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Secure Sustainable Together

GAS 2018

Analysis and Forecasts to 2023

INTERNATIONAL ENERGY AGENCY

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FOREWORD

The IEA Family has been growing. Thanks to the recent accession of Mexico as a member in February 2018, and Brazil joining as an Association country in October 2017, it will account for almost two-thirds of natural gas consumption growth in the next five years. This simple fact from our new gas market analysis is another illustration of the importance for the IEA to opening our doors to emerging energy consumers. This is a top priority for the IEA in its mission to support the global energy dialogue and bring the world on a secure and sustainable energy development path.

The role of gas in the global energy system is critical, and is set to grow. During our last Ministerial Meeting, in November 2017, energy ministers and CEOs of global energy companies all noted the growing role of gas in the world's energy mix and its importance to maintaining electricity security as well as for improving air quality, in the context of a growing and more globalized LNG market.

Natural gas is expected to be a key building block to a sustainable energy future. With 3% growth last year, natural gas demand had the fastest rise since 2010, a phenomenon that can be attributed to environmental policies, particularly China's determination to "bring back blue skies" by reducing air pollution. As the cleanest fossil fuel, natural gas should contribute to all of the energy-related Sustainable Development Goals, climate change mitigation, improved air quality and universal energy access. Indeed, we see that natural gas demand will grow even in our new Sustainable Development Scenario, which the IEA presented in the *World Energy Outlook 2017*.

The recent sharp growth in LNG trade, with new capacity coming on line in Australia and the United States has created a different landscape for LNG importers. US LNG has many of the characteristics – destination flexibility, hub-based pricing and spot availability – that can accelerate structural changes in the way gas is traded internationally. LNG importers, in particular those in the Pacific basin, are responding and the number of importing countries in the region has shown a dramatic increase.

Gas faces many challenges, however. The price competitiveness is also crucial to develop in price-sensitive markets, requiring sufficient and flexible supply from trade, but also action from governments to create the conditions for competition and fair access to markets. New investment in infrastructure will be needed to prevent a return to tight markets, with repercussions on prices and security of supply. Finally, efforts must continue to minimize the environmental footprint of natural gas use, including progress on methane emissions reductions and Carbon Capture, Utilization and Storage (CCUS).

This latest edition of our medium-term gas analysis and forecasts features leading roles for the United States in supply growth and China in demand growth, as well as petrochemical and other industry as the key growing sector. It should help policy makers, industries and other stakeholders better understand the natural gas market development and enhance market transparency.

Dr. Fatih Birol

Executive Director

International Energy Agency

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 Jean-Baptiste Dubreuil, Senior Natural Gas Analyst. Willem Braat, Jean-Baptiste Dubreuil, Jaime González-Puelles, Volker Kraayvanger, Minoru Muranaka and Tomoko Uesawa are the authors.

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

Valuable comments, data and feedback were received within the IEA, from Zakia Adam, Yasmine Arsalane, David Bénazéraf, Mariano Berkenwald, Alessandro Blasi, Stéphanie Bouckaert, Michela Cappannelli, Kieran Clarke, Laura Cozzi, Davide D'Ambrosio, Kate Dourian, Carlos Fernández Alvarez, Araceli Fernandez Pales, Lucie Girard, Tim Gould, Timur Guel, Cesar Alejandro Hernandez, Paul Hughes, Joerg Husar, Keunhyung Kim, Tae-Yoon Kim, Peter Levi, Christophe McGlade, Bruce Murphy, Pawel Olejarnik, Paul Simons, Glenn Sondak, Emily Stromquist, Miika Tommila, Kevin Tu, Aad Van Bohemen, Laszlo Varro, Talya Vatman, Brent Wanner, Kira West, Matthew Wittenstein, Xiang Li and Yang Lei.

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

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

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

The IEA would like to thank Jason Bordoff (Columbia University, United States), Laurent David (Engie), Andrew Garnett (University of Queensland, Australia), Francesco Gattei (Eni), David Goldwyn (Atlantic Council, United States), James Jensen (Jensen Associates), Ken Koyama (Institute of Energy Economics, Japan), Sarah Ladislaw (Center for Strategic and International Studies, United States), Todd Onderdonk (ExxonMobil), Gregor Pett (Uniper), Jonathan Stern (Oxford Institute for Energy Studies, United Kingdom), Nikos Tsafos (Center for Strategic and International Studies, United States), and Wim Thomas (Shell) for their review and comments.

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

TABLE OF CONTENTS

LIST OF FIGURES

LIST OF MAPS

LIST OF TABLES

LIST OF BOXES

EXECUTIVE SUMMARY

Three major transformations are set to shape the evolution of global natural gas markets in the next five years, setting the scene for this *Gas 2018* market outlook:

- **The People's Republic of China (hereafter, "China") becomes the world's leading importer of natural gas**. Driven by continuous economic growth and strong policy support to curb air pollution, China accounts for 37% of the global increase in natural gas consumption between 2017 and 2023, more than any other country. As domestic production cannot keep pace, China becomes the world's largest natural gas importer by 2019 and with 171 billion cubic metres (bcm) of imports by 2023, is mostly supplied by liquefied natural gas (LNG).
- Compared with the previous decade, **the industrial sector takes the lead from power generation as the main driver of global growth in demand for natural gas**. Emerging markets, primarily in Asia, account for the bulk of this increase with uses as a fuel for industrial processes as well as for feedstock for chemicals and fertilisers. Industrial gas demand also grows in major producing regions, such as North America and the Middle East, to support expansion of their petrochemicals sectors.
- **The United States is the source of much of the growth in natural gas production and most of the additional LNG exports**. The United States, already the world's top producer, accounts for almost 45% of the growth in global production and nearly three-quarters of LNG export growth. The development of destination-free and gas-indexed US LNG exports provides additional flexibility to the expanding global LNG market.

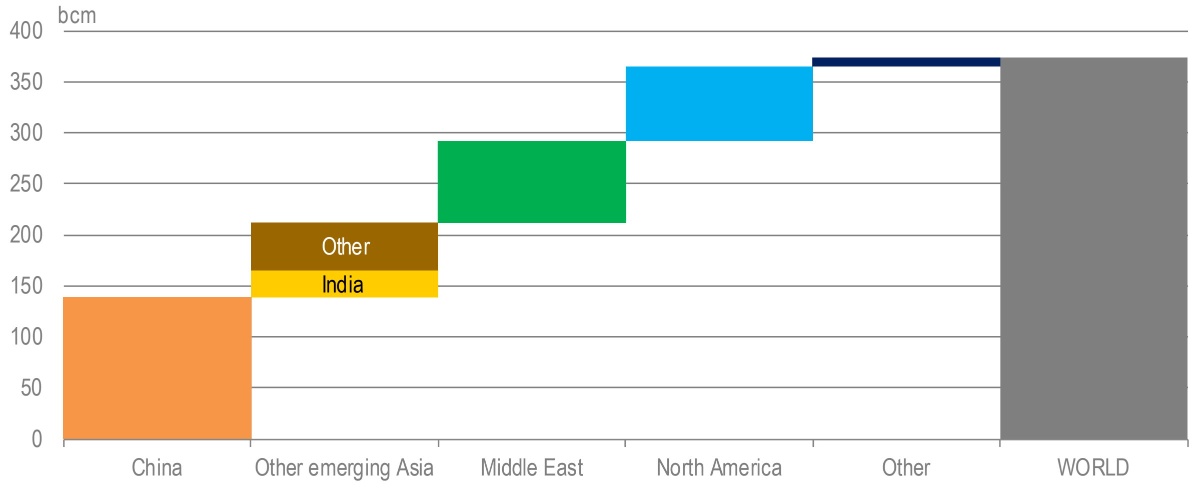
China and emerging Asian markets drive growth in global natural gas consumption growth

2017 was a year of strong growth for natural gas, mainly driven by China. Global natural gas demand grew by 3%, the highest increase since 2010. China, where demand grew 15%, accounted for nearly a third of the global increase, driven by a determined policy effort to improve air quality through coal to gas boiler conversions in the residential and industrial sectors. This led to an unprecedented surge in LNG imports, placing China as the world's second largest LNG importer after Japan.

The global natural gas market passes the 4 trillion cubic metres (tcm) mark by 2022, with an expected average annual growth rate of 1.6% throughout the forecast period. Emerging Asian markets, led by China, account for more than half of the growth in global natural gas consumption to 2023.

China becomes the largest natural gas importing country in the world by 2019, leading emerging Asian gas market growth. An increasing role for natural gas – defined as a clean energy source – in every sector of China's economy is backed by strong policy support from the 13th Five-Year Plan. China's demand grows at an average of 8% per year throughout the forecast period, accounting for over a third of global demand increase. The share of imports in China's supply rises from 39% to 45% over the forecast period. Other emerging Asian economies increase their natural gas consumption for industry (including fertilisers and petrochemicals) and power generation, and develop their domestic markets and infrastructure to import more LNG (Figure ES.1).

Figure ES.1 Global natural gas consumption growth, 2017-23



Natural gas-rich regions, led by the Middle East and North America, also experience sustained growth in consumption. The Middle East sees continuous growth throughout the forecast period, primarily led by increasing needs in industry, power generation and seawater desalination. In the United States, the abundance of local natural gas supply encourages further use of gas in chemicals and other industry sectors. The rebound in natural gas availability and use in Egypt plays a large part in the increase in consumption in Africa, while Latin American markets are reforming to develop the role of domestic production. Consumption in Eurasia slightly decreases due to sluggish economic growth. Mature net importing markets such as Europe, Japan and Korea are expected to see their natural gas demand stagnate.

Price competitiveness and market reforms will be critical to sustaining natural gas demand growth in emerging markets. Emerging markets are much more sensitive to price levels than traditional buyers; competitiveness of natural gas, either sourced from domestic production or imported, is therefore a crucial factor in sustaining such demand growth. Emerging Asian markets, where half of the global consumption increase is expected in the medium term, still mainly use oil-indexed mechanisms to define natural gas prices. Importing countries should pursue adequate market reforms to further open their own domestic gas markets if they intend to benefit from the development of more competitive wholesale gas markets, including market-based natural gas pricing mechanisms.

Industry takes the leadership from power generation in sectoral demand growth

Gas for power generation, once the primary source of growth, expands slowly amidst tougher competition among generation fuels. Power generation accounted for half of the growth in natural gas consumption over the last decade, helped by abundant fuel supply in mature markets, fuel switching from oil in emerging markets, and the reduction in nuclear generation in the aftermath of the Fukushima Daiichi nuclear accident. During the projection period, natural gas for power generation continues to grow in North America and the Middle East driven by cheap domestic resources, but slower global electricity demand growth, the rapid rise of global renewable electricity production and tough competition from coal, particularly in Asia, limit its growth prospects.

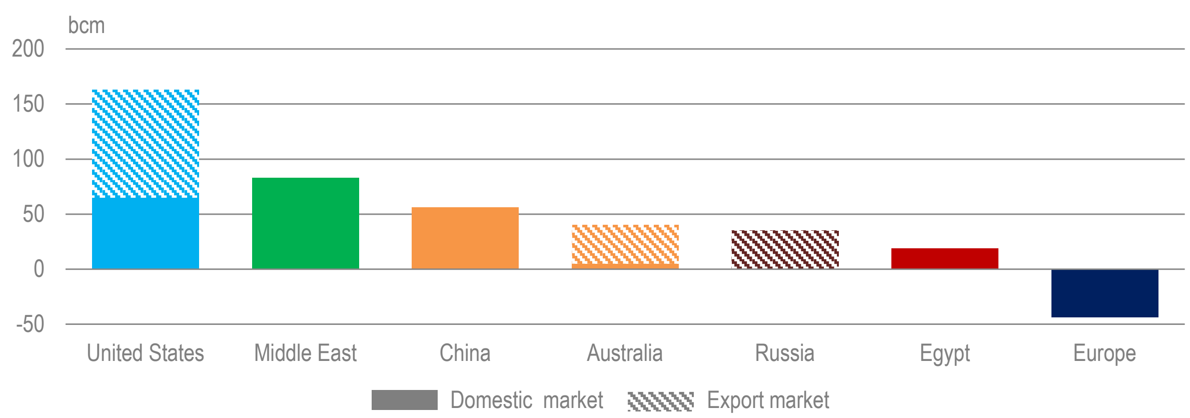
Industry emerges as the main driver of growth in natural gas consumption. The industrial sector is expected to account for 40% of the increase in natural gas consumption, replacing power generation as the main driver. Incremental industrial uses cover both energy for processes and feedstock for chemicals including fertilisers in emerging economies and feedstock for petrochemicals for export in regions with abundant natural gas.

The United States keeps its leading role in supply and export growth

The United States, the largest producer of natural gas, accounts for the largest share of supply expansion, with the production outlook given a boost by the gas associated with tight oil output. US natural gas production recovered in 2017 after a decline in 2016. Shale gas now accounts for two-thirds of total output. Shale gas from the Appalachian (dry gas) and Permian (mainly associated gas) basins are the main pillars of US gas production growth and continue to grow, with Permian taking the lead as recovering oil prices favour investment in US light tight oil (LTO) production, increasing associated natural gas output. Additional US production accounts for almost 45% of the global growth and two thirds of that is exported via pipeline to Mexico or as LNG globally.

Most of the increase in gas output from other major producing areas, such as the Middle East, China and Egypt, is dedicated to domestic markets. Outside of the United States, Australia and the Russian Federation (hereafter, "Russia") are the main contributors to export growth (Figure ES.2). Russia is seeking to diversify its export outlets through new export infrastructure, with a pipeline to China and LNG export terminals. By contrast, Europe's domestic supply deficit increases with the progressive depletion of North Sea production and the phasing out of the Groningen field, calling for additional LNG and pipeline imports to bridge the gap.

Figure ES.2 Natural gas production growth in selected countries and regions, 2017-23

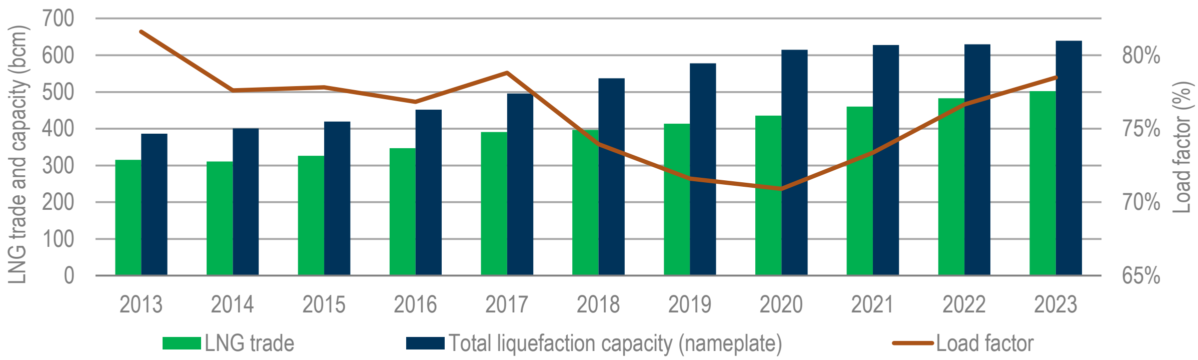


After a period of ample supply, the LNG market could start to tighten by 2023

LNG appears as the main driver of inter-regional natural gas trade growth, sustained by strong export capacity expansion. The wave of LNG export projects adds some 140 bcm of liquefaction capacity between 2018 and 2023, increasing global capacity by almost 30%. More than half of that expansion (over 80 bcm) takes place in the United States. Australia and Russia also provide significant contributions with 30 bcm and 15 bcm respectively. In comparison, pipeline expansion is more limited, happening mainly in North America (United States to Mexico) and from Eurasia to Europe and China.

The emergence of the United States as a global exporter challenges the traditional features of LNG trade. This wave of liquefaction projects, expected in the coming two years, ensures ample supply and growth of LNG trade but also challenges the traditional features of supply contracts. Emergence of US exports with flexible destination and gas-indexed pricing presents different models from the standard fixed-delivery, oil-indexed supply agreements. Australia and the United States appear as new global players likely to challenge Qatar in Asian markets.

Figure ES.3 LNG liquefaction capacity and utilisation, 2013-23



A lack of projects post-2020 could lead to a market tightening. Nearly all the new liquefaction capacity should be operating by 2020. In the short run, this massive capacity addition is likely to result in a surplus. This will increase competition among suppliers for customers while it can take time, especially for new customers, to construct receiving infrastructure. This loose market could be short-lived owing to the dynamic growth in Asian emerging markets. Without new investment, the average utilisation rate of liquefaction is likely to return to its pre-2017 level by 2023 (Figure ES.3). Owing to the long lead time of such projects, investment decisions need to be taken in the next few years to ensure adequate supply beyond 2023.

1. DEMAND

Highlights

- **2017 showed strong growth of 3% in global demand for natural gas**, principally driven by the People's Republic of China (hereafter, "China"), which accounted for 37% of the total increase. Most of the growth in global natural gas consumption was due to industrial demand as well as a weather-related contribution from residential, a significant departure from power sector-driven growth of over a decade long.
- **The global natural gas market is expected to pass the 4 trillion cubic metre (tcm) mark during the outlook period**, with an average annual growth rate of 1.6%, thus adding around 376 billion cubic metres (bcm) to annual demand by 2023.
- **The Asia and Pacific region accounts for half of this medium-term consumption growth**, mainly driven by China, which alone comprises over one-third of the global increase. India contributes 7% to global growth and the rest of the region 11%.
- **The United States is the second-largest individual contributor to growth in natural gas consumption after China,** with an average growth rate of 1.6% per annum, accounting for 15% of global demand growth by 2023.
- **Industry is the main driver of growth in global natural gas demand, followed by power generation**. Demand from the industrial sector (including non-energy uses) grows at an average of 2.6% until 2023 and accounts for 40% of the consumption increase.

Global overview

- Global demand for natural gas grew by 3% in 2017, significantly above the average rate of 1.5% experienced in recent years. China was the largest single contributor with a 14.5% annual increase, and Europe also saw sizeable growth – partly weather-related. Natural gas demand remained stable in mature Asian markets, while gas for power generation fell in the United States on lower electricity demand and a higher contribution from renewables.
- Natural gas consumption is expected to reach 4 116 bcm by 2023 (Table 1.1), adding about 376 bcm or 10% over the period, slightly more than the 358 bcm added over the course of the previous six years. The compound average annual growth rate (CAAGR) of demand is 1.6% over the forecast period.

  The **Asia and Pacific** region accounts for over half of total consumption growth until 2023, because of robust growth in developing Asia. China, whose market grew by an astonishing 15% in 2017 with a strong coal-to-gas switching programme in the residential and industrial sectors, continues to lead this trend with an expected average annual growth rate of 8% for the next five years. Other emerging Asian economies such as India, Bangladesh and Pakistan, are also expected to see sustained demand growth during the forecast period. By contrast, consumption in the Asia and Pacific region's more mature markets decreases over the period, with slight growth in Australia and Korea more than offset by the decrease in Japanese demand.

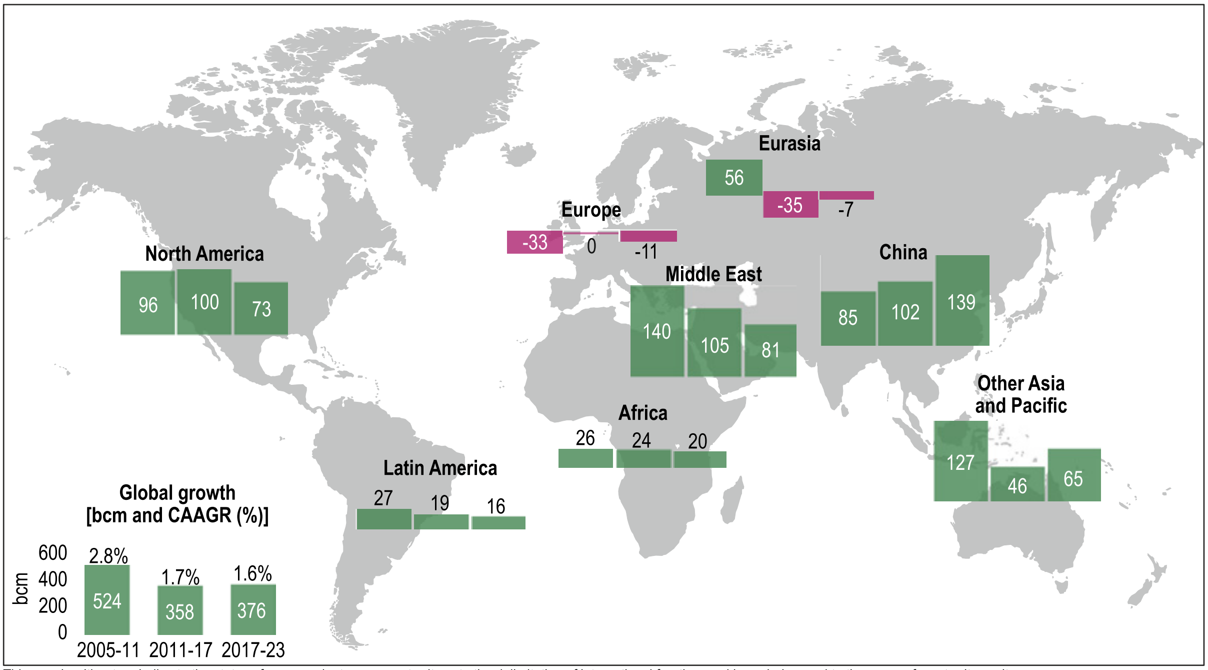
Table 1.1 Global natural gas demand by region, 2017-23 (bcm)

Region	2017*	2019	2021	2023	CAAGR 2017-23	Contribution to global growth
Africa	139	145	154	160	2.3%	5%
Asia and Pacific – China	237	277	331	376	8.0%	37%
Asia and Pacific – Other	537	555	582	602	1.9%	18%
Eurasia	645	644	641	638	-0.2%	-2%
Europe	547	535	533	536	-0.4%	-3%
Latin America	169	173	179	186	1.6%	4%
Middle East	502	526	553	582	2.5%	21%
North America	965	1 015	1 022	1 037	1.2%	20%
Total	**3 740**	**3 869**	**3 994**	**4 116**	**1.6%**	

* Provisional data.

- Natural gas demand in **North America** is expected to maintain the growth trend observed in recent years albeit at a slower pace, with an average annual consumption increase of 1.2%, adding 73 bcm over the forecast period – or 20% of global demand growth (Map 1.1). The United States accounts for 80% of the region's growth or 58 bcm, driven by abundant shale gas production.

Map 1.1 Global natural gas consumption growth by region, 2005-11, 2011-17, 2017-23



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

- Demand growth in the **Middle East** remains high, at an average of 2.5% per year, mainly driven by the strong power generation needs of Iran and Saudi Arabia.
- Annual demand in the **European** market is expected to decline by 11 bcm over the next five years. While the residential and industrial sectors remain flat, natural gas demand for power

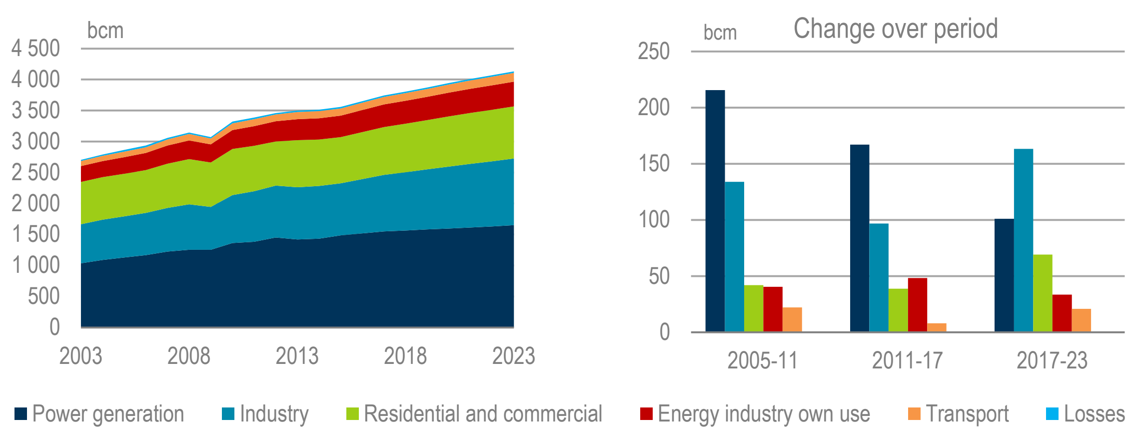
generation declines owing to the growth of renewables and despite a rebound over the final years with the impact of Germany's nuclear phase-out.

- **Eurasia's** demand is also expected to see a slight decline, at an average of -0.2% per year, with growth in Caspian and Central Asian countries being offset by decreases in Russia and Ukraine.
- Medium-term demand in **Latin America** sees average growth of 1.6% per year, mainly led by Argentina and Brazil. Demand in Argentina is expected to grow at a faster pace (2% per year) helped by the development of domestic production. Brazil's consumption decreases slightly (-1.4% per year) with developments in the industrial and transport sectors being offset by the decline in natural gas for power generation.
- **Africa** is expected to experience an average annual growth rate of 2.3% until 2023, driven by power generation needs in North Africa and in Egypt in particular. Market development in sub-Saharan Africa shows some positive signs, with several domestic production and liquefied natural gas (LNG) import projects, although demand is expected to remain flat for the next five years.

Sectoral outlook

Similar to the analysis in last year's report (IEA, 2017a), this forecast finds that the industrial sector accounts for over 40% of the consumption increase until 2023, larger than any other sector (Figure 1.1). This is a significant change compared to past trends where gas input for power generation was driving demand growth. Competition from cheaper renewable energy sources and coal has squeezed natural gas, and is expected to continue to do so through to 2023.

Figure 1.1 Global natural gas demand by sector, 2003-23



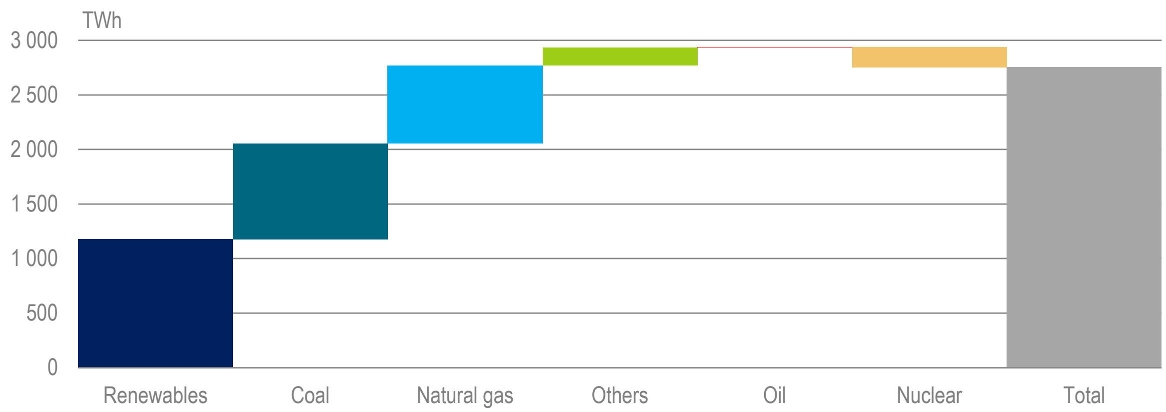
Global natural gas demand from the industrial sector grows at an average rate of 2.8% throughout the outlook period, reflecting the expectation of economic growth in emerging economies, especially in Asia where gas demand is expected to increase by over 5% per year. China emerges as a large industrial user of gas, with demand growth averaging 8% per year, encouraged by economic growth and fuel substitution policies. By 2023, Chinese industrial gas demand surpasses that of Eurasia and is close to European levels (130 bcm per year [bcm/y]). This rapidly growing consumption in the Asian region covers natural gas use as a fuel for industrial processes as well as non-energy uses as a feedstock for petrochemicals or fertilisers. Contrary to the industrial sector in Asia, which sees increasing reliance on imports, the same sector in natural gas-rich regions such as North America and the Middle East benefits from abundant and competitive domestic resources to develop its exports of petrochemicals. Both regions are expected to experience strong, if less spectacular growth, at respective average rates of 2.2% and 2.8% per year.

Power generation currently accounts for over 40% of total natural gas consumption. The sector was the main driver for natural gas demand growth over the past decade, accounting for half of the total increase in consumption (see Figure 1.1 and Box 1.1). This forecast expects gas for power to grow at a slower pace, increasing by 7% or around 100 bcm between 2017 and 2023, corresponding to an average annual rate of 1.1%. Emerging markets in Asia and the Middle East are the main regions for growth.

Box 1.1 Gas demand for power generation

Over the 2010-15 period,* global electricity generation increased by 2 754 terawatt hours (TWh), an average of 2.4% per year. Generation from coal, natural gas, and renewables all increased in absolute terms over this period, while oil generation remained relatively stable and nuclear generation fell in the aftermath of the Fukushima Daiichi nuclear accident (Figure 1.2). Renewable generation saw the largest increase, thanks principally to supportive policies and improving economics.

Figure 1.2 Change in annual world power generation, 2010-15



Note: *Others* include biofuel, waste and heat from chemical sources.

Source: IEA (2017), *World Energy Statistics*, OECD/IEA, Paris, www.iea.org/statistics/.

The share of natural gas in power generation grew slightly over the period so that by 2015, natural gas contributed 23% of electricity produced globally** (Table 1.2).

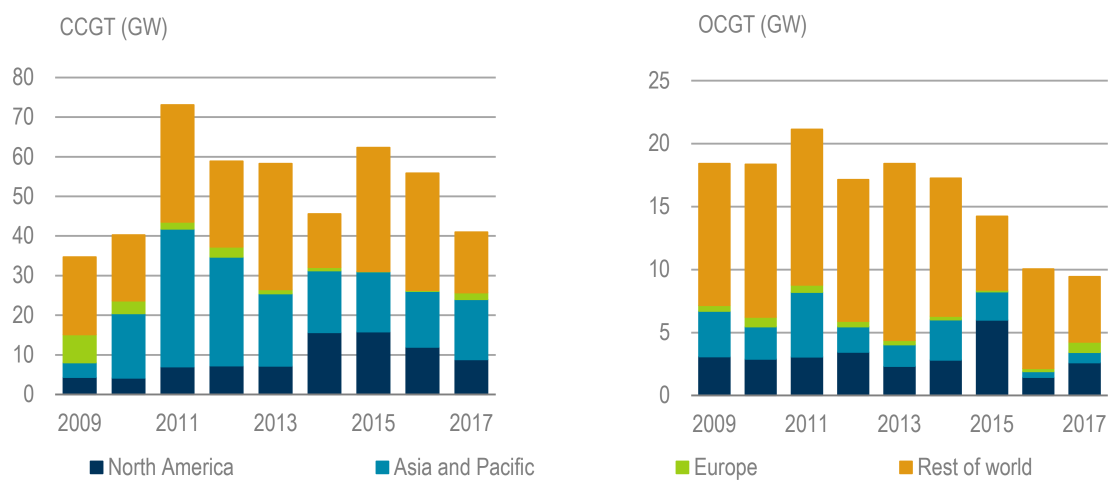
The increased efficiency of new natural gas generation has led to a small but notable increase in the efficiency of the natural gas fleet overall, meaning that the growth in gas-fired generation has been greater than the growth in the gas consumed for power generation. However, in many markets, natural gas generation finds itself squeezed by a combination of renewable generation growth and relatively low fuel cost coal-fired generation. Furthermore, many mature markets are seeing little or no increase in electricity demand. As a consequence gas demand growth for power generation has begun to slow down, with growth in 2017 about half the average of the previous six years.

Table 1.2 Fuel shares in the global power mix

Fuel	2010	2015
Nuclear	12.8%	10.6%
Coal	40.1%	39.1%
Gas	22.4%	22.8%
Oil	4.6%	4.1%
Renewables	18.4%	21.2%
Others	1.8%	2.3%

Not surprisingly, this is beginning to affect final investment decisions (FIDs) in natural gas generating capacity. Combined cycle gas turbines (CCGTs) are the key technology for gas-fired power generation, as these tend to be operated at higher load factors than other gas generating technologies. CCGT FIDs had been fairly stable but in 2017 experienced a significant drop. Investment in open-cycle gas turbines (OCGTs), less efficient but usually operated less frequently, has been steadily decreasing since 2013 (Figure 1.3).

Figure 1.3 FIDs for CCGTs and OCGTs by region, 2009-17



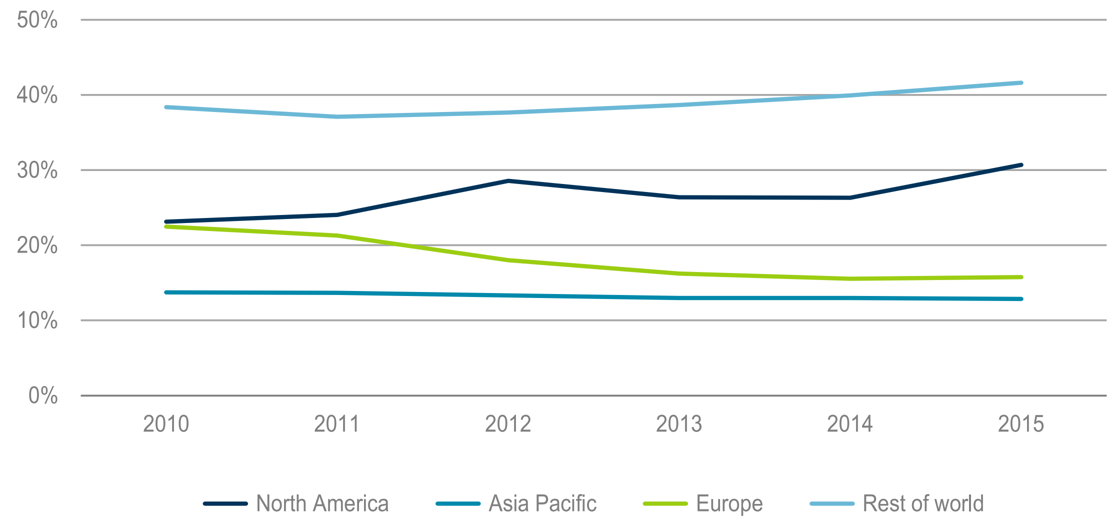
Note: GW = gigawatt.

Within this global picture are significant regional differences. North America had the strongest growth in gas-fired power generation of any region over this period, increasing from 23% of total generation in 2010 to 32% in 2016. This has been driven in large part by low natural gas prices and Mexico's push to increase its natural-gas power generation to substitute fuel oil-based generation

While the Asia and Pacific region was responsible for 82% of the growth in global electricity demand, relatively little of that growth in this coal-rich region was supplied by natural gas, with most of the additional generation coming from coal and renewables. Overall, the share of natural gas generation in the region declined from 13.7% in 2010 to 12.9% in 2015.

The European gas-fired power sector, in particular in the European Union, saw a reduction both in absolute terms and in its share of the power mix. While all conventional sources of generation were put under pressure by the growth of renewables and the decrease in demand, most of the reduction in output was borne by natural gas generation, which saw its share fall from 23% to 16% by 2015. Although during the last two years the share has begun to rise again, it is still well below 2010 levels (Figure 1.4).

Figure 1.4 Natural gas-fired generation share in each region, 2010-15



* 2015 data are the latest final global figures available at the time of writing.

** The preliminary IEA assessment of 2017 power generation, in *Global Energy and CO_2 Status Report* (IEA, 2018a), estimates that gas has maintained its share at 23%, but renewable technologies have moved ahead and now make up 25% of power generation.

Consumption in the residential and commercial sectors increases by an average of 1.3% to reach almost 840 bcm/y in 2023. China is pivotal in this sector and accounts for almost half of the global growth, supported by strong targets in clean air policies.

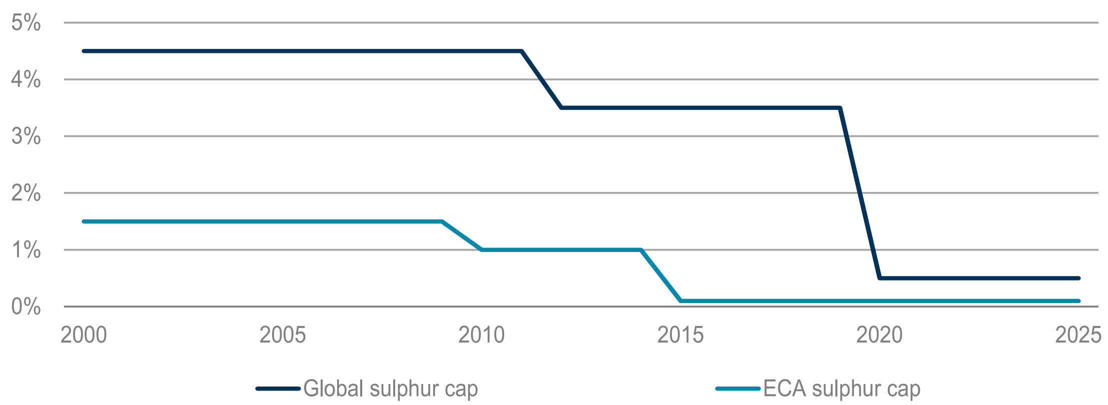
Demand for natural gas as a transport fuel is expected to grow at an average 2.6% annual rate, faster than other sectors but with a total volume that remains limited in comparison, reaching around 140 bcm/y by 2023. China accounts for 20% of global consumption by 2023, with the development of a strong fleet of compressed natural gas (CNG) and liquefied natural gas (LNG) fuelled vehicles. The development of LNG as a marine fuel, although spurred by tighter international regulation of sulphur emissions, remains limited in the medium-term horizon. Enforcement of the new sulphur cap on maritime fuels could have implications for the natural gas market, and specifically for LNG (see Box 1.2).

Box 1.2 Prospects for LNG as a bunker fuel

The International Maritime Organization (IMO) confirmed in October 2016 the enforcement of a new 0.5% global sulphur cap on maritime fuels as from 1 January 2020, compared to the current 3.5% limit (Figure 1.5). The initial decision was adopted in 2008 with the revised Annex VI to International Convention for the Prevention of Pollution from Ships (MARPOL) requiring the sulphur content of any fuel used on board ships not to exceed 4.50% prior to 1 January 2012, 3.50% from 1 January 2012, and 0.50% by mass from 1 Jan 2020 (with initial option to postpone until 2025).

Additionally, the revised Annex VI to MARPOL restricts the sulphur content of fuel oil used on board ships operating within an Emission Control Area (ECA) to 1.00% from 1 July 2010, and 0.10% from 1 January 2015. Currently adopted ECA areas are the Baltic Sea, North Sea and Channel, the US Caribbean ECA and the North American ECA.

Figure 1.5 MARPOL Annex VI sulphur limits



Several options are available for ship owners and charterers to comply with the new marine fuel specifications, impacting a market of more than 3 million barrels per day (mb/d) of high-sulphur bunker fuel:

- Installing exhaust gas cleaning systems (also known as scrubbers) would allow ship owners to continue burning heavy fuel oil while remaining compliant with sulphur caps. The operation includes laying up the vessel for a month in dry dock in addition to the investment cost estimated at up to US dollars (USD) 6 million,* which means that scrubber retrofits would not be effective for old vessels with limited remaining lifetime. Additionally, while scrubbers cope with sulphur emissions, they are not efficient at dealing with carbon dioxide emissions, which could imply additional compliance investment in case of future carbon emission regulations – in accordance with IMO's greenhouse gas emissions initial strategy issued in April 2018.
- Switching to lower-sulphur content fuels, such as very low 0.5% sulphur fuel oil or marine gasoil (MGO), would be less capital intensive than scrubbers – even though some retrofitting of engines could be expected in a switch to MGO. However, as illustrated in the IEA *Oil 2018* market report (IEA, 2018b), gasoil availability will be a major constraint during the switch, with additional demand from 2020 likely to trigger a spike in diesel prices.
- The last option would be to switch to alternative fuels, including LNG. If LNG has the advantage of lower sulphur, nitrogen and carbon emissions than oil-based fuels, it also has some disadvantages

from a ship owners' point of view, such as current lack of bunkering infrastructure, higher cost of development (retrofit would not be an economically sustainable solution), loss of cargo capacity incurred by larger tank space, or increased technical complexity for bunkering and maintenance.

The LNG-fuelled vessel fleet remains limited but is growing – at the time of writing it is understood that about 220 vessels running on LNG or LNG-ready are operating (excluding LNG carriers that can use their cargo as fuel), and about 100 more are under construction. The vast majority of these vessels are for short-distance travel, such as passenger ferries, car ferries, tugs, patrollers and other specialised vessels, which do not need to stock fuel for long journeys. Passenger cruise companies have shown growing interest in LNG as a marine fuel as it contributes to provide an environmentally friendly image and additional costs can more easily be passed through with higher-margin passenger transport than with cargo trade.

Several options are available for bunkering infrastructure, from truck to ship for small vessels, to ship to ship or even terminal to ship for the larger vessels. The LNG bunkering vessel fleet is still nascent, with the first special purpose vessel (*Engie Zeebrugge*) starting operations in mid-2017. At the time of writing only three vessels are operating, all of them in Europe, but several are under construction (see Table 1.3) with growing average tank capacity.

Table 1.3 LNG bunkering vessels operational and under construction

Vessel name	Operator	Home port	Capacity (cm)	Delivery
Engie Zeebrugge	Engie	Zeebrugge	5 000	2017
Cardissa	Shell	Rotterdam	6 800	2017
Coralius	Skangas	Baltic Sea	5 800	2017
Clean Jacksonville	Clean Marine Energy	Jacksonville, FL	2 200	2018
Flex Fueler 1	Titan LNG	Amsterdam	760	2018
(vessel)	Bomin Linde - Klaipedos	Baltic Sea	7 500	2018
*Coral Methane***	Shell	North Sea/ Mediterranean	7 500	2018
(barge)	Shell	Rotterdam	3 000	2019
(vessel)	Stolt Nielsen Gas		7 500	2019
(vessel)	Stolt Nielsen Gas		7 500	2019
(vessel)	Kogas		7 500	2019
(barge)	Shell	Caribbean	4 000	2020
(vessel)	Total - MOL		18 600	2020

Note: cm = cubic metre.

Source: Compilation based on information from companies' reports and investors' presentations. It appears that, while investments are made to develop LNG as a marine fuel, this market will remain limited over the medium-term horizon, apart from the existing consumption by the LNG carrier fleet.

* According to calculations provided by engine developer Wärtsilä, the cost of retrofitting a tanker with an 8 megawatt (MW) engine would be USD 4.2 million with a payback period of around five years, while for a typical container carrier with a 20 MW engine the cost would amount to USD 5.8 million with the same payback period.

** Conversion from LNG carrier.

Assumptions

This report uses the International Monetary Fund (IMF) January 2018 *World Economic Outlook* as a basis for its forecast. According to the IMF, the world's economy grew at an estimated 3.7% in 2017, and is expected to increase by 3.9% in 2018 and 2019, and then by 3.7 to 3.8% until 2023. The outlook foresees an increase in economic activity in emerging markets and developing countries. Developing Asia will see growth of 6.5% in 2018 and 2019, spurred by China and India. The gross domestic product (GDP) growth rate of the United States is projected to be 2.7% and 2.5% in 2018 and 2019, respectively, with investment supported by recent tax cuts, before slowing to an average of 1.7% as fiscal adjustment takes place. Lower growth is expected in Europe and Japan, with average GDP growth rates of 1.7% and 0.7% respectively over the forecast period.

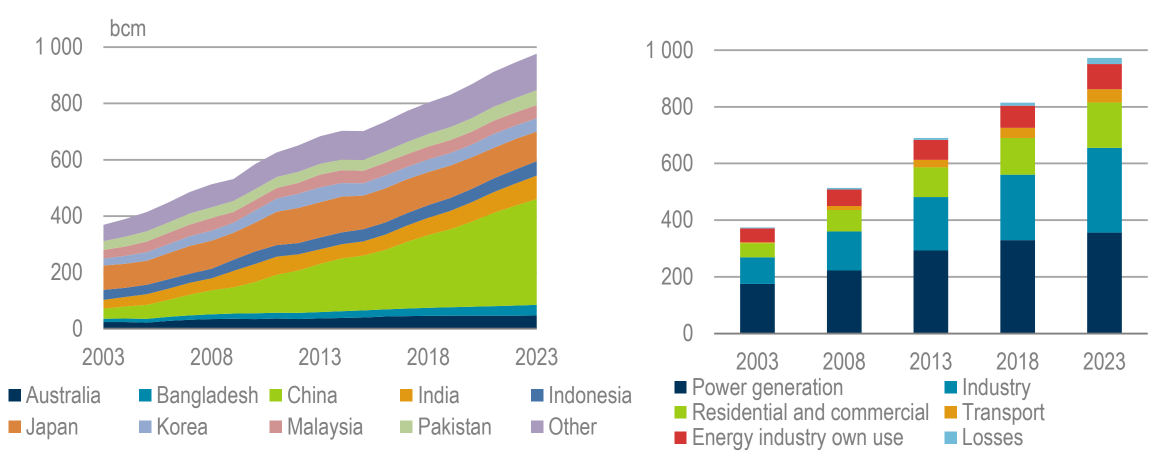
This report uses the average of future prices as taken over the period September 2017 to March 2018 as price indicators for oil, natural gas and coal. Futures are financial products used by the energy industry for hedging purposes and are not to be considered as price forecasts. As the liquidity of future contracts is much lower for the longer maturities (beyond 18 to 36 months, depending on the market), this report combines information from the futures curve with medium-term fuel price assumptions as contained in the *World Energy Outlook 2017* (IEA, 2017c) to provide an indication of assumed price evolution towards 2025.

Regional outlook

Asia and Pacific

The Asia and Pacific region is the main source of growth in demand for natural gas, contributing half of the global consumption increase to 2023. China alone accounts for over one-third of total demand growth over the next five years (Figure 1.6).

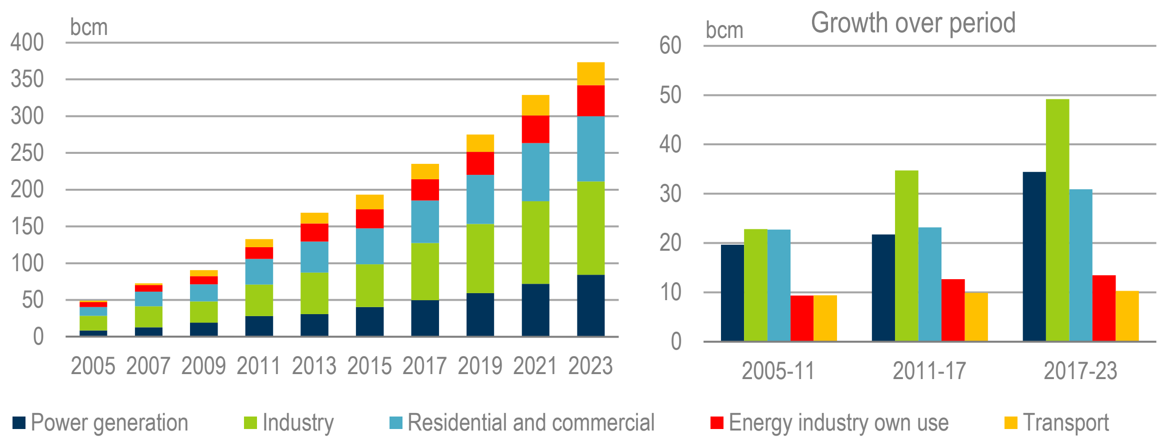
Figure 1.6 Natural gas demand by country and sector, Asia and Pacific, 2003-23



China

Natural gas consumption in China is gaining momentum under the country's "Blue Skies" policy. In 2017, the move towards a cleaner energy mix was strongly supported by decisive government action and reform to restrict the use of small coal boilers for industrial and residential use. The government intensified policy action last year in fulfilment of its 2013 Action Plan on Prevention and Control of Air Pollution objectives. However, the massive demand pull it created was so strong that it grew faster than China's supply, resulting in serious gas shortages in some regions of the country and soaring import gas prices over the winter months.

Figure 1.7 Gas demand by sector, China, 2005-23



Sustainable growth is ensured by the Action Plan framework, but double-digit growth cannot be taken as a given. Decisive policy action, as seen in 2017, needs to be repeated to lift gas demand, especially as economic growth decreases at the end of the forecast period. This report sees strong growth in China's natural gas consumption, with an average annual growth rate of 8% from around 237 bcm/y to 376 bcm/y (Figure 1.7). This takes into account the overall forecast for China's economy. The IMF estimates that the Chinese economy will grow on average by 6.2% per year between 2017 and 2023 (IMF, 2018).

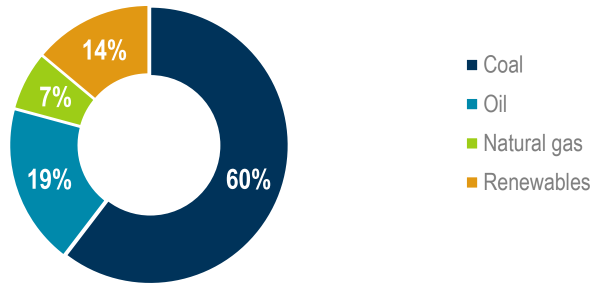
China's incremental natural gas demand will be an important driver for global growth in the forecast period, with incremental growth in annual demand amounting to 139 bcm. Growth and further fuel switching in the industrial, residential and commercial sectors will be the main drivers, accounting for 60% of overall natural gas consumption increase.

Continuously moving towards a cleaner energy mix

On the back of a growing Chinese economy (6.9% in 2017), the country's total energy consumption grew by 2.9% in 2017 to 3 143 million tonnes of oil equivalent (Mtoe) (NBS, 2018). Natural gas was the fastest-growing fossil fuel, up 15% year-on-year (y-o-y), increasing its share of the primary energy consumption to 7%, up from 6% in 2016 (Figure 1.8).

Both clean air policies and economic growth contributed to the 2017 record growth in Chinese gas consumption (in bcm terms). Demand increased by 30 bcm from 207 bcm to 237 bcm, resulting in double-digit growth rates of 15% after 8% in the previous year (NDRC, 2018). Every sector contributed to the gas surge, but the main factor was the switch from small coal-fired to natural gas-fired boilers for industrial and residential use.

Figure 1.8 Energy consumption by source, China, 2016-17



Source: NBS (2018), "Statistical Communiqué of the People's Republic of China", www.stats.gov.cn/english/pressrelease/201802/t20180228_1585666.html.

In 2017 natural gas demand grew faster than supply

The starting point of the demand surge in 2017 was the end of 2017 deadline to fulfil the 2013 Action Plan on Prevention and Control of Air Pollution objectives. These included the phasing out of small coal-fired boilers with an average rate of 10 tonnes per hour (t/h) of steam and below (Government of China [GOC], 2013). A notice issued in 2014 linked the fulfilment of the objectives to annual appraisals of local governments (GOC, 2014). By 2014, China had a total of around 560 000 industrial boilers, of which 460 000 were coal-fired with a capacity of around 1 770 000 t/h of steam – with an average capacity of 4 t/h (IEA, 2017d). The fulfilment of the FYP's objective to replace 189 000 t/h of small coal boilers between 2015 and 2020 would result in around 45 bcm of incremental gas demand.

The determination to fulfil the targets for a coal-to-gas switch gained momentum in spring 2017 with the Beijing-Tianjin-Hebei and Surrounding Areas 2017 Air Pollution Control Work Plan, as these areas were at risk of not meeting the envisaged objectives by the end of 2017 (GOC, 2017). Efforts were heavily intensified and Beijing and Hebei even exceeded their objectives.

Meeting this increased gas demand, much of it temperature sensitive, proved to be a challenge. With colder than normal weather at the beginning of winter, the risk of gas shortages in the country became an increasing concern, leading to further action by the government. In December 2017, the Ministry of Environmental Protection, Department of Air Environment Management, even issued a letter which permitted specific regions to continue using previous coal-fired heating methods on an interim basis (which were to be phased out by the end of 2017) to prevent heating shortages. Furthermore, to ensure residential natural gas users were given priority over the industry, on 18 December 2017, the National Development and Resource Commission (NDRC) ordered state-owned energy companies to cut supply to the industry to save around 15 million cubic meters per day (Chen, 2018). This was a particular setback for industrial customers who had just converted from coal-fired boilers to gas, but needed to interrupt production or switch to other fuels if possible.

Clean air policy and economic growth drive natural gas in the medium term

The example of 2017 elucidates the strong influence of policy measures on future gas consumption, in addition to China's overall economic development. The specific policy framework for the medium term is the 13th Five-Year Plan (FYP) for natural gas, which was issued by China's National Development and Reform Commission and National Energy Administration at the end of 2016.

Table 1.4 Reforms to promote gas demand in China, 2017

Date	Reform	Objectives	Main governmental institutions
March 2017	Beijing-Tianjin-Hebei and Surrounding Areas 2017 Air Pollution Control Work Plan	Ensure the completion of the objectives and tasks for 2017 defined in the Air Pollution Prevention and Control Action Plan	Ministry of Environmental Protection, National Development and Reform Commission, Ministry of Finance, Relevant Municipal People's Governments
June 2017	Opinions on the acceleration of natural gas use	Emphasises cross-ministerial efforts for meeting China's natural gas development goals	National Development and Reform Commission, Ministry of Science and Technology, Ministry of Industry and Information Technology, Ministry of Finance
August 2017	Notice to reduce non-residential natural gas reference city-gate prices	Baseline city-gate price reduced by USD 0.4/MBtu (CNY 100/1 000 cm)	National Development and Reform Commission
December 2017	Notice regarding the issuance of a 2017–21 winter clean heating plan for Northern regions	By 2021, clean heating shall be expanded to cover 70% of Northern region's total heated floor space. Includes specific natural gas heating development targets (Table 1.5)	National Development and Reform Commission, National Energy Administration, Ministry of Finance, Ministry of Environmental Protection

The plan sets specific targets for 2020 and envisages increasing the share of natural gas to between 8.3% and 10% of primary energy consumption, equalling annual consumption of 305-365 bcm. Based on China's 2017 gas demand of 237 bcm, this would mean a very ambitious CAAGR of around 15.5% to reach 365 bcm by 2020. Furthermore, the plan targets an increase in gas-fired power generation capacity to 110 GW.

In 2017, a series of additional reforms was issued to detail the 13th FYP and strengthen efforts to improve China's air quality (Table 1.4). In December 2017, the notice regarding the issuance of a 2017–21 winter clean heating plan for Northern regions was issued by the National Energy Administration (NEA, 2017). It has the objective of further reducing emissions and improving air quality, particularly by using centralised heating and reducing decentralised coal-fired heating for buildings in urban and rural areas of Northern China (equivalent to replacing 150 million tonnes of dispersed coal). The initiative includes use of several fuels as "clean heating fuels", including natural gas, but centralised coal-fired facilities with advanced air pollution controls will play the largest role in the plan.

Geographically, the initiative focuses particularly on the Jing-Jin-Ji area, which includes Beijing, Tianjin and some cities in Hebei, Shanxi and Henan provinces. On natural gas-related targets, the plan includes measures that will increase natural gas demand by 23 bcm by 2021 (Table 1.5).

The incremental gas demand for clean heating will be mainly concentrated in urban areas, accounting for 63% of the total. Rural areas account for 8.5 bcm or 37%.

Table 1.5 Natural gas heating development targets, 2017-21

Measure	Incremental gas demand in bcm/y, (2021 targets)
Switching coal-fired to gas-fired boilers (in 12 million households)	9.0
Newly built and reconstructed gas-fired co-generation, (additional capacity 11 GW)	7.5
Newly built and renovated gas-fired boilers (additional capacity 50 000 steam t/h	5.6
Gas-fired distributed heat (additional capacity 1.2 GW)	0.9
Total	**23.0**

Source: NDRC (2017), "Natural gas heating development target for '2+26'cities", www.gov.cn/xinwen/2017-12/20/5248855/files/7ed7d7cda8984ae39a4e9620a4660c7f.pdf.

Is 2017 growth China's new norm until 2023?

Double-digit growth cannot be taken as a given. Fulfilment of the 2013 Action Plan objectives released some pressure and thus gas demand growth in 2018 is expected to be lower than in 2017; however, it could again reach double-digit growth rates. The government set its energy consumption target 1.3% higher than energy consumption in 2017 at 3 185 Mtoe (or 4.55 billion tonnes of coal equivalent) (Zhou, 2018). The 2018 natural gas share of total energy consumption is targeted at 7.1%, an increase of 25 bcm from 237 bcm to 262 bcm. China's LNG imports over the five first months of 2018, up around 55% compared to the same period last year, provide indication that this target is likely to be achieved and could be exceeded.

The strong policy drive to improve air quality is a guideline for the coming five years. This is certainly expected to ensure persistent growth for natural gas in China. However, uncertainties remain: China's economic development, sufficient gas supply, gas price competition with alternative fuels, and expansion and accessibility of the gas supply infrastructure (e.g. underground gas storage facilities) are important factors that will have a great impact on how quickly China's gas market can develop. For instance, the working gas volume of China's gas storage facilities reached 10 bcm in 2017, reflecting only 4% of China's gas consumption (Duan, 2017). Against the background of an increasing level of temperature-driven consumption, the expansion of this supply infrastructure remains crucial.

In the power sector, state-of-the-art coal plants continue to play an important role in China's power generation portfolio, if only because of their lower fuel costs compared to gas-fired power plants. The rise in variable renewables adds further competition for natural gas in a power system. At the end of 2016, China had gas-fired capacity of 67 GW, a share of roughly 4% of the overall installed power capacity. Preliminary data for 2017 show an additional capacity of 6 GW, totalling 73 GW at the end of the year, only marginally increasing the overall share. Future growth in the power generation sector is expected to come from newly built capacity, but at a slower pace compared to the 13th FYP. This report assumes that the 13th FYP target of around 110 GW of gas-fired capacity is reached at the end of the forecast horizon for the reasons stated above. Based on an average gas consumption of around 0.18 cubic metres per kilowatt hour and 4 000 operating hours per year, China's gas-fired power generation fleet would consume around 80 bcm by 2023.

Natural gas in the industrial sector is used in various furnaces (drying, heating, hot treatment, roasting and smelting furnaces). The manufacturing industry, including raw chemical materials, chemical products and construction materials (e.g. glass) are currently the main industries with natural gas demand. They will be important sectors for incremental gas demand as the substitution of alternative fuels in manufacturing processes (steam production and melting) continues. However, incremental gas demand strongly relies on policy action to support natural gas, as price competition from coal and fuel oil is very strong. Additionally, industries such as ceramics not only need very pure fuels without contaminating matter – which natural gas can unquestionably provide – but also stable supply. A sufficient supply infrastructure is therefore crucial to further promote natural gas in industry. Efforts to increase domestic production are likely to increase energy industry own use, adding incremental gas demand of around 13 bcm by 2023.

In 2016, China's number of residential gas users was estimated at around 309 million. On the assumption that the population with access to gas reaches 470 million by 2020 in accordance with government targets, the potential of the sector is large. By comparison, Europe had around 110 million residential gas users in 2016. Gas demand in the residential and commercial sector clearly benefits from the ongoing coal-to-gas switch, which gained new momentum from the recently issued reforms. However, gas shortages in 2017 elucidated that the country currently has too little working gas capacity in relation to the magnitude of temperature-driven demand. Efforts to expand the gas supply infrastructure need to increase to reach government targets for the residential and commercial sector.

In the transport sector, a higher penetration of LNG-fuelled trucks and natural gas-fuelled taxis is expected to further support gas demand. The number of natural gas vehicles in China is further increasing, particularly in regions where gas is easy available and refuelling infrastructure is developed. In 2017, the number of natural gas stations reached around 7 300, including 4 750 CNG refuelling stations and 2 550 LNG refuelling stations. A total of 6.5 million natural gas vehicles are used in China, including 6.23 million CNG vehicles and 270 000 LNG vehicles (Table 1.6). According to the official plans, China expects to have 10 million natural gas vehicles by 2020 (Wang, 2017). However, this target is highly ambitious taking into consideration the strong political push for electric vehicles in China. Assuming that China reaches its target by 2023, incremental gas demand for transport increases by 10 bcm to around 31 bcm/y.

Table 1.6 Natural gas vehicles in China

Type	2012	2016	2017	2016-17
Natural gas vehicles ('000)	1 577	5 000	6 500	30% (growth)
Of which LNG vehicles ('000)	46	170	270	59% (growth)

Source: NGV Global (2018), *Current Natural Gas Vehicle Statistics* (database), www.iangv.org/current-ngv-stats/.

Sichuan Clean Energy Automobile Industry Association (2018), "A summary of the meeting of the National Natural Gas Automobile Association Association in 2018", www.scqjqc.cn/a/dongtai/2018/0419/1762.html.

Japan

Japan's natural gas demand was about 120 bcm in 2017, with power generation accounting for more than 65% of total consumption. As other sectors are expected to grow modestly consistent with its GDP growth, or even stagnate out to 2023, future gas consumption in Japan is sensitive to the power sector, and particularly the timing and quantity of nuclear power plant restarts and the growth of renewable electricity generation.

This report assumes that 19 GW of nuclear capacity, almost 40% of the nuclear capacity operating before 2010, will resume operations by 2023 and that renewable electricity generation will grow at around 5% per year. This leads to a drop in gas consumption in the power sector of around 20 bcm/y compared to 2017.

Figure 1.9 Natural gas demand and supply, Japan, 2003-23

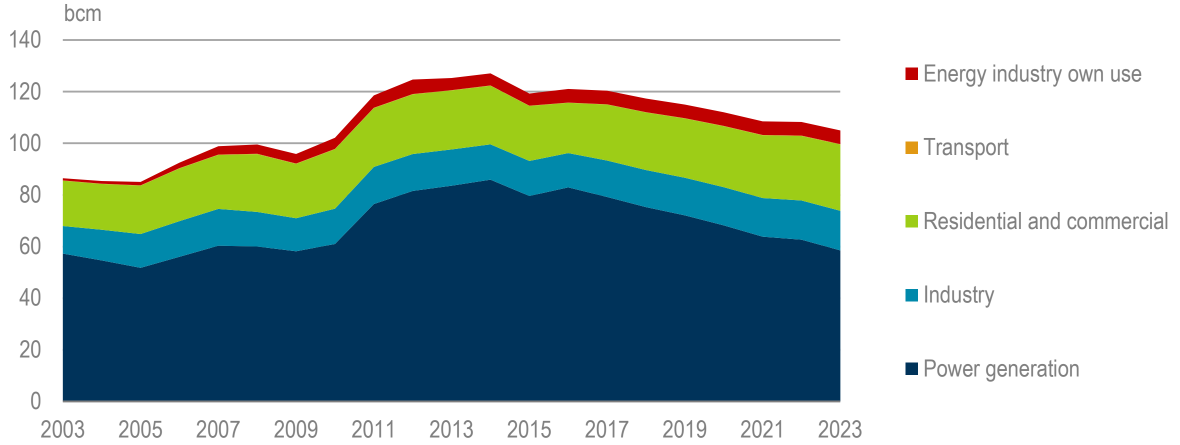
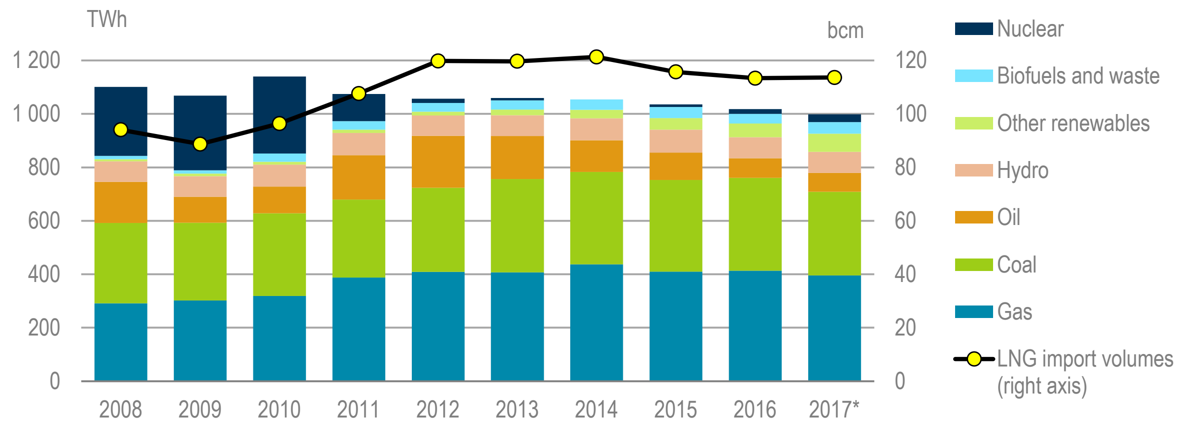


Figure 1.10 Power generation by fuel and LNG import volumes, Japan, 2008-17

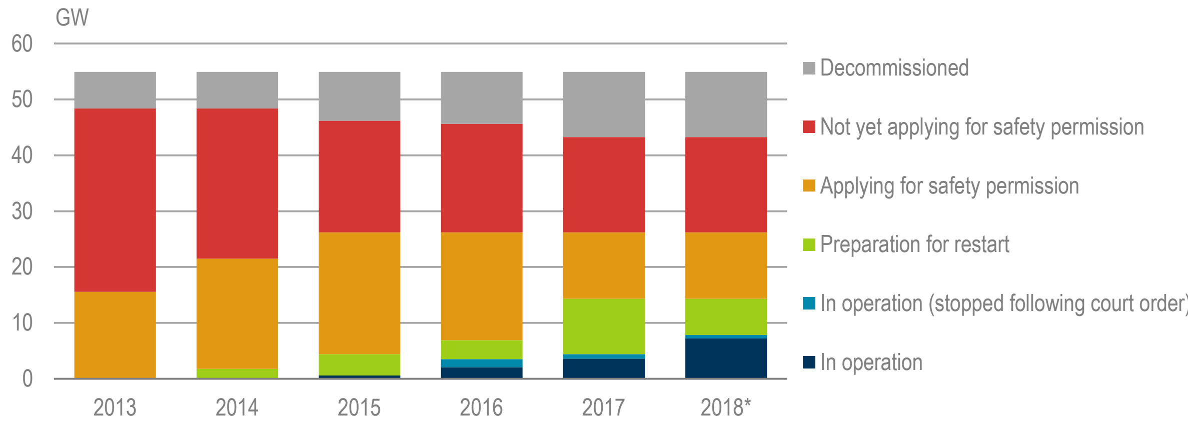


* Estimated.

Sources: METI (Ministry of Economy, Trade and Industry) (2017), *Power Generation Performance*; IEA (2018c), *Electricity Information* (database), www.iea.org/statistics/.

The outlook for the nuclear restarts remains uncertain. After decommissioning two large reactors of 1.2 GW each in 2017, Japan has 40 nuclear reactors and 3 units under construction, equal to around 43 GW in total (Figure 1.11). Following establishment of the newest nuclear safety measures by the Nuclear Regulation Authority, six reactors, including two advanced boiling water reactors Kashiwazaki Kariwa No. 6 and No. 7, were given approval to restart operations in 2017, with a total of 14 nuclear reactors having obtained approval. Twelve further reactors are applying and under review for safety approval to restart. Seventeen nuclear reactors have not yet applied. While no reactors restarted in 2017, the 1.2 GW reactor Ohi No. 3 restarted in March 2018 as the sixth reactor to restart by meeting the newest standards. However, one unit that had already restarted was shut down by a court order. An additional eight reactors are preparing to restart after approval. At the time of writing, two of them have resumed operation, one is expected to be operational before the end of 2018 and two in 2019.

Figure 1.11 Status of safety approval for nuclear power reactors in Japan, 2013-18



* Data for 2018 are based on the status of nuclear power plants at the time of writing.

Sources: International Energy Agency (IEA) compilation based on information from companies' websites.

Another pressure on gas consumption in the power sector is increasing generation from renewable energy sources. Between 2011 and 2017, power production from renewables increased from 127 TWh to 188 TWh (Figure 1.10), mostly led by solar power. This forecast assumes strong growth of renewable energy generation at a rate of around 5% per year, equivalent to an increase of around 60 TWh from the 2017 level.

The Japanese retail gas market was liberalised by 2017, with integrated gas companies subject to restructuring into segments, and residential and small business customers able to select their choice of retail gas supplier (see Box 1.3).

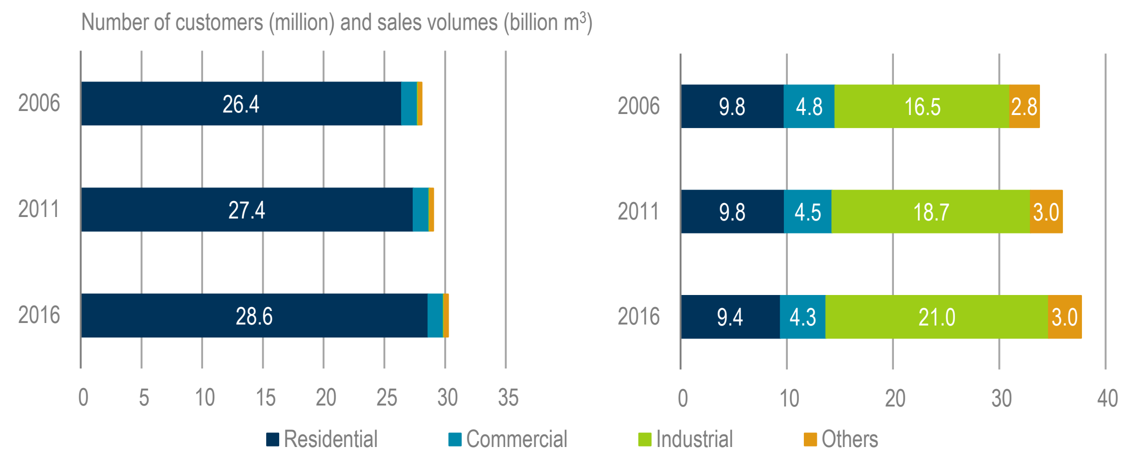
Box 1.3 Japanese gas market reform

Gas industry reform before 2017

Japan's city gas companies were monopolistic suppliers within their districts until the government started to introduce liberalisation in the retail market in 1995. The city gas business was considered a natural monopoly, given the conditions whereby the industry was required to make large upfront investment in infrastructure followed by high fixed operating costs. The sector would eventually achieve the advantage of economies of scale among a small number of players and also contribute to its obligations to provide safe and stable supply of gas. The government in turn imposed tariff regulations on the monopoly companies.

The city gas companies were able to supply natural gas to large-volume industrial customers and deliver large-scale supplies more efficiently via their own pipelines. At the same time, large-scale industrial users from areas outside city gas supply districts also created a growing demand for natural gas, switching from conventional fuels such as liquefied petroleum gas (LPG) and butane. As a consequence, during the 1990s Japan faced increasing consumption growth mainly from those large-volume industrial customers selecting their gas supplier outside monopoly city gas company networks (Figure 1.12).

Figure 1.12 Number of natural gas customers and sales volume by sector, Japan, 2006-16

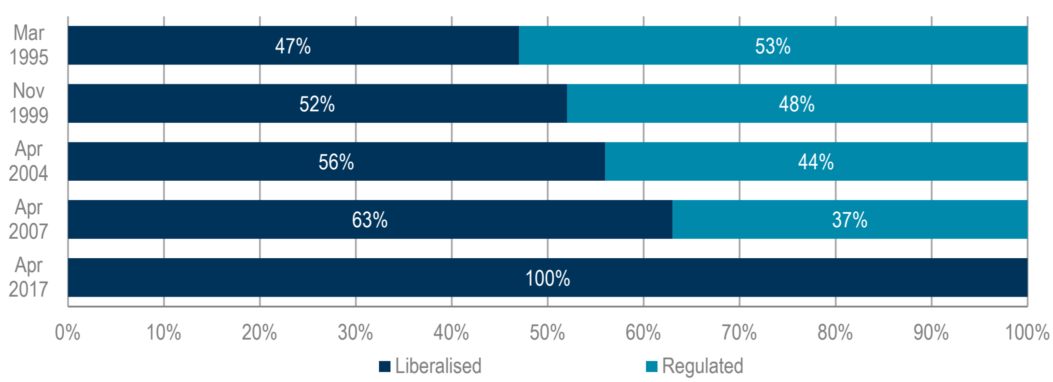


Note: m^3 = cubic metre.

Source: Japan Gas Association (2018), "Information about the city gas business", web page, www.gas.or.jp/kensu/.

The Japanese government therefore started city gas market reforms in phases, from 1995. Gas sales to customers consuming more than 2 million cubic metres per year were liberalised first, and those large-scale industrial users were able to choose their own preferred gas suppliers. Such users are mainly large factories, and the sales volume to those large-scale users totalled approximately 47% of all gas sales volumes in Japan. The new entrant gas suppliers, who were mainly electric power companies and trading houses with access to the infrastructure, could market and sell gas to the large-scale retail market just by registering with the government, while the incumbent city gas suppliers remained as designated gas suppliers to smaller-scale customers.

Figure 1.13 Evolution of gas retail market liberalisation, Japan, 1995-2017



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

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

The Japanese government implemented three more phases of natural gas market reform, in 1999, 2004 and 2007, by expanding the liberalised sale of city gas to customers with consumption of 1 million m^3 per year (such as large commercial facilities), 500 000 m^3 (such as hotels), and 100 000 m^3 (such as smaller-sized city hotels) respectively (Figure 1.13). In April 2017, the Japanese city gas market became fully open, the entire natural gas consumer base being able to select its own gas supplier.

Gas industry reform in 2017 and beyond

This ongoing gas system reform is a part of a broader set of energy system reforms, which include both power and gas systems in an integrated way.

Along with the phases of reforms, the gas suppliers' business structures are in the process of reform, starting from April 2017. The city gas businesses were originally vertically integrated and dominated by three companies, namely Tokyo Gas, Osaka Gas, and Toho Gas, who own about 70% of the physical pipeline network in Japan. These dominant companies were responsible for importing LNG to regasification terminals, pipeline operations and gas retail sales altogether. Under the 2017 reform, the chain of integrated gas businesses will be gradually segmented and restructured into three sectors:

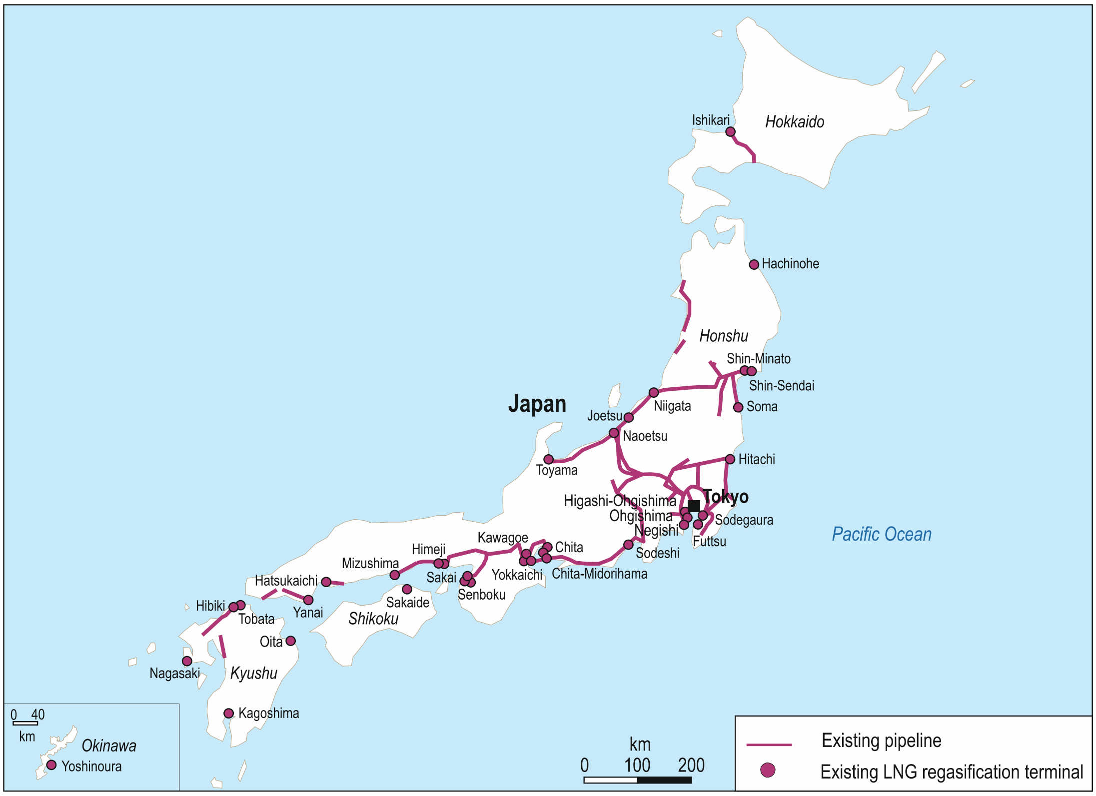
- "Gas manufacturing business", or the LNG terminal business, is a sector which procures LNG for its own regasification terminals and transforms it into gas. This business sector is open to any players; however, with the requirement of upfront infrastructure investment and the technical specialisation of managing LNG and regasified gas, the likelihood of new entrants is considered low.
- The second sector, "Pipeline service business", is where a pipeline service provider operates a pipeline network. The sector is further segmented into "general gas pipeline service business", which operates high-pressure to low-pressure gas networks and supplies small amounts of gas. The other segment, "specific gas pipeline business", is a pipeline service provider operating only high- and medium-pressure pipeline networks, and is regulated differently from "general gas pipeline service business".
- The last sector, "gas retail business", is where gas companies supply and sell gas. From April 2017, consumers were granted the right to source their gas supply from any registered and approved "gas retail business". This is one of the largest implications of the current gas reform, which is to move away from monopoly and to fully liberalise the retail gas market. To meet this target, in principle, the current tariff regulations are no longer imposed on retail companies, or "gas retail businesses". However, the aforementioned three large companies are currently granted a waiver from the reform until April 2022, for further study on the security of gas supply, and are obliged to supply gas subject to tariff regulations as a transitional measure.

Another implication of the reform is the promotion of third-party access (TPA) to gas infrastructure, which includes pipeline and LNG terminals. TPA is to be implemented in phases, starting with LNG terminals. Businesses that own LNG terminals are prohibited from rejecting third-party use without justifiable reasons. This is also applicable to LNG terminals owned by electricity companies and other industries. Under the reform, LNG terminal owners must report and publish their annual utilisation plan and benchmarks of their rate system. If the terms and conditions of use are inappropriate, the government can order changes in the conditions. The separation of pipeline service businesses from the major gas companies (Tokyo Gas, Osaka Gas and Toho Gas) is also targeted by 2022.

Prospects

Since the gas retail market's full liberalisation in April 2017, progress in switching gas supplier has been slow. As of mid-May 2018, 56 companies had registered as new entrants to the gas retail market and 19 out of the 51 had started supplying gas to residential customers, and at the end of April 3.7% of consumers had switched their gas suppliers.

Map 1.2 LNG terminals and pipeline network, Japan, 2018



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

Without a gas wholesale market being established in Japan, new entrants either have to import LNG or purchase regasified gas from existing importers (including electric power companies) to sell on the retail market. As one vessel of LNG could supply 2-3 million households for one month, which would be a challenging initial target number of customers for any new entrant, the purchase of regasified gas is a more realistic option; however, this would affect the competitiveness of the resale price of gas into the retail market as the gas purchasing price would vary from regasified gas sellers without competitive gas wholesale market.

The lack of pipeline interconnection within the country is also an obstacle for the new entrants, as historically the city gas industry was fragmented into vertically integrated regional models with their own distribution networks. Therefore, new entrants have to seek to use the incumbents' pipeline networks, or have their own LNG trucking and small-scale storage facilities for distributing to end customers (Map 1.2). Last but not least, unlike electricity, the retail gas market is highly regulated from a safety point of view. Gas retailers are required to have gas equipment regularly inspected and maintained, which calls for certified engineers and the building of trust with consumers.

Gas reform has liberalised the entire retail market and allowed consumers the right to select their preferred gas supplier; however, the progress of new entrants will require some time.

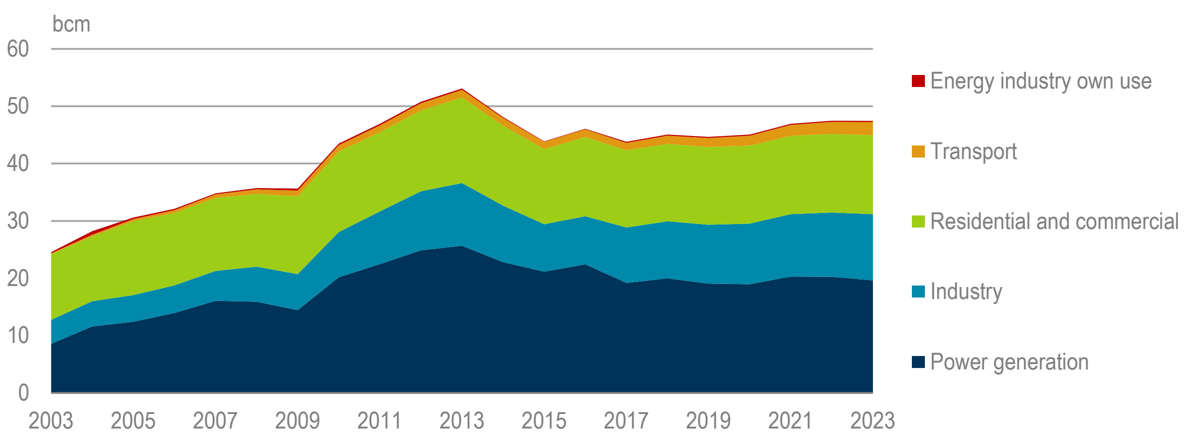
Korea

Natural gas consumption in Korea has shown a slight decrease at an annual average of 1.0% in the past five years, but increased by 2% in 2017 on colder than normal winter weather. LNG imports actually increased 12% last year, mainly driven by long term contracts ramping up, with the difference absorbed by Korea's ample LNG storage capacity. Demand peaked in 2013 when almost half of the gas was consumed in the power sector. Gas consumption in the power sector has slumped since then, declining 2.5% per year on average, as gas power generation was displaced by increased output from new coal-fired generation plants as well as nuclear power.

The residential and commercial sector accounts for roughly 30% of consumption, and this level is expected to continue throughout the forecasted period of 2018-23. The industrial sector, where consumption is led by iron and steel and chemical/petrochemical companies, accounts for 20% and is expected to recover to its previous levels over the forecast period.

The role of gas in the power sector will be influenced by government policy. The change in government in Korea has led to a significant shift in energy policy. In 2017 the Korean government set several demanding measures to reduce fine particulate emissions for the improvement of local air quality. With the target of reducing fine particulate emissions by 30% by 2022, the government imposed the plan in two phases, for imminent and long-term improvement. For the short-term goal, the government ordered the temporary shut-down of five old coal-fired plants in the high-demand season, which is March to June. Under the long-term goal, coal-fired plants aged over 30 years will gradually be closed.

Figure 1.14 Natural gas demand, Korea, 2003-23



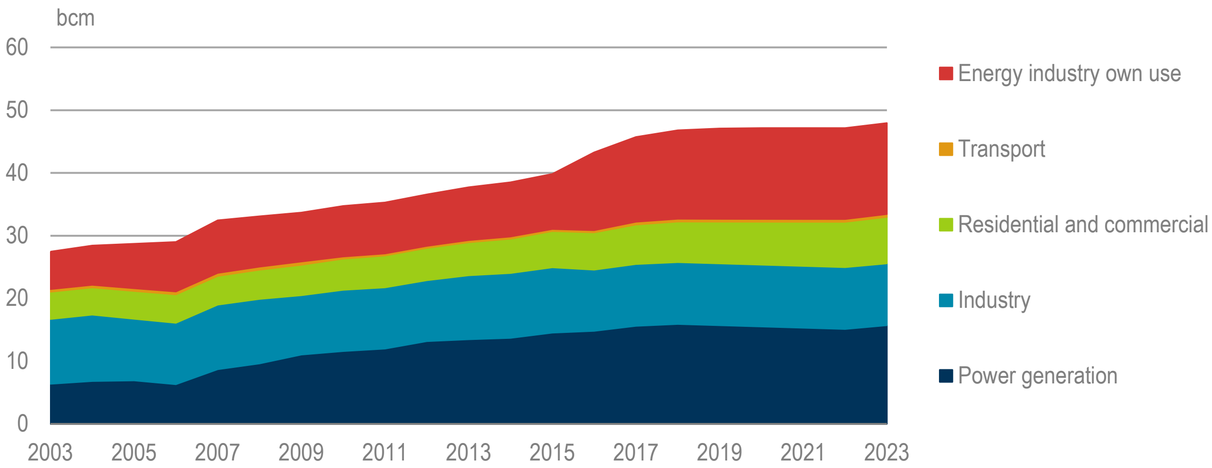
The eighth Electricity Plan for the period 2017-31 was issued in 2017. The plan targets an increase in renewables and termination of ten old coal-fired power plants. Three of these ageing coal-fired plants were closed during 2017, and the rest are scheduled for closure by 2022, totalling 3.3 GW capacity. The government is also targeting the phasing out of nuclear as per the current president's pledge, from a current share of 30.3% to 23.9% by 2030. One small nuclear plant is expected to close during the forecast period. As a consequence, Korea's 13th Long-term Natural Gas Plan, which was issued in 2018, forecasts increased demand for gas. The growth in gas demand is attributed mainly to increasing usage in the power sector. With a slight decrease in residential gas use, the plan predicts Korea's gas demand will reach around 56 bcm by 2031.

As the impact of these plans is likely to be seen from 2025, gas demand for the forecast period of this report has not been substantially affected.

Australia

Natural gas demand in Australia increased by 2.5 bcm or 5.7% in 2017, mainly driven by power generation needs from the energy industry. Over the forecast period, natural gas demand in the industry and residential sectors is expected to stagnate while demand for power generation slightly increases together with the energy industry own use to run the LNG export terminals. The continuous growth of renewables in the power sector continues to put pressure on natural gas, although gas-fired power generation continues to play an indispensable role to meet peak power demand in the country.

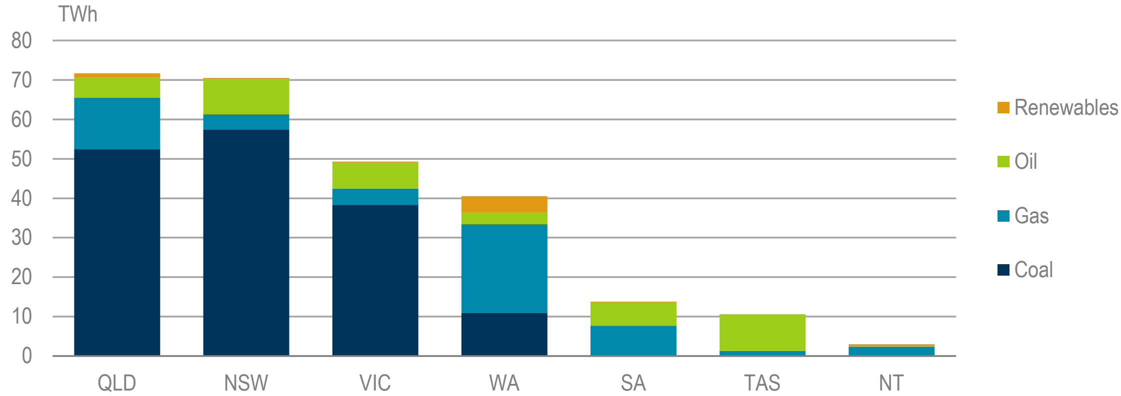
Figure 1.15 Natural gas demand, Australia, 2017-23



With the objective of moving to a low-carbon economy under the Paris Agreement, the high share of coal-fired power generation (63% in 2016) offers significant coal-to-gas switching potential in the three major states of New South Wales, Victoria and Queensland, and to a lesser extent in Western Australia (Figure 1.16). Most coal-fired capacity is expected to be closed between 2030 and 2040 (with about 3 GW closure before 2030 and 7 GW after 2040) and therefore will not influence gas demand over the forecast period. Up to 2023, only the 2.0 GW Liddell coal plant has been announced for decommissioning by 2022. The last plant closed, the 1.6 GW Hazelwood plant in March 2017, increased gas demand for power generation by about 0.3 bcm in Victoria last year (AEMO, 2017; IEA, 2018d).

Recent policies and the Australian Domestic Gas Security Mechanism (ADGSM) target the security of supply of gas and power to the domestic demand market as analysed in the *IEA Energy Policies of IEA Countries: Australia 2018 Review*, *Global Gas Security Review 2017* and *Gas 2017* (IEA, 2018d; 2017e; 2017a). Security of supply concerns are not uniform across the country and significantly differ by state. The state of Western Australia and the Northern Territory gas markets are not connected to the eastern and southeastern gas market, and each market has its own supply-demand dynamic (AEMO, 2017). Higher prices have a dampening effect on natural gas demand, especially in the industrial and power generation sectors, contributing to stagnating demand in the industrial sector.

Figure 1.16 Power generation by fuel and state, Australia, 2017



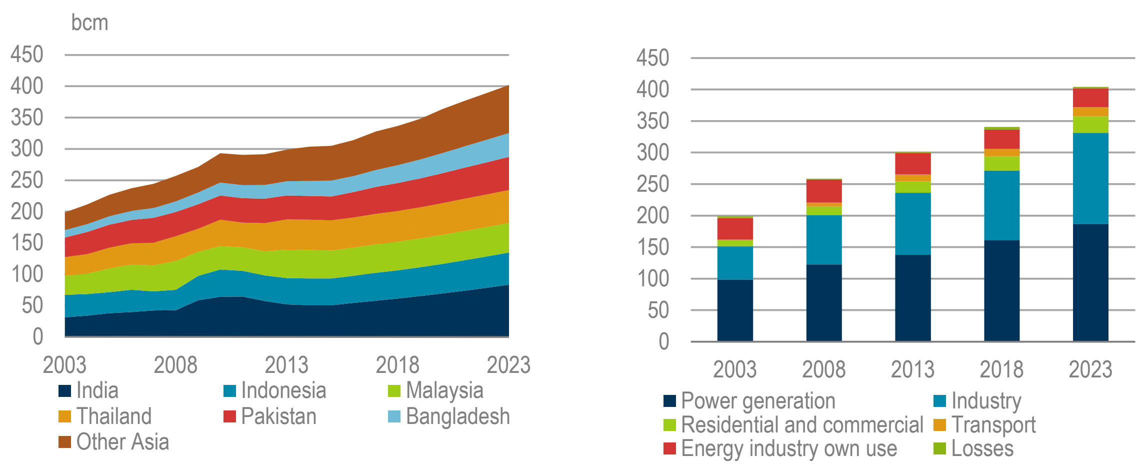
Notes: NSW = New South Wales; NT = Northern Territory; QLD = Queensland; SA = South Australia; TAS = Tasmania; VIC = Victoria; WA = Western Australia.

Source: Department of the Environment and Energy (2018), *Australian Energy Statistics, Table O, April 2018,* www.energy.gov.au/publications/australian-energy-statistics-table-o-electricity-generation-fuel-type-2016-17-and-2017.

Other emerging Asian economies

In other emerging Asian economies (excluding China) natural gas demand continued to show steady growth at a CAAGR of 1.5% during 2011-17, and is forecast to continue the trend throughout the outlook period, reaching 400 bcm/y by 2023 (Figure 1.17).

Figure 1.17 Gas demand by country and sector, other emerging Asian economies, 2003-23



South Asian countries (Bangladesh, India, and Pakistan) are forecast to drive a large part of the increase in natural gas demand in Asia. Southeast Asia – Malaysia and Indonesia in particular – was the area leading demand growth over recent years, driven by steep economic growth in industrial sectors and expansion of power generation capacity. However, this trend of gas demand growth is expected to flatten during the forecast period of 2018-23, mainly due to the expected increase of coal in the power mix. Both Malaysia and Indonesia are faced with strong electricity demand and power mix diversification objectives to reduce the share of natural gas. This translates as phasing out ageing gas turbines and installing additional coal-fired generating units. With the large amount of domestic gas production available, these two countries are traditionally natural gas exporters to neighbouring Asian countries. However, as their domestic gas production has started to plateau and decline in the long run (see Supply chapter), fuel switching for domestic uses is consistent with the strategy of maximising and prolonging the potential for export revenues.

Price sensitivity is higher in these emerging Asian markets than in China or for traditional buyers such as Japan or Korea. Competitiveness of natural gas either sourced from domestic production or imports is therefore a crucial factor to sustain such demand growth. This forecast sees strong growth in emerging Asian markets consistent with established economic growth and price assumptions. Moreover, reforms – including market-based natural gas pricing mechanisms – have been initiated in several Asian countries to open domestic gas markets, and will be needed if importers intend to benefit from the development of more competitive wholesale gas markets (Box 1.4).

Box 1.4 Natural gas pricing and market reforms in Asia

Natural gas pricing based on supply and demand fundamentals (also referred to as "gas-to-gas competition") accounted for 44% of world price formation in 2016, increasing from 31% in 2005 (IGU, 2017). This is more than twice as high as volumes priced on oil-indexed formulae, which represented 20%. Different types of regulated and bilateral pricing mechanisms accounted for 35% of total natural gas consumption. However, the bulk of gas-to-gas competition pricing is in North America and Europe as a consequence of market liberalisation, whereas its share remains limited in other markets. In the Asia and Pacific region, gas-to-gas competition only accounts for 20% whereas oil indexation holds a majority share of almost 55% owing to its preponderance in LNG imports pricing as well as in domestic production pricing mechanisms. In the other regions, market-based pricing mechanisms – relying either on gas-to-gas competition or on oil indexation – still play a limited role compared to overall consumption volumes. Regulated and bilateral pricing mechanisms cover a large majority of demand, accounting respectively for over 50% in Latin America, over 70% in Eurasia, and over 85% in the Middle East and Africa.

This forecast expects that most of natural gas demand growth will come from regions that currently have limited exposure to gas-to-gas competition pricing. In most of these regions, additional supply comes from domestic production or imports from neighbouring countries, pricing rationale could thus remain local and disconnected from international trade price references. In the case of Asia and Pacific, which accounts for 50% of demand growth, the situation is different as international trade (especially LNG) is expected to be a major source of additional supply. The emergence of market-driven natural gas pricing in Asian markets, reflecting natural gas price competitiveness and consistency with supply and demand fundamentals, therefore becomes of greater importance for this region as its weight in international trade increases.

The development of short-term trading in Asian markets followed a dynamic trend over the recent years. LNG spot trade almost doubled in between 2013 and 2017 and experienced an increasing diversification of buyers. This increase of LNG spot trading is a positive and necessary precondition to the establishment of market-driven competitive pricing mechanisms, which, however, also requires a larger set of reforms to establish efficient and competitive market frameworks.

Several Asian markets are undertaking structural reforms, thus enabling recent positive developments toward the establishment of more competitive markets and market-based pricing references:

- **Japan** completed its domestic market liberalisation reform programme (see Box 1.3), enabling the full liberalisation of downstream market as of 2017, the establishment of a Gas Market Surveillance Commission as a regulatory body, and the introduction of transportation unbundling – to be fully effective by 2022. In parallel, the Japan OTC Exchange (JOE), a subsidiary of the Tokyo Commodity Exchange (TOCOM) launched in April 2017 several LNG contracts products, including physical and cash-settled swap derivatives.

- **China**'s strong natural gas consumption growth favoured the development of independent buyers alongside the three NOCs, which own and operate the pipeline network. State regulator NDRC announced in September 2017 a plan to create a national natural gas pipeline company to ensure better access to infrastructure and help developing the use of natural gas. Prices to non-residential end-users are based on a Reference Citygate Price linked to the prices of competitive (oil-based) fuels, which can be adjusted by NDRC through a discount factor – the latest adjustment was in September 2017. Since November 2016, this has been relaxed to allow buyers and sellers to negotiate bilateral prices subject to a cap equivalent to 120% of the Reference Citygate Price. Residential prices are regulated at a local level. Market-based pricing is targeted at 2020 for natural gas as for most components of the economy, as per the October 2015 pricing orientations issued by the State Council (State Council, the People's Republic of China, 2015).

- **Korea**'s natural gas market is regulated as per the Urban Gas Business Act, which grants exclusive selling rights to a single wholesaler, Korean Gas Corporation (KOGAS), and 34 retailers. However, large-scale consumers known as "direct importers" are allowed to import LNG for their own use, only for additional volumes that are not already committed to KOGAS supplies. In 2017 the number of direct importers doubled from four to eight.

- **India** is characterised by regulated prices for both domestic production and for consumption. In recent years, India has taken steps to improve pricing for production, with the introduction in late 2014 of a basket of external market price references to replace the previous administrated pricing system, and the development of a price ceiling mechanism in 2016 to incentivise investment in new specific offshore developments.[*] The Petroleum and Natural Gas Regulatory Board (PNGRB) that oversees natural gas related policies, issued in April 2018 a tender to hire advisory services to launch as natural gas trading hub "*where natural gas can be traded, and supplied through a market-based mechanism instead of multiple formula driven prices*" (PNGRB, 2018). The expected launch of this natural gas hub has been set for October 2018.

- **Singapore** has unbundled natural gas transportation and competitive activities, imports being granted through licences. Transportation activity is ruled by a Gas Network Code, which provides non-discriminatory access to infrastructures. The pipeline import control regime, which prevented new pipeline imports in order to support the build-up of LNG imports, was lifted by the Energy Markets Authority in October 2017. The electricity market, which relies on natural gas for 95% of generation, will be progressively liberalised in 2018 with a soft launch for the Jurong area in April 2018.

[*] This applies to new offshore developments in difficult environments (deep water, ultra-deep water, and high-pressure high-temperature).

India

With the development of new natural gas fields from 2008, which doubled the volume of domestic production, India's consumption showed a large increase with a CAAGR of 9.3% between the years 2005 and 2011. However, India's annual natural gas consumption actually declined at an average of 1.8% or by an absolute volume of 6.8 bcm during the following period of 2011-17, matching a decline in domestic production and increased usage of relatively cheaper coal in the power generation sector.

Today, almost 70% of India's natural gas demand comes from the industrial sector, and mainly for non-energy use as feedstock for fertiliser production. As the country's fertiliser sector is expected to grow in the coming years, backed by a government initiative to encourage self-sufficiency in the fertiliser industry, India's annual natural gas demand is assumed to continue to grow at the rate of 6.3% or by an absolute volume of 25.7 bcm during the period 2017-23, with total natural gas demand reaching over 80 bcm/y in 2023. The government has a strong ambition to double the share of natural gas in the country's energy mix over the medium term through reforms to encourage investment in domestic production (see Supply chapter) and develop additional LNG import terminals. To achieve this goal and address the price sensitivity of end users, the country will need to foster the development of more competitive wholesale gas market (see Box 1.4).

The natural gas share in India's power generation mix is expected to remain limited as the government is strongly promoting green energy sources, such as wind, solar, biomass and hydro.

India started LNG imports in the early 2000s to supplement its growing gas demand, and is expected to increase its LNG imports during the forecast period. LNG import volumes grew by 4% in 2017, owing mainly to growing needs from the fertiliser industry and its competitive import cost. In addition to the four existing LNG receiving terminals located along the west coast, several future terminals are projected for construction, relying on future LNG supply development and increasing flexibility from sellers (Reuters, 2018).

Transport is another source of demand increase. Air pollution has been a major concern for India, and the government is currently seeking ways to cut carbon emissions by promoting usage of CNG, LPG and other alternative fuels to replace diesel and gasoline. As such, LNG is considered suitable for trucks and ships. The dimensioning of relevant LNG fuelling and bunkering infrastructure is currently being planned.

As the natural gas import gap is expected to widen in the coming years, the resulting demand for natural gas and LNG in the key sectors of fertilisers and transport will remain closely linked to the price competitiveness of imported LNG compared to energy substitutes or eventual import of fertilisers.

Pakistan

Natural gas demand in Pakistan increased at a steady average annual rate of 1.6% during the period 2011-17, with an average GDP growth rate of 5.3% in 2017. Consumption is likely to continue to grow, driven by increased usage for power generation and by industry led by healthy economic growth, to reach 53 bcm/y by 2023. Pakistan has so far met its demand requirements with domestic production. However, reflecting the slowdown in new gas field development, delays in completing the Iran-Pakistan gas pipeline project and expected delay in the Turkmenistan-Afghanistan-Pakistan-India pipeline (TAPI), the country started importing gas in LNG form in 2015 to meet demand in power sector. LNG imports are expected to continue growing in the medium term, given the delays in pipeline development.

Bangladesh

Natural gas demand in Bangladesh has been increasing at an annual average rate of 5.4% for the last five years, mainly driven by the power generation sector, which accounts for more than half of all natural gas demand in the country. Natural gas demand for power generation has been rising at a rate of 7-8% annually, led by strong growth in residential and commercial electricity consumption. Industrial demand, primarily fertilisers followed by textiles, has been growing more slowly at an average of 2.4% per year over 2011-17.

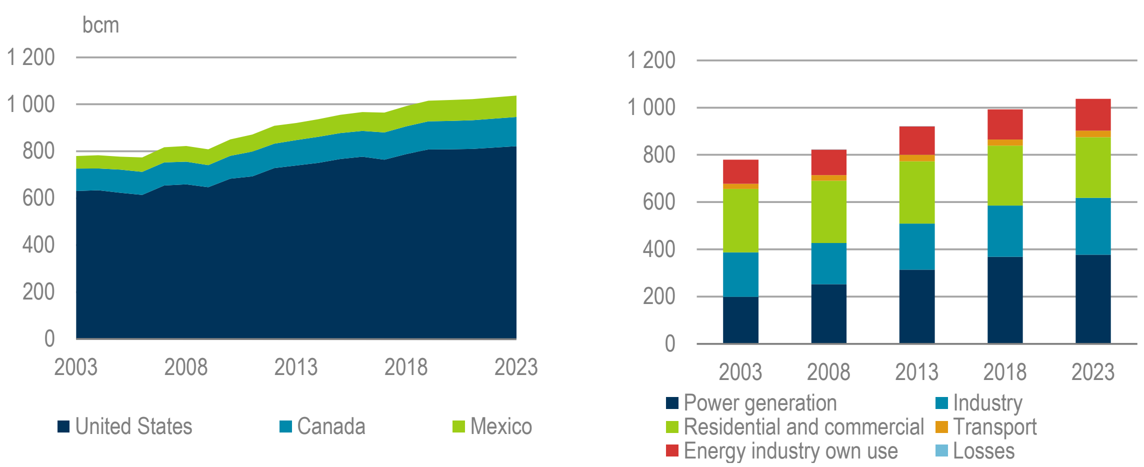
Overall natural gas demand in Bangladesh is forecast to grow at a higher rate during the forecast period, reaching 38 bcm/y in 2023. While the country has small reserves of oil and coal, and has traditionally depended on its natural gas resources to meet its growing demand in the power and industrial sectors, the country is facing the depletion of its major fields. This report forecasts that the strong growth in gas demand is to exceed current domestic gas development in the coming years, thus leading to future import needs.

Bangladesh received its first LNG cargo in April 2018. Imported LNG will be used both to supplement its growing power demand and also to gradually replace oil products for power generation. The government also aims to use imported coal as the future main fuel supply for power generation by 2030, with 19 projects under development. A small number of these projects could enter service by 2023.

North America

Since the shale gas revolution began a decade ago, the North American gas market has grown by almost twice the size of the UK gas market. Between 2007 and 2017, consumption increased by around 150 bcm/y, of which 80% is attributable to an increase in gas-fired power production in the United States. The increasing competitiveness of natural gas triggered a coal-to-gas switch in power generation and also incentivised industry – particularly the chemicals sector – to increase plant capacity where natural gas as a fuel and feedstock source is abundant and relatively cheap.

Figure 1.18 Natural gas demand by country and sector, North America, 2003-23

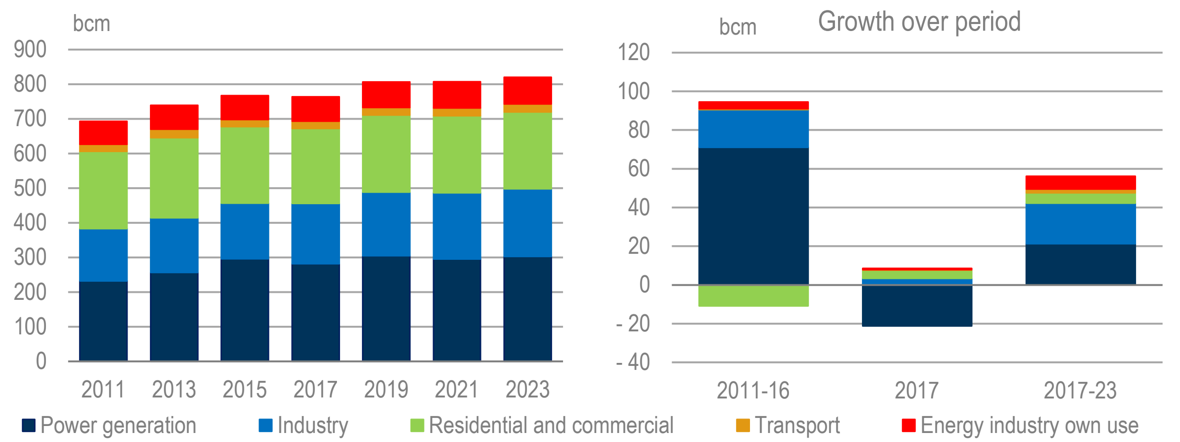


The increase in demand, mainly triggered by the power and industrial sectors, is expected to continue. Between 2017 and 2023, North American gas demand increases by around 70 bcm from 965 bcm to 1 037 bcm. Demand growth is encouraged by low gas prices, as gas associated with expanded oil production in the US Permian Basin keeps gas production levels growing, limited only by the Permian's gas infrastructure.

United States

US gas demand dropped nearly 2% (12 bcm) in 2017, thanks mainly to lower gas use for power generation. Gas consumption for power generation is expected to rebound to 2016 levels, with additional growth is driven by industry (mainly from non-energy use in chemicals) and energy industry own use as a consequence of liquefaction plant development. Annual US natural gas consumption is thus expected to increase by almost 60 bcm over the forecast period (Figure 1.19).

Figure 1.19 Natural gas consumption growth, United States, 2011-23

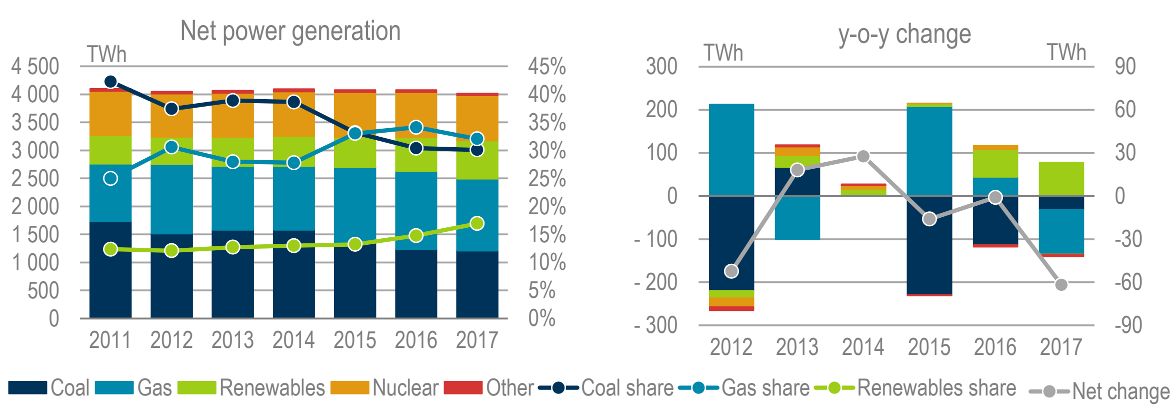


Natural gas will remain the main fuel for power generation

In 2017, total natural gas demand decreased for the first time after seven consecutive years of growth. The drop by 12 bcm from 776 bcm to 764 bcm was related to the power generation sector, where natural gas demand fell by 21 bcm. Total electricity demand decreased by 2% y-o-y, mostly attributable to weather – with a cooler summer leading to less electricity needs for air conditioning – combined with an increase in renewable capacity (see Figure 1.20).

Natural gas remained the first fuel for power generation with a share of 32%, followed by coal (30%), nuclear (20%), and renewables (17%). However, the renewable share is increasing quickly. Renewable generation capacity, mainly solar PV and wind, increases by 101 GW over this period. In 2023, renewables will account for the second largest share of generating capacity and increasing its share of electricity generation from 17% to 22%. (Figure 1.21).

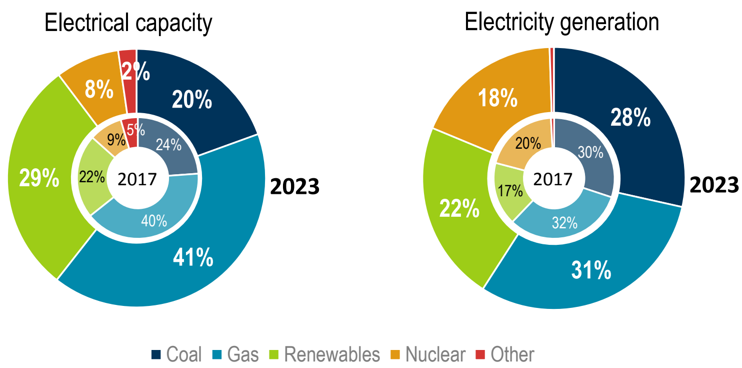
Figure 1.20 Power generation by source, United States, 2011-17



Notes: Left graph: right axis shows share of power generation sources; right graph: right axis shows net change.

Source: EIA (2018), *Electric Power Monthly*, www.eia.gov/electricity/monthly/current_month/epm.pdf.

Figure 1.21 Power capacity and generation mix, United States, 2017 and 2023



Source: IEA (2017c), *World Energy Outlook*, www.eia.gov/electricity/monthly/current_month/epm.pdf.

This forecast expects natural gas consumption for power generation to recover assuming average weather conditions. Growth in the next few years will be sustained by low gas prices relative to coal. After 2020, the continuing growth of renewable power production and meagre electricity demand growth lead to limited growth of natural gas consumption for power generation.

Chemical industry and liquefaction plant own needs drive future gas consumption growth

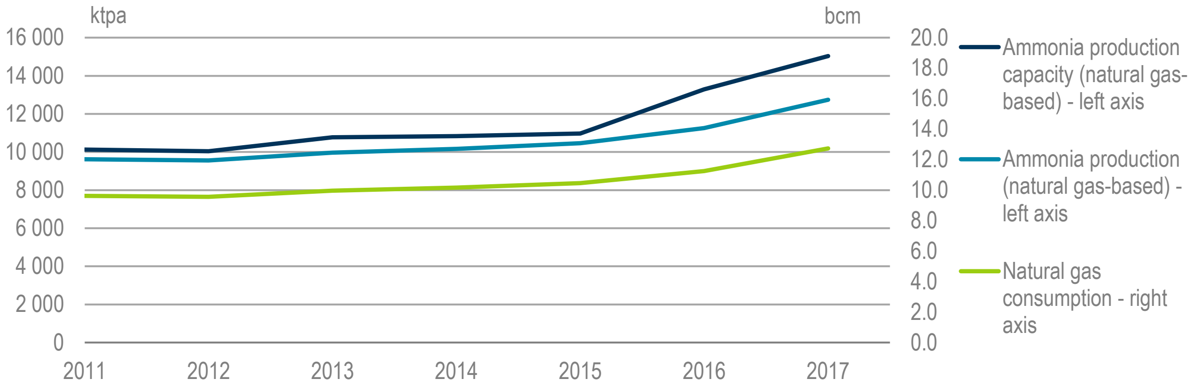
Natural gas consumption in the industrial sector continued its growth in 2017 (up 2% y-o-y), continuing a trend since the beginning of the decade.

The chemical sector is the main industrial user of gas, accounting in 2017 for 75 bcm, or 44%, of total industry demand, including the use of natural gas as a feedstock in the bulk chemicals sector, particularly for methanol and ammonia production.

Ammonia production has been a driver of recent industrial demand growth. Between 2011 and 2017, annual US ammonia production capacity increased by around 5 million tonnes to 15 million tonnes. In 2017 alone, ammonia production capacity increased as several plants started operation including the OCI plant in Lee County, Iowa, a facility with a production capacity of 195 thousand tonnes per year (ktpa), an expansion by Koch Fertilizer in Enid, Oklahoma (150 ktpa) and Simplot's Rock Springs ammonia plant in Wyoming (220 ktpa). Based on a utilisation rate of around 85%, this results in an additional feedstock gas consumption of around 3 bcm, reaching almost 13 bcm in 2017 (Figure 1.22). A higher utilisation rate of up to 100% could further increase natural gas consumption by 2 bcm/y based on 2017 ammonia production capacity. No further ammonia capacity is known to be under development over the forecast period.

Most of the growth in natural gas feedstock consumption over the medium term originates from new methanol production capacity, located in Louisiana and Texas. In January 2018, IGP Methanol announced plans to construct and operate a new four-train methanol facility in Louisiana (up to four-trains with a yearly production capacity of 1.8 million tonnes per train). This report assumes two trains operational until the end of the medium-term period. In 2018, OCI's Natgasoline plant is the next project due to start operation, as progress on construction was largely on track during 2017, despite some delays due to Hurricane Harvey. The four major US methanol plants are expected to increase production capacity by around 8.6 million tonnes by 2023, leading to a maximum feedstock requirement of around 7 bcm (Table 1.7).

Figure 1.22 Ammonia production capacity and gas consumption, United States, 2012-21



Notes: Natural gas consumption is based on IEA assumptions; for conversion purposes, 1 bcm of natural gas feedstock is assumed to produce 1 million tonnes of ammonia. For 2017, a production capacity utilisation rate of 85% is assumed.
Source: IFA (2017), *World Ammonia Capacities 2017*, (database), www.fertilizer.org/.

This forecast expects industry to be the main contributor to future natural gas demand growth, accounting for additional annual consumption of 23 bcm over the 2017-23 period, of which non-energy use for ammonia and methanol production could deliver up to 10 bcm based on nameplate capacity of plants existing and operating under capacity.

The surge in US liquefaction capacity results in additional feedstock gas use over the medium term. About 6 bcm/y of feedstock gas is consumed by 2023 to liquefy natural gas for the global LNG market, based on liquefaction projects already operating and under construction in the Gulf of Mexico and along the US East Coast.

Table 1.7 Methanol production capacity additions, United States

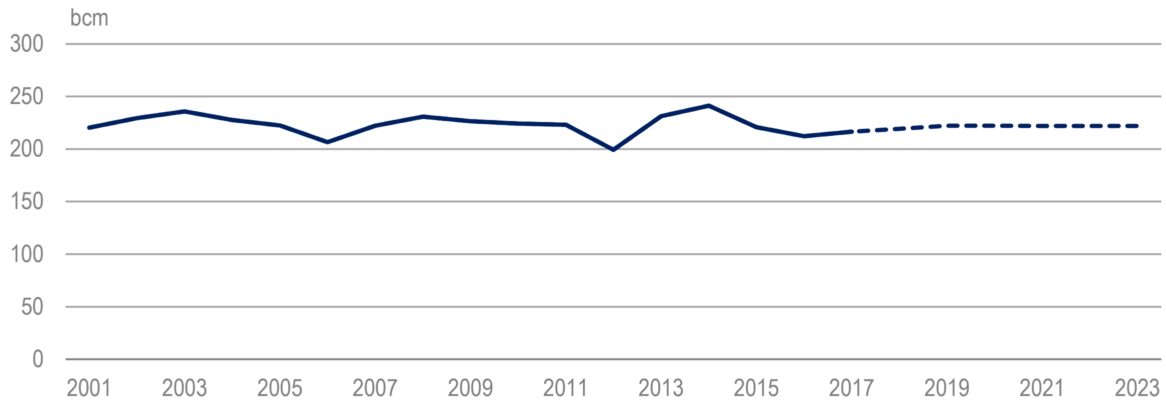
Company	Project	Location	Capacity (ktpa)	Feedstock	Maximum capacity feedstock requirement (bcm/y)	Scheduled year
OCI	Natgasoline	Beaumont, Texas	1 725	Natural gas	1.5	2018
G2X Energy	Big Lake Fuels	Calcasieu Parrish, Louisiana	1 500	Natural gas	1.3	2020
Yuhuang Chemical	YCI-M1	St James, Louisiana	1 800	Natural gas	1.5	2020
IGP Methanol	Gulf Coast Methanol Park	Plaquemines Parish, Louisiana	3 600	Natural gas	3.0	2023
Total			**8 625**		**7.3**	

Source: Compilation based on information from companies' reports and investors' presentations.

Residential and commercial demand resumes its average weather norm

In 2017, gas demand in the residential and commercial sectors grew slightly, by about 4 bcm from around 212 bcm to 216 bcm. It partly recovered from its low level of 2016, which marked one of the warmest winters recorded, but remained under its average over previous years. The sector accounts for around 28% of total US gas demand and is in essence highly temperature sensitive.

Figure 1.23 Natural gas consumption in residential and commercial sectors, United States, 2001-23



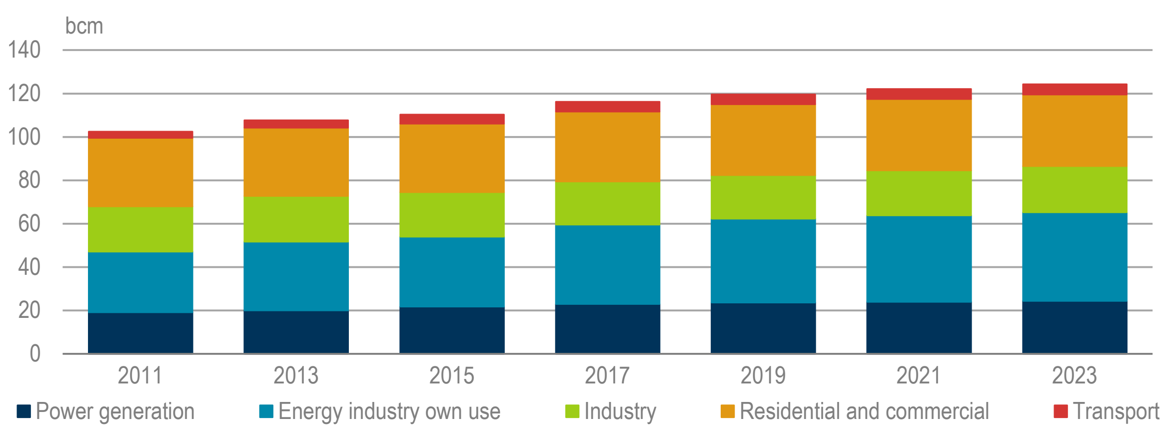
Source: IEA (2017), *World Energy Statistics*, OECD/IEA, Paris, www.iea.org/statistics/.

Data analysis from 2001 shows that, in spite of several outliers caused by warmer or colder winters, the average annual consumption remains stable at around 220 bcm (Figure 1.23) with a limited negative trend of less than 0.5% per annum. This forecast is based on normal winters and thus expects natural gas consumption for residential and commercial use to return to its average annual levels and follow the abovementioned slightly declining trend until 2023.

Canada

Natural gas consumption growth in Canada has been driven mainly by the energy sector's own use over recent years – especially with the development of oil sands production. This trend is expected to continue over the forecast period, whereas demand from other main consumption sectors grows at a slower pace or remains stable (see Figure 1.24).

Figure 1.24 Natural gas consumption by sector, Canada, 2011-23



Canada's oil production is expected to rise from 4.8 mb/d in 2017 to 5.6 mb/d in 2023, an increase of 790 000 barrels per day (IEA, 2018a). Oil sands are the major contributor to growth, driven by projects with long lead times commissioned before oil prices collapsed in 2014-16, but which appear more competitive with the price rebound since 2017. Further increases in oil sands production are expected to drive the energy industry's use of natural gas over the next five years. Energy industry own use is the main component of growth in natural gas consumption, accounting for over 70% of total demand increase to 2023.

The residential and commercial sectors currently account for almost 30% of total natural gas consumption. Demand is expected to grow modestly due to population and economic growth despite improvements in energy intensity.

Consumption in the industrial sector accounted for almost 20% of Canadian natural gas demand in 2017, with a major contribution from chemicals (including non-energy uses), which accounted for 40% of the sector's needs. Natural gas demand from industry is expected to keep growing thanks to the development of the petrochemicals industry over the forecast period, albeit at a slower pace.

Gas demand for power generation (18% of total natural gas consumption in 2017) has grown strongly since 2010, favoured by the development of new gas-fired capacity in Alberta and the phase-out of coal-fired plants in Ontario (completed in 2014). Coal, which currently accounts for 10% of Canada's power generation mix, is to be progressively phased out by 2030 as part of the Pan-Canadian Framework on Clean Growth and Climate Change, Canada's plan to reduce emissions. However, while the Alberta phase out could lead to extensive conversion of coal plants to operate with natural gas, the conversion will be gradual, which, combined with renewables growth, means that gas demand growth will be modest over the forecast period.

Mexico

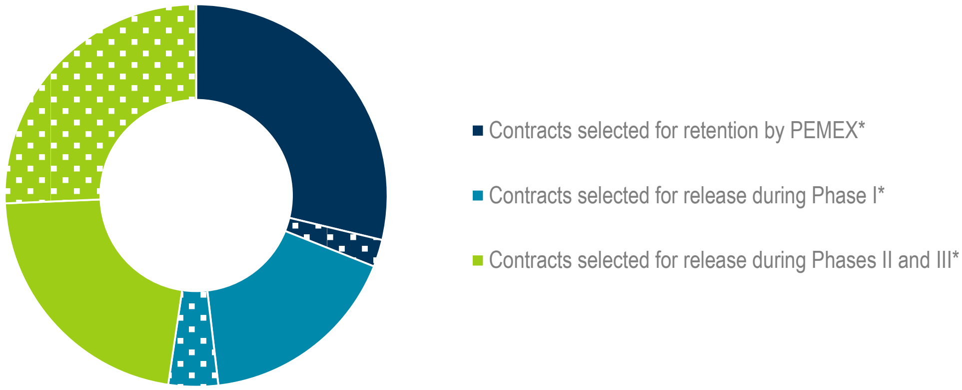
Efforts to develop a competitive gas market in Mexico have successfully supported the steady growth in natural gas demand in the recent years, encouraged by low natural gas prices in the United States and the shift from fuel oil to gas in power generation (IEA, 2017a).

One of the main announcements from the Comisión Reguladora de Energía (CRE), to gradually move away from the previous monopoly-driven system to create a more competitive landscape, was the gas release programme for the Mexican state oil company, Petróleos Mexicanos (PEMEX). The aim of this programme is to reduce the PEMEX gas sales portfolio by 70% over a period of four years. According to the results of Phase I – published by CRE in September 2017 – PEMEX has already released 32.16% of its contracts to other market players (Figure 1.25).

Among the released contracts, around 70% were related to the electricity sector while slightly more than 15% corresponded to industrial activities. On a regional basis, almost 50% of them belonged to the Gulf Area (CRE, 2017a). Phases II and III of the programme are due to be carried out between 2018 and 2019.

In addition to the gas release programme, other recent initiatives to increase competition in the gas market include the decision by CRE to fully liberalise the price of natural gas sold by PEMEX at point of origin, commonly known as first-hand sale price, which was previously regulated by CRE until 1 July 2017 (CRE, 2017b). Additionally, CRE has started to publish the national wholesale price index for natural gas as a means to increase market transparency and enhance information availability (CRE, 2017c).

Figure 1.25 Implementation of the gas release programme for PEMEX, Mexico, Phase I results



*Textured areas account for contracts that have already been released.

Source: CRE (2017a), *Programa de Cesión de Contratos – Resultados Fase I* (Gas release programme – results of Phase I), www.gob.mx/cms/uploads/attachment/file/264996/Resultados_Fase_I_PCC._2017.10.17_V2.pdf.

In this context, this report expects natural gas demand to continue the positive trend seen in previous years throughout the forecast period, growing at an average annual growth rate of 1.3% up to consumption of over 90 bcm/y by 2023 (Figure 1.26).

The increase in natural gas consumption is mainly driven by the development of new gas-fired power generation plants – especially up to 2020 (see Table 1.8) – and the increase in the number of industrial and residential users. By 2023, power generation is expected to represent around 55% of natural gas consumption in the country, while industry overtakes the energy sector as the second-highest consumer of natural gas due to an anticipated flattening in oil and natural gas production and subsequent decrease in production-related natural gas needs.

Figure 1.26 Gas consumption by sector, Mexico, 2011-23

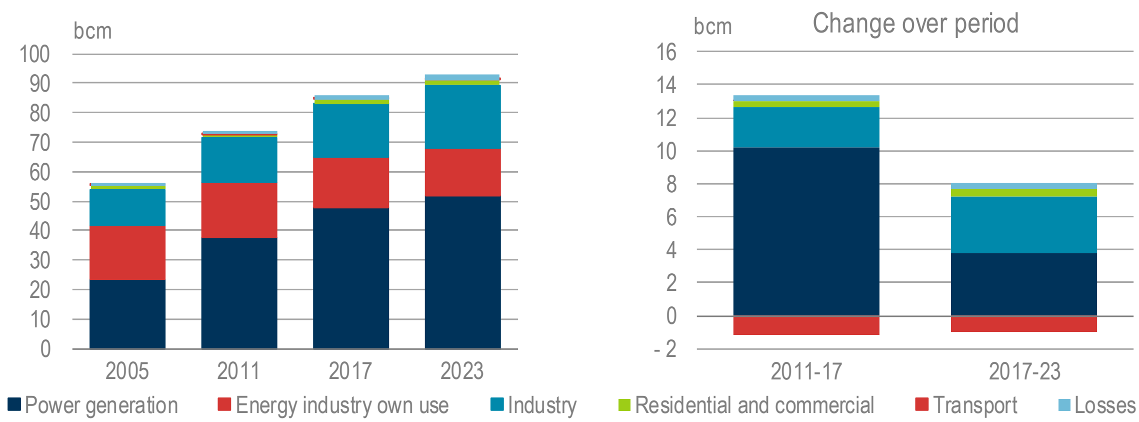


Table 1.8 CCGTs recently commissioned and under construction in Mexico

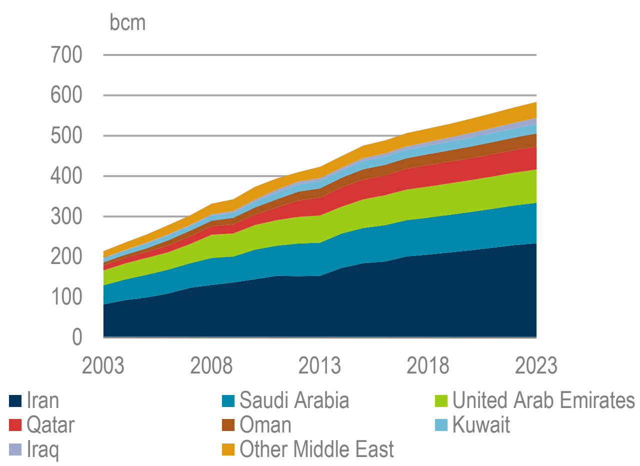
Name/location	Capacity (MW)	Investment (million USD)	Commissioning
Baja California III Ensenada, Baja	294.0	215.6	January 2017
Cogeneración Salamanca	373.1	319.9	March 2017
Centro I Yecapixtla, Morelos	642.3	439.8	April 2017
Empalme I Empalme Sonora	770.2	476.8	November 2017
Valle de México II Acolman, Edo de	615.2	425.3	January 2018
Empalme II Empalme, Sonora	791.2	397.0	April 2018
Noreste El Carmen, Nuevo León	857.2	345.5	July 2018
Noroeste Ahome, Sinaloa	887.3	334.4	January 2019
Norte III Cd. Juárez, Chihuahua	906.7	562.4	June 2019
Total	**6 137.2**	**3 516.7**	

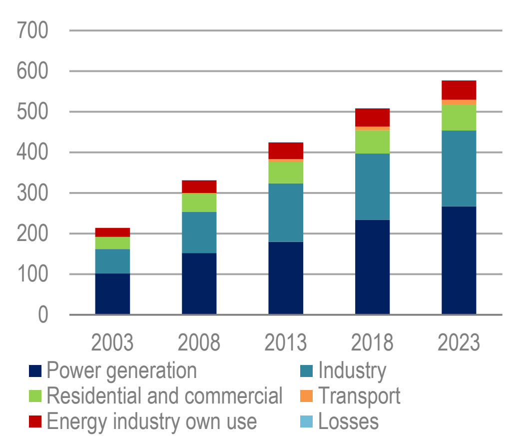
Source: Sener (2018), *Prospectiva de Gas Natural 2017-2031* (Natural gas outlook 2017-2031), www.gob.mx/cms/uploads/attachment/file/302380/PGN_17_FF1.pdf.

Middle East

Natural gas consumption in the Middle East is expected to grow at an average annual rate of 2.5% during the forecast period, with total demand to reach above 580 bcm/y by 2023 from a current level of 500 bcm/y. While almost all Middle Eastern countries are expected to have significant demand growth, Iran – which currently accounts for 39% of the region's demand – has the greatest contribution to growth with an increase of over 30 bcm (Figure 1.27). Saudi Arabia, the second-largest natural gas consumer in the region, sees its annual demand increase by 10 bcm by 2023.

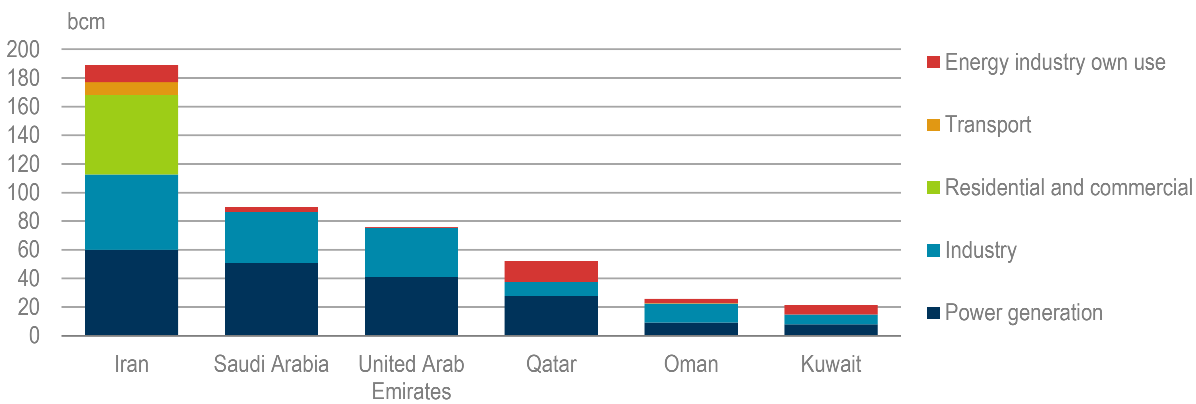
Figure 1.27 Natural gas demand by country and sector, Middle East, 2003-23





The steady increase in demand in the Middle East region is led by growth in power generation needs, including seawater desalination to provide fresh water supply, which accounts for 45% of total demand throughout the forecast period. It is followed by industrial demand at over 30% of total needs, half of industrial consumption coming from the petrochemicals sector. Iran is the only country within the region with diversified natural gas usage, including residential and commercial use accounting for 30% of the country's total gas demand, and a strong fleet of gas-fuelled transport vehicles accounting for about 8 bcm/y of consumption (Figure 1.28).

Figure 1.28 Natural gas consumption by country and sector, Middle East, 2017



While natural gas prices are regulated and heavily subsidised in Middle Eastern countries, some price reforms and targets to phase out subsidies have been introduced in several countries. Iran initiated a targeted energy subsidy reform in 2010, while Oman and Bahrain increased their respective regulated prices in 2015-16. Saudi Arabia, which raised its domestic natural gas price by two-thirds in 2016 with an objective of parity with international prices by 2020, has now extended the parity date to 2021 in light of price caps imposed to soften the impact of austerity measures on the economy. The United Arab Emirates, which liberalised its gasoline and diesel prices in 2015, maintained the level of subsidies for natural gas.

Islamic Republic of Iran

Iran's natural gas consumption grew by 6.6% during the first nine months of the 2017/18 fiscal year (FY) (March to December 2017), mostly owing to power generation needs. Electricity demand increased by 7% over the same period, favoured by highly subsidised prices. Natural gas, which accounted for over 90% of the power generation fuel mix in 2017, has been strongly driven by the switch from gasoil and fuel oil, whose share of the power mix declined from 45% in 2013 to a current 8%. The National Iranian Gas Company stated in January 2018 its objective to phase out fuel oil by the end of the FY (March 2018) and increase gas output for power generation from 62 bcm to 68 bcm between FY 2016/17 and FY 2017/18. The trend is expected to slow down over the forecast period to an annual average of 1.9%, and account for a fourth of additional gas demand to 2023.

The industrial sector currently consumes almost 55 bcm/y. Chemicals and petrochemicals account for half of industrial-sector gas consumption. Production of petrochemicals increased by more than 20% over the last five fiscal years, and by 6% in FY 2017/18 at 53 million tonnes. Over the same period, petrochemicals exports almost doubled to reach 22.5 million tons in FY 2017/18. Room for further growth is ensured by the remaining idle capacity, even though it has decreased from 25% to 16%

over the past five fiscal years. Natural gas demand from industry – and especially the chemical industry – is expected to continue growing over the forecast period at an average annual rate of 2.8%.

The residential and commercial sectors currently account for over 30% of total natural gas consumption, and grew at an average 2.7% over the past five years. They are expected to remain at the same level of growth for the forecast period. Other sectors also contribute to future growth, such as own use in the energy industry, in line with expected growth in oil and gas production capacity (IEA, 2018b).

Saudi Arabia

Saudi Arabia's natural gas consumption is expected to reach 100 bcm/y by 2023 from a current level of 90 bcm/y. The country's gas consumption has grown in tandem with domestic production, and has mainly been driven by the needs of the petrochemicals industry and power generation. Almost half of petrochemicals feedstock requires ethane from associated gas, and petrochemicals processing capacity doubled over the past decade. Electricity needs grew steadily, by over 75% since 2010, with a rising population and industrial growth putting pressure on power generation and leading to the rapid development of gas-fired power stations. Natural gas accounted for over 80% of fuel consumption growth for power generation over the same period.

The role of petrochemicals as a strong pillar of Saudi Arabia's economy has been confirmed in the National Transformation Plan to 2020 and the Vision 2030 policy objectives issued by the government in 2016, both as a core industry and as a base for development in adjacent industrial sectors. Capacity is projected to increase in the medium term, as highlighted by the 1.5 million tonne per annum Jubail steam cracker and petrochemical unit investment announced by Aramco and Total in April 2018 (Bloomberg, 2018). Industry uses account for 40% of natural gas growth over the forecast period, reaching almost 40 bcm/y by 2023. The role of natural gas in power generation is expected to increase further, albeit at a slower pace than previously, with strong power demand and further switch from oil being partially balanced by renewables development and energy efficiency targets. This prospect could, however, be challenged by the wider use of discounted heavy sulphur fuel oil (after IMO specification changes) in the power sector after 2020.

United Arab Emirates

Natural gas consumption in the United Arab Emirates grew at an average of 6% per year over the past decade, mainly driven by power generation use, which currently accounts for around 55% of total gas demand. Electricity needs increased at a rate of 7.9% over the same period, and the share of natural gas in power generation currently stands at above 95%.

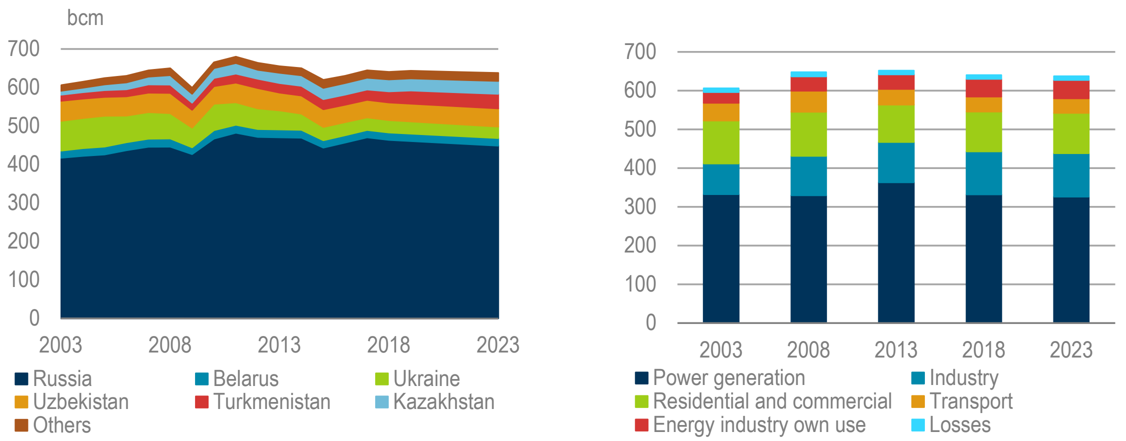
This forecast does not anticipate continuous strong growth in natural gas demand for power generation over the next five years. In spite of foreseen development of power demand, the generation mix is expected to further diversify, notably with the development of the four 1.4 GW reactors of the Barakah nuclear power station, as well as the 2.4 GW Hassyan coal-fired station. New capacity from renewables adds 2 GW by 2022 (IEA, 2017b), mostly from auctions for solar PV and concentrated solar power. The country has set ambitious targets for its long-term renewable development strategy, driven by the Dubai Emirate's objective to reach 75% of power sourced from renewables by 2050.

Natural gas consumption in industry is driven by the petrochemicals sector, with strong growth in output (8.8% in 2016 for the Abu Dhabi Emirate [SCAD, 2017]). Industry is the main contributor to natural gas demand growth over the forecast period, with an estimated 3% average annual increase in gas demand.

Eurasia

Preliminary data indicate an increase in natural gas consumption for the Eurasia region in 2017, owing mainly to an increase in Russian domestic demand. Eurasian natural gas demand is expected to stagnate over the coming years, with slight decreases from Russia and Ukraine being compensated by some growth from Caspian and Central Asian countries.

Figure 1.29 Natural gas demand by country and sector, Eurasia, 2003-23



Russia

Russia's natural gas consumption increased by an estimated 3% y-o-y in 2017 to around 470 bcm (CDU TEK, 2017). This is the second consecutive year of demand increase in the Russian domestic market since the beginning of the decade. It can be attributed to the return to positive economic growth rates, with GDP growth shifting from -0.8% in 2016 to +1.8% in 2017 according to the IMF, impacting primarily electricity demand and generation.

Prospects for medium-term economic growth are expected to remain moderate, slightly below an average of 1.5% per year, thus limiting the potential for natural gas consumption growth. This is particularly the case for the power generation sector (about 25% of natural gas demand currently), where new nuclear capacity and increasing fuel efficiency from the most recent gas-fired power plants are expected to contribute to a decrease in natural gas consumption in spite of overall electricity demand growth. Natural gas use for heat generation (around 30% of current consumption) is expected to increase gradually along with fuel substitution from oil products; yet this effect is practically offset by efficiency gains (providing sufficient investment is made in generation and infrastructure). Residential consumption is supported by gasification policy programmes funded by the Federal Treasury and carried out by Gazprom, which have increased market coverage from 53% to 67% over the past decade, but only led to limited consumption growth (around 1% CAAGR). Residential demand is thus expected to stagnate, with limited growth from future gasification but at the same time limited incentive to invest in more efficient appliances for existing residential customers.

Belarus

Belarus' natural gas consumption mainly relates to heat and power generation, which accounted for 70% of natural gas consumption in 2016 and almost all of the country's heat and power output (BELSTAT, 2017). The residential, chemical (both for energy and feedstock) and other industrial sectors accounted for 10% of natural gas demand each. Economic growth prospects are limited and natural gas market share is already very high, while most of the transmission and production infrastructure has a low level of efficiency, all these factors resulting in an anticipated stagnation of natural gas consumption in the medium term.

Ukraine

Ukraine's natural gas demand decreased in 2017 by an estimated 4% in 2017 to reach 32 bcm (Naftogaz, 2018). Following the trend observed over the past decade, the main negative impacts were seen in the sectors of residential supply (down 6%) and district heating for residential use (down 19%), while industrial demand also decreased (down 6%). Consumption in residential and industry is expected to further decrease in the medium term, leading to an expected CAAGR of around -1.5%.

Uzbekistan

Uzbekistan is the largest electricity producer in the Caspian region at 59 TWh in 2016, of which natural gas accounted for almost 90% of generation. Natural gas is also used by the largely energy-intensive economy with limited efficiency and substantial losses. Power company Uzbekenergo is progressively modernising its ageing generation fleet to increase its efficiency and substitute its last oil boilers with natural gas; the efficiency gains are expected to offset the impact of growing electricity consumption. Consumption from industry, and especially petrochemicals, is expected to increase as announced by UzbekNefteGaz plans to increase its downstream refining and petrochemicals capacity by 2021.

Turkmenistan

Turkmenistan's domestic natural gas consumption accounts for less than half of its production output, and is mainly driven by heat and power generation. In order to diversify its industry, the government commissioned the construction of a petrochemical complex in Kiyanly; the plant, which is due to start operations by the end of 2018, will have a nameplate annual feedstock capacity of 5 bcm of natural gas and will produce polyethylene and polypropylene (Trend News Agency, 2017). In parallel, Turkmengas commissioned the Ovadandepe gas-to-liquids plant, processing up to 2 bcm/y of natural gas feedstock to produce synthetic gasoline, starting operations by the end of 2018 or beginning of 2019.

Kazakhstan

Natural gas only accounts for about 10% of electricity production in Kazakhstan, which is mostly fuelled by coal. Most domestic natural gas use is related to the energy industry, for oil and gas production and refining. With the development of domestic production, the Kazakh government is contemplating plans to develop plants for manufacturing petrochemical products in order to diversify its industrial output and reduce its chemical products imports.

Europe

2017 was the third year of growth in European natural gas demand after the historic low of 481 bcm in 2014. Last year, European natural gas demand totalled almost 550 bcm (Figure 1.30), or 4.5% y-o-y growth. Last year's growth, like 2016's, was driven primarily by gas demand growth in the power sector. Preliminary data suggest that natural gas demand in the residential sector decreased as the number of heating degree days (HDDs) in key European residential markets decreased. Over the forecast period, total European gas demand is expected to decline slightly by 2023. For this report, the European region differs from the formerly used OECD Europe country aggregation.[1]

[1] Europe now includes all EU countries and Albania, Bosnia and Herzegovina, Former Yugoslav Republic of Macedonia, Iceland, Kosovo*, Montenegro, Norway, Serbia, Switzerland and Turkey. *This designation is without prejudice to positions on status, and is in line with United Nations Security Council Resolution 1244/99 and the Advisory Opinion of the International Court of Justice on Kosovo's declaration of independence.

While 2016 saw gas generation increase at the expense of coal, the increase in gas for power generation in 2017 was mainly the result of lower hydro generation (down 53 TWh) coupled with an increase in power demand. This was particularly the case in southern Europe. Figure 1.32 illustrates this dynamic for Italy, France and Spain, where almost two-thirds of the European hydropower generation decrease took place. The continuing competitive stance between coal and gas fired power generation was supported with a y-o-y natural gas price increase of about a fourth, a coal price growth of 40% and a strong y-o-y increase in European Emission Allowance (EUA) (+100%).

Figure 1.30 Gas demand by country and sector, Europe, 2003-23

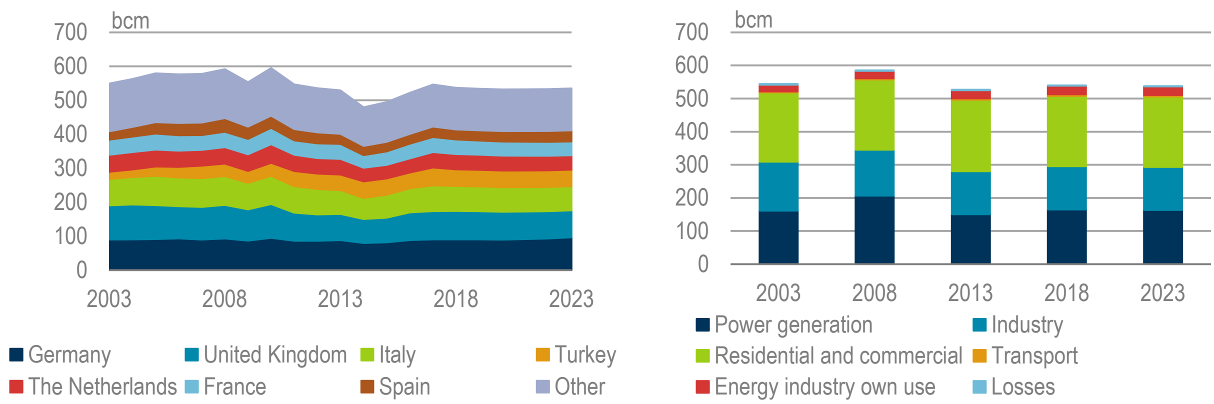
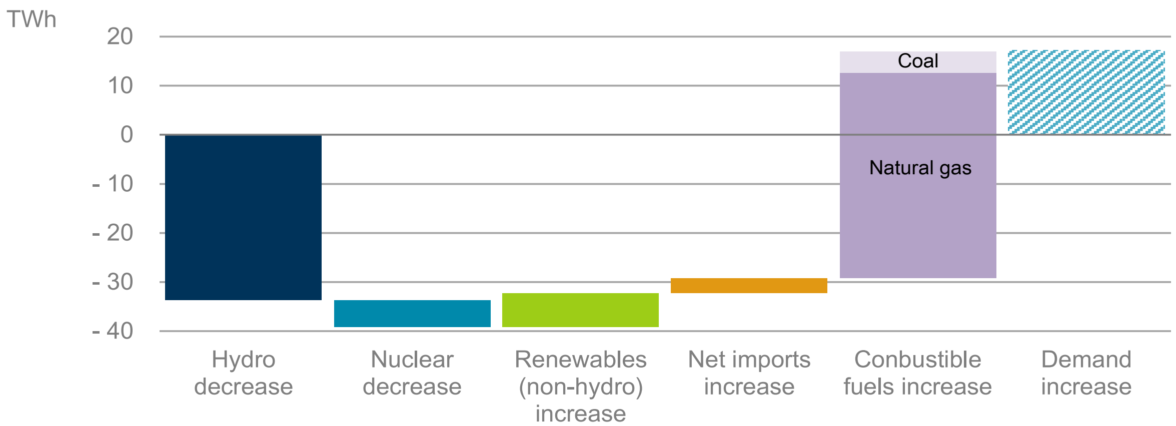


Figure 1.31 Changes in power generation by source, Italy, France and Spain

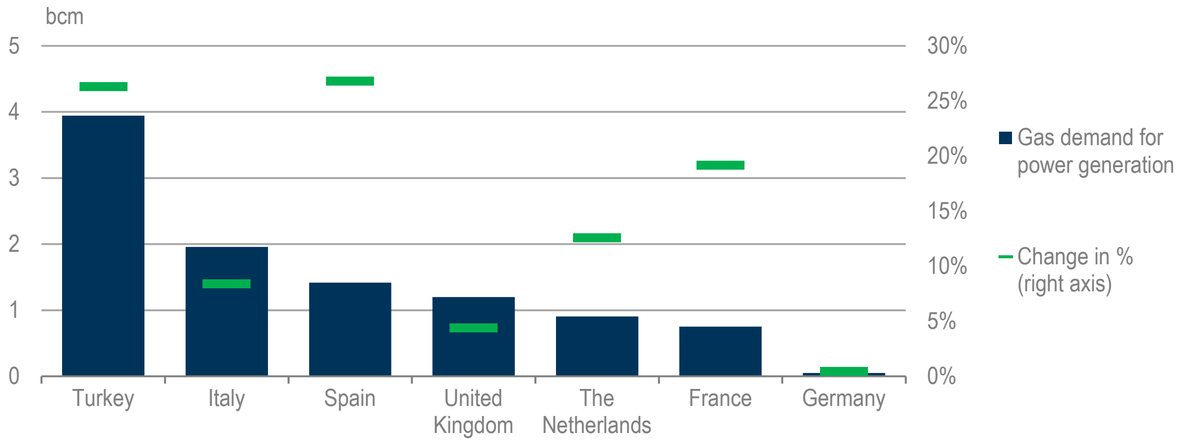


Source: IEA (2018e), *Monthly Electricity Statistics* (database), www.iea.org/statistics/monthlystatistics/monthlyelectricitystatistics/.

Figure 1.32 illustrates the growth in gas demand for power generation in key European countries. Turkey experienced similar conditions (increase in power demand; decrease in hydro), which boosted gas demand for power generation.

As for the residential sector, January 2017 was a cold month and showed a strong increase in gas demand compared to previous years. The month saw a number of demand-supply balance tightening events in southern Europe (as described in the *Global Gas Security Review 2017* [IEA, 2017e]). The other 2017 winter months together (February, March, October, November and December) did not show a strong change in gas demand. Compared to 2016 and to the long term average, 2017 had fewer heating degree days in key European residential heating markets (except in Italy, where it was significantly colder than in 2016). Residential gas demand in 2017 remained lower than the level expected in a normal temperature year. 2017 also showed a 16% increase in cooling degree days in the European Union, which had an impact on power demand for air-conditioning purposes (Eurostat, 2018a).

Figure 1.32 Annual change in gas demand for power generation in key European countries, 2016-17



Source: IEA (2018f), *Monthly Gas Statistics* (database), www.iea.org/statistics/monthlystatistics/monthlygasstatistics/.

Preliminary figures for industrial gas demand indicate growth of about 5 bcm, or 3.5%, which is supported by stronger than previously expected GDP growth of 2.5% in the EU-28 over the whole year of 2017 (Eurostat, 2018b; IMF, 2018).

Up to 2023, natural gas demand is expected to decline slightly. As residential and industrial gas demand remains more or less flat, the main driver of natural gas demand change is found in the power sector, with demand expected to go through a two-step change: a decline over the next three years before recovery towards the end of the forecast period.

The observed growth in gas demand for European power generation over the past three years is not expected to be repeated in the short term. It is rather the result of a succession of one-off events than a change in the underlying market fundamentals and a reversion to the mean is expected this year.

The permanent coal-to-gas switch in the United Kingdom of 2016, the nuclear shutdown and maintenance schedule of one-third of the French power fleet in 2016-17 and the strong hydro decrease in southern Europe in 2017 all pushed up gas demand in the power sector. With French nuclear and southern European hydro expected to return to typical levels, and with electricity demand growing slowly and renewables on the increase, gas for power generation has no room to grow in 2018-20.

The situation is expected to change in the period 2020-23 thanks to the planned German nuclear phase out. The lost electricity production from the retirement of 10 GW of nuclear capacity is much greater than the anticipated renewables growth in that period. Gas and coal power generation are expected to fill the gap when renewables generation growth falls short, in response to the step-change loss of generation when a nuclear plant is shut down. Government policies to phase out coal or nuclear generation in other countries can also be expected to affect gas demand for power, albeit mostly towards 2025-30 (see Box 1.5).

Box 1.5 Coal and nuclear phase-out plans in Europe

Coal phase-out strategy announcements in Europe

After the Paris Agreement of 2015, policies to phase out coal-fired power generation has gained momentum in several European countries with several governments announcing their intention to terminate coal-fired power generation. Many of these announcements are part of mid- to long-term national energy strategies and have not become policy or legislative measures at the time of writing. From another perspective, coal-fired power plant economics are under pressure from low wholesale electricity prices, low load factors from increasing variable renewable generation, and increasingly stringent emission standards under the EU Industrial Emissions Directive.

The United Kingdom has significantly reduced power generation from coal by introducing a national carbon price floor. While 12 GW of coal capacity is still operational in mid-2018, these plants mostly remain idle due to unfavourable economics compared to other power generation sources. The UK government has announced its intention to introduce legislation that would eliminate unabated coal-fired generation by 1 October 2025. The Netherlands is considering a similar carbon price floor measure as a driver for coal plant closures by 2030. France announced a coal phase-out target year of 2022/23 and is pushing for an EU-wide carbon price floor. Austria, Ireland and Italy have all announced plans to phase out coal by 2025, and Denmark, Finland, the Netherlands and Portugal have announced 2030 as their coal phase-out target. Companies in Austria and Denmark have announced earlier shutdowns of their coal-fired power plants and Belgium closed its last coal power plant in 2016.

The case for Spain remains unclear; so far the government's position is to keep open coal-fired power plants, while a number of operators plan to shut down a large part of their coal fleet. Germany, with the highest coal-fired power generation capacity in Europe, may announce an end date for coal-fired power generation at the start of 2019. This decision is a key uncertainty because any advancement in coal plant closures in combination with the nuclear phase-out is expected to have a significant impact on the position of gas in the power generation mix.

At the other end of the spectrum reside notably Turkey and Poland, plus a number of other countries. Turkey is planning to increase its coal-fired power generation, which has the order of magnitude to offset a significant part of the announced closures in other European countries. Poland, traditionally almost fully dependent on coal-fired power generation, is expected to remain heavily reliant on coal-fired power generation. The Czech Republic, Hungary, Greece, Romania and Bulgaria have no phase-out plans either.

As almost all coal phase-out plans remain announcements with a 2025 or 2030 target date at the time of writing, and no actual policy framework or legislative measures are in place, the impact on the gas-versus-coal equation in the power system up to the 2023 is difficult to assess. Political commitment to coal closure and increasingly stringent emission standards on the horizon both reduce the likelihood of recovering any investment in the refurbishment of coal-fired power plants. While renewable capacity expansion continues, gas-fired power generation is expected to increase by the time coal-fired power plants are pushed out of the generation mix (while perhaps remaining available as back-up).

Nuclear phase-out strategies Europe

The only country in Europe that has set a binding timeframe for the closure of each individual nuclear power plant is Germany. German nuclear power generation is set to be completely phased out by the end of 2022. Also significant is Belgium's federal energy strategy aimed at phasing out its 5 GW nuclear power generation capacity by 2025, which generated an amount equal to 55% of German nuclear power generation in 2017. The French nuclear fleet, generating about 75% of French power demand and having an important position in the European system, is likely to become subject to a 2030-35 capacity reduction target timeline, rather than 2025 as announced previously by the French government. Other countries have expressed the ambition to become nuclear-free with a more distant timeline beyond the timeframe of this report's forecast.

Germany

Germany stands out as the country with the highest natural gas demand for industrial use in Europe, representing 20% of the European total. While European GDP growth forecasts for 2017-21 were rather moderate in 2016 and 2017, last year Europe displayed strong economic growth, notably Germany at 2.5%. Although German natural gas demand for industrial use had been stable in recent years, GDP growth appears to have driven it up again in 2017. This is different from the trend observed in previous years in Germany and in Europe, when power demand and gas demand for industrial use stagnated while GDP growth continued at a moderate average rate of 1.3% (IMF, 2017).

For the forecast period, German natural gas demand is expected to grow by 1.1% CAAGR. The primary reason is the country's nuclear phase-out, with nuclear plant closures in 2019 (1.5 GW; Philippsburg 2), 2021 (4.3 GW; Brokdorf, Grohnde and Gundremmingen 2) and in 2022 (4.3 GW; Emsland, Neckarwestheim 2 and Isar 2). Nuclear plants run with a high load factor (97% in 2015) fulfilling a baseload generation function, and they represented 11.5% of German power generation in 2017 (IEA, 2017f; IEA 2018c). With the phase-out of nuclear generation, a large amount of baseload capacity has to be supplied by other sources in the generation mix and is likely to influence cross border electricity flows.

In Germany, baseload power generation is composed of nuclear, coal, renewables and, to a lesser extent, by natural gas. Peak-load power generation is determined by the gap between peak demand and renewable generation, filled by non-baseload coal and gas according to the merit order. Assuming an annual growth rate of 4.5% in renewables capacity (IEA, 2017f) and the average load factor of the German renewable fleet, renewable generation is not expected to fully replace the baseload gap left by the step changes of the nuclear phase-out up to 2023. Gas and coal are therefore expected to increase their market share by 2023 in the competition for more variable generation. The increasing power system dependence on variable generation by coal and gas is likely to be amplified by the north-south power transmission constraints. In situations when high levels of renewable generation in the north cannot be fully transported to the south due to transmission capacity constraints, grid operators are forced to redispatch (less conventional in the north because renewables have grid priority and more conventional in the south to compensate for the northern power that cannot reach the south) in order to balance supply and demand in both regions.

United Kingdom

Contrary to the strong y-o-y demand growth of 2016, 2017 did not bring significant changes in natural gas demand in the United Kingdom. There is hardly any further room for gas to grow because coal was largely pushed out of the generation mix in 2016 thanks to a rise in the carbon floor price, while demand in other sectors is stagnating. The current 12 GW of coal-fired power capacity is not mothballed but operates relatively little. Most of the capacity is expected to be retired by the early 2020s with the rest retiring before the end of 2025. Despite this, gas demand for power is actually expected to decrease, with an average of -0.8% per year, assuming normal temperature conditions, moderate GDP and power demand growth, and continuation of the ongoing growth in renewable power generation.

Italy

Italy is the third-largest natural gas consumer in Europe and consumption in 2017 grew by almost 5 bcm to 76 bcm. The power generation sector's demand of 29 bcm in 2017 stands above Germany (21 bcm) and just below the United Kingdom (31 bcm). In 2017, power-sector gas demand increased by 2 bcm. With 6% more HDDs in 2017, gas consumption in the residential sector increased to the level associated with average temperature levels. It is expected to remain at that level, assuming that average temperatures are seen each year.

As in most southern European countries, hydro generation decreased sharply in Italy in 2017 (down 5 TWh or 11%). In combination with the increase in power demand (up 10 TWh or 3%), non-hydro renewables output growth of 2 TWh, and 0.7 TWh increase of net imports, this created a power balance gap of 12 TWh (or 3.7% of total power demand) to be closed by thermal generation (natural gas and coal). Over the forecast period, gas-fired power generation is expected to decrease again in the initial years, rebalancing for average hydro generation and increasing renewable generation. Towards the end of the forecast period, the Italian plan to phase out coal by 2025 as part of the National Energy Strategy 2017 (ratified by the government in November 2017) is expected to create some space for gas-fired power generation to grow again amidst the steady expansion of renewable capacity and the growth in power demand.

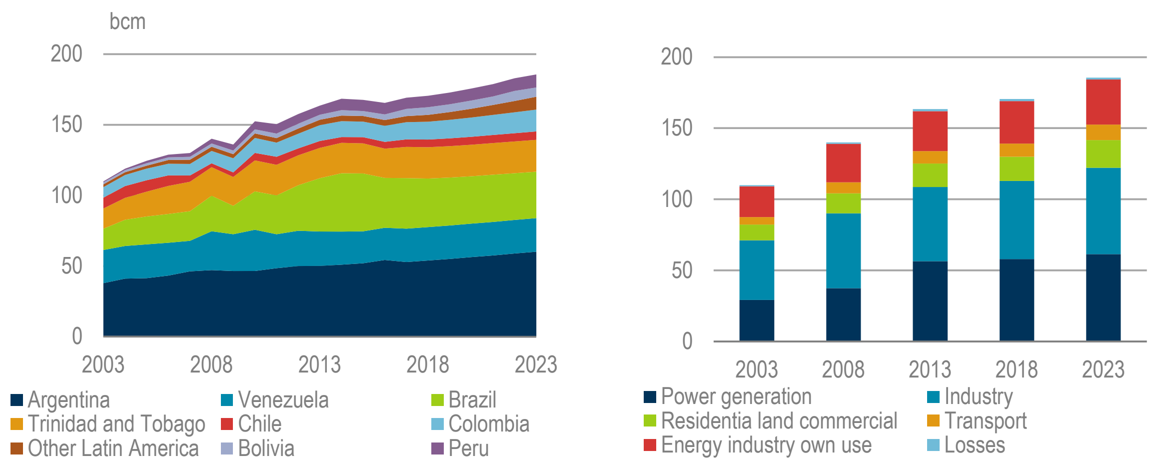
Latin America

Natural gas consumption in Latin America is expected to grow at an average annual growth rate of 1.6% over the forecast period, from nearly 170 bcm/y in 2017 to 186 bcm/y by 2023.

Energy reforms to increase efficiency and to implement liquid and well-functioning gas markets are supporting demand growth over the forecast period – especially in the industrial sector (in absolute terms) owing to better economic prospects.

At a country level, Argentina leads the increase in natural gas demand, confirming its position as the largest gas market in the region. By the end of the forecast period, Argentina's demand is expected to almost double that of Brazil (the second-largest consumer in the region) due to an anticipated decrease in gas consumption for power generation in Brazil.

Figure 1.33 Natural gas demand by country and by sector, Latin America, 2003-23

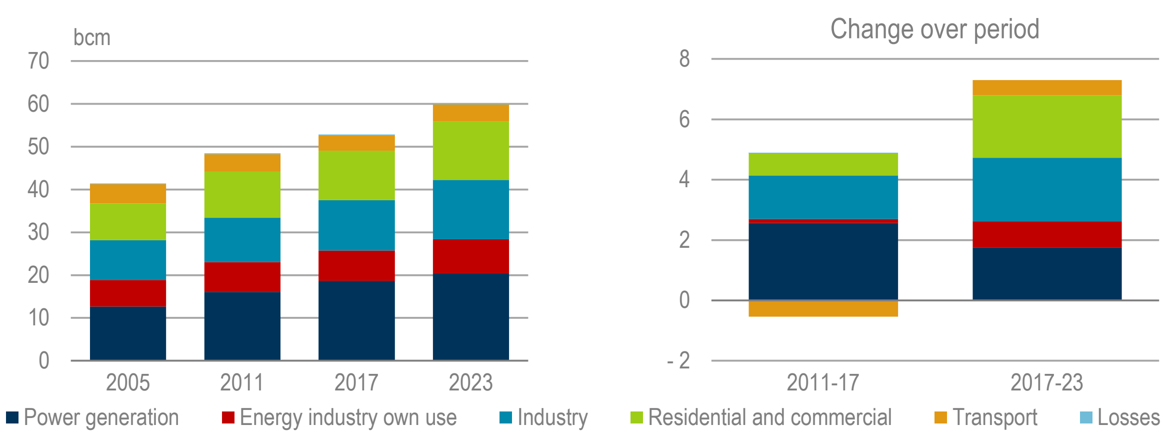


Argentina

Argentina is the largest natural gas consumer in Latin America. Natural gas demand in the country is highly seasonal, especially in the residential sector, peaking during the Southern Hemisphere winter when cold temperatures boost demand for heating.

Natural gas demand has grown continuously in the country in recent years, with a slight slowdown during the period 2011-17, when it experienced an average annual growth rate of 1.5%. This report expects natural gas demand to increase at a faster pace during the forecast period to reach 60 bcm by 2023, owing to the development of domestic production. This will represent an average annual growth rate of 2%. The increase in gas demand is mainly driven by the industrial and residential and commercial sectors, while gas demand for power generation is assumed to grow at a slower pace (Figure 1.34).

Figure 1.34 Natural gas consumption by sector, Argentina, 2011-23



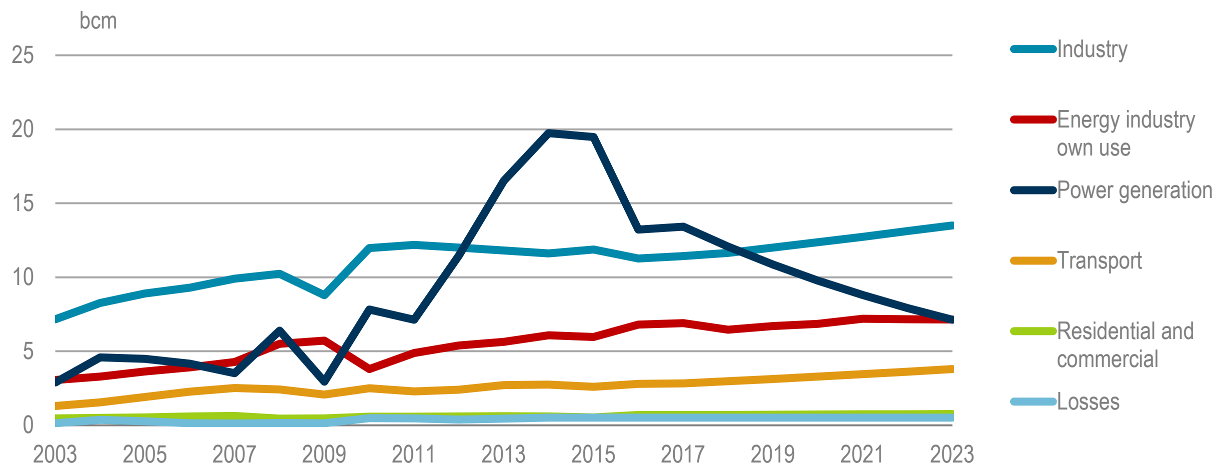
The country is undergoing several reforms and Mauricio Macri's administration is expected to continue with the anticipated roadmap to gradually reduce gas price subsidies to improve gas market efficiency (IEA, 2017a). In this regard, Argentina's Minister of Energy and Mining, Juan José Aranguren, announced in late March an average increase in natural gas tariffs of 32% from April 2018 onwards. The declared increases ranged from 28% for major consumers to 40% for small consumers, while in the Patagonian region – the coldest area in the country – increases vary between 29% and 36% (EFE, 2018). The recent currency crisis experienced by the country could however challenge the path of reforms and the forecasted demand growth.

Brazil

Industry has historically been the main gas consumer in Brazil, while power generation has traditionally relied mostly on hydropower. However, the severe hydro shortages experienced in the country in recent years – especially between 2012 and 2015 – boosted natural gas demand for power generation, which became the largest gas-consuming sector in that period (Figure 1.35). Nevertheless, the addition of new renewable capacity in the upcoming years (IEA, 2017f) is expected to squeeze natural gas demand for power generation to almost half the current level by the end of the forecast period.

Despite the decreasing share of natural gas in Brazil's power generation mix, the increase in intermittent renewable generation, i.e. wind and solar among others, will also require additional thermal generation capacity to provide flexibility and assure security of supply. In this respect, the "A-6" power auction that took place in December 2017 was the first to implement new rules designed to support the development of new gas-fired power generation.[2] Thanks to the new specifications, two gas-fired thermal projects were awarded a contract to supply electricity from January 2023 onwards, totalling 2 140 MW at an average price of USD 64.7 per megawatt hour (EPE, 2017). Of the awarded projects, one will be fed by domestic offshore gas production, while the other will be based on an integrated solution combining CCGTs with dedicated floating storage and regasification units (FSRUs), commonly known as LNG-to-power projects.

Figure 1.35 Evolution of natural gas consumption by sector, Brazil, 2003-23



[2] The new rules incorporate key recommendations from the Gas to Grow programme to increase synergies between the natural gas and electricity sectors. One of the main changes allows generators to declare seasonal changes in inflexible supply obligations, resulting in lower natural gas prices.

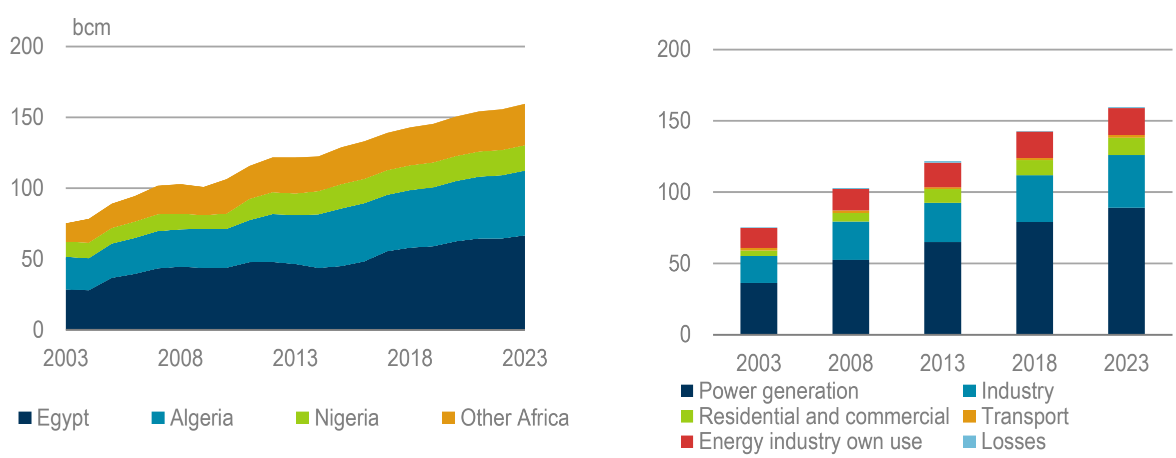
In its January update, the IMF projected Brazil's GDP to grow by 1.9% in 2018 and by 2.1% in 2019 (IMF, 2018). This recovery of the Brazilian economy is expected to continue throughout the forecast period, having a positive impact on gas demand in the industrial sector. Thus, industry is assumed to overtake power generation again as the major gas consumer in the country in the upcoming years (Figure 1.35).

In addition to the better economic outlook, the country is expected to keep pace with its Gas to Grow programme launched in 2016, which aims to support natural gas production and demand by developing a market-oriented regulatory framework that includes regulated third party access (TPA) to the transmission system and LNG facilities, and the definition of entry-exit zones with liquid virtual trading points. Underpinned by these reforms, natural gas demand is expected to grow in every sector besides power generation. However, this increase will not be enough to compensate for the decrease in gas demand for power generation and overall annual demand for natural gas is expected to decrease by nearly 3 bcm by 2023, an average annual rate of 1.4%.

Africa

Africa's natural gas consumption is expected to grow at an annual average of 2.3% for the forecast period, rising from almost 140 bcm/y to 160 bcm/y by 2023 (Figure 1.36). North Africa remains the main source of growth, particularly Egypt, which is boosted by the development of its domestic production and the prospect of returning to self-sufficiency. Power generation remains the main driver for consumption growth, both in North African and sub-Saharan markets. While future growth in natural gas consumption appears to be at hand in several sub-Saharan African countries with the development of LNG import terminals, this report judges that their impact may take some time before materialising and hence will not be visible in the next five years.

Figure 1.36 Natural gas demand by country and sector, Africa, 2003-23



Egypt

Egypt is the largest natural gas-consuming market in Africa, seeing steady growth in recent years (up 7% in 2016). The power generation sector is the main driver of growth in demand for natural gas, with strong increases in electricity consumption and natural gas-fired plants accounting for more than 70% of power generation output. According to state-owned Egyptian Natural Gas Holding Company (EGAS), power generation accounts for 57% of Egypt's natural gas consumption (Figure

1.37). Within industrial demand (accounting as a whole for 28% of natural gas consumption), fertiliser production plays a dominant and strategic role in supplying domestic agriculture. The oil and gas industry itself accounts for 10% of the total domestic consumption.

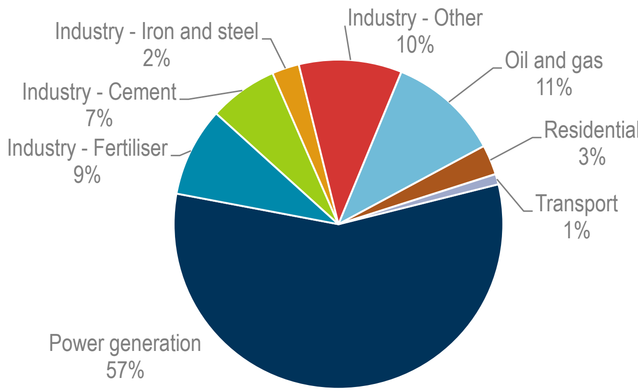
The commissioning of new production capacity, including the giant Zohr offshore field (see Supply chapter), has encouraged the Egyptian government to support development of the domestic natural gas market. Under a new Gas Market Law, signed by President Abdel Fattah El-Sisi in August 2017 but still pending implementation at the time of writing, private companies would be authorised to import natural gas as a means of reducing risk of shortages. It would also introduce TPA to infrastructure to accommodate this additional supply by private companies. An independent regulatory body is also expected to be created to oversee the domestic natural gas market and issue licences for the import, transporting and marketing of natural gas.

This forecast assumes that domestic consumption increases in the next five years at an average rate of over 3% per year, higher than the 2.5% annual average observed over the past six years. This future growth is sustained by a dynamic power consumption trend and the reforms to liberalise and incentivise flexibility in the domestic market.

The main driver of future growth is the power sector. Three new high-efficiency CCGTs are currently under construction and expected to be commissioned in 2018. The three plants, located in Beni Suef, Burullus and New Capital, will be the largest gas-fired power generation assets in the world, delivering altogether 14.4 GW of capacity to the Egyptian grid, or an increase of more than 40%, as well as a substantial improvement in average efficiency of the power generation fleet. Egypt is also looking for power diversification through the development of renewables, with a target to raise their share to 20% of the power mix by 2022; the country held its first competitive solar auction in December 2017.

Additionally, gas consumption is expected to grow in the chemical industry as the government wants to reduce imports of petrochemical products, as well as in the residential sector where an expansion programme to connect up to an additional 2.5 million households by 2020 is currently under way.

Figure 1.37 Sectoral breakdown of natural gas consumption, Egypt, 2016



Source: EGAS (2018), “Local gas consumption”, www.egas.com.eg/Egyptian_Natural_Gas/Local_Gas_Consumption.aspx.

Algeria

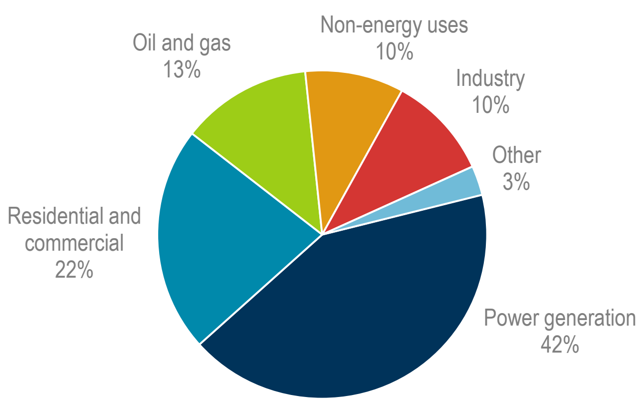
Power generation is the main consumer of natural gas in Algeria, accounting for 42% of domestic demand in 2016 (Figure 1.38), with 95% of power generated from natural gas. Algeria's natural gas consumption has remained relatively flat for the past three years after a decade of steady growth, as electricity demand stagnated.

The state-owned electricity production and distribution company Sonelgaz, in charge of electricity and gas distribution, has carried out development programmes for both networks ensuring coverage of 99% of the population for electricity and 59% for natural gas. As a consequence, the residential and commercial sector is a strong component of Algeria's natural gas consumption, taking almost a quarter of total demand.

The oil and gas industry accounted for 13% of domestic needs, with an important share driven by liquefaction plant own consumption, whereas industry took 10%, mainly in the construction sector. Non-energy use of natural gas saw its volume increase over the recent past with the development of petrochemical activity and the ramping up of ammonia and urea production at the Arzew plant.

Natural gas already has a dominant share of Algeria's energy mix and this is expected to remain stable or slightly decrease in the future with the development of renewables for power generation. As a consequence, natural gas consumption is expected to grow at an annual average rate of 2.3% in the 2017-23 period, from a past average rate of 5.0% over the last six years.

Figure 1.38 Sectoral breakdown of Algeria's natural gas consumption, 2016



Source: Algerian Ministry of Energy (2017), *National Energy Balance 2016*, www.energy.gov.dz/francais/uploads/2017/Bilans_et_statistiques_du_secteur/Bilan-Energetique/Bilan_Energetique_National_2016_edition_2017.pdf.

Nigeria

Power generation is the main component of natural gas consumption in Nigeria, accounting for 40% of current demand; energy sector own use and the industrial sector (mainly related to oil and gas) account for 35% and 25% respectively. Nigeria's national oil company, the Nigerian National Petroleum Corporation, set an assertive target in 2015 to double domestic gas demand by 2020 in accordance with the country's gas master plan. This task implies a massive extension of the domestic pipeline network in order to bring supplies to the relevant consumption areas, while dealing with the recurrent threat posed by sabotage attacks on infrastructure. As of today, the frequent power outages and lack of electricity production and transmission capacity are major issues to solve in order to ensure sustainable growth. The developments needed to overcome such shortcomings will require some time, and consequently there is no expectation of any visible growth in Nigeria's natural gas consumption in the coming five years.

Other West Africa

The use of natural gas is expected to develop in West Africa over the longer term, mainly as a substitute for oil products in power generation. After Nigeria, Côte d'Ivoire is currently the main consumer of natural gas in West Africa at an estimated 2 bcm/y, owing to its domestic production, and is mainly used for power generation. It is expected to increase gradually with the development of an LNG terminal. Senegal has so far seen very limited production, but the potential development of its offshore resources (notably the Tortue field shared with Mauritania) could provide additional supply to the domestic market.

South Africa

South Africa's natural gas consumption is estimated at around 5 bcm/y, supplied by a mix of domestic production, coal gasification and imports. The use of natural gas for power generation grew as state-owned incumbent Eskom struggled with recurrent power outages. In 2015 a government tender was issued for the construction of 3 GW of gas-fired capacity linked to FSRU units in the ports of Coega, Richards Bay and Saldanha Bay by 2020. In parallel, the government is encouraging the longer-term development of domestic shale gas resources. At the time of writing, such developments appear to be stalled as the administration seeks to revise its energy policy framework (Integrated Energy Plan and Integrated Resource Plan)(Bloomberg, 2017).

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2. SUPPLY

Highlights

- **2017 was a year of record natural gas output for the People's Republic of China** (hereafter, "China"), **Australia, the Russian Federation** (hereafter, "Russia") **and Norway** – for the latter three this strong production increase was driven by exports. The United States' net production remained stable on average, with a strong push from dry and associated shale gas in the second half of the year balancing the depletion of the earlier months.

- **Global natural gas production is forecast to increase at an average annual rate of 1.6% until 2023**, following the same trend as observed over the past six years, albeit at a slightly lower pace.

- **The United States is the largest single contributor to natural gas production growth, with over 160 billion cubic metres per year (bcm/y) of additional volume by 2023** – or the equivalent of almost all of Latin America's current annual production. As a whole North America accounts for almost half of total production growth until 2023.

- **US shale production is increasingly driven by light tight oil production, with a growing share of associated gas in the total shale gas production pool.** This (mainly) oil-driven US supply push leads to some domestic consumption increase but also to the opening of new outlets including increased pipeline exports to Mexico or through liquefied natural gas (LNG) exports.

- **Eurasia's production output is expected to grow by less than 1% per annum until 2023, lower than production capacity development**, spurred mainly by Russia's investment in exploration and production aimed at longer-term export outlets. This is likely to increase Russia's spare production capacity.

- **China's production grows at a steady pace**, and is expected to increase by over 35% over the next five years.

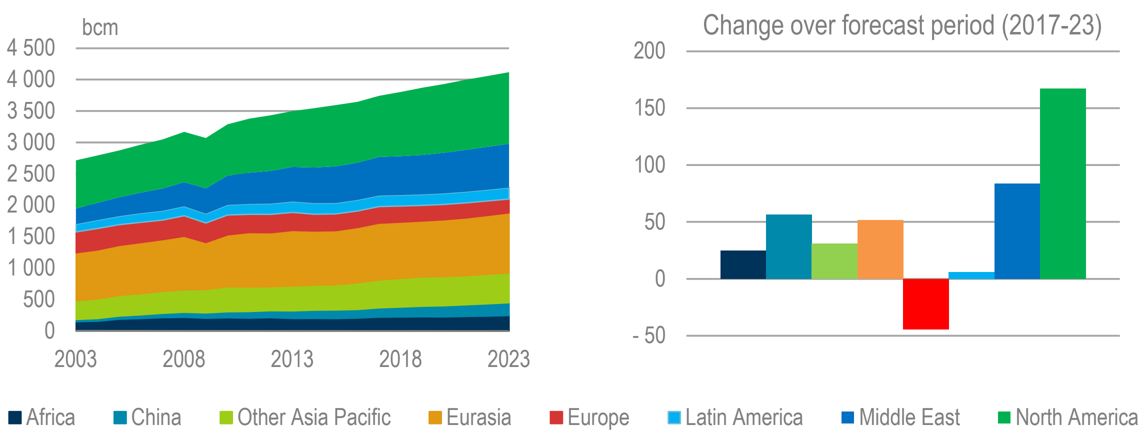
- **European domestic production declines further with the phasing out of the Groningen field.** The resulting supply gap is expected to increase by over 30 bcm/y.

Global overview

- Global natural gas production is forecast to rise from 3 740 billion cubic metres (bcm) in 2017 to 4 116 bcm by 2023, increasing by 10% in five years. The United States is the largest individual contributor to this increase, accounting for around 43% of total growth, with other major contributions from the Middle East, China and Eurasia (Figure 2.1).
- Crude oil production is the main driver of future growth in US natural gas production, as shale gas production associated with light tight oil (LTO) is expected to increase at a rapid pace and almost exceed the contribution from dry shale. Dry shale gas production from the Appalachian Basin (around Marcellus and Utica plays) is still expected to grow in the future,

but associated shale, especially from Texas' Permian Basin, will be the main driver for US natural gas production growth for the coming years.

Figure 2.1 Global natural gas production, 2003-23



- China's natural gas production is assumed to keep on increasing at a healthy annual rate of 5.5% over the forecast period, yet below 2017's record 7.3% growth. China becomes the world's fourth-largest natural gas producer by 2023.
- In the rest of the Asia and Pacific region, natural gas production increases mainly due to Australia's ramping up in the shorter term, and is then expected to remain stable as a whole with new production development compensating for depletions in other areas. India's output remains flat throughout the forecast period.
- Europe's production decline was halted in 2017 thanks to a strong increase in Norwegian output (up 6.6% at 125 bcm) and new fields commissioned in the United Kingdom, thus offsetting the decrease in Dutch production. While Norway's production is assumed to remain stable, the United Kingdom's returns to decline while the Dutch government's plan to accelerate the phase-out of the Groningen field further reinforces Europe's continuous production decline (Table 2.1). By 2023, production levels are forecast to have dropped to the same level as at the beginning of the 1990s.

Table 2.1 Global natural gas production by region, 2017-23

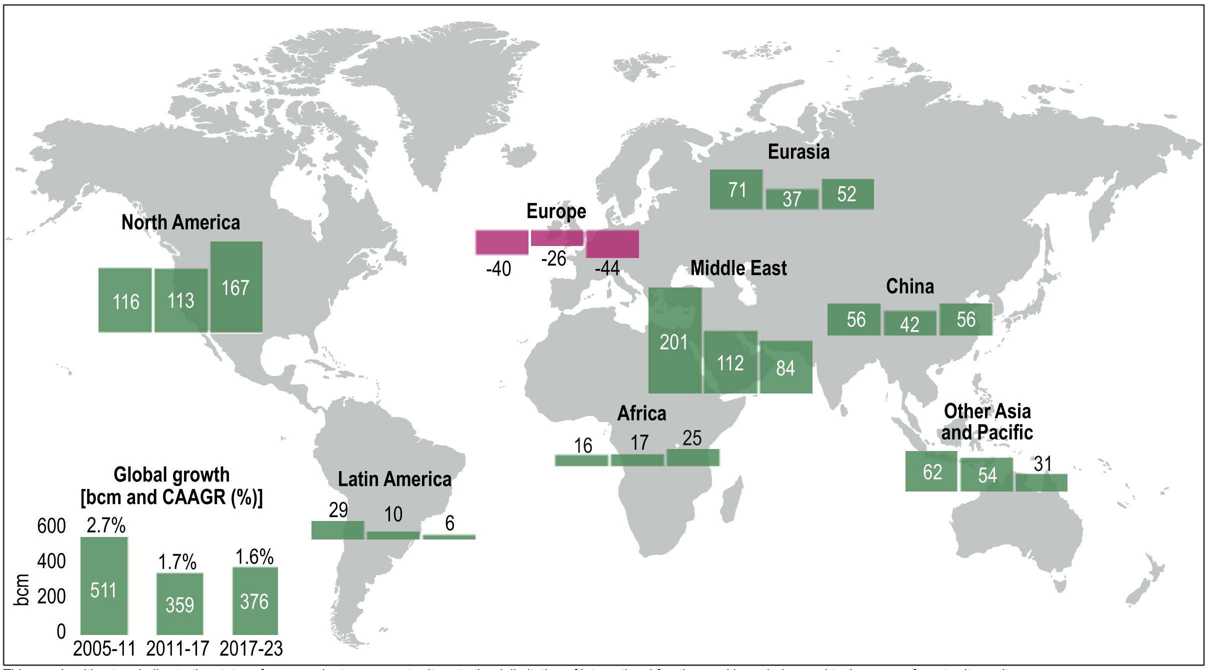
Region	2017*	2019	2021	2023	CAAGR 2017-23	Contribution to global growth
Africa	220	226	230	245	1.8%	7%
Asia and Pacific - China	148	168	185	204	5.5%	15%
Asia and Pacific - Other	444	468	463	475	1.1%	8%
Eurasia	904	889	916	956	0.9%	14%
Europe	262	248	240	220	-3.0%	-12%
Latin America	175	175	177	181	0.5%	2%
Middle East	615	627	670	698	2.1%	22%
North America	973	1 071	1 116	1 140	2.7%	45%
Total	**3 740**	**3 869**	**3 994**	**4 116**	**1.6%**	

* = provisional data.

Note: CAAGR = compound average annual growth rate.

- The production trend in Eurasia is expected to remain moderate at below 1% increase per annum average throughout the forecast. Russia's output reached a record level in 2017 at over 690 bcm, prompted by Gazprom's production and exports to Europe. Gazprom is targeting further production increases to 2025, but this report expects only limited demand growth potential from domestic and European export markets until 2023, while exports to China ramp up progressively from the end of 2020 with the commissioning of the Power of Siberia pipeline. The additional production capacity build-up therefore increases Russia's spare capacity for longer-term exports and resource replacement.
- Production in the Middle East grows at an average 2.1% per annum, predominantly driven by Iran and Saudi Arabia for their respective domestic markets. Qatar's production capacity is due to increase once its 30 bcm/y liquefaction expansion project achieves final investment decision (FID); however, according to Qatar Petroleum's latest statements it would not begin operations before the end of 2023.

Map 2.1 Global natural gas production growth by region, 2005-11, 2011-17 and 2017-23



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

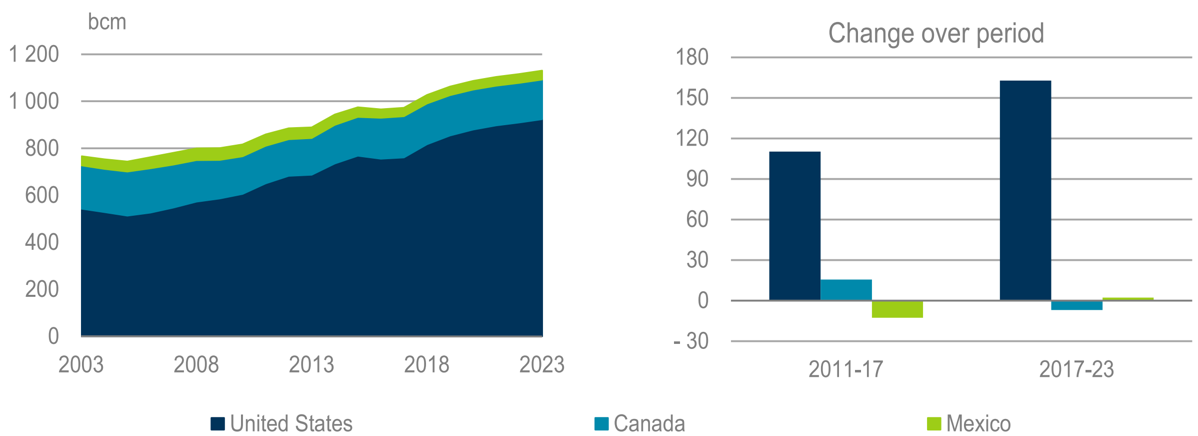
- Latin America's production growth is expected to remain modest until 2023 at an average annual rate of 0.5%, mainly driven by Argentina's shale gas developments in the Vaca Muerta play of the Neuquén Basin. This increase is partly offset by production decreases in other Latin American countries (Map 2.1).
- In Africa, natural gas production growth is mainly driven by developments in Egypt, with the Zohr field and neighbouring offshore prospects. Output from Algeria and Nigeria remains stable, while ramping up in Mozambique takes place in the latter years of the outlook. Other prospects from West and East African coasts are not expected to deliver production before 2023.

Regional supply outlook

North America

North America is expected to contribute almost half of the increase in global natural gas production over the forecast period. The second stage of US shale development, driven by LTO production, provides the main contribution to output growth in the form of associated gas. Northeast dry shale gas continues to grow, albeit at a slower pace than associated gas. Production output from Canada and Mexico remain stable throughout the outlook.

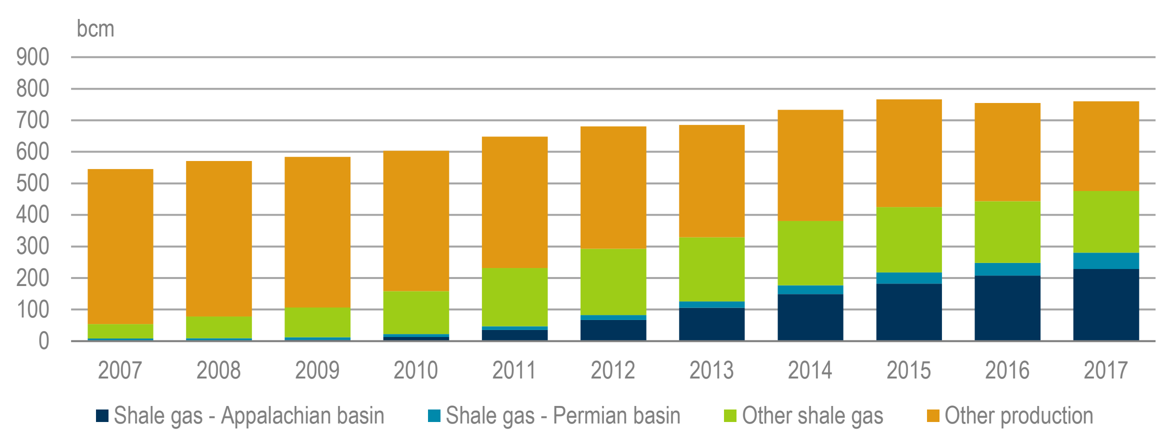
Figure 2.2 Natural gas production, North America, 2003-23



United States

During the forecast period, US gas production is expected to increase at an annual rate of 3.3%, from around 760 bcm in 2017 to above 920 bcm in 2023. Shale gas from the Appalachian (dry gas) and Permian (mainly associated gas) basins are the main pillars of US gas production growth (Figure 2.3). In 2017, US dry gas production increased by around 5 bcm, from 755 bcm to 761 bcm.

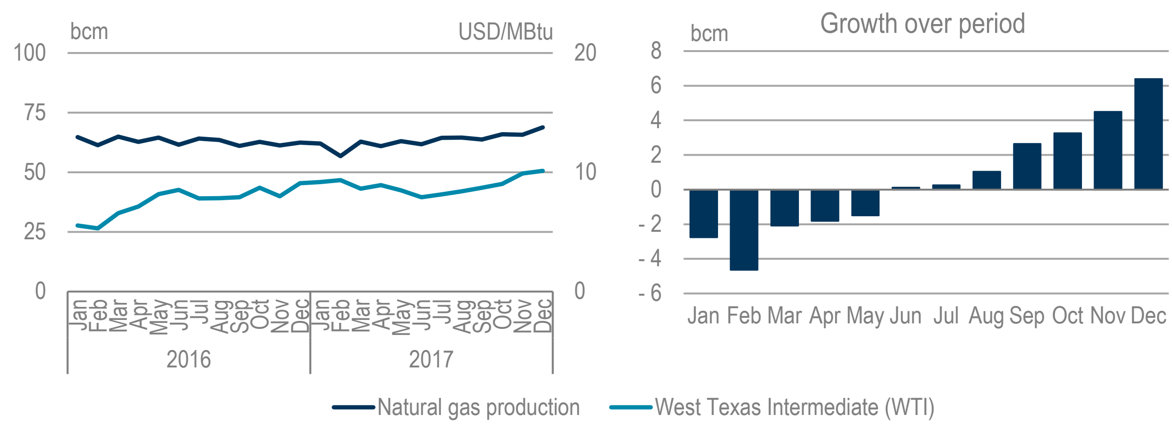
Figure 2.3 Natural gas production, United States, 2007-17



Source: EIA (2018a), *Dry Shale Production Estimates by Play* (database), www.eia.gov/naturalgas/data.php#production.

Production growth in 2017 was also driven by a recovery in the oil price, which bottomed out in February 2016 at a monthly average price of around USD 30 per barrel (bbl) (West Texas Intermediate [WTI]) or USD 5.3 per million British thermal units (MBtu) (Figure 2.4). WTI monthly crude oil averages climbed above USD 50/bbl (USD 9.2/MBtu) at the beginning of 2017, supporting US LTO production and associated gas. Year-on-year production grew from June 2017 onwards with incremental growth of up to 6 bcm in December 2017. The oil price recovery continued in the first quarter of 2018 with a three-month average of around USD 63/bbl or USD 11/MBtu.

Figure 2.4 Natural gas production and WTI crude oil price, United States, 2016-17

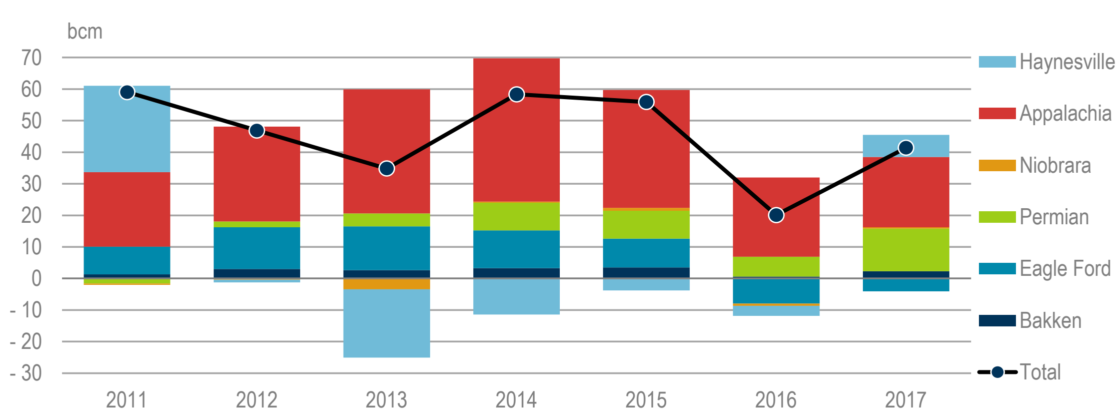


Source: EIA (2018b), *Natural Gas Gross Withdrawals and Production* (database), www.eia.gov/dnav/ng/ng_prod_sum_a_EPG0_FPD_mmcf_m.htm.

In 2017, the Appalachian and Permian basins were the main drivers of production growth (Figure 2.5). The importance of US shale gas has grown significantly since the beginning of this decade, reaching a share of around two-thirds of total gas production in 2017. The Appalachian and Permian regions, the two largest shale production basins, together represent roughly 60% of US shale gas production and 40% of total US natural gas production.

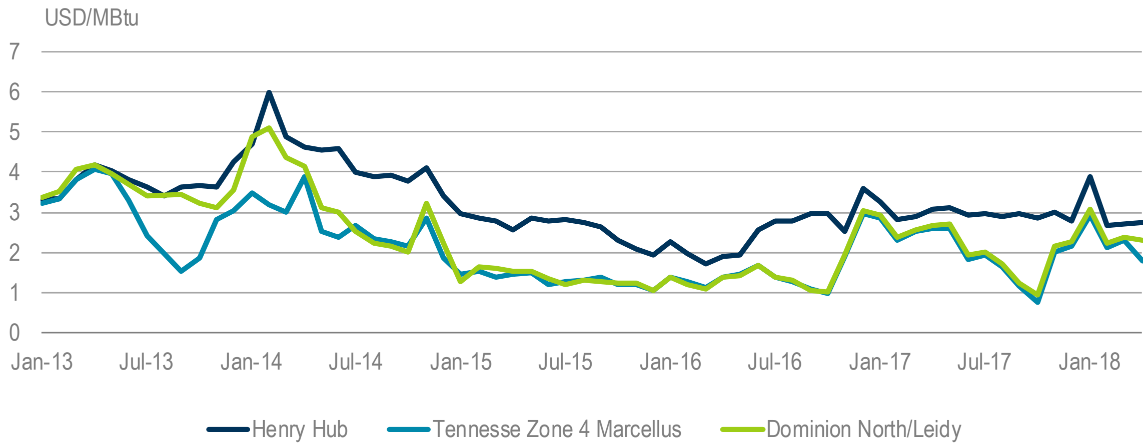
A bottleneck in pipeline capacity from the Appalachian Basin led to a disconnection between prices in producing and consuming regions during 2013 (Figure 2.6).

Figure 2.5 Natural gas production growth by major shale region, United States, 2011-17



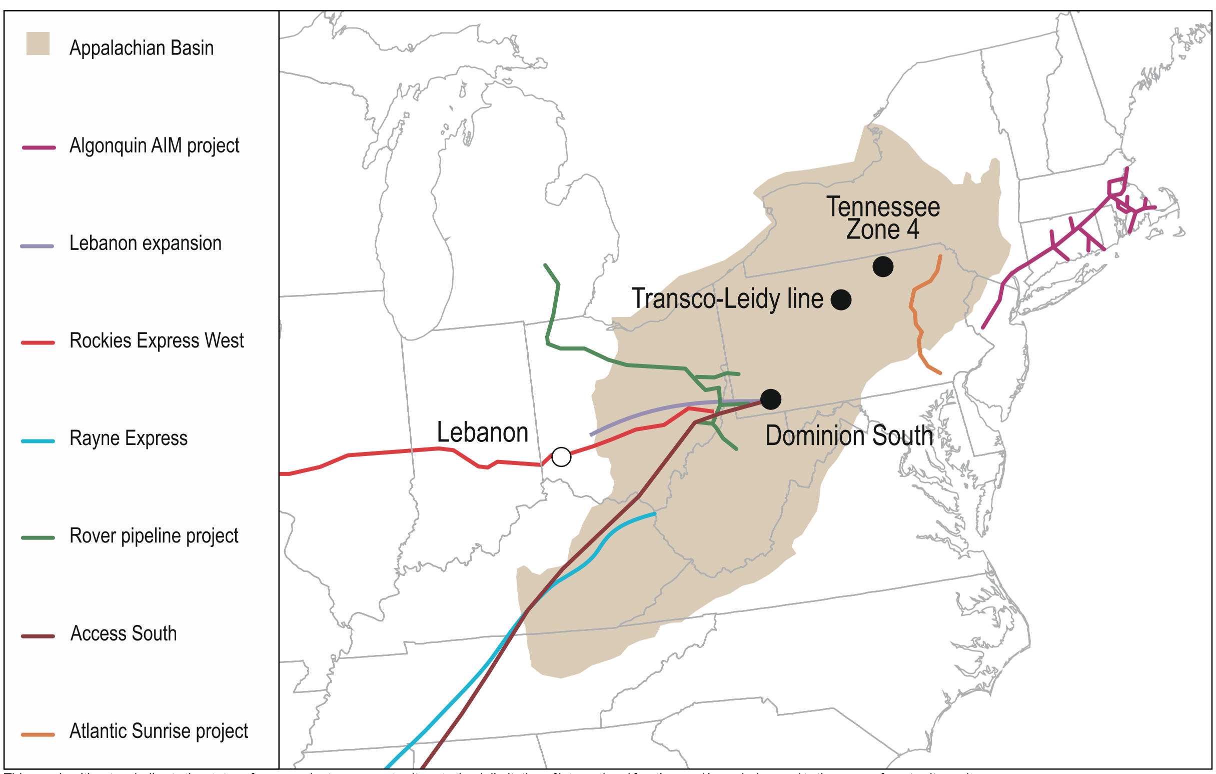
Source: EIA (2018c), *Drilling Productivity Report* (database), www.eia.gov/petroleum/drilling/.

Figure 2.6 Average monthly gas hub prices, January 2013-April 2018



Consumption in the northeast was much lower than the incremental natural gas production from the Appalachian Basin; however, the lack of sufficient pipeline capacity to other US regions and Canada kept a large portion of that gas where it was produced. This led to significant price differences between Henry Hub and price hubs in the Appalachian Basin (e.g. Tennessee Zone 4 Marcellus, Dominion North and Leidy), triggering the construction of more pipeline infrastructure.

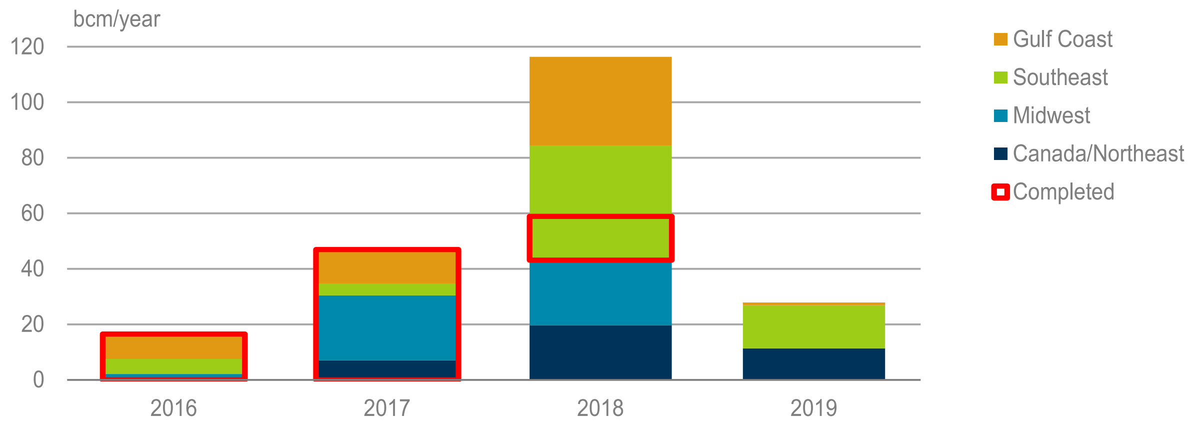
Map 2.2 Selected natural gas pipeline projects from the Appalachian Basin



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

As prices in the Appalachian Basin are influenced by production rates in the region and available pipeline capacity, the commissioning of new takeaway capacity is crucial, particularly in a region of strong incremental production growth. In general, price spreads between Henry Hub and regional prices in the Appalachian Basin narrowed in 2017 compared to the period between 2014 and 2016. However, the region still faces periods of oversupply when production exceeds available pipeline capacity, resulting again in lower prices compared to Henry Hub. During 2017, several projects for pipeline takeaway capacity were completed or partially completed, including the Rover Pipeline Project Phase 1 (17.6 bcm/y), REX Zone 3 Capacity Enhancement (8.3 bcm/y) and the Access South Project (3.3 bcm/y). In January 2018, the Rayne Xpress pipeline (15.8 bcm/y) had already added further capacity and more pipeline capacity additions are due to start operations in 2018 (Map 2.2). However, certain projects are facing delays owing (among other reasons) to opposition from local stakeholders, adding uncertainty to projected commissioning dates, particularly for greenfield projects.

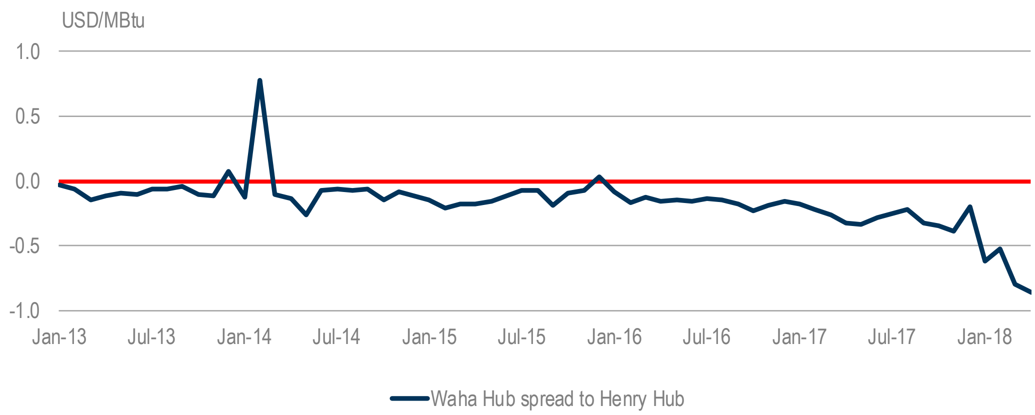
Figure 2.7 Additional takeaway capacity from the Appalachian Basin (selected projects)



Sources: EIA (2018d), *Pipeline Projects* (database), www.eia.gov/naturalgas/data.php#pipelines; company websites.

Boosted by the increase in oil prices, associated gas in the Permian Basin has also begun to challenge existing takeaway pipeline capacity, resulting in negative price spreads of the local Waha price hub to Henry Hub (Figure 2.8).

Figure 2.8 Waha price spread to Henry Hub (monthly averages), January 2013-April 2018



Source: Bloomberg Finance LP.

In the first quarter of 2018, Waha gas hub prices were on average 22% below Henry Hub prices (compared to 7% in 2016 and 6% in 2015).

Against this background, Mexico is becoming an important gas outlet for this region to release pressure on gas prices in Western Texas. In 2017, several projects were completed, including the Comanche Trail Pipeline (11 bcm/y), Nueva Era gas pipeline (6 bcm/y) and TransPecos pipeline (14 bcm/y) (Map 2.3). However, delays in pipeline expansion projects to Mexico are creating complications for producers as they stretch the timeline for further increases in export quantities.

Map 2.3 Cross-border pipeline projects from United States to Mexico

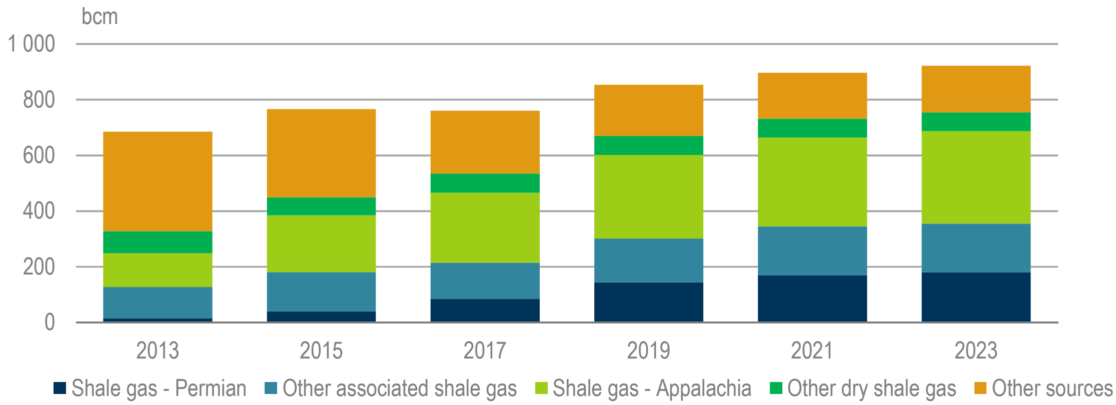
This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries, and to the name of any territory, city or area.

Projects under construction include the underwater South Texas–Tuxpan gas pipeline (27 bcm/y), Nueces–Brownsville pipeline (27 bcm/y) and Mier Monerrey pipeline (7 bcm/y), all planned to be commissioned in 2018. Three major projects are due to further enhance the pipeline capacity of the Permian Basin in the forecast horizon. In December 2017, Kinder Morgan announced an FID to proceed with the Gulf Coast Express Pipeline Project and construction started in May 2018. The project has now secured sufficient firm transport agreements with shippers (around 85% of the project capacity committed under long-term and binding transport agreements). The USD 1.75 billion project is designed to transport up to 20 bcm per year and will originate at the Waha Hub in the Permian Basin, terminating near Agua Dulce, Texas. The project is expected to be commissioned in October 2019.

The proposed Permian-Katy (P2K) gas pipeline will connect the gas resources of the Permian Basin to the Texas Gulf Coast and also Mexico. The project is proposed to transport up to 23 bcm per year of natural gas from the Waha Hub to the Katy Hub (both in Texas) and the Houston Ship Channel. The project schedule currently foresees FID being taken in the second quarter of 2018 and operations starting in the third quarter of 2020.

Encouraged by the crude oil price increase over 2017 and first months of 2018, US producers responded quickly with oil production growing by 5% y-o-y and with further 8% growth expected for 2018 and a doubling of production form the Permian basin, the main source of LTO (IEA, 2018b). This LTO development goes together with an increase of associated natural gas – mainly from the Permian Basin but also from other oil-driven shale plays such as Niobrara, and to a lesser extent Eagle Ford and Bakken (see Figure 2.9). Dry shale production increased by 10% in 2017, owing to continuous growth from Appalachia as well as some recovery in the Haynesville play. This forecast expects Appalachia to further grow while Haynesville will stabilise. Other sources of production – including conventional onshore and offshore, Federal offshore for the Gulf of Mexico, coalbed methane – will continue to decline.

Figure 2.9 Natural gas production, United States, 2013-2023



Natural gas production increases sharply over the first years of the forecast, driven by LTO associated shale gas, especially with the development of new pipeline takeaway capacity in 2018-19 enabling to transport associated gas from the Permian basin. The growth rate is expected to diminish progressively over the forecast as operators will be forced to move outside of the best areas (or "sweet spots") as they become congested or depleted. Appalachia is expected to follow a similar trend.

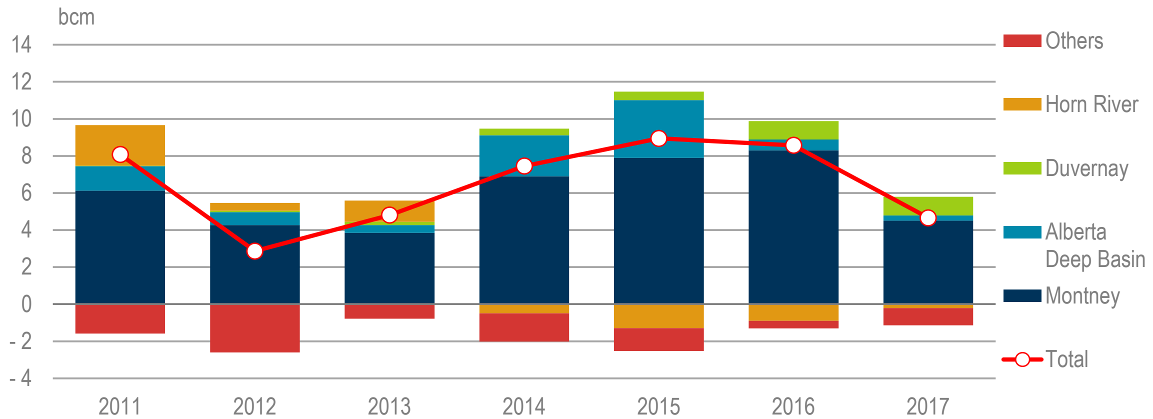
Total US production grows at an average 3.3% per year over the forecast period. This outlook could be revised upwards should additional LNG export projects declare Final Investment Decision soon enough to start operations before 2023 – see Trade chapter.

Canada

After six consecutive years of decline, Canada's natural gas production growth resumed in 2013, increasing at an average 2% y-o-y over the last five years (NEB, 2018). This recent recovery was mainly due to the development of tight and shale gas production, the share of which grew from 30% in 2007 to almost 65% in 2017.

The Montney play has been the main unconventional development in Canada (Figure 2.10) – a large formation extending from the province of British Columbia into Alberta with both dry and wet gas resources. The Montney play, which started operations in the late 2000s, currently accounts for almost one-third of Canada's natural gas production. The northeast British Columbia part of the basin is rich in liquids and saw its condensates production double in the last two years to about 48 thousand barrels per day (kb/d).

Figure 2.10 Tight and shale gas production growth by basin, Canada, 2011-17



Source: NEB (2018), *Marketable Natural Gas Production in Canada*, www.neb-one.gc.ca/nrg/sttstc/ntrlgs/stt/mrktblntrlgsprdctn-eng.html.

The Duvernay shale play is a much more recent development, but with strong prospects owing to its oil and gas liquids potential. US major Chevron announced in November 2017 its development plans in the Kaybob Duvernay, with an initial development of 22 000 hectares that could spur more drilling in its 130 000 hectare portion of the play.

With limited support from domestic market needs or pipeline exports to the neighbouring US market, prospects for Canada's production growth remain highly dependent on the confirmation of LNG export projects. At the time of writing there is still no clear decision to go ahead from any of the LNG export projects' developers, although in late April 2018 Shell-led LNG Canada announced the contractors for its engineering, procurement and construction, thus moving a step closer to a potential FID for the two-train, 17 bcm/y liquefaction project (which could be further doubled). The 2.8 bcm/y Woodfibre LNG project, which ordered its pre-construction works in early 2017, later announced in November 2017 the postponement of its construction decision to 2018.

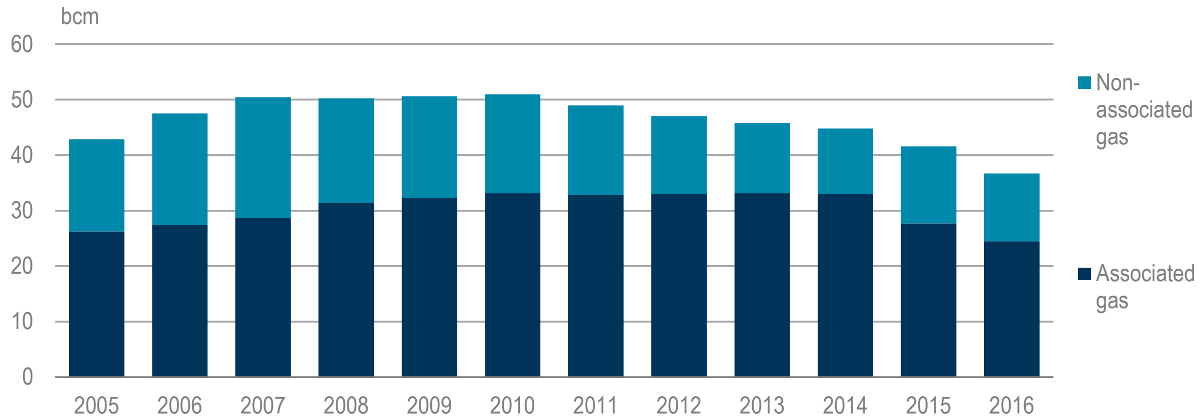
In the absence of confirmed LNG export outlets, this report forecasts an overall stagnation of Canada's natural gas production over the forecast period. Further developments, mainly from oil- and liquid-rich plays such as Montney, Duvernay and the Alberta Deep Basin, counterbalance the depletion of conventional production from other parts of the West Canadian Sedimentary Basin.

Mexico

Mexico's gas production has been declining steadily since 2010 at an average annual rate of 5.3%. As Figure 2.11 shows, around two-thirds of Mexican gas production comes from associated gas. According to the recently published *Market Report Series: Oil 2018*, oil production in the country is expected to see continued declines through the early 2020s and associated gas production is assumed to follow a similar trend.

However, recent developments could help to reverse the decline in gas production throughout the forecast period. In an effort to offset the decrease in investments from the Mexican state oil company Petróleos Mexicanos (PEMEX) in the Burgos Basin – a shale-rich basin in the northeast of Mexico – the government held Round 2.2 of its gas auction programme in July 2017 to open the onshore portion of the basin for natural gas exploration and production by private companies. This represented a key milestone since it was the first gas-oriented auction round after energy reform began back in 2013.

Figure 2.11 Natural gas production, Mexico, 2005-16

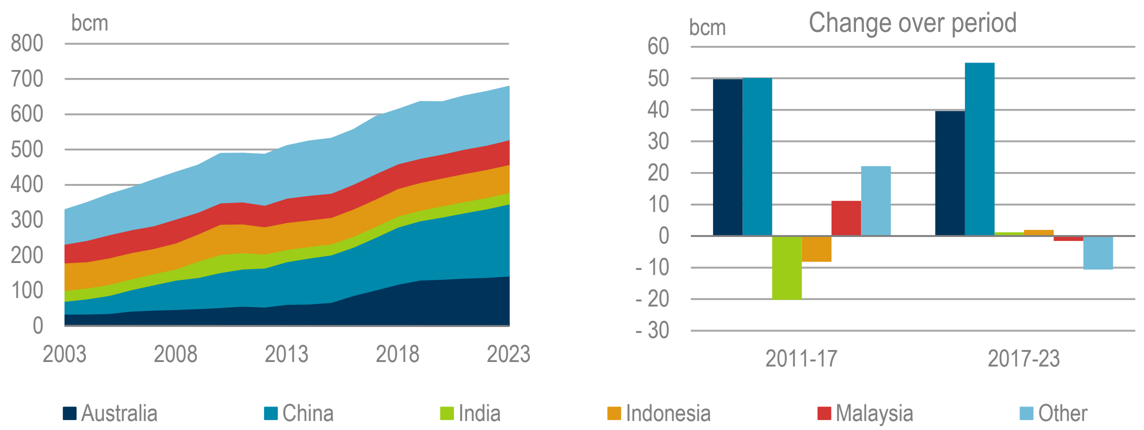


Source: IEA (2018c), *Natural Gas Information* (database), www.iea.org/statistics/.

Asia and Pacific

Asia and Pacific natural gas production growth is mainly driven by Australia and China, which together account for almost all of the regional production increment over the next five years and cover around half of the region's production by 2023 (Figure 2.12).

Figure 2.12 Natural gas production, Asia and Pacific, 2003-23



China

In 2017, 147 bcm of China's supply originated from its domestic production and 94 bcm from gas imports. During the forecast horizon, China becomes the fourth-largest natural gas producer worldwide, based on annual production growth of 5.5%, increasing by 57 bcm from around 147 bcm to 204 bcm. As natural gas imports are forecast to increase by 77 bcm to 171 bcm over the same period, the share of domestic production actuals falls from 61% to 54%.

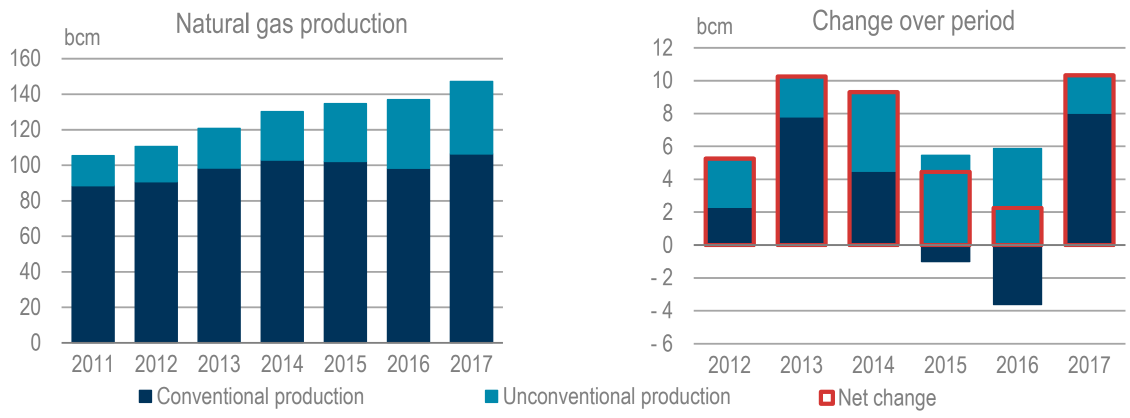
China's efforts to adjust its supply infrastructure capacity to the country's rapidly growing demand will be crucial, especially in cold winters. Although domestic production and particularly imports responded to the surge in gas demand, 2017/18's winter elucidated the structural issue of insufficient gas storage to balance seasonal demand. But this is not the only bottleneck to overcome: commissioning delays to distribution pipelines and additional LNG import capacity were additional challenges to the natural gas industry during 2017. National oil companies (NOCs) are increasing their efforts not only to improve the efficiency of their existing exploration and production activities, but also to invest in new projects both to increase domestic production and improve gas infrastructure.

Investment in domestic production supports further growth

Around 70% of China's indigenous production originates from conventional production, mainly from the Sichuan, Ordos and Tarim basins. In 2017, China's production increased substantially by 10 bcm y-o-y, or 7.3%, from around 137 bcm to 147 bcm after two consecutive years of weak incremental production increases (Figure 2.13). In 2017, around three-quarters of incremental production originated from conventional sources.

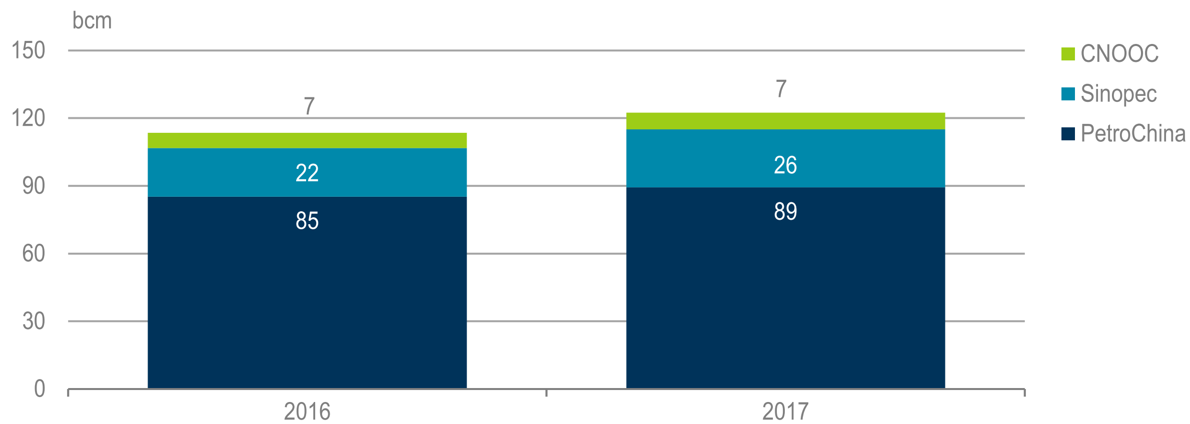
In 2017 domestic production failed to keep pace with China's impressive hunger for gas, forcing the country to continuously increase its dependency on pipeline and LNG imports. But even with record LNG imports, China clearly struggled to meet demand during last winter – partly owing to pipeline delivery issues from Turkmenistan – resulting in gas shortages in several Chinese regions. Incremental growth in domestic production was limited in some basins, particularly the Sichuan Basin: the area is hilly but also densely populated and cultivated, which makes intensive drilling a challenge.

Figure 2.13 Natural gas production, China, 2011-17



The dominant player in China's exploration and production sector is PetroChina, a subsidiary of China National Petroleum Corporation (CNPC). PetroChina's domestic marketable production amounts to 89 bcm, representing a share of around 73% in 2017. Sinopec and CNOOC, the two other NOCs, produced 26 bcm and 7 bcm respectively (Figure 2.14). All NOCs had a significant recovery in operating performance and achieved steady growth in key production indicators. All producers emphasised their ambition to continue these efforts in 2018.

Figure 2.14 Marketable domestic gas production of NOCs, China, 2016-17



Sources: Company reports of PetroChina, Sinopec and CNOOC.

PetroChina focused on improving efficiency and profitability of its exploration and production activities and average daily gas production went up in every production region between 2016 and 2017 (Table 2.2), in particular for the Tarim and Sichuan Basins. PetroChina's exploration activities will focus in the Songliao Basin, Erdos Basin, Tarim Basin, Sichuan Basin and Bohai Bay.

Sinopec prioritized low-cost and high-quality exploration activities during 2017, taking into account the favourable oil price environment. Amongst others, new discoveries were made in the Sichuan Basin. A production increase of around 7% is targeted for 2018, which would raise production levels to around 28 bcm from 26 bcm in 2017.

Offshore exploration and production activities have been pushed forward by CNOOC, the smallest of the NOCs in terms of production volumes (Table 2.2). CNOOC sees significant potential in the Bohai Basin and the South China Sea based on an increasing success rate of exploration wells. In Bohai, the new discovery Bozhong 19-6 is expected to be the largest gas discovery in that area. Other successful exploration activities included new discoveries of Lufeng 14-8 and Lufeng 8-1 South, which significantly increased the reserve scale of Lufeng area (Eastern South China Sea). For 2018, the company reports to continue its approach to target mid-to-large size oil and gas discoveries offshore China.

Table 2.2 Average daily natural gas production by region (mcm/day), China, 2015-17

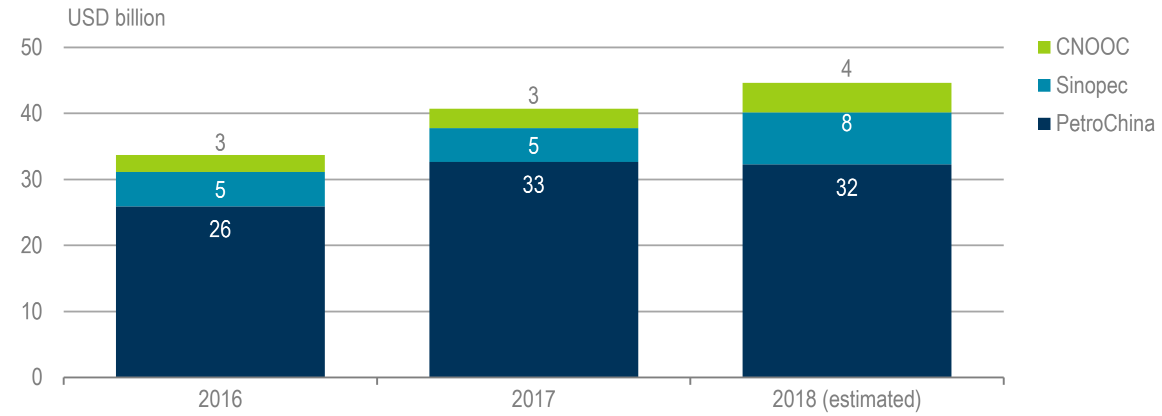
Producer	Production region	Production basin	2015	2016	2017
PetroChina	Chanqing	Songliao	90.1	87.9	88.4
	Tarim	Tarim	59.0	59.3	64.5
	Chuanyu	Sichuan	40.0	48.0	52.2
	Others (domestic)		36.2	37.6	39.5
	Others (overseas)		17.6	20.6	21.0
Sinopec					
	Puguang	Sichuan	15.0	10.3	15.8
	Fuling	Sichuan	8.7	13.8	16.5
	Others (domestic)		31.6	35.0	38.3
	Others (overseas)		0.3	0.3	0.3
CNOOC					
	Bohai	Bohai	3.9	3.8	4.2
	Western South China Sea	Yinggehai	8.9	7.8	7.7
	Eastern South China Sea	East China Sea	6.7	5.3	6.7
	East China Sea	East China Sea	1.3	1.5	1.6
	Others (domestic)		-	-	0.1
	Others (overseas)		13.7	13.4	12.3

Note: mcm = million cubic metres. Sources: PetroChina, Sinopec and CNOOC Form 20-F.

Total investment in the oil- and gas-related activities of China's NOCs increased by USD 7 billion from USD 34 billion in 2016 to USD 41 billion in 2017 (Figure 2.15). PetroChina was virtually the only driver of that growth, particularly due to its incremental investment in exploration and production of USD 5 billion. Construction of gas-related projects included the Third West-East Gas Pipeline and the Fourth Shaanxi–Beijing Gas Pipeline. In 2018, PetroChina's exploration and development investment is due to focus on key basins, such as the Songliao, Tarim, Sichuan and Bohai basins, including the development of unconventional resources, such as shale gas. Transmission projects are another major investment area, such as China–Russia East Natural Gas Pipeline Project, gas storage facilities and equipment for LNG storage and transport (Map 2.4).

Sinopec's exploration and production investments are allocated to the Fuling shale gas region and Hangjinqi natural gas field development projects. Investment in infrastructure included the LNG terminals in Tianjin, Wen-23 gas storage and Phase I of the Xinjiang gas pipeline. In 2018, investments are mainly due to comprise shale gas developments in Southwest China and natural gas projects in North China, as well as natural gas pipelines and storage projects that have not been specifically named so far.

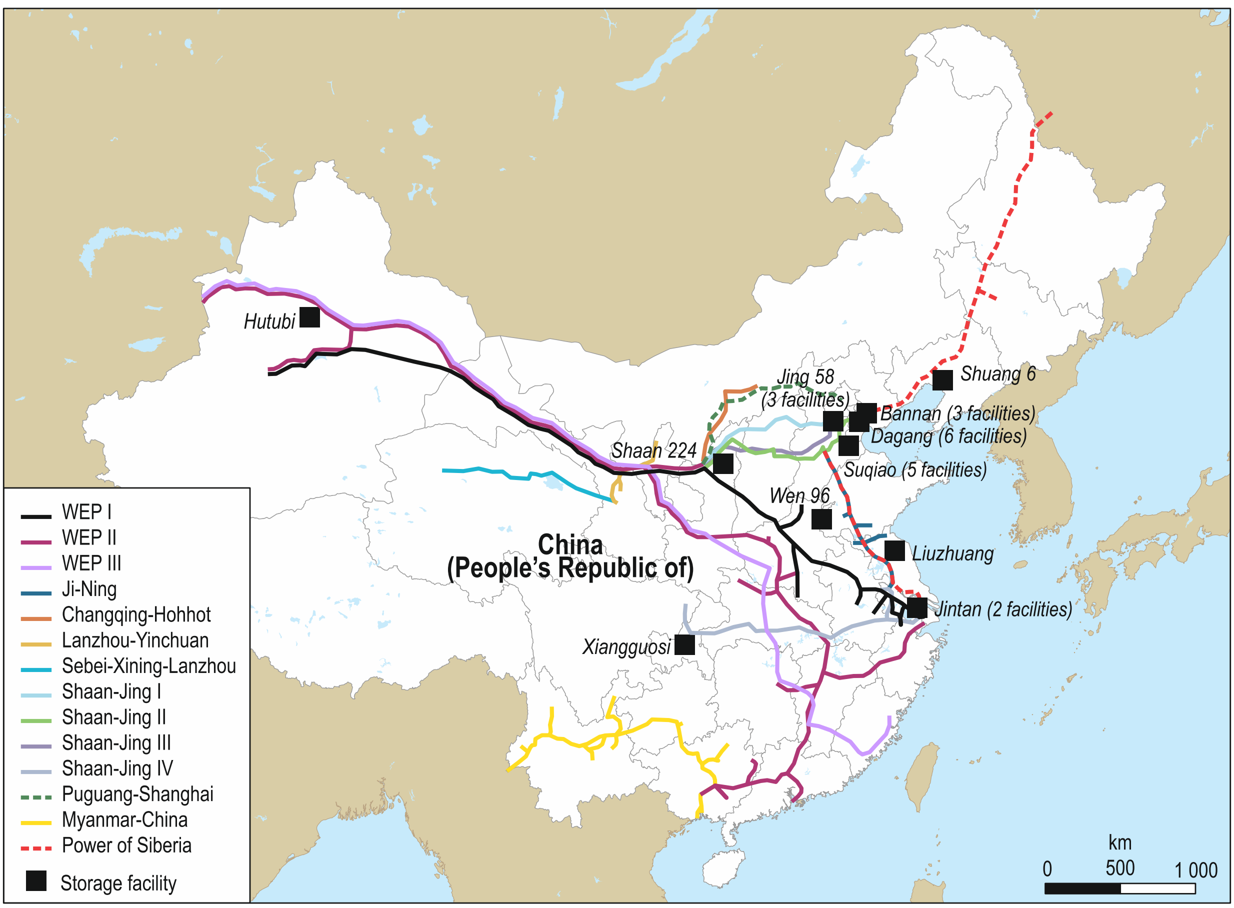
Figure 2.15 Gas- and oil-related NOC investment, China, 2016-18



Note: Values show investment in exploration and production (geological and geophysical exploration costs are included for PetroChina) and natural gas infrastructure in the case of PetroChina.

Sources: Annual reports of PetroChina, Sinopec and CNOOC.

Map 2.4 Major basins and gas infrastructure in China



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

Box 1.6 China emphasises needs to increase gas storage capacity

The contribution of China's underground gas storage (UGS) to balancing winter demand becomes an increasingly important topic given the country's fast increasing natural gas demand and temperature-driven consumption. During the winter season of 2017, severe gas shortages elucidated the lack of sufficient working gas capacity. Demand-side measures were ultimately needed to supply residential customers as the National Development and Reform Commission (NDRC) ordered state-owned energy companies in December 2017 to cut supply to the industry to divert gas supply to northern China.

At the time of writing, 25 domestic UGS facilities are in operation, of which 23 are owned by CNPC/PetroChina and 2 by Sinopec. Information about China's effective working capacity varies but according to the National Energy Administration (NEA) total working capacity has reached 10 bcm in 2017 (other sources quote 11.7 bcm). According to CNPC, 7.4 bcm were withdrawn from China's UGS capacity last year corresponding to around 3% of China's annual gas consumption in 2017 (for comparison, the relationship between working gas capacity and annual consumption in European countries with a high import dependency [e.g. Germany and Italy] corresponds to 25% and 33% respectively). According to the Ministry of Resources, the total daily withdrawal capacity is around 90 million cubic metres, equivalent to 10% of peak daily gas consumption.

In April 2018, the NEA issued a notice to accelerate and incentivise the construction of gas storage facilities to safeguard stable and safe gas supply. The various objectives include the establishment of independent gas storage operators and specific targets, e.g. the obligation for gas supply companies to have gas storage capacity by 2020 of not less than 10% of their annual sales. Efforts by CNPC and Sinopec have already gained momentum, with both companies announcing several projects. Sinopec's Wen23 gas storage project is already under construction and will be of China's largest gas storage facilities after completion. CNPC announced several projects including seven new gas storage facilities in the Sichuan-Chongqing area, an investment of around USD 3.3 billion (CNY 21 billion).

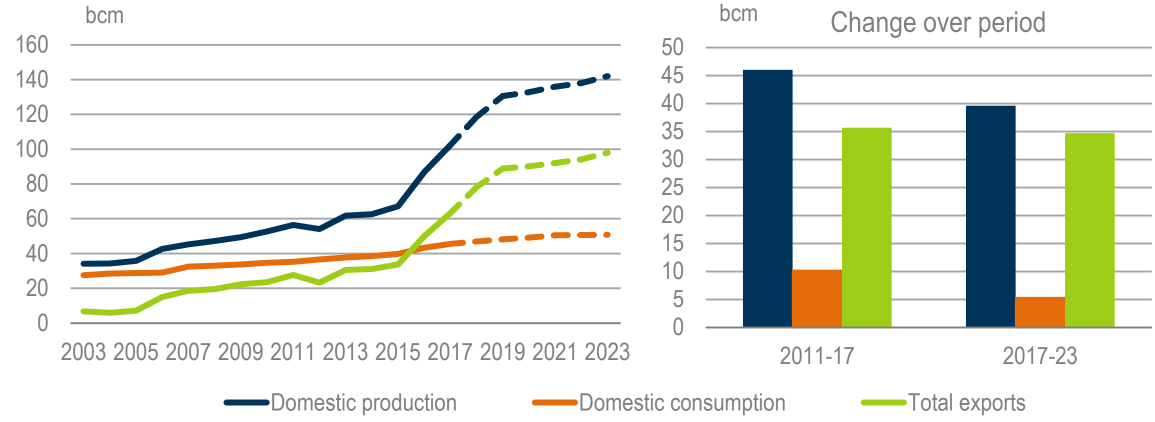
Source: NEA (2018), "PetroChina plans to build seven new gas storage facilities in Sichuan-Chongqing area ", www.nea.gov.cn/2018-03/30/c_137077202.htm, Chen, A. (2018), "China's LNG prices drop as industrial users curbed, supply crunch eases", www.reuters.com/article/us-china-lng-prices/chinas-lng-prices-drop-as-industrial-users-curbed-supply-crunch-eases-idUSKBN1ET10M (accessed 9 January 2018), Chen, A. (2018), "After winter gas crunch, China pumps for underground storage", www.reuters.com/article/us-china-pollution-gas-storage/after-winter-gas-crunch-china-pumps-for-underground-storage-idUSKBN1HI3EW, Ministry of Natural Resources (2018), "China's underground gas storage technology can be comparable to international", www.mlr.gov.cn/xwdt/kyxw/201801/t20180108_1735549.htm, Wang (2018), "China's natural gas peak shaving capacity of 11.7 billion cubic meters of gas storage capacity still has a huge gap", www.ce.cn/cysc/ny/gdxw/201804/16/t20180416_28829617.shtml.

Australia

Australian domestic gas production has been increasing by an annual average of 10.4% since 2011, or over 45 bcm in absolute terms, reaching above 100 bcm in 2017. This report forecasts a continuous increase in domestic production to around 140 bcm by 2023.

In parallel, the country's LNG export volume increased at an even greater annual average rate of 18.0%, or over 40 bcm in absolute terms, over the past five years. Even though the country's domestic consumption is forecast to increase at a healthy rate of 4.3%, exports in the form of LNG are the main driver for future natural gas production growth (Figure 2.16). Australian natural gas exploration and production activities rely on the operational status of current and new LNG liquefaction and exporting facilities.

Figure 2.16 Natural gas production and export volumes, Australia, 2003-23



The western market (Western Australia and Northern Territory) is primarily offshore conventional production producing LNG for export. The east coast market produces gas from coalbed methane in Queensland with conventional production in Victoria (offshore) and South Australia (onshore). The East Coast market, which serves most of Australia's domestic demand, also produces enough gas to export LNG through three liquefaction plants located in the Queensland region (Map 2.5). The first LNG exporting project in the eastern region started operations in 2014, and three projects are currently operational and exporting more than 30 bcm of LNG per year. The Western region has been exporting LNG since as early as 1989 and new gas fields and projects are in exploration and development (Map 2.5).

Australian LNG export projects are large (capacity ranges from 5 bcm/y to more than 22 bcm/y, averaging at more than 10 bcm/y per project), which typically requires upfront offtake commitment from the receiving countries to sanction feed gas production. Thus, most of the LNG volumes from Australian projects are committed under long-term contracts for almost 20 years, mainly to Asian countries, prior to commencement of production. Several projects that recently started LNG production are currently ramping up their capacity (Table 2.3) and after 2019 are expected to be close to full output, resulting in slowly growing feed gas production in Australia thereafter.

In recent years, the wave of new natural gas liquefaction projects has put Australia in the spotlight due to strong growth in gas production and LNG exports, as seen in Figure 2.16. As a consequence of this development, the eastern and south-eastern markets of Australia experienced large increases in gas prices. These markets also experienced electricity and gas supply security issues, as described in the IEA Global Gas Security Review (IEA, 2017a).

In response to these events, the Australian government implemented a temporary measure, the Australian Domestic Gas Security Mechanism (ADGSM), which allows the government to enact export restrictions when a shortage of domestic gas is forecast for the following year. The ADGSM has been effective since July 2017 and is a temporary measure intended to cover the period of LNG export projects ramping up production until the end of 2022.

Table 2.3 Australian LNG export projects, existing and under development

LNG export facility	Location	Nameplate capacity (bcm/y)	Start-up year
North West Shelf LNG	western	22.2	1989
Darwin LNG	northern	5.0	2006
Pluto LNG	western	5.9	2012
Queensland Curtis LNG	eastern	11.6	2014
GLNG	eastern	10.6	2015
Australia Pacific LNG	eastern	12.2	2015
Gorgon LNG	western	21.2	2016
Wheatstone LNG	western	6.1	2017
Ichthys LNG	northern	12.1	2018*
Prelude FLNG	western	4.9	2018*

* = projected.

Note: FLNG = floating liquefied natural gas.

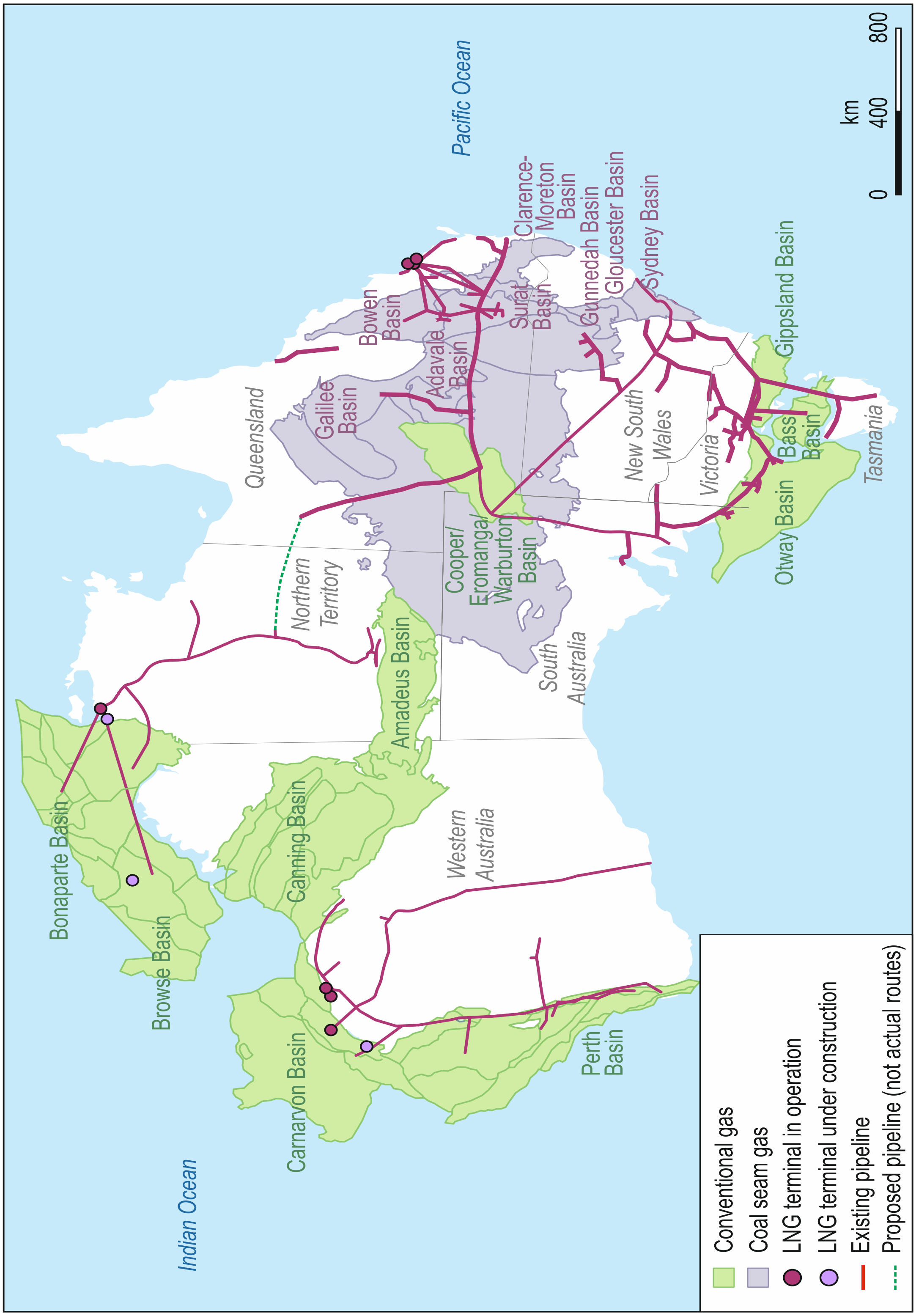
Sources: IEA compilation based on information from companies' websites.

The framework allows the Australian government to intervene if needed to ensure sufficient delivery of natural gas to the domestic market. In short, if supply-demand market dynamics point towards insufficient supply of gas to the domestic market, the mechanism calls for partial and temporary restriction of LNG exports in order to ensure enough gas is available for the domestic market. In October 2017, major east coast LNG exporters agreed to dedicate uncontracted volumes to the domestic market for the next two years, thus saving the government from issuing the declaration of intent as required under the ADGSM mechanism.

Meanwhile, as the new wave of LNG projects are starting to produce, and the last two projects aim to start producing during 2018 (Table 2.3), Australia's resources sector is facing a decline in capital expenditure, having peaked during 2012-14 (Australian Bureau of Statistics, 2018). Actual expenditure in 2017 was below AUS 10 billion in each quarter, a 16% decrease from the previous year. Expenditure in the industry has decreased by around 60% compared to the peak years of 2012-14, as the majority of the capital investment has focused on constructing the eight large LNG projects.

The Australian government is putting measures in place to attract investment into the sector to support the country's production growth and to improve security of supply. One of the measures is the AUD 26 million Gas Acceleration Program (GAP), introduced in late 2017, which is part of the Australian government's AUD 90 million investment programme to increase the domestic gas supply and improve gas security, reliability and affordability (Australian Department of Industry, Innovation and Science 2018). Its main objective is to increase supply to domestic gas consumers located in target markets. GAP will provide up to AUD 6 million to each project, up to 50% of eligible project cost. The projects are required to demonstrate proven prospects of significant new gas by mid-2020. Applications opened in January 2018 and closed in the following month. Currently, four projects have been selected and awarded, three in Queensland (eastern) and one in southern Australia, to accelerate drilling activity and produce domestic gas in the said areas by mid-2020.

Map 2.5 Natural gas resource basins in Australia



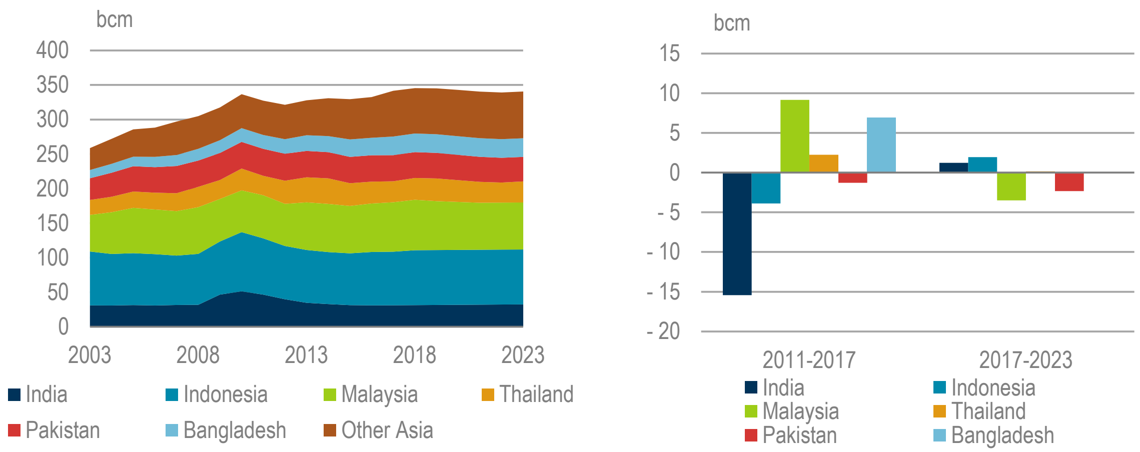
This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area.

Source: IEA (2018a), *Energy Policies of IEA Countries: Australia 2018 Review*, https://webstore.iea.org/energy-policies-of-iea-countries-australia-2018-review.

Other emerging Asian economies

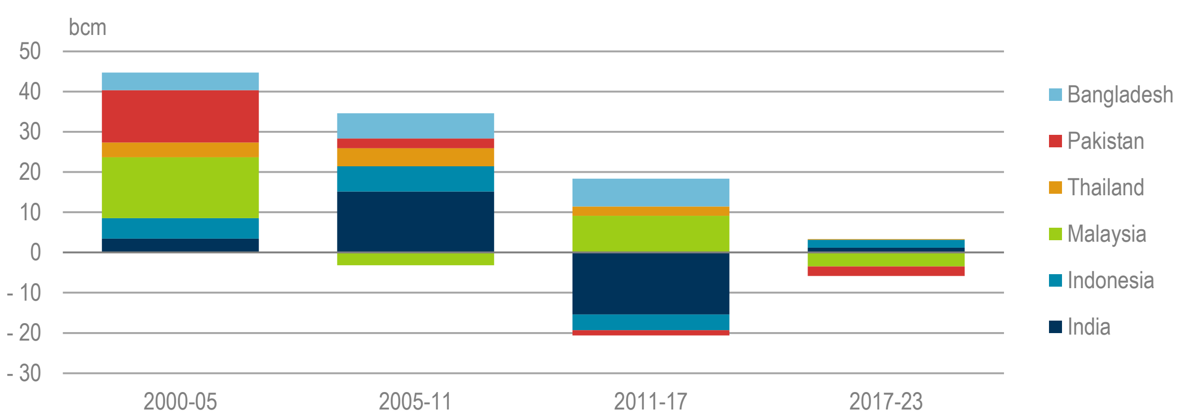
Despite strong growth in demand for natural gas, production in the other emerging Asian economies (excluding China, Japan and Korea) has been growing slowly at an average observed annual rate of 0.7% over the period 2011-17. Malaysia and Bangladesh led the region's gas production increase, up by 6.1 bcm/y during the period (Figure 2.17).

Figure 2.17 Natural gas production, other emerging Asian economies, 2003-23



About 80% of the subregion's gas production is in six countries, namely India, Indonesia, Malaysia, Thailand, Pakistan and Bangladesh. Over the past six years the six countries' production decreased by 2.2 bcm/y, mainly due to the large decrease in India (down 15.4 bcm/y). This drop, owing to lack of new investment in natural gas field development, offset increases in Malaysia and Bangladesh (16.1 bcm/y in total) (Figure 2.18). Production is expected to stabilise in most of these countries during the forecast period with the introduction of policies to stimulate and revitalise investment in the oil and gas upstream sector.

Figure 2.18 Change in natural gas production, other emerging Asian economies, 2001-23



India

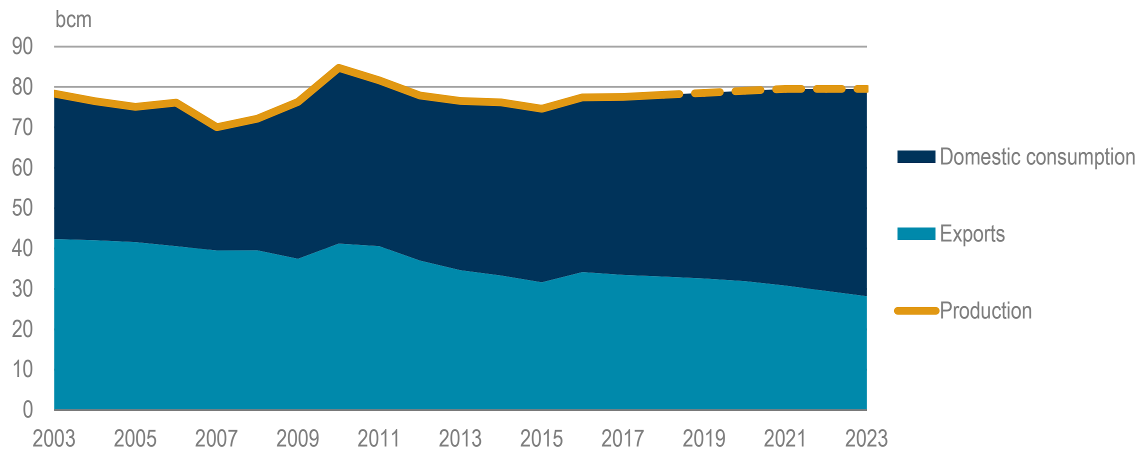
India's natural gas production is expected to stagnate around its current level of about 30 bcm/y throughout the forecast period. To revitalise the sector, attract investment and encourage development of large unexplored areas, the government has been introducing multiple measures in recent years with a target of reducing import dependency on oil and gas by 10% by 2022 (Ministry of Petroleum and Natural Gas, Government of India, 2018). These measures include streamlined unified licences, extended exploration licence periods, an improved revenue-sharing model and greater transparency in the marketing and pricing of produced natural gas. At the time of writing, exploration and production activity has not yet delivered new discoveries, hence the impact on future production seems limited during the forecast period.

In addition to these recent policy measures, the government has raised the price of domestic natural gas to further attract upstream investment and to reduce the gap between natural gas prices in the downstream market and imported LNG prices The current domestic price is set at USD 3.06/MBtu until 30 September 2018. In spite of recent increases, this price level is still substantially under the supply costs for both domestic production and LNG imports. According to domestic producers ONGC and Oil India Limited (which accounted for 80% of India's total natural gas output in the first 10 months of the financial year 2017-18), this price level is still insufficient to recover their average production costs, which stand at USD 3.59/MBtu and USD 3.06/MBtu respectively. New developments from specific offshore developments in difficult environments (deep water, ultra-deep water, and high-pressure high-temperature) are subject to a specific price ceiling mechanism,[1] which currently stands at USD 6.78/MBtu until 30 September 2018.

Indonesia

Indonesian natural gas production has been decreasing since it reached its peak in 2010. This declining trend was reversed in 2017 with the commissioning of the Jangkrik offshore field. This deepwater field, which is connected to the Bontang LNG processing facility in East Kalimantan, started production in May 2017 and is expected to reach a plateau capacity of 6 bcm/y (Reuters 2017a; UPI, 2017). The neighbouring Merakes field, which has an estimated 56 billion cubic metres of gas in place, received approval for production from the Ministry of Energy in April 2018 – at the time of writing, FID from Eni, the license holder, has yet to be taken.

Figure 2.19 Natural gas production for domestic and export, Indonesia, 2003-23



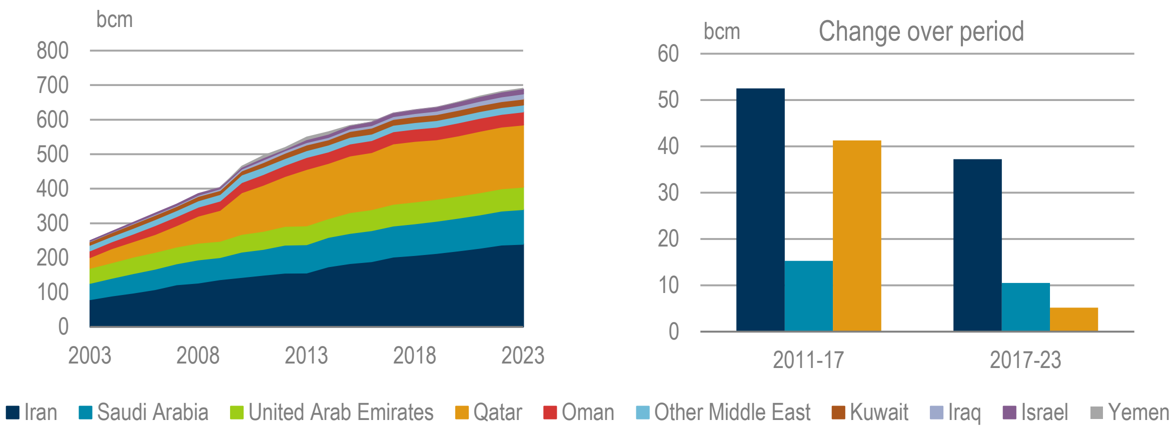
[1] This ceiling is based on lowest of (a) imported fuel oil price; (b) weighted average price of substitute fuels (0.3x coal + 0.4x fuel oil + 0.3x naphtha); and (c) LNG import price.

The Indonesian government issued in December 2017 a new fiscal framework to incentivise investment in oil & gas exploration and production. However, the impact is unlikely to be seen in terms of new production during the forecast period due to project lead time. Indonesia's production is therefore expected to remain stable until 2023 (Figure 2.19).

Middle East

Natural gas production in the Middle East is expected to grow at an average 2.1% per annum up to 2023. Driven predominantly by Iran, total production is expected to reach almost 700 bcm/y. This excludes a 30 bcm/y upside potential if Qatar pushes through an increase in North Field production and the development of additional liquefaction capacity as commissioning is not expected before the end of the forecast (see below).

Figure 2.20 Natural gas production, Middle East, 2003-23



Islamic Republic of Iran

Iranian natural gas production is expected to grow at an annual average rate of 2.8%. Most additional volumes are expected to meet domestic demand requirements as Iran's natural gas consumption grows. News reports indicate demand growth of about 7% from fiscal year 2016/17 to fiscal year 2017/18,[2] driven by strong absolute increases in natural gas demand in the industrial and power sectors, of which the latter appears to have grown due to low hydro generation.

The country aims to boost its oil and gas industry with USD 200 billion of investment, of which USD 130 billion is destined for the upstream sector. So far, foreign investment contracts have been awarded to Total (USD 5 billion; Total 50.1%, CNPC 30% and Petropars 19.9%) and Russian state-owned Zarubezhneft (USD 0.7 billion) under the terms of Iran's new generation of upstream contract, the Iran Petroleum Contract. The Total agreement entails the development of Phase 11 of the giant South Pars field, adding 20 bcm per year.

With the decision by the United States to withdraw from the Joint Comprehensive Plan of Action (JCPOA) regulating Iran's nuclear activities, the prospects of Iranian economic growth and Iranian natural gas development seem less promising. At the moment of writing the impact on the Iranian

[2] The Iranian fiscal year runs 21 March-20 March.

economy and upstream development remains unclear. There is a 180-day period for counterparts to adjust and it remains to be seen how waivers and other aspects of the sanctions will be implemented. In addition, other signatories to the JCPOA have said that they will continue with the agreement.

Qatar

Qatar remains the global number one LNG exporter. Despite diplomatic tensions with some of its neighbours, Qatar's natural gas production and its LNG and Dolphin pipeline exports to neighbouring United Arab Emirates and Oman continued in 2017 at the same levels as the previous year. Last year Qatar lifted the moratorium on the North Field development. At the time of writing, the latest news about the North Field development is that Qatar Petroleum is likely to shelve plans to invest in debottlenecking the Ras Laffan production facility, which were aimed at freeing up more natural gas (ICIS, 2018a). The apparent preference now points towards building three new liquefaction trains, which would allow for 23 million tonnes per annum (or above 30 bcm/y) of additional LNG exports by the mid-2020s. No FID has been taken yet and an announcement is expected in 2019-20. According to Qatar Petroleum's statements in late March 2018 on the occasion of awarding the front-end engineering and design contracts for the future expansion, LNG commissioning would be expected by end of 2023 (Platts, 2018) – it is thus not included in the present forecast.

Bahrain

In Bahrain, the country's Higher Committee for Natural Resources and Economic Resources announced in April 2018 a potentially sizeable off shore tight oil and gas discovery, with a first estimate of 300-600 bcm of deep natural gas resource in place below Bahrain's main gas reservoir. This first estimate would require further assessment, especially to estimate the recoverable fraction from the total resource in place. Bahrain's Ministry of Oil announced a target start of production in 5 years (Reuters, 2018a). In 2017 Bahrain produced 17 bcm.

Saudi Arabia

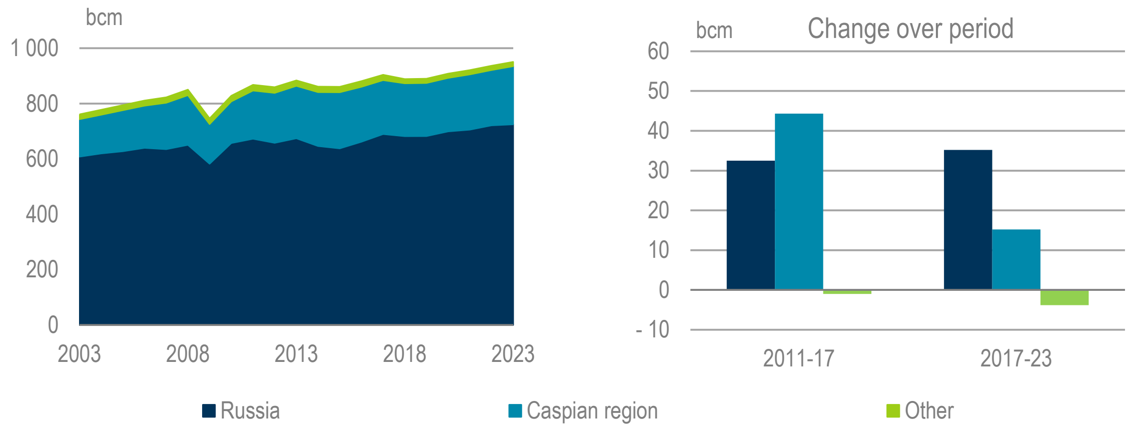
Saudi Arabia produced about 90 bcm of natural gas in 2017. Production is expected to rise by about 10 bcm to be close to 100 bcm in 2023 to supply the growth in domestic demand which will partly be driven by a transformation of the economy. Vision 2030, the country's ambitious economic and social transformation program, aims at diversifying the economy to be less oil dependent and to develop public services. Energy is at the heart of these reforms and natural gas will take a more prominent role, supplying growth in the petrochemical, power generation and mining sector. This growth will run parallel with the Kingdom's target to double domestic gas production in ten years' time.

Eurasia

Natural gas production in Eurasia is expected to grow at an average rate of 0.9% per year over the forecast period, to reach 956 bcm/y by 2023 (Figure 2.21). This increase is principally driven by export prospects, to China via pipeline and through the Yamal LNG project development.

The forecast for Eurasian production growth is based on currently known contractual export arrangements and hence is less than the growth in capacity expected from the industry's investments. Russia has sizeable spare production capacity which can be mobilised in case of changes in demand, such as that illustrated in 2017.

Figure 2.21 Natural gas production, Eurasia, 2003-23



Russia

Russian natural gas production reached a record level in 2017 at over 690 bcm, or a 7.9% y-o-y increase. Further production growth is to be expected in the coming years as several export-driven projects are under development or already ramping up.

Among those, Gazprom's giant Bovanenkovskoye field in the district of Yamalo-Nenets appears likely to be the largest source of production growth: commissioned in 2012, the field delivered 84 bcm in 2017 and is expected to reach around 115 bcm/y at its plateau, initially assumed to be 2022 but accelerated to 2020 as announced by Gazprom in January 2018. In Eastern Russia, the development of the Chayandinskoye and Kovyktinskoye fields is essential to the future supply of the Power of Siberia pipeline system, which is intended to deliver its first gas to China by 2020. In its investor communication Gazprom highlights a target of 27% net production growth for the 2016-25 period (Gazprom, 2018).

Table 2.4 Selection of Russian natural gas production projects

Field	Project leader	Status	Plateau	Plateau capacity
Rospan	Rosneft	Producing	2019	19 bcm/y
Bovanenkovskoye	Gazprom	Producing	2020	115 bcm/y
Chayandinskoye	Gazprom	Under development	2024	25 bcm/y
Kovyktinskoye	Gazprom	Under development	2025	25 bcm/y
Urengoyskoye Achimov III-IV	Gazprom	Development in 2020	2034	22 bcm/y

Sources: Compilation based on information from companies' reports and investors' presentations.

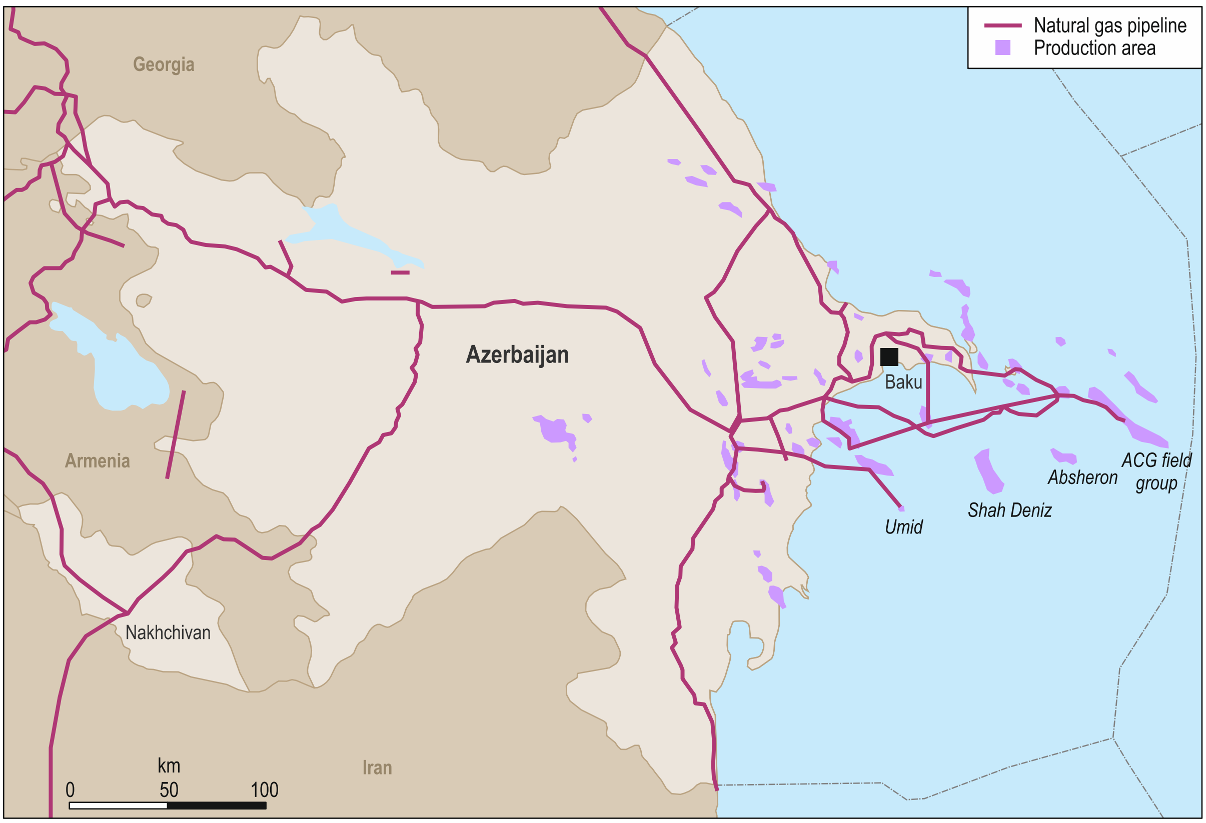
In spite of Gazprom's strong production capacity development target, this report forecasts an additional net need of just 35 bcm of annual production from Russia (for exports as domestic consumption does not increase), equivalent to an average 0.8% annual growth rate for the next five years – which could lead to a build-up of further spare capacity.

Azerbaijan

Azerbaijan's natural gas production amounted to around 29 bcm in 2017, or a decrease of 2.6% compared to 2016, which had itself marked a 1.7% production decrease. One of the main natural gas-producing assets is the Shah Deniz field, whose current Phase I was commissioned in 2006 and has a capacity of 10 bcm/y. Shah Deniz's Phase II expansion, which would add some 16 bcm/y, is expected to start operations at a low level in late 2018, ramping up to target capacity by 2021-22. Most of this Phase II production is earmarked for export to Europe under the future Trans-Anatolian Pipeline (TANAP) and Trans-Adriatic Pipeline (TAP) export system.

Future natural gas production prospects include the Umid field, discovered in 2010 and believed to contain a minimum of 200 bcm of natural gas and 30 million tonnes of condensate. According to Azerbaijan's national oil company, SOCAR, Umid would be able to produce between 2 bcm/y and 3 bcm/y once developed. Absheron, another discovery made in 2011, is believed to be capable of reaching an average plateau capacity of 5 bcm/y. The first well drilling in Absheron began in May 2018 and should be completed by mid-2019. Azerbaijani production is expected to stagnate over the next five years, Shah Deniz Phase II expansion compensating for the continuous decline of other existing fields, while no further developments are expected to start production prior to 2023.

Map 2.6 Main natural gas fields of Azerbaijan



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

Other Caspian

Half of Kazakhstan's natural gas production is concentrated in three major fields: Tengiz (dry gas and condensates), Karachaganak and Kashagan (both associated gas), and a substantial part of natural gas output is reinjected rather than exported or consumed locally. Output from Kashagan is still ramping up with a plateau expected by 2020, but beyond these megaprojects there is limited prospect of new developments to compensate for the decline of older producing fields. Kazakhstan began exporting natural gas to China in 2017, and in January 2018 the Kazakh NOC KazMunayGas and CNPC held bilateral negotiations leading to an agreement to increase exports to China to a plateau level of 10 bcm/y.

Turkmenistan's output suffered from the disputes with Iran and Russia, which led to an interruption of exports to these countries in 2016. Production is expected to recover slightly with the development of exports to China in the coming years.

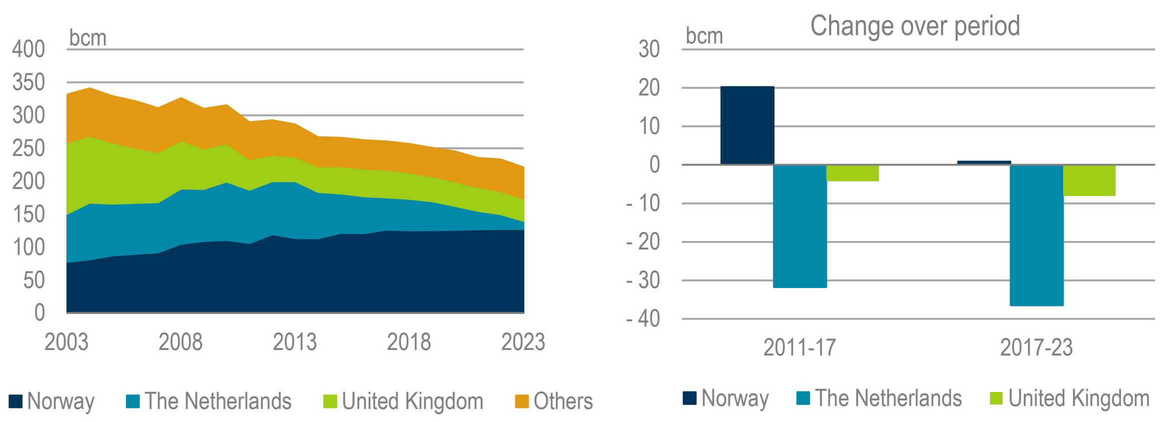
Uzbekistan's domestic production grew by 0.5% in 2017, and is expected to grow further in the coming years with the current ramping up of Gissar and Kandym fields, two projects led by Lukoil. Additional developments could be expected beyond the forecast horizon of this report, notably with the appraisal of the 25 Years of Independence field in the Uzbekistan Mustakilligi block by a Gazprom-led consortium (Azernews, 2018). The field is believed to be the largest in the country, with an estimate of over 100 bcm of reserves for the block.

Europe

European natural gas production has been declining for almost 15 years as North Sea output has declined. In 2017, however, production stabilised at 263 bcm, thanks to increased production in Norway (8 bcm), the UK, Romania and Ireland which more than offset the decline in the Dutch Groningen field and small field production.

European natural gas production is expected to be 220 bcm by 2023, losing over 40 bcm of annual production compared to 2017. This is a significant downward revision from last year's forecast. The recent announcement by the Dutch government to reduce Groningen natural gas production to zero by 2030 strongly reinforces the downward trajectory of European natural gas production up to 2023. Norway is expected to maintain production at the current level. Production in the Netherlands' and United Kingdom's part of the North Sea continue their natural decline, adding 24 bcm to Europe's annual production decrease. Production in other European countries such as Germany or Italy is also expected to decline, and to be counterbalanced by production increase in Romania towards the end of the outlook.

Figure 2.22 Natural gas production, Europe, 2003-23

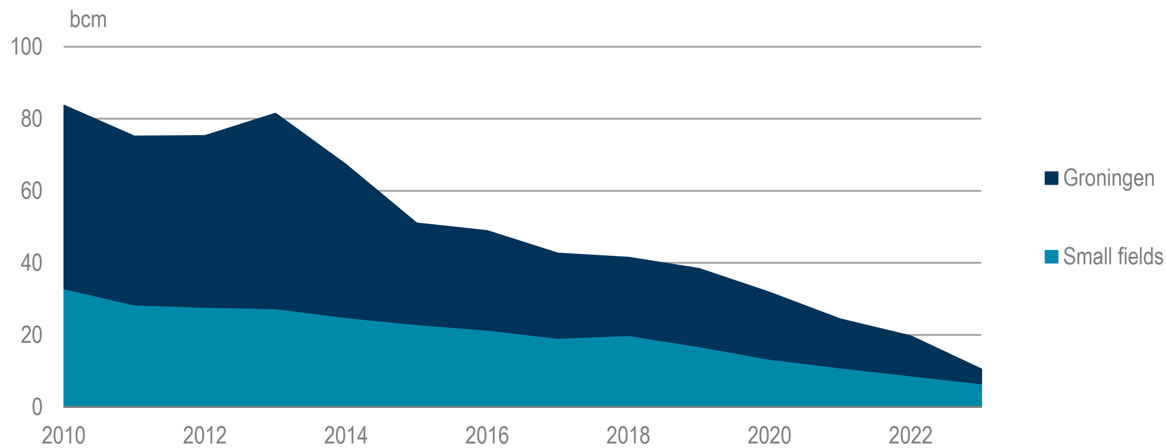


The Netherlands

The Netherlands produced 49 bcm (33.3 MJ/m^3) in 2017. Of this, 25 bcm was produced from the Groningen field and 24 bcm from the so-called Dutch small fields.[3] Over the period of 2017-23 Dutch natural gas production is expected to decrease by nearly three quarters, or 37 bcm. While the decline in small field production is significant (16 bcm), the majority of the decline (21 bcm) comes from reductions in production from the Groningen natural gas field.[4]

The Dutch government had been mandating caps on production from Groningen owing to impact of earthquakes affecting nearby communities caused by this production. As a result, production has already fallen from 54 bcm (35.17 MJ/m^3) in 2013 to 23.6 bcm in 2017.[5] However, these reductions were not successful in reducing the earthquake risk to an acceptable level. The low calorific value gas produced also serves customers in the Netherlands and neighbouring countries with equipment adapted to using this particular lower calorific value fuel. Gas from other sources has to be modified (principally by injecting nitrogen) to serve these customers. In February 2018, the Dutch State Supervision of Mines advised the Minister of Economic Affairs and Climate Policy from the perspective of the required Groningen gas production to decrease the likelihood of earthquakes to a level that “probably meet the safety standard and to reduce the risk of damage” (SODM, 2018a; 2018b) requires reducing Groningen natural gas production as fast as possible to 12 bcm. On the other hand, the Dutch Transmission System Operator (TSO) Gasunie Transport Services (GTS) simultaneously advised the minister that at least 14 bcm is needed to supply the low calorific gas market in a warm year while using 100% nitrogen conversion capacity[6] (GTS, 2018).

Figure 2.23 Natural gas production in the Netherlands, 2010-23



Source: Energie Beheer Nederland (EBN) (2017), *Focus on Energy,* www.ebn.nl/publicatie/focus-on-energy-2017/; NAM (2018), *Gas- en oliewinning* (Gas and oil extraction), www.nam.nl/feiten-en-cijfers/gaswinning.html#iframe=L2VtYmVkL2NvbXBvbmVudC8/aWQ9Z2Fzd2lubmluZyN0YWItdGFiLWluZm8tMzI0Yjk5NGZhOTlmNDJjMjgxYzc5MDY2N2MyNzNhYjk=; IEA (2018), *Natural Gas Information (database)*, www.iea.org/statistics/.

[3] In the IEA gas statistics a gross calorific value of 33.3 MJ/m^3 is used for the Netherlands. Other European countries mostly vary in the 38-41 MJ/m^3 range. The Groningen production cap is normally communicated with a gross calorific value of 35.17 MJ/m^3; a standard Groningen cubic meter of gas. The Nederlandse Aardolie Maatschappij (NAM) has reported 23.6 bcm (35.17 MJ/m^3) of Groningen gas production in 2017, which is equal to the abovementioned 25 bcm (33.3 MJ/m^3) (NAM, 2018).

[4] For the purpose of consistency with references of non-IEA publications, data and communications on Groningen field gas production and Groningen production caps, the following section on Dutch gas production reports volumes with a gross calorific value of 35.17 MJ/m^3.

[5] See footnote 1.

[6] For a cold year this is 24 bcm/yr or 27 bcm/yr (with, respectively, 100% and 85% of nitrogen conversion capacity utilisation).

In March 2018, the Dutch Ministry of Economic Affairs and Climate Policy introduced a phase out plan for the Groningen field production, targeting 3-4 bcm by 2023 and zero production by 2030 (EZK, 2018). The phase out plan includes a range of measures on the demand and supply side of low calorific gas with the aim to bring down the required Groningen natural gas production (Box 2.1). New annual production caps are expected to be introduced later in 2018. In late May 2018, the Ministry of Economic Affairs and Climate Policy announced its intention to increase tax deductions for new investments in offshore small fields.

Box 2.1 Impact of the Groningen natural gas phase out plan on Dutch domestic supply

At the end of March 2018 the Dutch Ministry of Economic Affairs and Climate Policy launched the plan to phase out Groningen natural gas production by 2030. The announcement marks a turning point for the country because this is the first time an end date of Groningen gas production is mentioned.

The Groningen natural gas field produces low calorific gas. With the discovery of this gas field in 1959 and the rapid marketing of the gas across north-west Europe, a 47-60 bcm low calorific gas market (depending on weather conditions) in the Netherlands, Germany, Belgium and France exists parallel to the high calorific gas market. The rest of the global gas market produces and consumes high calorific gas. Next to low calorific gas production from the Groningen gas field, low calorific gas can also be produced by (1) blending high and low calorific gas and by (2) converting high calorific gas to low calorific gas by injection of nitrogen to high calorific gas.[1]

The phase out plan details measures on both the supply and demand side of low calorific gas in order to reduce the production of low calorific gas from the Groningen natural gas field. This section provides an analysis of the impact of these measures.

The supply side measures are characterised by increasing the capacity to displace Groningen gas field production by producing low calorific gas from blending and nitrogen injection. In both cases, Groningen gas production is displaced by an increase in high calorific gas imports and/or the use of more nitrogen volumes.

On the demand side of low calorific gas, regardless of how the low calorific gas is produced, the measures target the reduction of low calorific gas demand from two sides; (1) by switching low calorific gas consumers to high calorific gas, and (2) by reducing the demand for natural gas. The first approach does not necessarily reduce the consumed natural gas volumes while the second approach directly leads to less natural gas volumes consumed.

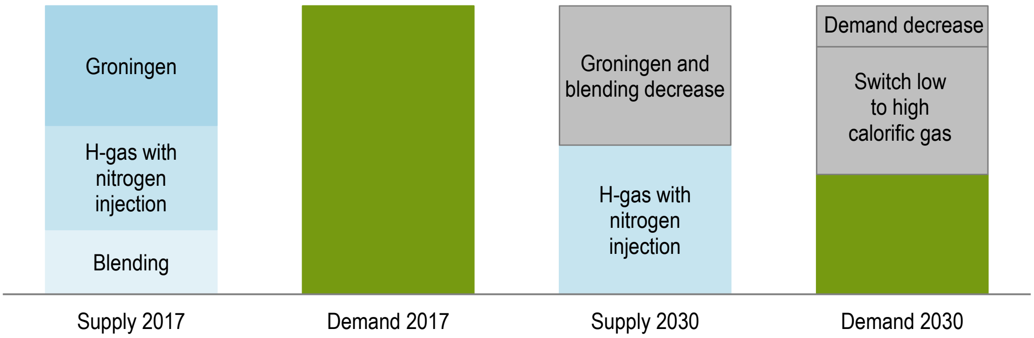
The following graph provides a schematic overview of how supply and demand side measures lead to lower Groningen gas field production over the period 2023-30.

The primary supply side measure and impact on the production is the following:

- The increase of nitrogen injection capacity at the Zuidbroek nitrogen conversion plant will lead to an increase of low calorific gas production by injecting nitrogen to high calorific gas. This replaces 7 bcm/y of low calorific Groningen gas production and will require additional (high calorific) gas imports. The capacity expansion is projected to be operational by October 2022.
- The possibility exists to increase the utilisation of the existing nitrogen injection capacity by the TSO, which could lead to lowering the requirement for Groningen gas production by 1-1.5 bcm/y.

GTG Nord, the TSO of the German market area of EWE, has a plan to invest in low and high calorific gas blending capacity and in a nitrogen injection plant. Both measures are projected to lead to further reduction of 1.7 bcm/yr of Groningen gas field production from 2020 onwards.

Figure 2.24 Schematic overview of low calorific gas supply and demand 2017-30



On the demand side, the following measures will lead primarily to a reduction of low calorific gas demand and therefore to a reduction of low calorific gas supply, which allows for a decrease in Groningen gas field production. This does not necessarily lead to a reduction of total gas demand for part of the measures.

- The switch to high calorific gas or other energy sources of Dutch industrial low calorific gas consumers is expected to gradually reduce the demand for Groningen gas field production with 4.4 bcm/yr by 2022. Up to date, there is no detailed information on the expected share of industries switching gas supply or to sustainable sources. It is assumed that most industry will switch to high calorific gas rather than sustainable energy sources due to the nature of the industrial processes. This reduction in low calorific gas demand is not an absolute decrease in gas demand, merely a switch in the consumed gas quality. With the switch of high calorific gas, process efficiency may increase because high calorific gas contains more energy per cubic meter.
- Switching the low calorific gas markets in Germany, Belgium and France to high calorific gas will lead to a decrease of low calorific gas demand of 2 bcm/yr from 2020 to 2030. This equals about 1.5 bcm/yr of lower Groningen gas production when taking into account the utilisation of a combination of nitrogen injection and blending. The impact up to 2023 on the Groningen gas production is assumed to be around 6 bcm/y and will strongly depend on the speed of the switching.
- The Dutch Climate Agreement (49% carbon reduction by 2030) includes the reduction of natural gas use in the building sector of 0.4-1.8 bcm/y by 2030. The gas use reduction up to 2023 for this sector is not expected to be of significant volumes though.
- Connecting a German low calorific gas power plant to high calorific gas. Reduction potential for low calorific gas demand is 1 bcm which equals a reduction of Groningen gas field production of 0.75 bcm/y because of nitrogen injection and blending. Additional smaller scale measures in both France and Belgium could lead to a low calorific gas demand reduction of 0.3 bcm/y.

The Dutch residential segment of 7 million households has an annual natural gas demand of about 30 bcm in an average temperature year. Before this phase out plan, it was the last segment of the North-West European low calorific gas market to switch to high calorific gas, after the switch in Germany, Belgium and France. By now, proposals are circulating to phase out traditional central heating gas boilers from 2021 onwards. The preliminary envisioned switching timeline is to switch 30 000 appliances in 2022 and scaling that up to 300 000 boilers per year, although it is not clear how fast this switching scale up is supposed to go. The plan also includes incentives for private consumers to switch from gas cookers to electric stoves. The exact impact on gas demand of the switching strategy is difficult to determine. This is a clear acceleration of the Dutch household segment switching compared to the previous approach before the latest phase out plan. However, this does not bring a significant decrease of Dutch residential gas demand in the timeframe of this year's forecast up to 2023.

In conclusion, the increase of capacity to produce low calorific gas from high calorific gas and nitrogen injection and switching customers from low to high calorific gas will both lead to the reduction of Groningen gas production. The implication of this will be a higher reliance on high calorific gas. Together with the decrease in Dutch small field production and production in the UK and Germany, this will lead to a higher dependence on imports.

[1] Note that "blending" refers to the mixing of high calorific gas with low calorific gas to increase supply of low gas volumes up to the level where the maximum allowable Wobbe index is reached. The Wobbe index is a parameter for gas quality, but is not equal to the energy content of natural gas that is generally used.

United Kingdom

In 2017 the United Kingdom produced 42 bcm of natural gas, maintaining production at the same level as in 2016. The commissioning of the Cygnus offshore field in late 2016, one of the largest producing fields in UK North Sea, enabled a momentary halt to the decline in UK natural gas production. The upstream sector has made substantial efficiency improvements, allowing them to maintain output at the same level since 2015 in an environment of naturally declining fields and lower oil prices. Oil and gas operating expenditure (OPEX) has decreased by close to 30% since 2014 and, with a significant cut in capital expenditure (CAPEX), average unit operating costs have halved over the last three years (OGA, 2018).

Despite these improvements, production in the United Kingdom is expected to decline by around 5% per year as OPEX efficiency improvements flatten out over the forecast period and CAPEX is expected to continue its decline, albeit with a less steep rate than in previous years (OGA, 2018). A large number of fields are in a mature state and the strong decline in exploration drilling over the last seven years, coupled with the low rate of development drilling over the last three years, all point to decreasing gas production over the forecast period.

The announced oil and gas tax mechanism, allowing the transfer of a field's tax history to new investors, brings a more positive prospect for mature fields. The mechanism will take effect in November 2018 (Government of the United Kingdom, 2018). Oil and gas companies receive tax relief when decommissioning a field; the tax relief depends on the tax history of a company in relation to the field – i.e. how much tax the company has already paid during ownership of the field. The company field tax history has traditionally not been transferable to a new investor. By making this transferable, new (smaller) investors will benefit from the taxes already paid on a field. With a significant reduction in end-of-lifecycle costs, new innovative entrants can unlock and recover oil and gas reserves from mature fields that were otherwise no longer economically attractive to current field owners.

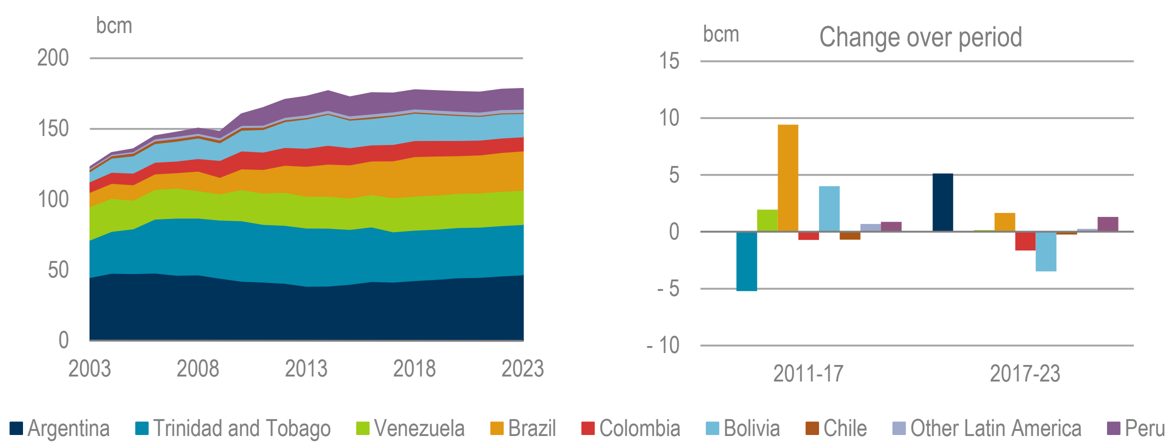
Norway

2017 marked a record year of gas production for Norway. The country produced 125 bcm in 2017, about 6.6% higher than in 2016. Exploration activity in the Norwegian Continental Shelf has suffered under the low oil price, but a 30% OPEX efficiency improvement and existing reserves are expected to keep oil and gas production at a stable level up to 2021. From next year onwards, an increasing share of field resources are expected to contribute to Norwegian production, substantially increasing oil production while maintaining gas output at the level seen in 2017 (NPD, 2018). As for the forecast period up to 2023, Norwegian gas production is expected to remain stable (Norsk Petroleum, 2018). As with all continental shelf oil and gas fields, maturation looms on the horizon, although for Norway the lower level of exploration activity is only expected to impact its high production levels after 2025 (NPD, 2018).

Latin America

This report expects natural gas production in Latin America to stagnate over the forecast period, adding slightly more than 5 bcm/y over the coming years.

Figure 2.25 Natural gas production, Latin America, 2003-23



While Argentina's production is assumed to increase thanks to the exploitation of the vast unconventional resources from the Vaca Muerta shale field, Brazilian production grows at a much slower pace than seen in the past, and Colombia and Bolivia are expected to show production decreases over the forecast period, offsetting Argentinian gains (Figure 2.25).

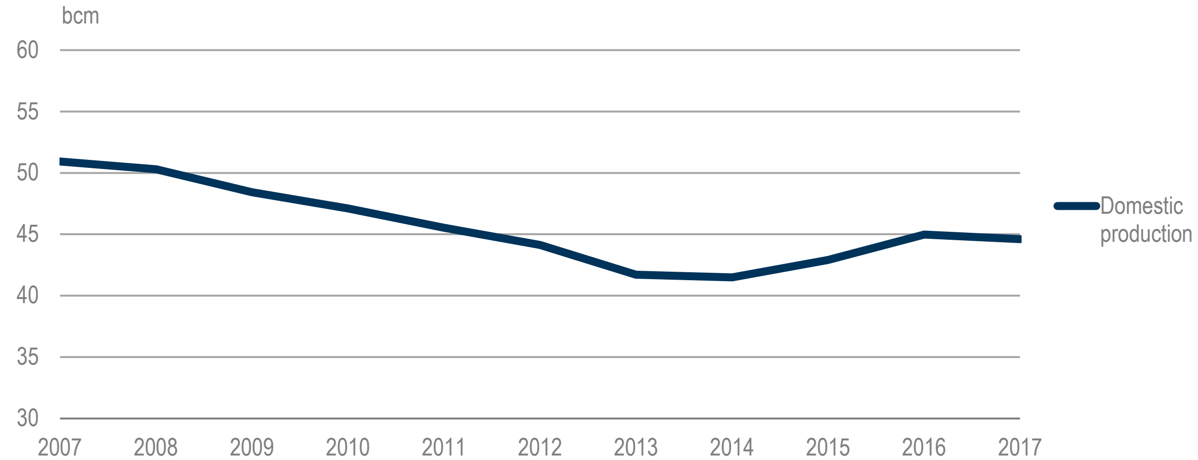
Therefore natural gas production lags behind the anticipated growth in demand, increasing import needs in the region, most of which will be covered by additional LNG imports.

Argentina

According to the Argentinian administration (Modernisation Ministry, 2018), domestic production of natural gas stalled in 2017 for the first time since it started to recover back in 2014 (Figure 2.26). However, this report expects gas production to resume the positive trend seen in the previous years to grow at an annual average growth rate of 2% throughout the forecast period, adding some extra 5 bcm/y by 2023.

The increase in natural gas production is mainly driven by unconventional production from the Vaca Muerta shale play. In October 2017, the state-owned company YPF – the largest oil and gas producer in the country – presented its five-year investment plan, which included an annual CAPEX target of USD 4-4.5 billion to achieve an annual production increase of 5% (YPF, 2017). In addition to YPF, companies that have operations in Vaca Muerta include Total, Chevron, ExxonMobil, Shell and PETRONAS. Other companies, such as the Argentinian producer Tecpetrol, have also announced their respective investment plans in this shale basin (Tecpetrol, 2017). According to a press release issued by the company in March 2017, it will invest up to USD 2.3 billion to 2019 to develop the Fortin de Piedra area of the Vaca Muerta play. With this investment, the company aims to drill 150 wells and install new treatment facilities, batteries and pipelines to be able to produce more than 3.5 bcm/y by 2019.

Figure 2.26 Natural gas production, Argentina, 2007-17



Source: Modernisation Ministry (Argentina) (2018), *"Producción y consumo de gas natural"* (Natural gas production and consumption), http://datos.gob.ar/dataset/produccion-consumo-gas-natural.

In an attempt to boost natural gas production in the country, the government also announced in November 2017 its decision to extend gas production price guarantee to the Austral Basin – in addition to the guarantees already planned for the Neuquén Basin, where Vaca Muerta is located. The minimum price guaranteed by the government will decrease gradually on a yearly basis to reach USD 6/MBtu by 2021 (Reuters, 2017b).

Figure 2.27 LNG imports by origin country, Argentina, 2017

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

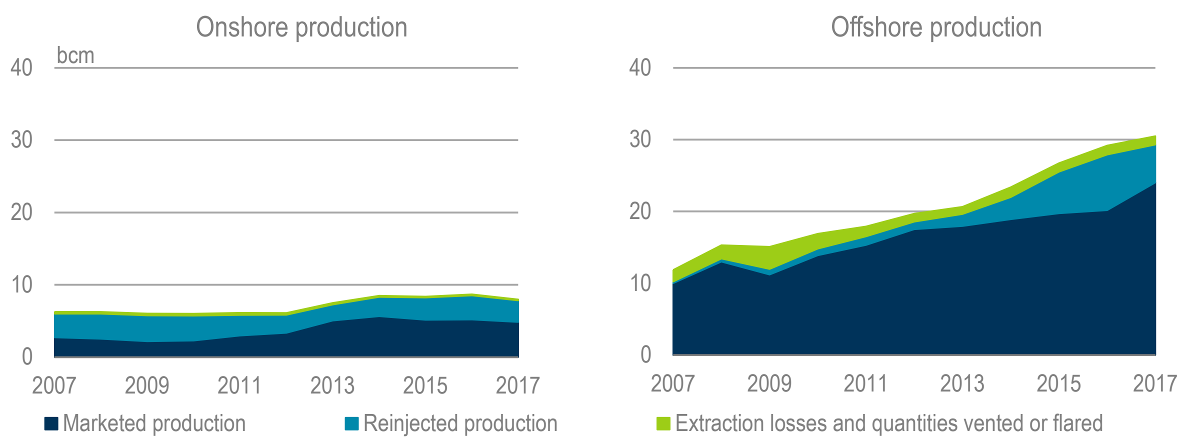
In spite of these attractive financial conditions and the sizeable potential of the Vaca Muerta play, its development is expected to take some time to accelerate as infrastructure proves to be an obstacle to unlocking its production potential – the railway infrastructure project to move equipment and raw material to Vaca Muerta is not expected before 2021 (Reuters 2018b). Thus the anticipated increase in gas production still lags behind demand and Argentina will depend on pipeline and LNG imports to meet its domestic demand, especially during the austral winter when gas demand peaks in the country.

Pipeline imports mainly come from Bolivia, while Chile started to export small volumes to the country in 2016 (IEA, 2017b). Regarding LNG imports, last year Argentina imported around 4.5 bcm, with Qatar being its major supplier, as shown in Figure 2.27, representing over 40% of Argentinian LNG imports.

Brazil

In 2017, Brazil's gross natural gas production remained relatively flat compared to the previous year with an annual overall increase of 0.6 bcm. However, the significant reduction in the quantities of gas that were reinjected, which decreased by 25.5% y-o-y, allowed marketed gas production to increase by 13.9% on a yearly basis, i.e. adding 3.5 extra bcm to supply the domestic market. This amount represented the highest annual growth in the last five years and marked the eighth consecutive year in a row of production increases (Figure 2.28).

Figure 2.28 Natural gas production, Brazil, 2007-17



Source: ANP (2018), *Produção Nacional de Gás Natural* (Natural gas national production), www.anp.gov.br/images/DADOS_ESTATISTICOS/Producao_gas_natural/Producao_de_Gas_Natural_m3.xls.

The reinjection of high quantities of gas in the country is due to the fact that most Brazilian gas production comes from associated gas from offshore oil fields (EIA, 2017a). Thus last year almost 80% of domestic production was offshore, especially from the Santos basin.

The state-controlled company Petrobras plays a major role in the Brazilian gas sector and is responsible for most domestic gas production. According to its latest Business and Management Plan 2018-22, presented in December 2017, the company projects stable gas production in the country through the period (Petrobras, 2017). This forecast expects natural gas production to increase by an annual average growth rate of 1% until 2023.

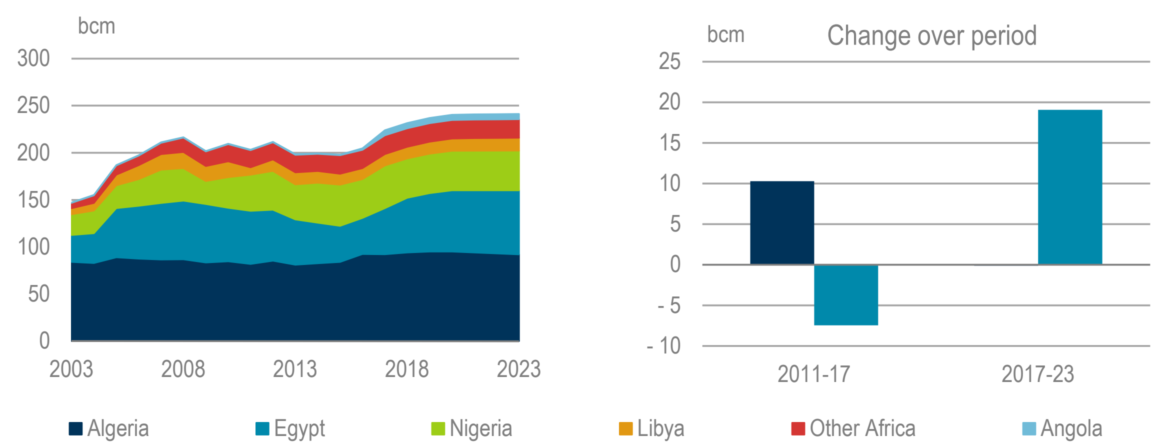
In addition to domestic production, Brazil imports natural gas via pipeline from Bolivia under a long-term contract and, more recently, with short-term LNG imports at three floating regasification and storage units (FSRUs) mainly used to balance its power generation mix when needed. Nevertheless, the contract to import pipeline gas from Bolivia is due to expire by the end of 2019 and negotiations are under way. In a study published by the Brazilian Energy Research Office in June 2017 (EPE, 2017), the organisation recommends renewal of the contract to extend pipeline imports from Bolivia, but suggests reducing firm volumes contracted to Petrobras down to 16 mcm per day. This would represent almost a 50% cut from the maximum volume that could be imported under the current terms, while the minimum take-or-pay clause is currently set at 24 mcm per day.

Despite the potential decrease in firm imports via Petrobras, the Brazilian Energy Research Office also states that other companies could book the spare capacity left by Petrobras – especially given the current partnership and divestment process that the company is undergoing (Petrobras, 2017).

Africa

Africa's natural gas production is expected to grow at an average 1.8% per year over the next five years, reaching 245 bcm/y by 2023. Most of this growth comes from Egypt's dynamic offshore developments in and around the giant Zohr field. Algeria's output is expected to stagnate owing to the lack of new medium-term developments and the depletion of pivotal Hassi R'Mel field. In West Africa, Nigeria's production is not assumed to grow, while some offshore developments in Mauritania and Senegal may provide additional growth at the very end of the outlook. The same goes for Mozambique in East Africa.

Figure 2.29 Natural gas production, Africa, 2003-23



Egypt

After three years of LNG imports, Egypt is due to become self-sufficient again in the course of 2018, owing to the fast-track development of the giant offshore Zohr field, discovered in August 2015 and put in production in December 2017. Several other discoveries have followed and are expected to go into production in the coming years, thus reinforcing Egypt's security of supply and reopening the prospect of a return to LNG exports in the future.

Egypt took the lead in the region's natural gas resource development with the commissioning of the giant Zohr field in December 2017. Starting at around 10 mcm per day (mcm/d), its output is expected to increase to almost 50 mcm/d by the end of 2018 with second and third production units commissioned in late April and early May respectively, reaching a maximum of 75mcm/d by the end of 2019 (Eni, 2018).

Zohr's discovery spurred exploration activity and led to more discoveries and developments in offshore Egyptian licences. The Atoll field, whose Phase I fast-track development conducted by BP delivered its first gas in February 2018, 10 mcm/d of gas and 10 kb/d of condensates (BP, 2018). The Nooros field, another fast-track development led by Eni, reached 32 mcm/d of output in March 2018.

According to Egyptian Energy Minister Tarek El-Molla, the future development of a set of recent discoveries, mainly made by BP and Eni in their respective offshore licences, could further increase domestic production by an additional 15 mcm/d (or almost 5 bcm/y) by 2023.

In order to further reinforce its domestic potential, national company EGAS is understood to be preparing a bid round in 2018 to auction new acreage for exploration both offshore and onshore. In parallel, the framework of the new Gas Market Law ratified by Parliament in July 2017 introduces potential flexibility and incentives, as it could allow foreign companies with a working interest in natural gas-producing fields to export their production share after a minimum of five years should the domestic market not need it.

As a consequence of such dynamism, this forecast expects an average annual growth rate of 6.5% for Egyptian natural gas production over the next five years, reaching around 70 bcm/y by 2023.

Algeria

Algerian natural gas production is expected to grow moderately over the forecast period in spite of a wave of new developments planning to produce their first gas before 2020, as highlighted in last year's report (IEA, 2017a).

The first reason for this moderate outlook relates to the regulatory framework. International oil and gas companies have shown modest interest in Algerian assets, especially as state-owned Sonatrach is required to hold a 51% majority stake in new exploration and production projects as per the amended Hydrocarbons Law of 2005. As a result, since 2005 only 12 exploration licences have been awarded in four licensing rounds – in the 2014 round, the licensing rate fell to 13% with only 4 blocks awarded out of 31 offered. This framework was partially modified in 2013 by introducing incentives for the development of unconventional oil and gas, but the subsequent drop in oil prices neutralised this potential gain for investors. Faced with declining revenues from oil and gas, the Algerian government is considering revising its regulatory framework, potentially in 2018. In parallel, Algeria's Ministry of Energy aims to invest over USD 7 billion in oil and gas upstream activity through to 2021.

The second reason is linked to the very structure of Algeria's natural gas system. The giant Hassi R'Mel producing complex, which historically accounted on average for 75% of Algeria's marketed natural gas production, entered into decline in the early 2000s, further hastened in 2013 due to operational errors that damaged recovery. Sonatrach announced in November 2017 its intention to invest USD 2 billion to stop Hassi R'Mel's decline and maintain a constant level of output in the coming years. The structure of the Hassi R'Mel complex leads to a relatively low ratio of marketed natural gas production compared to other natural gas exporting countries – in 2016 natural gas reinjection and cycling accounted for 47% of gross production output and 2% was flared, leaving only half available as marketed production.

The lack of new exploration combined with a high level of reinjection needed to maintain pressure in Hassi R'Mel lead to the expectation of a flat production trend for the forecast period.

West Africa – developments in Mauritania and Senegal

Offshore activity has seen dynamic developments off the coasts of Mauritania and Senegal as several discoveries have been made. The first discovery of the Tortue-1/Ahmeyim-1 well in Mauritanian waters in mid-2015 was confirmed by the Guembeul-1 (Senegal) and Ahmeyim-2 appraisal drillings in 2016. The resulting Tortue discovery is located across the maritime border of Mauritania and Senegal, a situation which has been alleviated by the joint government protocol to co-operate on the field's development signed in February 2018 (Reuters, 2018c). The Tortue project's developing partners, Kosmos and BP, are expected to take FID by the end of 2018. The Tortue complex is estimated to have 25 tcf (700 bcm) of gas in place.

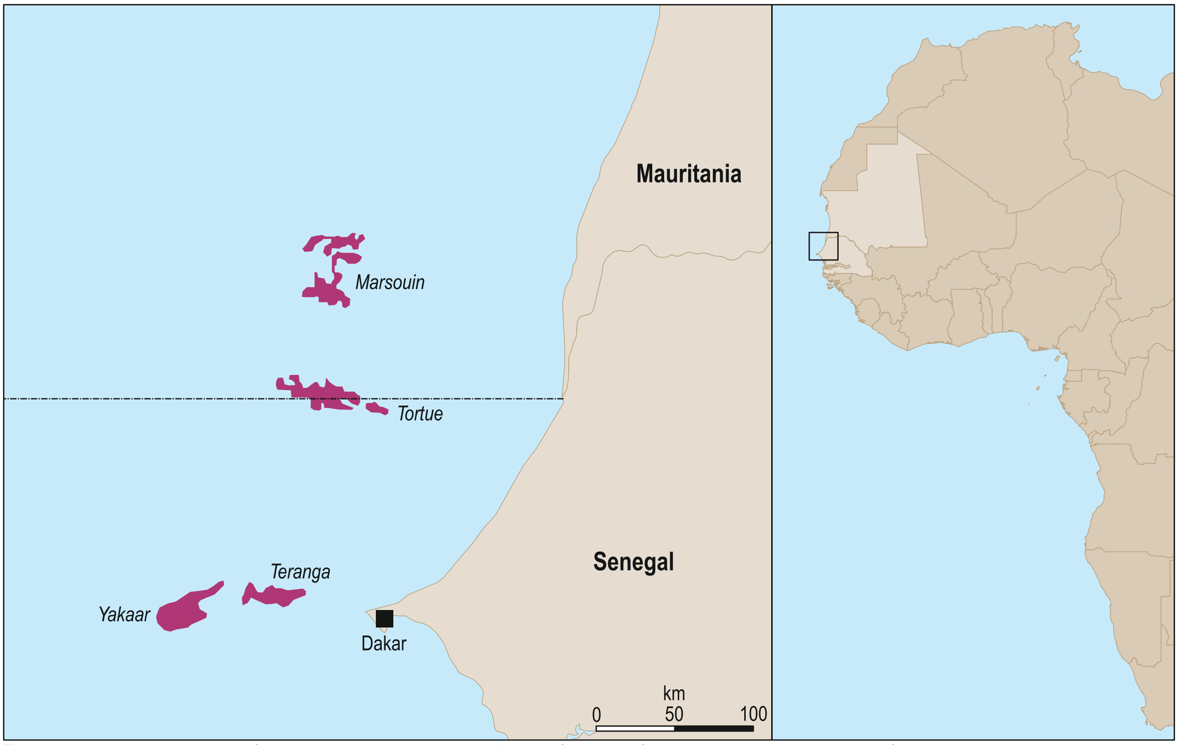
Other significant discoveries followed, such as the Teranga well in mid-2016 in Senegalese waters, which increased the potential gas in the Grand Tortue formation to 50 tcf (1 400 bcm). More recently, the Yakaar discovery in May 2017 resulted in an estimated 15 tcf (400 bcm) of natural gas being found (see Map 2.7).

In the absence of infrastructure or existing nearby consumption markets, the decision to develop these resources will depend on the viability of LNG export projects.

East Africa – developments in Mozambique

Natural gas production in Mozambique remained modest since Sasol began exporting to South Africa in 2004. However, developments took a step further in 2017 as the Eni-led Coral South LNG project achieved FID. The FLNG unit will source its output from the namesake Coral Field discovered by Eni in 2012 in Area 4 of the Rovuma Basin, which is assumed to contain 450 bcm of natural gas (Eni, 2017).

Map 2.7 Natural gas discoveries, offshore Mauritania and Senegal



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

A second export project (Mozambique LNG) led by Anadarko could achieve FID in the course of 2018, as it received approval from the government of Mozambique in March 2018 for the development of the Golfinho-Atum field. The field was discovered in 2010 by Anadarko in Area 1 of the Rovuma Basin, and has an estimated 75 tcf (2 100 bcm) of recoverable natural gas resources.

Encouraged by the prospects of such discoveries, Mozambique's Ministry of Mineral Resources and Energy is targeting the doubling of its natural gas reserves by 2030, banking on growing exploration and further discoveries in the gas-rich Rovuma Basin formation (Ministry of Mineral Resources and Energy of Mozambique, 2017). This report forecasts the first gas deliveries to the LNG export infrastructure to be expected by the end of the outlook period (2022-23).

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3. TRADE

Highlights

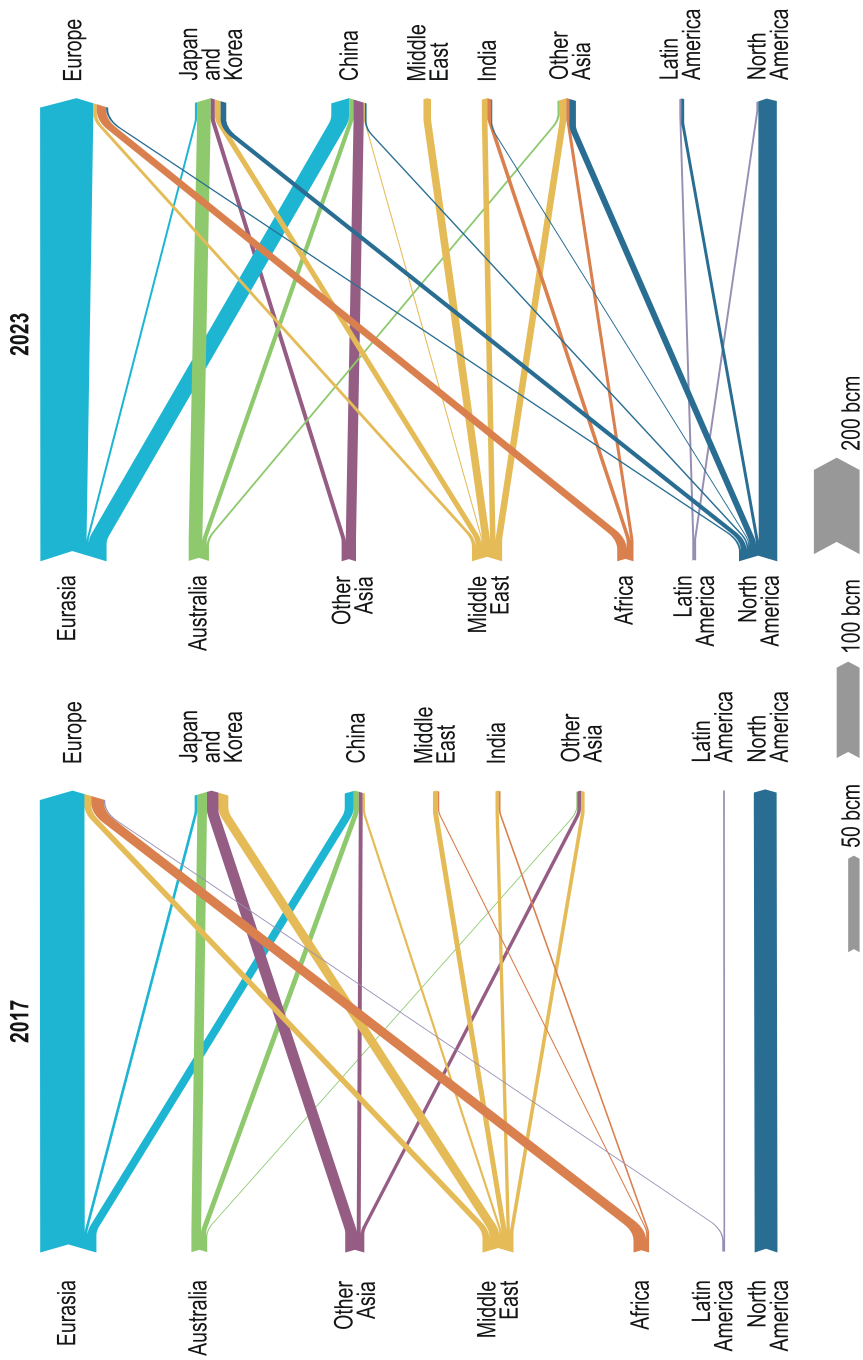
- **Global liquefied natural gas (LNG) trade is expected to pass the 500 billion cubic metre (bcm) mark in 2023**, driven by strong demand in developing Asian markets. The People's Republic of China (hereafter, "China") accounts for over a third of the increase in global LNG demand.
- **The United States surpasses Australia to become the second-largest LNG exporter by 2023 at 101 bcm**, but could overtake Qatar (105 bcm) as the top exporter if new US export projects achieve their final investment decision (FID) in the next two years. Qatari expansion is not expected to be operational before end-2023.
- **Three global LNG players provide 60% of supply by 2023.** Australia, Qatar and the United States together supply 60% of LNG exports, at around 100 bcm each, with the Russian Federation (hereafter, "Russia") gearing up to reach 37 bcm but still some way behind.
- **Eurasian producing countries are both increasing and diversifying their access to importing markets** – to Europe for Azerbaijan with the development of the Southern Gas Corridor pipelines (the Trans Anatolian Pipeline [TANAP] and Trans Adriatic Pipeline [TAP], to China for Russia with the Power of Siberia pipeline, and more globally for Russia with the ramping up of the Yamal LNG export project.
- **China becomes the largest natural gas importing country in the world by 2019**, with the share of imports rising from 39% to 46%. Much of the increase is LNG; imports are expected to increase by 80% from 51 bcm to over 90 bcm between 2017 and 2023. Pipeline imports from Eurasia also increase substantially thanks to new and expanded pipeline capacity**.**
- **Europe's import dependency further increases with the impact of Groningen field phase-out**, combined with the continuous depletion of domestic production. The European natural gas supply gap increases by 30 bcm over the forecast period to reach over 310 bcm by 2023. This increasing gap is bridged by a combination of additional LNG and pipeline gas from both new sources and traditional suppliers.
- **After a phase of strong liquefaction capacity expansion in 2019-20 and lower plant utilisation, utilisation is on the rise from 2021** to reach an average 78% load factor by 2023 (similar to 2017), with a potential for market tightening unless new export projects achieve their FID in the next two years. An increase in US tight oil production and subsequent associated gas development provides a supply push, and is likely to incentivise further FIDs in US LNG export projects. However, evidence from operating projects and those under development shows that it takes between 3.5 and 4.5 years from FID to achieve completion for a US brownfield project.

Global natural gas trade

Global natural gas trade has grown by over 40% over the past 15 years, with an increasing role played by LNG, which saw its share of the trade increase from 22% to 34% over the same period. By

2023, inter-regional traded volumes are expected to account for 31%[1] of total natural gas consumption, with LNG standing at 505 bcm or almost 40% of trade.

Figure 3.1 Main natural gas trade flows, 2017 and 2023



[1] Unless otherwise stated, trade figures in this chapter reflect volumes traded between regions, and they therefore do not include all intra-regional trade flows.

Trade flows are thus expected to change significantly over the forecast period, as shown in Figure 3.1. The picture of trade flows, currently dominated by a few major links, will evolve towards growing inter-regional trade and interdependence between buyers and sellers, enabled by the development of LNG.

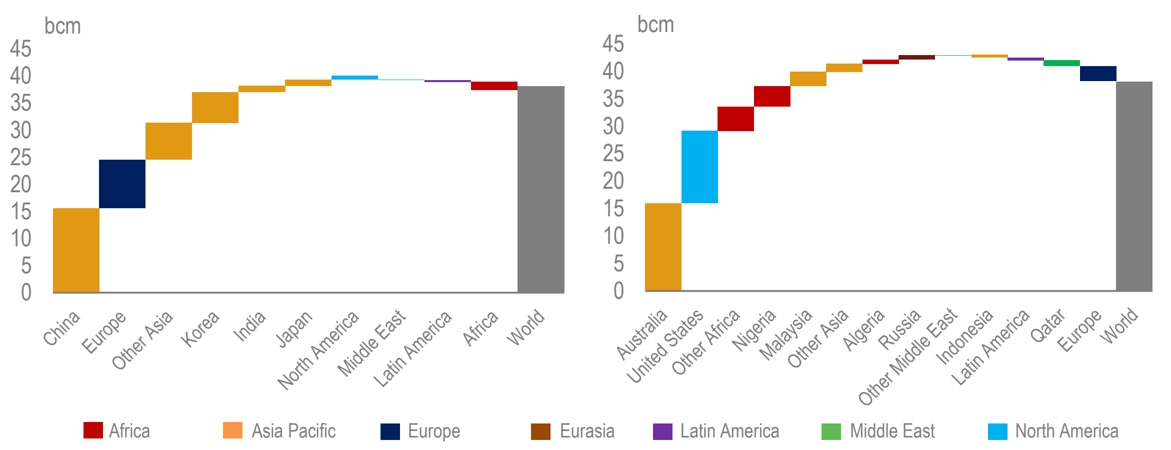
On the supply side, the Middle East's traditional position as the single global balancing supplier is increasingly challenged by the development of export capacity from North America, Australia and Russia.

On the demand side, Asia remains the main point of focus but with growing intra-regional diversification. The historical preponderance of traditional buyers, such as Japan and Korea, is increasingly counterbalanced by the emergence of new Asian buyers – China being the most important in volume terms, but also including India, Pakistan, Bangladesh and others.

Global LNG market

The LNG trade grew by 11% in 2017 to 391 bcm, adding some 38 bcm to the market. On the demand side, Asian markets accounted for most of the growth, with 30 bcm or 80% of incremental imports (see Figure 3.2). China on its own was the single largest contributor to LNG import growth with almost 16 bcm or 40% of the global trade increment. Mature Asian markets, such as Japan and Korea, also made a positive contribution to LNG trade development in 2017, especially Korea, which saw its imports increase by 12% year-on-year (y-o-y), driven by long term contracts ramping up. The European market experienced a strong rebound in LNG imports in 2017 to 64 bcm, at 9 bcm or 16% above its previous 2016 level; this remains below the absolute record of 2011 at the end of the LNG market bubble when deliveries to Europe reached an unprecedented level of 91 bcm. The increase in demand came mainly from southern European countries (Turkey, Spain, Italy, France, Portugal) principally related to consumption in the power generation sector (see Demand chapter). LNG imports decreased in Latin America and in Africa with the progressive diminution of Egyptian imports.

Figure 3.2 LNG trade increment, imports and exports, 2016-17



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

On the supply side, the two major contributions to LNG trade growth come from Australia and the United States, which accounted respectively for 42% and 35% of the total increase in exports. Both countries are at the forefront of the second wave of LNG liquefaction expansion and saw their export capacity increase respectively by 16 bcm/y (or 27%) and 13 bcm/y (or 330%) in 2017 as new liquefaction plants ramped up. Africa's incremental exports represented 24% of total LNG trade growth in 2017, with contributions from Nigeria and Angola. Europe's share of LNG exports diminished owing to the reduction of reloadings compared to 2016.

2017 saw the emergence of new major players in the LNG trade, with China being the single biggest driver of LNG import growth, and Australia and the United States as principal sources of LNG supply development. Such trends are expected to continue during the forecast period and influence the development of the medium-term market. Indeed, China is expected to remain the main driver for the development of LNG demand growth, followed by other emerging Asian economies, while Australia and the United States join Qatar as leading LNG exporting countries, with global coverage but with distinctive business models.

LNG demand: Towards greater diversification, driven by emerging Asian buyers

The global LNG market is expected to reach 505 bcm by 2023, adding some 114 bcm or almost 30% compared to 2017 trade figures (see Figure 3.4). Market diversification increases during this period, with the number of importing countries and territories growing from the current 41 to 46 by 2023.

China and emerging Asia account for over 90% of LNG import growth

As described above, China keeps its role as key market player and remains the single largest contributor to LNG trade growth on the demand side, with an expected increase in LNG imports of more than 40 bcm between 2017 and 2023, thus accounting over a third of global import growth (see Map 3.1).

However, China does not remain the sole source of import growth in emerging Asia, as several markets contribute to LNG trade growth in the coming five years. India and Pakistan, among others, also see their LNG imports grow significantly, while several new Asian importers such as Bangladesh (which received its first LNG cargo in April 2018) are expected to develop their imports over the coming years with import terminals in development, thus providing additional room for LNG trade expansion. The future imports' growth of these emerging Asian players will however be determined by the competitiveness of LNG, as most of these markets are more price-sensitive than China or traditional Asian buyers such as Japan or Korea. The development of the fleet of FSRU vessels would further encourage this market diversification by providing rapid and flexible access to new markets (see Box 3.1)

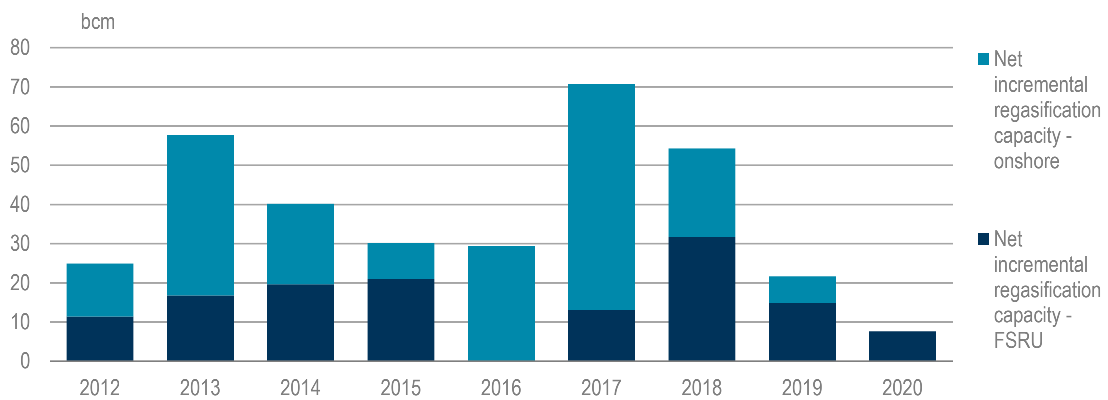
Box 3.1 The strong growth of FSRUs

FSRUs have opened the door to LNG for a range of additional markets recently, which import LNG to meet short-term gas demand when the LNG price is competitive with other fuels, to meet seasonal demand requirements (such as for Latin America) or when a fast supply development option is needed. FSRUs are used either as short to medium term options to bridge supply or infrastructure gap, or as more long term solutions as a replacement of costlier onshore regasification terminals. FSRUs have been attractive for new markets because of lower initial investment cost, shorter installation period (around 18 months for FSRUs versus more than 5 years for onshore conventional regasification terminals) and more flexibility in length of commitment than onshore regasification facilities. Some of the most recent countries to invest in FSRUs include Lithuania in 2014, Egypt, Jordan and Pakistan in 2015, Colombia, Turkey and the United Arab Emirates in 2016, China and Malta in 2017, and Bangladesh in 2018.

The world's first FSRU started operation in the United States in 2005, and at the time of writing 28 FSRUs are now in operation. In the coming years, more than 60 bcm/y of new FSRU capacity is expected to come on line (Figure 3.3).

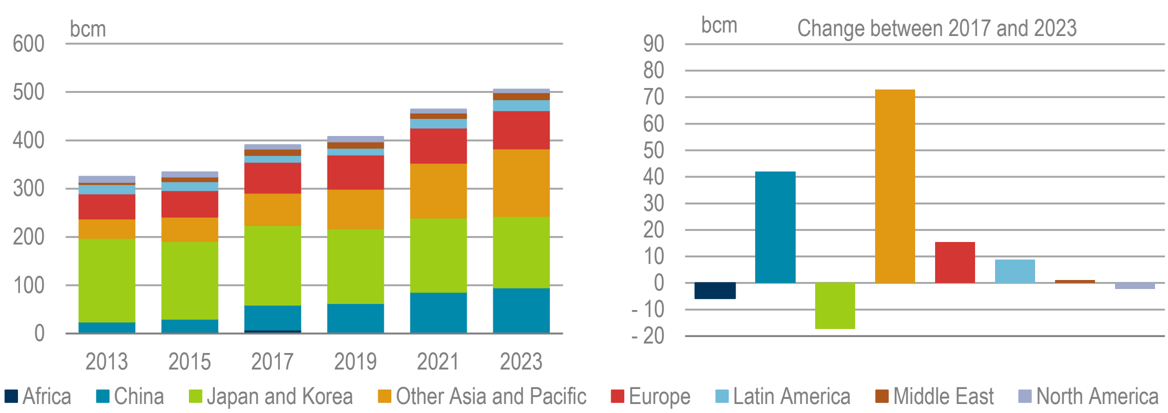
Since 2015, backed by low LNG prices, the volume of LNG received by FSRUs has grown. FSRU development has been advantaged by the projects' small size, fast project development time, and their relatively low capital intensive nature.

Figure 3.3 Incremental regasification capacity: conventional vs FSRU, 2012-20



More mature Asian economies, such as Japan and Korea, see their LNG imports decrease at an average 2% per year over the forecast period. Japan remains the largest LNG importer until 2023 but with some erosion of its import volume owing to the progressive restart of nuclear capacity. In Korea, policy targets of the new Moon administration aimed at reducing nuclear and coal capacity could prove positive for natural gas growth, albeit with some impacts expected to materialise by the end of the next decade and thus more limited visible consequences during the forecast period.

Figure 3.4 World LNG imports by region, 2013-23



In October 2017, Japan's Ministry of Economy, Trade and Industry (METI) announced a plan to finance new LNG infrastructure development projects in Asia with a value of up to USD 10 billion over the next five years, thus supporting Japan's ambition to open new markets in Asia and find outlets for its excess LNG supply (Reuters, 2017a).

Outside Asia, LNG import growth is mainly driven by Europe's increasing supply gap

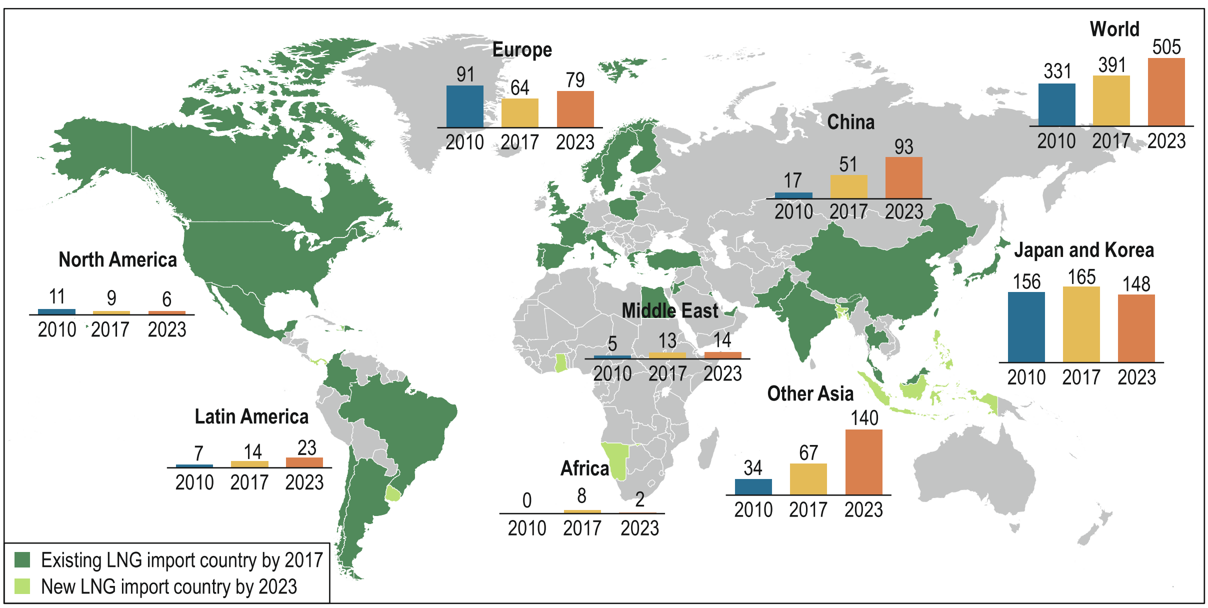
In Europe, in spite of limited prospects for demand growth, the combination of domestic resource depletion (reinforced by the phase-out plan for the Groningen field) and the objective of further diversification away from traditional suppliers creates new opportunities for LNG imports. This is accompanied by renewed competition in a context where most LNG supply contracts to Europe currently in force are due to expire during the outlook period.

Latin America encounters modest yet positive LNG import growth with the development of several new regasification terminals in both the Caribbean and Southern Cone regions. In North America the LNG trade situation remains broadly unchanged, with limited import volumes to Mexico and the northeastern United States.

LNG imports are expected to remain stable throughout the forecast period in the Middle East, where most demand growth will occur in producing countries such as Iran and Saudi Arabia.

In spite of the expected development of several new regasification facilities over the forecast period, LNG trade flows to Africa are negatively impacted by the phase-out of Egyptian imports subsequent to the development of the Zohr offshore field.

Map 3.1 LNG import countries and LNG import volumes, 2010-23



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

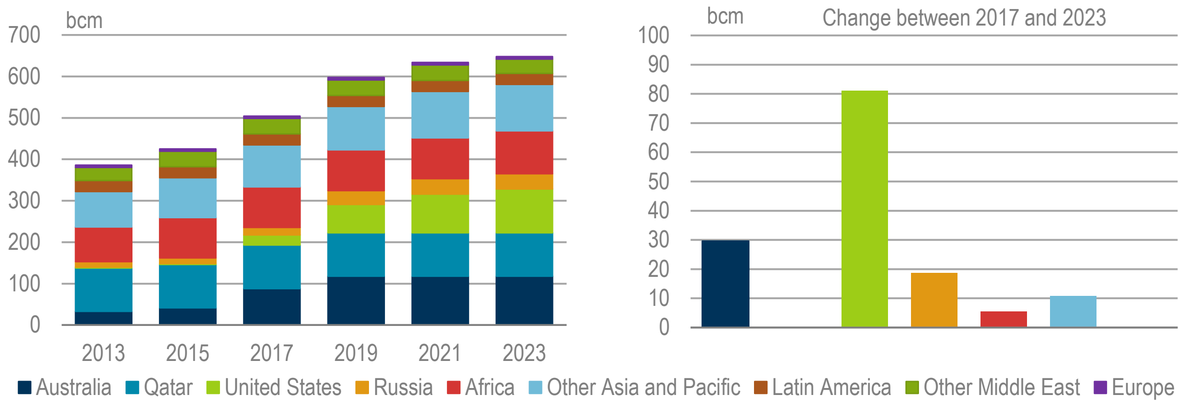
LNG supply: The emergence of three global players

At the beginning of 2018, global LNG nameplate liquefaction capacity reached 499 bcm/y, increasing by 10% over 2017. Total nameplate liquefaction capacity is expected to reach 645 bcm/y by the end of the forecast period in 2023 (see Figure 3.5).

United States accounts for over half of liquefaction capacity under development

Most of the medium-term capacity growth takes place in North America, with US projects under development adding up to over 80 bcm/y of capacity and accounting for over 50% of total expected liquefaction development to 2023. The bulk of this additional capacity will be commissioned by 2020, except for the third train of Cheniere's Corpus Christi LNG which took FID in late May 2018 and is expected to be commissioned by mid-2022 (Cheniere, 2018).

Figure 3.5 LNG nameplate liquefaction capacity, 2013-23



Australia comes second with around 30 bcm/y of additional liquefaction capacity or about 20% of the global capacity increase. Australia was ahead of the United States in this second wave of liquefaction development, with most of its nameplate capacity already commissioned (Australia's nameplate liquefaction capacity almost tripled between 2013 and 2017 from 33 bcm/y to 88 bcm/y). Russia is the third source of liquefaction development with the ramping up of Yamal LNG's first train (commissioned in December 2017) and the subsequent Trains 2 and 3, adding some 15 bcm/y of capacity to Russia's current 22 bcm/y liquefaction plants (14.5 bcm/y from Sakhalin II and 7.5 from Yamal's train 1) .

This report only considers liquefaction projects that achieved their FID as of early June 2018 as contributing to future export capacity for the forecast period (including US's Corpus Christi T3). It is assumed, however, that at least one of the US projects[2] currently in their final phases will achieve FID and start development before the end of 2019, and hence be commissioned by the end of the forecast period.

Notably, a significant proportion of global liquefaction capacity has remained off line in recent years – over the 2013-17 period, unplanned capacity disruptions resulted in 10% to 14% of nameplate capacity being offline (IEA, 2017). This forecast assumes that several liquefaction plants will remain off line or will run below their nameplate capacity until 2023 for several reasons (technical issues, feed gas limitations, security risk).

LNG diversity of supply increases with the development of new export sources

Most of the increases in LNG exports are sourced from new projects in the United States, Australia and Russia, thus increasing the diversity of supply sources and routes.

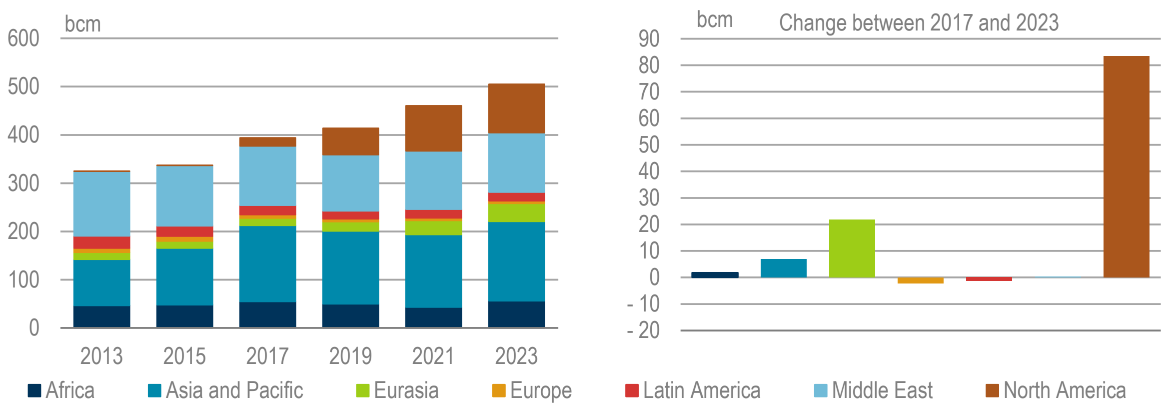
[10] Several US export projects have received all the necessary permits to achieve FID – see Box 3.3. This report does not discriminate between the different projects and assumes by default that an additional 5 bcm to 6 bcm capacity is commissioned by 2023 for the purpose of the forecast.

The development of the United States' output is the dominant feature of LNG market supply growth until 2023, with US projects accounting for over 75% of incremental exports in the 2017-23 period (Figure 3.6).

US LNG exports pass the 100 bcm mark by 2023 (Map 3.2), just ahead of Australia (at 98 bcm), but still slightly behind Qatar, which is expected to remain the number one LNG exporter at 105 bcm.

The Middle East remains the largest LNG exporting region throughout the outlook period, with a stable output of over 120 bcm per year. LNG activity in Yemen is assumed not to resume operations in the near future and is therefore considered to be off line until further notice.

Figure 3.6 World LNG exports by region, 2013-23



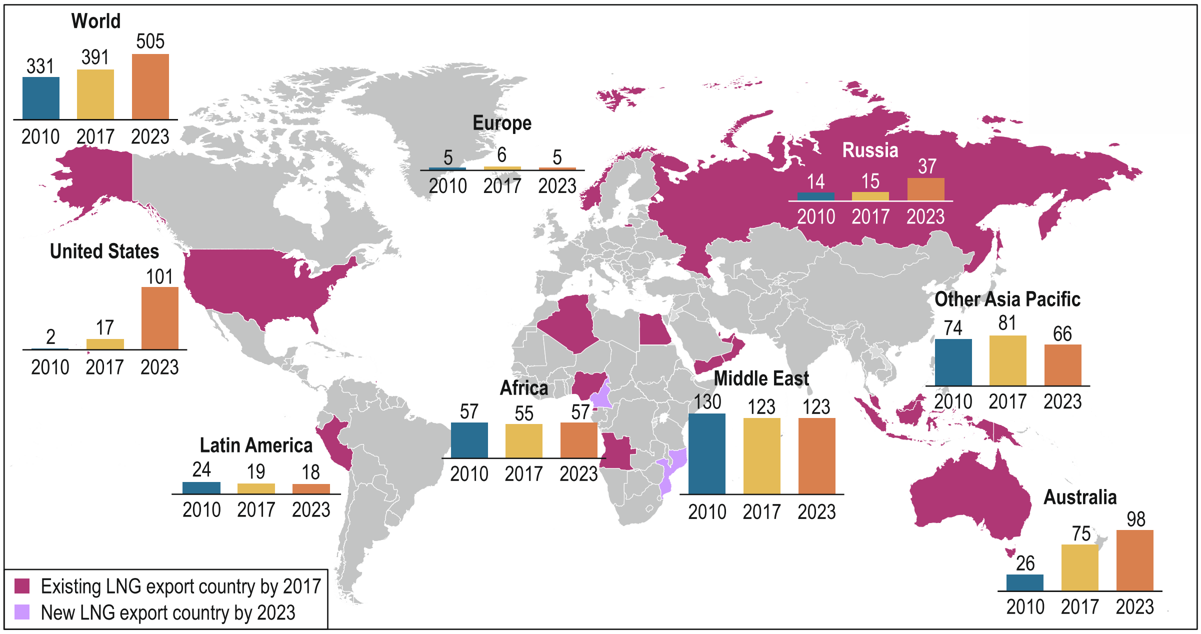
LNG exports from the Asia and Pacific region – outside Australia – increased by 3% to 81 bcm during 2017, owing mainly to an increase in Malaysia's exports (up 7.7%) but also to the ramping up of Papua New Guinea (up 5%), while Indonesia's output decreased (down 2%). In spite of this recent increase, it is assumed that output from the region and especially from South East Asia decreases over the next five years. Malaysia has strong exposure to Japanese buyers whose contracts are due to expire during the forecast period at a time when Japan will be in an over-contracted position, which could imply only partial renewal of these volumes. As for Indonesia, even with the prospect of new production developments, several plants are still faced with long-standing feed gas sourcing issues.

In Africa, overall LNG exports are expected to remain broadly stable, with slight increases up to 2023. In sub-Saharan Africa, output from existing exporters – Nigeria and Equatorial Guinea – remain stable, while Angola is likely to further use its existing capacity, and new projects in Cameroon and Mozambique ramp up (the latter being commissioned at the very end of the forecast period). In North Africa, Egypt is not assumed to restart regular LNG exports, even though the country may see some supply surplus from the development of domestic production, while Algeria's output gradually decreases with the impact of historical contracts expiring and potentially not being renewed up to their current levels.

LNG exports from Latin America slightly decrease by the end of the forecast period as Trinidad and Tobago is expected to face growing feed gas issues, while output from Peru remains stable.

Russia's LNG output more than doubles by 2023 with the development of Yamal LNG's three trains. Exports from Norway remain stable.

Map 3.2 LNG export countries and LNG export volumes, 2010-23



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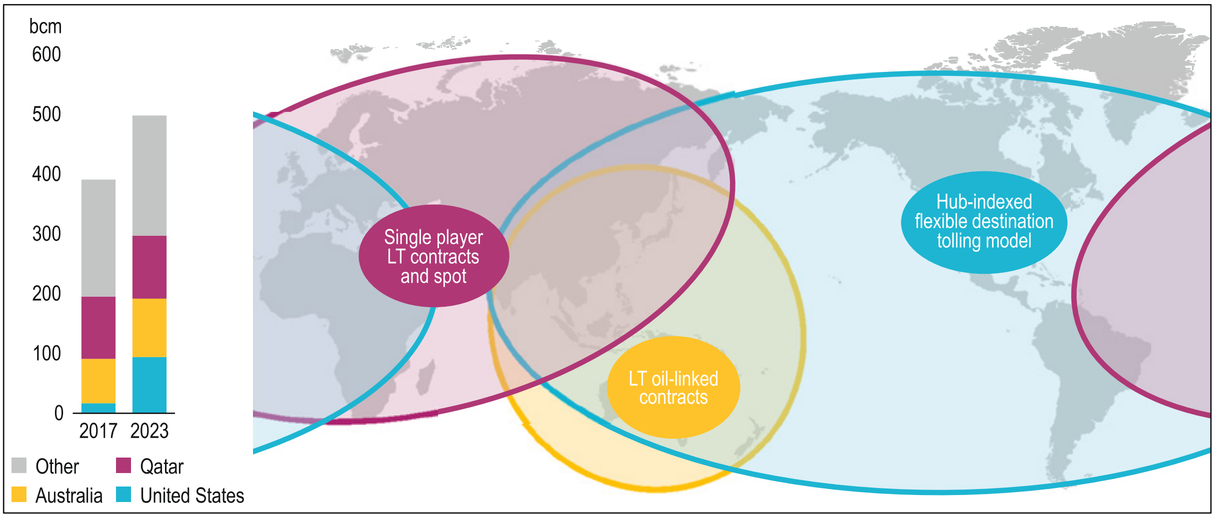
Australia, Qatar and the United States cover 60% of supply by 2023

Once the current wave of LNG liquefaction capacity development is completed, the balance of power between suppliers changes as Qatar's historical position as dominant LNG player is increasingly challenged. Three major LNG players – Australia, Qatar and the United States – together cover 60% of global LNG supply capacity (Map 3.3).

Map 3.3 The three major LNG export players and their respective business models



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

Note: LT = long-term.

Each of these three countries has around 100 bcm/y of nameplate export capacity by 2023, and global market coverage.[3] At the same time, they also represent three distinct LNG business models:

- Australia's liquefaction is structured around nine facilities with average nameplate capacity ranging from 6 bcm/y to 12 bcm/y (apart from North West Shelf and Gorgon, which are both above 20 bcm/y) owned by consortia of international oil companies (IOCs) and major Asian LNG buyers. Most of the export capacity is covered by long-term contracts with an average duration of 20 years, with oil-linked price formulae, and with a fixed destination for about two-thirds of contracted volumes. As most of these liquefaction plants are recent or still under development, contract expiry is not on the agenda for the forecast period – except for North West Shelf LNG, which was commissioned in 1989.

- Qatar's capacity is controlled by a single player, state-owned Qatar Petroleum, with minority equity held by IOCs and Asian players. The original organisation under two operating companies (Qatargas and RasGas) was simplified in January 2018 with the merger into a single company, Qatargas, which operates the 14 trains of the Ras Laffan complex. Qatar's portfolio of export contracts is more diversified: while its legacy contracts to Asia are traditional (oil indexed and with fixed destination), the volumes initially assigned to Europe and North America are flexible and have enabled Qatar to play the role of balancing supplier to both Atlantic and Pacific basins. The progressive expiry of the legacy contracts pushed Qatar to become more agile commercially, using traders and tenders to capture new customers – notably with Trafigura, which helped Qatar to supply LNG to some of the most recent importers, including Egypt, Jordan and Pakistan, who are securing part of their supply via short-term tenders.

- Most of the United States' liquefaction capacity is under development, with trains from six facilities achieving FID, of which two (Sabine Pass and Cove Point) are operational at the time of writing. The capacity is sold with flexible destination and at hub-based pricing – the procurement model is either traditional free on board (FOB) delivery in the case of Cheniere, or based on a liquefaction tolling fee for other projects (i.e. feed gas procurement falls to the buyer). Whereas most LNG export projects are integrated with upstream investment, US LNG projects are based on commodity supply and thus usually require only an investment in liquefaction. Most of the export capacity has been bought by global portfolio players and major European and Asian utilities – which also develop their portfolio activities.

These three major suppliers therefore offer LNG to the market under different commercial schemes, but are increasingly likely to compete in the Asian market to gain new customers or secure existing ones.

[3] More regional for Australia, but as Asia and Pacific accounts for around 75% of LNG demand, it can still be seen as global.

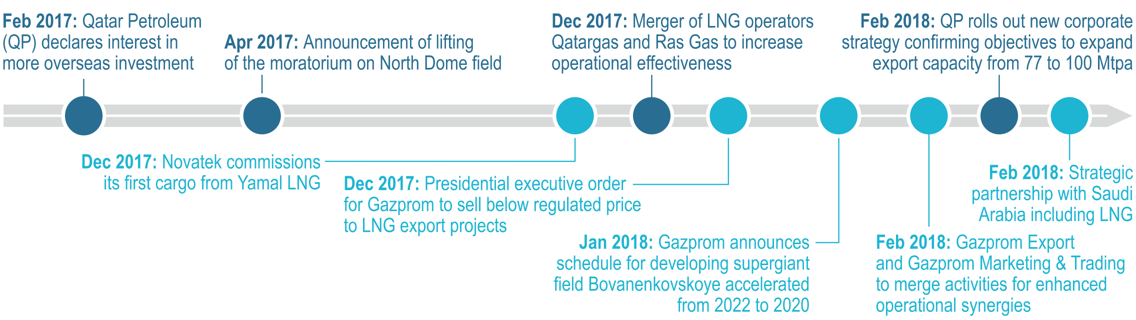
Box 3.2 Tug of war: Exporters brace themselves for more competition

The prospect of more competition on the LNG supply side, arising from the development of North American export projects, has triggered some reaction from major traditional suppliers (Figure 3.7).

Qatar, which enjoyed a strong and undisputed position in global LNG trade since the late 2000s, reacted in 2017 with three strategic measures:

- **Capacity development:** Qatar announced in April 2017 the lifting of its self-imposed moratorium on exploration and production in its giant North Field asset. This measure was initially declared in 2005 to assess the impact of rapid production on reservoir behaviour. Qatar's national oil company (NOC), Qatar Petroleum (QP), confirmed the capacity expansion target from 77 Mtpa to 100 Mtpa in February 2018. Qatar benefits from one of the most competitive production cost structures among major exporters thanks to the high level of valuable condensates associated with its natural gas output.
- **Market diversification:** A little earlier, in January 2017, QP stated its interest in expanding its overseas presence. QP is already involved in overseas projects and is among others majority owner in the US LNG export project Golden Pass LNG with multinationals ExxonMobil and ConocoPhillips.
- **Operational optimisation:** Qatar's LNG production had been developed through two distinct companies, Qatargas and RasGas, QP having a majority share in both companies. The two companies merged by the end of 2017 and the resulting "new" Qatargas entity started operations on 1 January 2018. Beyond operational cost savings estimated by QP at about USD 500 million per year, this merger reinforces Qatar's primacy with a single entity operating 77 Mtpa of liquefaction capacity and a chartered fleet of 70 LNG vessels.

Figure 3.7 Qatari and Russian strategies in response to LNG competition, 2017-18



Russia's strategy for LNG development has traditionally been somewhat limited and considered as a less competitive export option, not least because it generates less federal budget revenue* than traditional oil and gas exports. Russia instead has focused on its strengths in production and pipeline network development to both Europe and Asia. The advent of LNG competition, coupled with the commercial and technical success of Novatek's development in its Yamal LNG project, seemed to spur Russian interest in LNG exports. Yamal LNG Train 1's output was secured by equity owners Novatek, Total and CNPC, plus buyers Gas Natural Fenosa and Engie, in spite of competition from US export projects at Henry Hub pricing. Commissioning was completed according to schedule.

Russia's actions since late 2017 have followed a similar path to Qatar's, albeit accelerated:

- In late December 2017, the government released Gazprom from price regulation for selling natural gas from LNG export projects, thus granting a feed gas cost advantage to these projects (Kommersant, 2017).

- In parallel, Gazprom is optimising its operational structure by announcing in February 2018 its planned reorganisation of international activities with the merger of its subsidiaries Gazprom Export (in charge of long-term contracts) and Gazprom Marketing and Trading (responsible for short-term and downstream activities). The reorganisation should be fully completed by 2020 (Reuters, 2018).
- Russia is also pushing its production capacity as Gazprom announced in January 2017 an acceleration of the schedule for developing the supergiant Bovanenkovskoye field, with a plateau target of 115 bcm/y moved from 2022 to 2020 (against 84 bcm in 2017). The additional production will feed the Nord Stream 2 pipeline as well as potential LNG export projects in the Baltic Sea.
- Russia's recent overseas partnership strategy has focused on the Middle East. After Gazprom signed several memoranda with Iranian counterparts in December 2017 on natural gas production and liquefaction (Reuters, 2017b), Russia announced in February 2018 a strategic partnership with Saudi Arabia. This partnership covers several energy-related fields, including potential Saudi investment in Novatek's Arctic LNG 2 export project, and potential Russian LNG supply to Saudi Arabia.

[*] LNG projects are free from export taxes and benefit from tax break, including on natural gas extraction.

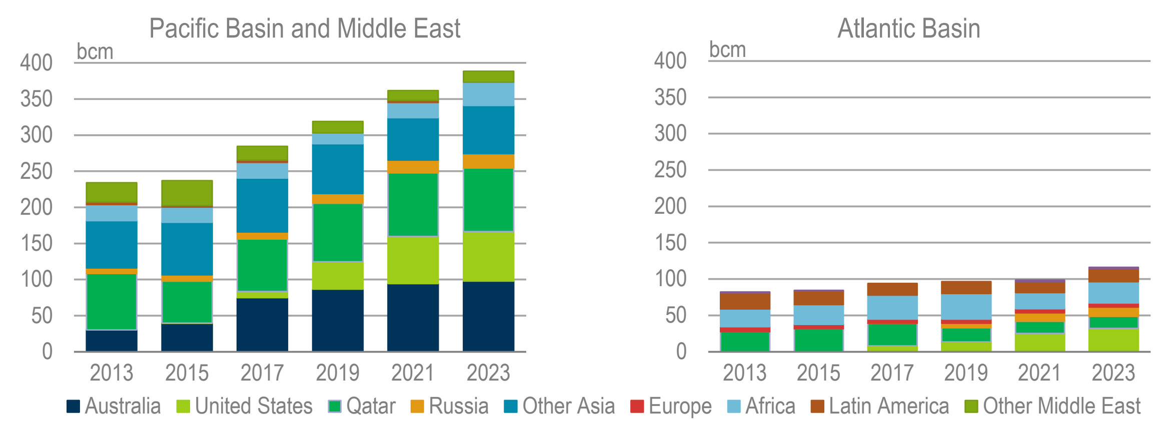
LNG trade flows: Go East

The Pacific Basin traditionally accounts for between 60% and 75% of global LNG imports. Its share is expected to grow to up to almost 80% during the forecast period, driven by the dynamics of additional LNG needs in China and other emerging Asian consumer markets (Figure 3.8).

In 2017, LNG trade into the Pacific Basin and Middle East amounted to 295 bcm or 75% of total LNG trade, compared to 96 bcm for the Atlantic Basin. By 2023, LNG trade to the Pacific Basin and Middle East is expected to reach above 390 bcm or 78% of total LNG trade, increasing by almost 40%. This increment will be met by the ramping up of Australian output, as well as by an increasing share of US exports – and to a lesser extent Russian exports.

LNG trade in the Atlantic Basin grows by 20% to reach 115 bcm by the end of the forecast period. US LNG will provide most of the increase.

Figure 3.8 LNG trade per basin and supplier, 2013-23

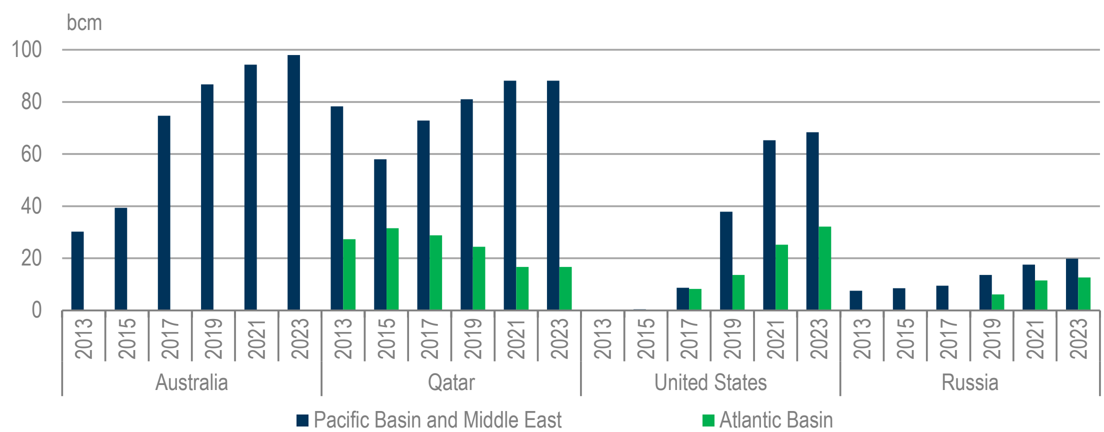


The expected evolution of Qatar's exports follows a progression of flexible and currently uncontracted flows to the Pacific Basin, which accounted for 70% of Qatar's exports in 2017 and grow to almost 85% by 2023 (Figure 3.9).

US LNG flows were equally balanced between the Atlantic and Pacific basins in 2017 owing to the preponderance of Mexico, which accounted for 30% of exports. LNG exports to Mexico are expected to decline, as they will be replaced by pipeline flows as additional capacity is commissioned. Although Europe will remain an attractive market for US LNG, flows will shift eastward to the Pacific Basin driven by higher demand growth and margins and account for around two-thirds of US LNG exports by 2023.

Russian exports from Sakhalin LNG are sold to Japanese and Korean buyers with a fixed destination, whereas most of the capacity of Yamal LNG (operating and under development) is sold to equity owners Novatek and Total and portfolio players with flexible destinations or options for reloading in Europe. By 2023, Russia's LNG exports are expected to be almost balanced between the Pacific (60%) and Atlantic (40%) basins, with some seasonality expected depending on the availability of Arctic shipping routes.

Figure 3.9 LNG exports per basin for a selection of suppliers, 2013-23

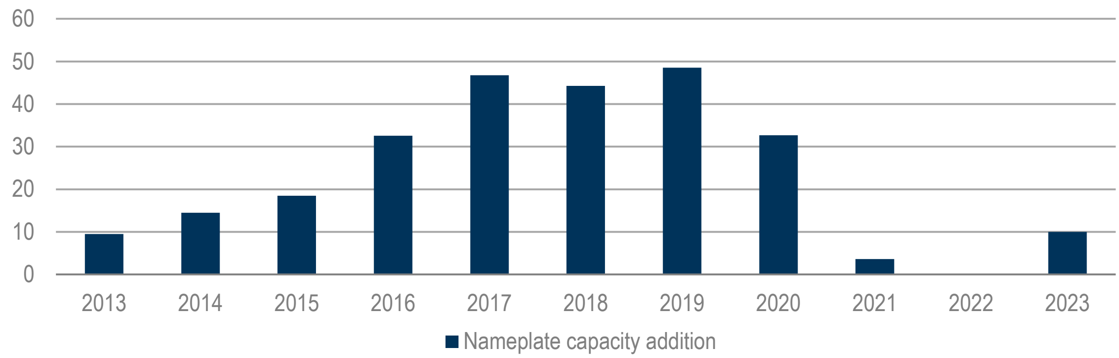


Towards a tighter LNG market?

The current wave of liquefaction projects, which reached FID during the past six years, will result in the addition of over 170 bcm/y of nameplate capacity between 2017 and 2020 (Figure 3.10). This massive addition over a limited period is likely to result in a lower average utilisation rate of liquefaction plants. Competition among suppliers will increase while receiving capacity in import countries could cause some bottlenecks, especially for new buyers in emerging markets where infrastructure is still in development.

This could result in looser LNG market conditions, especially between 2019 and 2020 when the bulk of new liquefaction capacity will begin operations – assuming that these new projects are commissioned according to their current schedule and no additional unplanned maintenance. However, this potentially looser market could be short-lived owing to the dynamic growth of Asian emerging markets, combined with the lack of additional investment in liquefaction capacity beyond the list of projects that have already achieved FID.

Figure 3.10 LNG export capacity additions, 2013-23



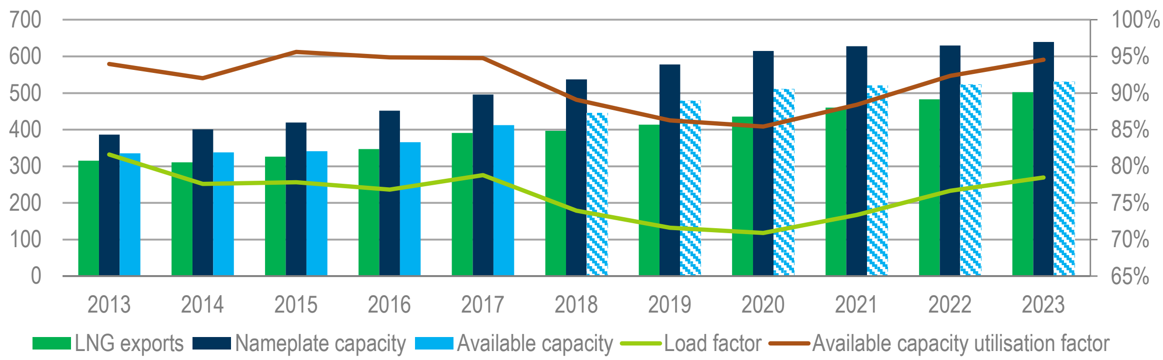
Note: Nameplate capacity for projects with FID at the time of writing, using commissioning years according to project companies' official planning and assuming that one FID will be taken for an additional 5 to 6 bcm/y US project to be commissioned by the end of the forecast period, excluding assumptions on unannounced delays and ramping-up rates of newly commissioned facilities.

Figure 3.11 shows the impact of such a configuration on liquefaction utilisation according to two factors:

- Load factor – the ratio of the actual output in a given year against the plants' nameplate capacity.
- Available capacity utilisation factor – the ratio of the actual output to the potential output of the facility, adjusted to account for both planned outages (maintenance) and unplanned outages (lack of feed gas, technical problems, or weather).[4]

The utilisation rate drops from its 2017 level to reach a low point in 2019-20, and then progressively recovers to its 2017 level and above by 2023. Based on a load factor of 78% in 2017, the trend sees it reach a minimum of 70% and then increase to 78% (compared to 82% in 2013's tight market). Looking at the available capacity utilisation factor, which stood at 95% in 2017, this implies a low point of 85% and a 95% rate by 2023.

Figure 3.11 LNG trade and liquefaction utilisation rate, 2013-23



[4] As mentioned earlier, it is assumed here that several liquefaction plants will remain off line or will run below their nameplate capacity until 2023 for several types of reason (technical issues, feed gas limitations, security risk).

This assessment only accounts for annual trade and reflects annual average utilisation rates at liquefaction plants. Notably, LNG trade in 2017 showed an increasing seasonal pattern of flows as China was using LNG as a substitute for its lack of seasonal storage, on top of its overall consumption growth. The potential tightness of the LNG market by the end of the forecast period could therefore be more pronounced.

This potential risk of a tight market could be alleviated by the development of new liquefaction capacity, which will be needed anyway beyond the forecast horizon if the growth trend in the LNG market continues. Several projects in different regions are currently being considered, and some of them could reach FID in the near future. North American projects at different stages of development pre-FID could be amongst the most likely candidates, as they do not require integrated upstream investment.

However, the timeliness of project development will be key to ensure commissioning in the near term. The feedback from US projects, operating and under construction, shows that the average lead time for developing a brownfield liquefaction plant ranges between 3.5 and 4.5 years from FID to completion for "traditional" projects with 4.5 Mtpa trains (see Box 3.3), which could be lowered to 3 years for smaller modular technologies. In any case, it would require these projects to reach FID within less than two years for them to be operational before the end of this forecast.

Box 3.3 US LNG liquefaction projects status and potential development

US LNG export projects are required to go through several authorisation processes before reaching FID:

- Submit a Free Trade Agreement (FTA) application to the Department of Energy (DOE) for trading with countries which have a free trade agreement with the United States*.
- Submit a Non-Free Trade Agreement (Non-FTA) application, similarly to the DOE for trading with all other potential countries not covered by the FTA application. An applicant may choose to submit a combined application for FTA and Non-FTA exports or separate applications.
- Construction authorisation: the Federal Energy Regulatory Commission (FERC) is responsible for authorising the siting and construction of onshore and near-shore LNG infrastructure, while the US Maritime Administration (MARAD) and US Coast Guard (USGC) are responsible for offshore installations. The process includes a mandatory pre-filing submission for any prospective projects, followed by a formal filling. It also covers the issuance of (both draft and final) environmental impact statements to assess the potential environmental impacts of the project.

At the time of writing, the pipeline of LNG export projects is as follows (see Table 3.1):

- Five projects have received their authorisations, achieved FID and are under construction.
- Four projects have received all the administrative authorisations but have not started construction.
- Twelve projects are in the course of the formal authorisation process.
- Four projects are at their pre-filing stage.

The second stage of this project pipeline – projects with authorisations but not under construction – comprises projects still pending FID. These account for a cumulative capacity of 6.79 billion cubic feet per day (bcfd) or the equivalent of 69 bcm per annum, and would by definition be the most likely to be able to achieve FID at short notice.

Table 3.1 US LNG export projects regulatory status

US jurisdiction	Project location	Project owner	Capacity (bcfd)
Approved – under construction			
FERC	Hackberry, LA	Sempra-Cameron LNG	2.10
FERC	Freeport, TX	Freeport LNG Dev/Freeport LNG Expansion/FLNG Liquefaction	2.14
FERC	Corpus Christi, TX	Cheniere-Corpus Christi LNG	2.14
FERC	Sabine Pass, LA	Sabine Pass Liquefaction	1.40
FERC	Elba Island, GA	Southern LNG Company	0.35
Approved – not under construction			
FERC	Lake Charles, LA	Southern Union-Lake Charles LNG	2.20
FERC	Lake Charles, LA	Magnolia LNG	1.08
FERC	Hackberry, LA	Sempra-Cameron LNG	1.41
FERC	Sabine Pass, LA	Exxon Mobil-Golden Pass	2.10
Proposed – pending application			
FERC	Pascagoula, MS	Gulf LNG Liquefaction	1.50
FERC	Cameron Parish, LA	Venture Global Calcasieu Pass	1.41
FERC	Brownsville, TX	Texas LNG Brownsville	0.55
FERC	Brownsville, TX	Rio Grande LNG-Next Decade	3.60
FERC	Brownsville, TX	Annova LNG Brownsville	0.90
FERC	Port Arthur, TX	Port Arthur LNG	1.86
FERC	Jacksonville, FL	Eagle LNG Partners	0.13
FERC	Plaquemines Parish, LA	Venture Global LNG	3.40
FERC	Calcasieu Parish, LA	Driftwood LNG	4.00
FERC	Nikiski, AK	Alaska Gasline	2.63
FERC	Freeport, TX	Freeport LNG Dev	0.72
FERC	Coos Bay, OR	Jordan Cove	1.08
Proposed – pre-filing			
FERC	Corpus Christi, TX	Cheniere-Corpus Christi LNG	1.86
FERC	Cameron Parish, LA	Commonwealth LNG	1.18
FERC	LaFourche Parish, LA	Port Fourchon LNG	0.65
MARAD-USGC	Gulf of Mexico	Delfin LNG	1.18

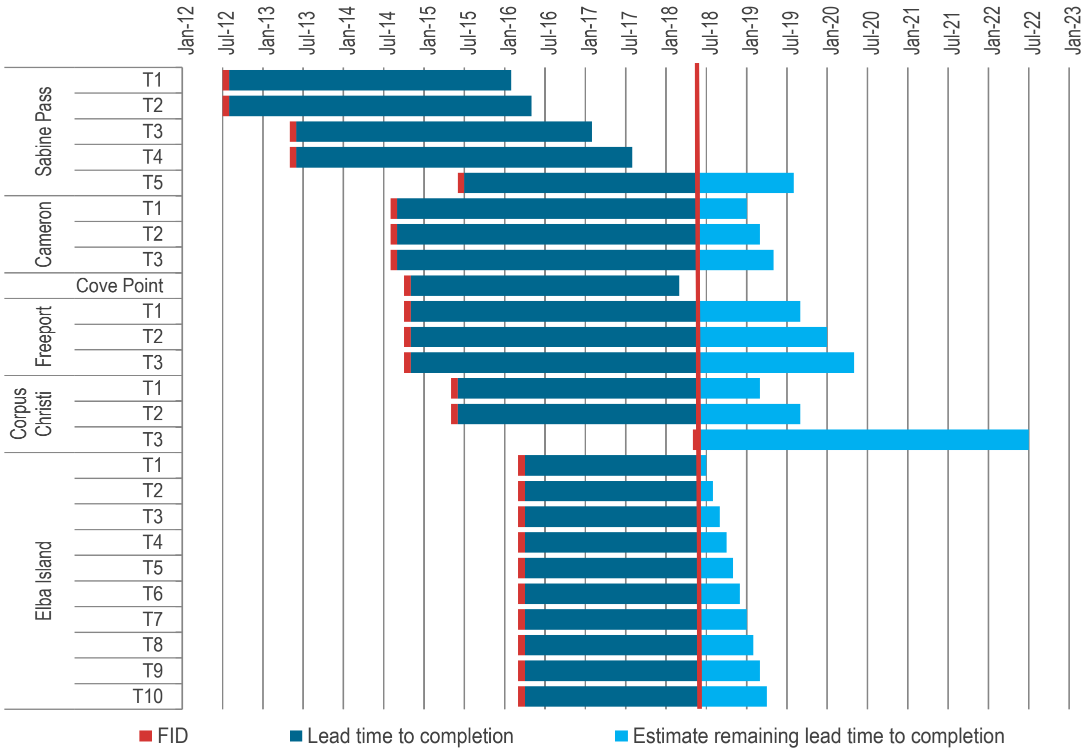
Sources: FERC (2018a), *North American LNG Import/Export Terminals Approved*, www.ferc.gov/industries/gas/indus-act/lng/lng-approved.pdf; FERC (2018b), *North American LNG Export Terminals Proposed*, https://ferc.gov/industries/gas/indus-act/lng/lng-proposed-export.pdf.

However, feedback from export terminals operating and under development shows that the lead time between FID and first operations takes a minimum of almost 3.5 years (see Figure 3.12):

- For Sabine Pass LNG, the first commissioning cargo of Train 1 was issued in February 2016 while FID had been taken in mid-2012. A similar range is observed for Cove Point LNG (one train), with FID taken in late 2014 and commissioning reached in March 2018.
- For Cameron LNG, impacts of hurricanes have led to construction delays and an estimated start date for Train 1 of early 2019, or about 4.5 years after FID. Similarly, Freeport LNG announced in late April 2018 additional construction delays and operations for its first train delayed to September 2019, or close to 5 years after FID.

- All the above are "traditional" brownfield projects (i.e. where initial regasification terminals are converted into liquefaction plants) with 4.5 to 5.5 Mtpa liquefaction trains, whereas Elba Island LNG (currently under construction) uses smaller modular trains of 0.25 Mtpa apiece, which would enable a reduced lead time of less than 3 years for the first module according to the project company's estimate.

Figure 3.12 US liquefaction projects development lead time as of early June 2018



Source and note: IEA compilation based on information as provided by LNG project companies' or parent companies' websites and therefore considered as best estimates at the time of writing.

Based on the observed lead times of US projects in operation and under construction, and all things being equal, if no FIDs are taken in 2018-19 it will be difficult to see new capacity being commissioned before the very end of the outlook, except for smaller train technologies.

*Australia, Bahrain, Canada, Chile, Colombia, Dominican Republic, El Salvador, Guatemala, Honduras, Jordan, Mexico, Morocco, Nicaragua, Oman, Panama, Peru, Republic of Korea and Singapore (DOE, 2018).

Regional trade outlook

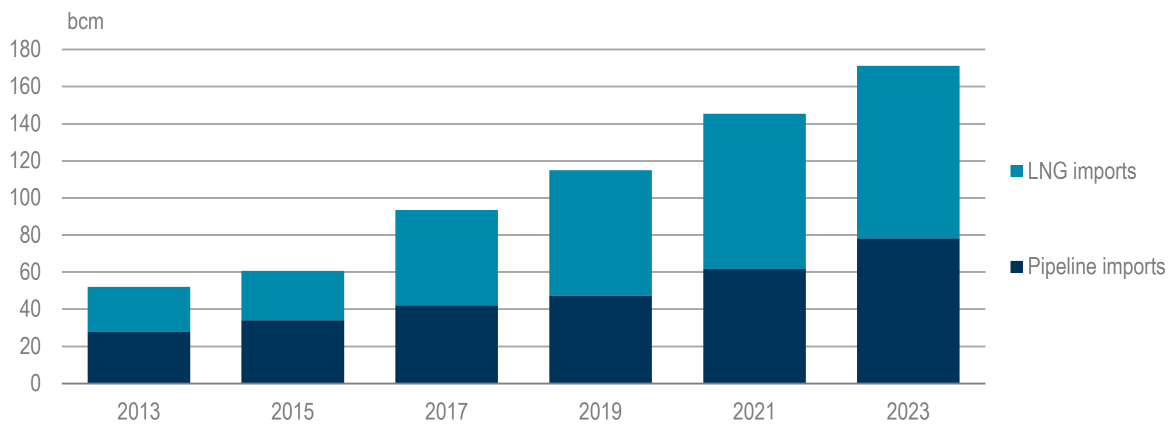
Asia

Asia is a major contributor to trade growth throughout the forecast period, accounting for an increase of about 90 bcm of LNG flows and 35 bcm of pipeline flows by 2023. This section provides a special focus on China's trade owing to its prominent role in regional and global natural gas trade growth.

China

2017 has been a year of record-breaking import growth for China, pushing the country to the position of number two LNG importer in front of Korea (see Box 3.4). This forecast expects continuous growth of Chinese imports throughout the forecast period, reaching 93 bcm and 78 bcm by 2023 for LNG and pipeline flows respectively. China will import more natural gas than any other country (Figure 3.13), becoming the largest natural gas importer by 2019, and with 171 bcm of imports by 2023.

Figure 3.13 Natural gas imports, China, 2013-23

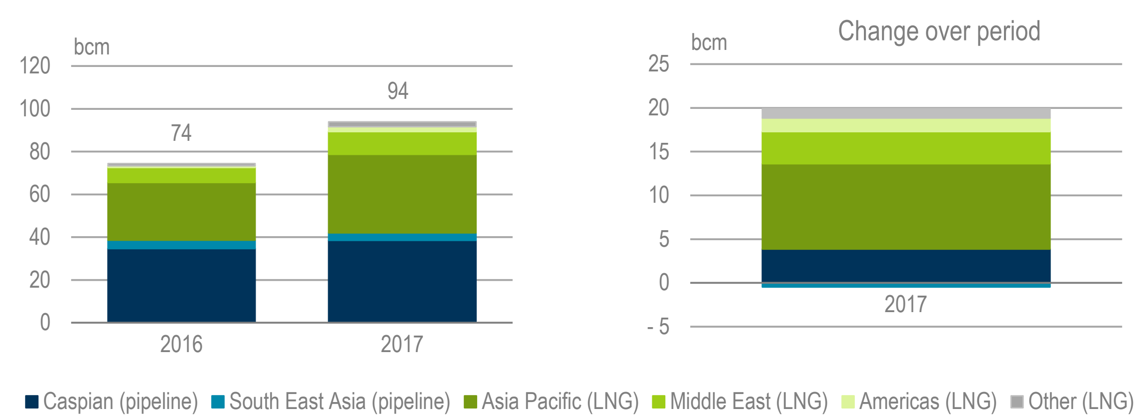


Box 3.4 2017 was a record breaking year for natural gas imports in China

Import dependency increased to all time high of almost 40%

2017 was a record year for natural gas imports in China. They increased by 20 bcm y-o-y from 74 bcm to 94 bcm, pushing the country's import dependency to an all-time high of almost 40% (Figure 3.14).

Figure 3.14 Natural gas imports by source, China, 2016-17



Note: Any comment on figures or tables in this report which use Argus data are IEA's opinions and are not approved by Argus and do not (necessarily) represent Argus' position or views.

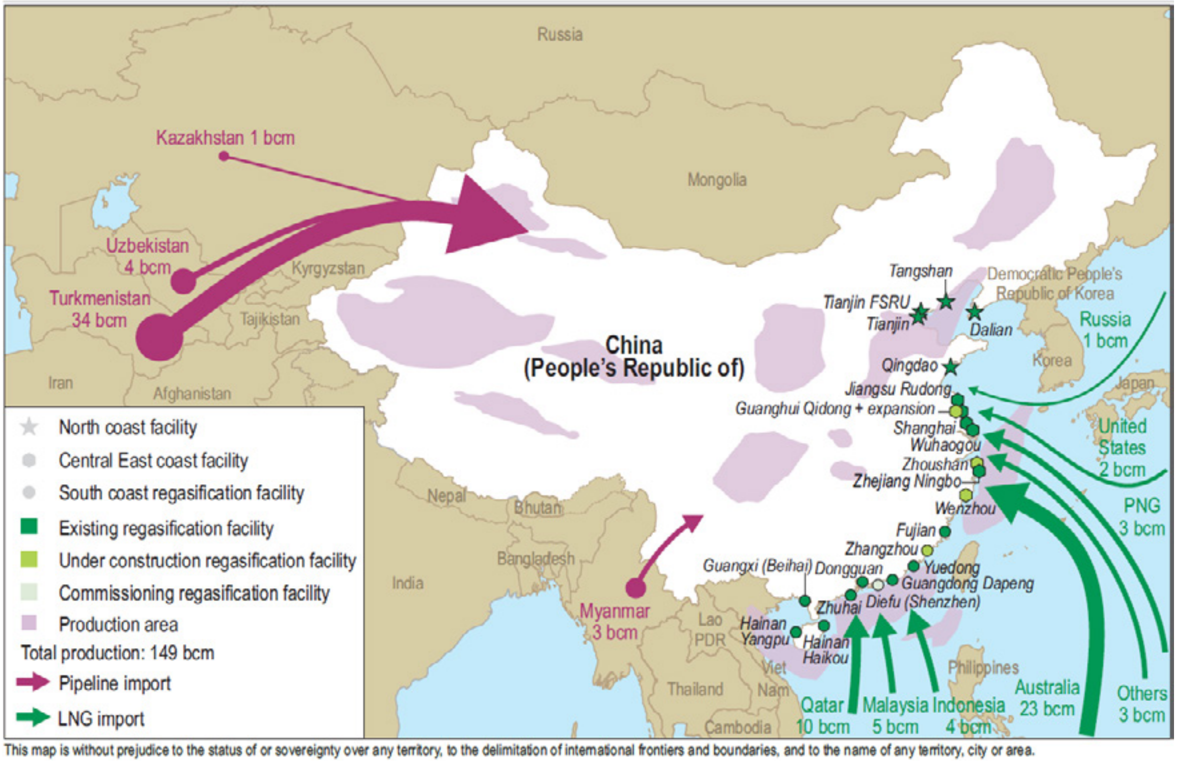
Source: IEA creates the figures above using data sourced from Argus Media Limited (2018), https://direct.argusmedia.com (subscription required); ICIS (2018), *ICIS LNG Edge*, www.icis.com/energy/liquefied-natural-gas/lng-edge (subscription required).

A mix of different factors led to the surge in natural gas imports in 2017: particularly cold temperatures in the North and North Eastern provinces from the very start of the winter and faster than expected progress on the coal to gas switch at (industrial) boilers amplified China's natural gas demand. Furthermore, domestic production – in spite of its 7.3% y-o-y increase – and gas storage infrastructure were not sufficient to balance incremental demand.

China's main supplier of pipeline gas remains the Caspian region, which represented 92% of all pipeline imports in 2017 (Map 3.4), the remaining pipeline import volumes originating from Myanmar. As a gas supplier to China, Turkmenistan dominates the Caspian region with a share of 88%, while Uzbekistan and Kazakhstan have a share of 9% and 3% respectively.

In 2017, LNG imports were clearly dominated by Australia with a share of 45%, followed by Qatar (20%) and Malaysia (10%). The share of the top three countries remained virtually unchanged between 2016 and 2017. As the United States ramps up liquefaction capacity, China is becoming more important as a destination for US LNG. The US share of total China's LNG imports stood at 4% in 2017.

Map 3.4 Natural gas supply sources, China, 2017



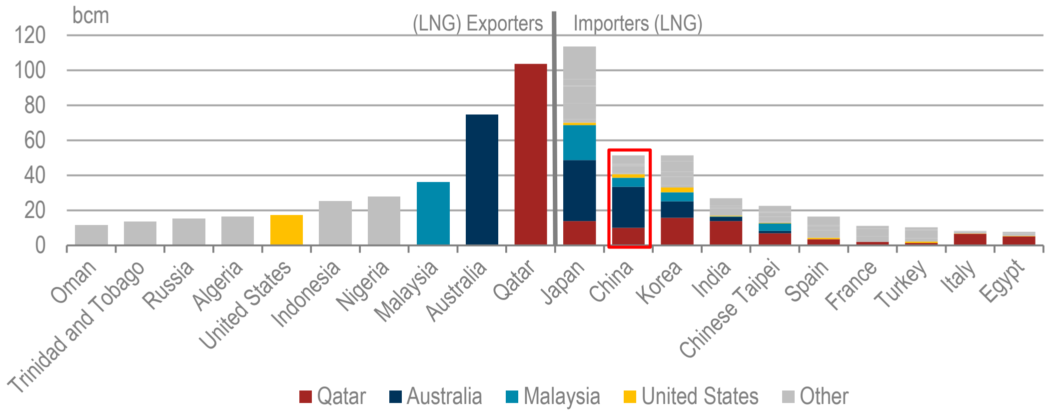
Source: IEA creates the figures above using data sourced from Argus Media Limited (2018), https://direct.argusmedia.com (subscription required); ICIS (2018), *ICIS LNG Edge*, www.icis.com/energy/liquefied-natural-gas/lng-edge (subscription required).

The world's new number two LNG importer

China's increasing need for imported natural gas was largely met by growth in LNG imports, which represented around 80% of the total import increase in 2017. The country's LNG imports grew by 46% y-o-y and China became the world's number two LNG importer after Japan, a position which Korea had held since 1994 (Figure 3.15). China's pipeline imports increased only moderately by 4 bcm. The fourth

Shaanxi-Beijing pipeline (Shaan-Jing IV), adding 25 bcm/y of capacity to northern China, was only completed by CNPC in late November, which limited the increase of Caspian gas delivery to the region. For the first time LNG had a higher share of total gas imports, at around 55%, thanks to the steepest increase in LNG imports in the history of the country. China continued to import significantly above 2016's quantities and exceeded Korea's LNG imports in nearly every month during 2017.

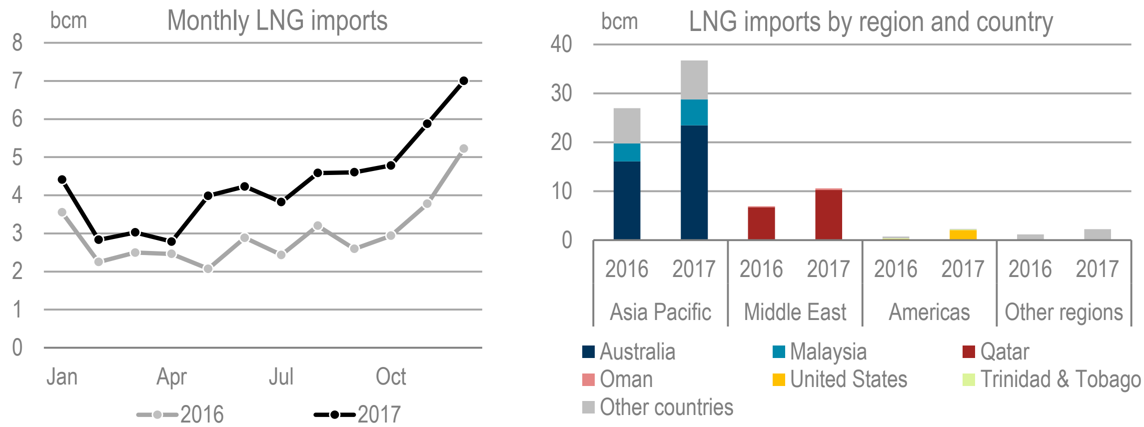
Figure 3.15 Top 10 LNG exporters and importers, 2017



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

LNG imports originated predominantly from Asia and Pacific (37 bcm) with Australia as the main single supplier and an overall share of 45% (and 64% of Asia and Pacific exports to China) (Figure 3.16). Virtually all volumes from the Middle East originated from Qatar (10 bcm), the second-largest single supplier. The United States exported 2 bcm to China.

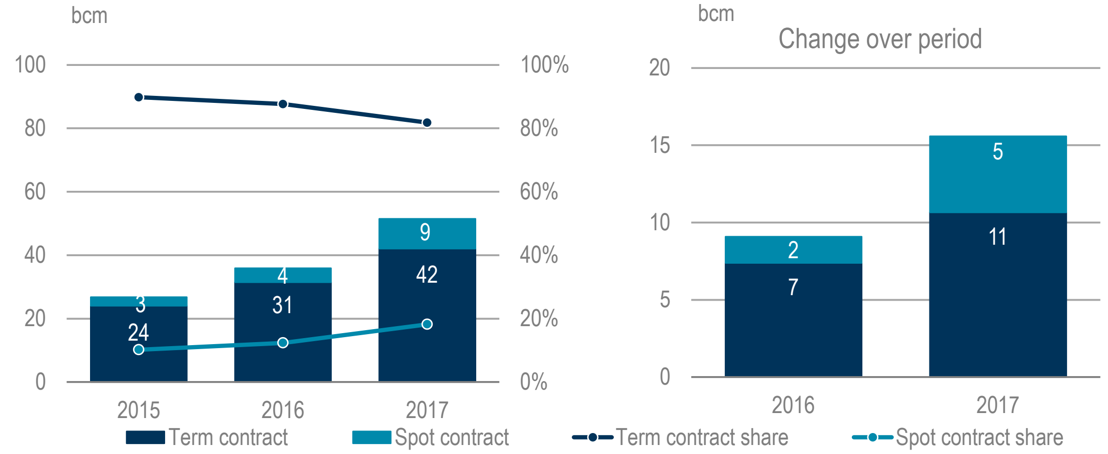
Figure 3.16 LNG imports, China, 2016-17



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

Spot purchases were an important driver for y-o-y growth, their volume tripling between 2016 and 2017, increasing the share of spot imports by 6% to 12% (Figure 3.17). National oil and gas companies, China National Offshore Oil Corporation (CNOOC) and CNPC, accounted for almost all of the spot purchases with a share of 95%. Spot cargoes increased significantly during the summer of 2017 when prices were relatively low compared to 2016. Of all spot cargoes, 40% berthed at terminals along the north coast and 30% each along the east-central and south coasts. At the beginning of winter, in the last quarter, spot purchases rose again, predominantly to supply terminals along the north and east-central coasts.

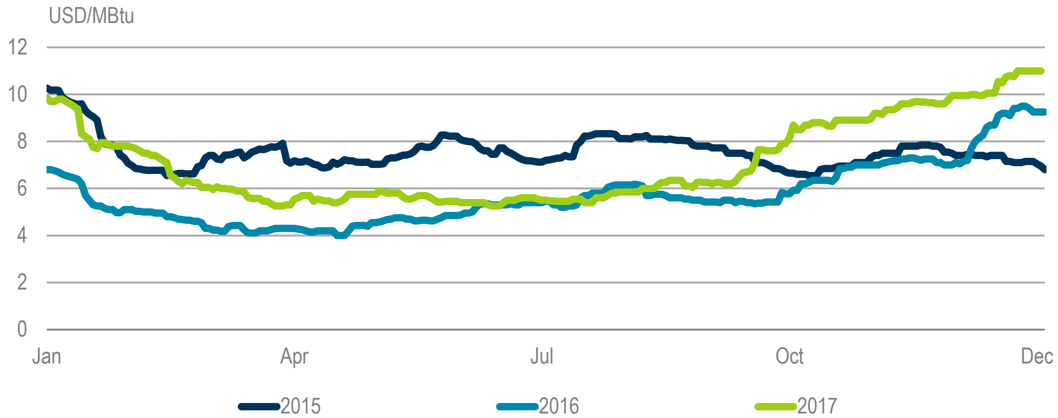
Figure 3.17 LNG imports by type of contract, China, 2015-17



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

China's activity on the spot market left a footprint on LNG pricing in the region, leading to higher spot LNG import prices, which averaged USD 7.1 per million British thermal units (MBtu) in 2017, up 25% y-o-y. Prices peaked at around 11 USD/MBtu in December (Figure 3.18).

Figure 3.18 Spot LNG import price, China, 2015-17



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

Regasification capacity will almost reach 100 bcm/y in the medium term

China's regasification capacity is further expanding. In 2017, two new terminals increased the country's regasification capacity by 3.5 bcm/y to 73.3 bcm/y (Sinopec's Tianjin terminal was commissioned in 2018). An additional 18.4 bcm/y is already under construction to further increase the country's import potential. At the end of 2017, capacity along the north coast was still not sufficient to cover local winter demand needs. CNOOC chartered additional FSRUs (Cool Explorer and Neo Energy) on a short-term basis to prepare for higher imports during winter (Chen, 2017). In addition to new terminals under construction, several expansion projects of existing terminals are also being considered by their operators.

At the time of writing, operating regasification capacity amounted to 77.4 bcm/y (Table 3.2). The highest share of regasification capacity is located along the south coast at around 45%, followed by the north coast 31% and the east-central coast 24%. Once operational, projects currently under construction will change the capacity share of the north and east-central coasts to 25% and 29% respectively.

Table 3.2 Operating LNG regasification terminals, China

Terminal	Start date	Operator	Capacity (bcm/y)	Utilisation rate (2017)
North coast				
Dalian	2011/2016	CNPC	8.2	34%
Qingdao	2014	Sinopec	4.2	149%
Tangshan	2013	CNPC	4.8	109%
Tianjin	2018	Sinopec	4.1	-
Tianjin FSRU	2013	CNOOC	3.0	101%
East-central coast				
Guanghui (Qidong)	2017	Ganghui Energy	0.8	14%
Jiangsu Rudong	2011/2016	CNPC	8.9	68%
Shanghai	2009	CNOOC	4.1	84%
Wuhaogou	2008	Shenergy	0.7	138%
Zhejiang Ningbo	2012	CNOOC	4.1	119%
South coast				
Guangxi (Beihai)	2016	Sinopec	4.0	37%
Guangdong Dapeng	2006	CNOOC/BP	9.2	91%
Dongguan	2013	Jovo	1.4	86%
Fujian	2008	CNOOC	6.9	64%
Hainan (Yangpu)	2014	CNOOC	4.1	12%
Hainan (Haikou)	2015	CNPC	1.4	6%
Yuedong (Guangdong)	2017	CNOOC	2.7	29%
Zhuhai	2013	CNOOC	4.8	45%
Total capacity			**77.4**	

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

The increase in regasification capacity is mainly supported by destination-flexible LNG cargoes, which are increasingly available on the market. As Chinese companies' activity on the global LNG (spot) market increases, so demands to sanction regasification projects only on the basis of long-term import contracts become weaker. At the time of writing, ENN's Zhoushan terminal is expected to be commissioned in July 2018. Assuming a ramp-up of this terminal in two phases, (1.4 bcm/y in 2018 and 2.7 bcm/y after 2020) around 11.6 bcm/y of regasification capacity is due to come online during 2018, with an additional 6.8 bcm/y to be commissioned at the beginning of the next decade (Table 3.3).

Table 3.3 LNG regasification terminals under development, China

Terminal	Status	Start date	Operator	Capacity (bcm/y)
East-central coast				
Guanghui (Qidong)(expansion)	Under construction	2018	Ganghui Energy	0.7
Wenzhou	Under construction	2018	Sinopec	4.1
Zhoushan	Under construction	2018	ENN	4.1
South coast				
Diefu (Shenzhen)	Commissioning	2018	CNOOC	5.4
Zhangzhou	Under construction	2020	CNOOC	4.1
Total capacity				**18.4**

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

The dominant share of operating capacity is owned by the major oil and gas companies, and capacity under construction will only slightly reduce their share to just over 90% (Table 3.4). Depending on the progress of an increasingly connected inter-provincial gas pipeline network, differences in regional seasonality will become easier to manage.

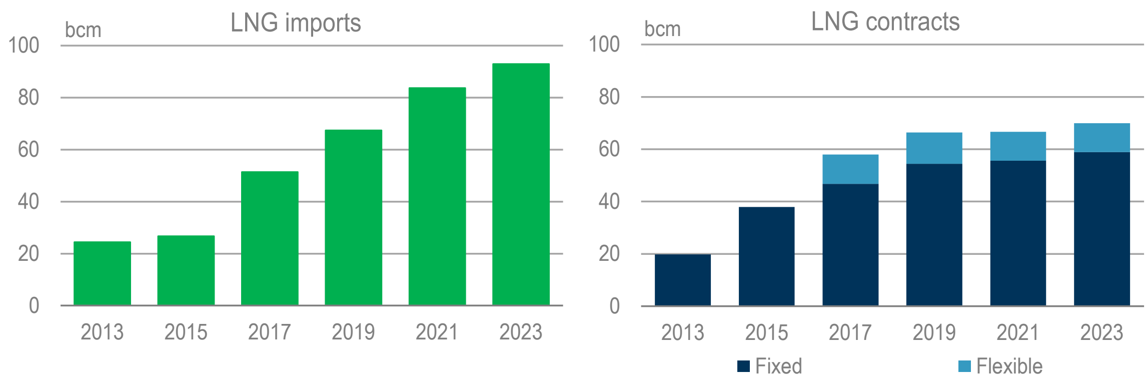
Table 3.4 LNG regasification terminals by operator, China

Operator	Capacity (operating) (bcm/y)	Share (operating)	Capacity (under construction) (bcm/y)	Share (under construction)
CNOOC	38.9	50%	9.5	52%
CNPC	23.3	30%	-	-
Sinopec	12.3	16%	4.1	22%
ENN	-	-	4.1	22%
Ganghui Energy	0.8	1%	0.7	4%
Jovo	1.4	2%	-	-
Shenergy	0.7	1%	-	-
Total capacity	**74.0**		**18.4**	

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

This forecast expects LNG imports to keep on growing a steady pace (9% y-o-y on average) over the coming years, although far from the record 46% y-o-y increase experienced in 2017. Figure 3.19 shows LNG growing strongly throughout the forecast period to reach above 90 bcm in 2023. Commitment from long-term supply contracts becomes insufficient beyond 2019 to cover import needs, thus calling for additional supply volumes (sourced through new term contracts or the spot market).

Figure 3.19 LNG imports and contracts, China, 2013-23

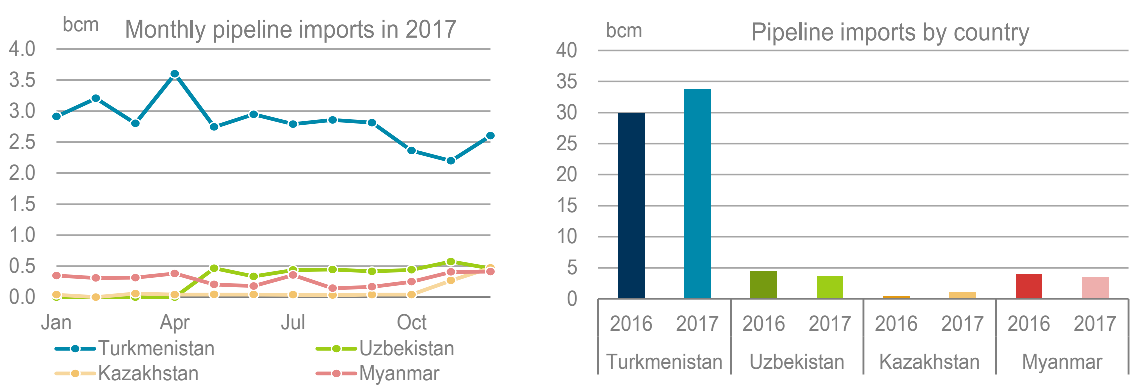


After 2021, supply from new pipeline capacity is expected to deliver most of additional imports (see following subsection and Figure 3.21).

Russia to lift China's pipeline imports at the end of the forecast period

The relatively slight annual increase in pipeline imports of 4 bcm in 2017 originated mainly from Turkmenistan. However, analysis of the data on a monthly basis shows that the country could not increase pipeline exports to China at the beginning of winter, instead reducing them by about 1 bcm in comparison to the summer months. It has been said that the country prioritised domestic demand during the cold spell in the last quarter of 2017, in addition to technical issues which led to a reduction. Fewer quantities from Turkmenistan in that period were partly balanced by higher deliveries from Kazakhstan and Uzbekistan (Figure 3.20).

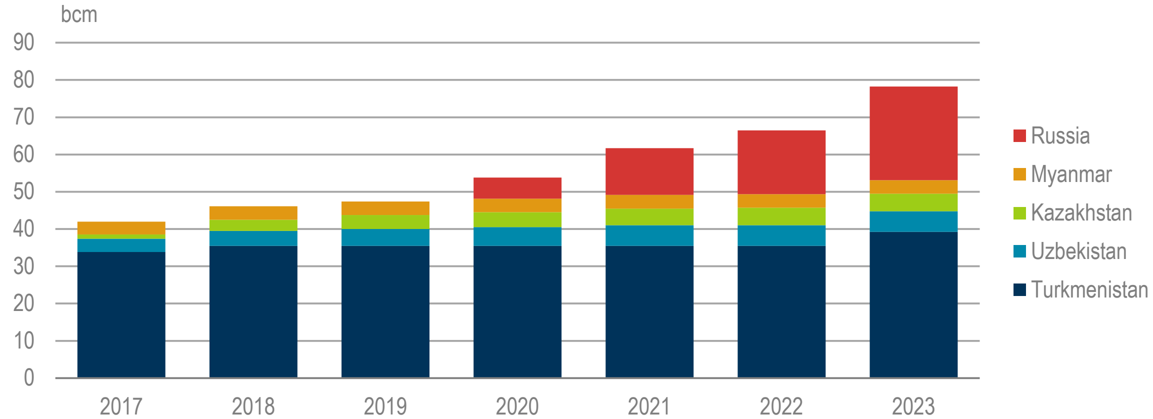
Figure 3.20 Pipeline imports, China, 2016-17



Source: IEA creates the figures above using data sourced from Argus Media Limited (2018), https://direct.argusmedia.com (subscription required).

Growth in pipeline imports during the forecast period are expected to be driven by the progress of the Power of Siberia pipeline project, which will connect China to the production areas of the Chayandinskoye and Kovyktinskoye fields in Eastern Siberia. The ramp-up in deliveries scheduled for December 2019 was confirmed by Gazprom and CNPC at the beginning of 2018. Uncertainties remain as to how quickly relevant volumes will be ramped up. This report expects pipeline imports from Russia of 25 bcm in 2023 (Figure 3.21).

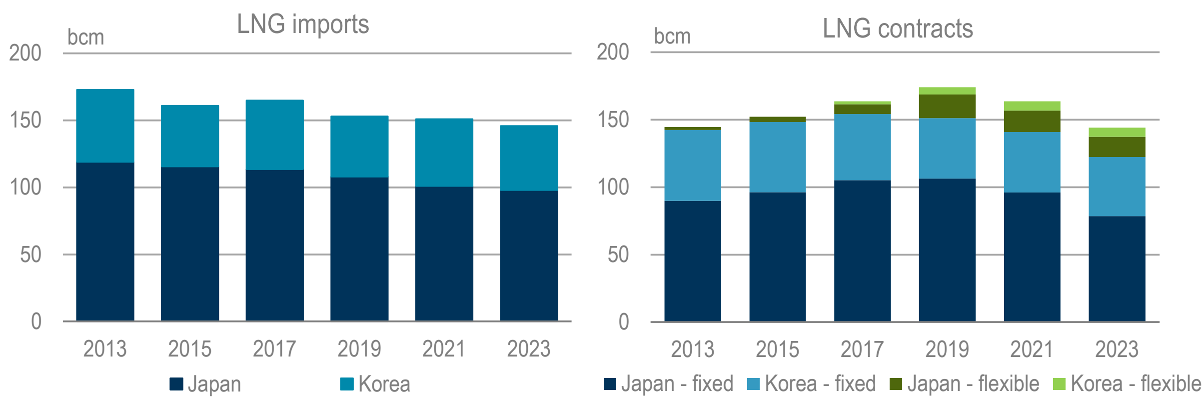
Figure 3.21 Pipeline imports, China, 2017-23



Japan and Korea

Japan and Korea see their LNG import needs decrease gradually during the forecast period, while their respective long-term contracted volumes increase until 2019, following that date contracted volumes start to decrease with the progressive expiry of some Japanese legacy contracts (Figure 3.22). The number of flexible contracts increase progressively, in parallel with the development of US LNG, and provide some room for manoeuvre to reduce the potential for domestic oversupply.

Figure 3.22 LNG imports and contracts, Japan and Korea, 2013-23

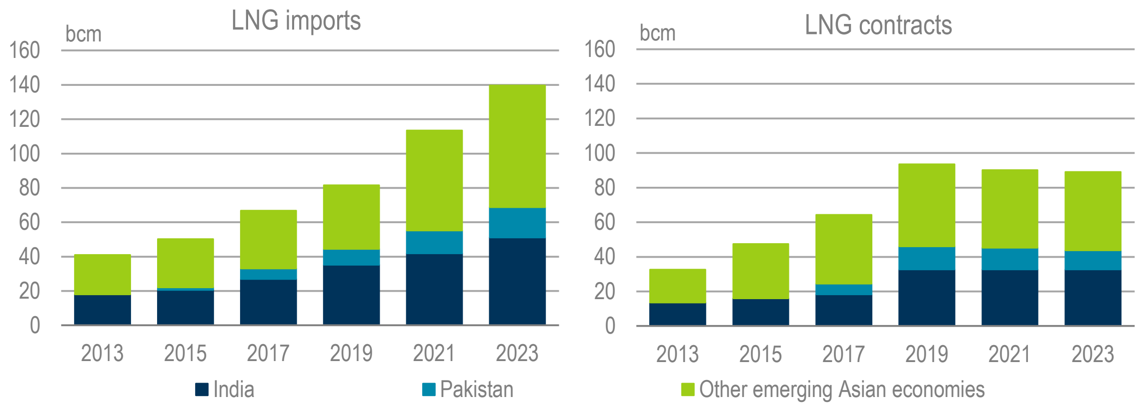


Another option to create more liquidity and avoid contractual oversupply lies in the renegotiation of flexibility within existing LNG contracts, as indicated by the June 2017 ruling of the Japan Fair Trade Commission (JFTC). The JFTC stated that competition-restraining clauses or business practices should be eliminated from new or revised LNG contracts, and LNG sellers should review such clauses or business practices in existing contracts. The commission stated that destination clauses are likely violate Japan's Antimonopoly Act. Following this ruling, the Korea Fair Trade Commission also started researching the legality of destination clauses in the LNG contracts.

Other emerging Asian economies

In the absence of transborder pipeline networks in Asia, trade development will mainly rely on LNG. LNG imports into emerging Asia are expected to double over the next five years, from 67 bcm in 2017 to reach 140 bcm by 2023.

Figure 3.23 LNG imports and contracts, Other emerging Asian economies, 2013-23



India is an important contributor to LNG import growth, as its domestic production is not expected to increase significantly. India's LNG imports double over the forecast period, sustained by the ramping up of already-signed long-term contracts (up 70%), to be complemented by future contracts or short- to medium-term procurement. Pakistan and Bangladesh are expected to grow in a similar fashion. Competitiveness of LNG imports will be a crucial factor to enable such growth in price-sensitive emerging Asian markets.

Commitments in long-term contracts already active or signed at the time of writing will increase during the initial years of the outlook to cover over 110% of expected import needs by 2019 – including flexible destination contracts (Figure 3.23) then stagnate.

Europe

European imports of natural gas are expected to increase by over 30 bcm over the forecast period to reach above 310 bcm by 2023, owing to the continuing depletion of domestic production, further exacerbated by the phasing out of the Groningen field in the Netherlands (Figure 3.24).

New pipeline gas imported through the Southern Gas Corridor, additional LNG and pipeline gas from traditional suppliers such as Russia bridge this increasing supply gap. After reaching a record market share of above one third in 2017, Russian gas is expected to return to its previous 30-32% level as new sources of supply arrive on the European market.

This includes the development of the Southern Gas Corridor bringing Azerbaijani natural gas to Italy, Albania, Greece and Turkey, as well as additional LNG expected by the end of the forecast period to replace domestic production in Northwest Europe.

Figure 3.24 Natural gas supply-demand gap, Europe, 2013-23

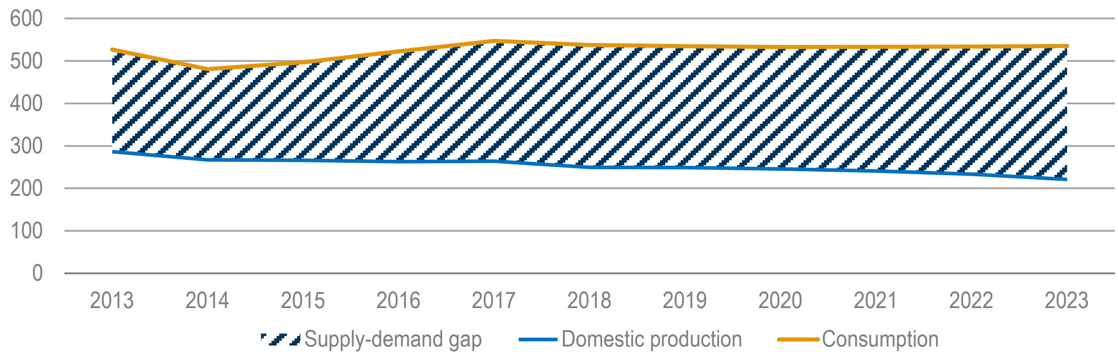
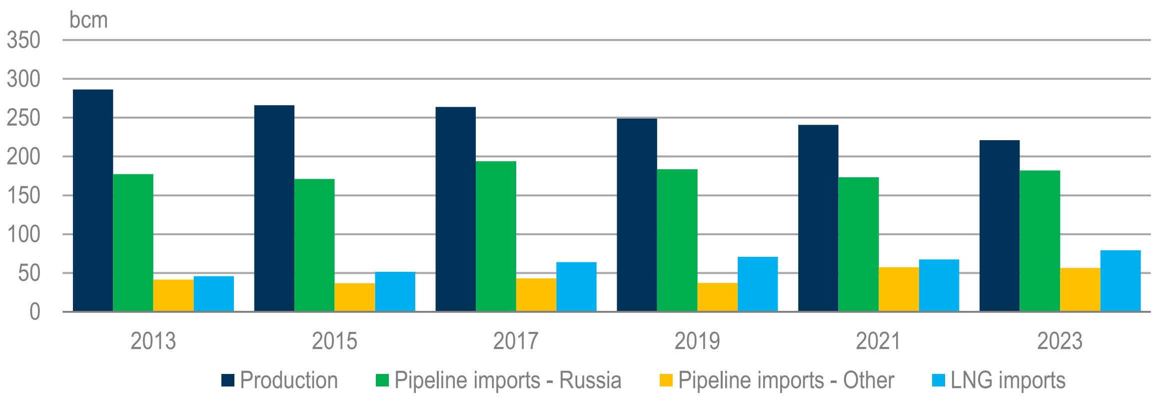


Figure 3.25 Natural gas balance, Europe, 2013-23



Russian exports to Europe broke another record in 2017

European natural gas consumption increased by 24 bcm, or 4.5%, year-on-year in 2017 owing mainly to higher demand from power generation and a cold snap in the first months of the year. Domestic production was stable, with record levels of output from Norway at 125 bcm (up 6.6% y-o-y) (Gassco,2018) and UK production reversing its depletion trend with a slight increase of 2.6%, the combination of both components balancing the slide in the Netherlands' output, which decreased by almost 14%.

Natural gas imports rose as a consequence, and Russian imports broke another record in 2017 reaching 194 bcm,[5] or 8% above the previous record of 178 bcm in 2016 (Gazprom export, 2018). Russia's market share reached above one third in 2017. LNG imports grew by 16% to 64 bcm. Algerian pipeline supply remained nearly stable in 2017 at 33 bcm compared to 34 in 2016, split between Italy (19 bcm) and Spain and Portugal (14 bcm).

[5] Volumes expressed in Russian cubic meters (Gross Calorific Value of 37.83 MJ per cubic meter at 15°C) to be multiplied by 0.92 to convert to European standard measure.

This forecast expects a slight decrease in European consumption for normal winters as well as new sources of supply competing to serve the European market. It therefore does not expect Russian imports to rise above its 2017 share in the forecast period.

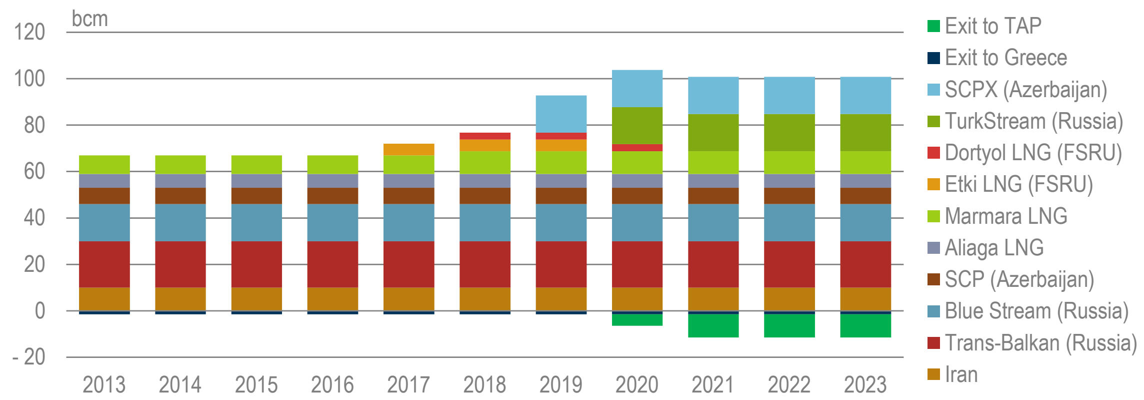
New pipeline projects offer diversification of trade routes

Several new natural gas pipeline projects are currently under development to further increase the diversity of supply routes to Europe. Projects that form the Southern Gas Corridor and the TurkStream pipeline are due to be commissioned during the forecast period, while projects in the north remain in the pre-construction phase.

- The development of the Southern Gas Corridor through Turkey is progressing and expected to deliver a substantial increase in entry capacity for the Turkish market by 2020 (Figure 3.26). Turkey is a market which recently increased its regasification capacity with the chartering of two FSRUs, the Neptune in Etki (November 2016) and the Challenger (February 2018) in Dortyol.
- The South Caucasus Pipeline Expansion (SCPX) from Azerbaijan through Georgia will enable the tripling of export capacity to Turkey to over 20 bcm/y (BP, 2018). This project is linked to the development of Phase 2 of the Shah Deniz field in Azerbaijan (see Supply chapter), and is also connected with downstream development of the Trans-Anatolian Pipeline (TANAP) through Turkey, and Trans-Adriatic Pipeline (TAP) through Greece, Albania and Italy. Shah Deniz Phase 2 is due to deliver its first gas by the end of 2018 and gradually increase its capacity over the coming years. At the time of writing, the SCPX project is over 95% complete (SCP, 2018), TANAP is over 90% (the first section connecting Ankara was launched in mid-June 2018) and TAP is close to 70%. TAP is expected to deliver its first gas to Italy by 2020 (TAP, 2018). These new infrastructures will add a maximum of 16 bcm/y of additional capacity to Europe – 6 for Turkey and up to 10 for southeast Europe and Italy. For the Turkish market, the additional volumes delivered by TANAP could alternatively be added or substituted to the existing 6 bcm/y Shah Deniz 1 contract expires during the forecast period and depending on its renewal.
- The TurkStream project comprises two offshore lines, each with 15.75 bcm/y of capacity and 930 kilometres (km) in length, linking Russia to Turkey and the rest of Southeast Europe through the Black Sea. The first line will be dedicated to the Turkish market and is due to be operational in 2019 in conjunction with the expiry of the current Russian long-term supply contract to Turkey via the Trans-Balkan pipeline (through Ukraine, Romania and Bulgaria) (TurkStream, 2018). The second line, which remains prospective, would be aimed at other export markets in Europe – Gazprom and Turkish incumbent Botaş are due to jointly build further export sections, routes still to be confirmed. At the time of writing, over half of the offshore pipes had been installed, with the offshore section of the first line completed and over 200 km laid for the second.

The Danish and Polish transmission system operators, Energinet and Gaz-System SA, are promoting another project in the Baltic Sea, the Baltic Pipe project. This project of 10 bcm/y capacity would connect the Norwegian natural gas export system (Europipe II) to Denmark and Poland via a 900 km offshore link (Energinet, 2018). This project, included in the European Union's list of Projects of Common Interest (PCI), has received European funds to carry out a feasibility study. An open season process was performed in late 2017 and FID would be expected by the end of 2018 for commissioning by the end of 2022.

Figure 3.26 Turkey's flow capacity per entry and exit point, 2013-23



Map 3.5 Russian natural gas export pipelines operating and projects

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

Box 3.5 Nord Stream 2 project update

In May 2018, Nord Stream 2 started offshore preparatory works for the subsequent pipelaying at the German coast (Bay of Greifswald) as well as in Finland. This was preceded by permits from both countries, which were granted in March (Germany) and April (Finland). In June 2018, Nord Stream 2 received all necessary permits from Sweden and Russia granted one out of two main permits. The second permit from Russia as well as Denmark's permits are pending at the time of writing.

The 1 230 km Nord Stream 2 pipeline runs through the Baltic Sea waters of Russia, Finland, Sweden, Denmark and Germany and will follow almost the route of the existing Nord Stream pipeline. The Nord Stream 2 project will add another 55 bcm/y to the existing Nord Stream capacity of 55 bcm/y, totalling a transport capacity through the Baltic Sea of around 110 bcm/y. According to the project plan, the pipeline will be commissioned at the end of 2019.

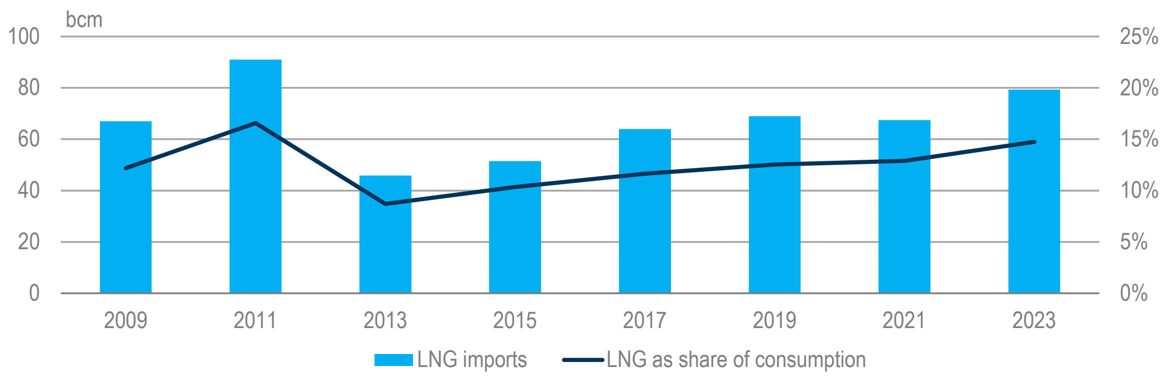
Gazprom is the sole shareholder of the project but Nord Stream 2 has support from five European financial investors, including Engie, OMV, Royal Dutch Shell, Uniper and Wintershall. The fully privately funded pipeline project is a gas infrastructure investment of around EUR 9.5 billion Euros (including financing costs).

In Northwest Europe, the BBL pipeline connecting the Netherlands to the United Kingdom is due to become bidirectional during the course of 2019, with a projected reverse flow capacity to the Netherlands of about one-third of its technical forward capacity, or around 5 bcm/y (BBL Company, 2018). This would help alleviate the excess of supply to the UK in the summer, which cannot be absorbed due to the lack of seasonal storage capacity (partly due to the decommissioning of the Rough storage facility). This additional capacity could also partly compensate for the loss of domestic production in the Netherlands with the phasing out of the Groningen field.

The role of LNG in Europe – a market of last resort?

Europe's LNG imports are expected to grow at a modest but steady pace throughout the forecast period. In 2017 Europe imported 64 bcm of LNG, and LNG stood at over 12% of natural gas consumption. By 2023, LNG imports are expected to amount to 79 bcm, or almost 15% of consumption (Figure 3.27).

Figure 3.27 LNG imports and share of consumption, Europe, 2009-23



This gradual increase compensates for part of the depletion of domestic production. Even if global liquefaction capacity were to strongly increase over the coming years, this forecast does not anticipate that Europe will experience a momentary surge of LNG flows, such as happened in the late 2000s. The LNG wave to Europe reached its highest point in 2011 with over 90 bcm imported, accounting for 17% of consumption (Figure 3.27). This was caused by a major influx of competitive LNG displacing oil-linked pipeline supply, also causing a switch in favour of natural gas in the power generation sector.

These two major factors would not work with the same impact in the current market situation:

- On the supply side, most long-term pipeline contracts have switched to (total or partial) natural gas indexation or have adjusted their formulae to be on par with such gas hub prices. Therefore, a price drop caused by a potential supply surplus would be translated into these contracts' pricing formulae and would prevent the price gaps as experienced in the late 2000s.
- On the demand side, the power sector's switching capability has eroded since the early 2010s with the decrease in coal consumption and the development of renewables.

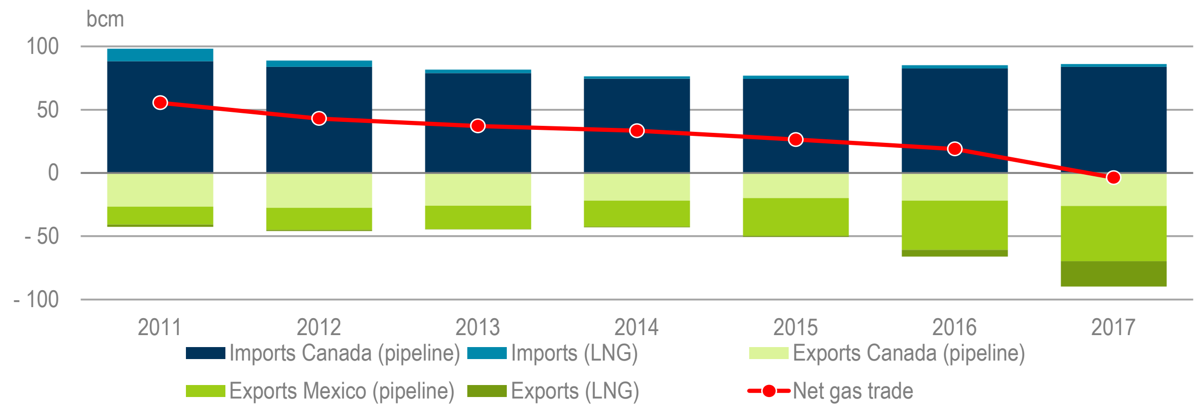
North America

The United States will be the main driver for North American natural gas trade growth, through the development of pipeline exports to Mexico and of LNG. Canadian pipeline exports to the United States are expected to decrease over the forecast period but remain a pivotal supplier to the US Midwest and West Coast markets.

United States

In 2017, the United States became a net exporter of gas thanks to the surge in LNG exports and increasing pipeline exports to Mexico and Canada. Between 2016 and 2017, incremental US gas exports grew by 24 bcm, from around 66 bcm to 90 bcm, of which 40% originated from additional pipeline exports and 60% from LNG exports (Figure 3.28).

Figure 3.28 Evolution of natural gas trade, United States, 2011-17



Source: EIA (2018), *US Imports and Exports by Country,* www.eia.gov/naturalgas/data.php#imports.

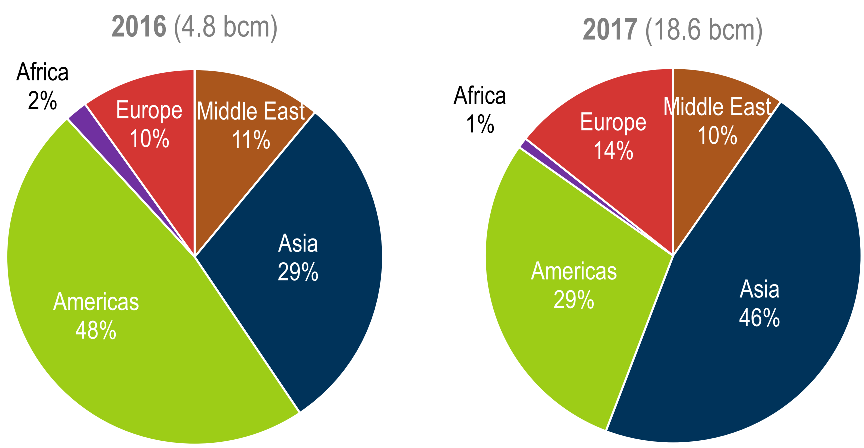
US LNG exports quadrupled from 2016 to 2017 boosted by the capacity increase of Sabine Pass, which started operations in 2016. It was the only commercially operating liquefaction terminal in the United States in 2017. Sabine Pass LNG Trains 3 and 4 were completed during 2017 and doubled the terminal's capacity to 24.5 bcm/y. A fifth LNG train is due to increase the terminal's capacity to 31 bcm/y by mid-2019.

Between 2016 and 2017, the primary destination of US LNG changed from the Americas to Asia (Figure 3.29). Europe increased its US LNG imports from 0.5 bcm in 2016 to around 3 bcm in

2017. The Middle East took 2 bcm in 2017 (Jordan, Kuwait and the United Arab Emirates) and Egypt was the only importer in Africa, taking 0.2 bcm.

The overall number of countries which imported US LNG increased from 17 in 2016 to 25 in 2017; however, new US LNG importers from Asia (Pakistan, Chinese Taipei and Thailand) and Europe (Lithuania, Poland, the United Kingdom, the Netherlands and Malta) only absorbed an additional 1 bcm. Asia clearly ranked number one destination ahead of the Americas, but Mexico remained the primary country for US LNG exports (17% of total US exports).

Figure 3.29 LNG exports by destination (region), United States, 2016-17



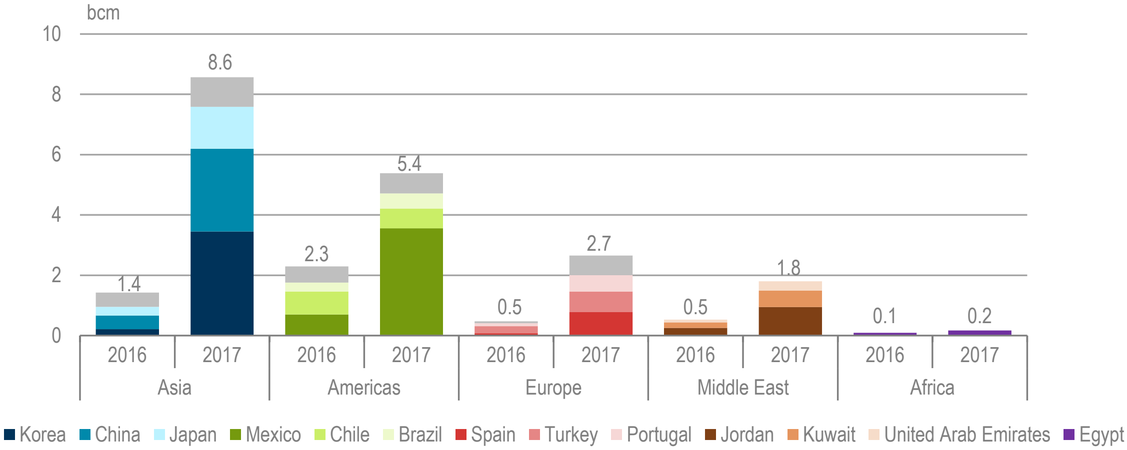
Source: ICIS (2018), *ICIS LNG Edge*, www.icis.com/energy/liquefied-natural-gas/lng-edge (subscription required).

During the medium term, Mexican LNG imports from the United States will face strong competition from US pipeline imports once delayed domestic pipelines in Mexico are commissioned and connected to US export pipelines. It is anticipated that US LNG will then only remain a competitive option for regions in Mexico with limited access to large transmission pipelines or in the case of pipeline imports facing technical issues.

The surge in Asian LNG imports from the United States partly originates from the start-up of deliveries under long-term contracts in Korea. In 2017, Korean importer KOGAS ramped up volumes and absorbed 3.5 bcm or 16% of all US LNG exports. However, the destination flexibility of US LNG and its relatively low prices (indexed to Henry Hub) also made it attractive for Asian buyers, particularly China, to buy US LNG on the spot market. China ranked number three and absorbed 2.7 bcm or 13% of US LNG, much more than expected. The Asian gas giant's LNG import surge began in mid-2017, originating from faster than expected fulfilment of the coal to gas switch in key regions (particularly with respect to small boilers). Additional spot volumes provided by global portfolio players, who resold the destination-flexible US volumes to Chinese importers when winter temperatures fell below normal during the last quarter of 2017 forced buyers to contract more gas.

In 2017, Europe was still not a major destination for US LNG as Russian pipeline imports proved to be a fierce competitor. But Europe might offer pockets of demand as the region's domestic production decreases much faster than expected owing to the Dutch government's decision to phase out the Groningen field.

Figure 3.30 LNG exports by destination (country), United States, 2016-17



Note: Light grey bars represent volumes of US LNG to destinations other than the top three importing countries in a region.

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

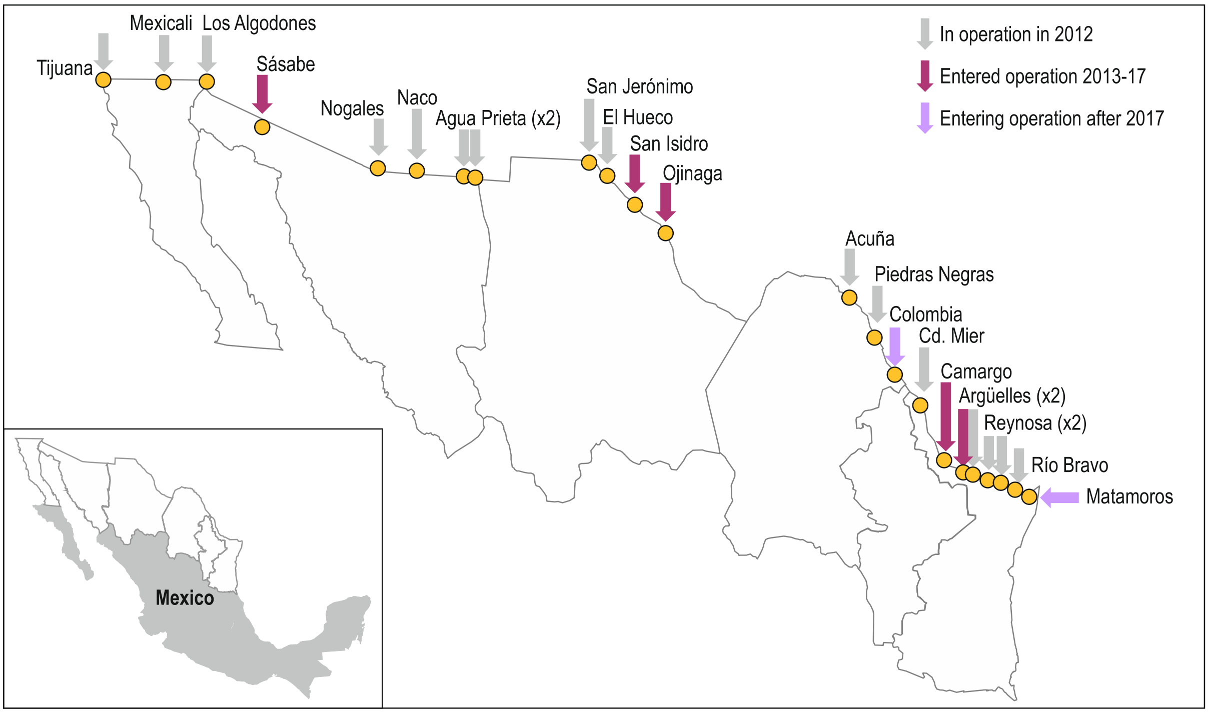
Mexico

In order to meet Mexico's sustained increase in natural gas demand and compensate for its decrease in gas production, gas imports have increased since 2010 at a remarkable average annual growth rate of 20%, especially pipeline imports from the United States. To allow for that increase, cross-border capacity between both countries has been expanded rapidly in the recent years. As shown in Map 3.6, Mexico had 16 cross-border interconnections with the United States in 2012.

At that time, pipeline interconnection capacity between both countries amounted to 28.5 bcm/y. Between 2013 and 2017 six importing points became operational (San Isidro, Sasabe, Camargo, Arguelles, San Isidro and Ojinaga). In addition, two more cross-border pipelines are expected to be commissioned within the next two years (Colombia and Matamoros). Altogether, cross-border capacity is expected to surpass 110 bcm/y before the end of 2019 (SENER, 2018).

In addition to cross-border pipelines, Mexico also has three LNG regasification terminals: Costa Azul (Baja California), Manzanillo (Colima) and Altamira (Tamaulipas). The LNG terminal in Ensenada only supplies gas to the Baja California region. In 2017, LNG imports amounted to 6.2 bcm and nearly 60% of them came from the United States (Figure 3.31). However, the increased availability of competitive pipeline gas from that country is expected to limit the potential of further LNG imports throughout the forecast period.

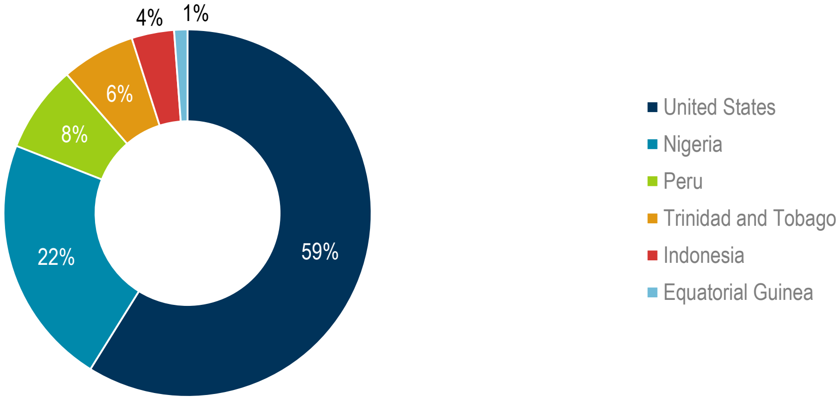
Map 3.6 Cross-border pipeline interconnections between the United States and Mexico



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

Source: SENER (2018), *Estatus de Gasoductos – Febrero 2018* (Gas pipelines status – February 2018), www.gob.mx/cms/uploads/attachment/file/311762/531.DGGNP.025.18.SGN.2.PP.01_Estatus_de_gasoductos.pdf.

Figure 3.31 LNG imports in 2017 by source, Mexico



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

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4. THE ESSENTIALS

Table 4.1 World natural gas demand by region and key country (bcm)

Region	2000	2010	2017*	2019	2021	2023
Asia and Pacific	**310**	**586**	**774**	**832**	**913**	**978**
China	*25*	*106*	*237*	*277*	*331*	*376*
India	*28*	*64*	*58*	*65*	*74*	*83*
Japan	*83*	*102*	*120*	*115*	*108*	*105*
North America	**794**	**850**	**965**	**1 015**	**1 022**	**1 037**
United States	*661*	*683*	*764*	*808*	*810*	*822*
Middle East	**174**	**369**	**502**	**526**	**553**	**582**
Iran	*62*	*144*	*201*	*211*	*223*	*234*
Saudi Arabia	*38*	*73*	*90*	*93*	*96*	*100*
Eurasia	**565**	**650**	**645**	**644**	**641**	**638**
Russia	*391*	*466*	*470*	*460*	*454*	*448*
Caspian region	*82*	*105*	*120*	*129*	*133*	*137*
Europe	**509**	**605**	**547**	**535**	**533**	**536**
European Union	*481*	*545*	*484*	*475*	*473*	*475*
Latin America	**96**	**152**	**169**	**173**	**179**	**186**
Argentina	*37*	*46*	*53*	*55*	*57*	*60*
Brazil	*9*	*27*	*36*	*34*	*33*	*33*
Africa	**57**	**106**	**139**	**145**	**154**	**160**
Algeria	*20*	*27*	*40*	*42*	*44*	*46*
Egypt	*18*	*44*	*56*	*59*	*65*	*67*
Total	**2 505**	**3 315**	**3 740**	**3 869**	**3 994**	**4 116**

Note: 2017* figures are estimates and supply and demand do not necessarily balance as a result of stock changes, figures can be different compared to previous reports due to statistical differences, rounding and stock changes.

China refers to the People's Republic of China and includes Hong Kong.

Caspian region: Armenia, Azerbaijan, Georgia, Kazakhstan, Kyrgyzstan, Tajikistan, Turkmenistan and Uzbekistan.

European Union: Austria, Belgium, Bulgaria, Croatia, Cyprus,[1] Czech Republic, Denmark, Estonia, Finland, France, Germany, Greece, Hungary, Ireland, Italy, Latvia, Lithuania, Luxembourg, Malta, Netherlands, Poland, Portugal, Romania, the Slovak Republic, Slovenia, Spain, Sweden and the United Kingdom.

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

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

Table 4.2 World natural gas demand per sector and region (bcm)

Region	2000	2010	2017*	2019	2021	2023
Asia and Pacific – China	**25**	**106**	**237**	**277**	**331**	**376**
Residential and commercial	*4*	*29*	*58*	*67*	*79*	*89*
Industry	*11*	*32*	*78*	*94*	*112*	*127*
Power generation	*3*	*22*	*50*	*59*	*72*	*84*
Asia and Pacific – Other	**285**	**480**	**537**	**555**	**582**	**602**
Residential and commercial	*38*	*60*	*65*	*68*	*71*	*75*
Industry	*69*	*116*	*137*	*150*	*164*	*180*
Power generation	*138*	*245*	*274*	*275*	*283*	*284*
North America	**794**	**850**	**965**	**1 015**	**1 022**	**1 037**
Residential and commercial	*262*	*254*	*250*	*256*	*257*	*257*
Industry	*232*	*182*	*211*	*224*	*235*	*241*
Power generation	*190*	*279*	*352*	*379*	*371*	*377*
Middle East	**174**	**369**	**502**	**526**	**553**	**582**
Residential and commercial	*22*	*47*	*60*	*64*	*68*	*72*
Industry	*56*	*122*	*160*	*169*	*179*	*188*
Power generation	*79*	*164*	*233*	*243*	*253*	*267*
Eurasia	**565**	**650**	**645**	**644**	**641**	**638**
Residential and commercial	*109*	*106*	*103*	*102*	*102*	*101*
Industry	*80*	*109*	*110*	*114*	*113*	*112*
Power generation	*308*	*340*	*337*	*331*	*329*	*326*
Europe	**509**	**605**	**547**	**535**	**533**	**536**
Residential and commercial	*195*	*226*	*213*	*212*	*212*	*213*
Industry	*148*	*131*	*130*	*131*	*130*	*131*
Power generation	*137*	*207*	*174*	*162*	*160*	*164*
Latin America	**96**	**152**	**169**	**173**	**179**	**186**
Residential and commercial	*11*	*15*	*17*	*18*	*19*	*20*
Industry	*34*	*57*	*54*	*56*	*58*	*61*
Power generation	*26*	*44*	*58*	*58*	*59*	*61*
Africa	**57**	**106**	**139**	**145**	**154**	**160**
Residential and commercial	*4*	*6*	*10*	*11*	*11*	*12*
Industry	*12*	*25*	*33*	*34*	*36*	*37*
Power generation	*28*	*57*	*76*	*81*	*86*	*89*
Total	**2 505**	**3 315**	**3 740**	**3 869**	**3 994**	**4 116**

Note: 2017* figures are estimates and supply and demand do not necessarily balance as a result of stock changes, figures can be different compared to previous reports due to statistical differences, rounding and stock changes. This table does not show other sectors such as energy own use, transport and losses. The industry sector includes non-energy uses (feedstock for chemicals).

Table 4.3 World natural gas production by region and key country (bcm)

Region	2000	2010	2017*	2019	2021	2023
Asia and Pacific	**290**	**490**	**592**	**636**	**648**	**679**
Australia	*33*	*53*	*102*	*131*	*136*	*142*
China	*27*	*96*	*147*	*168*	*185*	*204*
Indonesia	*70*	*86*	*77*	*79*	*79*	*80*
North America	**765**	**817**	**973**	**1 071**	**1 116**	**1 140**
United States	*545*	*604*	*760*	*853*	*897*	*922*
Middle East	**196**	**463**	**615**	**627**	**670**	**698**
Iran	*59*	*144*	*203*	*217*	*228*	*240*
Saudi Arabia	*38*	*73*	*90*	*93*	*96*	*100*
Eurasia	**709**	**828**	**904**	**889**	**916**	**956**
Russia	*573*	*657*	*690*	*682*	*706*	*725*
Caspian region	*118*	*150*	*196*	*190*	*205*	*210*
Europe	**319**	**315**	**263**	**248**	**240**	**220**
European Union	*264*	*204*	*134*	*119*	*110*	*88*
Norway	*53*	*110*	*125*	*128*	*129*	*130*
Latin America	**99**	**160**	**175**	**175**	**177**	**181**
Argentina	*41*	*42*	*42*	*44*	*45*	*47*
Brazil	*7*	*15*	*26*	*27*	*27*	*28*
Africa	**124**	**210**	**220**	**226**	**230**	**245**
Algeria	*82*	*85*	*92*	*95*	*94*	*92*
Egypt	*18*	*57*	*49*	*62*	*66*	*68*
Total	**2 503**	**3 284**	**3 740**	**3 869**	**3 994**	**4 116**

Note: 2017* figures are estimates and supply and demand do not necessarily balance as a result of stock changes, figures can be different compared to previous reports due to statistical differences, rounding and stock changes.

China refers to the People's Republic of China and includes Hong Kong.

Caspian region: Armenia, Azerbaijan, Georgia, Kazakhstan, Kyrgyzstan, Tajikistan, Turkmenistan and Uzbekistan.

European Union: Austria, Belgium, Bulgaria, Croatia, Cyprus[2], Czech Republic, Denmark, Estonia, Finland, France, Germany, Greece, Hungary, Ireland, Italy, Latvia, Lithuania, Luxembourg, Malta, Netherlands, Poland, Portugal, Romania, the Slovak Republic, Slovenia, Spain, Sweden and the United Kingdom.

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

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Table 4.4 LNG liquefaction capacity in operation and under development as of June 2018

Region	In operation (bcm/y)	Under development (bcm/y)
Asia and Pacific	**198**	**31**
Australia	*95*	*23*
Brunei	*10*	-
Indonesia	*43*	*6*
Malaysia	*41*	*2*
Papua New Guinea	*9*	-
North America	**28**	**73**
United States	*28*	*73*
Middle East	**136**	-
Oman	*14*	-
Qatar	*105*	-
United Arab Emirates	*8*	-
Yemen	*9**	-
Eurasia	**22**	**15**
Russia	*22*	**15**
Europe	**6**	-
Norway	*6*	-
Latin America	**27**	**-**
Peru	*6*	-
Trinidad and Tobago	*21*	-
Africa	**99**	**5**
Algeria	*38*	-
Angola	*7*	-
Cameroon	*2*	-
Egypt	*17*	-
Equatorial Guinea	*5*	-
Mozambique	-	*5*
Nigeria	*30*	-
Total	**516**	**123**

* Refers to capacity currently offline due to technical or security issues

Table 4.5 LNG regasification capacity in operation and under development as of June 2018

Region	In operation (bcm/y)	Under development (bcm/y)
Asia and Pacific	**649**	**73**
Bangladesh	*4**	*-*
China	*77*	*17*
Chinese Taipei	*18*	*4*
India	*52*	*36*
Indonesia	*11*	*-*
Japan	*277*	*-*
Korea	*163*	*-*
Malaysia	*10*	*-*
Pakistan	*15*	*-*
Philippines	*-*	*4*
Singapore	*15*	*-*
Thailand	*7*	*8*
Viet Nam	*-*	*4*
North America	**188**	-
Canada	*12*	*-*
Mexico	*23*	*-*
United States	*153*	*-*
Middle East	**31**	**8**
Bahrain	*-*	*8*
Israel	*5*	*-*
Jordan	*5*	*-*
Kuwait	*8*	*-*
United Arab Emirates	*13*	*-*
Europe	**234**	**6**
Belgium	*9*	*-*
Finland	*1*	*-*
France	*35*	*-*
Greece	*5*	*2*
Italy	*15*	*-*
Lithuania	*4*	*-*
Malta	*1*	*-*
Netherlands	*12*	*-*
Poland	*5*	*-*
Portugal	*8*	*-*
Spain	*67*	*-*
Sweden	*1*	*1*
Turkey	*22*	*3*
United Kingdom	*49*	*-*
Latin America	**44**	**9**
Argentina	*12*	*-*
Brazil	*13*	*7*
Chile	*8*	*-*
Colombia	*5*	*-*
Dominican Republic	*2*	*-*
Haiti	*-*	*0.4*
Jamaica	*0.3*	*-*
Panama	*2**	*-*
Puerto Rico	*4*	*-*
Africa	**13**	**5**
Egypt	*13*	*-*
Ghana	*-*	*5*
Total	**1 159**	**101**

* Commissioning cargoes as of mid-June 2018

GLOSSARY

Regional and country groupings

Africa

Algeria, Angola, Benin, Botswana, Cameroon, Congo, Democratic Republic of Congo, Côte d'Ivoire, Egypt, Eritrea, Ethiopia, Gabon, Ghana, Kenya, Libya, Morocco, Mozambique, Namibia, Nigeria, Senegal, South Africa, Sudan, United Republic of Tanzania, Togo, Tunisia, Zambia, Zimbabwe and other African countries and territories.[1]

Asia and Pacific

Australia, Bangladesh, Brunei Darussalam, Cambodia , Chinese Taipei, India, Indonesia, Japan, Korea, the Democratic People's Republic of Korea, Malaysia, Mongolia, Myanmar, Nepal, New Zealand, Pakistan, the People's Republic of China,[2] the Philippines, Singapore, Sri Lanka, Thailand, Viet Nam and other Asian countries and territories.[3]

Caspian region

Armenia, Azerbaijan, Georgia, Kazakhstan, Kyrgyzstan, Tajikistan, Turkmenistan and Uzbekistan.

Eurasia

Armenia, Azerbaijan, Belarus, Georgia, Kazakhstan, Kyrgyzstan, the Republic of Moldova, Russian Federation, Tajikistan, Turkmenistan, Ukraine and Uzbekistan.

Europe

Albania, Austria, Belgium, Bosnia and Herzegovina, Bulgaria, Croatia, Cyprus[4], Czech Republic, Denmark, Estonia, Finland, the Former Yugoslav Republic of Macedonia, France, Germany, Gibraltar, Greece, Hungary, Iceland, Ireland, Italy, Kosovo[5], Latvia, Lithuania, Luxembourg, Malta, Montenegro, Netherlands, Norway, Poland, Portugal, Romania, Serbia, Slovak Republic, Slovenia, Spain, Sweden, Switzerland, Turkey and United Kingdom.

European Union

Austria, Belgium, Bulgaria, Croatia, Cyprus,[4] Czech Republic, Denmark, Estonia, Finland, France, Germany, Greece, Hungary, Ireland, Italy, Latvia, Lithuania, Luxembourg, Malta, Netherlands, Poland, Portugal, Romania, the Slovak Republic, Slovenia, Spain, Sweden and the United Kingdom.

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[1] Individual data are not available and are estimated in aggregate for: Burkina Faso, Burundi, Cape Verde, Central African Republic, Chad, Comoros, Djibouti, Equatorial Guinea, Gambia, Guinea, Guinea-Bissau, Lesotho, Liberia, Madagascar, Malawi, Mali, Mauritania, Mauritius, Niger, Reunion, Rwanda, Sao Tome and Principe, Seychelles, Sierra Leone, Somalia, Swaziland and Uganda.

[2] Including Hong Kong.

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

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

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

[5] This designation is without prejudice to positions on status, and is in line with United Nations Security Council Resolution 1244/99 and the Advisory Opinion of the International Court of Justice on Kosovo's declaration of independence.

Middle East

Bahrain, the Islamic Republic of Iran, Iraq, Israel,[6] Jordan, Kuwait, Lebanon, Oman, Qatar, Saudi Arabia, the Syrian Arab Republic, the United Arab Emirates and Yemen.

Latin America

Argentina, Bolivia, Brazil, Chile, Colombia, Costa Rica, Cuba, the Dominican Republic, Ecuador, El Salvador, Guatemala, Haiti, Honduras, Jamaica, Netherlands Antilles, Nicaragua, Panama, Paraguay, Peru, Trinidad and Tobago, Uruguay, Venezuela and other Latin American countries and territories.[7]

North Africa

Algeria, Egypt, Libya, Morocco and Tunisia.

North America

Canada, Mexico and the United States.

List of acronyms, abbreviations and units of measure

Acronyms and abbreviations

ADGSM	Australian Domestic Gas Security Mechanism
ANRE	Agency for Natural Resources and Energy
BBL	Bacton Balgzand Line (pipeline)
CAAGR	compound average annual growth rate
CAPEX	capital expenditure
CNG	compressed natural gas
CNOOC	China National Offshore Oil Corporation
CNPC	China National Petroleum Corporation
CRE	Comisión Reguladora de Energía
DOE	Department of Energy
ECA	Emission Control Area
EGAS	Egyptian Natural Gas Holding Company
EWE	Energieversorgung Weser-Ems
FERC	Federal Energy Regulatory Commission
FID	final investment decision
FLNG	floating liquefied natural gas
FOB	free on board
FSRU	floating storage and regasification units
FTA	Free Trade Agreement
FY	fiscal year
FYP	Five-Year Plan
GAP	Gas Acceleration Program
GDP	gross domestic product
GTS	Gasunie Transport Services
IEA	International Energy Agency

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

[7] Individual data are not available and are estimated in aggregate for: Antigua and Barbuda, Aruba, Bahamas, Barbados, Belize, Bermuda, British Virgin Islands, Cayman Islands, Dominica, Falkland Islands (Malvinas), French Guyana, Grenada, Guadeloupe, Guyana, Martinique, Montserrat, St. Kitts and Nevis, Saint Lucia, Saint Pierre et Miquelon, St. Vincent and the Grenadines, Suriname and Turks and Caicos Islands.

IMF	International Monetary Fund
JFTC	Japan Fair Trade Commission
JCPOA	Joint Comprehensive Plan of Action
KOGAS	Korean Gas Corporation
LNG	liquefied natural gas
LPG	liquefied petroleum gas
LTO	light tight oil
MARAD	Maritime Administration
MARPOL	International Convention for the Prevention of Pollution from Ships
METI	Ministry of Economy, Trade and Industry
MGO	Marine Gasoil
NDRC	National Development and Reform Commission
NFTA	Non-Free Trade Agreement
NOC	national oil companies
OCI	Orascom Construction Industries
OPEX	operating expenditure
PCI	Projects of Common Interest
PEMEX	Petróleos Mexicanos
PV	photovoltaic
QP	Qatar Petroleum
SCPX	South Caucasus Pipeline Expansion
TANAP	Trans Anatolian Pipeline
TAP	Trans-Adriatic Pipeline
TPA	third-party access
TSO	transmission system operator
UGS	underground gas storages
US	United States
USD	United States dollar
USGC	United States Coast Guard
YPF	Yacimientos Petroliferos Fiscales

Units of measure

bbl	barrel
bcm	billion cubic meter
GW	gigawatt
Kcal	kilocalories
MBtu	million British thermal units
MJ	megajoule
Mt	million tonnes
Mtpa	million tonnes per annum
MW	megawatt
MWh	megawatt/hour
tcm	trillion cubic metres
TWh	terawatt hour

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

IEA Publications
International Energy Agency
Website: www.iea.org
Contact information: www.iea.org/about/contact
Typeset in France by IEA- June 2018
Cover design: IEA; Photo credits: © GraphicObsession

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€80 (61 2018 12 1E1)
ISSN: 2520-274X
ISBN: 978-92-64-30056-9

9 789264 300569

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