – Groningen gas extraction level in 2019-2020] www.rijksoverheid.nl/binaries/rijksoverheid/documenten/kamerstukken/2019/09/10/kamerbrief---gaswinningsniveau-groningen-in-2019-2020/Kamerbrief+-+Gaswinningsniveau+Groningen+in+2019-2020.pdf (accessed 12 September 2019).

General annex

Abbreviations and acronyms

DAP	delivery at place
DSR	demand-side response
e	estimate
FID	final investment decision
FSRU	floating storage regasification unit
GTS	Gasunie Transport Services
H-gas	high-calorific gas
IEA	International Energy Agency
L-gas	low-calorific gas
LNG	liquefied natural gas
LT	long-term
NBP	National Balancing Point
SPA	sale and purchase agreement
TSO	transmission system operator
TTF	Title Transfer Facility

Units of measure

bcm	billion cubic metres
bcm/y	billion cubic metres per year
GW	gigawatt
MBtu	million British thermal units
mcm/d	million cubic metres per day
Mtpa	million tonnes per annum
MWh	megawatt hour
PJ	petajoules

Acknowledgements

This publication has been prepared by the Gas, Coal and Power Markets Division (GCP) of the International Energy Agency (IEA). The analysis was led and co-ordinated by Peter Fraser, Head of GCP and Jean-Baptiste Dubreuil, Senior Natural Gas Analyst. Antonio Erias Rodríguez, Peter Fraser, Gergely Molnár, Sean O'Brien, and Tomoko Uesawa are the main authors. Sean O'Brien and Masamichi Wada provided essential research and statistical support. Keisuke Sadamori, Director of the IEA Energy Markets and Security (EMS) Directorate, and Peter Fraser, Head of GCP, provided expert guidance and advice. Aad van Bohemen, Lucie Girard and László Varró benefitted to the review.

Timely and comprehensive data from the Energy Data Centre were fundamental to the review.

The IEA Communication and Digital Office (CDO) provided production and launch support. Particular thanks to Jad Mouawad and his team: Astrid Dumond, Katie Lazaro, Isabelle Nonain-Semelin, Jethro Mullen, Rob Stone and Therese Walsh. Justin French-Brooks edited the report.

The report was made possible by assistance from Enagás, Mitsubishi Corporation and Tokyo Gas.

The IEA would like to thank Anne Braaksma (GasTerra), Laurent David (Total), Jasper Honkoop (GasTerra), Rik Komduur (GasTerra), Volker Kraayvanger (Uniper), Laurent Nery (Engie), Gregor Pett (Uniper), Rodrigo Pinto Scholtbach (Ministry of Economic Affairs and Climate Policy of the Netherlands), María Sicilia (Enágas), Kosho Tamura (Tokyo Gas), Wim Thomas (Shell) and Wim Van't Hof (Ministry of Economic Affairs and Climate Policy of the Netherlands) for their support, review and comments.

Tetsuya Furuhashi and Yutaka Shirakawa (Japan Oil, Gas and Metals National Corporation) have provided essential contribution to Chapter 2 by conducting interviews to Japanese LNG buyers.

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

For questions and comments, please contact GCP (gcp@iea.org).

Table of contents

Abstract	1
Foreword	2
Executive summary	3
Findings and recommendations	7
Key findings	7
Update on LNG market flexibility metrics	7
LNG supply security in Asia: An opportunity for traditional buyers	10
North-western Europe’s gas flex: Still fit for purpose?	14
Technical analysis	19
1. Update on LNG market flexibility metrics	19
Introduction.....	19
Update on LNG contract trends	19
Portfolio players and flexibility.....	25
Analysis of contract flexibility	28
Pricing trends	30
References.....	33
2. LNG supply security in Asia: An opportunity for traditional buyers?	34
Introduction.....	34
LNG flexibility in Asia.....	37
References.....	46
3. North-western Europe’s gas flex: Still fit for purpose?	47
Introduction.....	47
North-western Europe’s gas demand: Seasonality and volatility	48
Current state of flexibility tools.....	50
A transforming energy system.....	62
References.....	64
General annex	66
Abbreviations and acronyms.....	66
Acknowledgements	67

List of figures

Figure 1	Additions to global liquefaction capacity (2014–24) and FID volume (2014–19)	8
Figure 2	FID-enabling contracts by signing year and structuring model (2014–19)	8
Figure 3	Concluded LNG contracts by destination flexibility, exporting region and importing region (2014–19)	10
Figure 4	Structure of term contracts among traditional Asian LNG buyers and volume of LNG imports (2005–18)	11
Figure 5	Evolution of Asian LNG buyer types (2010–24)	12
Figure 6	LNG import volumes and percentage covered by contracts, emerging Asian economies (2014–24)	12
Figure 7	LNG volumes contracted to traditional Asian LNG buyers with flexible destination (2012–24) ...	13

Figure 9	Natural gas production and flexibility requirement in north-western Europe (2008/09–2018/19)	14
Figure 12	Spread between summer and winter gas prices on TTF (2008–18) and gas storage closures in North-western Europe (2013–17)	16
Figure 13	UK volatility in gas-fired power generation (2015–17) and announced power plant closures in north-western Europe (2018–25)	16
Figure 14	North-western Europe’s changing gas flexibility landscape	17
Figure 15	Additions to global liquefaction capacity (2014–24) and FID volume (2014–19)	20
Figure 16	FID-enabling contracts by signing year and structuring model (2014–19)	21
Figure 17	Contracts signed each year by contract exporting region and with no identified region (2014–19)	22
Figure 18	Contracts signed each year by contract importing region (2014–19)	23
Figure 19	Contracts signed each year by duration (2014–19)	24
Figure 20	Contracts signed each year by volume (2014–19)	25
Figure 21	Portfolio players’ volumes and market share of import and export contracts (2012–24)	26
Figure 22	Duration and size of contracts signed for LNG to be supplied by portfolio players (2017 and 2018)	27
Figure 23	Duration and size of contracts signed for LNG to be supplied to portfolio players, 2017 and 2018	28
Figure 24	Contracts signed each year by destination clause (2014–19)	29
Figure 25	LNG export capacity by destination flexibility (2014–24)	29
Figure 26	Oil indexed vs gas-to-gas indexed import volume (2014–24)	31
Figure 27	Oil indexed vs gas-to-gas indexed export volume, 2014–24	32
Figure 28	Evolution of Asian LNG buyer types (2010–24)	34
Figure 29	Natural gas supply prices and average domestic consumer prices in Pakistan (2015–19)	35
Figure 30	LNG imports into emerging Asian economies and proportion covered by term contracts (2014–24)	36
Figure 31	Structure of term contracts for traditional Asian LNG buyers and imported LNG volume (2005–18)	38
Figure 32	Structure of term contracts in emerging Asian LNG buyers and imported LNG volume (2005–18)	38
Figure 33	Structure of term contracts in China and imported LNG volume (2005–18)	39
Figure 34	LNG demand and contracted volume, Japan (2004–24)	42
Figure 35	LNG volumes contracted to traditional Asian LNG buyers with flexible destination (2012–24)	44
Figure 36	Simplified schematic of seasonal gas flexibility needs and supply balance in the northern hemisphere	48
Figure 37	North-western Europe’s gas demand by sector (2008–24) and by month (2008–24)	49
Figure 38	Natural gas production and flexibility requirement in north-western Europe (gas years 2008/09–2018/19)	51
Figure 39	Annual spare import capacity to north-western Europe by origin of imports (2013–18)	54
Figure 40	Spare import capacity in January to north-western Europe by origin of imports (2013–19)	55
Figure 41	Utilisation of interconnections in north-western Europe, January 2019	57
Figure 42	Interconnector flows to the Netherlands, 2017–18	58
Figure 43	Storage swing in north-western Europe (2012–19)	59
Figure 44	Spread between summer and winter gas prices on TTF (2008–18) and gas storage closures in north-western Europe (2013–17)	61
Figure 45	UK volatility in gas-fired power generation and power plant closures in north-western Europe	63

List of boxes

Box 1.	Oil-linked contract slopes	30
Box 2.	Natural gas conversion facilities in the Netherlands	51
Box 3.	Accelerating Groningen’s phase-out	53
Box 4.	Storage deliverability	60

List of tables

Table 1.	Laden voyage days between major Asian LNG delivery ports	45
----------	--	----

INTERNATIONAL ENERGY AGENCY

The IEA examines the full spectrum of energy issues including oil, gas and coal supply and demand, renewable energy technologies, electricity markets, energy efficiency, access to energy, demand side management and much more. Through its work, the IEA advocates policies that will enhance the reliability, affordability and sustainability of energy in its 30 member countries, 8 association countries and beyond.

IEA member countries:

Australia
Austria
Belgium
Canada
Czech Republic
Denmark
Estonia
Finland
France
Germany
Greece
Hungary
Ireland
Italy
Japan
Korea
Luxembourg
Mexico
Netherlands
New Zealand
Norway
Poland
Portugal
Slovak Republic
Spain
Sweden
Switzerland
Turkey
United Kingdom
United States

The European Commission also participates in the work of the IEA

IEA association countries:

Brazil
China
India
Indonesia
Morocco
Singapore
South Africa
Thailand

Please note that this publication is subject to specific restrictions that limit its use and distribution. The terms and conditions are available online at www.iea.org/t&c/

Source: IEA. All rights reserved.
International Energy Agency
Website: www.iea.org



This publication reflects the views of the IEA Secretariat but does not necessarily reflect those of individual IEA member countries. The IEA makes no representation or warranty, express or implied, in respect of the publication's contents (including its completeness or accuracy) and shall not be responsible for any use of, or reliance on, the publication. Unless otherwise indicated, all material presented in figures and tables is derived from IEA data and analysis.

This publication 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. All rights reserved.

IEA Publications

International Energy Agency

Website: www.iea.org

Contact information: www.iea.org/about/contact

Typeset in France by IEA - September 2019

Cover design: IEA

Photo credits: © Shutterstock