

Gas 2019

Analysis and forecast to 2024



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Foreword

In 2018, natural gas played a major role in a remarkable year for energy. Global energy consumption rose at its fastest pace this decade, with natural gas accounting for 45% of the increase, more than any other fuel. Natural gas helped to reduce air pollution and limit the rise in energy-related CO₂ emissions by displacing coal and oil in power generation, heating and industrial uses.

The global gas narrative varies across regions: cheap and abundant resources in North America; a key contributor to reducing air pollution in the People's Republic of China; a main feedstock and fuel for industry in emerging Asia; challenged by renewables in Europe; an emerging fuel in Africa and South America. What ties these together is the central position of gas in the global energy mix as one of the key enablers of the energy transition.

Natural gas can be part of the solution to a cleaner energy path – both on land and at sea as an alternative marine fuel – but it faces its own challenges. They include ensuring price competitiveness in developing economies, guaranteeing security of supply in increasingly interdependent markets, and continuing the reduction of its environmental footprint, particularly in terms of methane emissions.

Natural gas is at the heart of three core areas for the IEA: energy security, clean energy and opening to emerging economies. I hope that this latest edition of the IEA's outlook for gas markets will help enhance market transparency and enable stakeholders to better understand current and future developments.

This is particularly important for the IEA, which has seen the ranks of its member and association countries grow in recent years to include the world's largest emerging economies. Last year, we welcomed Mexico and South Africa. The expanding IEA family accounted for almost 70% of global gas consumption growth in 2018. This global footprint underscores the IEA's ability to help shape energy policies for a more secure and sustainable energy future for all.

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Executive summary

After another record year, gas demand is set to keep growing to 2024

2018 was another golden year for natural gas. Demand grew 4.6%, its fastest annual pace since 2010, with gas accounting for 45% of the total increase in primary energy consumption worldwide. The United States and the People's Republic of China ("China") were the two main contributors to this increase, owing to a combination of economic growth, moves to switch from coal to gas, and above average weather-related energy needs.

Natural gas consumption is expected to grow at an average annual rate of 1.6% to 2024, returning to the pre-2017 trend. 2018's strong growth is unlikely to be the norm in the future because of slowing economic growth, declining potential for switching from coal to gas, and a return to average weather conditions after last year's exceptionally hot summer in the northern hemisphere. By 2024, gas consumption is forecast to exceed 4.3 trillion cubic metres (tcm) – compared with 3.9 tcm in 2018.

Industry remains the principal driver of the increase in gas demand. Industrial use of natural gas, both as a fuel and a feedstock, is set to grow at an average annual rate of 3% and represent 46% of the rise in global consumption to 2024. Gas in power generation is expected to increase at a slower rate because of strong competition from renewables and coal. But power generation will remain the largest consumer of natural gas, accounting for almost 40% of total demand by 2024.

Asia is the key to demand growth, driven by China's push for gas

Gas consumption is forecast to grow in almost all regions, led by China and gas producing countries. China is expected to account for more than 40% of global gas demand growth to 2024, propelled by the government's goal to improve air quality. The United States, the Middle East and North Africa will account for most of the rest of global demand growth, thanks to their access to abundant and competitive domestic resources, which encourages further use of gas for industrial applications and power generation. Gas demand in Europe will benefit from closures of coal and nuclear plants, but its gains will be limited by the expansion of renewables and decreasing consumption for the heating of buildings.

Rapid demand growth in China is set to ease. The country's natural gas consumption grew by 14.5% in 2017 and 18.1% in 2018. But it is expected to slow to an average annual rate of 8% to 2024 as a result of lower economic growth.

South Asian countries are expected to lead growth elsewhere in Asia. In Bangladesh, India and Pakistan, the industrial sector is the main contributor to growth, especially for fertilisers to meet the needs of growing populations. Demand growth in South Asian markets depends on both the development of sufficient supply capacity and access to competitive sources in price-sensitive markets.

The United States leads global growth in natural gas supply and exports

Gas production in the United States jumped by 11.5% in 2018, its highest growth rate since 1951, making the country the largest contributor to global gas production growth. Other major producers – such as China, Australia, the Russian Federation (“Russia”) and Islamic Republic of Iran (“Iran”) – also experienced record output. Egypt and Argentina were among the countries that closed the gap between their domestic demand and supply in 2018 due to strong production recovery.

Shale production keeps on expanding. The United States will continue to lead global gas supply growth and its annual production is expected to exceed 1 tcm by 2024. This is driven by contributions from both wet (oil-associated) and dry shale gas resources.

Gas from the United States will remain the biggest contributor to growth in international trade. Output by the other main producer countries – such as China, Iran and Egypt – will increase mainly to meet domestic market needs. The United States, Australia and Russia are set to be the largest sources of incremental gas exports to 2024.

The global gas trade’s expansion is mainly driven by LNG

US liquefied natural gas (LNG) is the single largest contributor to trade growth. In the absence of confirmed investment plans from Qatar, the United States will become the world’s largest LNG exporter with 113 billion cubic meters (bcm) in 2024. New US capacity combined with the ramping up of Australian and Russian infrastructure is expected to account for almost 90% of additional exports.

China is set to become the world’s largest LNG importer by 2024 – and the largest pipeline gas importer by 2022. In spite of strong investment, Chinese domestic production will be unable to keep up with demand growth. Pipeline imports are forecast to double to 100 bcm by 2024 thanks to capacity increases from Russia and Central Asia, while LNG imports reach 109 bcm.

Other emerging Asian markets are also helping to drive LNG trade growth. This is due to the absence of strong domestic production increases and regional pipeline networks. LNG imports in the region are expected to almost double from 81 bcm to 155 bcm between 2018 and 2024.

Europe’s gas supply deficit will increase as domestic production continues to decline. The phasing out of the Dutch Groningen field and depletion in the North Sea will create an additional gap of almost 50 bcm per year. It is expected to be bridged by a combination of LNG and pipeline imports from both traditional and new sources.

LNG investment is increasing, but more will be needed

Investment in LNG export projects rebounded in 2018 after several years of decline. More investment in liquefaction will be necessary, as spare capacity margins will otherwise shrink after 2020 and could lead to a tighter market. Final investment decisions are due to be announced for a large number of projects in 2019 that could together increase export capacity by almost 150 bcm per year. This includes a second wave of US projects, Qatar’s expansion and projects in Russia and Mozambique.

Recent investment decisions highlighted an evolution in LNG financing models. Several projects – LNG Canada, Tortue LNG and Golden Pass LNG – went ahead without the support of long-term contracts. Global oil majors and utilities are using their own balance sheets to finance the investment and add the volumes to their supply portfolios, creating an alternative to traditional development approach of using project finance.

More ships are needed for LNG, and more LNG for ships. The recent volatility in rates for charter vessels prompted orders for new LNG carriers. However, additional orders will be needed to keep the LNG shipping market balanced beyond 2022. LNG is expected to emerge as a fast-growing fuel for marine traffic, supported by stricter maritime rules on sulphur content starting in January 2020 and infrastructure developments in major ports around the world. But LNG for shipping will remain a niche market in the medium term.

Towards a global convergence of natural gas prices?

Prices of gas markets in major regions are converging. Differences in regional prices have sharply decreased since the final quarter of 2018 (especially between Asia and Europe) thanks to well-supplied markets. But the Asian spot market still faces a higher degree of price volatility because of stronger seasonal patterns. The expansion of the LNG trade is likely to encourage greater price convergence.

Natural gas price reforms in major markets are sending encouraging signals. Countries with strong natural gas consumption and import growth – such as China, India and Pakistan – are reforming their domestic markets. They have carried out several price revisions in 2018 and 2019 with the objectives of greater convergence with international market prices and fostering investment in domestic production. Similar reforms are also being enacted in several producing countries.

1. Demand

Highlights

- **2018 showed the highest annual growth** in demand for natural gas since 2010 at 4.6%, accounting for almost half (45%) of the total increase in primary energy consumption. The United States and the People's Republic of China ("China") were the two main contributors to this increase, which was mainly due to a combination of economic growth, coal displacement and weather-related energy needs.
- **Natural gas consumption is expected to grow** at an average rate of 1.6% per year until 2024, reaching over 4.3 tcm) by the end of the forecast period, compared to 3.9 tcm in 2018.
- **Industrial sector needs – including the use of gas as a feedstock for petrochemicals and fertilisers – drive the global demand trend**, and account for almost half of the total natural gas demand increment to 2024. The power generation sector remains the main gas consumer, but is growing more slowly.
- **The Asia Pacific region is the leading contributor to natural gas consumption growth**, with an average rate of 4% per year and accounting for over half of the total increase over the coming five years. China's demand grows at an average of 8%, followed by other fast-growing economies such as India, Bangladesh and Pakistan.
- **Most other regions see their gas consumption growing**, with resource-rich North American and Middle Eastern markets together accounting for one-third of the global increase in demand. Demand in the mature industrialised markets of Europe, the Russian Federation ("Russia") and Japan is expected to stagnate or even decrease due to limited substitution potential and competition in power generation.

Global overview

Global energy demand grew by 2.3% in 2018, nearly twice the average rate observed since 2010, driven by robust economic growth and higher weather-related needs in some parts of the world. Natural gas consumption was the main contributor to this increase, accounting for nearly 45% of total energy demand growth and rising by an estimated 4.6% (IEA, 2019a). The United States and China were the two main contributors, together accounting for 70% of total growth in gas consumption.

This International Energy Agency (IEA) forecast does not assume that such strong growth will become the norm in the future – this is partly due to the role played by weather-related

consumption in 2018,¹ a slowing down of economic growth, and the declining potential for coal switching. However, global natural gas consumption is expected to keep on growing at an average of 1.6% per year for the next five years and reach over 4.3 trillion cubic metres (tcm) by 2024 (Table 1.1), compared to a level of 3.9 tcm in 2018.

Table 1.1 Global natural gas demand by region, 2018–24 (bcm)

Region	2018*	2020	2022	2024	CAAGR 2018–24	Contribution to global growth
Africa	151	163	170	177	2.7%	7%
Asia Pacific	837	906	982	1 063	4.0%	57%
Eurasia	666	667	664	662	-0.1%	-1%
Europe	536	532	537	538	0.1%	0%
Middle East	526	550	573	597	2.1%	18%
North America	1 056	1 079	1 096	1 116	1.0%	16%
Central and South America	168	172	178	181	1.2%	3%
World	3 940	4 069	4 200	4 332	1.6%	

* Provisional data; data for 2020 onwards are forecasts and do not account for storage variations.

Notes: bcm = billion cubic metres; CAAGR = compound annual average growth rate.

The Asia Pacific region accounts for over half of total growth in natural gas consumption until 2024, with an average growth rate of 4% per year, led by China's strong economic- and policy-driven push for natural gas development (China's annual average increase being 8% during the forecast period of 2018–24). Other fast-growing economies such as India, Pakistan or Bangladesh are also expected to provide strong contributions to consumption growth, providing that natural gas remains competitive and affordable in these highly price-sensitive markets.

North American gas demand keeps growing at an average annual rate of 1% thanks to abundant domestic resources, and is mainly supported by export-driven industry and energy sector needs in the United States. The Middle East sees its consumption grow by over 2% per year until 2024, pushed by its increasing structural need for cooling, water desalination and other electricity uses. Both Africa and Central and South America are expected to grow (2.7% and 1.2% respectively), yet in both cases prospects for further regional integration remain limited and growth is concentrated in gas-producing countries.

Europe, Eurasia and Japan experience limited growth – and even some decline in the latter two. In Europe, potential growth due to nuclear and coal phase-out plans is constrained by the development of renewables and limited growth for industrial and residential uses. Eurasian demand is impacted by efficiency gains in the gas-fired power generation fleet, while the expected progressive restart of nuclear reactors² and development of renewables in Japan reduce the need for gas.

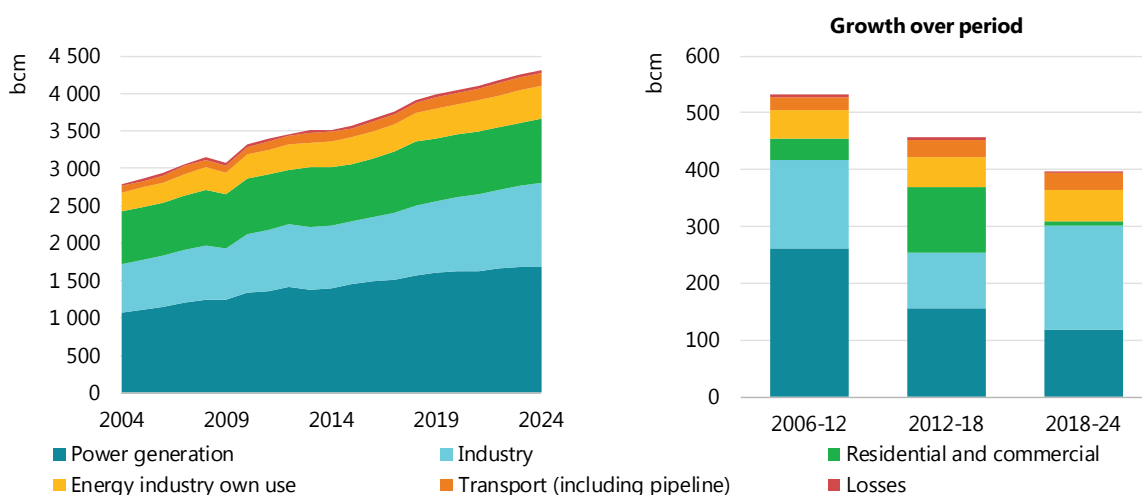
¹ Weather conditions affect natural gas consumption for residential and commercial uses in particular, and power generation to some extent for cooling needs, especially in North America. Around 20% of the increase in global gas demand in 2018 was due to colder than average winters and hotter than average summers. This forecast assumes average weather conditions.

² Subject to compliance with Nuclear Regulation Authority (NRA) regulations on building emergency facilities in the event of terrorist attack, with strong deadlines confirmed by the NRA in April 2019 (Stapczynski and Inajima, 2019).

Sectoral outlook

The industrial sector is expected to be the main contributor to global growth in natural gas consumption during the forecast period (Figure 1.1), its demand growing at an average rate of 3% per year until 2024 and accounting for almost half (44%) of incremental consumption. The Asia Pacific region is the main driver for industrial consumption growth, with an expected 6.4% average annual rate, driven by strong economic development and population growth – which in turn drive natural gas consumption for non-energy uses in fertilisers and petrochemicals. China is a leading contributor, with an annual growth rate of 8.4%, and its gas consumption for industry reaches over 140 bcm by 2024, surpassing Europe and Eurasia. Natural gas-rich regions such as the Middle East and North America also see their industrial consumption grow (at respective average rates of 2.3% and 2.2% per year), driven by exports and domestic use of petrochemicals.

Figure 1.1. Global natural gas demand by sector, 2004–24



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Industrial needs – including non-energy uses – drive natural gas demand growth to 2024 and account for almost half of the consumption increase in the coming five years.

The power generation sector’s contribution to growth keeps on declining during the forecast period, accounting for 30% of the total natural gas increment to 2024 (against 50% for 2006–12 and 35% for 2012–18). Yet it remains a sizeable part of additional consumption volumes and continues to be the main source of natural gas consumption to 2024, with a nearly stable share of 39% (against 40% in 2018).

The evolution of consumption in the residential and commercial sector is more complex, as the overall limited growth in volumes shown in Figure 1.1 hides a combination of factors: some strong growth in China driven by further coal-to-gas switching and household connections, balanced by structural declining trends (including factors such as energy efficiency in buildings and the switch to electricity) in mature regions, and limited incremental consumption from other emerging markets where heating needs are limited. Moreover, 2018 was marked by a strong contribution of weather-related consumption (especially in North America), providing a high starting point for this forecast, which assumes weather-normalised consumption.

Consumption from the transport sector grows at an average of 3% per year, but remains limited in its share of total natural gas consumption. Besides the development of gas-powered vehicles in Asia, the growing interest in liquefied natural gas (LNG) as a maritime fuel sees the establishment of an LNG-powered fleet of vessels and associated bunkering market.

Focus on LNG as a maritime fuel

Outside of LNG carriers, the use of LNG as a fuel for maritime transport is currently a niche market, mainly concentrated in Europe. As of early 2019 there are about 155 LNG-fuelled vessels in operation (excluding LNG carriers), of which a large majority are small ships used for short to medium-distance journeys – such as ferries, tugboats, car and small container vessels. However, the fleet of LNG-powered vessels is growing fast and is expected to double by 2024 with about 150 ships on order, and with additional potential from another 140 “LNG-ready” ships (equipped with the technology to use LNG as an alternative fuel) (DNV GL, 2019).

This growing interest of the shipping industry in LNG as a bunker fuel is driven by the implementation of a 0.5% global sulphur cap on maritime fuels by the International Maritime Organization (IMO) as from 1 January 2020, which will dramatically impact a market that consumed 3.4 million barrels per day (mb/d) of high-sulphur fuel oil in 2018 (IEA, 2019b).

LNG has several advantages as a marine fuel compared to more conventional options³ for complying with 2020 fuel specifications – it is a proven technology already extensively used by LNG carriers, it has a stable and standardised quality, and has a lower environmental footprint than oil-based fuels (besides having little sulphur, LNG does not emit particulates, and reduces nitrogen oxides and carbon dioxide emissions by up to 85% and 20% respectively). It would therefore also contribute to the IMO’s greenhouse gas emission strategy (which aims to reduce the sector’s total greenhouse gas emissions by at least 50% by 2050 compared to 2008). Moreover, LNG as a fuel has become increasingly competitive with oil-based marine fuels as gas prices have decreased strongly since the end of 2018.

However, switching to LNG also has additional costs and requirements. It is unlikely to compete with conventional fuels for the existing fleet, as the cost of installing exhaust gas cleaning systems (also known as scrubbers) is cheaper than conversion to a new propulsion system (with payback times up to three times faster than LNG [Parker, 2019]). Even for new-build vessels, there is an additional cost to choosing the LNG option over scrubbers, estimated by Fearnleys Securities at USD 20 million (United States dollars) for a 15 000 twenty-foot equivalent unit (TEU) container vessel (Latarche, 2019). In operational terms, it takes additional tank space (and therefore can have an impact on cargo capacity, especially for small vessels), requires special training of crew members and bunkering operations take longer than for oil-based products. From the emissions perspective, potential methane losses can be an issue, especially for low-pressure engines.

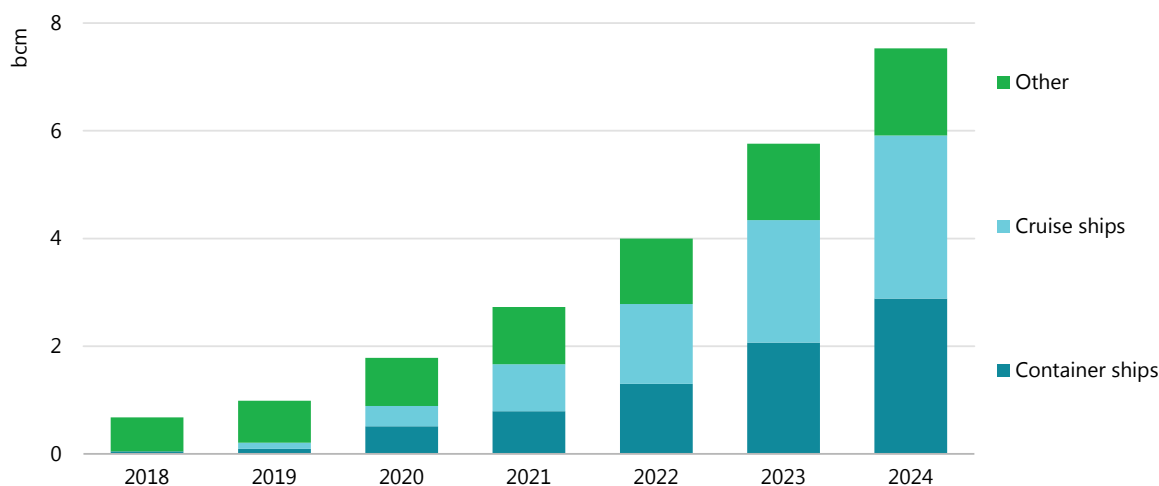
As regards bunkering infrastructure, the number of facilities is currently limited but expanding. As of early 2019 six bunkering vessels are active (mainly in northwest Europe) and nine are under construction, of which five are to be delivered in 2019. Alternative bunkering services by truck to ship are also available, enabled by the large number of LNG regasification terminals equipped with truck loading facilities. The current lack of standardisation and consistency in the licensing and control of LNG bunkering between countries remains a barrier to its development, although the harmonisation of standards and operations across different markets is progressing.

³ Being the installation of exhaust gas cleaning systems (“scrubbers”) or switching to marine gasoil or very low sulphur fuel oil.

LNG as a bunker fuel remains a market in an early stage of development. Its medium-term growth is expected to be supported by two main segments: container ships and cruise liners. They are considered the most suitable because they operate largely fixed shipping lines, which minimises logistical issues as bunkering infrastructure remains under development. CMA-CGM took the lead in the container segment with the first vessel commissioned in January 2019 and another 13 on order to be commissioned between 2019 and 2021. In the cruise liner segment, Carnival Corporation received its first LNG-powered vessel in December 2018 and has two further ships on order. Other types of vessel (crude oil tankers, bulk carriers, fishing boats) are also on order, but are expected to provide more limited contributions to the expansion of the LNG-powered fleet. The use of LNG for inland waterway transport is also developing, especially in China – see Box 1.1.

This forecast assumes a tenfold increase in LNG as a bunker fuel, from 0.7 bcm in 2018 to 7.5 bcm by 2024, with container and cruise ships accounting for almost 80% of consumption by 2024 (Figure 1.2).

Figure 1.2. LNG consumption for maritime shipping by main segment, 2018–24



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The growth in LNG as a marine fuel is supported by two main segments – cruise ships and container ships – which account for 80% of expected consumption by 2024.

Box 1.1 LNG as a shipping fuel in China

In August 2018 the Ministry of Transport published its draft opinions for extending the application of LNG as a shipping fuel (Ministry of Transport, 2018). The document's focus is on speeding up the construction of inland LNG terminals, promoting LNG transport along inland rivers and promoting LNG bunkering (both LNG fuelling stations in ports and LNG-fuelled ships).

Besides looking to develop more LNG terminals along the coast, especially in the Bohai Rim, and increase their capacity, the plan is looking at new ways of transporting LNG and new uses. The

plan wants to promote the multi-modal transport of LNG, especially one involving the transport of LNG in tanks, by river and ocean. Moreover, it looks to develop the corresponding ocean-going LNG-powered fleet (COSCO Shipping Group and China Merchants Group are encouraged to use LNG-powered vessels on their routes), develop floating storage and regasification units (FSRUs), and promote the development of an LNG-powered fleet for inland rivers, either by constructing a new fleet or adapting the old fleet. These LNG-fuelled vessels will be particularly promoted on the Beijing-Hangzhou Canal, Yangtze River, Xijiang shipping line and Pearl River Delta. As for new uses, the plan looks to promote the use of LNG in port vehicles, small ships like tugboats and other operating machinery, especially in key areas like Beijing-Tianjin-Hebei and surrounding areas and the Yangtze River Delta, and to develop LNG bunkering.

Concerning inland LNG, China is already making progress. In July 2018 private companies Guanghui Energy and China Huadian Corporation announced their intention to build an inland LNG terminal in Yueyang city (Hunan province), with a capacity of 2.72 billion cubic metres per year (bcm/y), the first phase to be ready by December 2020 (0.68 bcm/y). In January 2019, it was announced that the Chinese coal miner Huainan Mining Group received provincial approval for its inland LNG terminal in Wuhu (Anhui), with a capacity of 2.04 bcm/y, due to be ready for completion in 2022.

In November 2018, China National Offshore Oil Corporation (CNOOC) put in place the first multi-modal LNG transport when the company transported LNG in tanks from their LNG regasification terminal in Hainan, South China, to the northern region (Shandong province and the city of Jinzhou) (China LNG Group, 2018).

Sources: China LNG Group (2018), "Ceremony of CNOOC Jinzhou Port", www.lnggroup.cn/a/lng-new/jt/112.html; Ministry of Transport (2018), "Letter from the General Office of the Ministry of Transport for the opinions on deepening the advancement of the application of liquefied natural gas in the water operation industry", http://zizhan.mot.gov.cn/zfxxgk/bnssj/syj/201808/t20180810_3056391.html.

Assumptions

The International Monetary Fund (IMF) *World Economic Outlook*, published in April 2019, provides the main macroeconomic assumptions for this natural gas consumption forecast (IMF, 2019). After global gross domestic product (GDP) growth of 3.3% in 2019 and 3.6% in 2020, the IMF expects world output to expand at an average rate of 3.5% per year to 2024.

This report uses the average of futures prices taken over the period September 2018 to March 2019 as price indicators. Futures are financial products used by the energy industry for risk management purposes and are not to be considered as price forecasts. As the liquidity of futures contracts is much lower for the longer maturities (beyond 18 to 36 months, depending on the market), this report combines information from the average of futures curves with medium-term fuel price assumptions as contained in the *World Energy Outlook 2018* (IEA, 2018a) to provide an indication of assumed longer term price evolution. For Europe, this report assumed Title Transfer Facility (TTF) prices of USD 6.6 per million British thermal units (MBtu) for 2019-20 and USD 6.4/MBtu in 2021, growing in the second part of the forecast period to reach an average of USD 7.2/MBtu by 2024. In North America, the Henry Hub prices are assumed to stay below USD 3/MBtu until 2024. In Asia, oil-linked liquefied natural gas (LNG) import prices are assumed to stay around an average of USD 8/MBtu, whereas spot LNG prices are assumed to remain below oil-indexed prices on average. The price of coal imported into

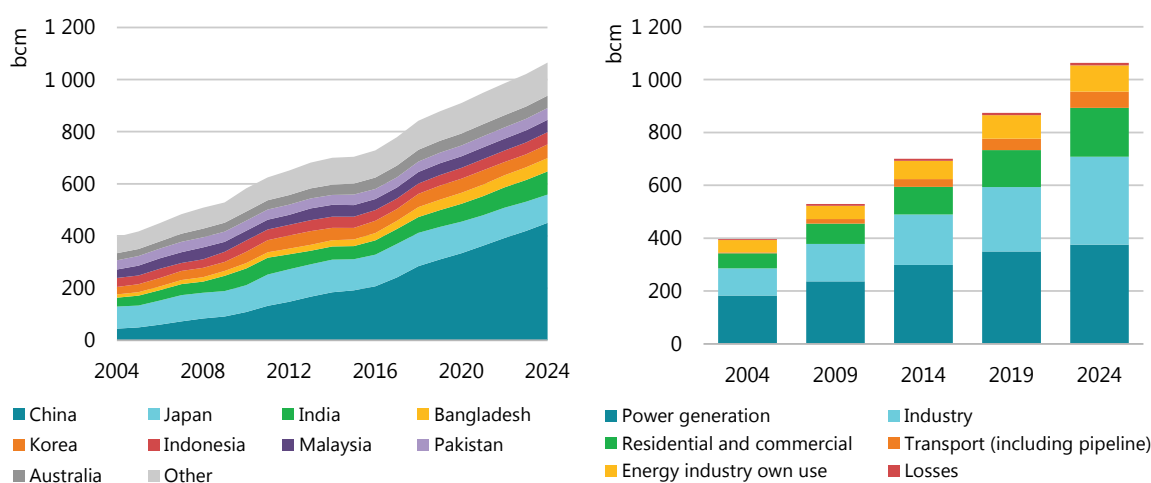
Europe is assumed to grow over the forecast period, from USD 65/t in 2019 to USD 72/t in 2024, while Asian coal prices are assumed to decline from USD 95/t in 2019 to USD 87/t in 2024.

Regional outlook

Asia Pacific

The Asia Pacific region is the main source of growth in demand for natural gas, contributing 57% of the global consumption increase to 2024. China alone accounts for 42% of global demand growth over the next five years and 74% of growth in the Asia Pacific region (Figure 1.3).

Figure 1.3. Natural gas demand by country and sector, Asia Pacific, 2004–24



IEA, 2019. All rights reserved.

China remains the principal source of growth over the forecast period, accounting for almost three-quarters of the Asia Pacific demand increase to 2024.

China

China⁴ is the world’s third-largest natural gas consumer after the United States and the Russian Federation (“Russia”), using 237 bcm in 2017 and 280 bcm in 2018 (283 bcm including Hong Kong). Its natural gas demand grew by 14.5% during 2017 and 18.1% during 2018, helped by strong environmental policies to replace coal with gas in urban industrial uses and residential heating. At a provincial level, Beijing (for example) increased its natural gas demand by 12.5% in 2018 to reach 18 bcm, Shandong by 9.4% to reach 14 bcm, and Zhejiang by 28% to reach 13.5 bcm, with Yunnan seeing consumption of 1.04 bcm, an increase in its consumption of 77%. Chinese gas demand grew at double-digit rates from 2004 to 2014, with a 17% average growth per year. The lowest increase was seen in 2015 at 4%, due to lower real GDP growth of 6.9% compared with an average of 9.7% from 2000 to 2014, and also the natural gas price increase

⁴ Unless explicitly stated, the following figures do not include consumption from Hong Kong, which stood at 3 bcm in 2018 and is expected to remain stable throughout the forecast period.

resulting from price reform (see Chapter 4). Consumption recovered in the following year after a decrease in prices enacted by the end of 2015.

The share of natural gas in the primary energy mix in China has increased from 2% in 2000 to 7% in 2017, and 8% in 2018. Although the country has seen rapid growth in the share of natural gas in its energy mix, it is still behind the world average of 22% (data for 2017). According to the 2018 Natural Gas Development Plan, the natural gas share of primary energy consumption is expected to reach 10%, 14% and 15% in 2020, 2030 and 2050 respectively.

In 2017 demand growth came from industry (with a 22.9% increase) and transport (up 27.4%). According to IEA estimates, growth during 2018 came from power generation, with over 28% year-on-year (y-o-y) growth, and residential and commercial, with a 20.2% increase, due to the government's coal-to-gas switching plan. Industrial demand growth slowed, with almost 17% y-o-y growth, while transport saw an 8.2% increase. Energy industry own use experienced an 18.5% increase in 2017 and almost 22% in 2018.

For 2019 the report forecasts a 9.1% increase in demand, with coal substitution as a main driver for demand growth. Growth is expected mainly to come from industry (9.4% increase) residential and commercial (9.1% increase) and power generation (up 7.5%). China is expected to consume a total of 310 bcm during 2019, with 96 bcm for industry, 74 bcm for residential and commercial, 69 bcm for power generation, and another 70 bcm for other uses (including energy industry own use, transport, and losses).

This sustained growth is ensured by the government's long-term goal to improve air quality. In June 2018, as part of its efforts to win the battle for a blue sky, the State Council announced a three-year action plan ("2018–2020 Three-year Action Plan for Winning the Blue Sky War") with new targets to lower emissions in urban areas (Table 1.2) (State Council, 2018). The plan focuses on the Beijing, Tianjin and Shanghai areas, and the key cities of Hebei, Henan, Shaanxi, Shanxi, Shandong, Jiangsu, Zhejiang and Anhui. Sulphur dioxide and nitrogen oxide emissions should decline by at least 15% from their 2015 levels, while the level of fine particulates in cities with low air quality standards should drop by at least 18%, also from their 2015 level.

Table 1.2 Three-year action plan to win the battle for blue sky

Action	Where	Share
Speed up clean and renewable energy	Nationwide	Non-fossil energy shall account for 15% of total energy consumption and curtailment of hydropower, wind and solar should be solved
Build gas supply and storage system	Nationwide	Natural gas shall account for 10% of China's energy consumption
Reduce share of coal in energy consumption	Nationwide	Less than 58%
Reduce consumption of coal	Beijing, Tianjin, Hebei, Shandong and Henan	By 10% compared to 2015 levels
Reduce consumption of coal	Yangtze River Delta	By 5%
Phase out coal-fired units that are below 300 MW and not updated	Located within 15 km of a 300 MW or above co-generation plant	
Eliminate distributed coal boilers	Beijing-Tianjin-Hebei region, the Yangtze River Delta, some parts of Shaanxi province	

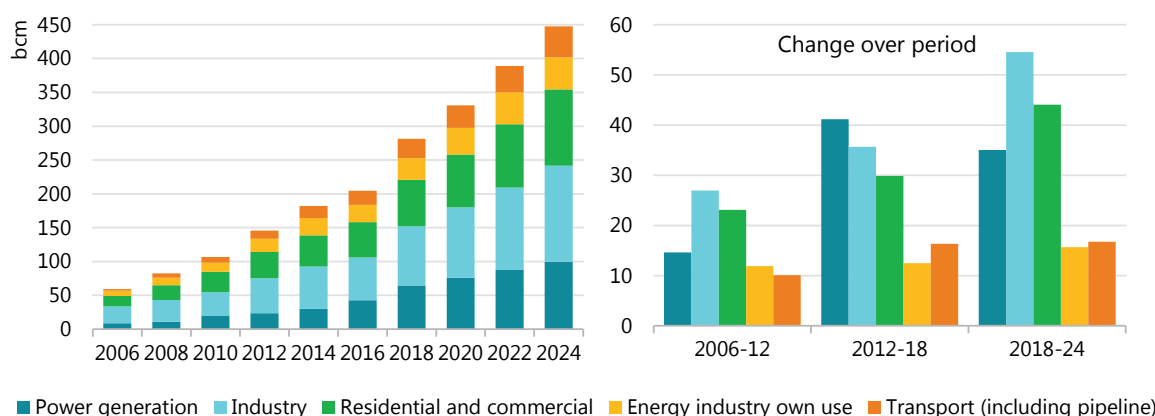
Action	Where	Share
Prioritise new gas projects in coal-to-gas switch	In urban cities and severely air-polluted areas	
Encourage production of new energy vehicles	Production shall reach 2 million units	
Switching in industry	Industrial furnaces are encouraged to use electricity and natural gas	

Note: km = kilometre; MW = megawatt.

Source: State Council (2018), "The State Council issues a three-year action plan to win the battle for the blue sky", www.gov.cn/zhengce/content/2018-07/03/content_5303158.htm.

During the forecast period, this report sees strong growth in demand at an average annual rate of 8%, from around 281 bcm in 2018 to 450 bcm in 2024 (Figure 1.4). The IMF estimates that the Chinese economy's rate of growth will decrease from 6.3% in 2019 to 5.5% in 2024 (IMF, 2019).

Figure 1.4. Natural gas demand by sector, China, 2006–24



IEA, 2019. All rights reserved.

Chinese natural gas demand reaches 450 bcm by 2024, led by the industrial and residential and commercial sectors.

China's incremental natural gas demand will be an important component of global consumption growth in the forecast period. The country is expected to consume an additional 166 bcm, or 58% more, by 2024 compared to 2018. Continuous economic growth and further switching in the industrial and residential and commercial sectors will be the main drivers of this consumption increase. These sectors represent 59% of the overall consumption increase.

The residential and commercial sector is set to remain a strong source for growth during the next five years. In 2019 the government announced that pollution control spending would increase by 25% as it continues to push for coal substitution in Northern China (Argus, 2019). The overall pollution control budget – including subsidies to replace coal as heating fuel with gas or electricity in 35 cities – represents CNY 25 billion (Chinese yuan, or USD 3.76 billion).⁵ In 2018, according to the Ministry of Ecology and Environment, 4.8 million households changed from coal to cleaner energy sources like gas and electricity, 20% more than the 4 million in 2017. This trend is expected to continue in the near future, with an annual average of 8.6% until 2024.

⁵ Using the average 2018 rate of USD 1 = CNY 6.64.

In the “Natural gas heating development targets for 2017–2021” (NDRC, 2017), the target has been set at converting 12 million households from coal-fired to gas-fired boilers, representing and incremental demand of 9 bcm by 2021.

Table 1.3 shows the number of new gas or electric heating users in 2017 and 2018 (Meng and Patton republishing data published by the Ministry of Ecology and Environment and the State Grid for the year 2018). Compared to 2017, Beijing and Tianjin saw the number of new gas and electric heating users decrease in 2018, while the other provinces increased, especially Henan with 114% more households switching and Shaanxi with 81% more. In 2018, among the 4.8 million households that changed to cleaner energy sources, 3.3 million chose gas heating, representing an additional 4.53 bcm of gas consumption. Hebei, with almost 1.8 million new gas heating users, was responsible for 44% of the additional gas consumption, at 2 bcm.

In the provinces of Beijing and Shaanxi the majority of new users converted to electric heating, while in Hebei, Tianjin and Henan, 82%, 81% and 67% of new users (respectively) changed to gas. On average, of the 4.8 million of new users, 68% switched to gas.

Table 1.3 New gas or electric heating users, China, 2018

	Beijing	Hebei	Tianjin	Shandong	Henan	Shanxi	Shaanxi	Total
New gas and electric heating users 2017	300 000	1 800 000	290 000	350 000	420 000	450 000	390 000	4 000 000
New gas and electric heating users 2018	161 600	1 769 000	190 000	450 000	898 000	663 000	707 000	4 838 600
Y-o-y change	-46%	-2%	-34%	29%	114%	47%	81%	21%
New gas heating users 2018	39 000	1 450 000	154 100	210 000	598 000	601 000	237 000	3 289 100
New electric heating users 2018	122 600	319 000	35 900	240 000	300 000	62 000	470 000	1 549 500
% switched households using gas 2018	24%	82%	81%	47%	67%	91%	34%	68%
% switched households using electric 2018	76%	18%	19%	53%	33%	9%	66%	32%
Gas consumption of switched users (bcm) 2018	0.054	2	0.212	0.289	0.824	0.828	0.327	4.534

Sources: Meng and Patton (2018), “China turns up gas heat in 3 mln more homes”, *Reuters*, <https://af.reuters.com/article/commoditiesNews/idAFL4N1Y53ZL>; Chyx (2017), “Forecast of coal-to-gas and electricity users in six provinces in the North of China, 2018”, www.chyx.com/industry/201712/594589.html.

Manufacturing is the main gas-consuming industry subsector, with energy-intensive users for smelting, process heat, chemical feedstocks and fertilisers. These subsectors remain important

for the additional natural gas demand as they switch from coal to gas. Such a switch results from government policy given that coal is cheaper than gas. In the “Three-year action plan to win the battle for the blue sky” published in June 2018, the State Council encourages industrial furnaces to use clean energy such as electricity and gas.

Growth in gas demand for power generation is estimated to have been almost 30% in 2018, with about 281 terawatt hours (TWh) of electricity produced from natural gas. The growth trend for the coming years is expected to be less robust, at an average annual rate of 7.5%. This assumes that the 13th Five-Year Plan (FYP) objective of 110 gigawatts (GW) of installed gas-fired capacity by 2020 is only achieved by 2023, due to the strong competition from renewable capacity development. In 2018 China built 44.3 GW of new solar capacity, less than the 53 GW in 2017. Additionally, in December 2018 China launched a new 2018–20 renewable quota system. The new quota sets minimum renewable power consumption targets for each region. In addition, since transmission capacity has been a problem for the large number of new wind, solar and hydro plants coming online across the country, the National Development and Reform Commission (NDRC) has announced that it is to create new mechanisms and price-setting policies, as well as force local governments to give renewable electricity sources priority access to power markets (NDRC, 2018).

Overcapacity in coal-fired power generation has also been an issue for several years, especially since approval of new plants was transferred to the provinces in October 2014. The 13th FYP established a target of 1 100 GW of additional coal-fired capacity by 2020. It appears that this will be surpassed, given the current coal capacity additions of almost 1 000 GW, with another 200 GW under construction, and despite the closure of 20 GW of old and inefficient plants (IEA, 2018b).

In the transport sector, in 2017 there were 6.5 million natural gas vehicles circulating in China. The target for 2020 was set at 10 million cars; however, in order to reach the target car demand would need to increase by 15% during 2018 to 2020. This report forecasts that the target is met by 2023, due to growing sales of other new energy vehicles. Sales of pure electric vehicles, according to China Automobile Association, reached 984 000 units in 2018, up 50% y-o-y, while plug-in hybrids reached 271 000, up by 118%, and fuel cell vehicles reached 1 527 units. According to the Blue Book on China’s hydrogen energy infrastructure, the fuel cell vehicle fleet will reach 10 000 by 2020 and 2 million by 2030.

This report forecasts annual growth in natural gas demand of 6.9% for energy industry own use between 2018 and 2024, mainly driven by needs from growing domestic production.

Box 1.2 Developing natural gas in South China

In December 2018 the Guangdong provincial government published a plan to promote the use of natural gas in the province. The main actions are increasing natural gas supply by encouraging private companies to invest in LNG terminals and storage facilities. Development of the Huizhou and Maoming LNG terminals and the Guangzhou Nansha and Yangjiang peak shaving stations are to be accelerated. The opening of existing LNG terminals to third-party access, especially the Dapeng, Diefu and Zhuhai terminals, will also be promoted, as will the signing of medium- and long-term contracts. The plan also looks to reduce pipeline transport costs, control the city gas companies’ profits and push forward the construction of interconnection projects. By 2020 all 21 cities of Guangdong should be connected to the pipeline grid, reaching 830 km, as should the

terminals and facilities of different companies. The plan also looks to continue the coal-to-gas reform, especially in major areas and industries. Distributed heating systems in industrial areas will be eliminated and by 2019 a new gas-fuelled district heating system will be brought into operation (Guangdong Government, 2018).

In February 2019 the government issued another notice to further develop the Greater Bay Area, focusing on Guangdong, Shenzhen, Hong Kong and Macao. The plan, with a timeline set between now and 2022 in the short term and then until 2035 in the long term, foresees turning the Greater Bay Area into a global technology innovation centre and building advanced manufacturing and modern services industries. Regarding energy, the plan promotes the development of green and low-carbon energy such as renewables, nuclear, clean coal and natural gas. The construction of new LNG import terminals, expansion of the capacity of the existing ones, and increasing pipeline coverage and gas reserves are also promoted. Gas supply pipelines to Hong Kong and Macao should also be enhanced to ensure security of supply in both areas (State Council, 2019).

Source: Guangdong Government (2018), "Guangdong province promotes natural gas utilization implementation plan", www.gd.gov.cn/zwgk/wjk/qbwj/yf/content/post_1053040.html; State Council (2019), *Outline of Development Planning for Guangdong, Hong Kong and Macao Dawan District, 2019*, www.gov.cn/zhenqce/2019-02/18/content_5366593.htm#allContent.

Box 1.3 Access to natural gas in China for residential customers

Access to natural gas has increased dramatically in China in recent decades. Between 2010 and 2017 the proportion of the population with access to natural gas grew at an annual average rate of 10%, while the transmission and distribution network grew by 14% per year on average. This resulted in the population with natural gas access doubling over the period, while the pipeline network grew by 143% (see table). Regions such as Beijing increased their total network length by 13% from 2016 to 2017, while others such as Liaoning increased their network length by 57% and the population with access to natural gas by 23% in just over a year.

Population with access to natural gas and km of pipelines, by region, China, 2010 and 2017

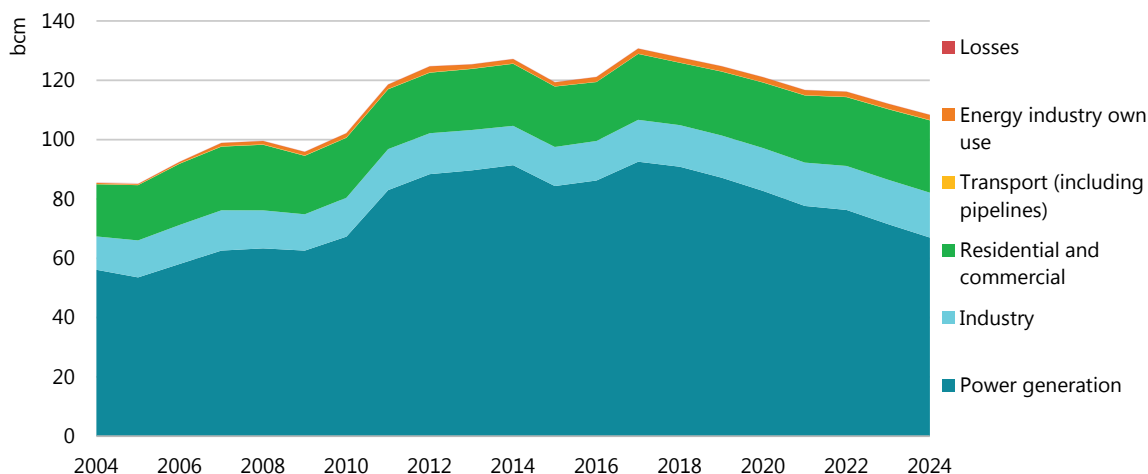
	2010	2010	2017	2017	Growth 2010–17	
	Population connected (million)	Length of pipe (km)	Population connected (million)	Length of pipe (km)	Population connected %	Length of pipe %
Total	170.2	256 429	339.3	623 253	99%	143%
Beijing	12.9	15 500	14.5	26 186	12%	69%
Tianjin	5.7	10 791	8.1	20 706	41%	92%
Hebei	8.4	8 155	15.0	23 533	79%	189%
Shanxi	4.3	3 429	10.0	14 774	132%	331%
Inner Mongolia	2.6	2 925	6.2	9 680	141%	231%
Liaoning	8.0	7 405	14.2	25 043	78%	238%

	2010	2010	2017	2017	Growth 2010–17	
	Population connected (million)	Length of pipe (km)	Population connected (million)	Length of pipe (km)	Population connected %	Length of pipe %
Jilin	2.9	3 976	7.4	10 060	155%	153%
Heilongjiang	5.7	6 032	8.7	9 610	53%	59%
Shanghai	10.9	17 317	17.2	30 387	57%	75%
Jiangsu	13.0	27 641	26.3	71 881	102%	160%
Zhejiang	5.5	13 962	14.5	39 097	161%	180%
Anhui	6.4	9 802	13.4	23 763	111%	142%
Fujian	2.7	4 296	5.7	9 513	107%	121%
Jiangxi	1.6	3 220	6.8	12 553	336%	290%
Shandong	14.4	24 518	30.2	55 981	109%	128%
Henan	8.3	11 914	18.7	22 683	124%	90%
Hubei	7.0	11 371	15.7	31 819	125%	180%
Hunan	4.2	7 177	10.2	17 025	142%	137%
Guangdong	9.2	10 683	23.0	31 346	150%	193%
Guangxi	1.1	3 974	4.8	5 513	351%	39%
Hainan	0.8	1 366	1.9	3 046	143%	123%
Chongqing	8.6	8 351	13.6	22 320	58%	167%
Sichuan	11.6	23 889	20.8	49 338	79%	107%
Guizhou	0.1	195	3.4	6 414	2 708%	3 189%
Yunnan	0.4	337	4.3	5 947	1 062%	1 665%
Tibet	0.0	-	0.2	3 450	-	-
Shaanxi	5.5	6 901	9.4	16 567	72%	140%
Gansu	2.0	900	4.4	3 140	125%	249%
Qinghai	0.9	830	1.6	2 244	76%	170%
Ningxia	1.1	2 424	2.3	6 279	115%	159%
Xinjiang	4.5	7 145	6.9	13 358	56%	87%

Japan

Japan's natural gas demand totalled about 128 bcm in 2018, a slight decrease on 2017, with power generation needs decreasing by almost 1% and accounting for more than two-thirds of total consumption (Figure 1.5).

Figure 1.5. Natural gas demand, Japan, 2004–24

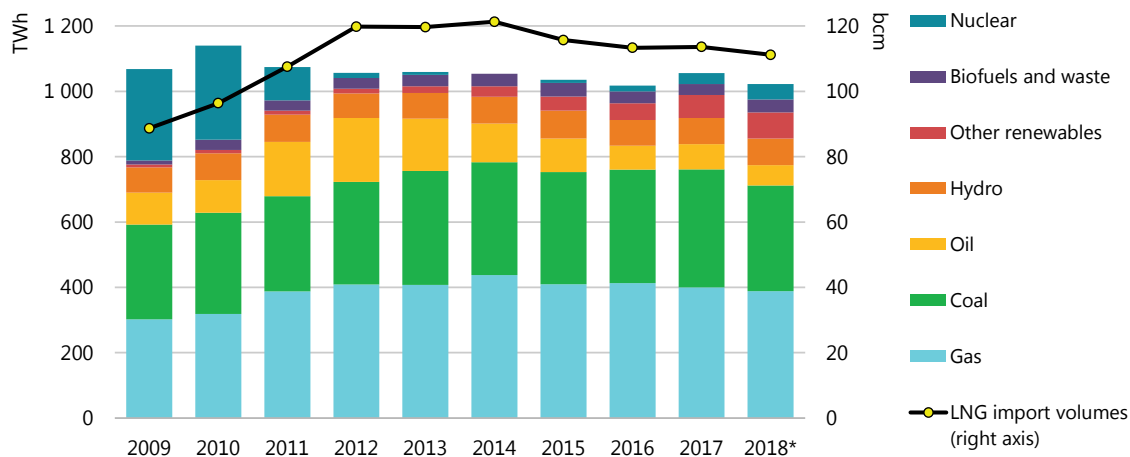


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Natural gas consumption is expected to further decline in Japan during the forecast period as more nuclear capacity is due to restart.

As other sectors are expected to grow modestly, consistent with GDP growth, or even stagnate out to 2024, future gas consumption in Japan is sensitive to the power sector, particularly the timing and quantity of nuclear power plant restarts and the growth of renewable electricity generation (Figure 1.6).

Figure 1.6. Power generation by fuel and LNG import volumes, Japan, 2009–18



IEA, 2019. All rights reserved.

* Estimated.

Sources: METI (2018), *Power Generation Performance*, www.meti.go.jp/english/press/2018/pdf/0716_01b.pdf; IEA (2019c), *Electricity Information* (database), www.iea.org/statistics/.

The share of natural gas in power generation reached its highest in 2013 in the aftermath of the 2011 Great East Japan Earthquake and Fukushima Daiichi nuclear accident.

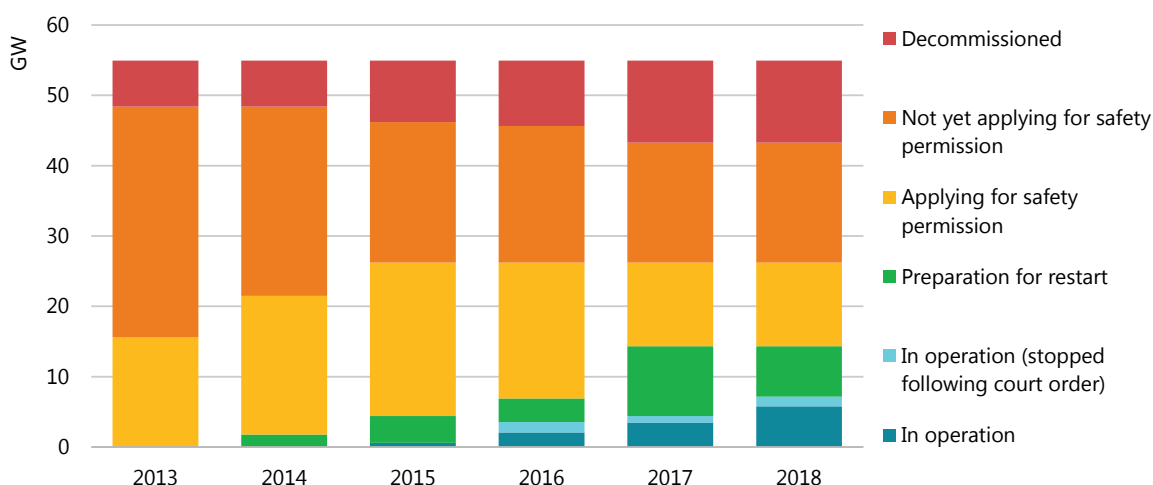
The outlook for nuclear restarts remains uncertain. After decommissioning two reactors of 1.1 GW in 2018, Japan has 38 nuclear reactors and 3 units under construction, equal to around 42 GW in total. Following establishment of the newest nuclear safety measures by the NRA, one

reactor was given approval to restart operations in 2018, with a total of 15 nuclear reactors having obtained approval. Ten further reactors are applying and under review for safety approval to restart. Sixteen nuclear reactors have yet to apply. In addition, four reactors restarted in 2018 by meeting the newest standards, Ohi No.3 and No.4, and Genkai No.3 and No.4, which are 1.2 GW each. Thus, nine reactors are operating in total at the time of writing. An additional six reactors are preparing to restart after approval (Figure 1.7).

However, the outlook for nuclear restarts could be further challenged as, in late April 2019, the NRA has reportedly refused to further extend deadlines for utilities to build emergency facilities for reactors in the event of terrorist attack, with a risk of shutdown for units that do not comply with construction timelines. The earliest deadline is in March 2020 for the Sendai No.1 reactor. This decision may affect at least 10 reactors with deadlines within the forecast period (Stapczynski and Inajima, 2019).

A further pressure on gas consumption in the power sector is increasing generation from renewable energy sources. Between 2011 and 2018 power production from renewables increased from 127 TWh to 191 TWh, mostly led by solar power (IEA, 2018c). This forecast assumes strong growth of renewable energy generation at a rate of around 5% per year, equivalent to an increase of almost 65 TWh from the 2018 level.

Figure 1.7. Status of safety approval for nuclear power reactors in Japan, 2013–18



IEA, 2019. All rights reserved.

Source: IEA compilation based on information from company websites.

Nuclear restarts began in 2016, but as of the end of 2018 less than one-quarter of capacity that applied for safety permission has actually resumed operations.

Korea

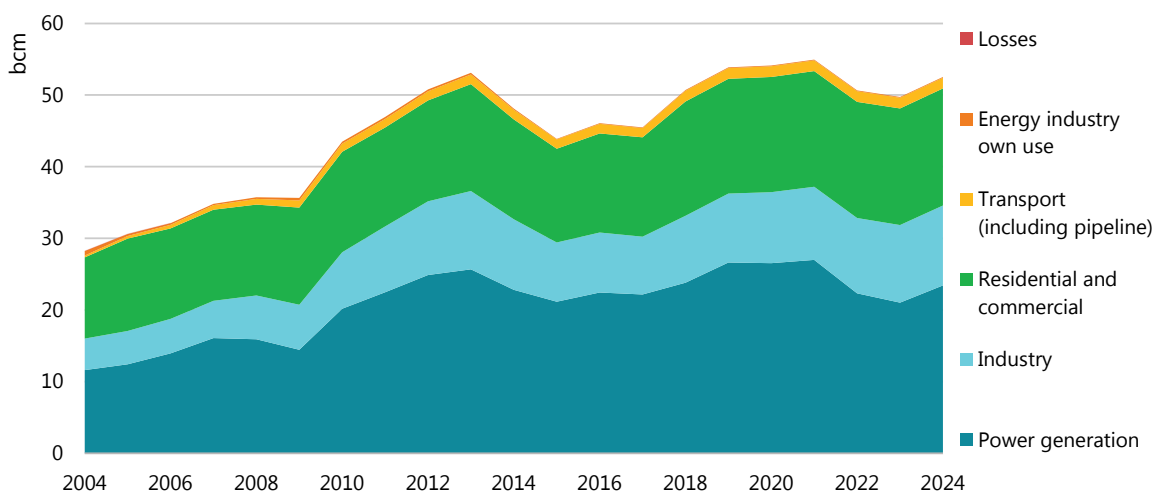
Natural gas consumption in Korea has shown a rebound since 2016 after decreases in 2014 and 2015 (Figure 1.8). LNG imports actually increased by 16% in 2018, mainly driven by new contracts and long-term contracts ramping up, with the difference absorbed by Korea's ample LNG storage capacity. Demand peaked in 2013 when almost half of the natural gas supply was consumed in the power sector. Gas consumption in this sector decreased in the following years, declining by 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. However, natural gas demand for power generation recovered to its 2012 level in 2018, thanks to limitations on coal generation.

The Korean government announced a policy of reducing coal generation due to severe air pollution in 2019. One of the main features is the simultaneous increase in coal import tax (up 28% to about USD 40/tonne) and a 75% cut in LNG import tax (to about USD 20/tonne) enacted from 1 April 2019 (Russell, 2019), alongside the setting of additional operational load limitations on coal-fired power plants. Furthermore, early retirement of older coal-fired power plants and conversion to natural gas will be considered. The detailed rules are expected to be included in Korea’s 9th Basic Plan for Long-Term Electricity Supply and Demand, which is due to be issued by the end of 2019. However, the commissioning of two new nuclear reactors (Shin Kori 5 and 6) scheduled in 2022 and 2023 respectively (WNN, 2019) is likely to introduce more competition for natural gas in power generation in the second half of the forecast period (Figure 1.8).

The residential and commercial sector accounts for roughly 30% of consumption, and this level is expected to continue throughout the forecast period of 2019–24. The industrial sector, where iron and steel and chemical/petrochemical companies lead consumption, accounts for 20% and is expected to retain this proportion over the forecast period.

Figure 1.8. Natural gas demand, Korea, 2004–24

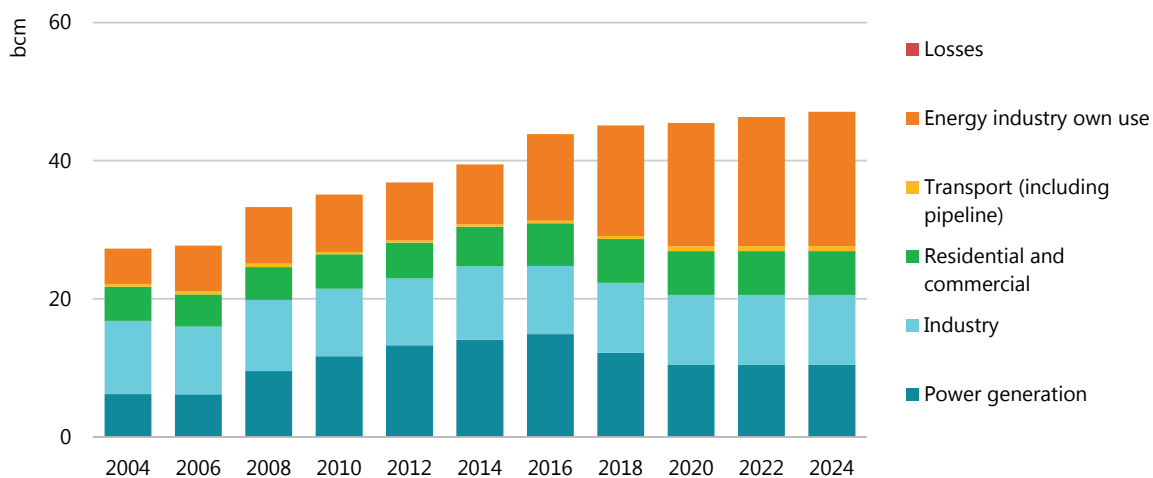


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Natural gas consumption has rebounded in Korea since 2017 with more stringent emission controls on coal, but is expected to decrease in 2022–23 as new nuclear capacity is scheduled to begin operating.

Australia

The structure of Australia’s natural gas consumption has been strongly affected by the development of LNG export projects – especially on the east coast – resulting in energy sector-related needs (or own use) accounting for a growing share of the country’s total natural gas consumption. Australian natural gas consumption increased by 1% in 2018, driven by this demand from the energy sector as the last LNG plants from the current wave of investment enter service. Consumption linked to natural gas production and liquefaction is expected to remain the main driver of total natural gas demand trends for the forecast period (Figure 1.9).

Figure 1.9. Natural gas demand, Australia, 2004-24

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Consumption by the energy sector – linked to the development of LNG export capacity – shapes Australian natural gas demand, while renewables squeeze gas in power generation.

Gas consumption by the power generation sector has been under strong pressure from the development of renewables. In 2018 some 2 GW of new renewable capacity was installed in addition to the development of decentralised production with the expansion of rooftop solar, resulting in a drop in gas for power generation needs. In spite of the planned retirement of 2 GW of coal-fired generation, natural gas is expected to struggle in the power generation sector due to the deployment of some 7 GW of additional renewable capacity – mainly from wind and solar – and up to 48 GW of proposed projects (AEMO, 2019). This forecast expects gas consumption for power generation to decrease in the early years due to the deployment of renewables, then stabilise over the later years to provide a complement to variable renewable energy.

Consumption from other sectors – industry and residential and commercial – is expected to remain stable over the forecast period.

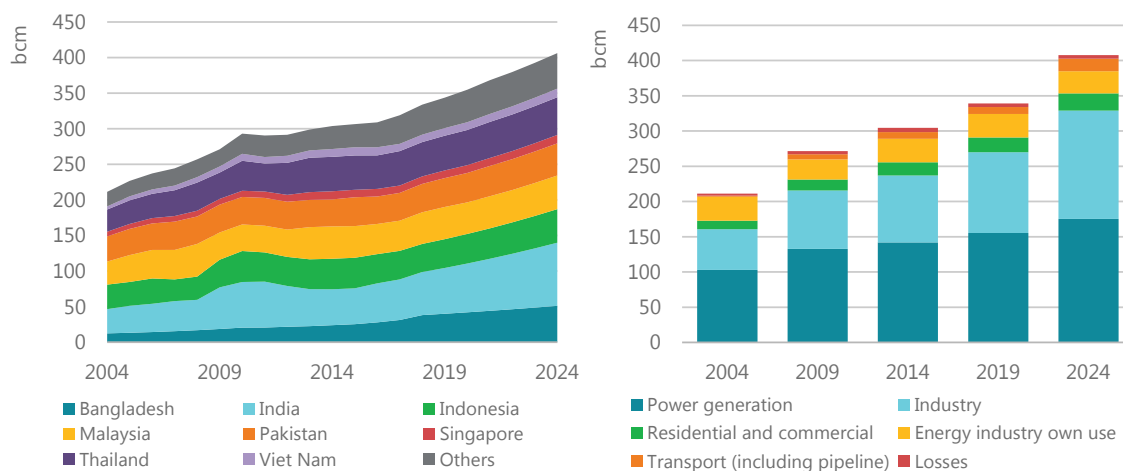
The Australian government introduced in 2017 the Australian Domestic Gas Security Mechanism (ADGSM) to ensure there is a sufficient supply of natural gas to meet the anticipated needs of domestic consumers (IEA, 2018d). This may, if triggered, require LNG projects to limit their exports or find new sources of supply. In 2018, the Federal Government decided not to apply export controls for the 2019 year following its consideration under the ADGSM. A new Heads of Agreement was made in September 2018 between the Prime Minister and the LNG export projects under which project owners made commitments for the domestic supply of gas in 2019 and 2020 (Department of Industry, Innovation and Science, 2018). LNG imports are also being considered in order to alleviate potential supply shortages on the east coast (Latimer, 2019).

Other emerging Asian economies

Other emerging Asian economies (excluding China) saw their natural gas consumption grow at an average rate of 2.8% during 2013–18. The industrial sector is the main driver behind this trend, with strong rates of 4% and above in Bangladesh, India, Malaysia, Myanmar, Thailand

and Viet Nam. This growth trend supported by industrial consumption is expected to continue during the forecast period, with total natural gas consumption reaching over 400 bcm/y by 2024 (Figure 1.10).

Figure 1.10. Natural gas demand by country and sector, other emerging Asian economies, 2004-24



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Industry is expected to remain the main driver of natural gas demand growth, accounting for almost 60% of additional volumes to 2024.

South Asian countries – Bangladesh, India, and Pakistan – are set to drive the demand growth in absolute terms, accounting for more than 40 bcm/y of incremental natural gas consumption by 2024 (Figure 1.10). Whereas natural gas use in power generation is expected to show modest growth in the coming years in South Asia due to competition with coal, continuous economic growth and population increase are driving additional natural gas needs in the industrial sector, with a strong contribution from fertilisers. Residential and commercial uses also increase, in conjunction with the expansion of domestic pipeline connections. Future natural gas development in South Asian markets is conditional on the development of sufficient supply capacity and access to competitive sources in a context of price-sensitive markets – both preconditions assumed as being met in this forecast.

Southeast Asian countries, which traditionally drove natural gas consumption in the emerging Asian countries via power generation, have gradually shifted towards slower demand growth rates over the recent past. Whereas local natural gas resources traditionally meet domestic needs, the outpacing growth in electricity demand – especially in Indonesia, Malaysia, the Philippines and Viet Nam – triggered the development of economically competitive coal-fired generating units. In Peninsular Malaysia, which accounts for over 80% of electricity demand in the country, ageing gas turbines with a total generating capacity of over 10 GW are scheduled to be phased out by 2024. Some 5 GW of more efficient gas turbines are planned to be developed, alongside coal and hydro. The Indonesian government has a target to raise the share of renewable energy in the national energy mix within the forecast period.

Power generation is the main consumer of gas in Thailand, accounting for over 60% of total gas demand. Gas consumption growth came to a halt after 2013 as the diversification of the power mix prompted lower demand growth for power uses, combined with decreasing use in the energy industry on falling domestic production. This forecast expects further growth from power generation, as the development of coal-fired plants faces strong opposition from local

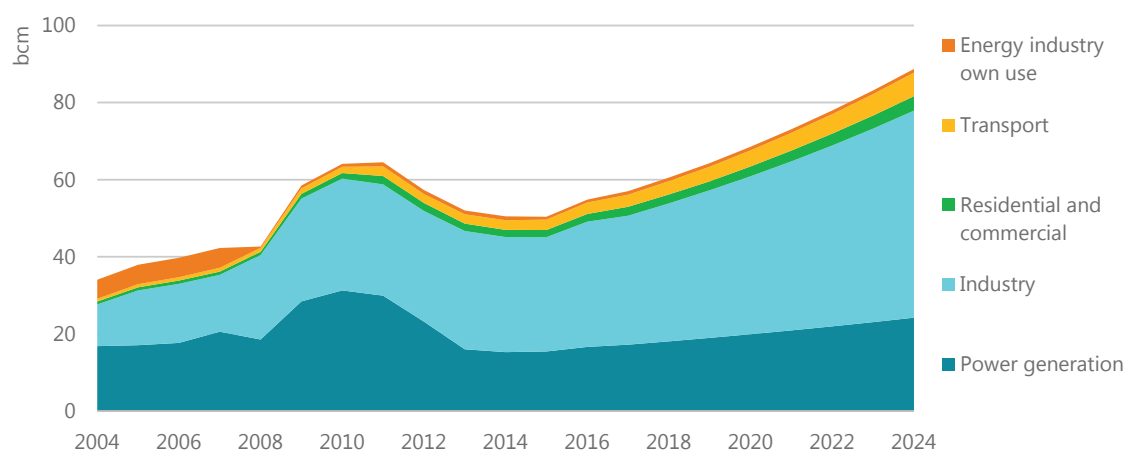
communities, and from industrial uses led by petrochemicals. This report expects the Southeast Asian countries to add around 20 bcm/y of natural gas demand in total by 2024.

India

India has traditionally relied on its domestic production of associated gas from oilfields to meet the country's requirement for both power generation and industrial uses. However, the country's strong economic and population growth led to further acceleration in natural gas demand, led by industrial uses. To meet the growing demand from industry and forecast usage in power generation (Figure 1.11), in 2004 India started to import natural gas in the form of LNG.

The decline of domestic production from 2011, combined with stagnating LNG imports until 2015 due to high price levels and slower development of relevant infrastructure, hampered the development of natural gas in power generation in India. Power generation from gas-fired power plants fell⁶ and was replaced by economically competitive coal-fired power plants. This trend continued during fiscal year 2016/17, when natural gas accounted for only 7% of installed generating capacity (or 25 GW), and less than 3% of electricity production (Figure 1.12).

Figure 1.11. Natural gas demand by sector, India, 2004–24



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Industrial uses of natural gas, mainly for fertilisers, refining and chemicals, remains the principal driver of Indian consumption in the near future.

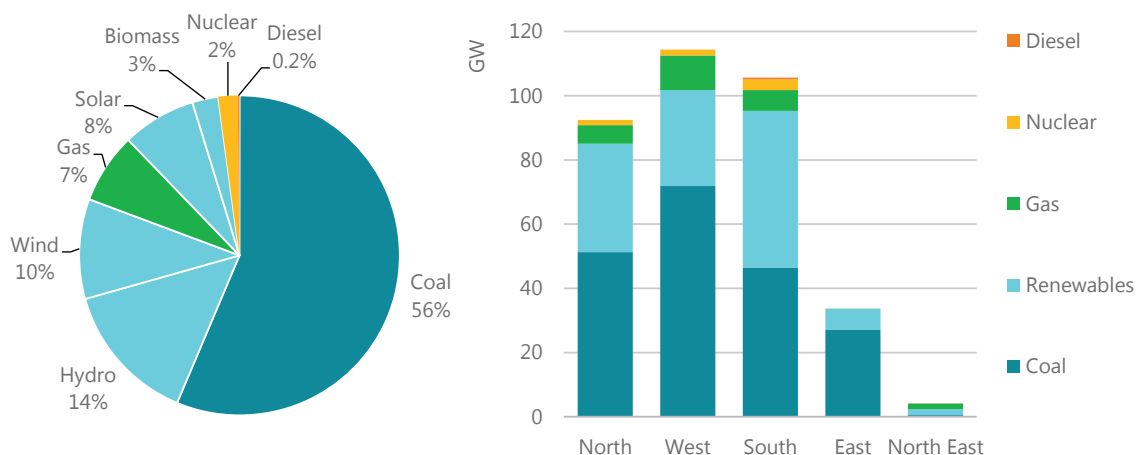
Concerns over air pollution issues in major cities in India have raised awareness of the need to develop cleaner sources of energy in the mix. Since renewable power sources, mainly hydro followed by wind, solar and biomass, already account for 35% of the country's capacity, the government of India aims to increase the use of natural gas in the power mix. It is setting an ambitious target of doubling the share of natural gas in India's primary energy mix from the current 7% to 15% by 2030.⁷ In order to increase the use of natural gas, the government is

⁶ Especially for the plants earmarked to be supplied by domestic production from the KG D6 offshore basin, which declined unexpectedly due to technical issues.

⁷ The previous target was 2022 and was put back to 2030 in 2018.

planning to expand the domestic pipeline network and import capacity, to ensure both the connection of fertiliser units and stalled power generation plants in the eastern regions, and the expansion of the city gas distribution network.

Figure 1.12. Power station installed capacity by fuel and by region, India, 2019



IEA, 2019. All rights reserved.

Source: Central Electricity Authority (2019), "All India installed capacity (in MW) of power stations" (monthly report), www.cea.nic.in/monthlyinstalledcapacity.html.

Natural gas only accounts for 7% of India's current power generation capacity. Coal is the main source in terms of capacity, except for the south where hydro and other renewables account for 40% of capacity.

The 10th City Gas Distribution Bidding Round, which concluded on 1 March 2019, was subject to strong competition with some 225 bids submitted. It led to the distribution of letters of intent to 12 consortia for city gas network development in 50 Geographical Areas (GAs). As per the commitment made by the bidders, over 6 million new connections and 1 500 compressed natural gas (CNG) stations should be installed by end of March 2023 (PNGRB, 2019).⁸

At the time of writing, the first phase of the 2 655 km-long Jagdishpur–Haldia and Bokaro–Dhamra gas pipeline project has been reportedly completed, with a 585 km-long section connecting the eastern Indian states, which is to be further extended by 729 km in the next phase. The pipeline connection has especially been a crucial step in reviving the fertiliser industry in the eastern region of India, where most of the natural gas-fired power and fertiliser plants have been mothballed since 2013 with the decline of domestic production, namely from the KG D6 offshore basin. The pipeline is also expected to supply natural gas to refineries, steel plants and other industries in the region. GAIL, the country's main natural gas infrastructure operator, is currently developing several pipeline expansion projects, which total over 4 200 km (Table 1.4).

⁸ For a total of above 20 million connections and almost 3 600 CNG stations to be installed by end of March 2023.

Table 1.4 GAIL's ongoing major natural gas pipeline projects, India, 2019

Projects	Length	Area covered
Jagdishpur–Haldia and Bokaro–Dhamra Pipeline	2 655 km	North and East Uttar Pradesh, Bihar, Jharkhand, Odisha, West Bengal
Vijaipur–Auraiya–Phulpur Pipeline	670 km	North Madhya Pradesh, Uttar Pradesh
Kochi–Kootanad Bengaluru Mangaluru Pipeline	879 km	South Karnataka, Kerala, Tamil Nadu
Total	4 204 km	

Source: GAIL (India) Limited (2019), "Natural gas", <http://gailonline.com/BV-NarutalGas.html>.

The government's strategy of expanding the role of natural gas in India, together with the development of the domestic pipeline network and the market and pricing reforms (see Chapter 4), are expected to enable further growth in natural gas consumption, triggered by industrial development and domestic agriculture's need for fertilisers to support a stable supply of food. As the use of fertilisers remains lower in India than in most developed and emerging countries, it is considered that the fertiliser industry has strong potential for growth, up to an average of 10% per year during the period 2018–24. The Indian government, in parallel, is aiming for self-reliance in urea⁹ production for fertilisers in order to cease imports by 2021. Based on this strong policy support in favour of industrial development, and the fertiliser sector in particular, this forecast expects an average 7% per year increase in natural gas consumption for industrial uses until 2024.

The expected growth of natural gas in the transport sector by deployment of CNG and LNG will be another driver of India's future gas demand. Under its Paris Agreement commitments, the country is to curb its carbon emissions intensity by one-third by 2030. One of the government's recent initiatives is to set up an additional 10 000 CNG distribution stations by 2030, to reduce the use of diesel and gasoline and improve urban air quality. In the longer term, the government is considering an affordable and efficient fleet of electric vehicles, including buses, rickshaws and smaller vehicles, by setting a target for all new vehicles to be electric by 2030.¹⁰ Consequently, the promotion of CNG- and LNG-fuelled automobiles and buses could be a time-limited solution. However, this forecast expects the initiative to encourage removal of the current infrastructure hurdles and improve the LNG importing capability of the country.

Since the beginning of LNG imports in the early 2000s, the lack of connectivity of the LNG receiving infrastructure has led to supply limitations in the country. As of 1 January 2019, there were four LNG receiving terminals in operation in India (Dahej, Hazira, Dabhol and Kochi),¹¹ of which one (Dabhol) cannot operate during the monsoon season due to the absence of breakwater infrastructure (under development for 2019). In addition to this operational limitation to meeting LNG demand, the lack of inland pipeline connectivity to the downstream

⁹ Urea is an inexpensive form of nitrogen fertiliser, manufactured with ammonia synthesised from hydrogen (from natural gas) and from nitrogen (from the air).

¹⁰ In addition to the Faster Adoption and Manufacturing of Electric and Hybrid Vehicles (FAME) plan. Currently the target has been scaled back to 15% of vehicle sales in five years.

¹¹ The Mundra LNG terminal was inaugurated in September 2018 by Prime Minister Narendra Modi, and has not yet received its first commissioning cargo at the time of writing (Pathak, 2019).

market further limits the use of the Kochi LNG terminal. As a result, the country's total receiving capacity remains at only 20–30 bcm/y on average, despite a nameplate capacity of over 47 bcm/y in total.

The government has long planned to build new terminals; however technical and financial issues have pushed back the development of new regasification terminals since 2013. The country's fourth LNG terminal and India's first east coast regasification project, Ennore LNG started operations in March 2019. The terminal is designed to receive over 6 bcm/y of LNG, to be used mainly as feedstock in the fertiliser industry as a substitute for naphtha. As four more terminals are planned to start operations during the forecast period, the bottlenecks in receiving and transporting LNG supply are more likely to be cleared for better distribution within the country.

Pakistan

Pakistan has historically relied on domestic production for its natural gas supply. However, the country's domestic gas production volume has plateaued since 2008, as drilling activities stagnated and discoveries remained limited and insufficient to offset declines from mature fields. Despite the government's efforts to attract foreign investors by amending natural gas regulation and policies, field development activities are not expected to accelerate during the forecast period.

The power sector in Pakistan has been relying on expensive oil imports. These are expected to be gradually replaced by alternative sources, including natural gas through planned LNG-to-power projects, and also by coal. The power sector accounted for about 30% of Pakistan's natural gas demand in 2018 (Sheldrick, 2018). However, the main source of natural gas demand growth has been the industrial sector, led by fertilisers, and this trend is forecast to continue during the coming years. Industrial sector demand accounted for 36% of total gas demand in 2018, and is expected to account for over 40% by 2024. With agricultural lands covering almost half of the country's surface, and estimated population growth of over 1.9% per year, total fertiliser sales are expected to continue to grow at a strong rate in the coming years.

Pakistan has a notable gas-fuelled vehicle fleet, with the transport sector accounting for 5% of total gas consumption, or about 2 bcm in 2018. CNG has been used for road transport in trucks and buses since the 1990s, and there are an estimated 3.7 million CNG vehicles in use in Pakistan. However, without domestic gas production activities or increasing imports of LNG, CNG is expected to face strong competition from power generation and industrial demand, and eventually from residential use of natural gas.

The country has been planning to import natural gas through the Turkmenistan–Afghanistan–Pakistan–India (TAPI) and the Iran–Pakistan–India (IPI) pipelines; however, neither project is expected to be confirmed or completed in the coming five years due to their complex financial and political constraints. As a consequence, the country started to import LNG in 2015. Pakistan has since been actively sourcing LNG from suppliers with competitive offers to fill its growing domestic demand. Pakistan has so far imported almost 70% of its LNG from Qatar – followed in 2018 by Nigeria, Equatorial Guinea, the United States and Australia.

In the absence of foreseeable international pipeline completion, combined with declining domestic production and domestic demand increasing in the industrial sector, Pakistan is likely to continue to rely on LNG imports during the forecast period. The country currently has two receiving terminals in operation with a total capacity of 15 bcm/y. The government plans over USD 8 billion of investment in gas infrastructure, including transmission lines and combined-

cycle gas turbine (CCGT) power stations. Six additional LNG import projects are under consideration, and if they materialise, these additional supplies would offset the incremental demand gap of 40 bcm/y by 2025. The country is also contemplating the option of developing biogas; however, this option is not expected to affect gas demand in the forecast timeframe.

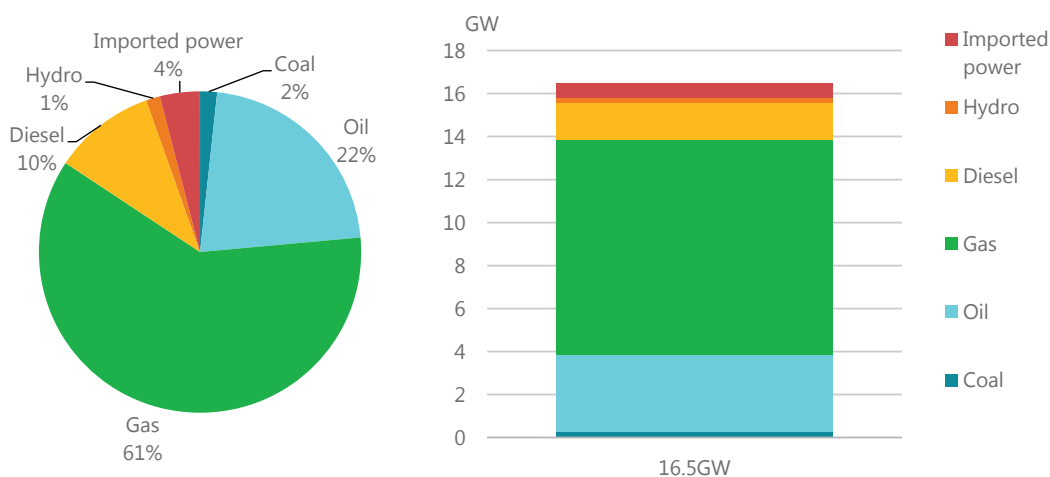
Bangladesh

Natural gas consumption in Bangladesh has doubled in the past decade, from 17 bcm/y in 2008 to almost 35 bcm/y in 2018. This strong demand increase has been met by increasing domestic production. The government plans to further develop LNG imports (which started in 2018) to supply expected future increases in natural gas demand and support the development of gas-intensive industries in the country.

More than half of Bangladesh's natural gas demand comes from the power generation sector, with its average annual demand for gas increasing by almost 8% throughout the last decade. Natural gas consumption in the power sector doubled from 9 bcm/y in 2008 to 18 bcm/y in 2018, accounting for almost 50% of all natural gas consumption in 2018 (Figure 1.13).

Faced with severe power shortages, the government supported the development of additional gas-fired power generation in the country, with the latest high-efficiency CCGT technology. For this purpose, it has secured foreign financial investment support (from the Asian Development Bank, the Islamic Development Bank and Japan's Fund for Poverty Reduction) to develop some 800 MW of gas-fired capacity to be completed by the mid-2020. A second phase of 600 MW has been announced and is due to start commercial operations by 2021. In addition, a 3.6 GW LNG-fired power plant project has been proposed to stabilise the supply of power in the southern part of the country, with plans to start operations by 2022.

Figure 1.13. Power generation sources in Bangladesh, 2018



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Source: Bangladesh Power Development Board (2019), "Power generation units (fuel type wise)", www.bpdb.gov.bd/bpdb/index.php?option=com_content&view=article&id=150&Itemid=16.

Natural gas is the main source of electricity supply in Bangladesh, relying historically on domestic production.

However, with the strong growth in industry, led by the fertiliser sector and followed by the textile and leather sector, the use of natural gas in the industrial sector is set to outpace the growth in gas demand for power generation and is expected to reach almost 30% of total natural gas demand by 2024. Although agriculture contributes less than 20% of the country's GDP, the production of urea is the largest natural gas-consuming industry in the country. While the country currently depends on imported urea to meet its fertiliser needs, the government plans to improve the domestic fertiliser infrastructure to increase the country's self-reliance. The textile industry, especially ready-made garments (RMG), is one of the fastest-growing industry sectors in the country. The RMG sector currently accounts for more than 80% of Bangladeshi export earnings in US dollar terms, and the government supports the industry by increasing the cash incentives for export to non-traditional markets, which are all the markets other than European Union and United States. The resulting natural gas demand for industrial uses is expected to reach around 24 bcm/y by 2024.

In order to cope with this domestic demand increase, Bangladesh is planning its first onshore LNG import terminal, on the Bay of Bengal 380 km from the country's capital and largest city, Dhaka. The planned capacity is about 10 bcm/y and the project is currently in the process of inviting developers to bid on a build-own-operate basis for 20 years, with the aim of starting imports of LNG under long-term commitment from 2024–25. Until completion of the onshore terminal, as an interim solution the country plans to import LNG through FSRUs, which will be anchored at Moheshikahi Island in the Bay of Bengal and use underwater pipelines to deliver natural gas to the mainland of Bangladesh. The first FSRU received its inaugural LNG cargo from Qatar in the spring of 2018. After solving technical and weather-related problems, the country successfully imported gas in the summer of the same year, and continues to receive LNG cargoes from Qatar regularly, with further supplies sourced from Nigeria, Oman and Indonesia.

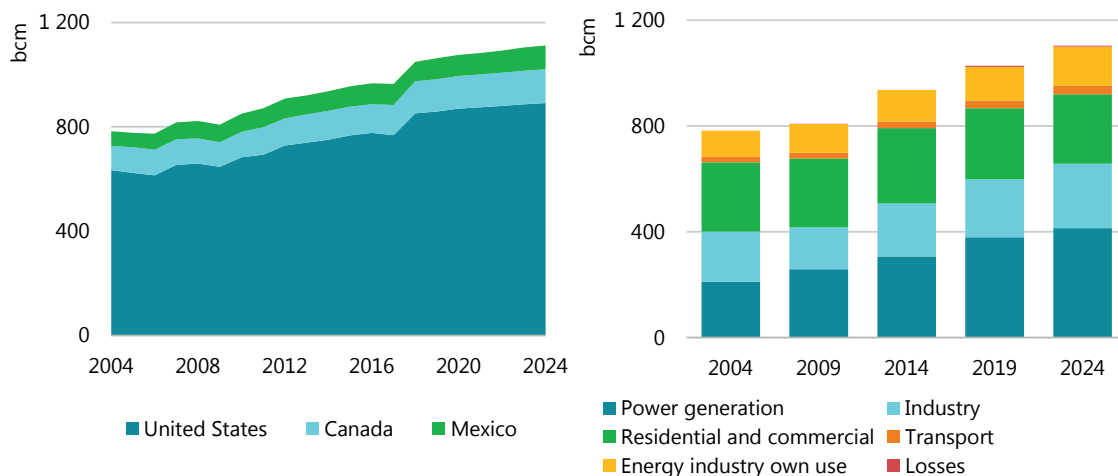
A second FSRU arrived in Bangladesh in late April 2019. This second FSRU is set to double the country's importing ability to 10 bcm/y, with a current firm plan to build a 2 400 MW gas-fired power plant connected to the FSRU.

North America

Over the past decade North American gas demand has increased by 230 bcm/y, or an average 2.3% growth per year. Most of the increase occurred in the United States, where greater consumption for gas-fired power generation accounted for almost 65% of the increase in demand. In 2018 North American natural gas demand exceeded one trillion cubic metres for the first time in history.

This increase in consumption continues, and by end of the forecast period natural gas demand increases by another 59 bcm, or an average 1% per year (Figure 1.14). Consumption associated with power generation, new industrial projects and energy industry own use support this increase.

Figure 1.14. Natural gas demand by country and sector, North America, 2004–24



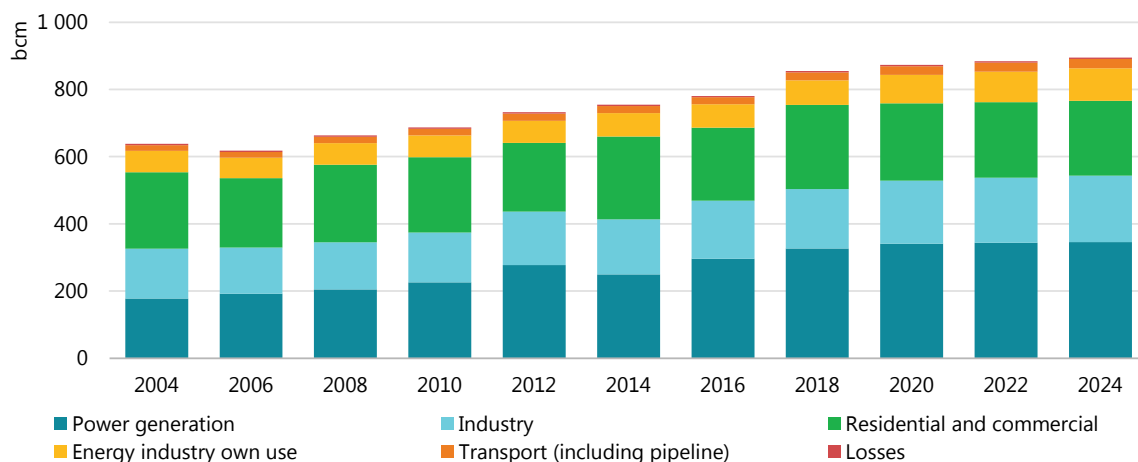
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North American natural gas consumption is expected to grow at an average of 1% per year during the forecast period, driven by uses in the US industrial, power generation and energy sectors.

United States

In the United States, by far the world’s largest gas-consuming country, gas demand increased by almost 11% in 2018 due to a combination of higher consumption resulting from weather conditions (Figure 1.15) and displacement of coal generation. Gas demand for power leapt by 15% as gas generation rose to meet higher cooling demand – the summer of 2018 ranked as the fourth-hottest summer on record in the United States, prompting a 13% y-o-y increase in cooling demand (NOAA, 2018) (Kemp, 2018). The incremental gas was in part used by the additional 19.3 GW of gas-fired generating capacity, some of which displaced retiring coal plants. Colder weather relative to 2017 accounted for most of the rest of the gas demand increase.

Figure 1.15. Natural gas consumption and growth, United States, 2004–24

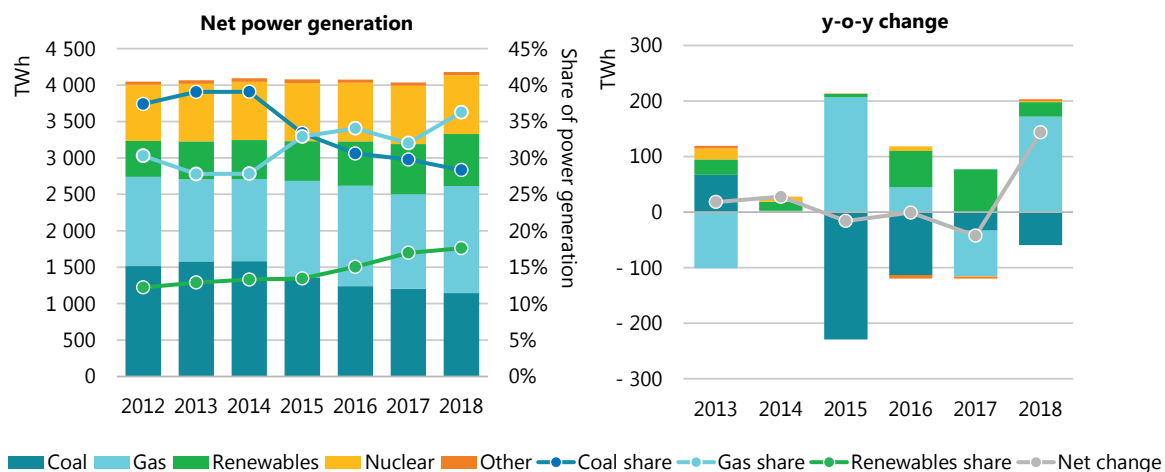


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2018 was an exceptional year for US natural gas consumption due to strong requirements for power generation and weather-related demand from residential and commercial users.

2018 marked a return to growth in gas consumption for power generation after 2017 showed the first year-on-year decrease since 2010 (Figure 1.16). In 2018 natural gas-powered generation gained market share and hit an all-time record of 35% of total generation at utility-scale facilities, an increase from 32% in 2017 (EIA, 2019a). Renewables captured almost 18% of power generation, up from 17% in 2017, whereas the share of coal went below 30% for the first time.

Figure 1.16. Power generation by source, United States, 2012–18



Source: EIA (2019b), *Electric Power Monthly*, www.eia.gov/electricity/monthly/current_month/epm.pdf.

Natural gas hit its highest-ever share of US power generation in 2018, and accounted for most of the annual growth in electricity demand.

Total natural gas consumption is expected to increase only slightly by around 1% in 2019, assuming average weather conditions, but 2018's new gas-fired generation capacity ensures consumption for power generation still grows by about 2%. Natural gas consumption for power generation increases by an average of 1% throughout the forecast period to 2024, slowing in the latter years with fewer coal retirements and a growing share of renewables in the power mix.

Population-adjusted cooling degree days (CDD), a metric that indicates air-conditioning demand, reached a historic high in 2018 driving up electricity demand, while the heating season, though not exceptional, was significantly colder than the previous year as measured by heating degree days (HDD). Residential and commercial gas consumption increased by almost 12% in 2018, and since consumption in this sector is highly temperature sensitive, it is likely to decrease from its 2018 level. Since 2000, average annual residential and commercial consumption in the United States has been around 225 bcm with the exception of outlier years (colder winters). The forecast period considers normal temperatures and shows a reversion to the mean over the period.

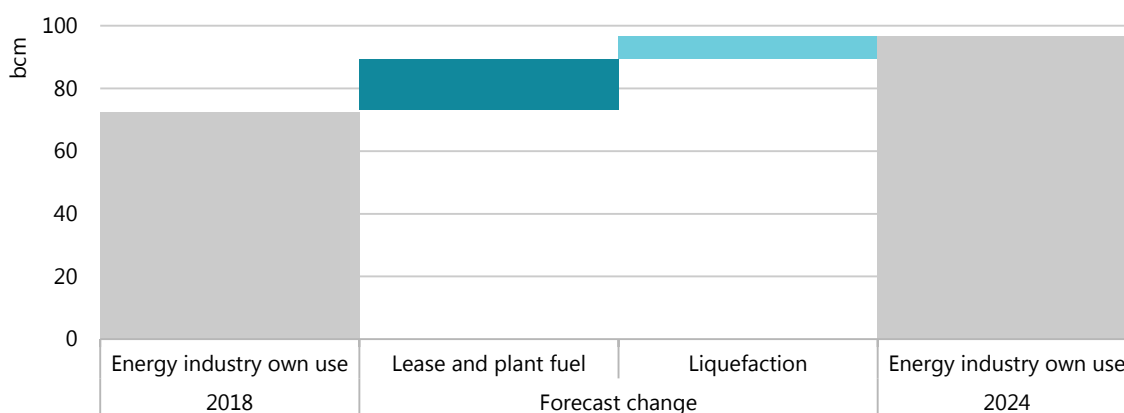
Natural gas consumption for industrial uses has seen annual average growth rates of about 2% over the past decade. The chemicals sector is the main industrial consumer of natural gas, accounting for about one-third of industrial consumption of gas as a source of energy. Natural gas is also a primary feedstock for the production of bulk chemicals, principally methanol and ammonia. Investment in these facilities has increased over the past ten years, seeking to take advantage of the favourable feedstock gas pricing driven by the strong development of natural

gas production from US shale. While ammonia production has been a key driver historically, the medium-term forecast shows that most industrial consumption growth will be due to additional methanol projects in Louisiana and Texas.

In 2018 US methanol exports increased by almost 60% (ICIS, 2019). The United States is projected to reach net exporter status in 2019, with the Asian market as the primary offtaker. OCI’s Natgasoline project in Beaumont, Texas, started up in June 2018, requiring 1.5 bcm/y in feedstock gas. Total additional gas consumption by new methanol projects over the forecast period is 5.8 bcm/y. This could increase, as Methanex has announced plans to nearly double the capacity of its 2 million tonne per annum (Mtpa) Geismar, Louisiana plant (The Advocate, 2018). The expansion would lead to another 2.4 bcm/y of natural gas consumption as feedstock if the project reaches final investment decision (FID) – due to be announced by mid-2019.

To the end of 2024, the energy sector’s own use of gas increases by an average 4.7% per year due to greater consumption from new gas liquefaction facilities and the lease and plant fuel needed to support record amounts of crude oil and natural gas production (Figure 1.17). Considering only liquefaction terminals that have achieved FID at the time of writing, LNG export capacity expansion adds consumption of about 7 bcm/y by 2024 (see Chapter 3 for more information on US LNG export projects and global LNG trade). As US crude oil production continues its dramatic ascent and reaches 19.56 mb/d by 2024 (from 15.48 mb/d in 2018 [IEA, 2019b]), the resulting natural gas needs in lease and plant fuel consumption are expected to grow by 16 bcm over the forecast period.

Figure 1.17. Energy industry own use consumption, United States, 2018–24

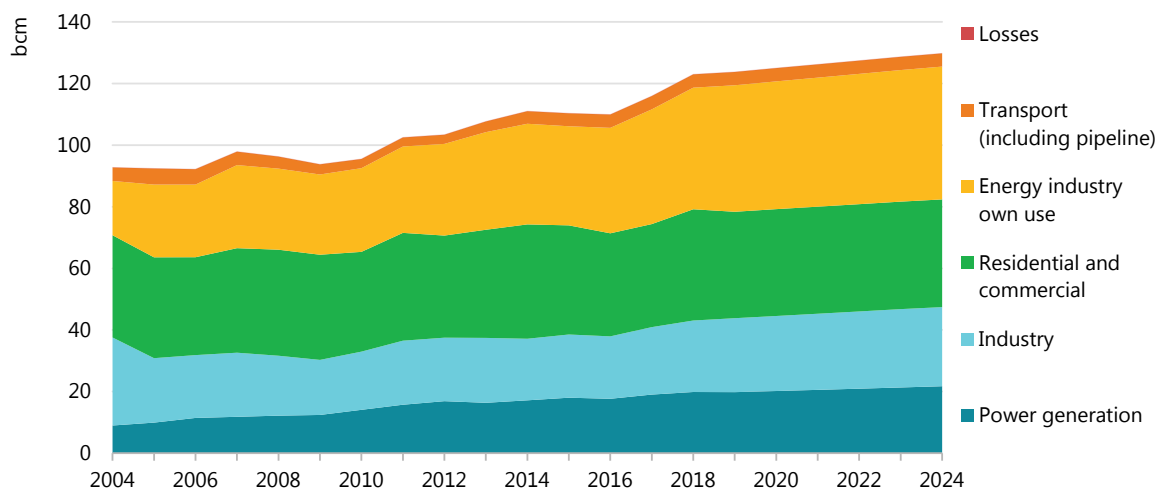


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Natural gas consumption in the energy sector is driven by the strong growth in oil and gas production and the expansion of natural gas liquefaction capacity during the forecast period.

Canada

Canadian natural gas consumption growth has recently been driven by own use in the energy sector to support oil sands operations. This category accounts for about 30% of Canadian natural gas demand. A forecast of slower oil production growth over the next five years compared to last year (IEA, 2019b) tempers the pace of this growth trend (Figure 1.18).

Figure 1.18. Natural gas consumption by sector, Canada, 2004–24

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Canadian natural gas consumption growth has mainly been driven by the development of oil sands, which is expected to decelerate in the near future due to infrastructure bottlenecks.

The pace of the increase in oil sands production has been too rapid for Canadian pipeline capacity to accommodate. With limited available rail capacity to meet the transport demand, the large discounts between Canadian volumes and US grades reached up to USD 50 per barrel in 2018 (IEA, 2019d). These heavy discounts incited government-mandated production cuts in Alberta, with enforcement planned throughout 2019 while participants build out further rail capacity. Permitting issues, legal challenges¹² and construction delays challenge the build-out of the pipeline infrastructure necessary to support previously forecast levels of oil production in the country. Consumption growth in energy sector own use to the end of 2024 is therefore expected to average 1.5% per year during the forecast period (against above 4.5% annually over the past five years), mostly driven by previously sanctioned smaller projects that are unaffected by these bottlenecks.

In October 2018 a Shell-led consortium including PETRONAS, PetroChina, Mitsubishi Corporation and KOGAS took FID on the USD 31 billion LNG Canada liquefaction project in Kitimat, British Columbia. The two-train, 14 Mtpa project is planned to come online in 2025 and is the largest private-sector industrial project in Canadian history. Operations will marginally increase energy industry own use at the end of the forecast period due to gas consumption during the liquefaction process.

Residential and commercial demand is around 30% of natural gas consumption in Canada. Demand in this sector is anticipated to grow marginally due to population and economic growth outpacing the country's planned improvements in energy efficiency. The increase observed in 2018 was due to weather conditions and returns to usual consumption levels assuming normal weather.

¹² The Alberta government enacted Bill 12 (the Preserving Canada's Prosperity Act) on 1 May 2019, which enables it to restrict oil and gas flows to neighbouring British Columbia by requiring companies to obtain a licence before exporting energy products. British Columbia government lawyers filed two court actions (Williams, 2019).

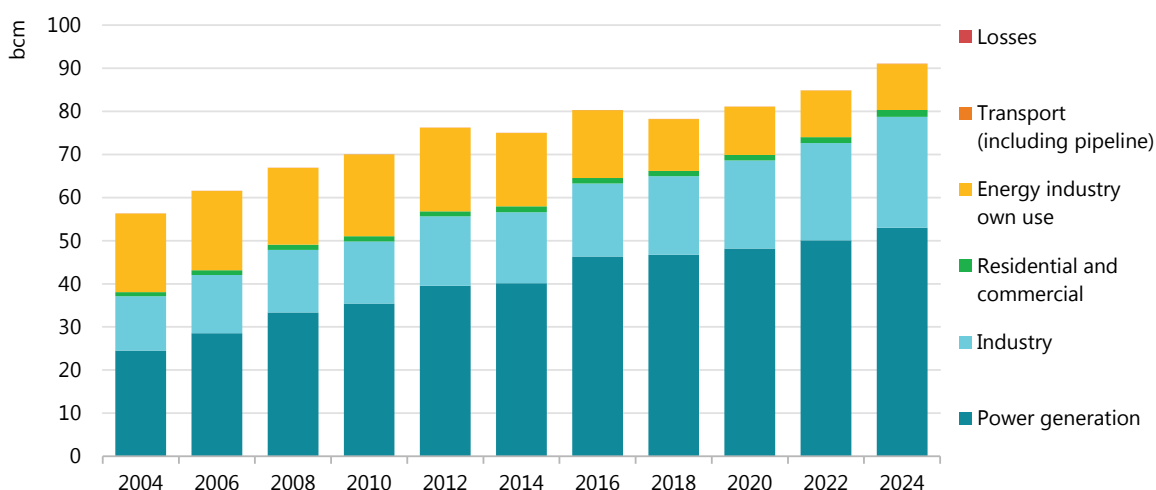
Natural gas consumption for power generation has grown at an average of 2.7% per year since 2012. Canada’s government plans to reduce emissions by phasing out coal-fired generation by 2030, and aims to have 90% of electricity from non-emitting sources by that time. Coal and gas each currently account for only 9% of Canadian power generation. While the coal phase-out target might be expected to present an opportunity for natural gas, the 90% non-emitting target discourages further gas growth. Consumption for gas-fired power generation displays more limited growth due to the expansion of renewable capacity, and is expected to increase at an average 1.7% per year during the forecast period. In December 2018 the Canadian government finalised its plan to reduce emissions, with the announcement of final regulations for the coal phase-out and greenhouse gas regulations for natural gas-fired electricity (Government of Canada, 2018).

The industrial sector accounts for about 20% of natural gas consumption in Canada and is mostly driven by chemicals – both for energy-related uses and as feedstock. The development of petrochemicals production is expected to remain the main growth factor for natural gas consumption in the near future, although at a slower pace with an average 1.7% annual increase to 2024 (compared with 2% over the past five years).

Mexico

Natural gas demand in Mexico slightly decreased in 2018, mostly due to lower consumption in power generation and industry compared to previous years (Figure 1.19). Gas consumption in both sectors has been increasing since 2012 and is projected to continue this trend over the forecast period, with a compound average annual growth rate of 2.5% for total consumption until 2024.

Figure 1.19. Natural gas consumption by sector, Mexico, 2004–24

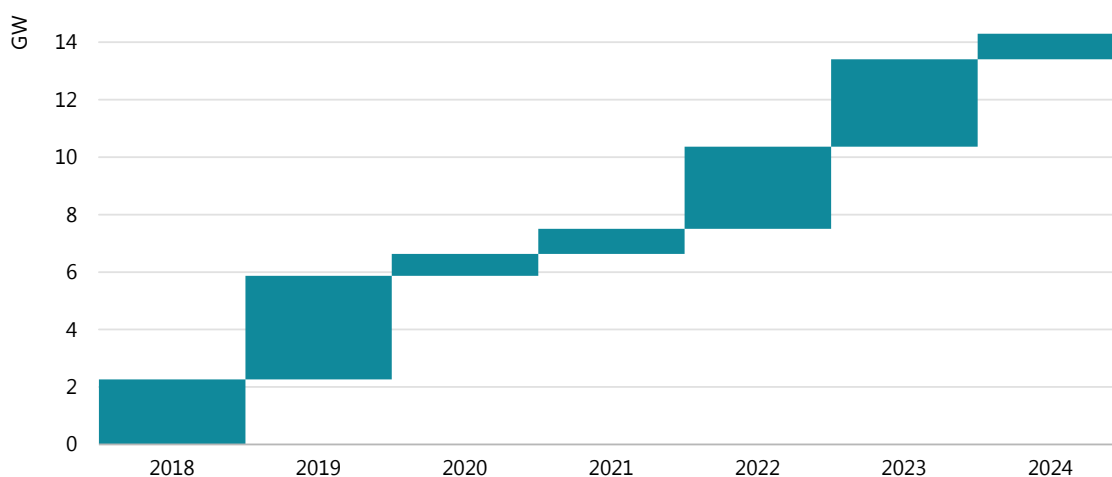


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Natural gas consumption for power generation and industry is expected to resume growth after a decline in 2018.

Natural gas consumption for power generation decreased in 2018, even though net generation from gas-fired capacity increased as a result of the commissioning of 2.27 GW of new capacity in the form of CCGTs (SENER, 2018a). With CCGTs being more efficient than legacy equipment, Mexico's power infrastructure was able to provide an amount of electricity equal to that in 2017, but with less natural gas consumed. Mexico plans to add another 12 GW of gas-fired generating capacity by end of the forecast period (Figure 1.20).

Figure 1.20. Gas-fired power generation capacity development plan, Mexico, 2018–24



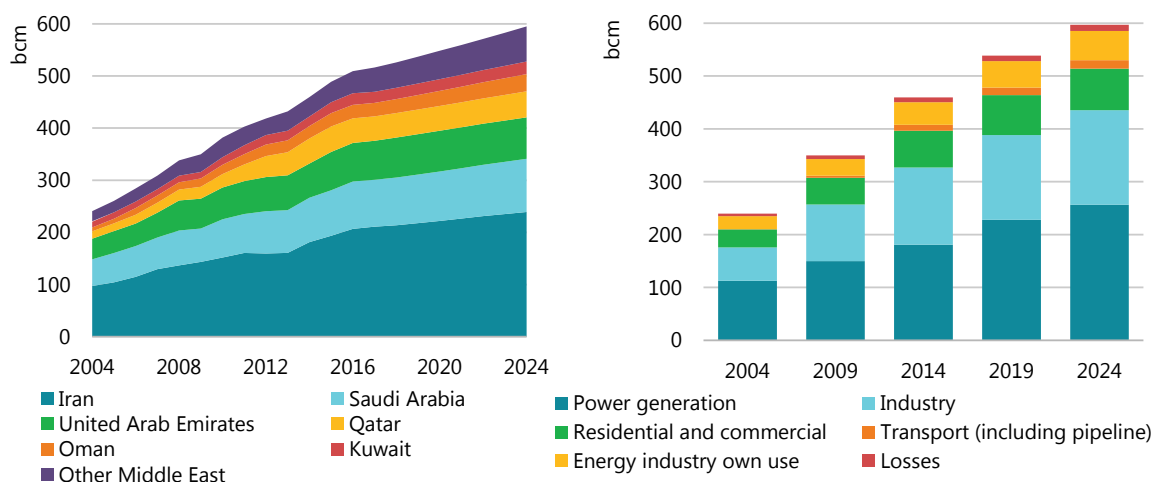
Source: SENER (2018b), *Prospectiva de Gas Natural 2018–2032* [Natural Gas Outlook 2018–2032], http://base.energia.gob.mx/Prospectivas18-32/PGN_18_32_F.pdf.

New gas-fired power generation capacity is likely to increase the role of gas in power generation, while improving the thermal fleet efficiency due to the replacement of ageing turbines by CCGTs.

Power generation is expected to remain the principal driver for natural gas consumption growth in Mexico in the near future, alongside the development of process-related needs in the industrial sector, while the energy sector's needs flatten due to the absence of growth in domestic oil and gas production.

Middle East

Natural gas consumption in the Middle East is expected to grow at an average annual rate of 2.1% during the forecast period, with total demand to reach almost 600 bcm/y by 2024 from a 2018 level of almost 530 bcm/y (Figure 1.21). This growth will be almost entirely driven by the gas needs of the power generation sector and by gas-intensive industrial sectors such as petrochemicals, accounting for 50% and 32% of incremental demand respectively (Figure 1.21). The growth in gas-to-power is supported by the rapidly rising electricity needs of a growing population (including for cooling and water desalination), and by government policies to replace fuel oil with natural gas in the power sector. Industrial demand, accounting for 30% of total regional gas consumption, is expected to grow as a result of investment in the petrochemicals and chemicals sectors. Residential and commercial gas consumption has limited upside potential in the region as space heating needs are relatively low outside of the Islamic Republic of Iran ("Iran").

Figure 1.21. Natural gas consumption by country and by sector, Middle East, 2004–24

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Power generation and industry drive Middle Eastern gas consumption, together accounting for 90% of demand growth through the forecast period.

Iran

Preliminary estimates indicate that Iranian natural gas consumption grew by 3.2% in the 2018/19 fiscal year (FY), primarily driven by gas-intensive industrial sectors. 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 less than 10%. It has been reported that gas burn in power generation decreased by 2.8% in 2018 due to internal gas shortages. This coincided with a low level of hydropower output (shrinking by 68% y-o-y), leading to higher diesel and fuel oil consumption in the power sector (NGW, 2019). This means that the objective set last year to completely phase out fuel oil by the end of the FY (March 2018) was not reached. This forecast expects gas-to-power demand to grow at a rate of 2% annually through to 2024, supported by the continuation of the oil-to-gas switching policy and the rising electricity needs of a growing population.

The industrial sector accounts for approximately 30% of total natural gas consumption, with around half from the chemical and petrochemical sectors. Production of petrochemicals increased by almost one-third over the last six FYs, to 53 Mtpa in 2017/18 FY. Petrochemical production rose by almost 4% y-o-y to 55 million tonnes during the 2018/19 FY (21 March–22 September 2018) (Financial Tribune, 2019a). This supported natural gas demand from the petrochemical plants, growing by 10% y-o-y from 37.2 bcm in 2017 to 40.9 bcm in 2018 (Financial Tribune, 2019b). 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 2.7%, supported by the development of new petrochemical complexes. In September 2018 Iran inaugurated the Marjan plant, with a capacity of 1.65 Mtpa of methanol, and the third phase of the Pardis petrochemical plant, with capacity to produce 1.755 Mtpa of urea and ammonia (Platts, 2018). In January 2019 it was reported that the Lordegan petrochemical plant, with a capacity of 1.755 Mtpa of ammonia and urea, is 94% complete and could start operations in 2019 (Shana, 2019a).

The residential and commercial sector currently accounts for over 30% of total natural gas consumption. Limited growth in demand is expected from this sector, owing to the already high gasification rates of the country. In January 2019 it was reported that 99% of Iran's urban population and 85% of its rural population have already been connected to the gas distribution network (Shana, 2019b). Other sectors also contribute to future growth, such as own use in the energy industry (growing at an average 2.5% per year during the forecast period), in line with expected growth in oil and gas production capacity.

United Arab Emirates

The United Arab Emirates has been an LNG exporter since its first shipment from Das Island, Abu Dhabi, to Japan in 1977. However, in order to meet its fast-growing domestic demand, the country started to import natural gas from Qatar via the Dolphin pipeline in 2007 and became a net gas importer in 2008. The country's natural gas consumption has increased by an average annual rate of 3% over the past decade. This demand increase has mainly been driven by industrial needs, with the sector recording strong average annual growth of 13% in its gas requirement during the 2006–12 period. The power generation sector has been another strong driver of growth, with almost all of the current 27 GW of installed capacity generated from natural gas, and consumption reaching 44 bcm/y in 2018.

This forecast expects natural gas demand for power generation to grow much more slowly (at less than 1% per year to 2024 compared to almost 6% over the past six years), due to the commissioning of the four nuclear power units (5.6 GW) at the Barakah plant and the new Hassyam coal-fired plant (2.4 GW). Industrial needs will become the main driver for gas consumption over the coming years – especially in the petrochemicals sector.

Saudi Arabia

This forecast expects Saudi Arabia's natural gas consumption to grow at an annual average rate of 1.8% to 2024, similar to the trend of the previous six years (2% per year during 2012–18). Power generation and feedstock use for petrochemicals are the traditional drivers of natural gas consumption, and will continue to steer gas consumption in the medium term.

Electricity demand has almost doubled over the past 12 years and led to the rapid development of gas-fired generation capacity. However, the country still heavily relies on oil products, with an estimated 700 000 barrels per day burned for power generation during the summer months. The Energy Ministry announced in January 2019 its objective to phase out liquid fuels from power generation and cut the country's overall energy consumption by 1.5 to 2 million barrels of oil equivalent per day by 2030, thanks to an ambitious plan to develop renewable energy (El Gamal and Carvalho, 2019).

The government has a target to develop about 60 GW of renewable energy capacity by 2030 – including 40 GW of photovoltaic (PV) solar power, 16 GW of wind and 3 GW of concentrated solar – and expects to issue tenders for at least 12 renewable projects in 2019. The share of gas-fired capacity is also due to grow from 50% to 70% of total generation capacity by 2030. However, and in spite of this push, residual fuel oil demand is likely to be boosted in the shorter term by the implementation of the IMO marine fuel regulations in 2020, resulting in large volumes of discounted higher-sulphur fuel oil becoming available. This has the potential to postpone some oil-to-gas switching in power generation (IEA, 2019b).

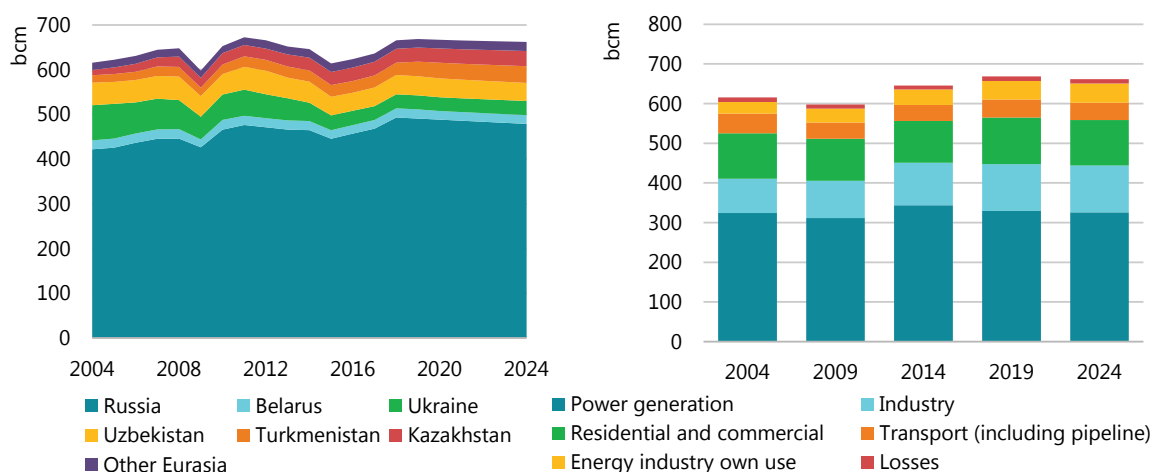
The development of petrochemicals remains a strong priority for the Saudi government. The reshuffling of the state-owned company portfolio and the development of stronger export ambitions is expected to further push oil and natural gas feedstock consumption. In March 2019

the government announced that national oil and gas company Saudi Aramco would acquire a 70% stake in petrochemicals producer Saudi Basic Industries Corporation (SABIC).

Eurasia

Preliminary data indicate that natural gas consumption in the Eurasia region continued to grow in 2018, mainly driven by rising domestic demand in Russia. Eurasian natural gas demand is expected to stagnate over the coming years, with slight decreases in Russia and Belarus being compensated by some growth in Caspian countries (Figure 1.22).

Figure 1.22. Natural gas consumption by country and by sector, Eurasia, 2004–24



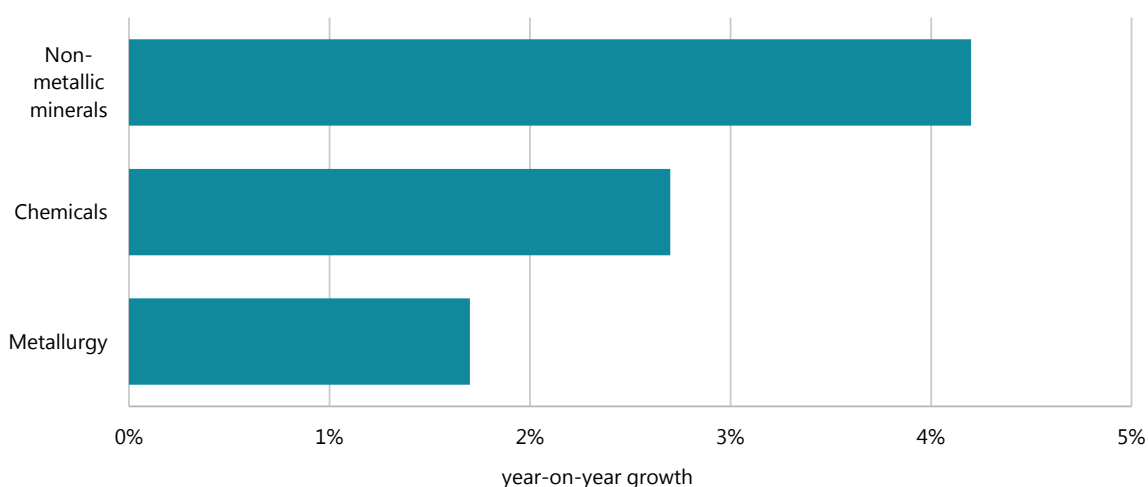
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Investment in chemicals and petrochemicals production drives Eurasian gas consumption, whilst improving fuel efficiency and deployment of new nuclear capacity in Russia and Belarus reduces gas burn for power generation.

Russia

Russia’s natural gas consumption increased by an estimated 5.3% y-o-y in 2018 to around 493 bcm (Gazprom, 2019a). This is the third consecutive year of demand increase in the Russian domestic market since the beginning of the decade.

This has been primarily driven by economic growth, higher gas burn in the power sector and demand from the residential sector. Preliminary data from Russia’s Federal Statistics Service (Rosstat) indicates that economic growth climbed to a six-year high in 2018, with a rate of 2.3% (Figure 1.23). In particular, gas-intensive and export-oriented sectors such as non-metallic minerals, metallurgy and chemicals (altogether accounting for over 70% of Russian industrial gas consumption) grew strongly, which supported incremental gas demand (Rosstat, 2019).

Figure 1.23. Natural gas consumption growth in gas-intensive industrial sectors, Russia, 2017–18

Source: Rosstat (2019), *Индексы производства по Российской Федерации* [Industrial Production Indices of the Russian Federation], www.gks.ru/wps/wcm/connect/rosstat_main/rosstat/ru/statistics/enterprise/industrial/#.

Russia's export-oriented and gas-intensive industrial sectors, representing over 70% of industrial gas consumption, continued to grow strongly in 2018 and supported incremental gas demand.

Russia's Economic Development Ministry foresees economic growth slowing to 1.3% in 2019, whilst in the medium term it is expected to be more moderate, averaging 1.5% per year (TASS, 2019; IMF, 2019). Gas-to-chemicals is expected to be the most important driver behind Russian industrial gas demand in the medium term. Low feedstock gas prices in Russia (at about USD 2.5 per million British thermal units [MBtu] in 2018) makes gas-to-chemicals production highly competitive. Moreover, the development of the chemical sector is set as a priority in the Russian Energy Strategy up to 2030, envisaging the construction of new chemical complexes in the medium term (Minenergo, 2009). Table 1.5 provides a summary of the largest gas-to-chemicals plants currently under development in Russia.

Table 1.5 Large gas-to-chemicals plants under development in Russia

Plant	Products and capacity	Planned start-up	Impact on gas demand
Nahodinsky fertiliser and methanol complex	methanol 1.8 Mtpa ammonia 1.8 Mtpa	2022	3.5 bcm/yr
Kuybyshev Azot expansion	ammonium nitrate 0.84 Mtpa urea 0.55 Mtpa	2021	1 bcm/y
Uralkhim expansion	urea 0.28 Mtpa	2021	0.2 bcm/y
Shekino Azot	ammonia 0.15 Mtpa methanol 0.5 Mtpa	2018/19	0.7 bcm/y
Evrokhim Phosphorit expansion	ammonia 1 Mtpa	2019/20	1.3 bcm/y

Sources: Company reports.

Gazprom's deliveries to power companies grew by over 10% in 2018 (Gazprom, 2019b). This was supported by growing electricity and heat generation (1.8% and 1.7% respectively) and by rising domestic coal prices incentivising coal-to-gas switching in the power sector, driven by the

reaction to increasing international coal prices (ARA Rotterdam climbed by 9% y-o-y) and higher Russian coal exports (10% increase y-o-y).

This could change in 2019, with Rotterdam coal futures trading almost 20% lower compared to last year's average price. Hence, coal could potentially regain market share within Russia's thermal generation mix at the expense of gas. In the medium term increasing fuel efficiency from the most recent gas-fired power plants, as well as the refurbishment of the existing power fleet, is expected to contribute to a decrease in natural gas consumption in spite of overall electricity demand growth. Steam power plants with an average electrical efficiency rate of 30% currently represent three-quarters of the Russian gas-fired fleet, whilst modern CCGT plants operate with an efficiency rate of 50–55%.

In January 2019 the Russian government adopted a programme for the modernisation of thermal power generation plants. Accordingly, 41 GW of capacity is due to be upgraded to higher technical and efficiency standards between 2022 and 2031, of which 11 GW between 2022 and 2024 (Vedomosti, 2019). In addition, the deployment of new nuclear capacity in the western part of Russia (where most gas-fired power generation is concentrated) will further weigh on gas demand from the power sector. As shown in Table 1.6, 3.65 GW of nuclear capacity is currently under construction, all of which is expected to enter operation between 2020 and 2024, whilst two reactors (Kursk 1 and 2) with a combined capacity of 1.9 GW are set to retire by the end of the forecast period.

Gazprom's deliveries to the residential and commercial sector grew by 4.3% in 2018, driven by a prolonged heating season in the first and second quarters and late cold snaps in the fourth. Gazprom is continuing its gas connectivity programme, with the average mains gas penetration level increasing from 53% in 2005 to 68.6% by the beginning of 2019 (Gazprom, 2019b). However, higher connection rates do not necessarily lead to increasing gas consumption, as the newly connected consumers (located in towns and villages with low population density) have in general a lower demand potential compared to the large traditional consuming centres. According to Gazprom, in 2017 the 1% increase in the gas connection rate translated into a mere 0.4% of incremental demand potential (Gazprom, 2018). It is expected that higher building efficiency standards, especially in new buildings, will mitigate increased demand for space heating through the forecast period. Residential demand is forecast to stagnate, with limited growth from future gasification and the slowly improving thermal insulation of the building stock. Overall, Russia's gas demand declines by a mere 0.5% through the forecast period.

Table 1.6 Power reactors under construction in Russia

Plant	Technology	Capacity (MW _e net)	Planned start-up	Impact on gas demand*
Novovoronezh II-2	VVER-1200/V-392M	1 200	2019/20	1.9 bcm/y
Leningrad II-2	VVER-1200/V-491	1 199	2022/23	1.9 bcm/y
Kursk II-1	VVER TOI/V-510	1 255	2022/23	2 bcm/y

* Considering a CCGT with electrical efficiency of 45%.

Note: MW_e = megawatt electrical.

Source: World Nuclear Association, *Nuclear Power in Russia*, www.world-nuclear.org/information-library/country-profiles/countries-o-s/russia-nuclear-power.aspx.

Belarus

Belarus's natural gas consumption mainly relates to heat and power generation, which accounted for 71% of natural gas consumption in 2017. Natural gas accounts for almost all of the country's heat and power output (Belstat, 2018). The commissioning of the Ostrovets 1 and 2 nuclear reactors during 2019–21 (2.388 gigawatts electrical [GW_e]) will reduce electricity import needs from Russia (2.3 TWh in 2017 and 0.56 TWh in 2018) and will weigh on gas demand from the power sector (SO-UPS, 2019). The country's 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 decline in natural gas consumption over the medium term.

Ukraine

Ukrainian gas consumption rose in 2018 by 1.3%, the first increase since 2010. This has been driven by the recovery of the industrial sector, and in particular by chemicals and petrochemicals production output growing at a rate of 17.4% and metallurgy increasing by 9% y-o-y (UkrStat, 2018). Gas burn in the power sector has been rising, as growing electricity production coincided with a low level of nuclear availability (69.6%) (UA Energy, 2019). In the medium term, further growth in demand from industry and the power sector is supported by GDP growth averaging above 3% (IMF, 2019). Consumption in the residential and commercial sector is expected to continue to decline in the medium term as gas prices are set to rise, incentivising fuel switching and energy efficiency investment. This will mitigate demand growth from industry and for power generation, with overall Ukrainian gas demand expected to stagnate over the forecast period.

Caspian

Preliminary data suggest that Turkmen gas consumption increased by 2% in 2018. Domestic gas demand is dominated by power generation and the residential and commercial sector, together accounting for almost 80% of Turkmenistan's gas demand. Gas connection levels have reached 99%, leaving very little space for additional gas demand from this sector (Azernews, 2019). Gas burn in the power sector is expected to increase with the recent commissioning of the 400 MW_e Zerger and 1 574 MW_e Mary-3 gas-fired power plants (NCA, 2018a). Both will primarily serve export markets, Afghanistan and Pakistan respectively.

In order to diversify its industry, the Turkmen government continues to develop its chemical and fertiliser sectors. In September 2018 the Garabogaz fertiliser plant was commissioned with a production capacity of 1.1 million tonnes of urea per year. The plant will use approximately 1 bcm of natural gas as feedstock per year (NCA, 2018b). A new chemical complex was inaugurated in October 2018, with annual production capacity of 386 000 tonnes of polyethylene and more than 81 000 tonnes of polypropylene – with annual feedstock requirements estimated to be 5 bcm. This forecast expects these investments to translate into gas demand growing at an annual rate of 5.3% throughout the period to the end of 2024 – the highest in the Eurasian region.

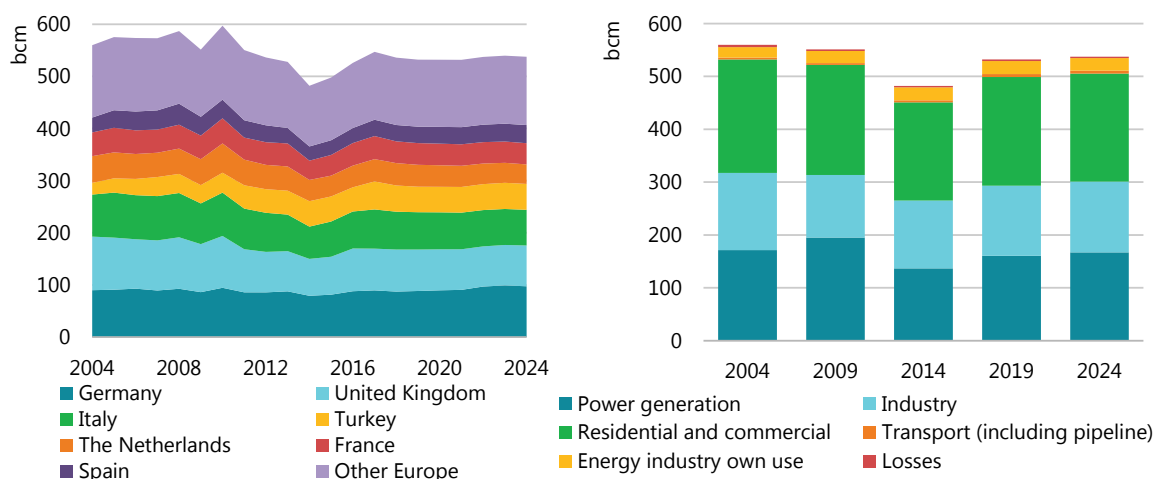
The high level of gas connectivity in other Caspian countries limits further gas demand growth, especially if some of the gas efficiency potential is realised. In Kazakhstan, where two-thirds of gas consumption relates to energy industry own use, further demand is limited by the plateauing of oil production. In Azerbaijan, where the share of gas is over 90% both in the power and residential sectors, gas demand remains stable over the forecast period. Uzbekistan

launched the modernisation of its district heating system for the period 2018–22, with total investment estimated to amount to USD 200 million (MFA, 2017).

Europe

After three years of consecutive growth, European natural gas demand decreased in 2018 by 2%, from 547 bcm/y to 536 bcm/y. This has been partly driven by lower gas burn for power generation and a mild end of year, reducing natural gas demand for space heating in the residential and commercial sector. European natural gas consumption is expected to remain stable through the forecast period, growing by a mere 0.1% per year (Figure 1.24). Incremental demand is primarily supported by the nuclear and coal phase-out plans, but restrained by the expansion of renewables and decreasing consumption for space heating amidst continued switching to alternative fuels in a number of countries.

Figure 1.24. Natural gas consumption by country and by sector, Europe, 2004–24

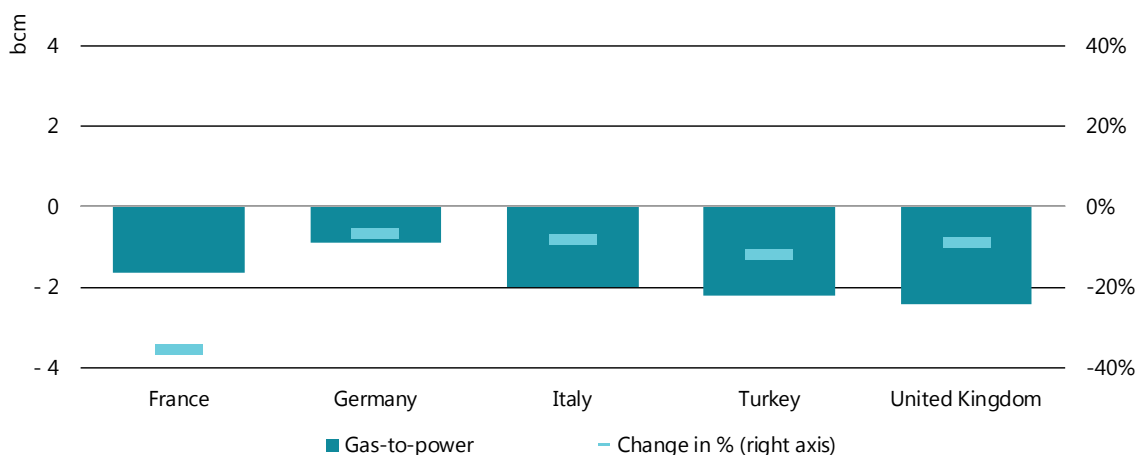


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Gas-to-power is the key driver behind incremental gas demand in Europe during the forecast period, as a number of countries phase out nuclear and coal-fired power plants.

Power generation

In both 2016 and 2017 European natural gas consumption was primarily supported by the power sector. In 2016 low nuclear availability in France and the surge in coal prices supported higher gas burn in the power sector. In 2017 a sharp fall in hydro generation (down 53 TWh) coupled with an increase in power demand (thanks in part to hotter summer weather) increased the call on flexible power generation in southern Europe. In 2018 hydro generation output recovered by 38 TWh, which naturally translated into lower natural gas demand. The continued deployment of wind and solar capacity resulted in additional output of 38 TWh of electricity, further weighing on Europe’s gas-to-power demand. Moreover, European natural gas prices rose more rapidly than coal through 2018 (29% and 9% respectively), further undermining gas’s competitiveness in the power sector despite a rally in the price of European emission allowances. As a result, in 2018 gas-fired power generation in Europe fell by 6.7%, or 47.5 TWh, translating into a decrease in gas burn at power plants of over 10 bcm. Figure 1.25 illustrates the decline in gas-to-power demand in key gas-consuming European countries.

Figure 1.25. Annual change in gas-to-power demand in key European countries, 2017–18

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

European gas demand fell in 2018, primarily driven by lower gas burn for power generation amidst higher nuclear availability in France, higher hydropower generation in southern Europe, and more coal and hydro generation in Turkey.

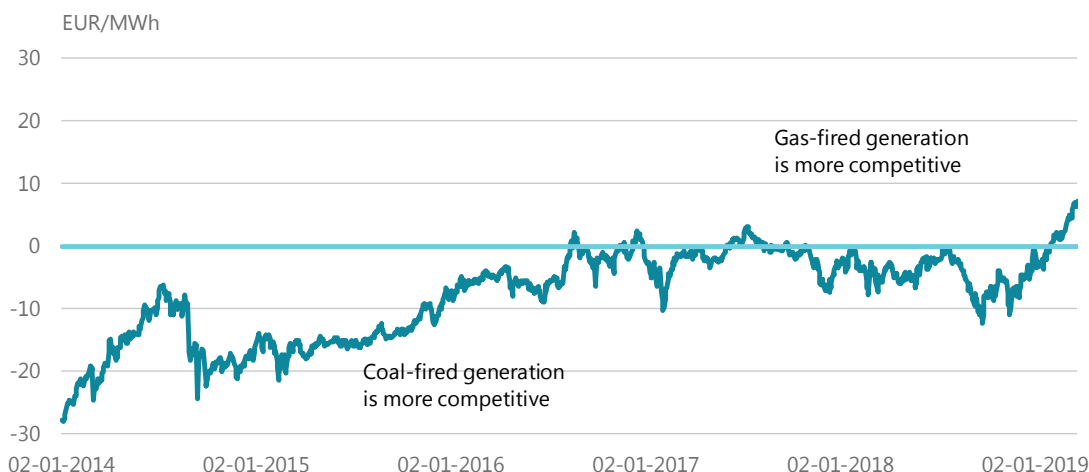
In the first quarter of 2019 gas-fired power generation has again been on the rise in Europe. This has been largely driven by fuel economics increasingly favouring gas versus coal burn in the power sector. European natural gas prices have halved from their highs in September 2018, from USD 10/MBtu to below USD 5/MBtu by late March 2019. This has been driven by a number of factors, including lower-than-expected LNG demand especially in China and Japan and above-average temperatures in both Europe and Northeast Asia through the 2018/19 winter, as well as a high level of gas in European storage sites at the end of the heating season. During the same period, coal prices have been decreasing at a much slower pace, with the ARA Rotterdam price falling by 28% from an average of USD 100/tonne in September 2018 to USD 72/tonne in March 2019. Moreover, the price for European emission allowances doubled from EUR 11 (Euros) per tonne of CO₂ equivalent (tCO₂-eq) in March 2018 to EUR 22/tCO₂-eq in March 2019, further weighing on the fuel economics of coal-fired power plants.

Figure 1.26 shows that, considering these price dynamics, gas-fired power plants with an average electrical efficiency of 55% became more cost-competitive than coal-fired power plants whose average efficiency was 38% (or below) in the first quarter of 2019.

Preliminary data suggest that this combination of factors has resulted in coal-fired generation declining by 30 TWh y-o-y, whilst gas-fired output rose by 15 TWh. However, different dynamics have been at play in individual countries such as Turkey, where both gas and coal-fired generation decreased in the first quarter of 2019 amidst higher hydro output (8 TWh increase y-o-y). However, Turkey's gas-fired generation has been displaced to a much greater extent (down 10 TWh) compared to coal and lignite (down 1 TWh), as natural gas has continued to lose its cost-competitiveness in power generation. Natural gas prices in Turkey did not decline in the same way as in northwest Europe, a result of their high degree of interlinkage with oil prices. In fact, gas prices on the Turkish gas hub continued to increase between September 2018 and March 2019. A further factor affecting the inter-fuel competition between natural gas and

lignite within the power sector is the depreciation of the Turkish lira, weakening by almost 60% vis-à-vis the US dollar since January 2018.¹³ Moreover, Turkey does not have an emissions pricing system that could have a negative impact on the economics of coal-fired power generation.

Figure 1.26. Gas- versus coal-fired power generation costs, 2014–18



Note: MWh = megawatt hour.

The graph shows the difference between the electricity generation costs of coal-fired and gas-fired power plants. When the difference is negative, it means that coal-fired power plants are more cost-competitive.

With gas prices plummeting below USD 5/MBtu and emission prices holding steady above EUR 20/tCO₂-eq, gas-fired generation increased its cost-competitiveness during the first quarter of 2019.

With French nuclear and southern European hydro expected to remain at typical levels, electricity demand growing slowly and renewables on the increase, gas for power generation has little room to grow in 2020–22. This rapidly changes through the second part of the forecast period because of the nuclear and coal-fired power plant closures announced by several countries and companies in the region (see Table 1.7).

It is important to note that such closures will not directly translate into additional gas demand, as some of the market space is expected to be captured by the continuous build-up of the renewables fleet. A higher share of intermittent renewables in the power mix might incentivise further investment in flexible peaking generation capacity (such as CCGTs, reciprocating gas engines and gas turbines). This forecast expects natural gas demand for power generation to increase by an average 0.6% per year for the coming five years.

¹³ A weaker lira is effectively supporting the cost-competitiveness of domestically produced lignite (priced in local currency) vis-à-vis imported natural gas, which is usually denominated in US dollars and hence translates into a higher fuel cost in lira terms.

Table 1.7 Nuclear and coal-fired plant closures in Europe, 2019–24

Country	Type	Capacity (GW _e net)	Closure date
Austria	Coal	0.246	2020
Germany	Nuclear	1.4	2019
		4.11	2021
		4.12	2022
	Hard coal	7.7	2022
	Lignite	5	2022
France	Coal	2.9	2022
The Netherlands	Coal	0.65	2019
Spain	Coal	6-7	2020
United Kingdom	Coal	4	2019
	Nuclear	0.973	2023
		2.335	2024

Sources: Announcements made by governments and companies.

Residential and commercial

Weather-normalised consumption data indicate that residential and commercial gas demand has been declining at an average rate of 0.3% per year between 2010 and 2017 in the European Union. This has mainly been driven by the gradual electrification of space heating and efficiency gains in a number of member states. During the same period, residential and commercial demand in Turkey has been rapidly rising at a rate of over 10% per year, in line with the ongoing gas connection programme and the phase-out of fuel oil usage.

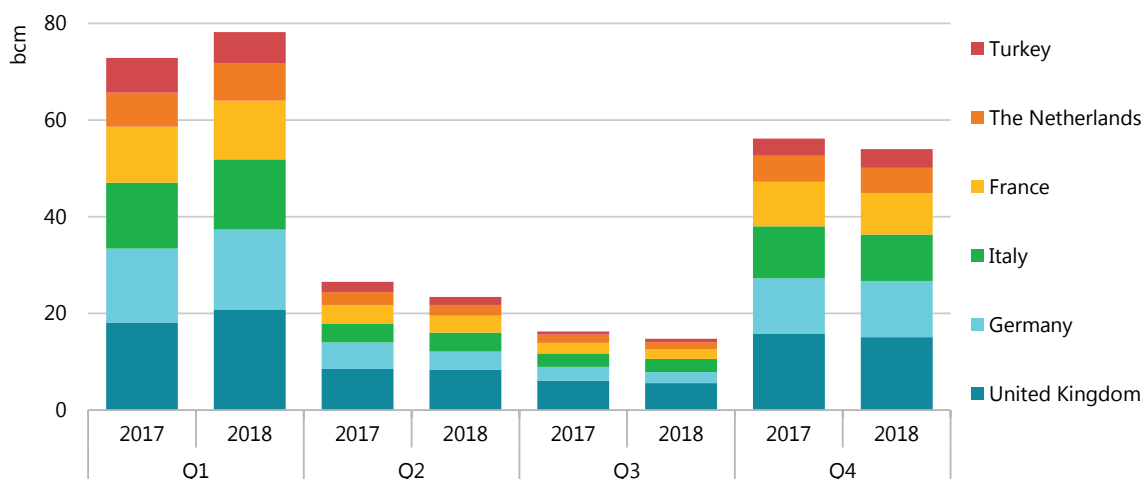
Preliminary data suggest that European residential and commercial gas demand slightly decreased in 2018, with total HDD being 3% lower compared to 2017 (Eurostat, 2019a) and consumption declining by approximately 1% from 210 bcm in 2017 to 207 bcm last year. Figure 1.27 shows the evolution of residential and commercial gas demand in 2018 across the six largest European gas-consuming countries, together representing over 80% of European gas consumption in this sector.

Preliminary data suggest that the mild temperatures during the first quarter of 2019 in most parts of Europe had a dramatic impact on gas demand, falling by 10% in the residential and commercial sector.

Natural gas demand in the residential and commercial sector is expected to decrease at an average annual rate of 0.3% through the forecast period. This is driven mainly by the gradual shift towards electricity and decentralised renewable energy technologies for space heating, especially in northwest Europe. One example is the Netherlands, where the amendments made to the Gas Act effectively prohibit the connection of new houses and buildings to the gas grid from 1 July 2018. Moreover, the Ministry of Economic Affairs and Climate envisages the gradual disconnection from the gas grid of around 30 000 to 50 000 homes per year until 2022, from

which date the process will be accelerated to 200 000 homes a year (HollandTimes, 2018). The United Kingdom is currently considering banning gas boilers in new buildings after 2025.¹⁴ Across the European Union the share of renewables and biofuels in residential energy consumption grew from 14% in 2007 to 17% in 2017 (Eurostat, 2019b). There is, however, some upside potential for gas in countries where fuel oil is still present in the residential and commercial sectors and hence can be replaced by cleaner heating fuels such as natural gas (including, amongst others, Spain and Turkey).

Figure 1.27. Quarterly change in residential and commercial gas demand in key European countries, 2017–18



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Gas consumption in the residential and commercial sector slightly decreased in 2018, as higher demand in a particularly cold first quarter was balanced by lower needs through the rest of the year.

Industry

European natural gas demand from the industrial sector has remained stable over the past few years, increasing at a mere 0.5% per year between 2010 and 2017. This has been largely driven by Turkey, where demand has been rising at a rate of 7.4%. Half of this growth came from the chemicals and iron and steel subsectors. In contrast, natural gas consumption from the industrial sector has been stagnating in the European Union, with an average annual growth rate of 0.1% over the same period, as gas usage increased for chemicals but declined in subsectors such as iron and steel and machinery.

Preliminary data indicate that industrial gas demand decreased slightly in 2018 to a level of 130 bcm (against 131 bcm in 2017). In the European Union the production of chemicals decreased by 2%, mainly due to lower output of agrochemical products, plummeting by 6.4%. This is partly due to the unusual seasonal pattern of European gas prices in 2018, which increased during the summer when the production of agrochemicals is at its highest (for further discussion on gas prices, please refer to Chapter 4).

¹⁴ In his Spring Statement in March 2019, the Chancellor indicated that “the government will introduce a Future Homes Standard by 2025, so that new-build homes are future-proofed with low carbon heating and world-leading levels of energy efficiency” (Gov.uk, 2019).

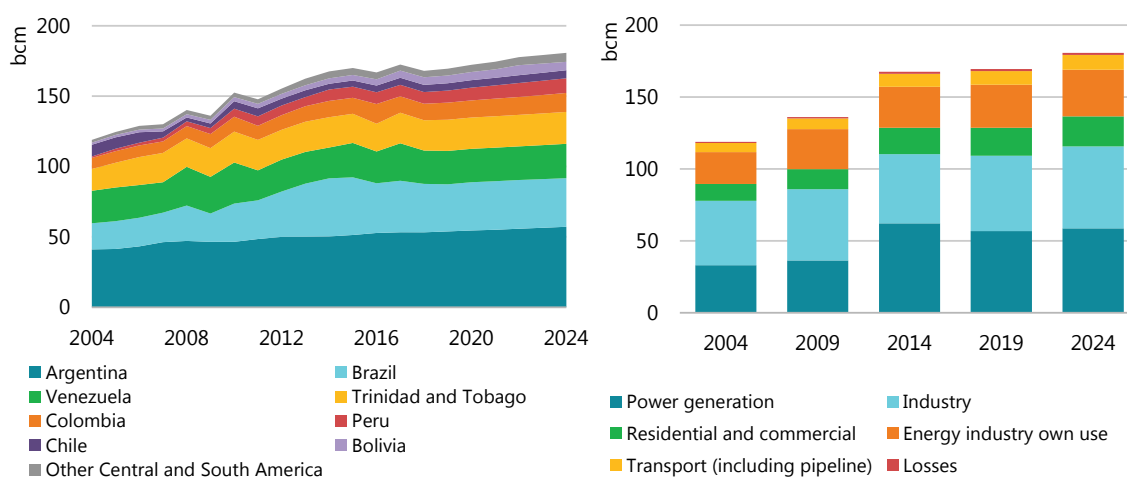
This decline in chemicals output has been balanced by some production growth in other gas-intensive subsectors, including non-metallic minerals (1%), food and beverages (0.8%) and petroleum products (0.8%) (Eurostat, 2019c). The highest growth in gas demand for industry has been observed in Spain, with a rate of 4% or almost 1 bcm (Enagás, 2019), increasing in all sectors (except textiles). In Turkey, the economic slowdown weighed on industrial gas demand, declining by 11% or 1.4 bcm (GAZBIR, 2018). This was mainly due to declining iron and steel production (down 1%) and output of non-metallic minerals (down 2.7%).

Natural gas demand for industry is therefore expected to stagnate in Europe, as energy-intensive industry in the region struggles to be cost-competitive with other regions where energy prices are set to remain well below European price levels, including the United States and Russia.

Central and South America

Natural gas consumption in Central and South America is expected to grow at an average annual rate of 1.2% over the forecast period, adding 13 bcm to the 168 bcm of demand in 2018. Demand growth over the forecast period is led by the industrial sector, both in absolute and growth rate terms, with an annual growth rate of 1.7% adding an additional 5 bcm/y to overall demand, owing to better economic prospects (Figure 1.28).

Figure 1.28. Natural gas demand by country and by sector, Central and South America, 2004–24



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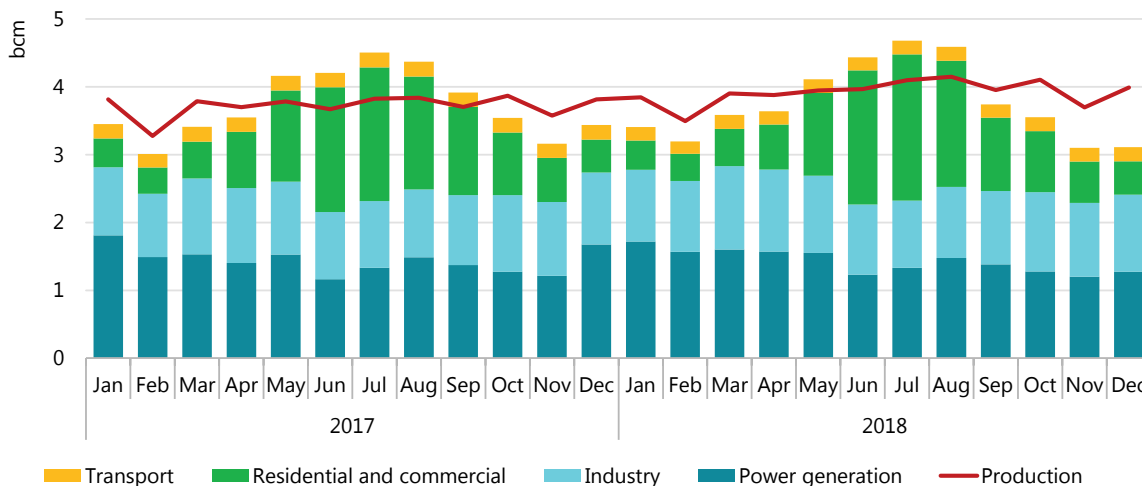
Regional natural gas demand growth is expected to average 1.7% per year to 2024, mainly driven by industry.

At a country level, Argentina leads the increase in demand, representing over 70% of the growth in natural gas consumption over the forecast period, or almost 10 bcm/y, reaching 57 bcm/y by 2024. Brazil is expected to remain the second-largest consumer, with almost 35 bcm/y of natural gas demand by 2024.

Argentina

Argentina is the largest natural gas-consuming country in the region, representing around 32% of total consumption in 2018. Demand is highly seasonal, especially due to the residential and commercial sector (Figure 1.29).

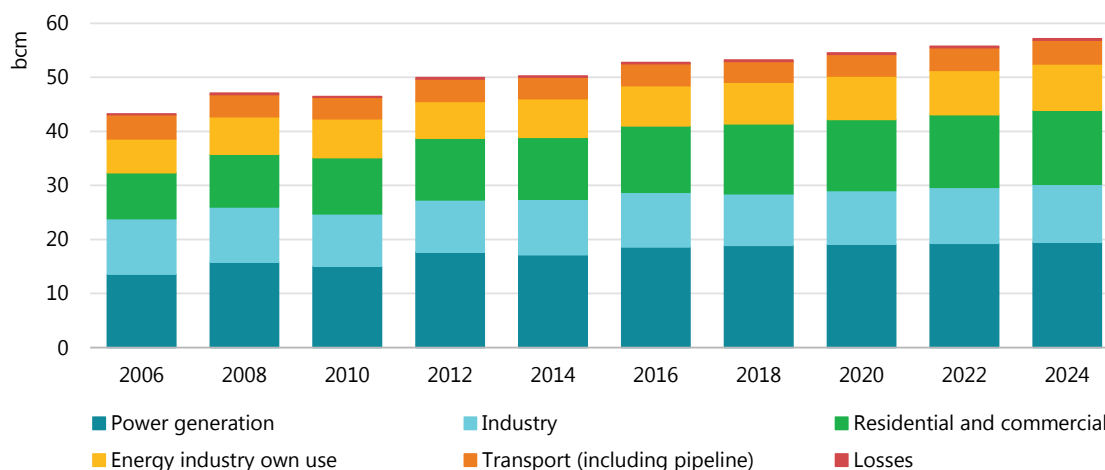
Figure 1.29. Natural gas consumption by sector, Argentina, 2017–18



Source: Gobierno Argentina (2019), “Exportaciones por sector de actividad, saldo comercial y rangos de exportación de la empresa exportadora”, https://datos.gob.ar/dataset/sspm-produccion-consumo-gas-natural/archivo/sspm_364_3.

Argentina’s demand peaks during the southern hemisphere winter, when domestic production is not sufficient and the country needs to import natural gas.

Figure 1.30. Natural gas consumption by sector, Argentina, 2006–24



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Industry drives Argentina’s natural gas demand growth to 2024, with total consumption growing at an average rate of 1.2% per year.

This forecast expects natural gas demand in Argentina to reach 57 bcm/y by 2024 (Figure 1.30). Consumption for power generation is set to keep increasing due to a switch from other fossil fuels, and oil products in particular. In the residential sector, growth is expected to come from new connections, as the government has a goal of 68% of households to be connected by 2025. Growth from industry is expected to come from the post-2019 economic recovery, as the IMF forecasts negative GDP growth of -1.2% in 2019 followed by 2.2% in 2021 and increasing up to 3.6% in 2024. In its energy scenarios to 2025, the Argentinian government expects growth to come mainly from the residential and commercial sector (with 2.2% growth), followed by industry (2%) and transport (2%). Commercial demand is expected to grow at a slower pace of 1.9% (Ministerio de Energía y Minería, 2016).

Box 1.4 Argentina's gas market reform

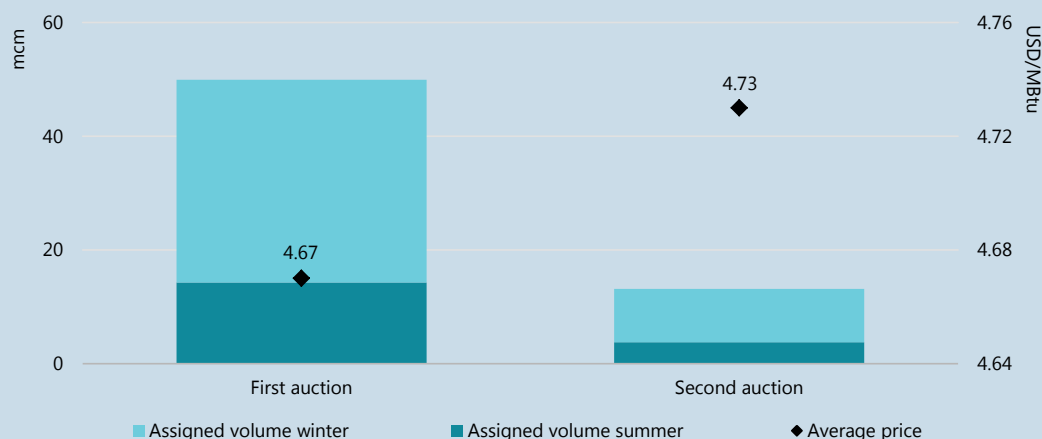
Before President Mauricio Macri took office in 2015, Argentina's gas and power sector was tightly regulated by the federal government and prices were heavily subsidised.

Macri's programme has included reducing government intervention and setting up an energy market where prices would be driven by competition. Reforms started in 2016 by increasing regulated gas prices for power distribution companies and CNG prices for vehicles, and reducing subsidies for end users. In 2017 the government introduced a price incentive for unconventional gas production, and in 2018 it agreed to gas exports to Chile without re-import commitments, albeit with interruptible contracts. Additionally, the government announced that thermal power plant users could start bidding for their natural gas supply, moving from the existing fixed-contract systems with Cammesa, the power system operator. In total, two auctions of gas for thermal power were held for interruptible volumes between the end of 2018 and early 2019. In February 2019 the country held two further auctions for firm gas purchase between suppliers and gas distribution companies for April 2019 to March 2020 (the first open auctions for contracted volumes in this category). It was a reverse auction, where the buyer places an order with the corresponding details, and the seller of natural gas with the lowest price wins the auction.

The Neuquén, Golfo San Jorge and Austral basins auction took place on 14 February 2019 and the Norwest basin auction on 15 February (El Economista, 2019). The auctions took place in the Mercado Electrónico de Gas (MEGSA), with take-or-pay clauses for the distribution companies and deliver-or-pay clauses for the producers, both fixed at 70% of daily maximum capacity. The distribution companies will have 65 days to pay for the natural gas after delivery. This might be an issue in respect of working capital requirements as distribution companies receive payment from end users every two months, so they would need to finance the payment to producers, with the respective cost of capital. Distribution companies argued they would either pass through the additional financing cost to end users or not participate in the auction at all. On their side, producers argued they would also incur financing costs, which would be reflected in higher auction prices. The government decided to adopt an average of 65 days (neither the original 75 days, as before, nor the 30 days proposed during a public consultation). The distribution companies have to buy at least 50% of their annual volumes in the auction, and have the possibility to buy the other 50% through bilateral contracts with the oil companies (same system as before the auction) (El Cronista, 2019).

During the first auction, 14.3 million cubic metres (mcm) were awarded for the summer season and 35.7 mcm for the winter, with an average price of USD 4.67/MBtu. During the second auction, the price was USD 4.73/MBtu and volumes were 3.8 mcm and 9.4 mcm for the summer and winter season respectively (MEGSA, 2019a, b).

Results for auctions on 14 and 15 February, Argentina, 2019



Source: MEGSA, www.megsa.com.ar/.

Argentina plans monthly auctions for the offer of domestic gas and is due to launch a separate four-year auction for the offer of winter gas at prices indexed to imported LNG (Reuters, 2019).

Sources: El Economista (2019), "Se viene la subasta de gas del Gobierno", www.eleconomista.com.ar/2019-02-se-viene-la-subasta-de-gas-del-gobierno/; El Cronista (2019), "Gas: Así será la subasta que definirá el precio a trasladar a tarifas", www.cronista.com/economiapolitica/Gas-asi-sera-la-subasta-que-definira-el-precio-para-trasladar-a-tarifas-20190210-0006.html; MEGSA (2019a), "Resultados subasta", www.megsa.com.ar/pdf/Resultados1502.pdf; MEGSA (2019b), "Resultados subasta", www.megsa.com.ar/pdf/Resultados1402.pdf.

Brazil

Industry was the largest consumer of natural gas in Brazil until 2013, when power generation surpassed it due to the severe hydropower water shortages experienced between 2013 and 2015. During this period natural gas use for power generation peaked at almost 19 bcm/y (Figure 1.31).

Renewables other than hydro are expected to grow in the medium term as the Brazilian Ministry of Mines and Energy announced in February 2019 the award of construction licences for over 1.5 GW of green projects, awarded in September 2018. Among the 53 projects, 44 are for wind power generation, 7 are hydropower, 1 is biomass and 1 is a natural gas power project of 362.20 MW. The projects are due to start in 2024, with a power purchase agreement of 25 years for the gas-fired plant (Renewables Now, 2019). However, due to the historical dependence on hydro and the foreseen increase in intermittent renewable generation, Brazil is also building new thermal power generation to provide flexibility. A previous power auction in December 2017, the first to implement new rules designed to support the development of new gas-fired power generation, awarded licences for 2 large gas-fired power plants totalling around 2 140 MW.

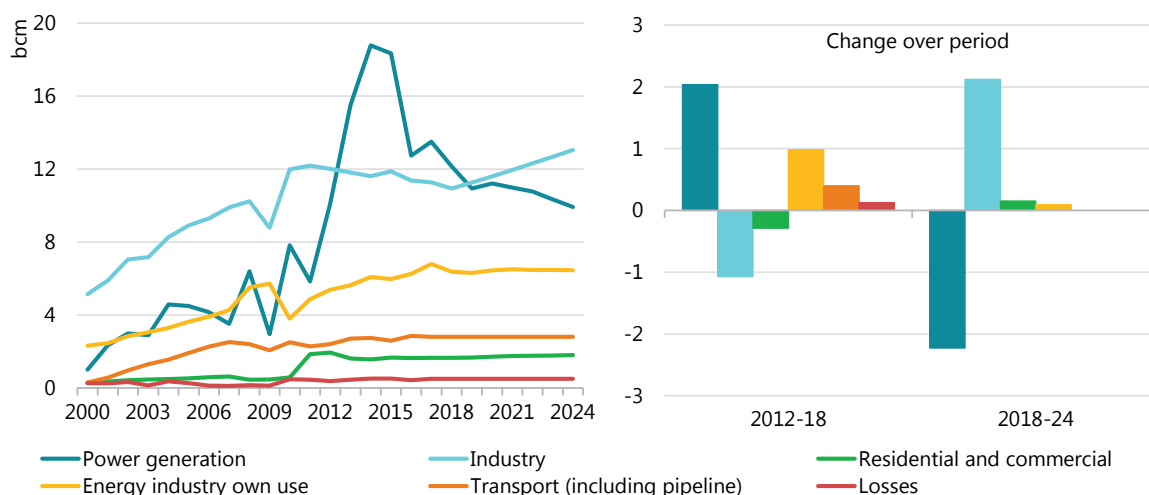
In February 2019 a joint venture formed by Patria Investimentos, Shell and Mitsubishi Hitachi Power Systems Americas announced a project to build and operate a gas thermal power plant in Marlim Azul in Macaé (Rio de Janeiro), using associated pre-salt gas from Shell’s own production. The Marlim Azul power plant, with a capacity of 565 MW, is due to be operational by 2022 (MHPS, 2019)

The Sergipe LNG-to-power project – comprising a CCGT power plant with a total installed capacity of 1.5 GW, a 33-km transmission line, and an FSRU – will upon completion in January 2020 be the largest thermal power plant in Brazil by capacity. The sponsors are Ebrasil and Golar Power (BNamericas, 2018). The FSRU is expected to arrive by mid-2019.

Another LNG-to-power project is under construction in the port of Açu (Rio de Janeiro). The 1.3 GW plant is expected to start operations in early 2021 and to use LNG supplied by a floating regasification terminal – supply is then expected to switch to associated gas from domestic pre-salt production, when it becomes available.

According to the IMF, Brazil’s GDP is expected to grow by 2.1% in 2019. This recovery is expected to increase industrial-sector demand for natural gas, with an annual average growth rate of 2.4% through the forecast.

Figure 1.31. Natural gas consumption by sector, Brazil, 2000–24



IEA, 2019. All rights reserved.

Industry accounts for almost all medium-term natural gas demand growth in Brazil to 2024.

In March 2019, Brazilian Mines and Energy Minister Bento Albuquerque announced that in June the government would present a programme to promote the development of the natural gas sector. The programme, “New Gas Market”, pursues the same objectives as the previous “Gas for Growth” programme during the former Temer administration, and is part of the Bolsonaro administration’s goal to introduce free-market policies into the economy. According to the Economy Minister Paulo Guedes, the government will promote cheap energy that will reduce the cost of natural gas by 50% (Spring, 2019).

Box 1.5 Brazil's gas market reform: developing a competitive market

In 2016 the Brazilian government launched the "Gas to Grow" programme, looking to improve the market-oriented regulatory framework in order to boost both domestic production and consumption of natural gas, now being developed further by the new administration. The programme seeks non-discriminatory third-party access to pipelines, processing plants and LNG terminals, as well as enforcement of an independent transmission system and creation of entry–exit zones with liquid virtual trading points.

To develop a competitive wholesale market in the country, a reduction in Petrobras's dominant position is foreseen through a partnership and divestment programme (PPI, Programa de Parcerias para Investimentos):

At the end of 2015 Petrobras finalised the sale of 49% of Gaspetro (natural gas distribution company) to Mitsui for USD 593 million (Petrobras, 2015). Gaspetro controls Petrobras' stake in 19 state-run natural gas distributors.

In April 2017 Petrobras finalised the sale of 90% of Nova Transportadora do Sudeste (NTS) to a Brookfield Brazil Asset Management fund for USD 5.2 billion. Petrobras will continue using the pipeline, and Transpetro (Petrobras's transport company) will continue the operation and management.

In April 2019 it was announced that a consortium led by Engie had won the bid for a 90% share of Petrobras's TAG pipeline, with an USD 8.6 billion offer (Kar-Gupta, 2019). Canada's provincially owned financial and investment firm Caisse de Dépôt et Placement du Québec is also in the consortium. TAG operates 4 500 km of pipelines in the north and northeast of Brazil, representing 47% of Brazil's entire gas infrastructure.

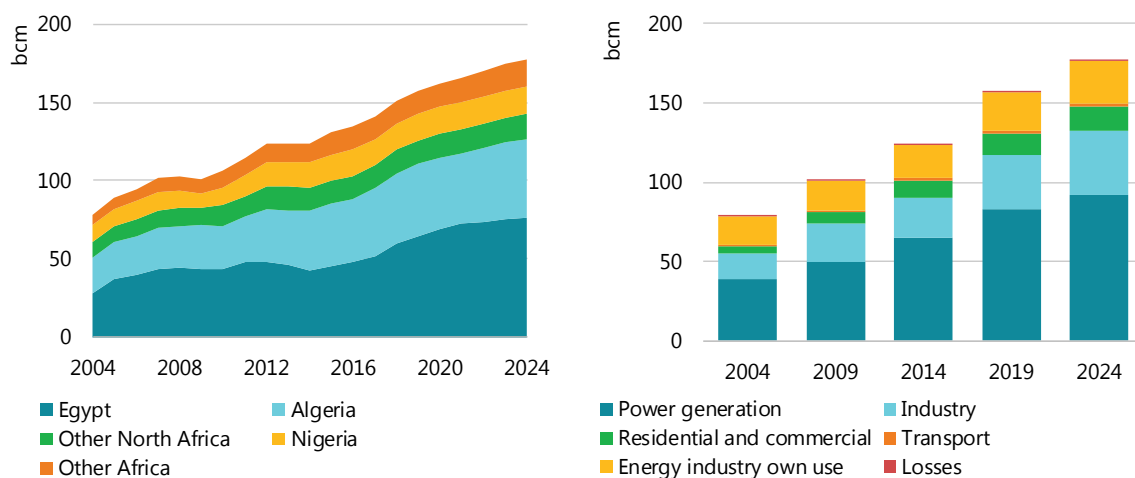
Sources: Petrobras (2015), "Conclusion of sale of interest in Gaspetro", www.investidorpetrobras.com.br/en/press-releases/conclusion-sale-interest-gaspetro; Kar-Gupta, S. (2019), "Engie-led consortium seals \$8.6 billion purchase of Petrobras pipeline unit", *Reuters*, www.reuters.com/article/us-petrobras-divestiture-tag-engie/engie-led-consortium-seals-86-billion-purchase-of-petrobras-pipeline-unit-idUSKCN1RKoM1.

Africa

Africa's natural gas consumption grew by almost 7% in 2018, thanks mainly to the strong development of domestic production in Egypt. In 2019 Egypt is set to remain the main driver of gas consumption growth in the continent, with the bulk of the increase provided by the power generation and chemicals sectors.

Africa's gas consumption is expected to grow by an average of 2.7% for the coming five years, to reach almost 180 bcm/y by 2024 (Figure 1.32), slowing from its recent strong year-on-year increases as North African markets reach a certain level of saturation. North Africa – which currently accounts for 80% of the continent's gas demand – remains the main source of consumption growth, driven by Egypt's power generation and industrial sectors.

Figure 1.32. Natural gas consumption by country and sector, Africa, 2004–24



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North Africa is expected to account for the majority of natural gas consumption growth in the near future, led by the needs of the Egyptian power and industrial sectors.

Egypt

Egypt is Africa’s largest natural gas market, with an estimated 60 bcm consumed in 2018 – or about 40% of the region’s total natural gas demand. Natural gas consumption has increased steadily since 2016 with the development of domestic offshore production from the Mediterranean. Power generation is the main driver of this growth, with power demand tripling since 2000 – an increase mainly attributed to the development of the industrial sector and the growing use of electronic equipment in the residential sector. This forecast expects continuous growth of Egyptian natural gas consumption, at an average annual rate of about 4% for the next five years.

Power generation capacity is dominated by gas-fired thermal plants (over 90% of installed capacity) and surged in 2018 from 42 GW to an estimated 58 GW, mainly due to the commissioning of natural-gas fired capacity (principally new projects, as well as some conversion of open cycles to combined cycles). This included the three 4.8 GW high-efficiency CCGTs of Beni Suef, El Burullus and New Capital in the north of the country, which were inaugurated in mid-2018 (Table 1.8). Additional power capacity projects from renewable sources (solar and wind) are under development, to help achieve the country’s 8th Five-Year Plan target of 20% renewables in the power mix by 2022. The Egyptian Electricity Holding Company assessed the plan’s requirements to meet electricity demand and concluded that no additional thermal generation was needed to 2022 beyond capacity already under construction (EEHC, 2017).

Domestic electricity demand growth is expected to remain dynamic, and the government’s electricity policy includes a phase-out of subsidies and the introduction of private wholesalers in 2021, followed by electricity trade liberalisation by 2022 (Egypt Today, 2018). The electricity surplus will be exported according to a specific regional electricity export programme targeting neighbouring countries in Africa, Europe and the Middle East. Egypt already exports electricity

to Jordan and Libya, and started exports to Sudan in early 2019, while several agreements and memoranda of understanding have been signed with Cyprus,¹⁵ Greece and Saudi Arabia.

Table 1.8 Main power generation capacity additions, Egypt, 2018

Plant	Project type	Technology	Capacity (GW)
El Burullus	New	CCGT	4.8
Beni Suef	New	CCGT	4.8
New Capital	New	CCGT	4.8
West Damietta	Conversion of 500 MW open cycle	CCGT	0.25
Assiut	Conversion of 1 000 MW open cycle	CCGT	0.5
Benban	New	Solar PV	1.8*
Gabal el Zeit	New	Offshore wind	0.2

* Total capacity, to be fully commissioned in 2019.

Sources: Contractors' websites.

Industry is another sector seeing natural gas consumption growth, mainly driven by construction and chemicals. Petrochemicals and fertilisers are the most important areas for development in Egypt's industrial sector, supported by the country's return to natural gas supply self-sufficiency in 2018. The Tahrir Petrochemical complex, announced in mid-2018, will upon completion be the largest plant in the region. The export capacity of the Damietta methanol and fertiliser complex is undergoing expansion with the development of additional berthing infrastructure. Another 1.1 Mtpa fertiliser plant, developed by local private company Evergrow, is set to start operations by 2020, aiming for both domestic and export markets. In late March 2019 fertiliser manufacturer El Nasr awarded an engineering, procurement and construction contract for a new plant to be built in Ain Sukna on the Red Sea coast – upon construction in 2022 the plant will be able to produce 440 000 tonnes of ammonia, 380 000 tonnes of urea and 300 000 tonnes of calcium ammonium nitrate per year.

The oil and gas sector, which currently accounts for 11% of the country's natural gas consumption, is expected to grow in the future due to the expansion of domestic production, increases in refining capacity and the partial restart of gas liquefaction plants.

Algeria

Algeria, where natural gas accounted for 37% of the country's primary energy consumption in 2017 (Algerian Ministry of Energy, 2018), is already a mature market. Consequently, natural gas consumption growth is expected to slow to an annual average rate of 2% until 2024, from an average of almost 5% over the past six years.

¹⁵ 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 the 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.

Power generation remains the strongest component of domestic consumption, with an average 4.7% annual growth over the past decade and accounting for almost 45% of natural gas use. About 95% of electricity is produced from natural gas. State-owned operator Sonelgaz, which supplies electricity and operates the electricity and gas grids, has carried out development programmes for both networks ensuring coverage of 99% of the population for electricity and 60% for natural gas. Algeria's gas-fired power generation fleet is underutilised, with 5 GW to 7 GW of unused capacity out of a total of 20 GW. Sonelgaz plans to develop exports to neighbouring countries in North Africa and to Spain¹⁶ in order to generate additional revenues and to enhance its utilisation rate. Energy Minister Mustapha Guitouni announced in January 2019 that negotiations were under way with Spain to solve tax-related issues and enable the state-owned company to operate on the Spanish electricity wholesale trading market (APS, 2019).

Algerian regulatory agency CREG assumed in its 2019 ten-year gas and electricity development plans the development of some 1.8 GW of thermal and renewable capacity to match additional electricity demand needs, with a central assumption of 2.2% annual gas consumption growth for power generation over the next decade (CREG, 2019). This forecast takes a more conservative approach, with a decrease in natural gas consumption over the first years linked to the commissioning of renewable capacity followed by a rebound triggered by growing domestic electricity demand, thus resulting in a stable gas-for-power demand level between 2019 and 2024.

Industrial use of natural gas covers one-quarter of total consumption and has grown at a dynamic average rate of almost 10% since 2012, led by the building materials and petrochemicals sectors. State-owned oil and gas production company Sonatrach reported in early 2019 several petrochemical joint ventures under negotiation to monetise its natural gas through channels other than pipeline and LNG exports. Industry is therefore expected to remain the main driver of natural gas consumption growth in the near future.

Residential and commercial demand is set to remain stable, with limited consumption growth owing to gas already having high market penetration. The energy sector's own consumption also stagnates as domestic oil and gas production is not expected to grow in the near future.

Other North Africa

Natural gas development prospects in Morocco remain limited in the medium term. Power generation accounts for almost all of the country's natural gas demand, with a CCGT inaugurated in 2005 (Tahaddart, 385 MW) and another in 2010 (Ain Beni Mathar, 470 MW). The project to develop an LNG import terminal in Jorf Lasfar – to reduce dependence on Algerian gas imports and further develop gas-fired power generation – is still officially under consideration, but seems to be challenged by the gas discovery in the Tendirara region as well as the objective to develop renewable energy sources.

Tunisia's natural gas demand remained stagnant over the recent past and is expected to remain so in the coming years. It relies on both domestic production and Algerian imports for its gas supply. The Nawara field development – expected to start production by mid to late 2019 – will reduce dependence on imports, but is not intended to increase domestic consumption as the country aims to develop power production from renewable sources. It has the objective of

¹⁶ Although Spain currently has gas-fired generation capacity to spare and is further developing its renewable generation capacity.

developing 800 MW of solar PV and wind capacity, with the tender process ongoing at the time of writing.

Gas demand in Libya has not increased over the past two years in spite of the decrease in pipeline exports to Italy. This reflects challenging production conditions owing to security issues in the country's remote interior, which are likely to remain a major limitation to future production and domestic consumption growth.

Sub-Saharan Africa

Natural gas consumption in sub-Saharan Africa remains limited to producing countries and highly dependent on the availability of local resources, which are often dedicated to export when monetised. In the absence of defined gas connectivity projects and policies at the time of writing, this forecast expects a continuation of the observed growth trend, with an average of 2% per year growth in the sub-region.

Nigeria accounts for the large majority of natural gas consumption in sub-Saharan Africa, at an estimated 17 bcm in 2018. Power generation is the primary consumer of natural gas, just ahead of the oil and gas industry's own use at about 40% of total domestic consumption. However, the country's power system is hampered by the lack of feed gas availability to run power plants, a challenge that is not expected to disappear in the near future. On the industrial side, the Dangote fertiliser plant at Ibeju Lekki will upon completion be Africa's largest, producing up to 2.8 Mtpa of urea. It is expected to receive 70 million cubic feet per day (or about 0.7 bcm/y) of natural gas feedstock as per the contract with state-owned Nigerian National Petroleum Corporation (NNPC) and Chevron (Premium Times Nigeria, 2019). NNPC announced in March 2019 its intention to build 4 GW of (presumably gas-fired) independent power plants in Abuja, Kaduna and Kano to stabilise the grid, as well as a fertiliser plant in Brass, with a global objective of monetising the country's natural gas reserves (NNPC, 2019). However, no FID or timeline have been confirmed at the time of writing – these projects are therefore not included in the present forecast.

Growth prospects for natural gas consumption appear limited in the near future in other West African countries. Côte d'Ivoire – where natural gas is used for power generation – announced the development of a new CCGT near Abidjan, which will increase efficiency and thereby enable higher electricity production without increasing gas consumption. The discovery and development of resources off the coast of Mauritania and Senegal does not so far include projects to develop a domestic market. Cameroon's consumption grew at an average of 9% between 2011 and 2018 according to the Ministry of Energy, but this was mainly due to the expansion of the country's refinery and no major projects are expected to further develop domestic demand. In Ghana, the LNG import project – on hold since late 2017 – revived at the end of 2018 with a floating regasification option.

Southern Africa shares a similar situation, with limited domestic market implications for Mozambique's natural gas development projects, and no projects sanctioned yet in Tanzania. Natural gas demand in South Africa has remained stagnant in recent years; however, it forms an important part of the country's future energy mix according to the 2018 draft version of the Integrated Resources Plan, with ambitions to install an additional 8.1 GW of gas-to-power capacity in South Africa by 2030 (Department of Energy, 2019). Several projects have been proposed, including power generation incumbent Eskom's 3 GW CCGT at Richards Bay, but none have been confirmed at the time of writing.

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2. Supply

Highlights

- **2018 was another year of record output for major producers** such as the United States, People's Republic of China ("China"), Australia, Russian Federation ("Russia") and Islamic Republic of Iran ("Iran"). Other countries, such as Egypt and Argentina, saw their domestic supply gap close on the back of strong production recovery.
- **Global natural gas production is expected to grow** at an average annual rate of 1.6% over the forecast period, driven by a limited number of countries, mainly for domestic market needs (e.g. China, Iran and Egypt) but for a few by developing exports (the United States and Russia, and Australia mainly in the early part of the projection period).
- **The United States continues to lead in terms of individual contribution to gas production growth**, mainly driven by oil-rich associated gas production increases over the first two years of the forecast, then by further development of dry shale gas plays. US production passes the 1 tcm mark by the end of the forecast period.
- Apart from Australia, **Asia Pacific countries and territories see their supply gap increase** in the medium term. Strong growth in production in China cannot keep pace with consumption growth. For most other countries production growth is limited while domestic needs increase strongly.
- In spite of its stable consumption, **Europe sees its supply gap widen** due to domestic production depletion or phase-out in the case of the Netherlands. This results in higher import dependency due to a loss of above 45 bcm of production by 2024 compared to 2018.

Global overview

Global natural gas production is forecast to rise from 3 940 billion cubic metres (bcm) in 2018 to 4 332 bcm by 2024, an average annual increase of 1.6% (Table 2.1). The United States provides the largest individual contribution to this increase thanks to the continuous development of its ample shale gas resources, both for domestic and export markets. US production reaches above 1 trillion cubic metres (tcm) by the end of the forecast period. Canadian production growth remains limited by the absence of export outlets until 2024 – the LNG Canada project is assumed to start operations by 2025.

China and Australia drive production growth in the Asia Pacific region. Australian growth takes place mainly during the early years of the projection period, driven by the ramping up of its liquefied natural gas (LNG) export projects, whereas China is expected to have strong and continued growth of 7.1% on average – although not sufficient to cover the country's

consumption needs. Production growth in other Asian economies remains limited due to the depletion of historical resources and the lead time of exploration and production investment.

Gas production in the Middle East keeps on growing at a stable rate, but is mainly driven by domestic needs in Iran and Saudi Arabia. While prospects for production development in Qatar remain uncertain, especially surrounding the timing of LNG export capacity expansion, this forecast assumes a stable level of production to 2024 in the absence of a final investment decision (FID) on LNG expansion at the time of writing (see Chapter 3). Eurasian natural gas production growth is mainly driven by export projects as domestic demand remains stable or even declines in some countries.

Table 2.1. Global natural gas supply by region, 2018–24 (bcm)

Region	2018*	2020	2022	2024	CAAGR 2018–24	Contribution to global growth
Africa	231	248	259	271	2.7%	10%
Asia Pacific	625	653	683	724	2.5%	25%
Eurasia	939	954	990	1 016	1.3%	20%
Europe	250	232	218	202	-3.5%	-12%
Middle East	640	653	686	713	1.8%	19%
North America	1 076	1 153	1 182	1 216	2.1%	36%
Central and South America	179	176	182	190	1.1%	3%
World	3 940	4 069	4 200	4 332	1.6%	

* Provisional data; data for 2020 onwards are forecasts.

Note: CAAGR = compound annual average growth rate.

Europe remains the only region with falling production over the forecast period, due to a combination of declining output from ageing fields in the North Sea and the progressive phase-out of the Groningen field in the Netherlands.

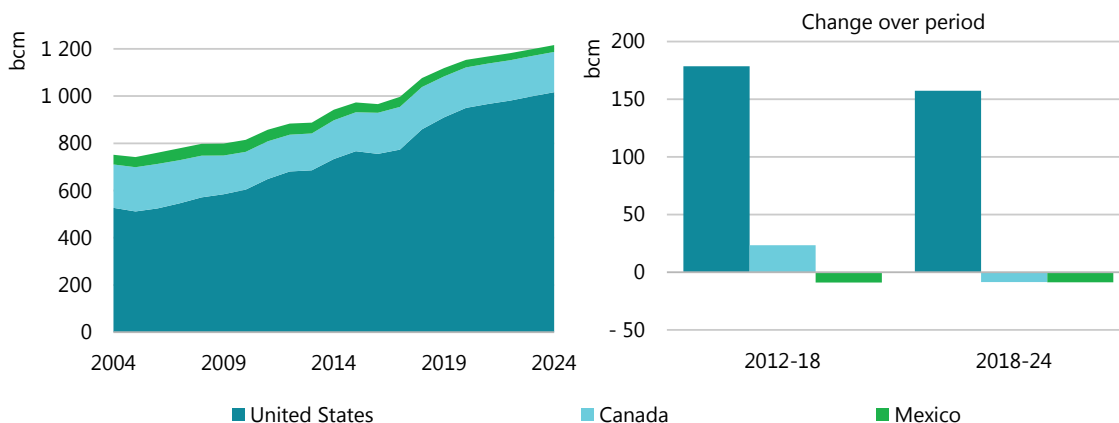
South American production growth is mainly driven by the development of Argentina's shale gas resources, as development potential in other countries appears limited until 2024. Production increases in Africa are principally tied to the rapid development of Egyptian offshore projects, which are expected to deliver growth over the next three years and principally for the domestic market. Additional developments are provided by LNG export projects commissioning in sub-Saharan Africa in the second half of the forecast period.

Regional supply outlook

North America

North America is expected to account for 36% of global natural gas production by 2024, with the United States being the single largest contributor to production growth at almost 40% of the total production increase (Figure 2.1). Production from Canada and Mexico are expected to stabilise throughout the forecast period.

Figure 2.1 Natural gas production, North America, 2004–24



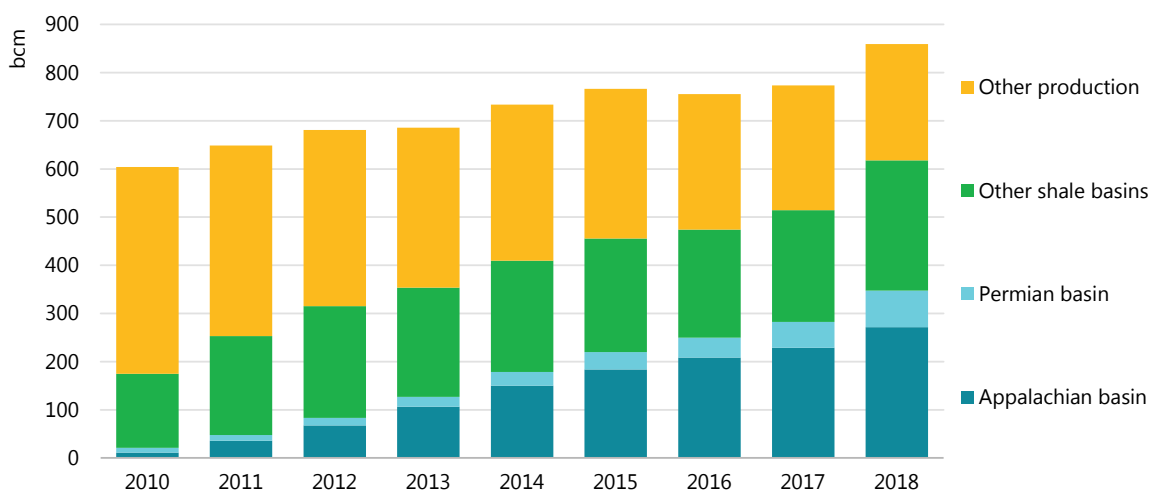
IEA, 2019. All rights reserved.

The United States is expected to account for all North American natural gas production growth through the forecast period. Canada’s growth is limited by the lack of export infrastructure.

United States

The United States was the largest single contributor to global natural gas production growth in 2018 with a net natural gas addition of 86 bcm or 11.5% year-on-year (y-o-y), its highest growth rate since 1951. The share of shale gas in total US production has more than doubled since the beginning of the decade, rising from 29% in 2010 to 72% in 2018 (Figure 2.2).

Figure 2.2 Natural gas production, United States, 2010–18



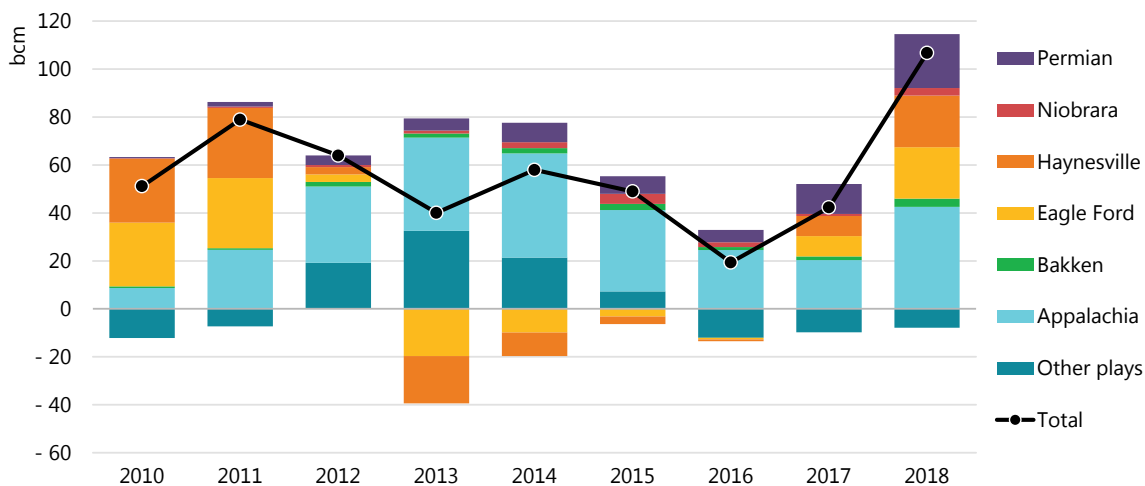
Source: EIA (2019a), *Dry Shale Production Estimates per Play* (database), www.eia.gov/naturalgas/data.php#production.

US natural gas production grew at an average annual rate of 4.5% from 2010 to 2018, supported by strong growth from major shale gas plays and in particular by the Appalachian basin in the Northeast.

The Appalachian basin (dry gas) has been the main source of supply growth since 2012 (Figure 2.3). The incremental contribution from the Appalachian basin more than doubled in volume in 2018 (from 20 bcm in 2017 to 43 bcm), yet its share of total shale gas growth decreased due to the strong rises observed in almost all shale plays. This can be explained by the crude oil price recovery in 2018, which supported US light tight oil (LTO) and associated gas production. It is particularly visible in the Eagle Ford play – where incremental shale gas production almost tripled from 8 bcm in 2017 to 22 bcm in 2018 – and in the Permian basin (from 12 bcm to 22 bcm).

A further source of growth was the strong development of the Haynesville dry shale gas formation, which was one of the main shale gas development areas in the 2000s. It peaked in 2012 and then fell to half of its peak output in 2016 due to higher drilling costs compared with less deep formations in the Appalachian basin. Recovering natural gas prices since 2016 and increased well productivity brought Haynesville back to production growth, growing by almost 45% from 47 billion cubic metres per year (bcm/y) in 2017 to 68 bcm/y in 2018.

Figure 2.3 Shale gas production growth by major basins and plays, United States, 2010–18

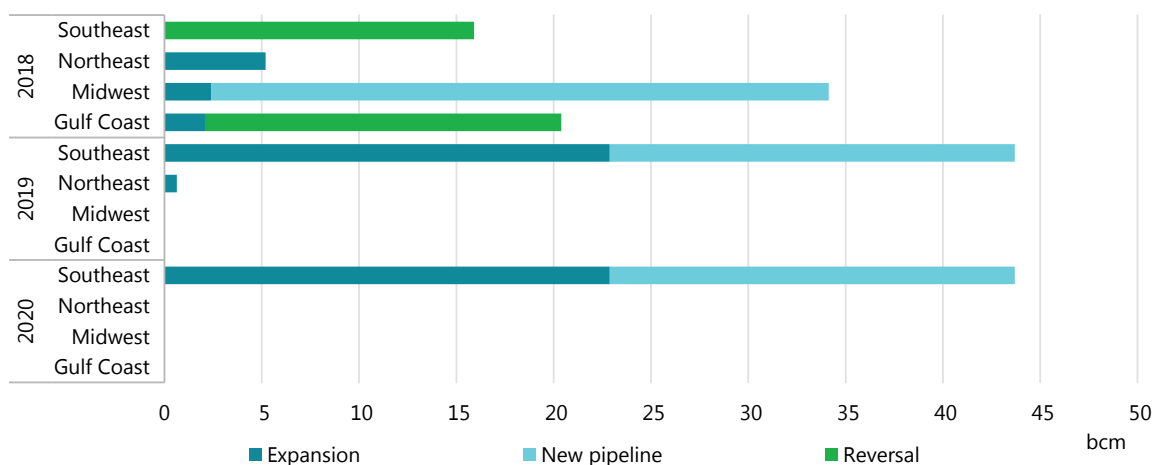


Source: EIA (2019a), *Dry Shale Production Estimates per Play* (database), www.eia.gov/naturalgas/data.php#production.

2018 saw shale gas production increase by over 100 bcm, with strong contributions from almost all major dry and associated gas plays.

The growth in production from the Appalachian basin also comes from the progressive debottlenecking of pipeline takeaway capacity, which had led to a price disconnection between local hub prices and the Henry Hub from mid-2013. This price spread narrowed in 2017 and 2018 with the development of additional export pipeline capacity.¹ Pipeline capacity additions reached a high in 2018, with several projects commissioned to improve takeaway from the Appalachian basin – including new pipeline capacity in the Midwest, reversal of existing pipelines to the Gulf Coast and Southeast regions, and capacity expansions (Figure 2.4). Further additions are under construction and scheduled to start operations in 2019 and 2020, such as the Mountain Valley Pipeline (20.8 bcm/y), the Atlantic Coast Pipeline (15.6 bcm/y) and the extension of the Mountaineer Xpress Pipeline (22.9 bcm/y).

¹ However, the differential remains higher during the summer months (e.g. USD 1.5 (United States dollars) per million British thermal units lower than Henry Hub for the Leidy Hub in June 2018)

Figure 2.4 Pipeline capacity developments from the Appalachian basin (selected projects)

Source: EIA (2019b), *Pipeline Projects* (database), www.eia.gov/naturalgas/pipelines/EIA-NaturalGasPipelineProjects.xlsx.

Strong takeaway capacity development enables the debottlenecking of shale gas production from the Appalachian basin.

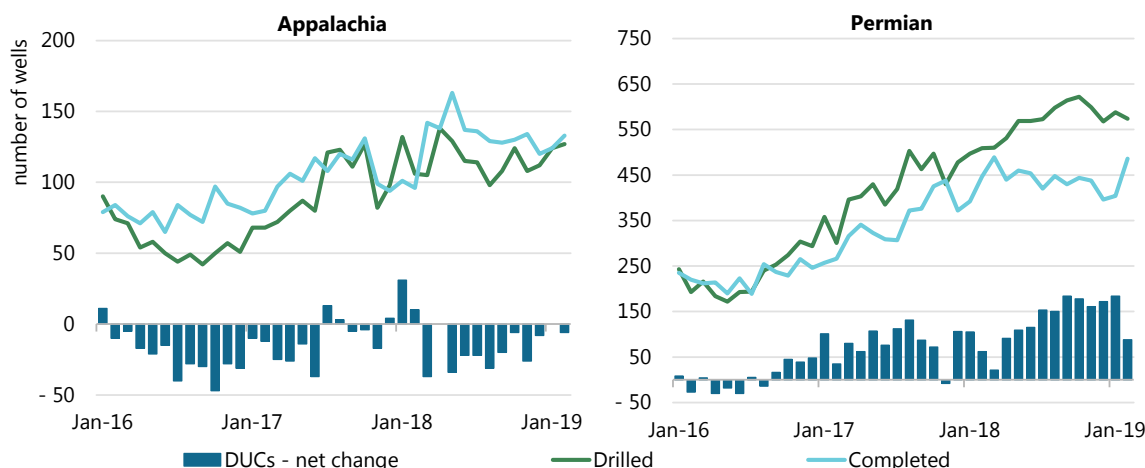
Such an improvement in interconnection capacity is likely to spur further production increases from the Appalachian basin in the near future – according to Energy Information Administration (EIA) estimates, production for the first quarter of 2019 increased by 16% y-o-y (EIA, 2019c).

Associated production from the Permian basin, the other major contributor to US shale gas growth, is still hampered by the lack of pipeline takeaway capacity. Permian gas output is driven by LTO production, which increased by over a third in 2018 (IEA, 2019a), leading to growing associated gas oversupply and resulting in an increase in flaring and negative pricing. The number of flaring permits issued by the Railroad Commission of Texas grew from 3 708 in 2017 to 5 488 in 2018 (RRC, 2019) and the amount of gas flared in the Permian rose by about 85% in 2018, reaching 553 million cubic feet per day in the fourth quarter (Bloomberg, 2019). In March 2019 prices at the local Waha trading hub plunged to negative values, reaching USD -3.38 per million British thermal units (MBtu) as of early April (DiSavino, 2019).

Another consequence of oil and gas infrastructure bottlenecks is the build-up of drilled but uncompleted wells (DUCs).² Figure 2.5 shows that the completion rate of drilled wells improved in the Appalachian basin from early 2016, with a net reduction of DUCs following completion of previously uncompleted wells. As a result the overall DUC count decreased by half, from above 1 000 in early 2016 to around 500 in the first quarter of 2019. By contrast, drilling activity in the Permian basin shows a widening gap between the numbers of drilled and completed wells, driving the DUC count from 1 200 to 4 000 between early 2016 and the first quarter of 2019. This lack of takeaway capacity led to negative prices in West Texas' Waha hub in March 2019 (see Chapter 4).

² According to the EIA definition, a DUC is a new well after the end of the drilling process, but its first completion process has not been concluded (EIA, 2016).

Figure 2.5 Monthly drilling and completion activity, Appalachia and Permian, 2016–19

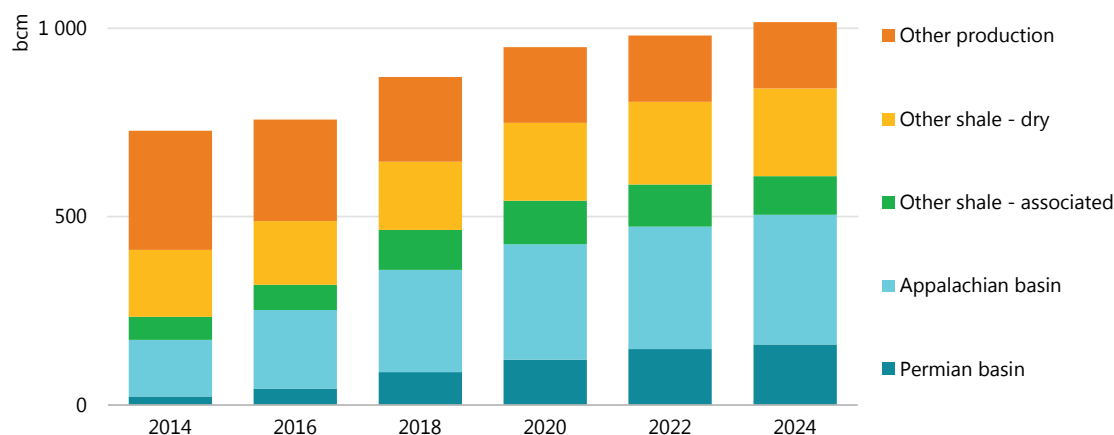


Source: EIA (2019d), *Drilling Productivity Report – DUC Data* (database), www.eia.gov/petroleum/drilling/xls/duc-data.xlsx.

Pipeline bottlenecks hamper the development of Permian reserves and have led to a build-up of DUCs, whereas Appalachia’s improving interconnections improved its completion rate.

This forecast expects most of the LTO growth to happen in 2019 and 2020 as per the assumptions of the latest IEA *Oil 2019* market report (IEA, 2019a), enabled by the rapid completion of many of the DUCs in the Permian when oil export pipelines start operations. However, this will not translate immediately into commensurate growth of associated gas production, until the abovementioned limits on gas pipeline capacity are alleviated. The contribution of Permian to shale gas growth decelerates after 2020 as the underlying LTO production growth slows. Total US natural gas production is expected to grow at an annual average rate of 2.8% over the forecast period and to reach the 1 tcm mark by 2024 (Figure 2.6). Appalachia’s contribution keeps increasing to reach 34% of total production by 2024 (from 31% in 2018). Shale gas as a whole is expected to account for over 80% of US natural gas production by the end of the forecast period – up from a current 72%.

Figure 2.6 Natural gas production, United States, 2014–24



IEA, 2019. All rights reserved.

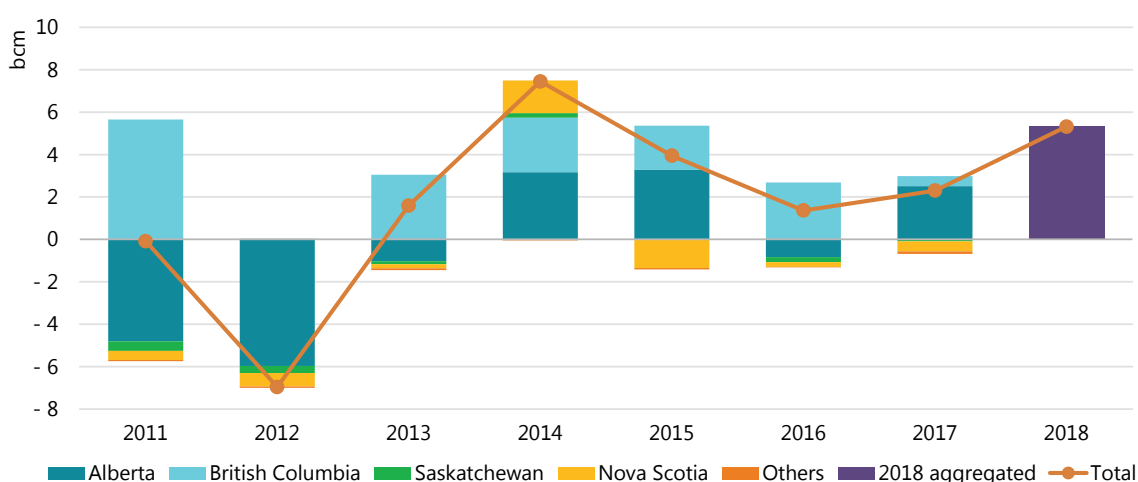
US production reaches 1 tcm by 2024, with Permian contribution to growth in the short term up to takeaway infrastructure limits and then slowing with falling LTO growth.

Canada

Canadian natural gas production started to recover in 2013 and since then has been increasing at an average growth rate of 4% per year. This has been mainly driven by the development of tight and shale gas production, the share of which grew from 30% in 2007 to almost two-thirds in recent years.

Most of these resources are located in Alberta and British Columbia, which together accounted for almost all cumulative production growth since 2013 (Figure 2.7). This tight and shale gas development comes mainly from two plays: the Montney play, which extends from British Columbia into Alberta and currently accounts for about one-third of Canadian production, and the liquids-rich Duvernay shale play in Alberta.

Figure 2.7 Natural gas production growth by Canadian province, 2011–18



Source: NEB (2019), "Marketable natural gas production in Canada", www.neb-one.gc.ca/nrg/sttstc/ntrlgs/stt/mrktblntrlgsprdcn-eng.html.

Alberta and British Columbia have been leading the Canadian natural gas renaissance since 2013, supported by their vast reserves of tight and shale gas.

However, the current low price environment could hinder any substantial investment in Canadian upstream projects without the prospect of having access to more lucrative export markets. In 2018 natural gas prices averaged USD 1.2 MBtu in Alberta's AECO trading hub, reaching their lowest level since at least the beginning of the current century. In January 2019 it was reported that some producers have shut in natural gas wells because of low prices (KallanishEnergy, 2019).

The development of the Shell-led LNG Canada export project, which took FID in October 2018, will bring online some 14 million tonnes per annum (Mtpa) of liquefaction capacity by 2025. Feed gas for the liquefaction plant will be supplied from the respective upstream assets of the project companies, as well as from procurement on the open market. Other potential LNG projects on the Canadian and US west coast could offer additional export outlets in the medium term.

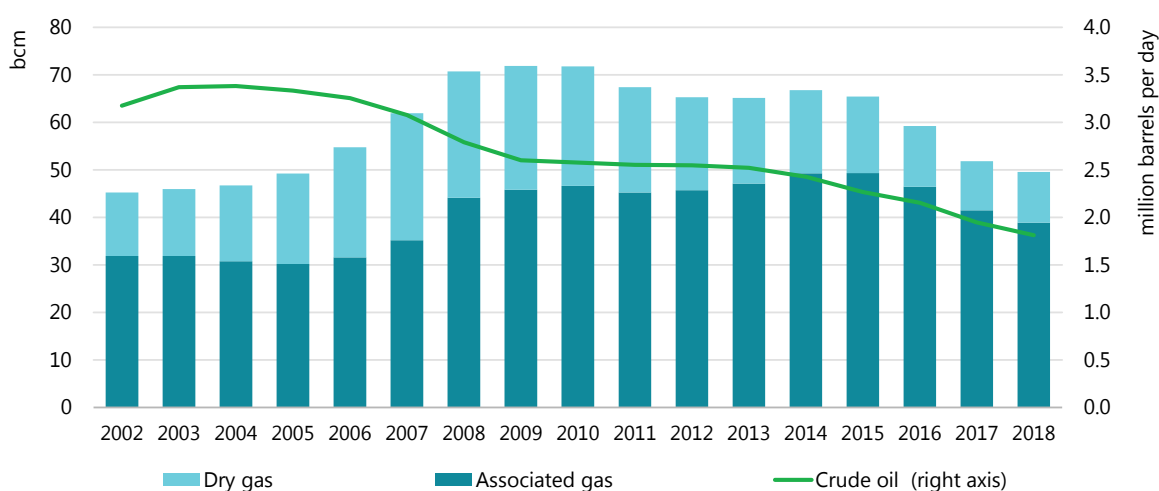
However, these projects, if sanctioned, would begin commercial operations after 2024 and thus their impact on Canadian production would extend beyond the scope of this forecast. Further

developments, mainly from 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 domestic natural gas production reached a peak in 2010 (Figure 2.8) and then started to decline at an average annual rate of 2.2% until 2018. In 2018 gross production reached 49.6 bcm, with 78.5% in the form of associated gas. Crude oil production has also been declining, at an average annual rate of 4% since 2003. Of the associated gas, 75% comes from offshore regions, 20% from the Southern onshore region and 5% from the Northern region. During the first quarter of 2019 production decreased by 3% y-o-y, with associated gas volumes remaining flat and an 11.7% decrease in non-associated gas.

Figure 2.8 Gross natural gas and crude oil production, Mexico, 2002–18



Sources: SIE (2019), *Estadísticas Energéticas Nacionales* [National Energy Statistics], <http://sie.energia.gob.mx/bdiController.do?action=cuadro&subAction=applyOptions>; PEMEX (2019), *Estadísticas petroleras febrero de 2019* [Oil statistics for February 2019], www.pemex.com/ri/Publicaciones/Paginas/IndicadoresPetroleros.aspx.

Mexico's natural gas production decreased by 4% in 2018, driven by the falling associated production from oil fields.

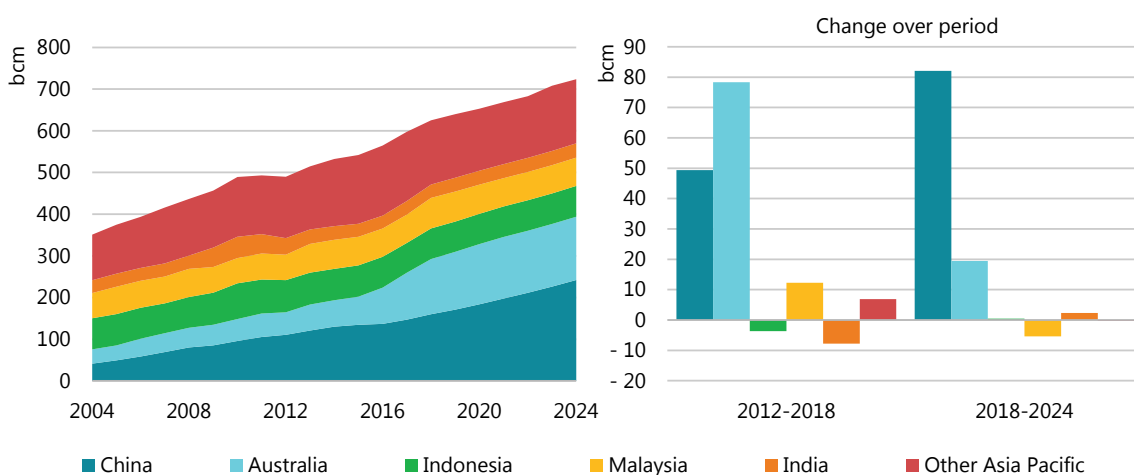
Domestic oil production is expected to fall until 2020 and then stabilise in the medium term (IEA, 2019a). The new government increased PEMEX's upstream budget by 24.5% in 2019 to reach MXN 25 billion (Mexican peso, or USD 1.3 billion),³ while the country shifts its focus to short-cycle shallow-water and onshore projects. Although this shift and higher budget could provide some stimulus, the growth is not expected to be enough to exceed the decrease from mature fields. Associated gas production is expected to follow a similar trend. In December 2018 the new Mexican administration declared a three-year suspension of new oil and gas auctions, cancelling *de facto* the February 2019 round that included 37 conventional and 9 shale blocks (Mexican Government, 2018; Financial Times, 2018; Reuters, 2018a).

³ Using the average 2018 rate of USD 1 = MXN 19.22.

Asia Pacific

Natural gas production in the Asia Pacific region is expected to increase by almost 100 bcm/y to 2024, an annual average growth rate of 2.5%. China and Australia are expected to represent around 55% of the region's total production by 2024 and almost all of the incremental production over the forecast period (Figure 2.9).

Figure 2.9 Natural gas production, Asia Pacific, 2004–24



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China and Australia drive natural gas production growth in the Asia Pacific region.

China

China's natural gas production increased from 135 bcm in 2015 to 137 bcm in 2016, 147 bcm in 2017 and 160 bcm in 2018. Since 2016, production has been driven by the 13th Five-Year Plan (FYP) objective of reaching 170 bcm/y of conventional gas, 30 bcm/y of shale gas and 16 bcm/y of coalbed methane (CBM) by 2020. However, in 2018, China's national oil companies (NOCs) made additional efforts to increase their production in order to reduce the country's dependency on imports. This followed President Xi Jinping urging them in August 2018 to improve national security by boosting domestic production and reserves, in the aftermath of the supply shortages experienced during the winter of 2017/18.

These efforts have led to a rebound in investment in natural gas production and supply, which grew by 5% and 6% in 2017 and 2018 respectively. Data show that during January and February 2019 investment increased by almost 30% compared to the same period of 2018, reaching CNY 14 billion (Chinese yuan renminbi, or USD 2.1 billion) (Figure 2.10).⁴

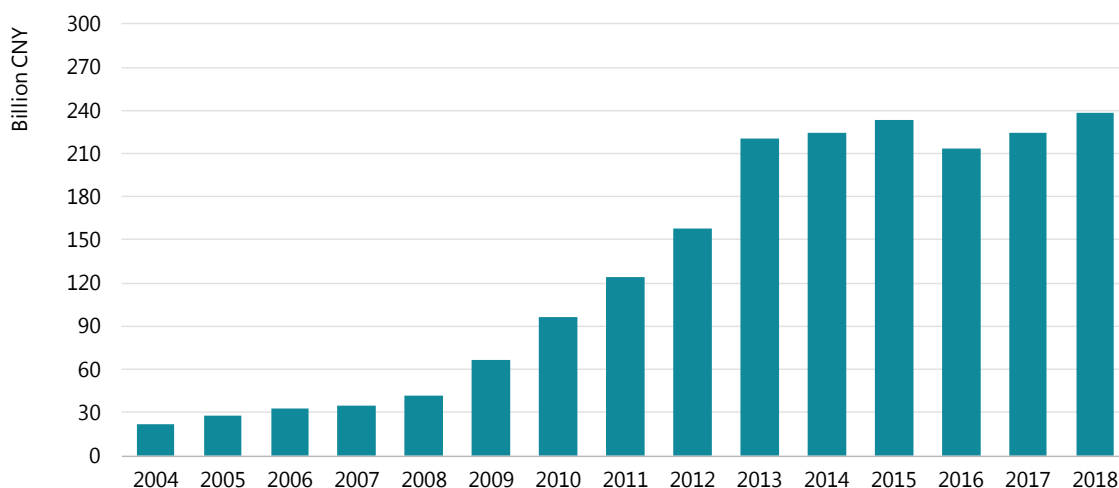
In February 2017 the National Energy Administration (NEA) published the *2017 Energy Work Guidance*, which set a target for annual natural gas production of around 170 bcm, including 10 bcm of shale gas (CEC, 2017), while effective production reached 147 bcm in 2017.

⁴ Using the average 2018 rate of USD 1 = CNY 6.64.

In 2018 China National Petroleum Corporation (CNPC) accounted for almost 68% of total production, or 109.4 bcm, representing a 5.9% increase y-o-y, including 4.27 bcm of shale gas with 41.2% y-o-y growth. South Sichuan became the largest shale gas production base in China, with an output of over 7 bcm/y (CNPC, 2019).

Sinopec produced 27.6 bcm in 2018, or a 7.08% y-o-y increase (Sinopec, 2019). The company's major breakthrough has been in the first large-scale shale gas field in China, the Fuling shale gas field, where the number of productive wells increased by 38% in 2018 reaching an annual output of 10 bcm.

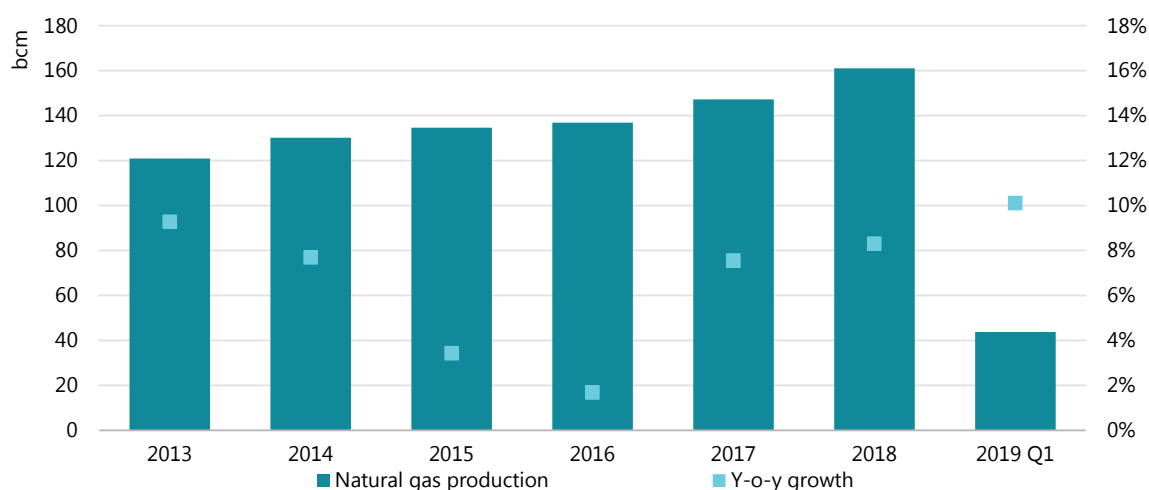
Figure 2.10 New investment in natural gas production, China, 2004–18



Source: NBS (2019), National Data, <http://data.stats.gov.cn/easyquery.htm?cn=A01>.

In 2018 investment in production reached CNY 238.5 billion (USD 35.9 billion), its historical maximum.

Figure 2.11 Natural gas production, China, 2013–18



Source: NBS (2019), National Data, <http://data.stats.gov.cn/easyquery.htm?cn=A01>.

In 2018 China's natural gas production increased by 8.3%, its highest growth rate since 2013.

As for China National Offshore Oil Corporation (CNOOC), the company produced 8.5 bcm in 2018, or a 15% y-o-y increase. The biggest growth came from the Eastern South China Sea, where the company produced 3.6 bcm, a 45% y-o-y increase, and in the Bohai Bay, with 1.7 bcm and a 10% increase. In its two other regions, the Western South China Sea (2.7 bcm) and the East China Sea (0.6 bcm), CNOOC's production decreased by 3% and 11% respectively (CNOOC, 2019a).

The three provinces of Shaanxi, Sichuan and Xinjiang were responsible for 73% of total natural gas production in 2018 (Table 2.2).

Table 2.2. Major basins and natural gas production by locality, China, 2018

	Production in bcm
Shaanxi Province	44
Sichuan Province	41
Xinjiang Region	33
Guangdong Province	10
Qinghai Province	6
Chongqing City	6
Shanxi Province	5
Heilongjiang Province	4
Tianjin City	3
Guilin Province	2
Beijing City	2
Others	4
TOTAL	160

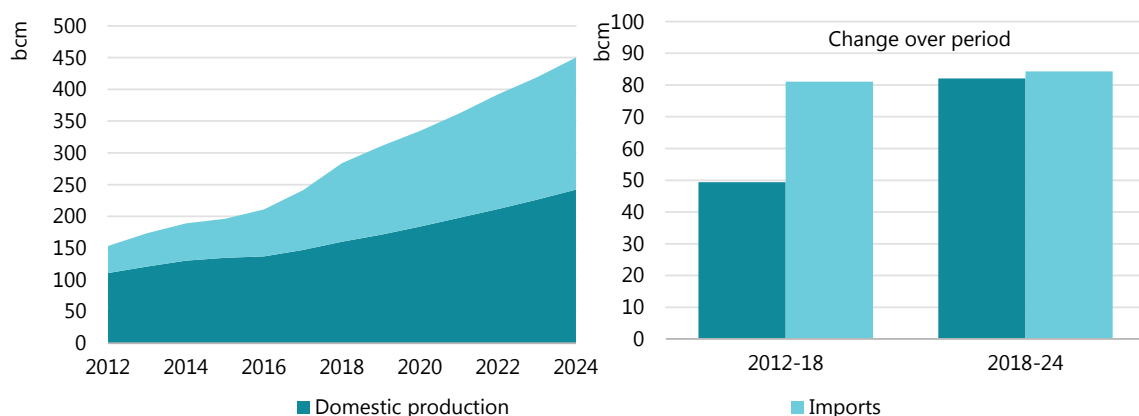
Source: NBS (2019), *National Data*, <http://data.stats.gov.cn/easyquery.htm?cn=A01>.

For 2019 this forecast expects production to total 171 bcm, representing 6.9% y-o-y growth. CNPC is planning a fivefold increase in capital expenditure from CNY 1 billion to CNY 5 billion (USD 0.15 billion to USD 0.75 billion) between 2018 and 2019. CNOOC plans to invest CNY 12 billion (USD 1.8 billion) in exploration and drilling domestically, doubling its investment from 2017 levels. Sinopec plans to invest CNY 59.6 billion (USD 8.98 billion) in exploration and production. For gas, the company will focus on the Fuling and Weirong shale gas fields, as well as the construction of gas pipelines and storage.

China is expected to produce 242 bcm/y of natural gas by 2024, with an average annual growth rate of 7.1% throughout the forecast period (Figure 2.12).

This report forecasts annual average growth of 6% for conventional natural gas production, from an estimated 136 bcm in 2018 to over 192 bcm in 2024, or an increment of 56 bcm. Unconventional gas is expected to add 26 bcm of annual production during the forecast period, to reach a volume of almost 50 bcm by 2024, with average annual growth of 13%.

Figure 2.12 Natural gas supply, China, 2012–24



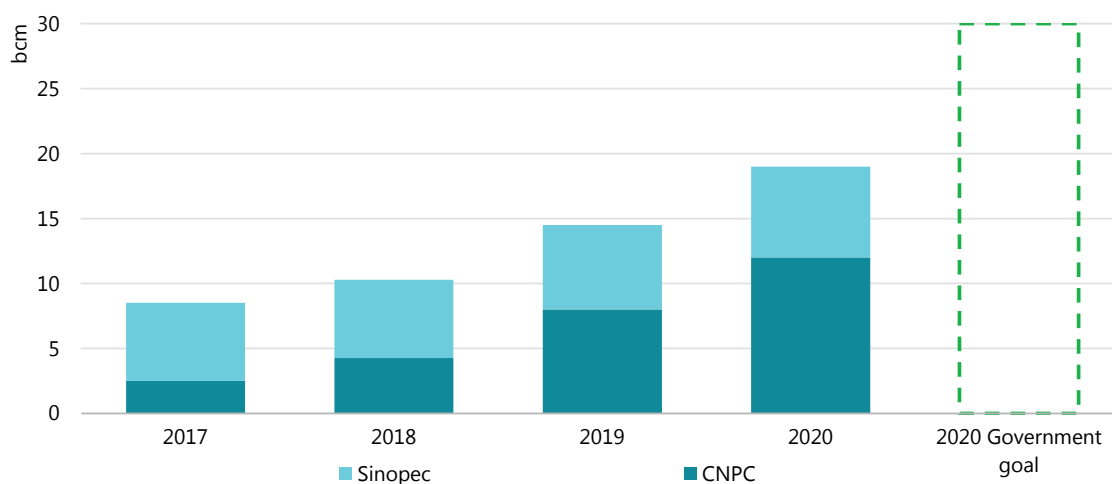
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Domestic production is expected to grow more strongly during the forecast period thanks to investment by Chinese NOCs in exploration, production and infrastructure.

Unconventional gas

Shale production continued to rise in 2018, with a 14% y-o-y increase to reach 10.3 bcm. Both CNPC and Sinopec have announced their production targets to 2020, which when combined amount to 19 bcm/y or almost double the 2018 level. This, however, remains below the 30 bcm/y target set in the 2016–20 shale gas development plan (Figure 2.13). This report forecasts the 30 bcm/y goal to be reached between 2023 and 2024. In order to incentivise investment in exploration and production, central government has approved a cut in the resources tax on shale gas from 6% to 4.2% from 1 April 2018 to 31 March 2021 (Argus, 2019a).

Figure 2.13 Shale gas production, China, 2017–20



Source: Data sources from CNPC (2019), *2019 Working Meeting*, <http://news.cnpc.com.cn/system/2019/01/19/001717652.shtml>; and Sinopec (2019), *Annual Report 2018*, www.sinopec.com/listco/en/Resource/Pdf/201903240301.pdf; data for Sinopec for 2019 are estimated.

By 2020 Sinopec and CNPC forecast shale gas production of 19 bcm/y, almost double the 2018 level yet below the 30 bcm/y target set by the 13th FYP.

China plans to build two large CBM production bases, one in the Qinshui Basin and another in the Ordos Basin, both in Shanxi province. Each has a recoverable reserve of 1 tcm, according to the Shanxi Provincial Development and Reform Commission. By 2020 the country plans to produce 24 bcm/y of gas from its CBM production bases, of which 20 bcm/y will come from Shanxi. The province expects by 2020 to be able to send 6 bcm/y to other parts of the country using pipelines (Xinhua Net, 2018). Coalbed methane production reached 7.62 bcm in 2018, with a 4.2% increase (NBS, 2019).

Regarding tight gas, which accounted for 30% of total gas production in 2018, reserves are concentrated in the Sichuan and Ordos basins. According to CNPC's *2019–2025 Domestic Exploration and Production Plan*, the company is looking to reach output of 32 bcm/y by 2020 and 35 bcm/y by 2025 (Youlong, 2019). In December 2018 CNPC and Shell started the second phase of development at the Changbei tight gas block, in northwest China's Ordos Basin in Shanxi, with expected production of 0.5 bcm in 2019 reaching to over 2 bcm/y by 2024. FID was taken in March 2018. By the end of 2024 CNPC aims to produce 3.64 bcm/y from the two phases of the Changbei block (Argus, 2018). Sinopec is also looking to develop tight gas production at the Daniudi tight gas field in the Ordos Basin.

Developing the network to reduce internal supply bottlenecks

The National Development and Reform Commission (NDRC) issued in February 2018 a notice to accelerate the interconnection of natural gas infrastructure, in order to improve the prevailing lack of connection between the north and the south of the country and to avoid any further supply shortages during the 2018/19 winter. The notice highlighted "10+1 key projects" (divided into 27 smaller projects) that included new pipelines and compressor stations. The goal was to increase supply capacity to Beijing, Tianjin, Hebei and the surrounding areas. The different projects, distributed along the provinces of Guangdong, Hunan, Ningxia, Jiangsu, Jiangxi and Anhui, sought to connect import facilities such as the Guangxi LNG Terminal (Sinopec) with the China–Myanmar pipeline (CNPC) or improve the connection with storage facilities, such as between the Dalian LNG terminal (CNPC) with the Shuang 6 underground gas storage (UGS) plant (CNPC) (Wall Street China, 2018) (CNPC, 2018a).

On their side, state-owned companies have also been working to increase internal capacity:

- At the end of 2017 CNOOC started to inject natural gas from its LNG terminals (Zhuhai and Diefu) and its South China Sea production plant in Guangdong into CNPC's West–East pipeline, supplying natural gas to the north of Guangdong, so that CNPC can allocate these volumes to northern regions. This connection already has a capacity of 30 million cubic metres per day (mcm/d) (or 10.95 bcm/y). CNOOC auctioned imported volumes on the Shanghai Petroleum and Gas Exchange to be transported through CNPC's pipeline network.
- CNPC committed to invest more than CNY 25.8 billion (USD 3.89 billion) to implement 33 interconnection projects starting in 2018/19, in order to optimise the pipeline system (national and regional) and solve the bottleneck problems. CNPC has been working with CNOOC to connect the Guangdong LNG terminal to the West–East pipeline (CNPC, 2018b; 2018c).
- Sinopec successfully connected a feeder line to CNPC's China–Myanmar gas pipeline in September 2018, allowing the company to inject 55 mcm/d of gas into the pipe, helping boost supplies to the northern regions of China (Sinopec, 2018). Sinopec is looking to connect its Shaanxi–Beijing line to CNPC's Power of Siberia pipeline. Additionally, in November 2018 the company started operating the first phase of the Erdos–Anping–

Cangzhou pipeline of 700 kilometres. The pipeline will use the Tianjin LNG terminal as its gas source, alleviating winter supply shortages in Hebei and Henan provinces.

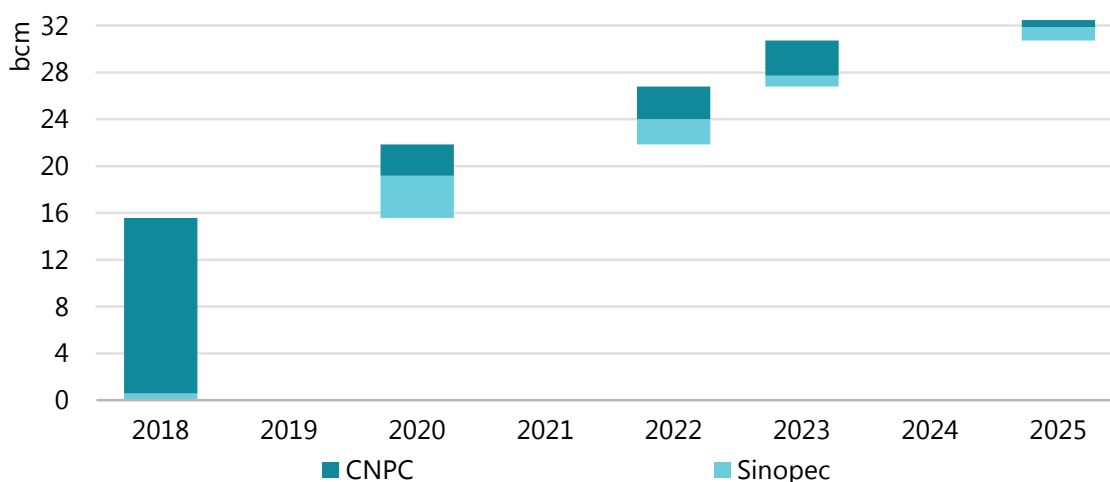
Such investments in the domestic pipeline network are expected to continue and thus help to alleviate network bottlenecks and improve internal transport capacity during the forecast period.

Increasing UGS capacity to develop seasonal flexibility

China is also boosting its UGS capacity in order to increase the supply of seasonal flexibility for winter demand. Sinopec has two UGS facilities, Wen 96 located in Zhongyuan in Henan province, and Jintan in Jiangsu province. Sinopec is due to start operations of the Wen 23 UGS by 2020, becoming the company's third and largest gas storage site. Located in the Zhongyuan field, the UGS has a design capacity of 10.43 bcm and nameplate working capacity of 4.47 bcm (of which 8.43 bcm and 3.27 bcm respectively are for the first phase). This site will store natural gas from Sinopec's terminal in Tianjin, and hopes to be able to inject at least 2 bcm in 2019.

Sinopec has plans to add 5.6 bcm of additional storage capacity at the Zhongyuan field in Puyang in Henan province. Additionally, the company announced its plan to develop three new UGS facilities (Huangchang, Zhongyuan Wei 11 and Zhujiadun) and expand its Jintan facility, reaching 14.6 bcm of UGS capacity by 2024. CNPC runs 23 UGS facilities with a total working capacity of 16.4 bcm (and a maximum of 17.5bcm), and is expected to reach 23.5 bcm of total working capacity by 2024 (Figure 2.14).

Figure 2.14 UGS working capacity, China, 2018–25



Source: Created using data sources from Argus: Chinese Underground gas storage projects, <https://direct.argusmedia.com/search/search?keywords=china§ion=FundamentalsAndDownloads&orderby=date> (subscription required).

About 17 bcm of new UGS capacity is expected to be commissioned by 2025, resulting in a doubling of working gas capacity over the next six years.

At a provincial level, governments are also seeking to boost their local storage. Yunnan province is looking to add another 1.5 bcm of gas storage capacity by 2025 to meet increasing demand, from the current 0.0139 bcm – equivalent to just 0.9% of 2018 gas demand in that province, which was 1.545 bcm. Demand is expected to reach 3.2 bcm and 4 bcm in 2020 and 2025 respectively. The local firm Yunnan Natural Gas plans to invest around CNY 2.8 billion

(USD 0.42 billion) to build a UGS at a salt mine, with a nameplate capacity of 150 million cubic metres (mcm) to be operational by 2021, reaching 850 mcm after a second phase in 2025 (Argus, 2019b).

In Sichuan natural gas accounts for over 12% of the province's primary energy consumption, when the national average is around 7% (2017). The province has gas storage of 0.1 bcm with good conditions for UGS (the depleted Wixi Yantian Salt Cave, for example), or the possibility to turn its LNG plant tanks into LNG storage tanks. The Sichuan Development and Reform Commission issued its gas storage facility construction plan in September 2018, with a goal to triple natural gas storage capacity by 2035 from 0.8 bcm to 2.3 bcm (Table 2.3).

Table 2.3. Natural gas production, demand and storage planning, Sichuan province, 2020–35

	2020	2025	2030	2035
CNPC Southwest	27.5	44	52.5	63
Sinopec Southwest	5.5	12	20.5	20
Sinopec Puguang	9	9	7	7
Total production	43	65	80	90
Total demand	26	31	36	40
Total gas storage capacity	0.8	1.1	2	2.3
of which gas	0.65	0.9	1.8	2.1
of which LNG	0.15	0.2	0.2	0.2

Note: Values in bcm.

Source: Sichuan DRC (2018), *Gas Storage Facilities Construction Plan*, http://fgw.sc.gov.cn/sfgw/yqkf/2018-09/11/content_185194df23ce43e5b4061of39ec63cb2.shtml.

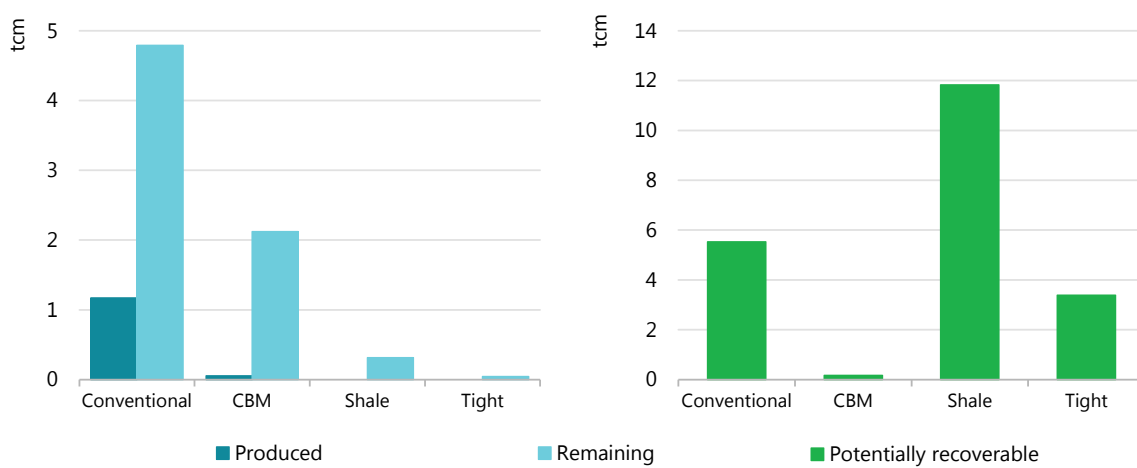
Australia

Australian natural gas production has been increasing at an annual average rate of 16% since 2012. The country's natural gas production activity is driven by LNG project ramp-up and operations. The recent addition of large LNG export projects drove Australian natural gas production to reach 132 bcm in 2018. This forecast expects an average growth rate of 2.3% per year, to reach 152 bcm by 2024.

According to the government's resource assessment, Australia has nearly 5 tcm of remaining recoverable conventional natural gas, and around 2 tcm of CBM) (Figure 2.15) (Geoscience Australia, 2019). In order to ensure the long-term supply of both the domestic market and LNG export contracts, government authorities at both the federal and state levels are encouraging the continuous investment and development of natural gas. The Queensland government granted a licence to infrastructure operator Jemena in February 2019 to build the Atlas Gas Pipeline Project, which will connect the Atlas production developments to the Wallumbilla gas hub. It is expected to start operations in 2019. ExxonMobil and BHP took FID in December 2018 to develop the West Barracouta offshore field in Victoria, with the first gas expected in 2021, to supply the Australian east coast domestic market. Moreover, in 2018 the Australian government awarded seven offshore exploration permits off the coasts of Western Australia and Victoria, anticipating further development in the area.

The government is also moving forward to develop prospective shale gas potential. According to the *Australian Energy Resources Assessment*, the potentially recoverable shale gas resources are estimated at 12 tcm out of a total of 250 tcm of prospective shale gas resources (Figure 2.15). The largest shale gas deposit is located in the Canning basin in Western Australia, along with other smaller formations in Queensland, South Australia and the Northern Territory. The Northern Territory lifted its moratorium on fracturing in April 2018, and some first drilling is currently targeted for 2019. The Government of Western Australia also lifted its moratorium on hydraulic fracturing in November 2018, but limited activity to existing petroleum titles – accounting for only 2% of Western Australia’s territory.

Figure 2.15 Natural gas produced, remaining and potentially recoverable, Australia



Note: Produced and remaining gas as of 2014.

Source: Geoscience Australia (2019), *Australian Energy Resources Assessment*, <https://aera.ga.gov.au/>.

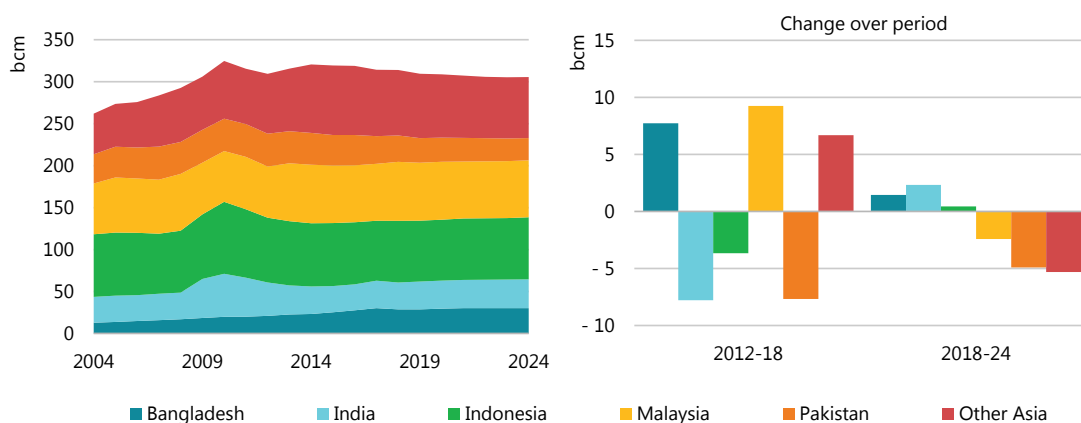
The country has a strong remaining conventional resource base and prospective shale gas potential for a supply source in the longer term.

To further encourage the natural resource sector to adopt a longer-term policy approach, the Australian government released the *National Resources Statement* in February 2019 (DIIS, 2019). The statement includes a goal to develop new resources, industries and markets and remove barriers, and also to attract investment by delivering a globally attractive and competitive investment destination for resources projects.

Other emerging Asian economies

Despite the strong demand growth forecast in the other emerging Asian economies (see Chapter 1), domestic natural gas production in this region is anticipated to plateau at 310 bcm/y during the forecast period (Figure 2.16).

Figure 2.16 Natural gas production by country, other emerging Asian economies, 2004–24



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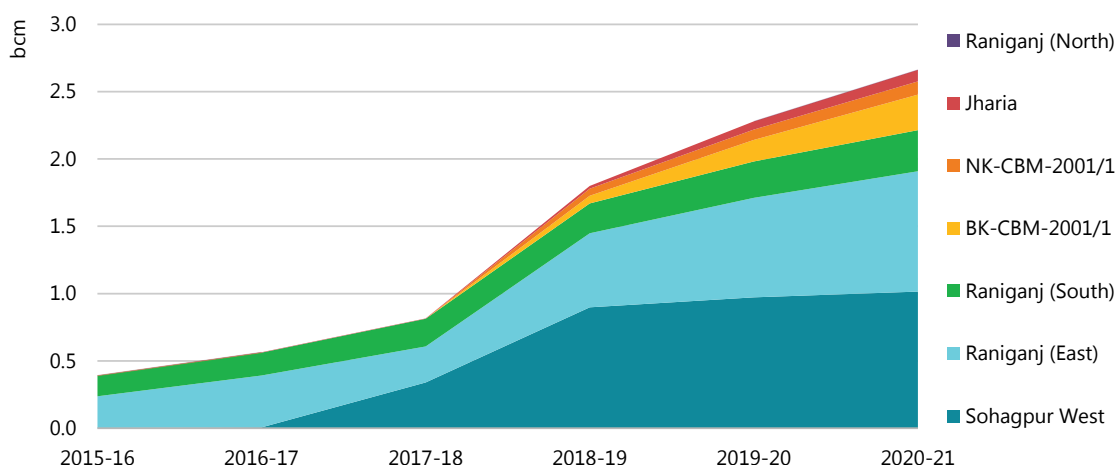
Regional natural gas production slightly declines over the forecast period.

India

India recorded its first gas production increase in seven years in fiscal year 2017/18, from 31 bcm/y to 32.7 bcm/y, or an increase of about 6%. The previous decline in production was mainly related to the stalled activities in the offshore blocks of the KG-D6 field off India’s east coast, together with lack of new investment. Since the government’s initiative to develop the hydrocarbon sector, which targets the reduction of dependency on oil and gas imports by 10% by 2022, the implementation of some of its policies has already materialised.

India’s production recovery results from new investment in onshore capacity, including CBM production. Production from three of India’s seven CBM blocks has increased, in total from 0.57 bcm in fiscal year 2016/17 to 0.81 bcm in fiscal year 2017/18, or a 45% increase (Figure 2.17). Due to the slow installation of gas gathering stations, the projected production increase is limited to those three fields – Sohagpur West, Raniganj (East) and Raniganj (South).

Figure 2.17 CBM production by block, actual and government projection, India, 2016–21



Notes: Production figures provided in fiscal years. Projection starts from fiscal year 2018/19.

Source: Standing Committee on Petroleum & Natural Gas (2018), “Ministry of Petroleum & Natural Gas Twenty Fifth Report”, http://164.100.47.193/lsscommittee/Petroleum%20&%20Natural%20Gas/16_Petroleum_And_Natural_Gas_25.pdf.

Domestic CBM production is projected to reach 2.7 bcm by fiscal year 2020/21.

The majority of natural gas exploration and production activity is done by state-owned companies (known as public sector undertakings or PSUs) – namely Oil and Natural Gas Corporation (ONGC) and Oil India (OIL). Private and foreign players entered Indian exploration and production in the late 1990s under the NELP (New Exploration Licensing Policy) framework.

According to the Ministry of Petroleum and Natural Gas, the balance of recoverable conventional natural gas reserves as of 1 April 2018 amounted to 1 340 bcm, of which 61% are located offshore. Reserves under the production-sharing contract (PSC) regime account for 49% of the total, whereas ONGC and OIL account for a respective 42% and 9%. As for unconventional resources, recoverable CBM reserves are estimated at 108 bcm, while different estimates for shale gas resources range from 45 to 2 100 trillion cubic feet (or 1.3–59 tcm).

For fiscal year 2017/18, ONGC and OIL accounted respectively for 71% and 9% of total natural gas production, the remaining 20% being produced under the PSC regime. Over two-thirds (67%) of natural gas production came from offshore fields, and in particular from the Mumbai Basin where the ONGC-operated Bassein and Mumbai High fields accounted for 33% and 16% of total production respectively.

Greater flexibility in the production pricing regime was introduced gradually to further incentivise investment: pricing freedom was introduced in 2016 subject to a ceiling for production from discoveries in deepwater, ultra-deepwater and high-pressure high-temperature fields. In February 2019 the government granted marketing and pricing freedom to all new natural gas discoveries whose field development plans had yet to be approved (see Chapter 4).

The Ministry of Petroleum and Natural Gas shared its latest outlook on domestic production during the July 2018 session of the Parliamentary Standing Committee on Petroleum and Natural Gas. It forecasts a doubling⁵ of production by fiscal year 2021/22 and significant changes in the production mix, as private producers under the PSC regime are expected to quadruple their output.

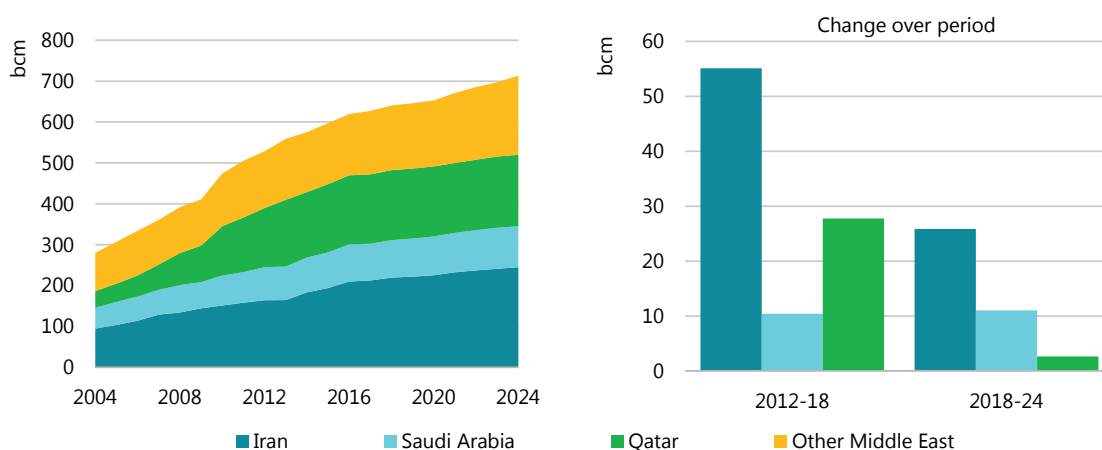
Indonesia

Indonesian gas production is expected to slightly increase during the forecast period. Pertamina, the state-owned oil and natural gas corporation, is seeking approval from the government for its plan to increase upstream spending by as much as 25% or a maximum of USD 3 billion, to boost exploration activities. Repsol announced in February 2019 the largest gas find in Indonesia since 2001 in South Sumatra, with a preliminary estimate of at least 2 trillion cubic feet (about 58 bcm) of recoverable resources. Further drilling and seismic campaigns are planned in 2019–20.

Middle East

Natural gas production in the Middle East is expected to grow at an average 1.8% per annum up to 2024. Driven predominantly by Iran and Saudi Arabia, total production is expected to surpass 700 bcm/y at the end of the forecast period (Figure 2.18). This forecast does not include a 45 bcm/y upside potential if Qatar pushes through an increase in North Field production and the development of additional liquefaction capacity, as no FID has been taken at the time of writing.

⁵ This forecast assumes a more conservative view with a 6% increase in production to 2024.

Figure 2.18 Natural gas production, Middle East, 2004–24

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Iran and Saudi Arabia drive Middle Eastern gas production, together accounting for over half the additional gas supply in the region through the forecast period.

Iran

Iranian natural gas production is expected to grow at an annual average rate of 1.8% over the forecast period. Most of the additional volumes are expected to meet domestic demand requirements, as Iran's natural gas consumption is growing, primarily driven by industry and power generation. Preliminary data suggest that Iranian gas production rose by approximately 3% in 2018 with the development of the South Pars field. According to the Ministry of Energy, the supergiant field accounted for over 70% of total gas volumes produced in the first 10 months of the fiscal year 2018/19 (March 2018–January 2019) (Reuters, 2019a), up from an estimated 40% in 2012.

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 by 2021. Foreign investment contracts were awarded to Total and CNPC (USD 5 billion divided into 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. However, with the re-introduction of US sanctions against Iran in 2018, Total left the project in August (Reuters, 2018b) and CNPC has allegedly halted its investment in November 2018 (Chen, 2018).

Iran nevertheless continued the development of South Pars in 2018, with the installation of a second offshore platform at the field's Phase 14, increasing its production capacity by an additional 14 mcm/d (or 5 bcm/y) (Financial Tribune, 2018). In March 2019 four new phases of South Pars (13, 22, 23 and 24) were inaugurated. Total investment made in these megaprojects is estimated at about USD 11 billion and will add production capacity of 110 mcm/d (or 40 bcm/y) (Reuters, 2019b). In the medium term, South Pars is expected to remain the backbone of Iranian gas supply, with the Ministry of Energy foreseeing additional growth of 25% in its output by the end of 2020/21 financial year (Financial Tribune, 2019).

Qatar

Qatar remained the global number one LNG exporter in 2018 at 105 bcm – almost one-quarter of global LNG production.

Despite diplomatic tensions with some of its neighbours, Qatar's natural gas production and exports to neighbouring United Arab Emirates and Oman continued in 2018 at similar levels to previous years. In September 2018 the CEO of Qatar Petroleum reiterated the company's intention to continue to supply the United Arab Emirates with gas via the Dolphin pipeline in the medium term, given that the contract expires only in 2032 (Middle East Monitor, 2018).

At the beginning of December 2018 Qatar announced its intention to leave the Organization of the Petroleum Exporting Countries (OPEC) to focus on the development of its gas industry (Knecht, 2018). Indeed, in April 2017 Qatar lifted its self-imposed moratorium on the North Field development and in July Qatar Petroleum announced that the country's LNG production capacity would increase by 30% from 77 Mtpa to 100 Mtpa by 2024. The expansion plan was revised upwards in September 2018 to 110 Mtpa. According to Qatar Petroleum, four new liquefaction trains will produce 32 Mtpa of LNG, 1.46 Mtpa of ethane, 95 million barrels per year of condensate, 4 Mtpa of LPG, and 7 300 tonnes of pure helium per year. In February 2019 Qatar Petroleum's CEO confirmed that Qatar is in advanced negotiations to order between 50 and 60 new LNG carriers with an additional transport capacity of almost 50 Mtpa (WMN, 2019).

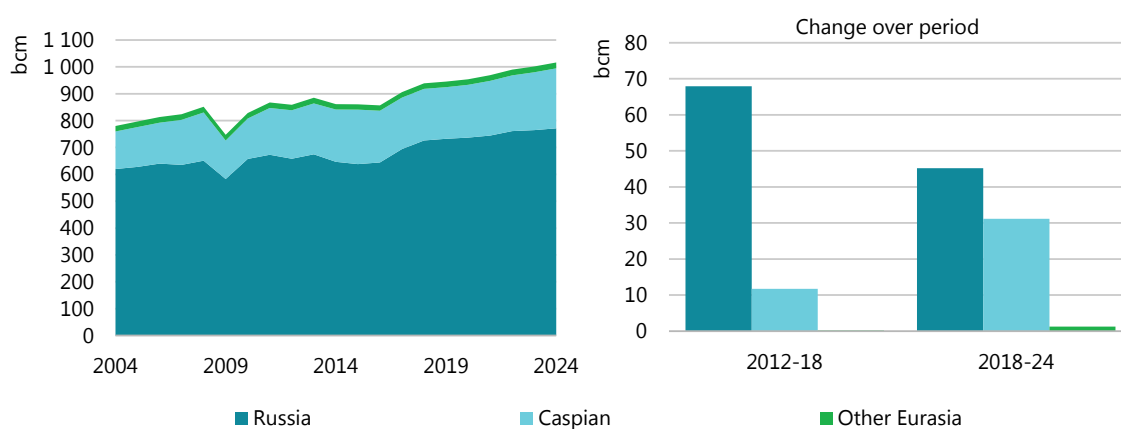
Saudi Arabia

Saudi Arabia produced over 90 bcm of natural gas in 2018. Production is expected to grow at an annual rate of almost 2% through the forecast period to reach 100 bcm/y by 2024. The Saudi Minister of Energy, Industry and Mineral Resources in November 2018 reiterated the country's target to double its natural gas production by 2030, with investments totalling about USD 150 billion over the next decade. This includes the development of the country's vast unconventional gas reserves (Saudi Aramco, 2018). However, the currently low domestic natural gas prices, regulated at a level of USD 1.25/MBtu, might hinder major investment in reserves with higher production costs over the medium term.

Eurasia

Natural gas production in Eurasia is expected to grow at an average rate of 1.3% per year over the forecast period, to reach over 1 tcm by 2024 (Figure 2.19). This increase is principally driven by Russian export prospects to China via pipeline and through the Yamal LNG project development.

Figure 2.19 Natural gas production, Eurasia, 2004–24



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Eurasian natural gas production continues to be driven by Russia, accounting for almost 60% of the incremental supply through the forecast period.

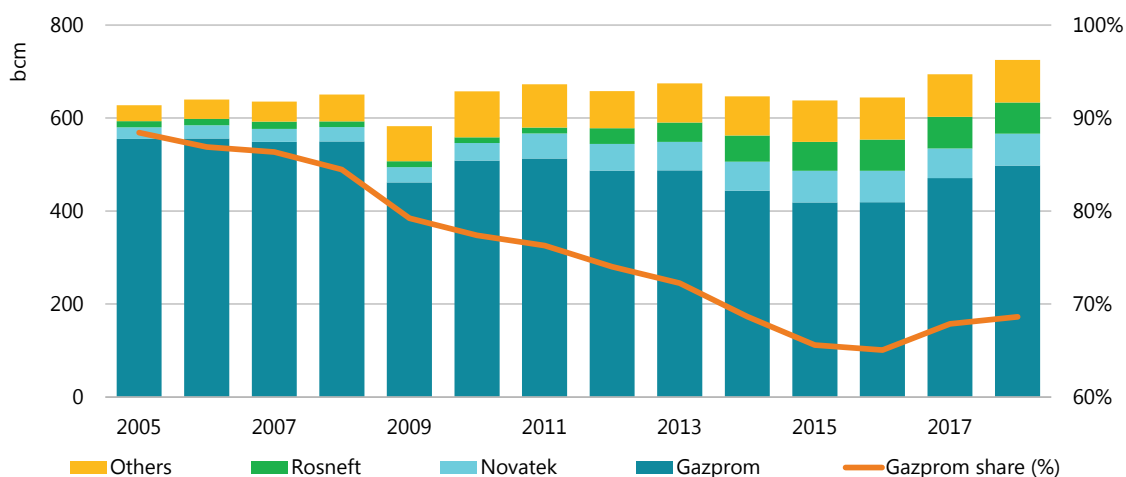
Russia

Russian natural gas production has risen strongly over the last three years, at an average annual rate of 4.4% (totalling almost 90 bcm/y of additional supply) from 638 bcm in 2015 to 725 bcm⁶ in 2018 – its highest level in 18 years (Minenergo, 2019). This has been driven by growing domestic consumption (up 5.3% in 2018) and by increasing exports (up 8.5% in 2018), both via pipelines and via LNG. The three trains of Yamal LNG, each 7.48 bcm/y, were commissioned during 2017 and 2018. A fourth, smaller train (1.22 bcm/y) is expected to be commissioned by the end of this year, bringing total Russian liquefaction capacity up to 37 bcm/y.

In the first quarter of 2019 Russian gas production increased by 3.3% to 197 bcm. Most of this was driven by Novatek, presumably amidst higher LNG exports from its Yamal LNG plant (FOMAG, 2019). Russian gas production is expected to grow at an average annual rate of 1% throughout the forecast period, driven by demand from export markets. Due to the decline in domestic consumption (see Chapter 1) natural gas exports are expected to grow at a faster rate than production, adding some 50 bcm/y to 2024.

Russian domestic natural gas production continues to be dominated by Gazprom. However, as shown in Figure 2.20, the company's share has declined from almost 90% in 2005 to 65% in 2016 as Novatek, Rosneft and other producers have been increasing their output. This trend has been reversed in the last two years and Gazprom's share is again on the rise. This can be explained with the increasing export volumes via pipeline – over which Gazprom holds a monopoly.

Figure 2.20 Russian natural gas production by company, 2005–18



Source: Compilation based on information from company reports, investor presentations and other information resources.

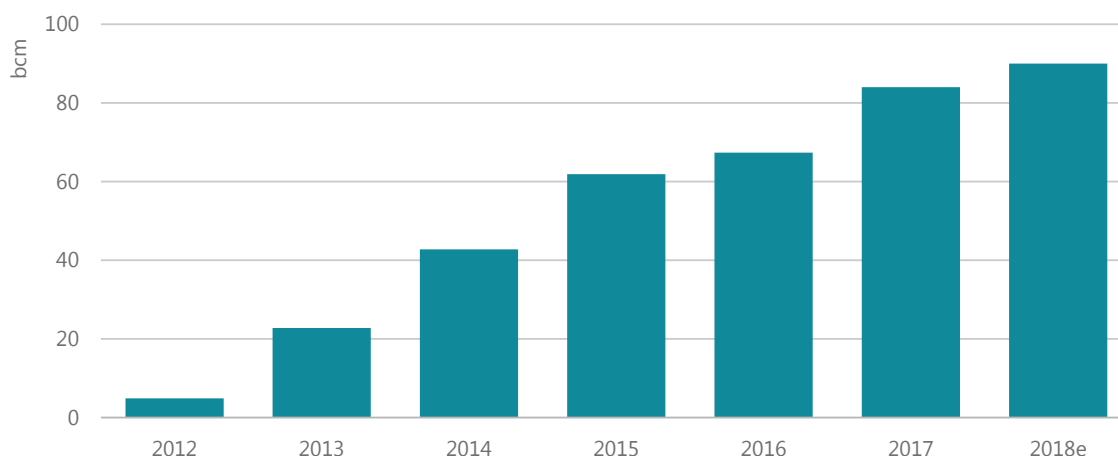
Gazprom's share of total Russian production has been rising again in the past two years, mainly driven by increasing exports via pipeline.

A second important change in Russian natural gas production is the gradual shift away from the Nadym-Pur-Taz (NPT) region, which traditionally accounted for the majority of Russian gas

⁶ Volumes expressed in Russian cubic metres (gross calorific value of 37.83 megajoules per cubic metre at 15°C); multiply by 0.92 to convert to European standard measure.

output. According to Gazprom, the cumulative depletion level of fields located in NPT will reduce their share of the company's production portfolio from 70% in 2018 to about 60% by 2024/25 (Gazprom, 2019a). Hence, most of the incremental gas supply is expected to come from new areas of production. Amongst them, Gazprom's giant Bovanenskoye field in the district of Yamalo-Nenets has been the largest source of production growth in recent years; commissioned in 2012, the field delivered 84 bcm in 2017 and an estimated 90 bcm in 2018 (Figure 2.21).

Figure 2.21 Production ramp-up of the Bovanenskoye field, 2012–18



Note: 2018 is an estimate.

Source: Gazprom annual reports and press releases.

The Bovanenskoye field has added 90 bcm of production capacity over the last 7 years – more than the total growth in Russian natural gas production over this period.

In December 2018 the third (and final) gas production facility at Bovanenskoye was commissioned, adding production capacity of 30 bcm/y. As a result, the field has reached its design production capacity of 115 bcm/y (Gazprom, 2019b) with production expected to gradually ramp-up to that level in 2019–20. 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 the end of 2019.

Table 2.4 provides a summary of field developments announced by major Russian gas producers.

Table 2.4. Selection of natural gas production projects, Russia

Plant	Project leader	Status	Plateau	Plateau capacity
Bovanenskoye	Gazprom	Producing	2020	115 bcm/y
Rospan	Rosneft	Producing	2019	19 bcm/y
Kharampur	Rosneft	Under development	2020 – commissioning	11 bcm/y
Sibnetfegaz fields	Rosneft	Under development	2022	16 bcm/y

Plant	Project leader	Status	Plateau	Plateau capacity
North-Russkoye	Novatek	Site preparation	2022/23	14 bcm/y
Kharasaveyskoye field	Gazprom	Under development	2023	32 bcm/y
Chayandinskoye	Gazprom	Under development	2024	25 bcm/y
Kovyktinskoye	Gazprom	Under development	2025	25 bcm/y

Source: Compilation based on information from company reports and investor presentations.

In spite of the strong production capacity development plans of Russian gas producers, this report forecasts an additional net need of 45 bcm of annual production from Russia (primarily driven by exports as domestic demand declines), equivalent to an average 1% annual growth rate for the next five years.

Azerbaijan

Azerbaijan's commercial natural gas production increased by 5.5% to 19 bcm in 2018 from 18 bcm in 2017, primarily driven by exports, which rose by around 10%. Preliminary data indicate that commercial gas output rose by 25.9% y-o-y in January/February 2019 (CaspianBarrel, 2019). This report expects Azeri gas production to increase at an average annual rate of 7.3% through the forecast period, primarily driven by higher exports to Europe.

One of the main natural gas-producing assets is the Shah Deniz field, whose current Phase I was commissioned in 2006 and which has a capacity of 10 bcm/y. Shah Deniz's Phase II expansion started operations in July 2018, with first commercial deliveries to Turkey resulting in a 15% (or 1 bcm) y-o-y increase in Azeri gas delivered to Turkey in 2018 (BP, 2018; IEA, 2019b). Shah Deniz Phase II will ramp up to its production capacity of 16 bcm/y by 2021/22, with approximately 6 bcm/y earmarked for Turkey via the Trans-Anatolian Pipeline (TANAP) (commissioned in June 2018) and further west to Europe via the Trans-Adriatic Pipeline (TAP) export system. According to the Italian *Proposal for an Integrated National Plan for Energy and Climate*, TAP will connect to the Italian grid by 2020 (Ministry of Economic Development, 2018). This forecast expects most of the additional Azeri gas supply to come from the ramp-up of Shah Deniz Phase II.

Future natural gas production prospects include the Umid field, discovered in 2010 with estimated reserves of 200 bcm of natural gas and 30 million tonnes of condensate. According to SOCAR, Azerbaijan's national oil company, Umid could produce between 2 bcm/y and 3 bcm/y once developed. Absheron, another discovery made in 2011, has reserves estimated at 320 bcm. Total, which has a stake of 50% in the field, said in September 2018 that production could start in the third quarter of 2020 with a volume of 1.5 bcm/y, to be ramped up to 4 bcm/y in the second stage (Azernews, 2018). Another promising area is the Shafag-Asiman field, which contains an estimated 1.2 tcm of gas and 240 million tonnes of condensate. BP and SOCAR could start first exploratory drillings in 2019; however, first gas production is not expected before 2030 (CaspianPolicy, 2019).

Other Caspian

Turkmenistan is set to remain the largest natural gas producer in the Caspian region, with an annual output of almost 70 bcm. Preliminary data suggest that domestic natural gas production

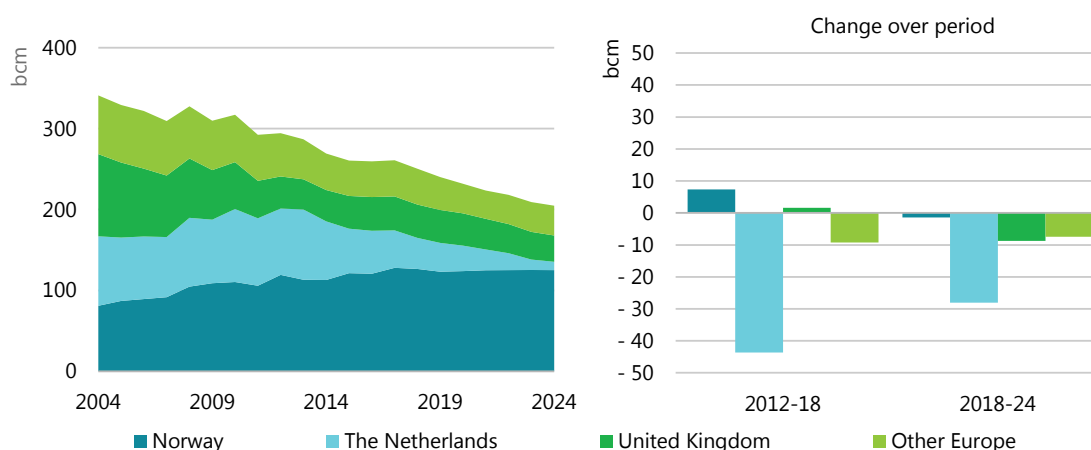
rose by 0.5% in 2018 (TurkmenNewsAgency, 2019). Turkmen gas production is expected to grow at an average annual rate of 4.9% through the forecast period, driven both by rising domestic consumption and by increasing exports. The Galkynish supergiant field remains the largest source of additional supply. In 2016 the Turkmen Oil and Gas Ministry stated that total output from the field could reach 95 bcm/y once all the three stages are developed (AzerNews, 2016).

Uzbekistan's gas production rose by 6% to 60 bcm in 2018. Production in January and February 2019 amounted to 10.05 bcm – an increase of 4.2% y-o-y (Kun, 2019). In the medium term, this forecast expects Uzbek gas output to remain stable as declining production from existing fields (e.g. the Shurtan field, which is 75% depleted) is compensated by the current ramping up of the Gissar and Kandym fields. In Kazakhstan, total natural gas production grew by 3.6% to a level of 54.8 bcm in 2018; however, about 40% of this gas is reinjected to increase oil output. Moreover, natural gas production is intimately linked to oil production in the form of associated petroleum gas. The ramp-up of the Kashagan giant field will continue to provide some support for additional gas production until the plateau is reached by 2020/21, after which Kazakh natural gas output is expected to stagnate.

Europe

Following a slight increase (0.7%) in 2017, European natural gas production declined in 2018 by 4.6% to 250 bcm. This was largely driven by falling output in the Netherlands (down 8 bcm/y), accounting for two-thirds of the total European production decrease last year. Natural gas production in Europe is expected to decrease at a rate of 3.5% per year through the forecast period, meaning that approximately 45 bcm of domestic gas supply will be lost. This is largely driven by the decision of the Dutch government to phase out the giant Groningen field by 2030 at the latest. As shown in Figure 2.22, the Netherlands accounts for over 60% of the decline in European natural gas supply over the forecast period.

Figure 2.22 Natural gas production, Europe, 2004–24



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European natural gas production continues to decline through the forecast period, at an annual rate of 3.5%, driven by the Groningen phase-out in the Netherlands and lower output from the North Sea.

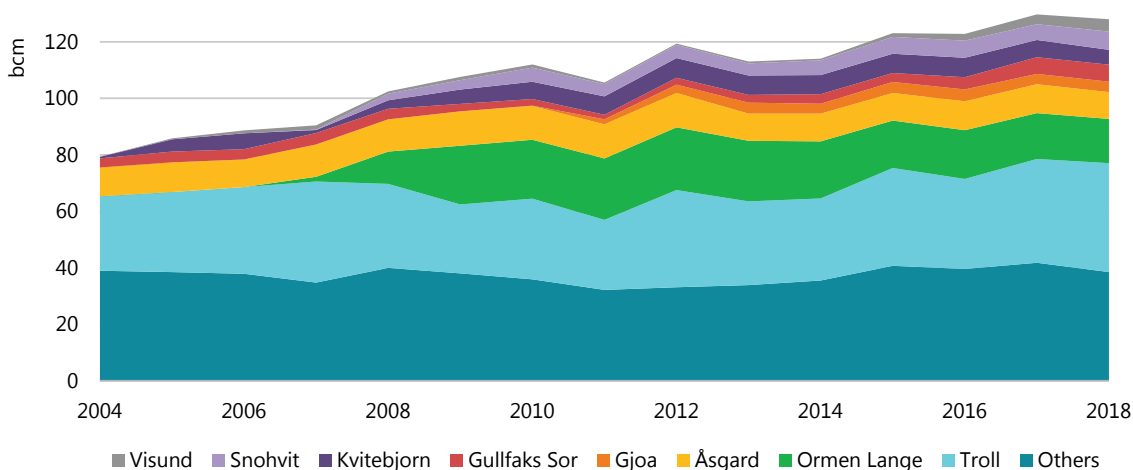
Falling UK production is the second source of European production decline (18% of the region's decrease between 2018 and 2024). Production in other European countries such as Denmark, Germany and Italy is also expected to decline, and to be counterbalanced by production increases in Romania towards the end of the outlook. Norwegian gas production, the largest contributor to European domestic supply, is expected to remain stable to 2024. Given that European natural gas demand is expected to remain stable throughout the forecast period, declining domestic supply will further increase European gas import needs. Another consequence is the loss of some flexibility and timeliness associated with domestic production, which will foster the importance of other sources of supply flexibility such as gas storage, interconnectors and demand-side response.

Norway

Norway accounts for just over half of total European natural gas production and its share is set to increase over the forecast period up to 62%. Norwegian gas output is expected to remain stable whilst gas production in other parts of Europe continues to decline. In 2017 Norwegian natural gas output reached an historical record of 128 bcm. Preliminary data suggest that Norwegian natural gas production decreased by about 1% in 2018 to 126.5 bcm. This figure includes gas used by the energy industry own use (mainly at the well level and on gas processing platforms). Hence, the saleable gas volumes are somewhat lower, amounting to 121.5 bcm last year.

As shown in Figure 2.23, Norwegian saleable natural gas production has risen by over 50% in the last 14 years from 80 bcm in 2004 to a peak of 124 bcm in 2017. Norway's two giant fields, Troll and Ormen Lange, together accounted for over 50% of the increase between 2004 and 2018. In the first quarter of 2019 Norwegian natural gas production remained stable, increasing slightly by 1% (NPD, 2019b).

Figure 2.23 Saleable gas production by major fields, Norway, 2004–18



Source: NPD (2019a), *Saleable Production Report*, <https://portal.diskos.cgg.com/prod-report-module/>.

Norwegian gas production has risen by 3.1% over the past 14 years, with half of the growth coming from two giant fields: Troll and Ormen Lange.

Norwegian natural gas production is set to remain stable through the forecast period. This forecast is aligned with the Norwegian Petroleum Directorate (NPD) projection as of January

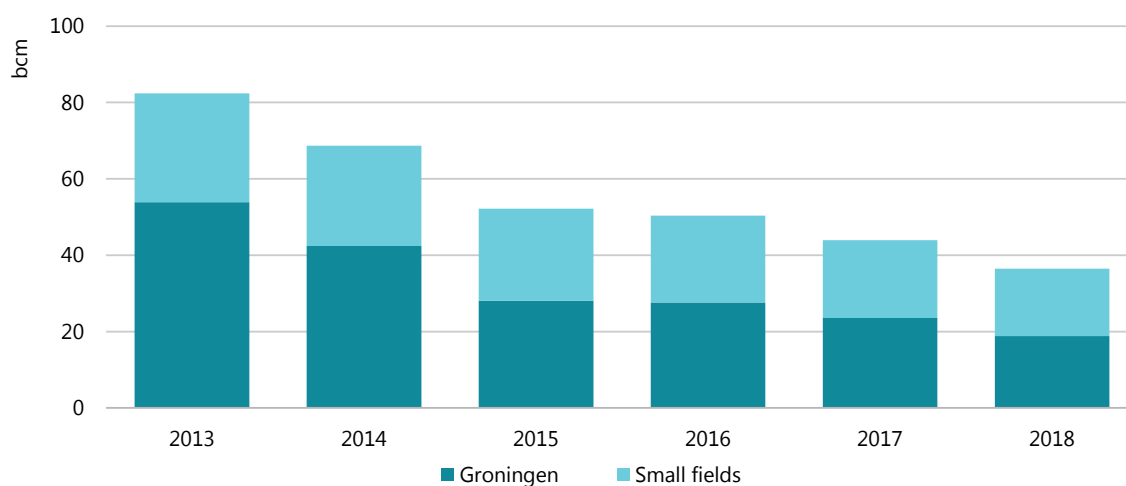
2019, which foresees a slight decline in saleable gas production in 2019 and a recovery between 2020 and 2022 up to a level of 121.4 bcm/y (NPD, 2019c). Depletion from mature fields will be compensated by supply from the development of new fields.

In December 2018 Equinor announced the commercial start-up of the Aasta Hansteen field, which together with the Senfrid Nord field will produce at plateau 8.4 bcm/y. The field is connected via the Polarled pipeline to the Nyhamna processing plant, from where the gas feeds into the Norwegian pipeline system via the Langeled North pipeline (Equinor, 2018a). In addition, the Johan Sverdrup field's Phase 1 is set to start up in November 2019 (Reuters, 2019c). According to the NPD's estimates, the field has recoverable gas reserves amounting to 10.24 bcm. The gas will be processed at the Kårstø processing plant, which mainly serves the continental European market (NPD, 2019d). In December 2018 the Norwegian Ministry of Petroleum and Energy approved the plan for development and operation of the Troll Phase 3, which is due to start up in the first half of 2021 and extend the plateau production of Troll by seven years (Equinor, 2018b).

The Netherlands

Dutch gas production has halved over the last 5 years, from over 80 bcm⁷ in 2013 to less than 40 bcm in 2018. The Netherlands lost its place to the United Kingdom as Europe's second-largest producer in 2016 and the country became a net importer of natural gas for the first time in its history in 2018. As shown in Figure 2.24, most of this decrease has been driven by the giant Groningen field, which saw its production falling from 54 bcm in 2013 to less than 19 bcm in 2018.

Figure 2.24 Natural gas production, the Netherlands, 2013–18



Sources: CBS (2019), *Natural Gas Balance Sheet, Supply and Consumption*, <https://opendata.cbs.nl/statline/#/CBS/en/dataset/84472ENG/table?ts=1554386607207>; NAM (2019), "Gas- en oliewinning", www.nam.nl/feiten-en-cijfers/gaswinning.html#iframe=L2VtYmVkJ2NvbXBvbmVudC8_aWQ9ZzZFd2lubmluZw.

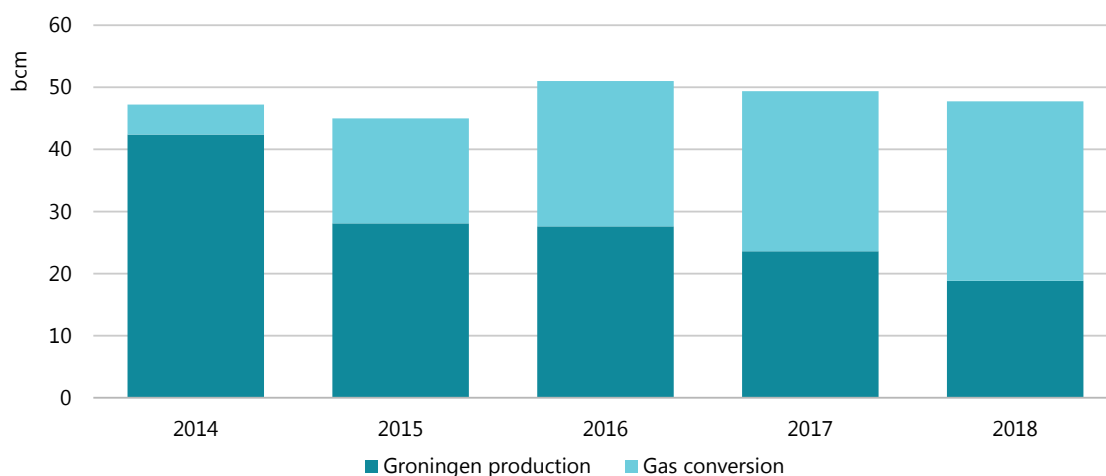
Dutch natural gas production has halved over the last 5 years and 75% of this decline has been driven by the lower output from the country's giant Groningen field.

⁷ Calorific value is 35.7 megajoules per cubic metre (MJ/m³).

Following an increasing number of earthquakes in the province of Groningen, linked to the natural gas extraction in the area, the Dutch authorities have imposed successive caps on Groningen's gas production starting from 2014. The turning point was the 3.4 magnitude earthquake, which hit the Groningen province in January 2018 and led the Dutch government to decide on the Groningen phase-out plan in March 2018. According to the plan, natural gas extraction from the Groningen field will fall below 12 bcm/y no later than October 2022 and be completely phased out by 2030 at the latest (van den Berg, 2018). In December 2018 the Dutch government announced a revised plan, aiming to reduce Groningen production to below 5 bcm/y from 2023 (Reuters, 2019d).

Groningen gas has a notably lower calorific value (L-cal) compared to the average European natural gas (33.3 MJ/m³ vs 40 MJ/m³), which means it cannot simply be replaced by other (imported) natural gas sources. These need to be converted to low-calorific gas (principally via nitrogen blending). Figure 2.25 shows that in the last four years conversion facilities have been increasingly replacing the declining natural gas production from Groningen. Gas conversion has risen six-fold over the last 5 years, from 4.8 bcm in 2014 to almost 29 bcm in 2018. This also means that converted gas now accounts for over 60% of total L-cal gas production in the Netherlands.

Figure 2.25 L-cal gas production in the Netherlands, 2014–18



Source: Gasunie annual reports.

Gas quality conversion now accounts for about 60% of total L-cal gas output in the Netherlands, whilst the utilisation level of conversion plants reached 88% in 2018.

In its latest annual report, Gasunie noted that the utilisation rate of conversion facilities was 88% through 2018 (Gasunie, 2019a). Moreover, GasunieTransportServices, the Dutch transmission system operator, notified market participants on numerous occasions through the last heating season that quality conversion had almost reached its maximum capacity. This led to market participants being asked to adjust their high-calorific to low-calorific gas balance to reduce nitrogen usage (GTS, 2019). In order to accommodate the gradually declining production cap on the Groningen field without disrupting the natural gas supply-demand balance in the Netherlands and northwest Europe, a number of measures have been undertaken. A new conversion facility in Zuidbroek is due to be commissioned in the first quarter of 2022, allowing Groningen gas production to decrease by 7 bcm/y (Gasunie, 2019b). In addition, the nine largest industrial users of Groningen gas will be forced to switch to other

sources of energy by 2022, which could reduce demand for low-calorific gas by another 4–5 bcm/y. GasTerra also has a target of negotiating the gradual phase-out of its long-term L-cal gas export contracts. In line with these developments, it is expected that Dutch natural gas production will fall by almost three-quarters through the forecast period to a level of 10 bcm/y.

Other Europe

Natural gas production in the United Kingdom recovered between 2013 and 2017, increasing at a rate of 3% per year. This was reversed in 2018, with gas output decreasing by 3% to just below 41 bcm. It is expected that domestic gas production will continue to decline at a rate of 3.7% through the forecast period, as decreasing output from depleting fields will not be entirely compensated by the additional output from new fields. This includes the Culzean field, which is expected to begin commercial operations in 2019, with plateau production due to be reached in 2020/21. According to Maersk Oil, the field could by then meet almost 5% of total UK gas demand (4 bcm/y) (BBC, 2017). In September 2018 Total announced a major discovery on the Glendronach prospect near the Shetland Islands, with gas reserves estimated to amount to 28 bcm. First gas production is expected in 2020 (Rystad, 2018). In January 2019 Total and CNOOC made a discovery in the Glengorm prospect, with estimated reserves of almost 38 bcm (Platts, 2019).

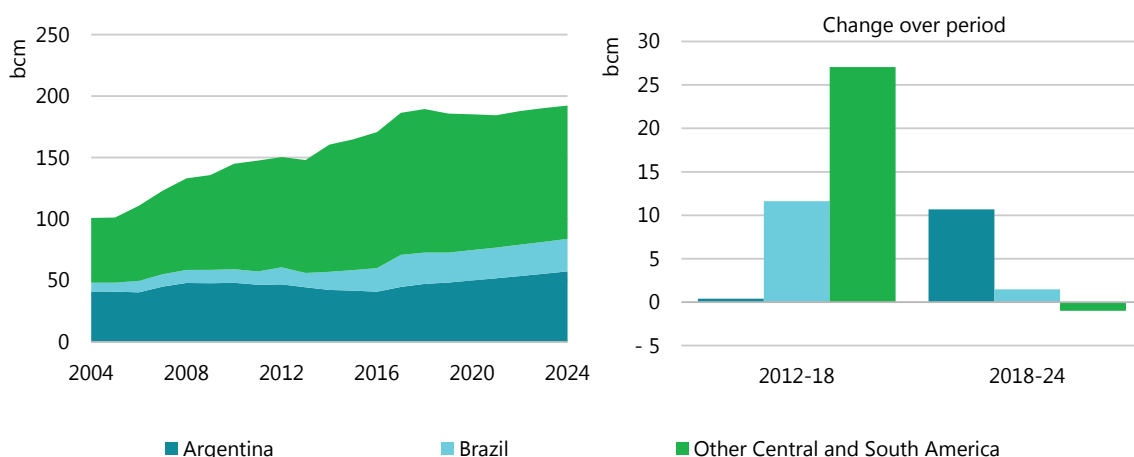
In Denmark, the Tyra field will be temporarily shut down from 19 September 2019 to July 2022 (Energinet, 2019). The field accounts for approximately 90% of domestic Danish natural gas production, with an output of 3.65 bcm in 2018. The redevelopment of the field will allow its lifespan to be extended by at least 25 years (OffshoreTechnology, 2019). During the shutdown, Danish gas imports are expected to increase to meet both domestic consumption and exports to Sweden.

Romanian natural gas production is expected to grow at a rate of 1% through the forecast period. However, this does not include the development of the offshore Neptun block, which has an estimated natural gas reserve base between 42 bcm and 84 bcm. An FID was expected in the last quarter of 2018; however, ExxonMobil and OMV Petrom decided to postpone given the regulatory changes in the Romania energy sector. Under a new law, companies producing in the Romanian offshore would need to sell at least 50% of their yearly output in Romania, considerably reducing potential revenues from exports (Reuters, 2018c).

Central and South America

This forecast expects an average annual increase in natural gas production in Central and South America of 1.1%, with additional production of 11 bcm/y to 2024 (Figure 2.26).

The growth is mainly led by Argentina, representing over 80% of the growth, with Brazil as the second-largest source of growth. Other regional production is expected to slightly decrease over the forecast period, mainly due to production decline in Colombia and Bolivia.

Figure 2.26 Natural gas production, Central and South America, 2004–24

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Argentina accounts for almost three-quarters of natural gas production growth in the region over the forecast period.

Argentina

Argentina's natural gas production stalled in 2017 after three years of continued growth, and then recovered in 2018 with a 4% increase to reach 47 bcm (Argentina.gob.ar, 2019). Unconventional gas, which represents 41% of total production as of early 2019, increased by 43% in 2018 reaching 19 bcm, while conventional gas decreased by 13% to 28 bcm.

Shale gas production increased by 215% y-o-y in January 2019, reaching production of 29 mcm/d (or the equivalent of 10.6 bcm/y), accounting for almost 53% of unconventional production, while production of other unconventional gas decreased by 12.5%. Shale exploration increased as shown by the strong growth in hydraulic fracturing. In 2018 there were on average 402 shale oil and gas fracturing operations per month, or 41% more than the average of 248 per month in 2017. Hydraulic fracturing activity reached 712 operations in February 2019 (The Dialogue, 2019).

The growth in domestic production has allowed Argentina to start exporting some volumes to Chile and is developing a 0.8 bcm/y floating LNG export infrastructure (Newsbase, 2019). However, the country is still importing natural gas, especially during the peak demand season in the southern hemisphere winter, when supply is not able to meet demand. In March 2019 Energy Secretary Gustavo Lopetegui announced a programme for replacement of natural gas imports (RIG). The programme's goal is to replace winter LNG imports with higher domestic natural gas production. Thermal power generation will have priority dispatch using RIG programme gas. The programme, which will facilitate the development of additional pipeline capacity, will be applicable during winter up to a maximum of 12 mcm/d from producers (The Dialogue, 2019). The programme is intended to run from 2020 to 2023.

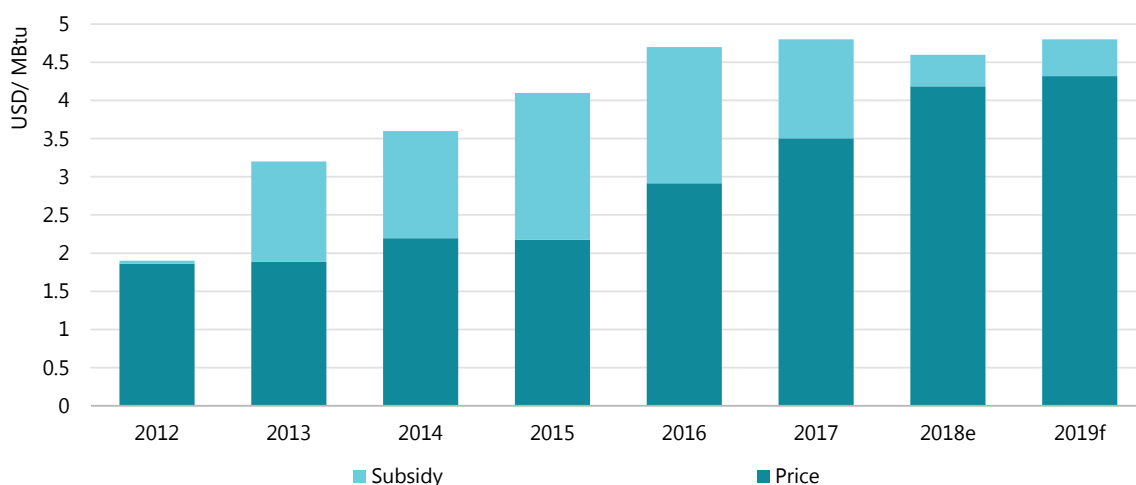
Under the Gas Plan 2012, a governmental programme that looks to incentivise incremental domestic production of all sources of gas, the government ensured a price of USD 7.5/MBtu for any additional volume above the production volumes announced by companies between 2012

and 2017. The government started to scale back production incentives from 2018, adjusting its previous flat price to USD 7/MBtu in 2018 and then reducing it to USD 6/MBtu in 2021, still higher than the USD 4/MBtu market price.

In 2018 the International Monetary Fund set as a condition of its USD 57 billion line of credit bailout the reduction of subsidies and a balanced budget for 2019. The first measure enacted by the government was to raise utility rates to reduce subsidies to end users. In January 2019 the Energy Secretary Lopetegui announced that the production price incentives would be capped at the volumes declared in the original production plans as presented by the companies when they applied to the production subsidy scheme (Clarín, 2019). These modifications to both the production incentives and end-user gas subsidies could impact growth in domestic production. According to the state budget of 2019, the government has ARS 28.7 billion (USD 0.74 billion)⁸ set aside for the Gas Plan to guarantee a price of USD 7/MBtu. Considering a price of USD 3.90/MBtu in the Neuquén Basin as of early 2019, the budget could only subsidise an annual equivalent of 6.3 bcm (whereas the Fortin de Piedra development has already surpassed an annual equivalent of 5.8 bcm) (Rio Negro, 2018).

Domestic gas producers are achieving better market prices. While the price increased by 50% from USD 3.2/MBtu in 2013 to USD 4.80/MBtu in 2017, subsidies have decreased (they fell from representing 41% of the total price in 2013 to 27% in 2017). According to the government, the price is expected to reach USD 4.19/MBtu in 2018 and USD 4.32/MBtu in 2019 (Figure 2.27).

Figure 2.27 Domestic natural gas prices and share of subsidy in producer income, Argentina, 2012–19



Note: Data for 2018 are estimated and forecast for 2019.

Source: The Dialogue (2019), *Energy in Argentina, Investment Opportunities for the International Community*, www.thedialogue.org/wp-content/uploads/2019/03/2019-03-13-IAD-Energy-in-Argentina-Investment-Opportunities-for-the-International-Community.pdf.

Subsidies are being reduced, while domestic gas producers are achieving higher prices.

⁸ Considering the strong exchange rate variations observed in 2018, this conversion uses the average first quarter of 2019 rate of USD 1 = ARS 38.92.

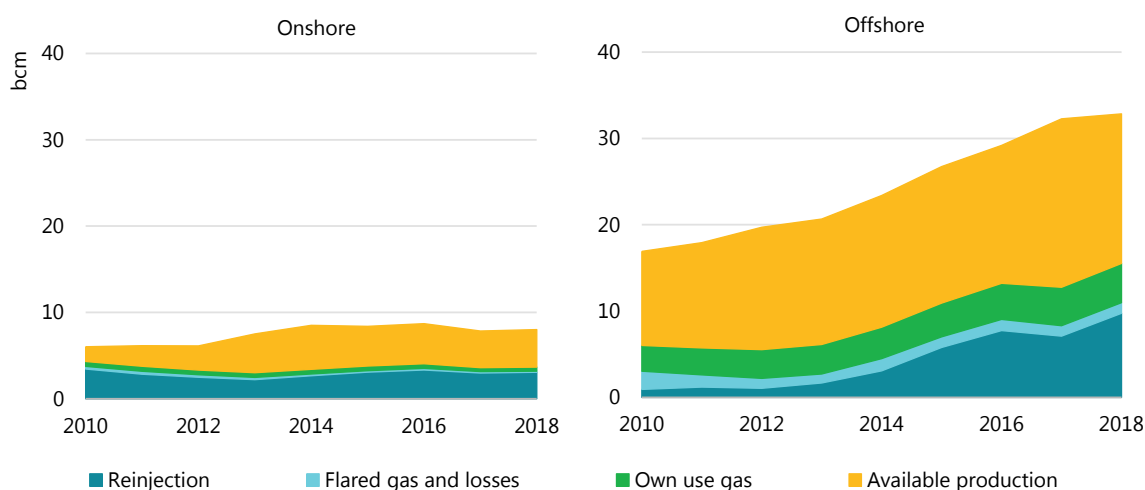
This forecast expects annual average growth of 3.5% to 2024, although development of the Vaca Muerta field remains partially uncertain due to operational bottlenecks, such as the lack of nearby sand resources needed for hydraulic fracturing (currently delivered from Entre Rios, 1 600 km away), rail development to ensure access to the production areas, and gas storage (due to the highly seasonal demand). There is also a need for better midstream infrastructure to connect production with natural gas demand centres. Argentina is already working on those bottlenecks; for example, in March 2019 the Energy Secretary announced plans for a new 22 mcm/d (8 bcm/y) pipeline from Vaca Muerta to Buenos Aires (Pipeline News, 2019).

Brazil

In 2018 Brazilian gross natural gas production increased by 1.8%, reaching almost 41 bcm. However, due to an increase of 27% in gas reinjected, or an additional 2.8 bcm, available natural gas decreased by almost 9% to 22 bcm in 2018 – after having reached a peak of almost 24 bcm in 2017.

Available natural gas represented 53% of gross production in 2018, reinjection 31%, losses and vented or flared gas 3% and own use gas 12% (Figure 2.28). The strong share of reinjection is due to the preponderance of associated gas produced from offshore oil fields. Offshore net production represented 80% of total available natural gas.

Figure 2.28 Natural gas production, Brazil, 2010–18



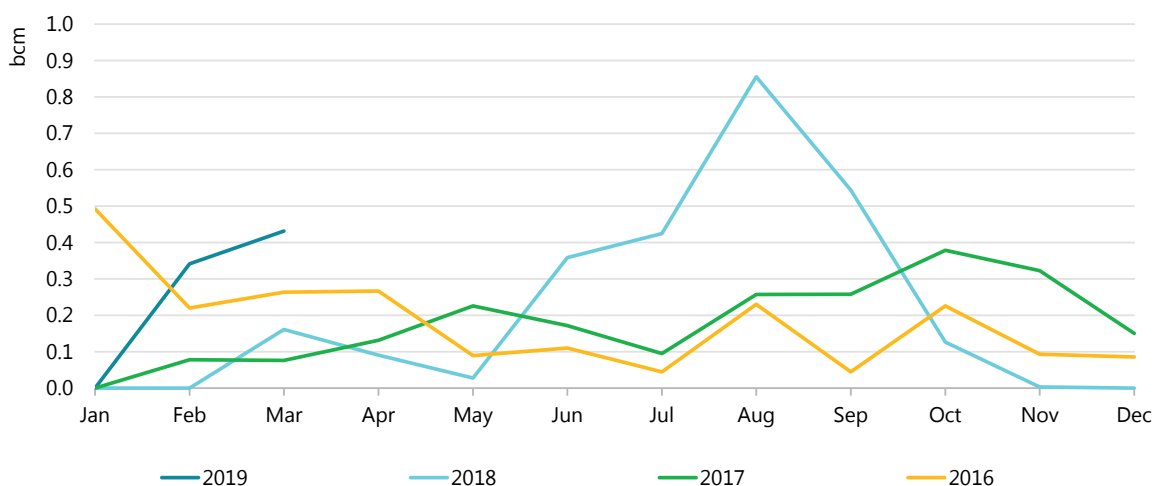
Source: ANP (2019), *Dados Estadísticos [Statistical Data]* (database), www.anp.gov.br/dados-estatisticos.

Brazil's gross production increased by 1.8% in 2018, while available natural gas decreased by 8.8% due to higher reinjection in oil fields.

According to Petrobras' *Business and Management Plan 2019–2023* (Petrobras, 2018), deepwater operations will be prioritised by investing USD 68.8 billion to 2023 in exploration and production (56% pre-salt and 44% post-salt) and USD 3.7 billion in natural gas offloading, processing and transport to shore. Despite the expected expansion of oil and gas production in pre-salt fields in the medium term, this forecasts estimates annual average growth of 1.7%, as a significant proportion of the additional gas produced in the pre-salt fields will be reinjected to stimulate oil production.

Brazil imports natural gas via pipeline from Bolivia via a deliver-or-pay contract at close to 31 mcm/d (or about 11.3 bcm/y) until 2019, and through the three floating storage and regasification units (FSRUs) in Pecem, Bay of All Saints and Guanabara Bay, all operated by Petrobras. Another FSRU is currently under construction in Sergipe, with a regasification capacity of 5.8 bcm/y, for an LNG-to-power project (see Chapter 1). In 2018 the country imported 2.6 bcm of LNG, or 21% more than in 2017. As seen in Figure 2.29, LNG imports are very flexible and are mainly used for power generation. Imports in the first quarter of 2019 have more than quadrupled compared to the first quarter of 2018, from 0.16 bcm to 0.77 bcm.

Figure 2.29 LNG imports, Brazil, 2016–19

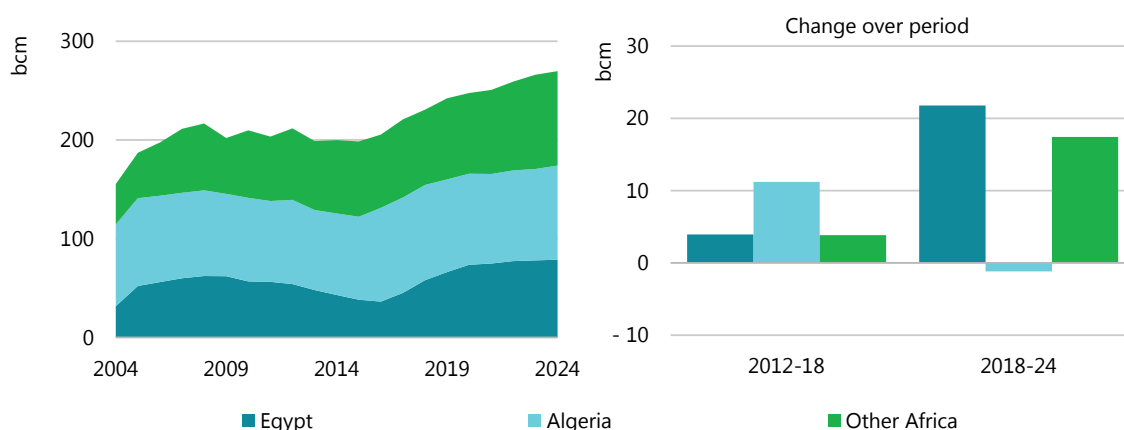


Source: ICIS (2019), *ICIS LNG Edge*, www.icis.com/energy/liquefied-natural-gas/lng-market-intelligence-solution/ (subscription required).

Brazil imported 21% more LNG in 2018 than in 2017.

Africa

Natural gas production in Africa is expected to grow at an average rate of 2.7% per year over the next five years to reach over 270 bcm by 2024 (Figure 2.30). Egypt will take the lead on production expansion, with several fields currently under development or in early phases of production. In Algeria, the absence of confirmed new developments to counterbalance the decline of historical fields' output leads to a slight reduction in production by 2024. Other developments are mainly driven by LNG export projects.

Figure 2.30 Natural gas production, Africa, 2004–24

Egypt is expected to support over half of Africa's natural gas production growth during the forecast period, due to strong development from the recent Zohr and West Nile Delta fields.

Egypt

Egypt's natural gas production rose to around 58 bcm in 2018 according to early estimates. According to Petroleum Minister Tarek El-Molla, the country achieved self-sufficiency by the end of September 2018, owing to the completion of new stages to increase the production of natural gas from four major fields in the Mediterranean Sea: Zohr, Nooros, Atoll and the first and second phases of the West Nile Delta complex.

The Zohr field became in 2018 the main asset in Egypt's natural gas production rebound, with production of about 10 bcm/y after commissioning in December 2017, on a par with the Nooros field which started operation in 2016 and reached its expected plateau level in 2018 (Figure 2.31). According to Eni, which jointly operates Zohr with the state-owned Egyptian General Petroleum Corporation (EGPC), the field is set to reach production of 2.7 billion cubic feet per day in 2019 – or around 28 bcm/y equivalent (Eni, 2019a).

Several other fields were recently developed under BP-led operations: Atoll (close to Zohr's Shorouk offshore block), which delivered its first gas in February 2018, and the Giza and Fayoum fields in the second phase of the West Nile Delta (WND) complex in February 2019⁹ (BP, 2019). With the expected start-up of the Raven field in late 2019, the three phases of WND are expected to deliver up to almost 15 bcm/y, equivalent to about one-quarter of Egypt's current gas production. All the gas produced will be fed into the national gas grid.

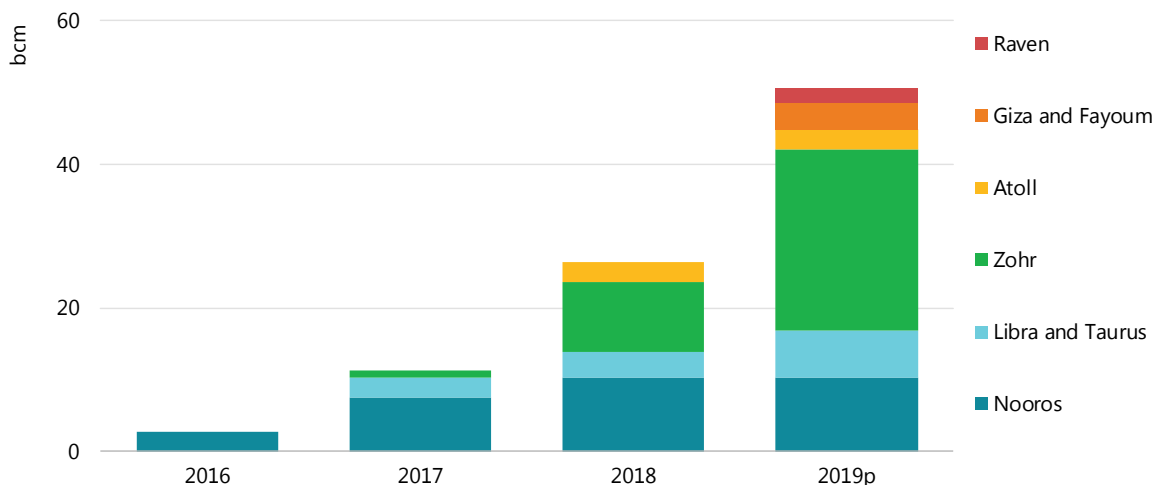
According to the Ministry of Petroleum, Egyptian natural gas production should reach the equivalent of almost 80 bcm/y in fiscal year 2019/20¹⁰ (Daily News Egypt, 2019). Based on current projects under development, this forecast does not share the ministry's optimistic outlook. It nevertheless expects strong growth until 2023 with a plateau of 77 bcm/y – or an average annual growth rate of 4.8% for the forecast period. However, Eni's discovery at Nour in March 2019 (under evaluation at the time of writing, [Eni, 2019b]) may lead to further developments in the offshore Egyptian Mediterranean. In parallel the government launched a bid round in March 2019 for ten blocks in the less-explored offshore Red Sea.

⁹ The first phase, comprising the Taurus and Libra fields, started operations in 2017.

¹⁰ From July to June.

In spite of this strong recovery in production, this forecast does not expect a full restart of LNG exports (see Chapter 4) as supplying the growing domestic need remains a priority.

Figure 2.31 Natural gas production from new fields, Egypt, 2016–19



Note: 2019 data are prospective.

Source: Compilation based on information from company reports and investor presentations.

New offshore production start-ups, led by the giant Zohr field, drive Egypt's natural gas production recovery.

Algeria

Algerian natural gas production is expected to stagnate and even slightly decrease over the forecast period in spite of new production start-ups in 2019, due to the continuous decline of historical production.

The country's marketed natural gas output remained stable over the recent past and even increased in 2016, but this was achieved thanks to a drastic reduction in gas reinjection – which accounted for most gross gas use until 2011 (Figure 2.32). This shift was driven by the imperative of meeting the structural rise in domestic needs (see Chapter 1) without impacting natural gas exports, which are a key source of revenues for Algeria's economy.

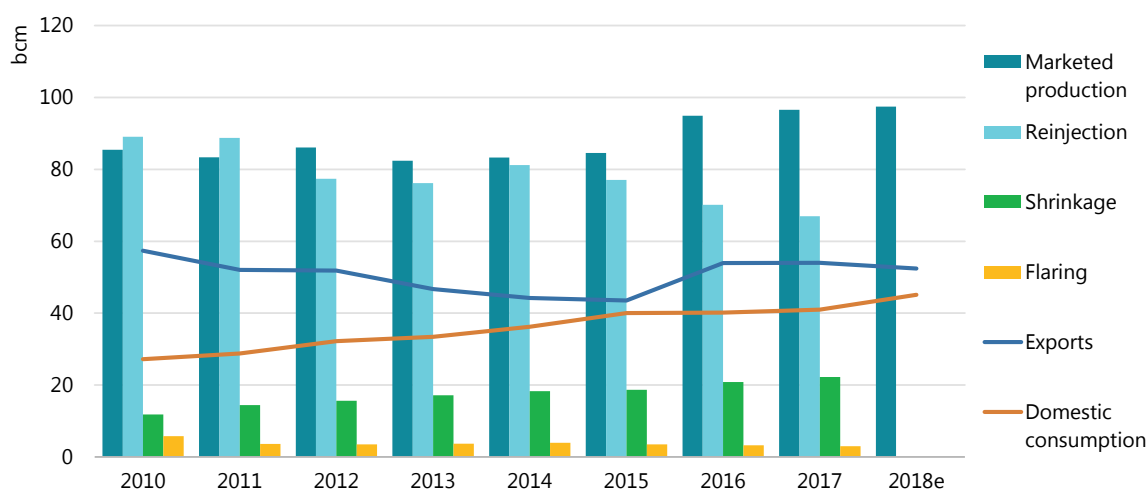
This drop in reinjection is understood to have caused some damage to reservoir integrity and led to lower pressure and recovery in the Hassi R'Mel complex, the main historical contributor to Algeria's natural gas production. It accounted for up to 75% of the country's total gas production in the early 2000s. State-owned operator Sonatrach announced investment to prevent further decline, which is due to be completed in 2020.

New production assets have recently started production as part of the 9 bcm/y Southwest Gas project to counterbalance this decline: the Reggane and Timimoun fields both delivered their first gas in 2018, and the project's third and largest element, the 4.5 bcm/y Touat field, is expected to start deliveries by mid-2019.

However, the outlook remains uncertain in the absence of further announced developments to limit production decline over the medium term. This lack of production growth, combined with the expected continuous increase in domestic demand, has led to some concerns over Algeria's

export capacity, as voiced in December 2018 by the then-Energy Minister Mustapha Guitouni, who highlighted the risk of seeing natural gas exports ending by 2032 (El Watan, 2018). Algeria has been preparing changes to its hydrocarbon law to attract greater foreign investment. These were expected during the first half of 2019, having been announced by the CEO of Sonatrach in late 2018. However, his dismissal in late April 2019 adds further uncertainty to the timing of oil and gas reform (Financial Times, 2019).

Figure 2.32 Natural gas production and uses, Algeria, 2010–18



Note: 2018 data are estimated.

Sources: GECF (2018), *GECF Annual Statistical Bulletin*, www.gecf.org/resources/files/events/launch-of-the-gecf-annual-statistical-bulletin-2018/gecf-asb-2018-.pdf; IEA estimates for 2018.

Algeria's gross natural gas production has stagnated over the past decade, with an increase in marketed volumes obtained by lower field reinjection and putting the reservoirs' pressure at risk.

Sub-Saharan Africa

Most forecast natural gas production developments in sub-Saharan Africa are related to LNG export projects. For example, in the Rovuma Basin off the coast of Mozambique, the Coral South floating LNG (FLNG) project (which took FID in 2017) is expected to produce first gas by 2022, and other potential liquefaction projects are located in the same basin. In West Africa, the development of the Tortue field across the maritime border of Mauritania and Senegal started after notification of the FID on the Tortue FLNG export project in December 2018.

Other developments are also expected from other West African countries, including Nigeria where China's CNOOC expects to invest USD 3 billion in offshore oil and gas projects (Oil Review Africa, 2018).

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3. Trade

Highlights

- **International LNG transactions are the main driver** of the expansion in global natural gas trade through the forecast period, with LNG trade reaching 546 bcm by 2024 from 432 bcm in 2018. People's Republic of China ("China") and other emerging Asian markets continue to be responsible for most of this growth.
- **China becomes the largest LNG importing country in the world by 2024** at 109 bcm, ahead of Japan. China alone accounts for almost one-third of the growth in global LNG trade to 2024. Pipeline imports from Russian Federation ("Russia") and the Caspian countries are another source of import increases, accounting for 48% of the country's total imports by 2024 and reaching 100 bcm/y – China also becomes the largest pipeline importer during the forecast period.
- **The United States is the leading source of natural gas exports** (both for pipeline flows to Mexico and LNG exports) and accounts for two-thirds of global LNG supply growth. Altogether, the United States, Australia and Russia are responsible for almost 90% of the increase in LNG exports to 2024. The United States surpasses Qatar and Australia to become the world's largest LNG exporter by the end of the forecast period, at 113 bcm in 2024.¹
- **Europe's supply gap widens to reach 336 bcm by 2024**, increasing by almost 50 bcm/y during the forecast period, as domestic production continues its decline with the phasing out of the Groningen field and depletion in the North Sea. This gap is bridged by a combination of additional LNG and pipeline imports from both traditional suppliers and new sources.
- After several years of decline, **investment in new LNG export projects rebounded** in 2018 and further accelerated in early 2019, with a strong number of projects expected to achieve their final investment decision in the course of the year. These developments enable further growth in global LNG trade, yet spare capacity margins erode by the end of the forecast period in spite of these additions. Recent charter rate volatility prompted orders for new LNG carriers; however, additional orders will be needed to keep the LNG shipping market balanced beyond 2022.

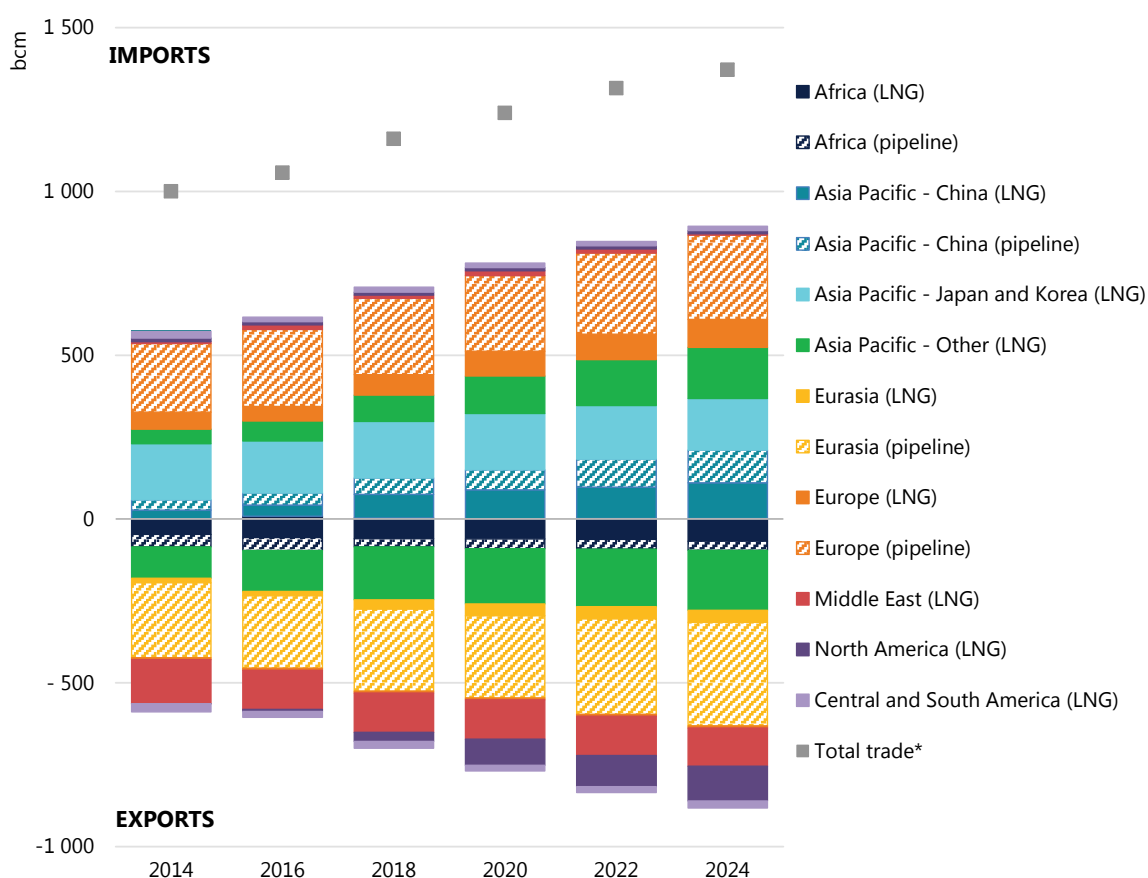
¹ This report only considers liquefaction projects that had taken their final investment decision as of early June 2019 as contributing to future export capacity for the forecast period.

Global natural gas trade

The recent growth in interregional² natural gas trade mainly owes to the development of liquefied natural gas (LNG) flows, whereas interregional pipeline trade has remained stable and concentrated around a limited number of trade axes – from Eurasia to Europe and China, and from North Africa to Europe.

Figure 3.1 shows that interregional trade is expected to continue to grow in a similar fashion during the forecast period, with a strong contribution from LNG as well as an increase in pipeline flows between Eurasia (both Caspian countries and Russian Federation (“Russia”) and China.

Figure 3.1 Interregional natural gas trade balance, LNG and pipeline imports and exports, 2014–24



* Total trade includes major regional pipeline flows.

Note: bcm = billion cubic metres.

The future growth in interregional natural gas trade is mainly driven by Asian LNG and pipeline gas on the imports side and by North American LNG and Eurasian pipeline gas on the exports side.

² Unless otherwise stated, trade figures in this chapter reflect volumes traded between regions, and they therefore do not include all intraregional trade flows.

This forecast expects natural gas trade to grow at an average annual rate of almost 4% over the next five years to reach 32% of total natural gas consumption. Global LNG trade is expected to stand at 546 bcm by 2024, or about 60% of interregional trade.

Global natural gas trade is set to increase not only in volume, but also in terms of number of participants with an increasing number of new buyers and sellers, enabled mainly by the development of LNG flows.

On the demand side, the Asia Pacific region keeps its role as main importing area, but with a shift from traditional buyers such as Japan and Korea to rapidly growing economies, led by China but also including major emerging markets in South and Southeast Asia.

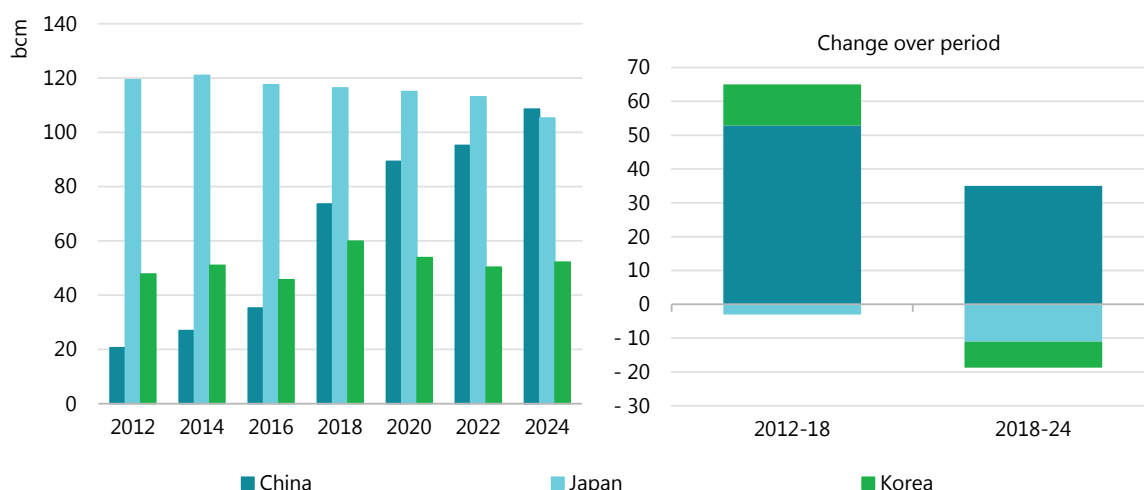
On the supply side, Eurasia keeps its position as the largest pipeline exporting region, with growing capacity and flows to China (from both Russia and Caspian), while the LNG export picture is redefined by the development of Australia and the United States, which challenge the strong position of the Middle East – and Qatar in particular.

Regional trade outlook

Asia Pacific

Most additional trade in the Asia Pacific region is expected to come from LNG imports – except for China, where pipeline deliveries from Russia and Caspian keep increasing with the development of new capacity. China is also the main contributor to LNG trade growth in the region, surpassing Korea in terms of imports in 2017 and becoming the world’s largest LNG importer in 2024, ahead of Japan (Figure 3.2).

Figure 3.2 LNG imports, China, Japan and Korea, 2012–24



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China is expected to become the world’s largest LNG importer by 2024.

China

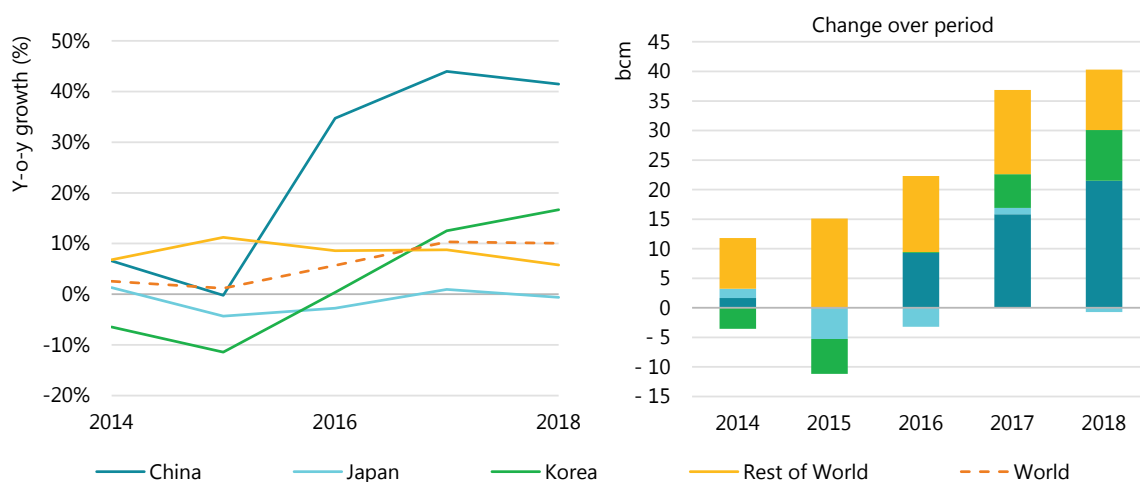
Domestic production in China has not been able to keep up with demand growth, which is why imports have been playing a more important role in recent years. Domestic production decreased from 80% to 57% of total supply between 2011 and 2018, and is expected to account for 54% by 2024.

China's LNG imports have grown strongly since the country's first regasification terminal (Guangdong Dapeng) was commissioned in 2006. LNG imports reached almost 74 bcm in 2018 (42% year-on-year [y-o-y] increase).

China is a growing contributor to LNG trade development: in 2014 the country accounted for 20% of the total increase in LNG imports, then 43% in 2017 and 55% in 2018 (or 21.5 bcm out of a global increase of 39.6 bcm).

As shown on Figure 3.3, China's annual LNG import growth has been greater than any other importer since 2016. While global LNG trade increased by 10% in 2018, China's growth reached 42%. Korea also experienced a strong increase of 17% y-o-y growth, reaching 60 bcm during 2018.

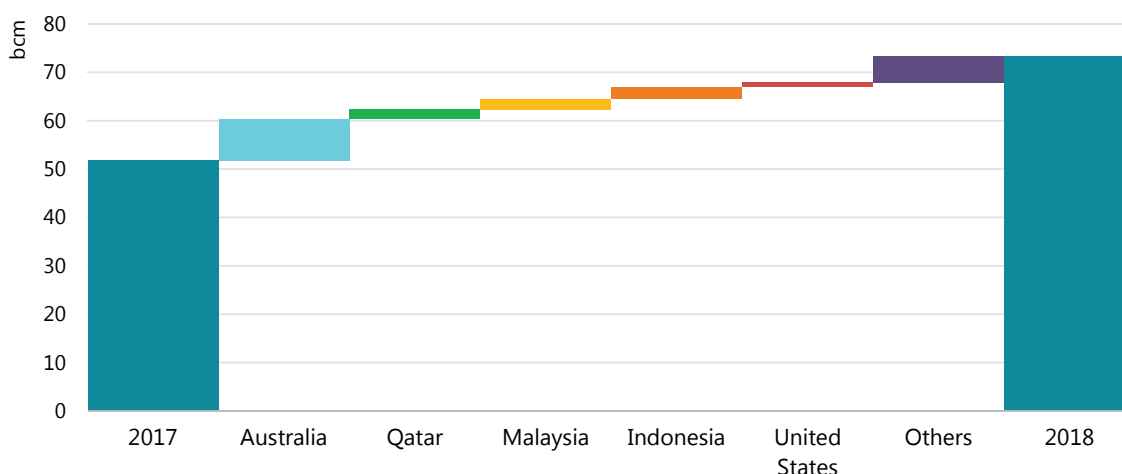
Figure 3.3 LNG imports y-o-y growth and incremental growth, 2014–18



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

In 2018 China accounted for 55% of global LNG trade growth.

In 2018 China became the foremost natural gas importer, with 124 bcm of LNG and pipeline imports, surpassing Japan (113 bcm, 1% y-o-y growth). It accounted for 17% of total LNG imports, second to Japan (26%) and ahead of Korea (14%). LNG imports represented 73% of the country's total increase in imports. The largest increment came from Australia (8.5 bcm), followed by Malaysia (2.3 bcm) and Qatar (2 bcm). The United States supplied almost 1 bcm more than in 2017 (Figure 3.4).

Figure 3.4 LNG trade increment by origin, China, 2017–18

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

Australia accounted for 40% of additional LNG volumes imported by China in 2018, mainly via long-term contracts.

LNG infrastructure

At the end of 2018, China had 19 LNG import terminals for a total nameplate regasification capacity of 92.8 bcm/y. Almost half of China's incremental LNG imports (46% of the almost 22 additional bcm imported by China in 2018) arrived at North Coast terminals, with 39% at terminals on the East Central and 15% on the South Coast. Utilisation rates at terminals in the North (117%)³ and East Central (129%) remain much higher than in the South (48%) due to pipeline capacity limitations affecting the movement of natural gas from the south to the north of the country.

State-owned companies took several measures to improve interconnection and flexibility in 2018 in order to avoid another winter supply shortage:

- China National Offshore Oil Corporation (CNOOC), the largest LNG regasification operator, used its terminals in the South (Zhuhai and Diefu) to inject gas into the China National Petroleum Corporation (CNPC) pipeline to the north of Guangdong, thus enabling CNPC to allocate those volumes to the north of China. It also started to provide third-party access to its terminals in Guangdong and Zhejiang during the second half of 2018.
- In November 2018 CNOOC launched a trial project to deliver surplus capacity from the Yangpu terminal (Hainan) to the port of Jinzhou in Liaoning (North China). Some 130 LNG tanks of 25 000 cubic metres (m³) each were transported on a container feeder ship. CNOOC also leased a floating storage and regasification unit (FSRU), capable of storing 150 000 m³ of LNG for the winter season, as an emergency source of supply. The vessel was eventually not needed and the lease was terminated in January 2019.
- Sinopec reinforced its pipeline infrastructure with the commissioning of the first phase of the Erdos–Anping–Cangzhou pipeline – linking its Tianjin terminal to Hebei and Henan

³ Utilisation rates are calculated as a percentage of an infrastructure's nameplate capacity (defined as its maximum rated output under specific conditions set by the equipment manufacturer). Operational output can usually reach higher levels, leading to above 100% utilisation rates.

provinces. The company also prepared for emergency winter supply needs by renting a fleet of 2 600 trucks to deliver LNG from the south to the north.

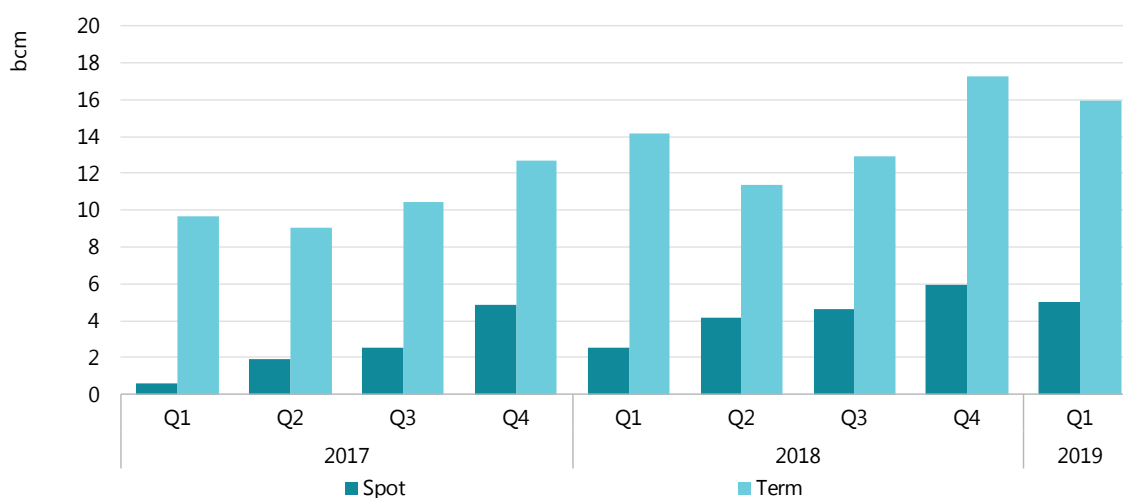
Some 14.3 billion cubic metres per year (bcm/y) of new regasification capacity was commissioned in 2018, in Tianjin Nangang (4.1 bcm/y), Shenzhen Diefu (5.4 bcm/y), Zhoushan (4.1 bcm/y) and Qidong (0.7 bcm/y). In January 2019 CNOOC's Fangchenggang offshore terminal located in Guangxi started operations with a designated transshipment capacity of 0.8 bcm/y. CNOOC has also started to use LNG iso-containers to export from its Hainan terminal (Argus, 2019a).

A total of 32.5 bcm/y of additional regasification capacity is currently under construction and scheduled to start operations between 2019 and 2022. Some 8.2 bcm/y are expected to be added in 2019, from the new Chaozhou (4 bcm/y) and Jiangyin (2.7bcm/y) LNG terminals, as well as from the expansion of the Fujian LNG terminal (1.5 bcm/y).

LNG supply

LNG spot⁴ imports increased by 75% in 2018, from 10 bcm to 18 bcm (Figure 3.5), reaching 24% of total LNG imports. National oil companies (NOCs) accounted for 93% of total spot imports, with CNOOC representing 42%, Petrochina 40% and Sinopec 11%. Spot procurement decreased during the first quarter (Q1) of 2019 compared to the fourth quarter (Q4) of 2018, yet doubled from their Q1 2018 level.

Figure 3.5 LNG imports by type of contract, China, 2016–18



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

Spot contracts are gaining momentum, representing 24% of China's total LNG supply in 2018.

In addition to this growth in spot volumes, Chinese buyers signed several new medium- to long-term contracts in 2018 and early 2019 to further increase and diversify the country's LNG supply (Table 3.1). Aside from the 4.6 bcm/y contract signed with Qatargas in September 2018, these contracts have relatively limited volumes (ranging from 0.6 to 1.6 bcm/y).

⁴ Defined as a one-time transaction, as opposed to term deals which involve supply over a period of time.

Table 3.1. LNG term contracts signed by Chinese buyers, 2018–19

Date of signature	Seller	Buyer	Volume (bcm/y)	Start	Duration (years)
Sale and purchase agreements (SPAs)					
February 2018	Cheniere Energy	Petrochina	1.63 (total)	2018 2023	25 20
July 2018	ExxonMobil	Petrochina	0.61	2018	3
September 2018	Qatargas	Petrochina	4.60	2018	22
October 2018	ExxonMobil	Zhejiang Energy	1.60	2020	20
October 2018	Total	CNOOC	+0.68*	2008	20*
December 2018	Petronas	CNOOC	0.68	2019	5
April 2019	Total	Guanghui	0.95	-	10
Heads of agreement (HOAs)					
October 2018	Woodfibre LNG	CNOOC	1.00	2023	13
April 2019	Woodside	ENN	1.36	2025	10

* Extension from the original 15 -year contract for 1.36 bcm/y.

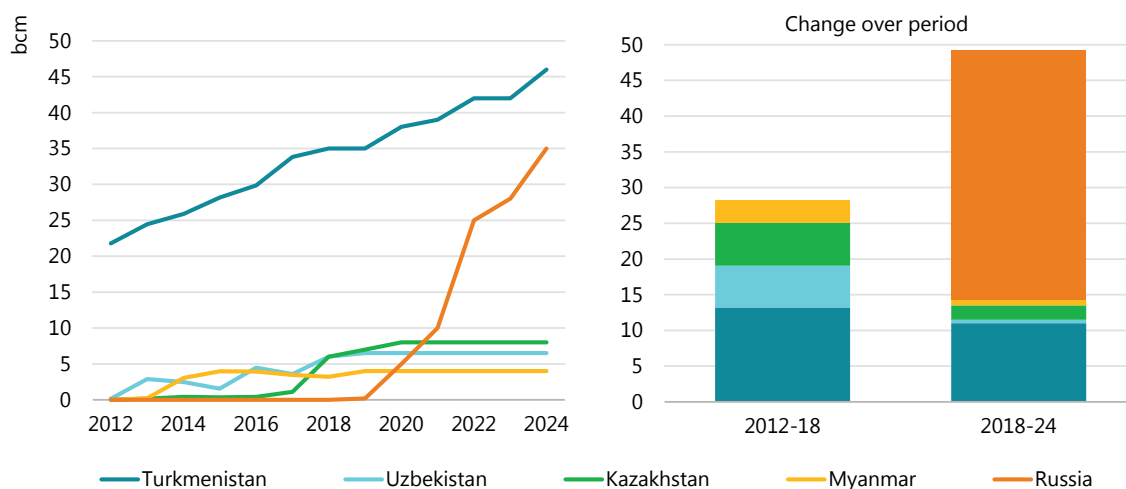
This forecast expects LNG imports to grow at an annual average rate of 7% over the forecast period to reach 109 bcm by 2024, with China becoming the world's largest LNG importer.

Pipeline imports and infrastructure

During 2018 China imported 50 bcm by pipeline, or a 19% increase compared to 2017. China imported around 47 bcm from Caspian countries (up 23% on 2017, mainly driven by Kazakhstan), while imports from Myanmar totalled 3 bcm.

CNPC announced in late 2018 that due to strong demand from downstream users, the daily gas transmission volumes from the Central Asian pipeline would reach 160 million cubic metres per day (mcm/d) during the winter season, representing 100% capacity (CNPC, 2018). Additionally, CNPC completed the second development phase of Turkmenistan's Samandep gas field and added a new compressor station, boosting production capacity by 2.34 bcm/y (Argus, 2018a).

CNPC and Kazakh state-owned company KazMunaiGaz signed a one-year supply contract for 5 bcm in October 2017, which started delivering in October 2018 through Line C of the Central Asia–China system. Exports from Kazakhstan are scheduled to double to 10 bcm/y from 2019, under the contract signed between Petrochina and Kaztransgaz in October 2017. Kaztransgaz plans to build three additional compressor stations on its Beyneu–Bozoi–Chimkent route, lifting the pipeline capacity from 5 to 15 bcm/y (Argus, 2018b).

Figure 3.6 Pipeline imports by source, China, 2012–24

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Turkmenistan is expected to remain the largest pipeline exporter to China to 2024, with Russia being the largest source of incremental supply through the forecast period.

This report assumes that the Central Asia–China system’s Line D between Turkmenistan and China will start operations in 2022 with a design capacity of up to 30 bcm/y. Construction is underway in Turkmenistan, and expected to start in Kyrgyzstan by the end of 2019 (Trend News Agency, 2019). Upon completion, China will be able to import up to 65 bcm/y from Turkmenistan.

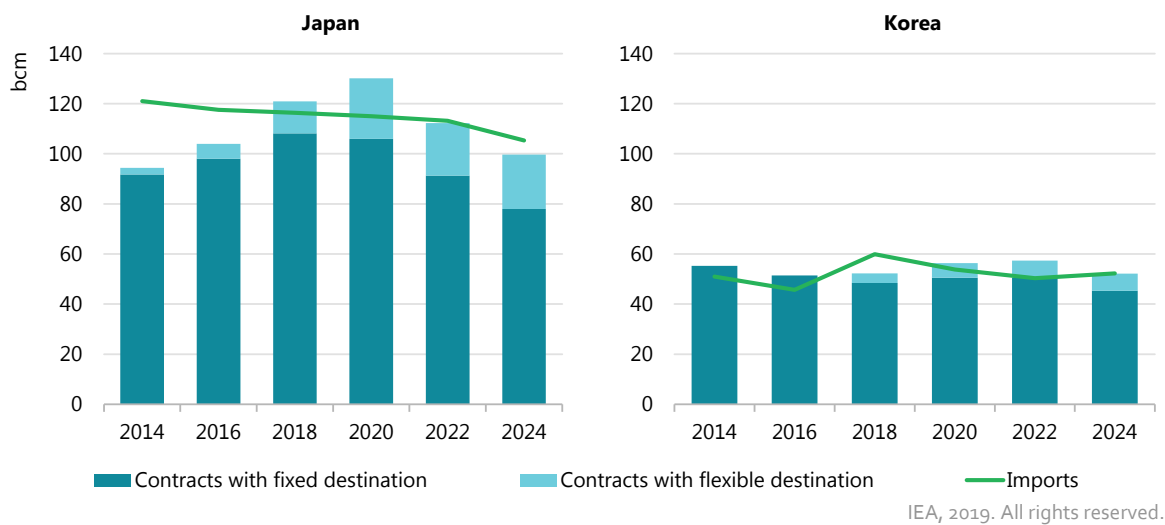
The main pipeline development is the 38 bcm/y Power of Siberia from eastern Russia, which is expected to start operations in December 2019. This report expects a progressive ramp up of Russian exports to China, from 5 bcm in 2020, to 25 bcm by 2022 and 35 bcm by 2024 (Figure 3.6). China’s total pipeline gas imports are therefore expected to double from 50 bcm in 2018 to 100 bcm by 2024, making China the world’s largest gas pipeline importer.

Japan and Korea

Japan is expected to see its LNG imports decrease from their 2018 levels due to the assumed progressive restart of its nuclear generation fleet. Japan’s total contracted volumes reach their maximum by 2020 due to the increase in flexible volumes, while the volume of legacy contracts with fixed destination starts declining after 2018 (Figure 3.7). After a short period of over-contracting in 2020 (including volumes with flexible destination), Japan’s total contracted LNG volumes decrease to almost align with domestic needs in 2022, and below by 2024.

Korean import needs remain equal to or below total contracted LNG volumes during the forecast period, and always above the amount of fixed contracted volumes.

Figure 3.7 LNG imports and contracts, Japan and Korea, 2014–24

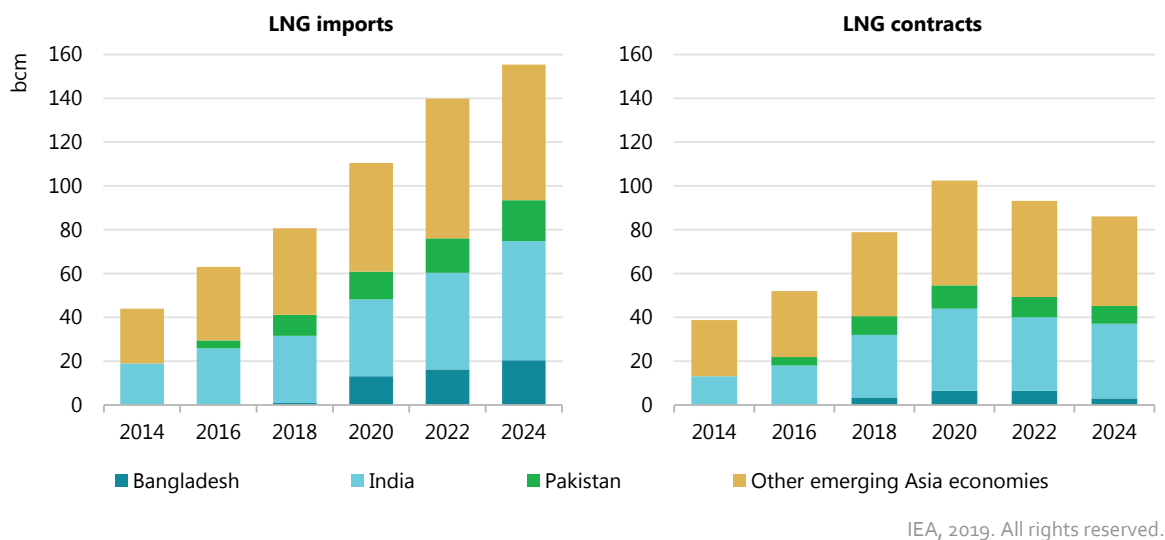


Japan’s contracted volumes (including flexible volumes) briefly surpass needs by 2020 and decline afterwards, leaving a net supply gap to be filled. Korean contracts are broadly aligned with needs.

Other emerging Asian economies

Natural gas trade growth relies on LNG imports in emerging Asian economies in the absence of regional pipeline network development, and are expected to almost double between 2018 and 2024 (Figure 3.8).

Figure 3.8 LNG imports and contracts, Other emerging Asian economies, 2014–24



India is the leading contributor to LNG trade growth among emerging Asian economies other than China.

India accounts for a large share of this growth and sees its imports increase from 31 bcm/y to 54 bcm/y during the forecast period – sustained by the ramping up of contracted volumes until 2020, and then by additional sources of supply or future contracts.

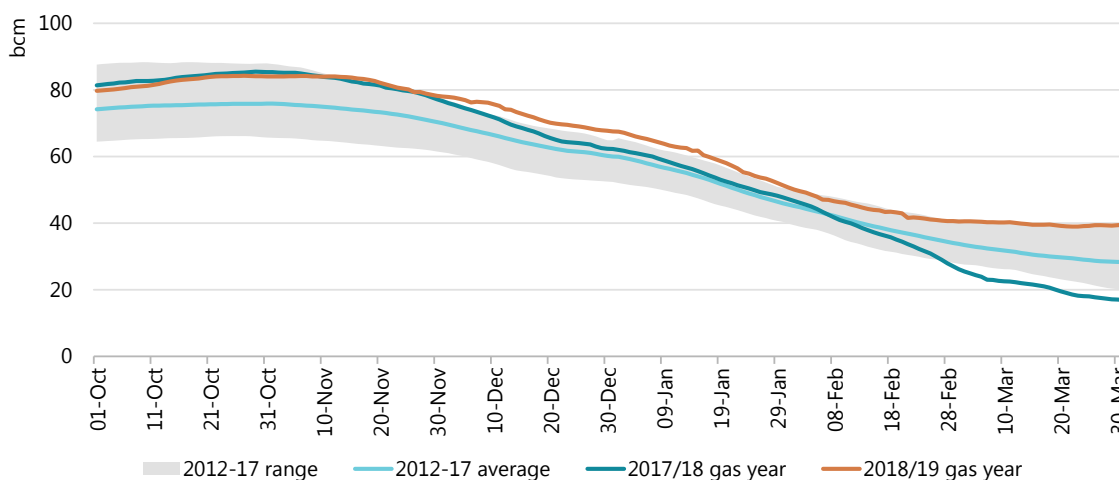
Pakistan and Bangladesh are expected to grow in a similar fashion. The competitiveness of LNG imports will be a crucial factor for enabling such growth in price-sensitive emerging Asian markets. Import development in other Asian emerging markets – mainly Southeast Asia – are sustained by already-signed long-term contracts over the initial years of the forecast period (which remain stable after 2020 and are supplemented by additional sources of supply).

Europe

Recent trends

European natural gas import flows rose by 1.1% (or 3 bcm) y-o-y in 2018 as domestic production fell at a faster pace (down 4.6% or 13 bcm) than consumption (down 2.5% or 10 bcm).⁵ A second driving force behind higher import flows was the low level of gas storage stocks at the end of the 2017/18 heating season. Figure 3.9 shows that European natural gas storage sites were below the five-year average by about 40% or 11 bcm. This raised the injection needs of European gas storage sites during the summer and hence supported higher import flows into the region.

Figure 3.9 European gas storage stocks at end of heating season, 1 October–30 March



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

European natural gas storage sites were 11 bcm below their five-year average at the end of the 2017/18 heating season, which supported additional import flows through the summer of 2018.

Russia's pipeline export sales broke another record in 2018, increasing by 3.8% and surpassing the 200 bcm⁶ mark for the first time ever (Gazprom, 2019a). According to Gazprom, this has been mainly driven by higher natural gas sales to continental northwest Europe,⁷ growing by

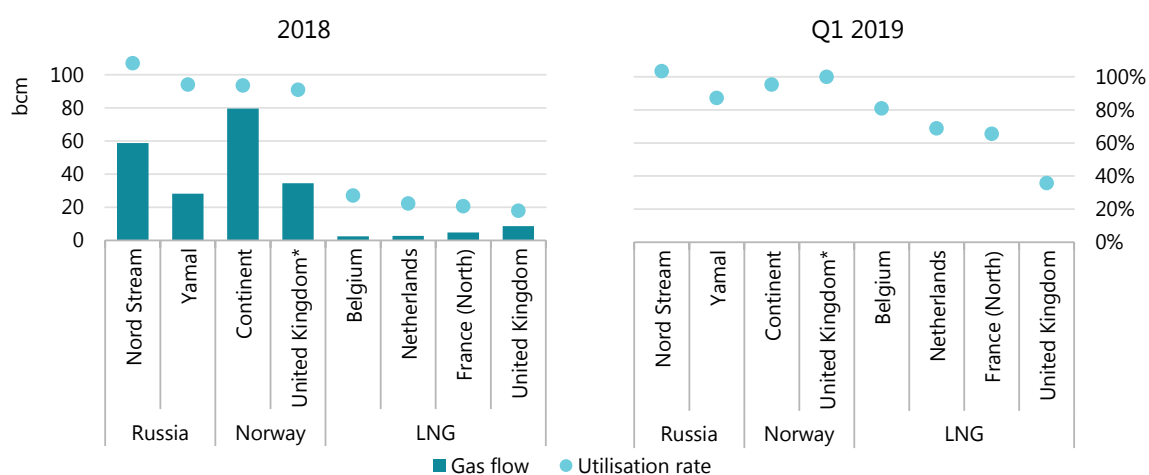
⁵ For more details on consumption and production, please refer to Chapters 1 and 2.

⁶ Volumes expressed in Russian cubic metres (gross calorific value of 37.83 megajoules per m³ at 15°C) to be multiplied by 0.92 to convert to European standard measure.

⁷ Belgium, France, Germany and the Netherlands.

15% (or 11 bcm/y) (Gazprom, 2019b). This indicates that in 2018 Gazprom effectively captured part of the market space left by the decreasing domestic production, mainly in the Netherlands (declining by 7 bcm/y in 2018) but also in Norway (down 1.5 bcm/y) and Germany (down 1 bcm/y). Algerian pipeline gas exports to Europe remained stable, at a level of 33 bcm/y, but with increasing deliveries to the Iberian Peninsula (up 2 bcm/y) and lower gas supplies into Italy (down 2 bcm/y). Azerbaijani gas deliveries to Turkey rose by 1 bcm in the second half of the year, following the launch of the Trans-Anatolian Natural Gas Pipeline (TANAP) in June 2018. In contrast, natural gas imports from Islamic Republic of Iran ("Iran") decreased by almost 1.5 bcm in the second half of 2018.

Figure 3.10 Natural gas infrastructure utilisation rates, 2018 and Q1 2019



* Accounting for the technical capacities of the Langeled and Vesterled pipelines.

Sources: IEA (2019), *Gas Trade Flow*, www.iea.org/gtf/; ENTSG (2019), *Transparency Platform*, <https://transparency.entso.eu/>; National Grid (2019), *Data Item Explorer*, <http://mip-prod-web.azurewebsites.net/DataItemExplorer/Index>; ICIS (2019), *ICIS LNG Edge*, <https://lngedge.icis.com/> (subscription required).

The high utilisation rates of natural gas pipelines servicing northwest Europe demonstrate limited flexibility for upside potential.

LNG imports to Europe decreased by 10% in the first three quarters of 2018, as Asian LNG spot prices were trading on average at a premium of over USD 2 (United States dollars) per million British thermal units (MBtu). This has been changing since October, with the Asian premium gradually eroding (see Chapter 4) amidst lower-than-expected Asian demand, combined with an increase in global LNG supply capacity. This in turn triggered higher LNG import flows to Europe, rising by almost 60% (almost 10 bcm) y-o-y in the last quarter of 2018. The LNG influx continued during the first quarter of 2019, with LNG imports increasing y-o-y by 88% to reach a total of 28 bcm over the quarter. April 2019 set the historical record for monthly European LNG imports, with regasified volumes totalling to 10.6 bcm. Preliminary data indicate that over 75% of the additional LNG volumes imported during the period September 2018–March 2019 were delivered to northwest European gas markets. This in turn pressured European hub prices, contributing to their halving from USD 10/MBtu in September 2018 to below USD 5/MBtu by the beginning of April 2019 (see Chapter 4). This also further increased market liquidity as trading volumes on the Dutch gas hub, the Title Transfer Facility (TTF), rose by 44% y-o-y in the first quarter of 2019, reaching an historical high of 343 bcm in March (GTS, 2019). Both

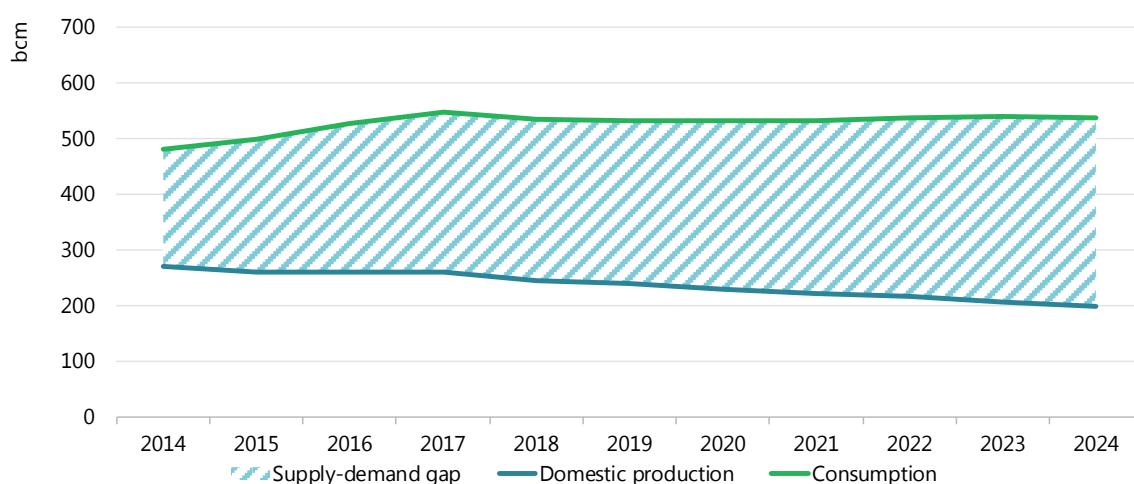
Norwegian and Russian⁸ pipeline gas deliveries to Europe remained stable in the first quarter of 2019, whilst exports from Algeria to Spain and Italy plummeted by 40%. Gazprom has been also actively auctioning natural gas on its Electronic Sales Platform, launched in August 2018, with over 3 bcm of natural gas sold between August 2018 and March 2019 (Gazprom Export, 2019a).

Figure 3.10 shows that the natural gas pipelines servicing northwest Europe⁹ reached a very high average utilisation rate over the course of 2018, whilst regasification terminals were used just above one-fifth of their technical capacity. This changed over the first quarter of 2019, with over 50% of regasification capacity being utilised amidst higher LNG imports into northwest Europe.

A widening supply–demand gap

European natural gas import requirements are expected to increase by almost 50 bcm/y over the forecast period to reach 336 bcm/y in 2024 (Figure 3.11). Whilst European gas consumption is set to remain almost flat, domestic production is set to fall at an average rate of 3.5% per year, primarily driven by the Groningen phase-out in the Netherlands and declining production in the North Sea (see Chapter 2).

Figure 3.11 Natural gas supply–demand gap, Europe, 2014–24



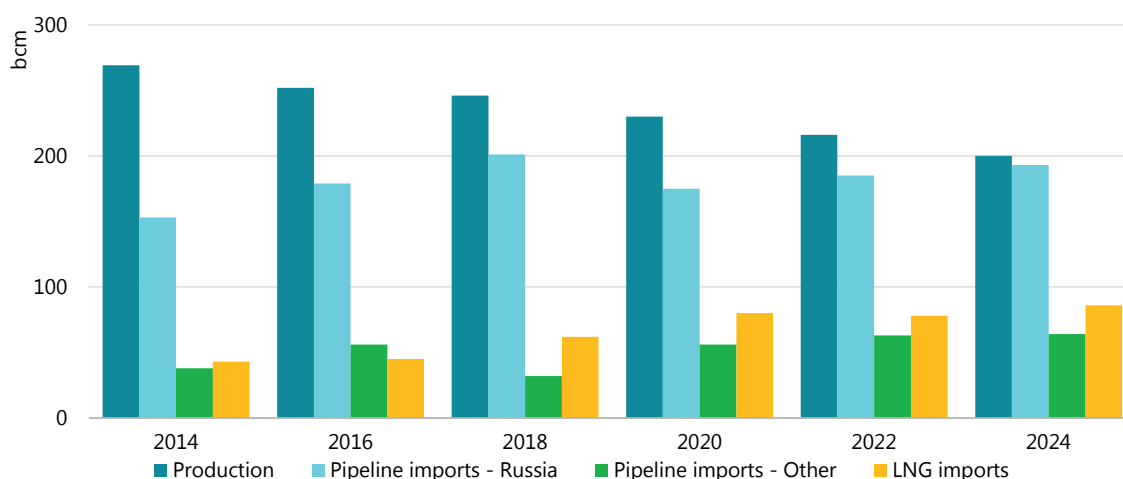
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With domestic production declining and consumption remaining flat, European natural gas import requirements are set to increase by almost 50 bcm/y between 2018 and 2024.

Incremental import requirements will be met by a variety of supply sources, including new pipeline gas imported through the Southern Gas Corridor, additional LNG volumes from an increasingly flexible global gas market and from traditional suppliers such as Russia (Figure 3.12). Because of this diversification, the market share of Russian pipeline gas is expected to decline from its 2018 record high of 37% to a range of 33–36% through the forecast period.

⁸ Excluding deliveries via Blue Stream.

⁹ There is spare capacity through the Ukrainian route; bottlenecks in the European midstream infrastructure would limit these gas volumes from reaching the northwest European market.

Figure 3.12 Natural gas balance, Europe, 2014–24

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Amidst declining domestic production, Europe is set to further diversify its natural gas import sources, whilst Russia's market share in the supply mix is expected to remain within a range of 33-36%.

Natural gas infrastructure

Given Europe's widening supply–demand gap and the rising utilisation rates of key natural gas infrastructure, the development of projects enabling imports and interconnectivity will be crucial through the medium term to ensure the diversity of supply sources and routes to Europe.

The projects forming the Southern Gas Corridor (from Azerbaijan to Italy) are well advanced. The South Caucasus Pipeline Expansion (SCPX) from Azerbaijan through Georgia was completed at the end of June 2018, effectively tripling the export capacity of the pipeline to 20 bcm/y (BP, 2019). The pipeline is linked to the development of Phase 2 of the Shah Deniz field in Azerbaijan (see Chapter 2) and connects to the TANAP running through Turkey. TANAP was inaugurated at the beginning of June 2018 and the first commercial gas deliveries to Turkey started at the beginning of July after the announced start-up of the Shah Deniz 2 field (TANAP, 2018a). TANAP will add 16 bcm/y of additional capacity to the European market, 6 bcm/y for Turkey and up to 10 bcm/y for southeast Europe and Italy once the Trans-Adriatic Pipeline (TAP) is commissioned. The pipeline connection between TANAP and TAP was completed in November 2018 (TANAP, 2018b), and at the end of February 2019 TAP was 85.7% completed (TAP, 2019). TAP is expected to deliver its first gas to Italy by 2020, with an import capacity of 8.8 bcm/y, equating to over 10% of Italy's annual natural gas consumption (CaspianNews, 2019).

Russia's Gazprom is advancing two pipeline export projects to Europe, TurkStream and Nord Stream 2, both scheduled to start commercial operations by the end of 2019.

- TurkStream consists of two strings, each with a capacity of 15.75 bcm/y. The first string is destined for the Turkish market, whilst the second will supply southeast and central Europe. The offshore pipe laying was completed in November 2018 and the connection between the offshore and nearshore sections was completed in March 2019 (TurkStream, 2019). The pipeline is set to begin commercial operations by the end of 2019. However, the downstream pipeline system channelling natural gas from Turkey to southeast and central

Europe through Serbia, Bulgaria and potentially via Hungary is still in the conception phase and is unlikely to be finished before the end of 2020. At the end of January 2019, Bulgartransgaz, the Bulgarian transmission system operator, successfully completed the binding open season for the Bulgarian section of the export channel, and in April 2019 Serbia's Gastrans held a non-binding open season.

- Nord Stream 2 also consists of two strings, each with a capacity of 27.5 bcm/y and with a landing point in Germany near Greifswald. Construction works began in September 2018 and by late May 2019 52.6% of the 55 bcm/y pipeline system was completed (Gazprom Export, 2019b). However, at the time of writing the project company had still not received all the permits necessary to construct the pipeline in the Danish exclusive economic zone, through which it needs to transit (Nord Stream 2, 2019). Upon completion, Nord Stream 2 is to be connected to the Eugal pipeline developed by GASCADE, which similarly will consist of two strings, with a capacity totalling 55 bcm/y. The first string of Eugal is set to start commercial operations by the end of 2019, whilst the second string is scheduled to start by the end of 2020 (Eugal, 2019). Eugal is to deliver gas to Germany and northwest Europe, as well as to central and eastern Europe via the Czech Republic.

The expiry of the Gazprom–Naftogaz transit contract at the end of 2019 and the development of the TurkStream and Nord Stream 2 projects raises questions regarding the future of the Ukrainian gas transit route, which accounted for over 40% of Gazprom's exports into Europe in 2018. Gazprom and Naftogaz, with the European Commission acting as a facilitator, are holding a set of trilateral negotiation talks to find a compromise in respect of transit post-2019 (European Commission, 2019).

In April 2019 the European Council adopted the amendments to the European Gas Directive. Accordingly, EU gas market rules (including ownership unbundling, third-party access, non-discriminatory tariffs and transparency requirements) will be applicable to natural gas pipelines connecting EU member states to a third country – up to the border of the member state's territory and territorial waters. The new regulatory framework will be applicable retroactively; however, exemptions could be granted to natural gas pipelines that started commercial operations prior to the entry into force of the amended Gas Directive. Member states will have nine months to transpose the amendments into national jurisdiction from mid-April 2019 (European Council, 2019).

Development of interconnectors in northern Europe further strengthens the region's resilience:

- The Danish and Polish transmission system operators, Energinet and Gaz-System SA, reached a final investment decision (FID) on the Baltic Pipe project in November 2018 (Baltic Pipe, 2018). The pipeline, with a capacity of 10 bcm/y, is to connect the Norwegian natural gas export system (Europipe II) to Denmark and Poland via a 900-kilometre offshore link. The project is due to receive EUR 215 million (Euros) of funding from the Connecting Europe Facility (Baltic Pipe, 2019) and should be commissioned by October 2022.
- The BBL pipeline, connecting the Netherlands and the United Kingdom, is set to become bidirectional from October 2019 with a capacity of 5.5 bcm/y from the United Kingdom to the Netherlands (BBL, 2018). This will further deepen the interconnectivity between Europe's two most liquid hubs, the Dutch TTF and the British National Balancing Point (NBP). The bidirectional pipeline will help channel excess gas from the United Kingdom during the summer (which cannot be absorbed due to the lack of seasonal storage capacity following the decommissioning of the Rough storage facility) and could mitigate the

increasing import needs of the Netherlands (as the Groningen field is gradually phased out).

The role of LNG

Europe is also seeking to further diversify its supply options via LNG and additional investment in regasification terminals. In Poland, Polskie LNG has taken FID on the expansion of the Świnoujście LNG terminal from the current 5 bcm/y to 7.5 bcm/y, to be completed by the end of 2022 (InterfaxEnergy, 2018). In January 2019 Krk LNG in Croatia reached FID to procure and operate an FSRU vessel. It will have a regasification capacity of 2.5 bcm/y and is scheduled to start commercial operations in the autumn of 2020. The total project is estimated to cost EUR 234 million. A grant of EUR 101.4 million has been received from the European Commission and a further EUR 100 million from the Government of Croatia (KrkLNG, 2019).

Germany, Europe's largest natural gas market, has no LNG import terminal at present. This is likely to change through the forecast period given that LNG is seen as a tool to introduce wider supply options and diversity to the German gas market. Four projects are currently under consideration, located in Brunsbüttel (with a capacity of 5 bcm/y and supported by Gasunie, Oiltanking and Vopak), Stade (4 bcm/y and backed by Dow Germany), Wilhelmshaven (10 bcm/y and promoted by Uniper) and Rostock (0.4 bcm/y, supported by Fluxys and Novatek). Both Brunsbüttel and Wilhelmshaven are targeting start-up by the end of 2022. Whilst none of the terminals had reached FID at the time of writing, Germany's Economy Minister stated in February 2019 that it can be expected that at least two projects "will be realised" in the near future (Reuters, 2019a).

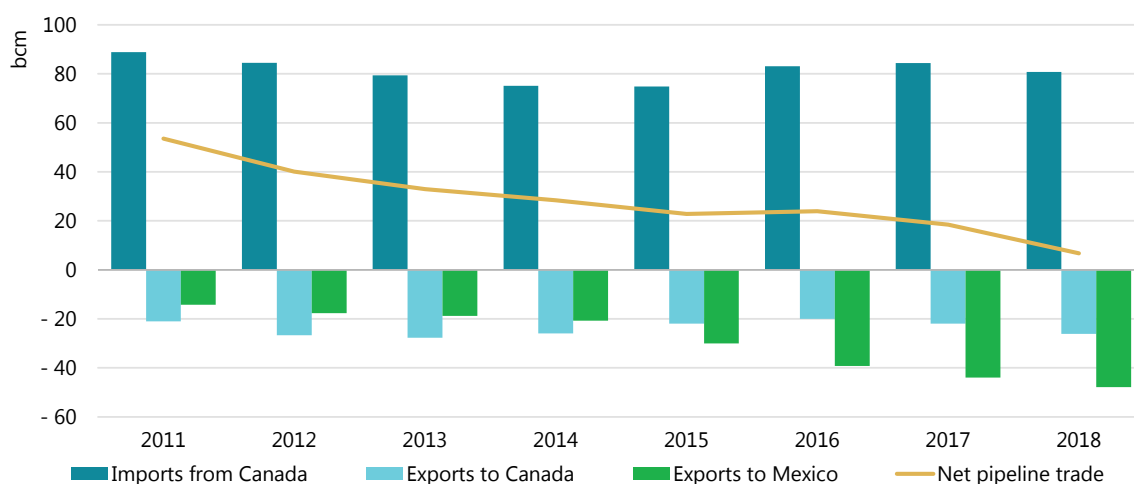
LNG is expected to play an increasingly important role in Europe's natural gas supply portfolio, growing at a rate of 4% per year through the forecast period from 66 bcm in 2018 to 86 bcm by 2024.

Americas

North America

The United States is the main driver of natural gas trade growth within North America, with the development of pipeline exports to Mexico. The US pipeline trade balance has evolved over recent years towards a gradual reduction in net imports as export flows to Mexico more than tripled – from 14 bcm in 2011 to 48 bcm in 2018 (Figure 3.13). Imports from Canada slightly decreased in 2018 while exports increased.

Pipeline trade flows between the United States and Canada remain stable over the forecast period in spite of the strong growth of US domestic production, as Canada remains a pivotal source of supply to the US Pacific Coast, Northeast and Midwest markets, which have limited interconnection capacity with major US shale production areas. US LNG imports are mainly limited to the supply of the Everett terminal in the Northeast (around 2 bcm/y).

Figure 3.13 Evolution of pipeline imports and exports, United States, 2011–18

Sources: EIA (2019a), *U.S. Natural Gas Exports and Re-Exports by Country*, www.eia.gov/dnav/ng/ng_move_expc_s1_a.htm; EIA (2019b), *U.S. Natural Gas Imports by Country*, www.eia.gov/dnav/ng/ng_move_imp_c_s1_a.htm.

The strong growth in US pipeline exports to Mexico, combined with stable flows to Canada, almost offset US pipeline imports in 2018.

Mexico is expected to further increase its pipeline gas imports from the United States to meet its growing domestic consumption needs. Pipeline interconnection capacity has expanded over recent years, from 16 interconnections in 2012 with a capacity of 28bcm/y, to 24 interconnections with a total capacity of 112.5 bcm/y as of April 2019 (SENER, 2019). The growing availability of competitive pipeline gas from US shale basins is likely to limit the potential of LNG import growth during the forecast period.

South America

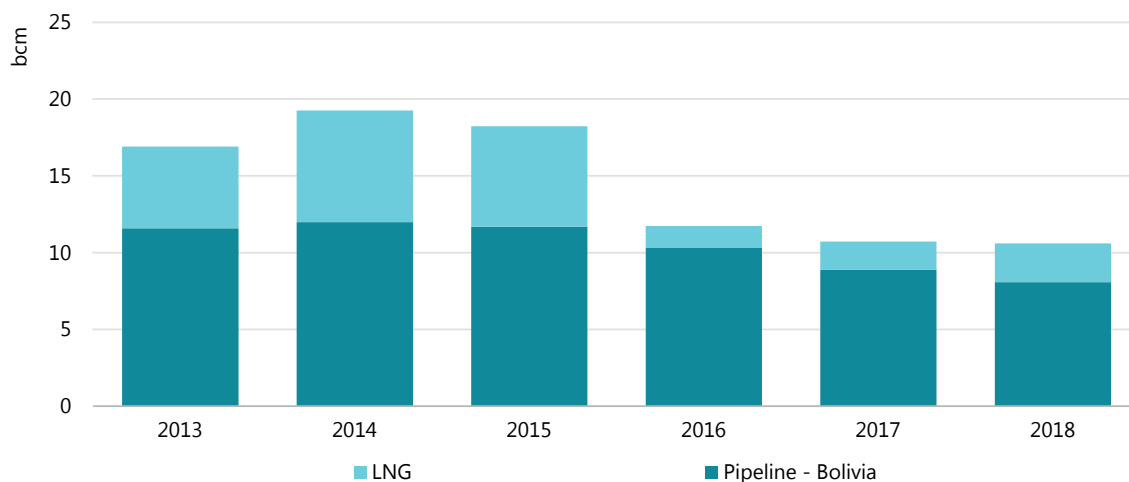
Interconnections between South American markets remain limited and are in most cases monidirectional from net exporters to importers – with the notable exception of bidirectional capacity between Argentina and Chile.

Argentinean natural gas imports have been declining over recent years as domestic production has continued expanding. In November 2018 Argentina resumed its exports to Chile after a 12 year interruption, and in March 2019 the government authorised Total and state-owned YPF to further increase export volumes by 2 mcm/d during an eight-month period of lower local demand (Reuters, 2019b). In February 2019 Argentina and Bolivia reached an agreement that will allow Argentina to receive reduced natural gas volumes during the months of lower consumption in 2019 and 2020. The country had two FSRUs, the Excelerate Exemplar in Port de Bahia Blanca and the Excelerate Expedient in Port Escobar. However, the Exemplar left Bahia Blanca in October 2018. In November 2018 YPF and Exmar reached an agreement to use a floating liquefaction unit (FLNG) to start exporting natural gas. Exports are expected to be limited with an objective of eight cargoes per year for the next ten years.

Brazil's natural gas imports strongly correlate with hydro availability for power generation needs. In 2018 natural gas imports stood at almost half their peak levels of 2014, which were due to El Niño-related droughts (Figure 3.14). Brazil and Bolivia have a long-term contract for up to 11 bcm/y, where natural gas is directly delivered to Petrobras via the Gasbol pipeline, Petrobras then reselling part of the volumes to third parties. The contract expires at the end of

2019 and is currently under renegotiation; however, the clauses concerning volumes are likely to be revised downward as Petrobras stops sourcing gas for other players and buys only for its own needs (IEA, 2018a).

Figure 3.14 Pipeline and LNG imports, Brazil, 2013–18



Source: MME (2019), “Boletim mensal de acompanhamento da indústria de gás natural – Dezembro 2018” [Monthly gas industry monitoring bulletin – December 2018], www.mme.gov.br/documents/1138769/0/Boletim_Gas_Natural_nr_142_DEZ_18.pdf/49912e53-03ee-47cc-a45e-7ffa093ff777.

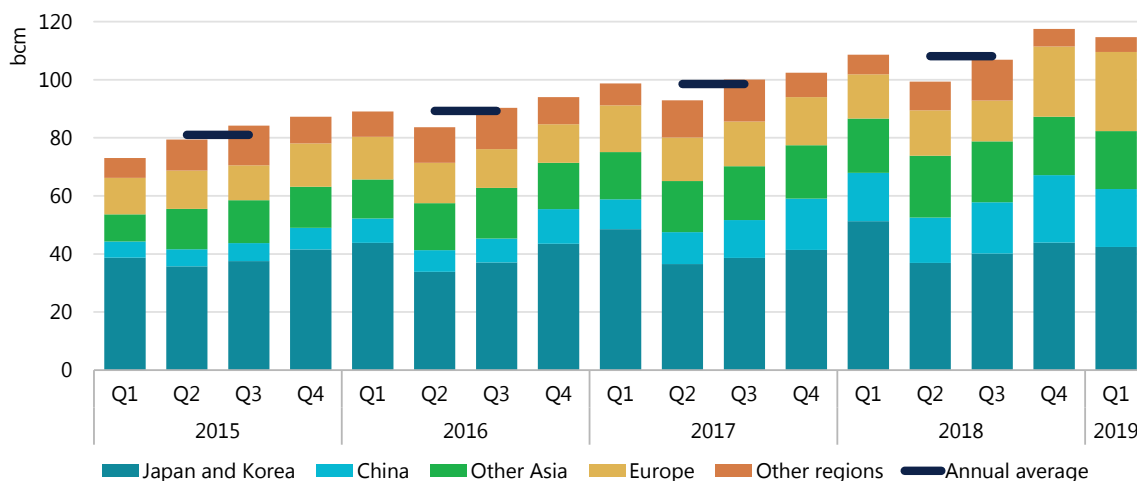
Brazilian gas imports from Bolivia have shown a structural decline since 2014, while LNG is used as a balancing source of supply for power generation to compensate for hydropower volatility.

Global LNG market

2018 marked a third year of strong LNG trade growth

2018 was another year with a double-digit growth rate for LNG trade, with flows increasing by 10% to reach 432 bcm (including reloads). This third consecutive year of strong growth follows an almost 11% increase in 2017 and 10% in 2016, after two years of relative stagnation in 2014 and 2015. Trade data from the first quarter of 2019 confirm the trend, with 115 bcm or 6% y-o-y growth in spite of mild temperatures in the northern hemisphere (Figure 3.15).

On the consumers’ side, Asian markets accounted for most of the growth recorded in 2018, with an increment of almost 39 bcm or 85% of the net growth in LNG imports (or over 101% of total growth when considering import decreases in Africa, Eurasia and the Middle East). China was the single largest contributor to LNG import growth for a third consecutive year, with an increase of almost 22 bcm to reach a total of 73 bcm of LNG imported, thus accounting for 55% of global import growth. South Asia was another major source of growth, with India increasing by 13% and passing the 30 bcm mark, Pakistan growing by almost 60% to reach 10 bcm, and Bangladesh importing its first LNG cargo in the first half of 2018 and with almost 1 bcm of imports at the end of the year. Other emerging Asian buyers such as Thailand, Singapore and Indonesia saw their imports grow at double-digit rates (up 16%, 15% and 11% respectively). Korea saw its LNG flows increase by 16% y-o-y to reach an all-time record of almost 60 bcm on strong power generation consumption to compensate for low nuclear utilisation, while Japanese imports slightly decreased by 1%.

Figure 3.15 Evolution of LNG imports, quarterly volumes and annual averages, 2015–19

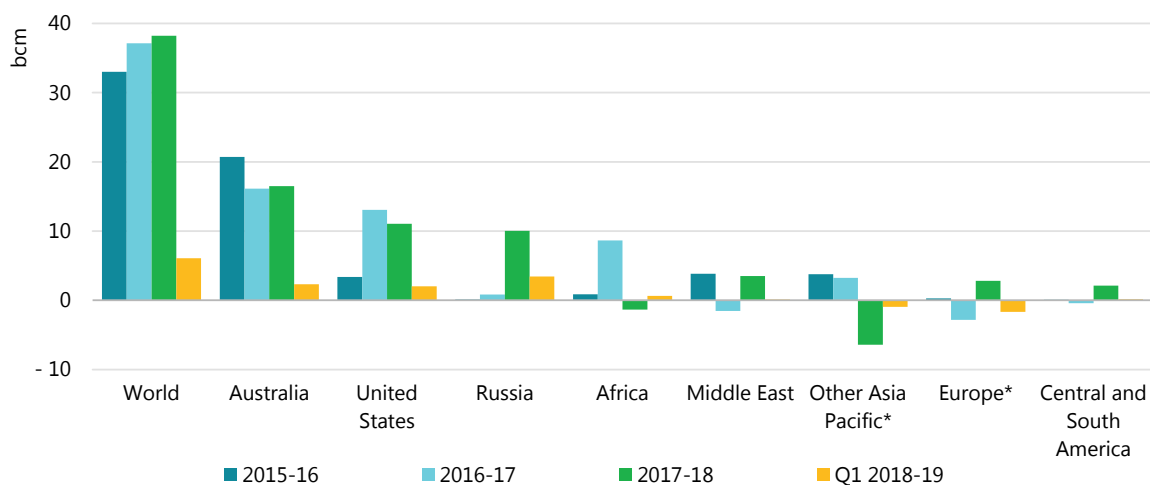
Source: IEA analysis based on ICIS (2019), *ICIS LNG Edge*, www.icis.com/energy/liquefied-natural-gas/lng-market-intelligence-solution/ (subscription required).

Global LNG trade grew at an average of 10% per annum between 2016 and 2018, with strong import increases in emerging Asian markets, Korea and Europe (in late 2018).

Europe was the second main source of trade growth in 2018 with a total of 69 bcm¹⁰ imported, 6 bcm or 10% above the 2017 level, which already showed some recovery compared to the lower levels recorded between 2013 and 2016 (all below 55 bcm/y) in the aftermath of the Fukushima Daiichi nuclear incident. Most of this LNG increase materialised in the last quarter of 2018 (which accounted for 35% of Europe's annual imports), as the prospect of a tight market in Asia did not materialise due to milder-than-expected temperatures. At the time of writing, LNG flows to Europe remain high, with data for the first quarter of 2019 showing some 65% y-o-y increase at 27 bcm, as spot price spreads between Europe and Asia have narrowed. This makes LNG reloads to Asia uneconomical. For more information on market prices, see Chapter 4. Other regions of the world experienced a variety of import trends in 2018: LNG flows increased by 4% in Central and South America in spite of a decrease in Argentina's import needs, with new import facilities ramping up in Colombia and the Caribbean, and Panama starting imports; LNG flows into the Middle East decreased sharply (down 21%) on lower imports into Jordan and the United Arab Emirates, and into Africa (down 63%) due to Egypt's domestic production recovery.

On the supply side, 2018 confirmed Australia's position as largest single contributor to LNG supply growth, with 16 bcm of additional exports, followed by the United States with 11 bcm (Figure 3.16). Together these two countries accounted for 79% of the LNG export increment in 2017 and 72% in 2018. Russia saw its export capacity increase rapidly following the commissioning of the first train of Yamal LNG at the end of 2017, growing by 10 bcm in 2018 and above 3 bcm for the first quarter of 2019 with the start-up of the second and third trains. This makes Russia the largest source of LNG supply growth for the beginning of the year. Both Middle Eastern and Central and South American exporters saw their LNG flows increase in 2018 (up 3 bcm and 2 bcm respectively) mainly due to export increases from Oman and Trinidad and Tobago.

¹⁰ Including 4 bcm of reloads to other European countries or other regions.

Figure 3.16 LNG annual export increment by main country and region, 2015–18 and Q1 2019

* Including reloads.

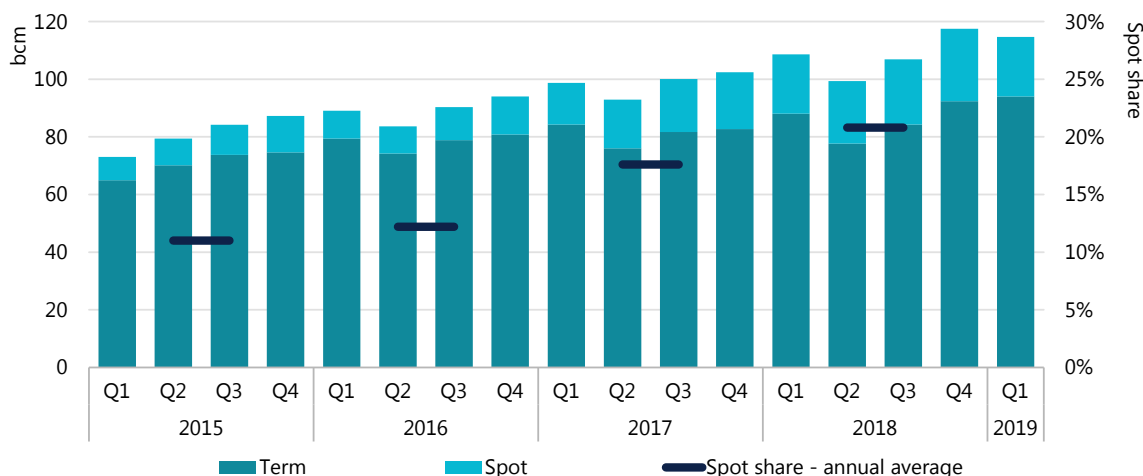
Source: IEA analysis based on ICIS (2019), *ICIS LNG Edge*, www.icis.com/energy/liquefied-natural-gas/lng-market-intelligence-solution/ (subscription required).

Australia has been the main contributor to the growth in LNG exports between 2015 and 2016, followed by the United States. Russia was the largest contributor in the first quarter of 2019.

A rebound in reloading activity from northwest Europe and Spain and the start of transshipment of Russian LNG in Norway led to a 2 bcm increase in European LNG (re)exports in 2018. Reloading activity was almost non-existent in Europe during the first quarter of 2019, except for 0.2 bcm in Norway and 0.1 bcm in France, due to the absence of favourable price spreads with Asia. Exports from the Asia Pacific region (other than Australia) decreased by 6 bcm in 2018 due to production shutdown in Papua New Guinea following the February 2018 earthquake and lower send-out from Indonesia and Malaysia. African LNG exports decreased by over 1 bcm, mainly due to lower Algerian volumes (down 17%) but partly offset by growth from Angola and the progressive restart of Egyptian exports – Egypt shipped almost 1 bcm in the first quarter of 2019, equivalent to almost half of its total exports of 2018.

The strong growth in LNG trade volumes over recent years was also accompanied by an increase in flexibility, which keeps improving in a move towards a liquid global market. The trend for an increasing share of long-term volumes signed from new export projects without destination clauses has fostered the development of midstream flexibility provided by major portfolio players. These companies, which account for the largest share of long-term offtake from recent liquefaction projects, resell those volumes to third parties – thus enabling the development of a secondary market and providing access to LNG for smaller buyers and new entrants. This trend towards more diversification of buyers is evidenced by the continuous increase in spot traded volumes, which rose from an average of 11% of LNG trade in 2015 to 21% in 2018 – or the equivalent of 90 bcm (Figure 3.17).

Figure 3.17 Evolution of LNG trade, quarterly term and spot volumes, 2015–19



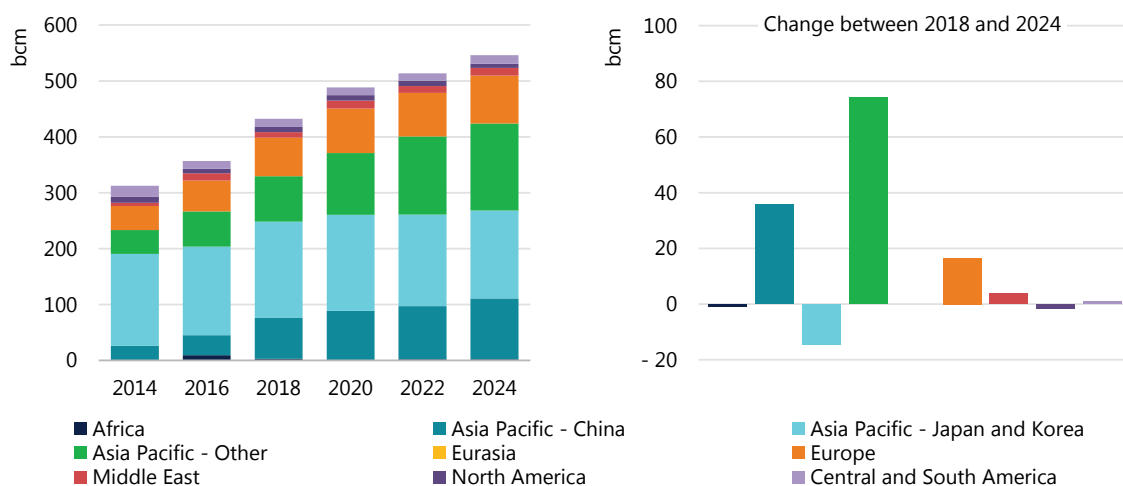
Source: IEA analysis based on ICIS (2019), *ICIS LNG Edge*, www.icis.com/energy/liquefied-natural-gas/lng-market-intelligence-solution/ (subscription required).

The share of spot volumes within global LNG trade almost doubled between 2015 and 2018 to reach an average of 21%.

LNG demand outlook

Global LNG trade is expected to reach 546 bcm/y by 2024, increasing by 26% compared to 2018 (Figure 3.18). The bulk of additional imports are into emerging Asian economies, and especially China, which sees its LNG imports increase by almost 50% between 2018 and 2024. China is the single largest contributor to LNG import development, accounting for almost one-third of total growth, and becomes the world’s largest LNG importer by the end of the forecast period at 109 bcm/y against 105 bcm/y for Japan.

Figure 3.18 World LNG imports by region, 2014–24



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Fast-growing Asian economies – led by China – and Europe account for almost all of the increase in LNG imports to 2024.

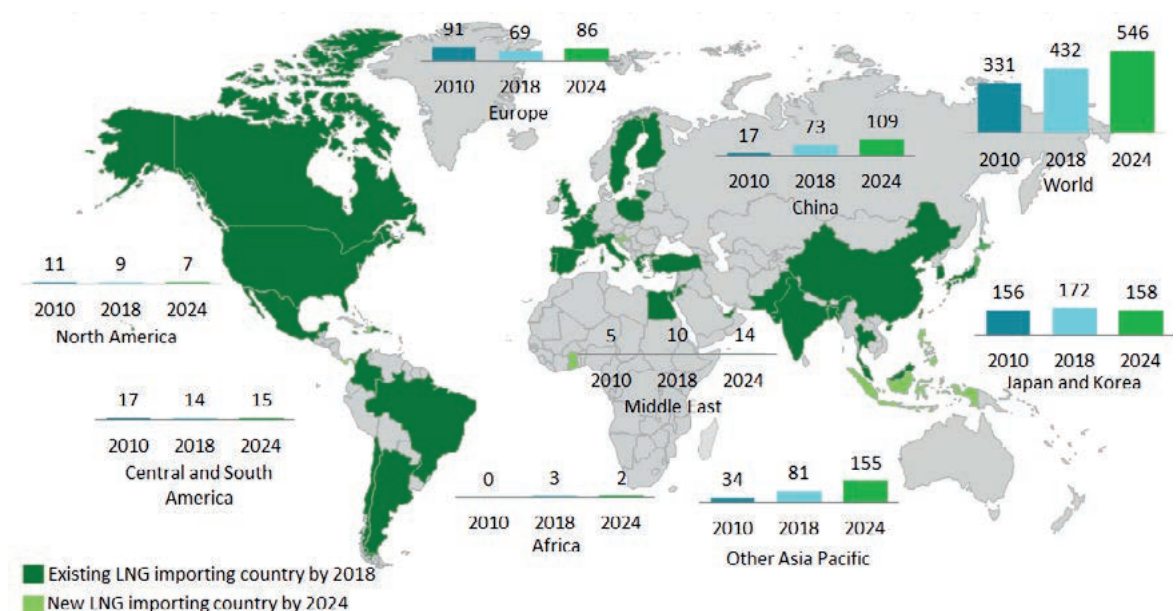
Other rapidly growing Asian markets represent another sizeable source of LNG import growth, accounting for 74 bcm/y of additional volumes during the forecast period. India emerges as one

of the leaders in terms of LNG growth, driven by its strong domestic consumption and the doubling of its regasification capacity over the forecast period to reach 80 bcm/y by 2024. India has four projects under construction plus the Ennore terminal, which started operations during the first quarter of 2019. Pakistan and Bangladesh are also likely to see their imports grow over the coming years, due to their strong reliance on natural gas in their energy mix and their stagnating or declining domestic production. South East Asian countries also see their import capacity further develop in the near future, with several projects currently under development to expand Thailand’s existing regasification capacity and build new infrastructure in Viet Nam and the Philippines.

The two large traditional Asian LNG importers, Japan and Korea, see their imports decline by 15 bcm/y during the forecast period. Japan’s import needs slowly decrease in parallel with the expected progressive restart of its nuclear power generation fleet, ceding its position as number one LNG importer to China by 2024, whereas Korea’s imports are expected to stabilise after 2022.

Outside Asia, Europe is the main source of LNG import growth, helped by a combination of decreasing domestic production in northwest Europe and the ambition to increase the diversity of supply vis-à-vis traditional pipeline suppliers. About 7 bcm/y of additional regasification capacity is under development as of the beginning of 2019, including capacity extensions to existing terminals as well as a new project in Croatia, the first in the country. Additionally, other European countries are considering the LNG option, including Germany with four projects proposed. The German government, which is promoting the development of at least two of the said projects to provide alternative sources of supply to its domestic market, announced in March 2019 a plan to incentivise investment by lowering the cost of connection to the transport network by 90% (Witkop, 2019; Reuters, 2019c).

Figure 3.19 LNG importing countries and territories and LNG import volumes, 2010–24



IEA, 2019. All rights reserved.

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

China becomes the largest buyer of LNG by 2024, surpassing Japan and accounting for one-fifth of world LNG imports.

Contributions from regions other than Asia and Europe appear rather limited (Figure 3.19). Africa already saw its LNG imports shrink in 2018 as Egypt moved back to self-sufficiency, and most import projects in sub-Saharan Africa are currently stalled. LNG imports are expected to remain stable in the Middle East and in Central and South America, and progressively decline in North America as Mexico sees greater access to pipeline gas from the United States.

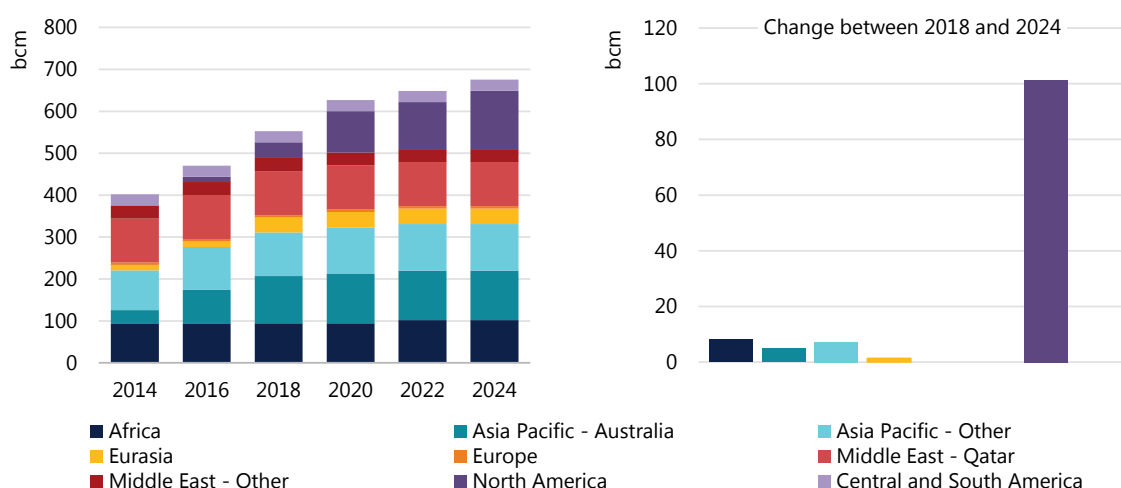
LNG supply outlook

By the end of 2018 global liquefaction nameplate capacity reached 553 bcm/y, increasing by 48 bcm/y or 10% y-o-y, due to new projects commissioned in Australia, the United States, Russia and Cameroon.

This report only considers liquefaction projects that had taken their FID¹¹ as of early June 2019 as contributing to future export capacity for the forecast period. Based on this assumption, total nameplate liquefaction capacity is expected to reach above 670 bcm/y by 2024 (Figure 3.20).

Australia, which had surpassed Qatar as number one country in terms of liquefaction nameplate capacity by the end of 2018, reaches the end of its LNG export investment cycle, with a total of 80 bcm/y of nameplate capacity added between 2015 and end 2018. The last remaining project, Prelude FLNG, shipped its first condensate cargo in March 2019 (Reuters, 2019d).

Figure 3.20 LNG nameplate liquefaction capacity, 2014–24



IEA, 2019. All rights reserved.

As the cycle of capacity development reaches its end in Australia, the United States remains the only major source of incremental liquefaction capacity to 2024 (based on FIDs as of early June 2019).

The United States accounts for over 80% of new liquefaction capacity due to be commissioned in the coming five years, with a large majority of projects starting operations between 2019 and 2021: Cameron (3 trains), Freeport (3 trains), Elba Island (10 small-scale LNG modules), Sabine Pass train 5 and Corpus Christi trains 2 and 3. The Golden Pass LNG project, which took FID in February 2019, is scheduled to be commissioned by the end of the forecast period in 2024, and

¹¹ With the notable exception of the Calcasieu Pass LNG project in the United States, which reportedly started construction in early April 2019 after having received its final authorisation from Federal Energy Regulatory Commission and export authorisation from the Department of Energy without officially declaring FID (Reuters, 2019d).

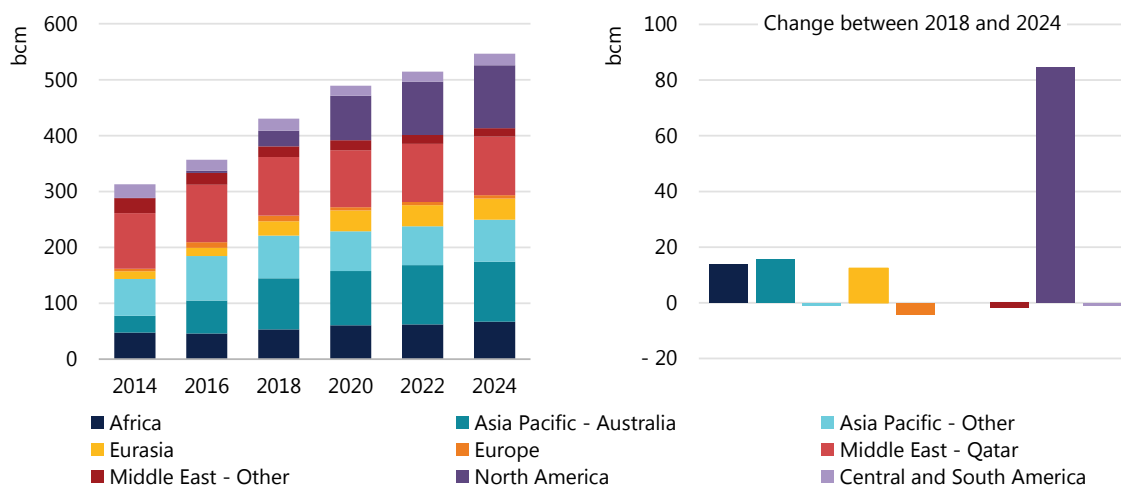
the Calcasieu Pass LNG project, which started construction in April 2019, is set to be commissioned in 2022. Sabine Pass train 6 took FID in early June 2019, with long-term contracts with Vitol and PETRONAS starting in 2022 and 2024 respectively.

Three other projects – Tangguh LNG train 3 in Indonesia, Petronas FLNG 2 in Malaysia, and Yamal LNG train 4 in Russia – are all expected to start operations by end-2020, altogether adding almost 9 bcm/y to global export capacity.

Africa also contributes to LNG export capacity expansion. After the commissioning of Cameroon’s floating unit in 2018 (the first new project on the continent since the development of Angola LNG), two offshore projects – Coral South FLNG in Mozambique and Tortue FLNG in Mauritania and Senegal – are scheduled to start operations by 2022.

These developments result in a concentration of capacity additions over the coming two years. However, a significant proportion of global liquefaction capacity has remained offline in recent years: over the past four years, unplanned capacity disruptions resulted in 12–14% of total nameplate capacity being offline (IEA, 2018b). This forecast assumes that several liquefaction plants will remain offline or will run below their nameplate capacity until 2024 for several reasons (technical issues, feed gas limitations, security risk).

Figure 3.21 World LNG exports by region of source, 2014–24



IEA, 2019. All rights reserved.

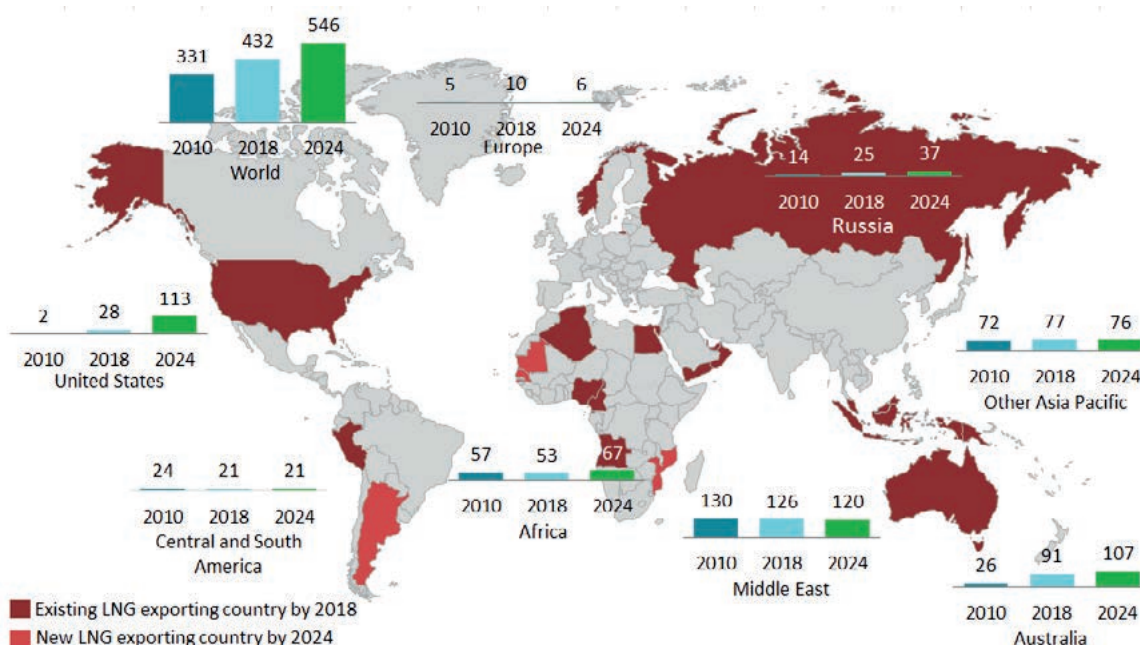
Australia, Russia and the United States together account for almost 90% of LNG export growth to 2024 – with the United States alone rising to two-thirds of total growth.

In accordance with its strong position in new capacity development, the United States is the largest contributor to LNG export growth over the forecast period, accounting for two-thirds of additional volumes to be marketed between 2018 and 2024 (Figure 3.21).

US LNG is expected to become the largest source of supply by the end of the forecast period, reaching 113 bcm/y in 2024, ahead of Australia (107 bcm/y) and Qatar (105 bcm/y) (Figure 3.22). Australia will see its exports increase by 16 bcm/y as the last projects to be commissioned ramp up, while Qatar’s output is assumed to remain flat in the absence of FID for expansion at the time of writing. On a regional basis, the Middle East remains the second-largest exporting region at 120 bcm/y after Asia Pacific (183 bcm/y) and ahead of North America. Yemen is not

assumed to resume its LNG operations in the near future (in spite of the government’s announced objective of restarting the Balhaf plant in 2019 [Malek, 2019]) and is considered to remain offline.

Figure 3.22 LNG exporting countries and territories and LNG export volumes, 2010–24



IEA, 2019. All rights reserved.

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

The United States is set to become the largest LNG exporter by 2024, ahead of Australia and Qatar.

LNG exports from the Asia Pacific region – outside Australia – are expected to remain stable throughout the forecast period thanks to the stabilisation of domestic production in Indonesia after several years of decline due to recent discoveries and developments (see Chapter 2).

Russia’s LNG exports increase by almost 50% to reach 38 bcm/y by 2024,¹² with the current ramp-up of Yamal LNG’s train 3 and the commissioning of train 4 (scheduled for 2020). Exports from Europe and South America remain stable.

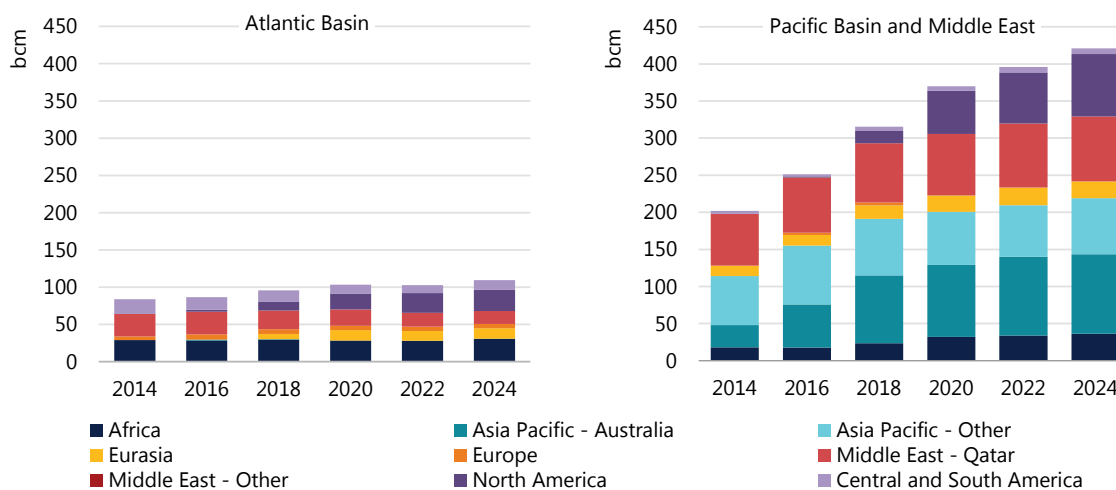
In Africa, exports from existing infrastructure in Algeria and the Gulf of Guinea are assumed to remain stable – and even slightly decline in the case of Algeria due to additional needs from the domestic market and the progressive expiry of legacy export contracts. New offshore projects (Coral FLNG in East Africa and Tortue FLNG in West Africa) are both expected to begin exporting in the second half of the forecast period, thus contributing to the continent’s overall export growth. Egypt saw its LNG exports grow after 2016 thanks to its upstream recovery; however, it is assumed that the policy of prioritising domestic use will remain in force for the foreseeable future and that Egypt’s exports remains at a maximum of 4 bcm/y (based on the extrapolation of the 0.9 bcm exported during the first quarter of 2019) and declining by the end of the forecast period.

¹² Including Novatek’s small-scale Vysotsk plant in the Baltic Sea (0.9 bcm/y), which started operations in April 2019.

LNG trade flows

LNG trade in the Pacific Basin and Middle East accounted for 78% of total LNG flows in 2018 at a volume of 337 bcm, increasing from 301 bcm in 2017. This results mainly from the growth in imports into China (up 21 bcm/y), Korea (up 8.5 bcm/y) and Pakistan and India (up 3.5 bcm/y each), while Japanese imports were almost stable (down 1 bcm/y) and those into the Middle East declined (down 2.6 bcm/y).

Figure 3.23 LNG import in the Atlantic and Pacific Basins by origin, 2014–24



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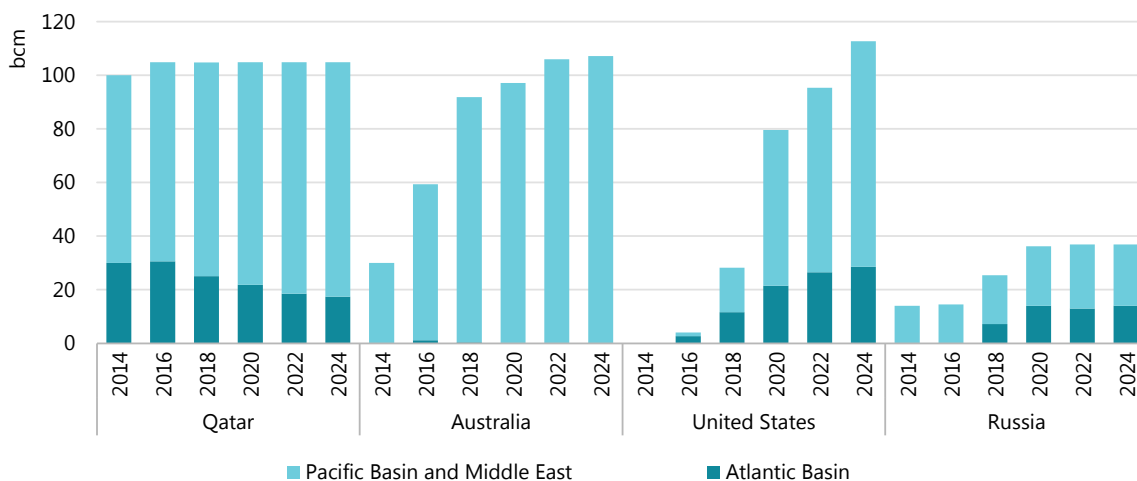
The Pacific Basin remains the main source of LNG trade growth, with a doubling of its imports between 2014 and 2024.

In the Atlantic Basin, imports increased marginally from 94 to 96 bcm/y between 2017 and 2018 as a whole, but with some compensating effects between a 10% increase in Europe (up 6 bcm/y), some stability in both North and South America (down 0.5 bcm/y each), and a steep decline in Egyptian imports (down 5 bcm/y) as the country saw its own production increase sharply.

By 2024 LNG flows in the Pacific Basin and Middle East are expected to reach 436 bcm/y or a 30% increase from 2018, thus accounting for 80% of total LNG trade (Figure 3.23). Growth in export volumes from US, Australian, African and Russian projects currently under development account for most of the additional trade east of the Suez Canal. Flows in the Atlantic Basin grow by 14% to 110 bcm/y by the end of the forecast period, with US LNG providing the bulk of additional volumes.

Exports from Qatar are expected to shift further to the east, as the Pacific Basin's share of its trade increases from 76% in 2018 to 83% by 2024 (Figure 3.24). US LNG flows were almost balanced in 2018 (59% to the Pacific Basin) with Korea becoming its largest destination, after its first two years of exports were slightly dominated by Atlantic Basin destinations; Chile and then Mexico were the largest destinations by volume in 2016 and 2017. Exports to the Pacific Basin are expected to increase strongly to reach a share of 75% of US LNG flows by 2024, while Europe becomes the main destination on the Atlantic Basin. Additional Russian LNG flows from the Yamal peninsula are expected to be almost equally balanced between basins.

Figure 3.24 LNG exports by basin for a selection of exporting countries, 2014–24

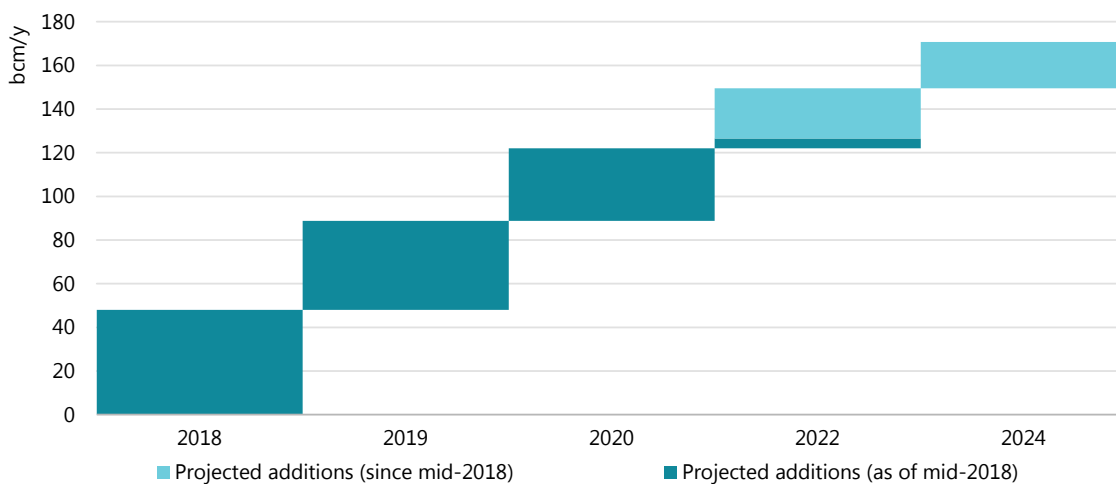


IEA, 2019. All rights reserved.

The Pacific Basin attracts a growing share of US and Qatari LNG flows during the forecast, whereas its share of Russian exports remains stable.

Liquefaction capacity and investment

Figure 3.25 LNG export nameplate capacity additions, 2018–24



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Note: Nameplate capacity for projects with FID at the time of writing, using commissioning years according to project companies' official planning, excluding assumptions on unannounced delays and ramping-up of newly commissioned facilities.

Liquefaction projects that have achieved FID since mid-2018 provide additional LNG supply capacity towards the end of the forecast period.

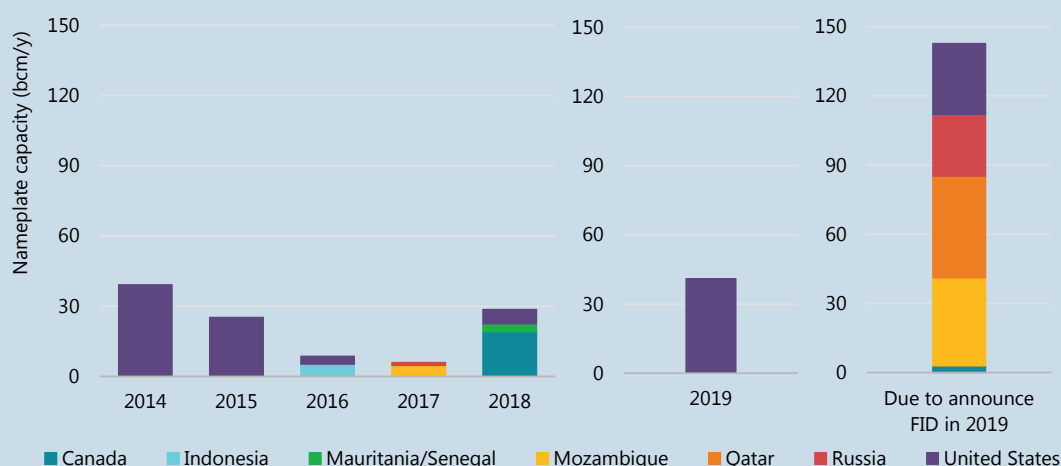
The global LNG supply outlook has evolved substantially since the last issue of this report, with a total of 63 bcm/y of new projects taking FID or starting construction since mid-2018,¹³ and a significant number of additional greenfield and expansion projects scheduled for FID in the course of the year (see Box 3.1). A large share of this additional capacity (44 bcm/y) is scheduled to be commissioned during the forecast period.

Because of this recent acceleration in FIDs, the build-up of additional liquefaction capacity has extended beyond 2022 and contributes to enabling further growth in global LNG trade by the end of the forecast period (Figure 3.25).

Box 3.1. Will 2019 mark the beginning of a new LNG investment cycle?

The recent and ongoing liquefaction capacity additions result from a cycle of LNG investment decisions that took place during the first half of the decade, with a net decline in FIDs after 2014. FIDs slowed from 39 bcm/y in 2014 to less than 6 bcm/y by nameplate capacity in 2017, with only one project sanctioned (Coral South FLNG in Mozambique) and the construction of Yamal LNG’s fourth train.

LNG export projects FID or construction start, 2014–19



Source: IEA calculation based on information from project companies.

2018 marked a return to investment growth with FIDs on two greenfield projects (LNG Canada and Tortue FLNG) and an expansion (Corpus Christi LNG train 3), totalling almost 29 bcm/y of additional nameplate capacity. The pace of new investment is gathering speed in 2019, with Golden Pass LNG taking FID in February, Sabine Pass LNG train 6 in early June and Calcasieu Pass LNG announcing construction start-up in April after it received its final authorisations from the Federal Energy Regulatory Commission (FERC) and the US Department of Energy (DOE) (Reuters, 2019e). Together these three projects amount to around 40 bcm/y of nameplate capacity, higher than the sum of new projects that took FID in 2017 and 2018 combined. Several of these recently sanctioned projects

¹³ LNG Canada took FID in October 2018, Tortue FLNG in December 2018, Golden Pass LNG in February 2019, and Sabine Pass train 6 in June 2019, plus Calcasieu Pass LNG reportedly started construction in April 2019.

(LNG Canada, Tortue LNG, Golden Pass LNG) took FID without the support of long-term contracts, with equity holders adding the volumes to their portfolios and relying on their own balance sheets to finance the investment. This stands in contrast to traditional LNG project development, where long-term offtake contracts are used to secure project financing.

Besides this strong growth in sanctioned liquefaction projects, there is a long list of potential projects that have announced that their FID is set to be taken in 2019, totalling over 140 bcm/y of additional export capacity. The largest remains Qatargas's expansion project, which would include the construction of four trains for a total additional nameplate capacity of about 44 bcm/y and would push Qatar's total export capacity from a current 105 bcm/y to 149 bcm/y upon completion (scheduled for 2024). Mozambique is the second source of FIDs due for announcement in 2019, with two projects – Mozambique LNG and Rovuma LNG – totalling 38 bcm/y, closely followed by the United States¹⁴ with Tellurian's Driftwood LNG greenfield project and the expansion of Cheniere's Corpus Christi LNG (Stage 3). In Russia, Novatek's 27 bcm/y Arctic LNG 2 project is moving forward with an FID announcement expected in mid-2019. Canada's Woodfibre LNG (3 bcm/y) is also due for confirmation in 2019.

The present forecast only considers projects that had achieved FID or started construction at the time of writing; however, such a strong build-up of projects announced as being at a late stage of decision is likely to lead to further FIDs in the course of the year.

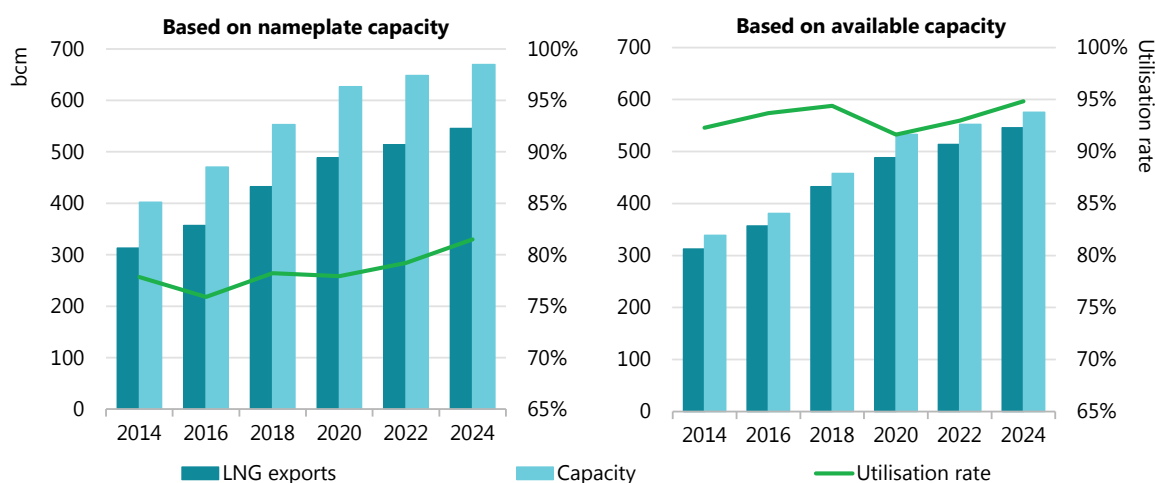
Figure 3.26 shows that the utilisation rate of liquefaction is expected to increase gradually from 2020:

- The utilisation rate based on nameplate capacity recovered in 2018 from a low point of 76% in 2016. It stagnates over the two coming years as LNG demand grows at the same rate as capacity development, then increases from 2020 to reach above 81% by 2024.
- The rate based on available capacity – adjusted to take into account both maintenance and unplanned outages¹⁵ – shows a slightly different evolution over the initial years. The availability of liquefaction capacity has increased thanks to improvements in productivity over the past two years (IEA, 2018b), which led to a less pronounced growth in the utilisation rate between 2016 and 2018. Assuming that such productivity gains remain in the future, the utilisation rate of available liquefaction capacity decreases until 2020, then resumes its growth to reach 95% (slightly above its estimated level of 94% in 2018).

Based on this forecast's LNG trade assumptions and confirmed liquefaction capacity additions, LNG export spare capacity is expected to diminish gradually towards 2024 to a market situation similar to that in 2018 – with enough supply capacity on an annual average basis, but with limited spare volumes in case of seasonal swing or peaks. This market retightening could be alleviated if more liquefaction projects take FID in 2019, providing additional LNG export capacity for the second half of the forecast period – depending on the amount and timing of commissioning of these additional projects.

¹⁴ In addition to the abovementioned Golden Pass LNG and Calcasieu Pass LNG projects, and Sabine Pass LNG's extension.

¹⁵ As mentioned previously, this forecast assumes that several liquefaction plants will remain off line or run below their technical capacity for technical issues, lack of feed gas, weather-related events or security risks.

Figure 3.26 LNG trade and liquefaction utilisation rate, 2014–24

IEA, 2019. All rights reserved.

The overall liquefaction utilisation rate is expected to increase from 2020 as LNG demand growth outpaces new capacity additions.

LNG shipping outlook

The LNG shipping market is being affected by the changes that have occurred in LNG trading in recent years, with increasing demand for flexibility in supply and contracts of shorter duration. The development of spot LNG carrier (LNGC) chartering emerged in the aftermath of the Fukushima Daiichi accident as demand for spot cargoes surged. Spot LNGC charter rates reached their lowest levels in 2016/17 at below USD 30 000/day, driven by an excess of shipping capacity. The increasing LNG imports into China – especially for the winter months – led to the development of seasonal price patterns for spot charter rates, with a first cycle during the winter of 2017/18, followed by a much stronger cycle at the end of 2018 (Figure 3.27). Spot charter rates rose up to USD 190 000/day in November 2018 as market operators used LNGCs as floating storage ahead of an expected tight supply market in Asia – which did not materialise because of warmer-than-average temperatures (Jaganathan, 2018). This led in turn to a sharp drop in spot rates, which returned to their pre-2018 levels of USD 35 000/day at the end of the first quarter of 2019.

Such high prices and strong volatility prompted a series of new-build orders for LNGCs in 2018, with a total of 100 new LNGCs on order as of the end of the first quarter of 2019, accounting for an increase of 20% in total shipping capacity (or 6 million m³ of LNG). According to an average construction time of two to three years, most of this additional shipping capacity will be commissioned by the end of 2021. This forecast's shipping balance (Figure 3.28) shows that the current order book would provide sufficient shipping capacity increment to maintain a fleet utilisation rate of about 95% (the equivalent of 2018), but will require additional vessels beyond 2021 to maintain a balanced market, albeit one with limited spare capacity. The equivalent of at least 70 new vessels¹⁶ (assuming a constant fleet size without retirements) would be required between 2022 and 2024 to maintain an average fleet utilisation rate of 95%.

¹⁶ At a standard capacity of 174 000 m³.

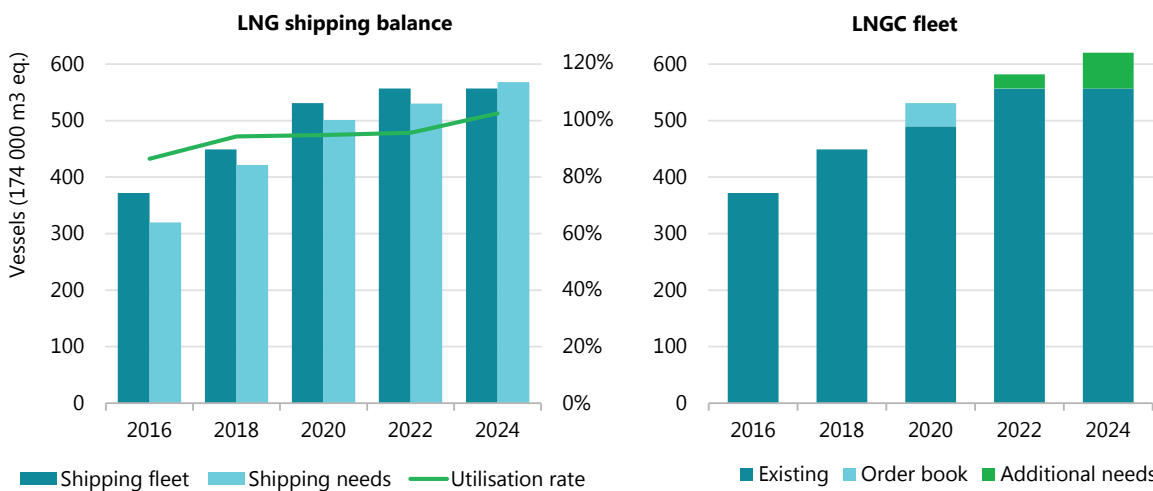
Figure 3.27 Evolution of spot charter rates for LNG carriers, Asia Pacific, 2016–19



IEA, 2019. All rights reserved.

Spot charter rates for LNGCs surged over the final months of 2018 in the expectation of tight winter supply in Asia.

Figure 3.28 LNG shipping balance, fleet utilisation rate and development needs, 2016–24



IEA, 2019. All rights reserved.

The current order book would be sufficient to ensure a constant 95% fleet utilisation rate until 2022, and would require a minimum of 70 net additional ships thereafter to maintain this ratio.

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4. Prices and market reforms

Highlights

- **Market prices for natural gas continued to recover** in 2018 with year-on-year average increases varying between 6% and 38%. This has been partly driven by the strong increase in global natural gas demand and the strengthening of oil and coal prices.
- In spite of a global increase in the share of competitive gas-to-gas pricing over the past decade, **oil-indexed or regulated prices still account for most natural gas consumption** volumes outside North America and Europe.
- Almost all of the **forecast growth in natural gas consumption to 2024 is expected to come from regions where gas-to-gas competition does not currently play a major role** in setting prices for end users.
- **The continuous development of LNG short-term and spot trade in Asia** is a positive precondition to the development of market-driven pricing mechanisms in the region, and several mature LNG buyers have recently liberalised their domestic gas markets – fully in the case of Japan, and more progressively in Singapore and Korea.
- **Countries with strong natural gas consumption and import growth**, such as People's Republic of China ("China"), India and Pakistan, are **reforming their domestic markets** with the objective of greater convergence with international market prices. In producing countries, similar reforms are also being enacted – over the past decade in Russian Federation ("Russia"), and more recently in Egypt as part of a wider set of economic reforms.

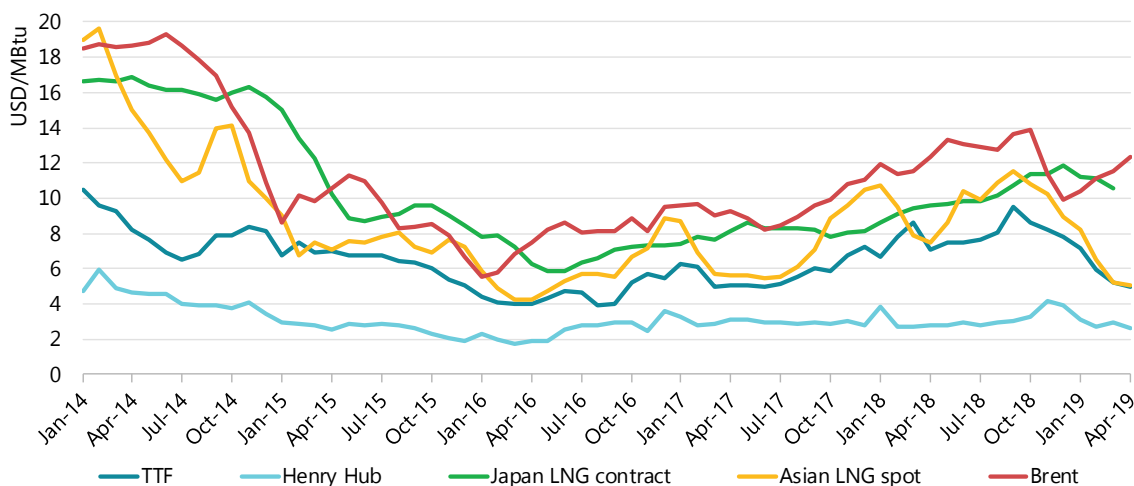
Market prices in 2018–19

After almost three years of decline from the end of 2013 to the first half of 2016, global natural gas prices increased in 2017 and 2018. Depending on the region, the 2017–18 year-on-year (y-o-y) average rate of growth varied between 6% and 38%. This has been partly driven by the strong increase in global natural gas demand, which grew by 4.6% – its highest growth rate since 2010 (IEA, 2019). Other factors contributing to the strengthening of natural gas prices were the rise in Brent crude prices, increasing y-o-y by 30% in 2018 to an average of USD 71 (United States dollars)/barrel from USD 54/barrel in 2017 (Figure 4.1). This supported natural gas prices both directly, via oil indexation in long-term contracts, and indirectly via the arbitrage mechanisms between spot purchases and optimisation of long-term contracts.

Coal prices recovered in a similar fashion to crude oil, starting to rapidly increase following China's decision in April 2016 to reduce the number of statutory working days for its coal miners

from 330 to 276 a year. Coal prices rose by over 40% y-o-y in 2017 and by almost 10% in 2018, to reach an average of USD 92/tonne in 2018 from USD 45/tonne in April 2016. Each of these factors (demand growth, oil indexation and inter-fuel competition) weighed in a different manner on natural gas prices in the distinct consuming regions. Whilst natural gas markets are becoming increasingly interlinked, regional price-setting dynamics retain their dominance.

Figure 4.1. Crude oil and natural gas monthly average prices, 2014–19



Notes: LNG = liquefied natural gas; MBtu = million British thermal units; TTF = Title Transfer Facility (the Netherlands).

Sources: TTF, Henry Hub, Japan LNG contract and Brent data: Bloomberg Finance LP (2019), (subscription required); Asian LNG spot data: ICIS (2019), *ICIS LNG Edge*, www.icis.com/energy/liquefied-natural-gas/lng-edge (subscription required).

Global natural gas prices continued to recover in 2018, with y-o-y average growth varying between 6% and 38% depending on the region.

Asian LNG prices – from tight to loose

Asian LNG import prices remain heavily influenced by oil price dynamics. It is estimated that about 60% of Asian LNG import contracts include some form of oil indexation, most commonly linked to the price of the Japanese Customs-cleared Crude or “Japanese Crude Cocktail” (JCC). Figure 4.2 shows a very strong correlation (over 0.98) between the Japanese LNG contract price¹ and the five-month average of JCC, indicating the persisting dominance of oil indexation.

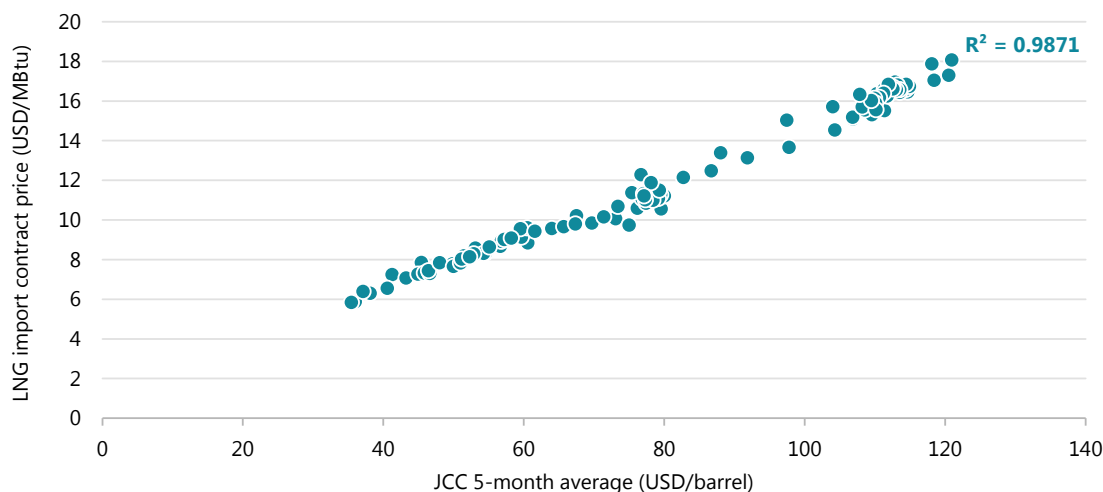
Japan’s LNG import contract price continued its recovery in 2018 and rose by 25.5% y-o-y from an average of USD 8/MBtu in 2017 to USD 10.1/MBtu in 2018 (Figure 4.1). This has been driven by the increase in crude oil prices, with Brent strengthening by 30% and JCC by 32% y-o-y and filtering through the LNG import contract price with a lag of 4–6 months. Crude oil prices started to recover in mid-2017, as Brent prices rose from USD 46/barrel in June 2017 to USD 81/barrel in October 2018. This supported LNG import contract prices rising to almost USD 12/MBtu by December 2018, from an average of USD 10/MBtu through the summer.

As shown in Figure 4.1, the Asian LNG spot price – which is more reflective of short-term supply–demand dynamics – has been following a somewhat different trajectory. During the first quarter of 2018 it was trading at a premium compared to the average contract price. This was

¹ Defined as Bloomberg LNG Japan Import Price (ticker symbol: LNGJLNJP Index), source: Bloomberg Finance LP (2019), (subscription required).

primarily due to the higher LNG import needs of China, suffering from a cold snap and lower supply availability from the Caspian countries. Spot prices strengthened again through the summer of 2018 due to the heatwave experienced in the Asia Pacific region (driving up gas-to-power demand amidst higher cooling needs) and China's strategy of purchasing spot cargoes to build up floating storage ahead of winter.

Figure 4.2. Correlation between JCC and Japanese LNG contract price, 2010–18



Sources: Bloomberg Finance LP (2019)(subscription required).

The Japanese LNG import contract price continued to exhibit a strong correlation with the JCC price over the past decade.

This increasingly tight market outlook changed through October–November 2018, when spot prices started to fall below oil-linked long-term contracts. This was driven partly by above-average temperatures in the Asia Pacific region through the heating season and China's reduced demand for spot cargoes (resulting from the build-up of floating storage through the summer, as well as the signing of more term contracts). At the end of November it was reported that about 30 laden LNG carriers were at sea without firm destinations as traders hoped for improving price conditions (Shiryaevskaya, 2018). Prices continued to fall through the winter season, as lower-than-expected LNG import demand coincided with the start-up of several liquefaction projects (including Corpus Christi train 1 in the United States and Yamal LNG train 3 in Russia). By the end of March 2019, Asian LNG spot prices had fallen to the level of European gas prices and have been trading at a discount to TTF between the second half of March and first half of April 2019.

Europe – a counter seasonal price pattern

Natural gas prices in Europe strengthened by 38% y-o-y during 2018,² from an average of USD 5.74/MBtu in 2017 to an average of USD 7.93/MBtu in 2018. In the first quarter of the year this trend was driven by the below-average temperatures, resulting in heating degree days almost 10% higher than their five-year average. The late cold snap at the end of February/early March tightened the northwest European market and drove up average monthly prices by 30%

²This report uses as its reference the Dutch Title Transfer Facility, or TTF.

from USD 6.6/MBtu in January to USD 8.6/MBtu in March. Natural gas prices on the TTF continued to increase through the second and third quarter of 2018, from a level of USD 7/MBtu in April to almost USD 10/MBtu in September.

A number of factors have been driving this counter seasonal price dynamic. The cold winter of 2017/18 emptied northwest European gas storage sites, with storage inventory at the end of the heating season being 10 billion cubic metres (bcm) (or 40%) below the five-year average. This in turn increased injection needs through the second and third quarters (accounting for approximately 30% of total northwest European demand during this period) and kept upward pressure on gas prices. This coincided with a relatively tight supply situation on the Asian gas markets, as discussed in the previous section. A third factor potentially strengthening gas prices in Europe, via fuel competition within the power sector, was the increase in Rotterdam coal prices, rising by 25% through the April–September period, from USD 80/tonne to USD 100/tonne.

During the 2018/19 heating season natural gas prices halved on the TTF, from almost USD 10/MBtu at the beginning of September 2018 to below USD 5/MBtu by March 2019. This has been partly driven by the above-average temperatures in Europe, putting downward pressure on natural gas consumption for space heating purposes, and the lower-than-expected LNG import demand in Asia and the relatively loose LNG market resulting from it. In European markets, natural gas prices falling below USD 5/MBtu combined with carbon prices holding above EUR 20 (Euros) per tonne of carbon dioxide equivalent have improved the competitiveness of natural gas vis-à-vis coal in the power sector (see Chapter 1).

This counter seasonal price pattern resulted in negative summer–winter spreads for the 2018/19 gas year, indicating that natural gas prices were higher during the injection season than in the heating season.

North America – stability and volatility

In the United States natural gas prices on the Henry Hub rose by 6.4% in 2018 to USD 3.16/MBtu, from an average USD 2.96/MBtu in 2017. This was driven by the record growth of 10% (or 80 bcm) in domestic natural gas consumption. Ample domestic supply, primarily from the Appalachian and the Permian basins, mitigated a stronger price response. Price volatility on the Henry Hub in 2018 was higher than the ten-year average by 12 percentage points (66% vs 54%). As shown in Figure 4.3, this volatility was driven primarily by the price spike in January 2018, when a cold snap drove up US natural gas consumption to its highest monthly level since at least 2001, whilst well freeze-offs³ reportedly limited gas production (EIA, 2018a).

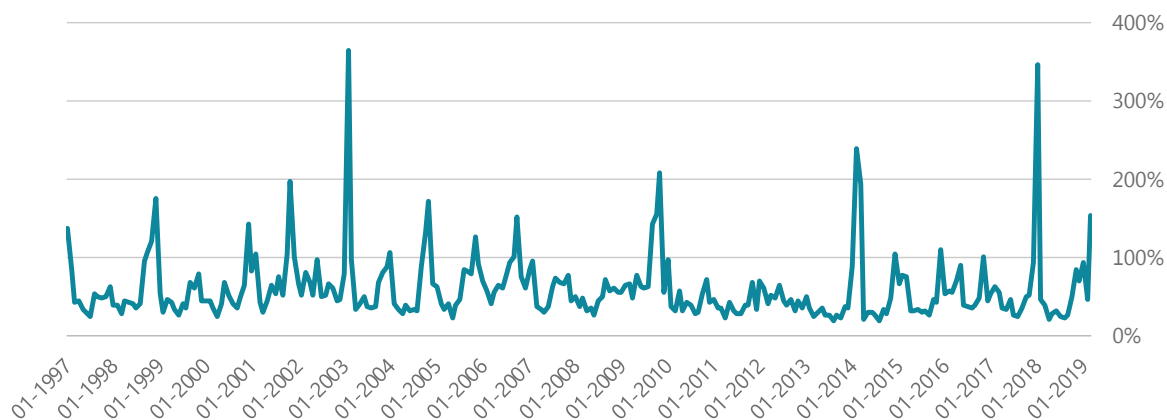
Moreover, the January 2018 cold snap widened the locational spreads between Henry Hub and some of the balancing hubs, especially in the eastern markets. While Henry Hub remained at price levels around USD 3–6/MBtu, eastern markets reached price levels of USD 80/MBtu near Boston (Algonquin) and USD 140/MBtu near New York City.

Locational spreads re-emerged in the United States on several occasions during 2018. The Sumas Hub, located in the northwest of the United States on the border with Canada, has been suffering from high price volatility since October 2018, when a rupture occurred in Enbridge's

³ Well freeze-offs happen when liquids in well piping freeze and block natural gas flows.

British Columbia natural gas pipeline (EIA, 2018b). Import flows from Canada during November 2018–February 2019 were about one-third lower compared to last year, putting further pressure on natural gas prices on the Sumas Hub during this period, rising to USD 10.56/MBtu versus USD 2.62/MBtu a year earlier.

Figure 4.3. Henry Hub monthly price volatility, 1997–2019



Source: EIA (2019), *Henry Hub Natural Gas Spot Price*, www.eia.gov/dnav/ng/hist/rngwhhdm.htm.

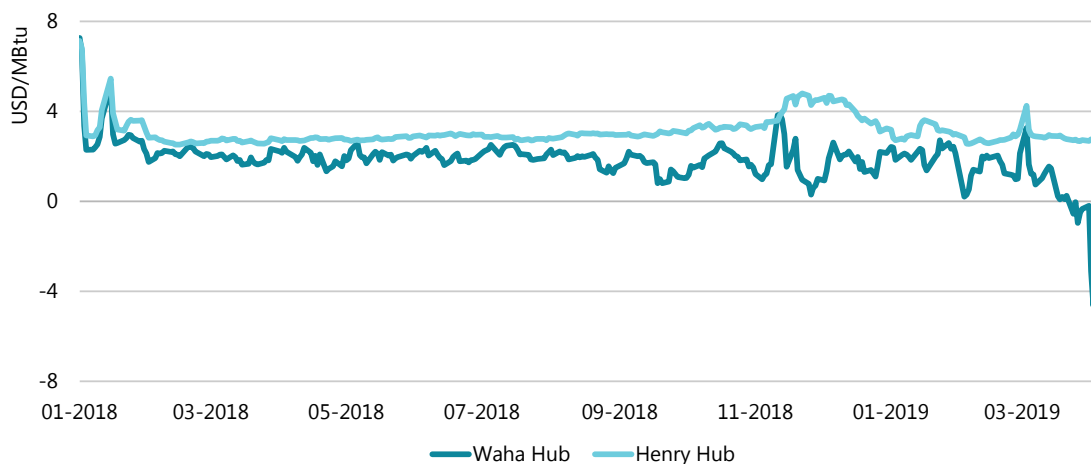
The January 2018 cold snap drove up Henry Hub price volatility to levels not seen since the polar vortex that hit the United States in January 2003.

On the other side of the border, natural gas prices on Alberta’s AECO Hub plummeted by 30% y-o-y from an average USD 1.66 in 2017 to USD 1.17 in 2018 – their lowest level since at least the beginning of this century.

In contrast with the premium in the northwest United States, natural gas has been trading at a discount to Henry Hub on the Waha Hub located in the Permian basin, with the price differential averaging USD 1.13/MBtu during 2018. Natural gas production in the Permian has risen almost eightfold in the last 8 years, from 10 bcm in 2010 to 75 bcm in 2018, mainly on the back of tight oil production in the form of associated petroleum gas. The lack of sufficient midstream takeaway capacity (including processing plants and transmission pipelines)⁴ has depressed natural gas prices over the last couple of years, with the average yearly Waha discount widening from USD 0.03/MBtu in 2014 to last year’s USD 1.13/MBtu. As shown in Figure 4.4, natural gas prices on the Waha Hub plunged into negative territory in late March 2019, reaching a record low of USD -4.63/MBtu in early April.

The strong region-dependent spreads in North America point towards pipeline capacity constraints in connecting supply regions with demand centres.

⁴ See Chapter 2.

Figure 4.4. Natural gas prices on the Henry and Waha Hubs, January 2018–April 2019

Source: Bloomberg Financial LP (2019) (subscription required).

The Waha Hub traded at an average discount of USD 1.1/MBtu compared to the Henry Hub through 2018, as pipeline capacity constraints weighed on natural gas prices in the Permian basin.

Global natural gas pricing overview

Natural gas pricing established on the basis of supply and demand fundamentals (also referred to as “gas-to-gas competition”) accounted for 47% of world price formation in 2018, increasing from 31% in 2005 (IGU, 2019). This is more than twice the volumes priced according to oil-indexed formulae, which represented 19%. Different types of regulated and bilateral pricing mechanisms accounted for 34% of total natural gas consumption.

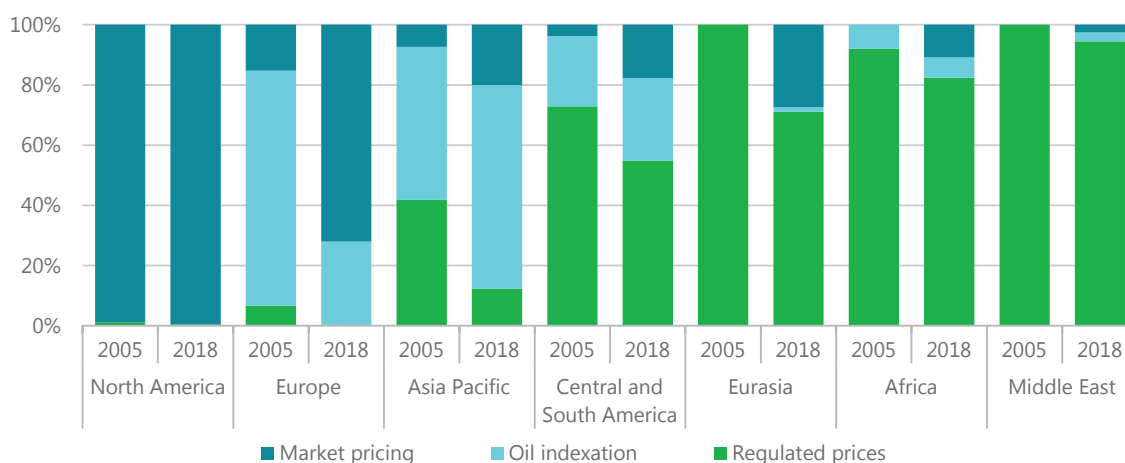
However, a breakdown of global aggregates yields different results for each category:

- Pricing by gas-to-gas competition accounted for 46% of domestically consumed production in 2018, most of it in North America and Europe. Oil indexation only covered 10% of domestically consumed production, and the remaining 44% was priced via bilateral or regulated pricing mechanisms.
- In the pipeline trade a 61% share was priced according to gas-to-gas competition, principally in North America, but increasingly in Europe too. Oil indexation accounted for 30% and covered the majority of trade in Asia, Central and South America, the Middle East and residual volumes in Europe.
- LNG, by contrast, is dominated by oil indexation, which accounted for 66% of these volumes, mostly in Asia. The share priced by gas-to-gas competition is only 34% for LNG volumes.

The evolution of gas pricing mechanisms by region is illustrated in Figure 4.5. In North America and Europe – accounting together for 40% of natural gas demand in 2018 – most consumption is priced on gas-to-gas competition as a consequence of market liberalisation and diversified sources of supply (either local or imported). In the case of Europe, the share of gas-to-gas competition pricing has increased gradually over the past decade as references to hub prices progressively replaced oil indexation in long-term supply contracts.

In the Asia Pacific region – which accounted for 21% of natural gas demand in 2018 and about one-third of interregional natural gas trade – oil indexation holds a majority share owing to its preponderance in LNG import pricing as well as in domestic production pricing mechanisms (Figure 4.5). 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 55% in Central and South America, over 70% in Eurasia, over 80% in Africa and 95% in the Middle East.

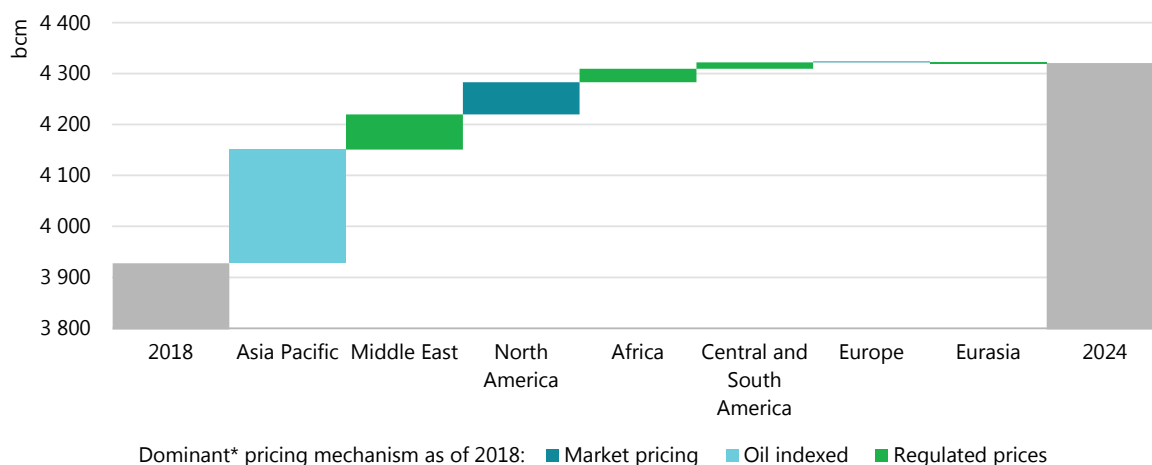
Figure 4.5. Evolution of natural gas pricing mechanisms by region, 2005–18



Source: IGU (2019), *Wholesale Gas Price Survey 2019 Edition*, www.igu.org/sites/default/files/node-document-field_file/IGU_Wholesale_Price_Survey_2019.pdf.

Gas-to-gas competition has increased in most regions with the development of market pricing, especially in Europe where it has largely replaced oil indexation.

This report expects most natural gas demand growth to come from regions that currently have limited exposure to pricing based on gas-to-gas competition (Figure 4.6). In the Middle East – which accounts for 20% of anticipated demand growth – future supply mostly comes from domestic production; the pricing mechanism could therefore remain local and disconnected from international trade price references. In the case of Asia Pacific (almost 60% of expected demand growth) the situation is different as international trade is a major source of additional supply, especially for LNG trade where the region accounts for most of the anticipated growth over the forecast period. Natural gas price competitiveness and consistency with supply and demand fundamentals therefore become of greater importance for this region as its weight in international trade increases. This is both in terms of giving a downstream benchmark value to natural gas to ensure competitiveness vis-à-vis other fuels, and of providing a consistent price signal to suppliers, especially domestic producers, to trigger adequate investment. In the case of a net importing region such as Asia Pacific, the price signal also reflects the attractiveness of the local market in instances of tight supply.

Figure 4.6. Expected natural gas demand growth by region, 2018–24

IEA, 2019. All rights reserved.

* Accounting for at least 50% of demand in 2018, as shown in Figure 4.5.

Regions where regulated pricing or oil indexation dominate account for over 85% of natural gas demand in the coming five years.

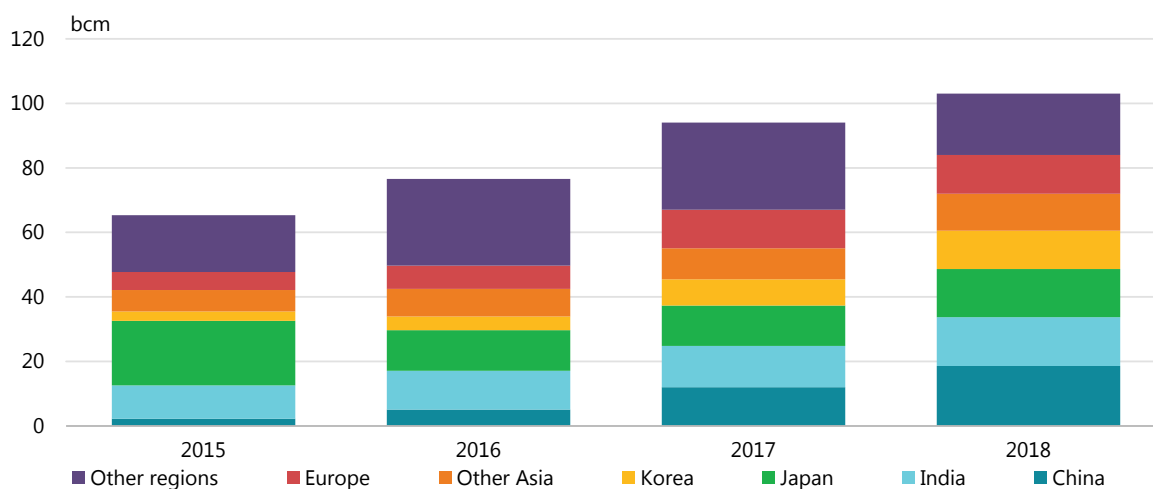
For other emerging markets such as Central and South America and Africa, additional supply is expected to come mainly from domestic production or neighbouring countries rather than from trans-regional LNG trade. Here the development of gas-to-gas competition pricing makes sense from the viewpoint of local downstream competitiveness and upstream development, while the price attractiveness dimension is of lesser importance.

The emergence of market-driven natural gas pricing in fast-growing markets (in particular Asia) is therefore an important feature to ensure the sustainability of these markets in the longer term.

Prospects for natural gas trading hubs in Asia

The development of short-term and spot LNG trading has followed a robust growth trend over recent years. They increased by almost 60% between 2015 and 2018, moving from 65 bcm/y to over 100 bcm/y (Figure 4.7), of which three-quarters were imported by Asian countries. In addition to this volume increase, the trend has also shown increasing diversification within Asia. The Asian LNG spot trade expanded rapidly in the aftermath of the Great East Japanese Earthquake of 2011 and, until 2014, Japan accounted for almost all short-term and spot LNG trade in Asia. Japan's share halved between 2015 and 2018, from 31% to 14%, when its short-term and spot LNG volumes decreased from 20 bcm/y to 15 bcm/y. Meanwhile, volumes to other Asian markets increased from 22 bcm/y to 57 bcm/y over the same time period. This reflects not only the development of China's short-term and spot LNG import market (from less than 2 bcm/y to almost 20 bcm/y), but also the development of new Asian LNG importers that rely mostly on short-term and spot procurement.

This increase in LNG spot trading is a positive and necessary precondition for the establishment of competitive market-driven pricing mechanisms, which, however, require a larger set of factors to be efficient and sustainable. These institutional and structural factors have been summarised in a previous International Energy Agency (IEA) report entitled "Developing a natural gas trading hub in Asia" (IEA, 2013), and are recalled in Box 4.1.

Figure 4.7. Evolution of spot and short-term LNG trade by main importer, 2015–18

Source: ICIS (2019), *ICIS LNG Edge*, www.icis.com/energy/liquefied-natural-gas/lng-edge/ (subscription required).

The share of Asian buyers in short-term LNG trade has increased in recent years and become more diversified as new players have entered the market.

Box 4.1. Institutional and structural requirements for creating natural gas hubs

Initial institutional requirements need to be met to support competition in a natural gas market, where governments have to start actively creating the foundations for natural gas trade. In general, a successful attempt at increasing competition will meet the following institutional requirements (in no specific order):

- **A hands-off government approach to natural gas markets:** this implies an administrative mindset that is carried on through the respective natural gas market governing entities. It also implies a shift from direct policy making and market involvement to market monitoring through an independent regulatory agency.
- **Separation of transport and commercial activities:** The natural gas industry is known for its ability to behave as a natural monopoly, since the high costs of infrastructure investment prohibit the development of parallel infrastructures to supply the same customers (especially at the retail level). It is widely recognised that these vertically integrated supply systems need to be broken up. Subsequently, the independent transport entity will levy a fair and indiscriminate transmission fee on a proportional basis for all shippers.
- **Wholesale price deregulation:** Part of the governmental hands-off approach involves letting the market set the price level for natural gas in the wholesale market. It allows large customers to seek a supplier who can deliver the product that suits their need at the least possible cost. Eventually, this freedom of choice can also be offered to individual households, but this is not strictly necessary for a functioning wholesale market to emerge.

In addition to institutional requirements, market participants need a minimum degree of certainty that a market is genuinely competitive and is functioning as such. To ensure continued

functioning of a spot market, structural requirements need to be secured (by the government or the independent entity) as follows (in no specific order):

- **Sufficient network capacity and non-discriminatory access to networks:** Essential to a well-functioning natural gas market is its accessibility via non-discriminatory access to networks, and the availability of capacity on these networks. An independent transmission system operator (TSO), either divested or functionally separated, and a clear and unbiased investment regime based on a well-developed network code are essential to guarantee these structural requirements.
- **Competitive number of market participants:** Lowering barriers to entry through a well-regulated network code should increase competition for the incumbent natural gas company. However, a meaningful number of parties, each with a competitive market share, is generally needed along a non-regulated value chain (upstream and downstream) to create a genuinely competitive gas market.
- **Involvement of financial institutions:** To allow a market to efficiently service supply and demand, investment will be needed along the natural gas value chain (in upstream development, transport, storage and distribution capacity). Apart from capital investments that will be recouped by operational revenues, a competitive natural gas market will also need financial parties that are willing to cover financial/operational risks for parties involved in the natural gas trade, providing tools for customers to smooth out and optimise revenue streams from their activities in the natural gas market.

These structural requirements are essential to kick-start a natural gas market, and should be guaranteed by a regulator (ideally independent from companies and government) that monitors the market and can act independently when needed (e.g. force an incumbent company to facilitate more competition).

Source : IEA (2013), *Developing a Natural Gas Trading Hub in Asia*, www.iea.org/publications/freepublications/publication/AsianGasHub_FINAL_WEB.pdf.

This analysis in 2013 focused on several Asian markets with ambitions to develop natural gas hubs and pricing references at that time, highlighting their respective strengths and weaknesses (see Table 4.1).

Updating this analysis in the context of 2019 shows several positive developments toward the establishment of natural gas hubs in Asia, and thus of market-based pricing references for the region:

- Japan completed its domestic market liberalisation reform programme in 2017 with full liberalisation of the downstream market, the establishment of a Gas Market Surveillance Commission as a regulatory body, and the introduction of gas transport unbundling – to be fully effective by 2022.
- Korea's natural gas market is still dominated by state-owned incumbent KOGAS. However, the number of "direct importers" – major consumers allowed to import LNG for their own needs, but only for volumes in addition to existing supply contracts with KOGAS – doubled in 2017 from four to eight. Direct buyers' share of the country's total LNG imports more than doubled between 2015 and 2018, rising from 6% to 16%.

- Singapore unbundled natural gas supply and transport activities, and lifted its pipeline import control regime at the end of 2017. The opening of the electricity market (which relies on natural gas-fired generation) began in 2018 and will be completed in 2019.
- Association of Southeast Asian Nations (ASEAN) member states are promoting the development of a co-ordinated and connected common gas market, through the enhancement of capacity building and technical assistance among members, the improvement of framework and price reforms, and the support of investment, as highlighted in the ASEAN Ministers on Energy Meeting in October 2018 (ASEAN, 2018).
- Recent natural gas market and pricing reforms in China and India are detailed in the next sections.

Table 4.1. Potential for natural gas hub development in several Asian markets, 2013–19

Market	Analysis of 2013 status		Evolution as of H1 2019
	Strengths	Weaknesses	
Japan	The largest LNG importer Well-developed LNG infrastructure Large role of natural gas in power generation Well-developed financial markets	Segmented onshore infrastructure Segmented, monopoly electricity markets	Natural gas market liberalisation: Establishment of a Gas Markets Surveillance Commission (2016) Full liberalisation of retail market (2017) Legal unbundling of transport (2022)
Korea	Well-developed LNG infrastructure Already a major LNG spot buyer due to lack of storage	Monopoly domestic gas market Wholesale price regulation	Number of direct importers doubled in 2017
China	Diversified gas supply structure Rapid infrastructure build-up Strong demand growth	Lack of clear TPA regulation Infrastructure bottlenecks Overlapping price regulation Capital controls	Market reform framework – Oil and gas industry reform plan, city gate price reforms, introduction of exchanges
Singapore	Already an important commodity trading hub Good location TPA, bidirectional storage	Small domestic market Administrative controls on imports	End of pipeline import control in 2017 Progressive liberalisation of electricity market since 2018
India	Not covered in the 2013 report		Introduction of price freedom for new domestic production assets in 2019 Pipeline capacity booking platform opened in 2018 Proposed launch of domestic trading hub

Note: TPA = third-party access.

Pricing and market reforms in regulated environments

China

City gate prices

China's natural gas price reform has been progressing gradually since 2011 when the National Development and Reform Commission (NDRC) reformed the then-existing cost-plus tariffs applying to city gate prices.⁵ This “netback market value pricing” system linked the price of natural gas with competing sources of energy – such as fuel oil for industry or liquefied petroleum gases (LPG) for the residential sector. This netback methodology was introduced in Guangdong and Guangxi in 2011, and further expanded to Sichuan and Chongqing in 2012. It was then extended at a national level in 2013 with the introduction of a two-tiered price ceiling with different prices for existing consumption volumes at the time of the reform’s implementation and for incremental consumption volumes (Figure 4.8), following different price adjustment paths (progressive for existing volumes and one-off for incremental volumes).

The second phase of the reform occurred in 2014 when the NDRC further increased the price of existing volumes to narrow the gap with incremental volumes, while on the supply side deregulating prices of imported LNG, shale gas, coalbed methane and synthetic gas from coal.

The third and final step of the city gate price convergence process was enacted in 2015 with another adjustment of city gate prices so that existing volumes reached parity with incremental volume prices. As a result, a new single natural gas price was formulated from the unification of incremental and existing volumes. The new city gas price in each area changed from a ceiling to a benchmark, where sellers and buyers can negotiate around the city gate price within a 20% range (excluding residential consumers and fertiliser production), thus introducing some flexibility to the prices.⁶ The price for fertiliser production, for which natural gas is a major input, was deregulated by the NDRC in November 2016.

Further reforms were enacted by NDRC in 2017, with the introduction of a pilot market reform programme in Fujian province to rationalise market pricing, reduce city gate prices and introduce a requirement that all natural gas prices publicly traded on trading platforms such as the Shanghai and Chongqing Petroleum and Gas Exchanges (Box 4.2) be formed by the market.

Box 4.2. Natural gas exchanges in China

There are currently two active natural gas exchanges in China: the Shanghai Petroleum and Natural Gas Exchange (SHPGX) and the Chongqing Petroleum and Gas Exchange. In addition, some local commodity markets and private enterprises are also involved in natural gas transactions.

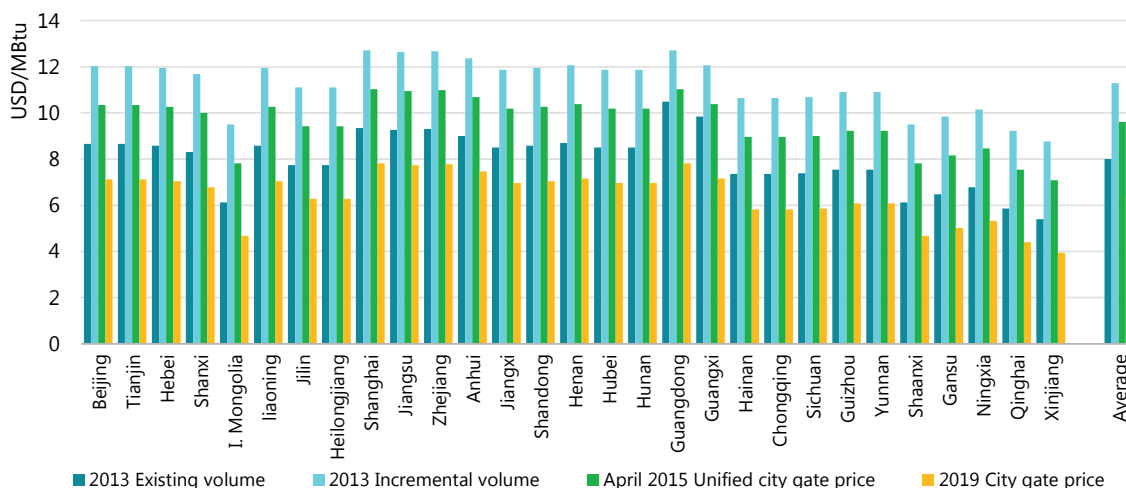
⁵ City gate prices refer to the regulated cost at which China’s downstream gas distributors purchase natural gas from suppliers.

⁶ However, price increases were forbidden during the first year of the new pricing system.

SHPGX was registered and established in the Shanghai Free Trade Zone in March 2015. It began trial operation in July 2015 and was officially operational in November 2016. The shareholders of SHPGX include Xinhua News Agency, China National Petroleum Corporation (CNPC), Sinopec, China National Offshore Oil Corporation (CNOOC), Shenergy, Beiran, ENN Energy, China Gas, Towngas and China Huaneng. In September 2017 SHPGX carried out the first competitive price transaction of pipeline gas in China. According to SHPGX, by the end of 2018 some 60.5 bcm (bilateral) of natural gas had been transacted through its system. Of this total, the bilateral volume of pipeline natural gas was 55.5 bcm (mainly concentrated in East and North China) and that of LNG was almost 4.5 bcm, mainly in East and South China. SHPGX membership is rising fast, with 2 242 members at the end of 2018 – an increase of 40% on the 1 592 members at the end of 2017 – and with more than 500 active trading participants.

Chongqing Petroleum and Gas Exchange was established in July 2017, with its shareholders including national oil and gas companies such as CNPC, Sinopec, China Resources Gas, ENN Energy and China Gas, the regional energy and chemical enterprises such as Chongqing Energy, Chongqing Chemical & Pharmaceutical, Yanchang Petroleum, Hubei Energy, and FinTech innovation enterprises such as Citic Global and BORN Technology. It completed its first pipeline natural gas transaction on 26 April 2018, and its first LNG transaction on 17 May 2018. By the end of 2018, Chongqing Petroleum and Gas Exchange had over 1 400 trading members.

Figure 4.8. Evolution of city gate prices in China, 2013, 2015 and 2019



Note: The conversion from the original prices expressed in CNY (Chinese yuan renminbi)/1 000 cubic metres (m³) uses the following conversion factors: 1 000 m³ is equivalent to 37.9 MBtu (Natural Gas Information Statistics 2017), and USD 1 = CNY 6.89 (2017 average rate from World Bank).

Sources: NDRC (2013), *Notice of the NDRC on Adjusting Natural Gas Prices, 2013 adjustment*, <http://zfxqk.ndrc.gov.cn/web/iteminfo.jsp?id=1719>; NDRC (2015), *Notice of the NDRC on Adjusting Natural Gas Prices, 2015 adjustment*, www.ndrc.gov.cn/zcfb/zcfbtz/201502/t20150228_665694.html; NDRC (2018), *Notice on Adjustment of Residential City Gate Gas Prices*, www.ndrc.gov.cn/fzqggz/jjgl/zcfg/201805/t20180525_887252.html.

Since 2013 natural gas pricing in China has been moving from netback prices to internal market-led price formation.

In May 2018, the NDRC promulgated the *Notice on Rationalising Residential Gas Gate Station Prices*, introducing the convergence of residential and non-residential city gate gas prices (effective in June 2018) as well as the possibility of an increase in residential prices of up to 20% from June 2019 (NDRC, 2018). This increase in residential prices – the first in eight years – could incentivise further investment in domestic production. LNG import prices have been high throughout 2018, especially compared to residential city gate prices, resulting in reported financial losses for the national oil companies (NOCs) in charge of natural gas supply (Platts, 2018). According to the NDRC, the May 2018 reform will help to establish an elastic mechanism that reflects changes in supply and demand, foster development of storage capacity in response to the development of seasonal price differentials, and guide the setting of prices for end users by local governments. City gate prices decreased marginally in April 2019 following value-added tax reductions (from 10% to 9%).

End-user prices

End users do not pay the city gate prices – local gas distributors buy natural gas from NOCs at the city gate price, then transport it through their local distribution pipelines. Local pricing bureaux set end-user prices across China, which include the distribution costs and allowed return on investment. Direct sales between NOCs and large industrial users and sales of offshore gas produced by CNOOC are not regulated.

The residential sector pricing system introduced by 2015 consists of three categories. The first applies to 80% of the average monthly household volume, the second to the next 15%, and the third to any volumes above 95% of the monthly average (Hua and Stanway, 2014). Under this system, customers incurring the third-tier tariff pay around 50% more than the base price for that gas, with the second tier at around 15% more. The increase in the non-residential end-user price in 2014 reportedly reduced demand growth from a 10% growth rate in 2014 to 4% in 2015. The subsequent city gate price decrease at the end of 2015 (down 30%) fed into end-user prices in 2016, leading to 8% consumption growth.

From 2017, gas conversion objectives from the “Blue Skies” policy took the lead in driving residential consumption growth: in 2017, the coal-to-gas conversion target was set at 3 million households and ended with 4 million making the conversion. The plan continued in 2018, targeting another 4 million homes, and reaching 4.8 million. Upon its June 2018 announcement of city gas price deregulation, the NDRC reported that a household using 20 m³ of gas a month would see its bill rise by around USD 1/month.

Industrial prices are higher than average residential prices – although tiers 2 and 3 of residential prices may be higher than industrial prices in some cities. Industrial end-user prices have shown more variation than residential, with some correlation to international markets. Coal to gas pricing is a key driver in industrial fuel choices; in 2014 the price of gas was around 2.5 times that of coal, a differential that had narrowed only slightly by 2018. Even if industrial consumption reacted to prices (with lower growth in 2015 and a rebound in 2016), it is also the policy push from coal-to-gas switching objectives that has driven industrial gas consumption since 2017. Some industrial consumers reportedly halted production in late 2018 as they could not cope with the rise in natural gas prices (Reuters, 2018).

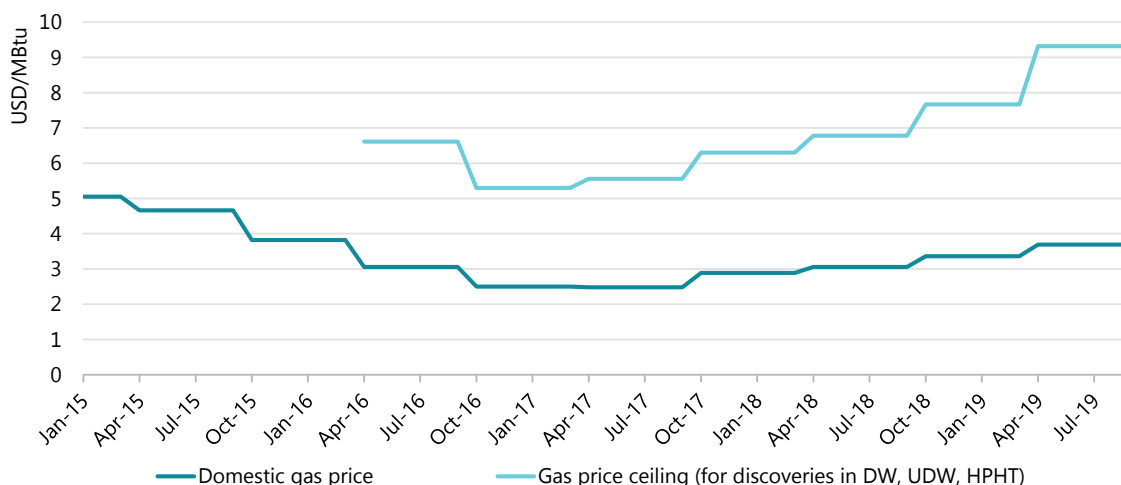
India

India’s natural gas market is characterised by regulated prices for both domestic production and for consumption. In recent years, India has taken steps to improve pricing for production and to control the cost of imports, and is now looking to establishing a trading hub.

The Indian government has introduced successive pricing reforms since 2010, leading to an increase in prices under the Administered Pricing Mechanism (APM) first introduced in the 1970s. The reforms aimed to incentivise investment in declining domestic natural gas production capacity. In late 2014 price reforms moved away from the existing cost plus-based APM fixed by the government, to introduce a basket of external price references – the formula includes price indices from the United States (Henry Hub), the United Kingdom (National Balancing Point), Canada (AECO Hub) and Russia (regulated price), weighted by their respective domestic consumption volumes. This basket price index is linked to external market supply and demand dynamics, and does not reflect India’s domestic production costs or cost of imports (mostly oil-indexed for LNG long-term supplies). It thus led to a price decrease until mid-2017 (see Figure 4.9). The rebound in international prices implied four price increases over the past year, first in October 2017 (up 17%), then in April 2018 (up 6%), October 2018 (up 10%) and April 2019 (up 10%).

Consequently the current domestic price is set at USD 3.69/MBtu until 30 September 2019. In spite of the successive increases, this price level is still under the supply costs for both domestic production and LNG imports. According to domestic producers Oil and Natural Gas Corporation (ONGC) and Oil India Limited (which accounted for 83% of India’s total natural gas output in the first half of the financial year 2018/19 [PPAC, 2018]), the price level at the end of 2018 (USD 3.36/MBtu before the 1 April 2019 revision) was still insufficient to recover their average production costs, which stood at USD 3.59/MBtu and USD 3.06/MBtu respectively (The Economic Times, 2018).

Figure 4.9. Evolution of domestic natural gas price and price ceiling for India, 2015–19



Notes: DW = deep water; UDW = ultra-deep water; HPHT = high pressure and high temperature.

Source: PPAC(2019a), *Domestic Natural Gas Prices* (database), www.ppac.org.in/content/155_1_GasPrices.aspx.

Domestic supply pricing has evolved to greater flexibility with the introduction of price freedom, yet the resulting consumer price remains below import costs.

As part of the Hydrocarbon Exploration Licensing Policy (HELP) regime introduced in 2016 to further incentivise investment in domestic natural gas production, pricing freedom was introduced subject to a ceiling for production from discoveries in deepwater, ultra-deepwater and high-pressure high-temperature fields. This ceiling price is set by the Ministry of Petroleum and Natural Gas and updated twice a year. This ceiling is based on the lowest of: (a) the imported fuel oil price; (b) the weighted average price of substitute fuels (0.3x coal + 0.4x fuel oil + 0.3x naphtha); and (c) the LNG import price. This ceiling price recovered from its low point of late 2016 at a faster pace than the domestic price (see Figure 4.9) with five successive increases, and currently stands at USD 9.32/MBtu until 30 September 2019. In February 2019 the government granted marketing and pricing freedom to all new natural gas discoveries whose field development plan had yet to be approved.

The Petroleum and Natural Gas Regulatory Board (PNGRB), which oversees midstream and downstream natural gas-related policies, issued in April 2018 a tender to hire advisory services to launch a natural gas trading hub “where natural gas can be traded, and supplied through a market-based mechanism instead of multiple formula-driven prices” (PNGRB, 2018a). The expected launch of this natural gas hub had initially been set for the end of 2018; in December 2018 the Minister for Petroleum and Natural Gas reaffirmed the objective to set a trading hub “soon” to allow ease of access to gas suppliers and buyers (The Hindu Business Line, 2018a).

This objective of developing a platform for multiple buyers and sellers, although challenging, is nonetheless achievable if conducted in parallel with other market reforms such as further downstream price deregulation, unbundling of network operation and marketing activities, rationalisation of transport tariffs, or enabling more downstream flexibility currently limited by downstream natural gas allocation mechanisms. The following have been achieved to date:

- In August 2018, GAIL (the largest state-owned natural gas processing and distribution company in India) launched an online platform for capacity booking. Under PNGRB guidelines, up to 25% of the total pipeline capacity is to be earmarked for third-party access on a first-come first-served basis and for a period of less than one year.
- The following step towards the potential unbundling of GAIL remains on hold; after considering full unbundling in early 2018 on PNGRB’s recommendation, the government later reconsidered it as a legal and accounting separation; the decision is currently understood to be on hold.
- LNG terminals are currently not open to third parties. PNGRB issued a draft regulation in 2018 for the setting up and operation of LNG terminals, which stipulates that new terminals would have to offer at all times 20% of their short-term (less than 5 years) uncommitted regasification or a minimum of 0.5 million tonnes per annum (Mtpa) to third parties (PNGRB, 2018b).

However, such a transition could prove challenging owing to the price sensitivity of Indian domestic consumption, as power generation and several industrial sectors – among them fertilisers – have regulated prices and benefit from subsidies. In the case of fertilisers, government subsidy covers about half of the retail price (see Box 4.3).

Box 4.3. Fertiliser pricing and subsidies in India

The fertiliser industry accounted for almost 30% of India's natural gas consumption in 2018, and was supplied by LNG imports (55%) and domestic production (45%) (PPAC, 2019b). Natural gas is the primary source of feedstock for the production of urea fertiliser and accounts for 70% to 80% of the total production cost. Nutrient-based (NPK for nitrogen, phosphorus and potassium) fertilisers are derived from ammonia, which in India is produced from natural gas or refined oil products.

Fertilisers are subsidised to ensure sufficient and affordable supply for the country's agricultural sector. Urea is the main component of the fertiliser subsidy budget, accounting for above two-thirds of the total envelope over the recent fiscal years (see table). The budgeted fertiliser subsidy amounts to INR 701 billion (Indian rupee, or about USD 10 billion) for fiscal year 2018/19, of which INR 450 billion (USD 6.5 billion) is for urea.

The Indian government reformed its urea subsidy policy in 2015 by introducing natural gas price pooling to have a single reference price for feedstock from different sources of supply – domestic production or LNG imports. The share of (cheaper) domestic gas production in overall supply to the fertiliser industry declined from 75% in 2013 to 45% in 2018, partly due to the gradual shutdown of the KG-D6 offshore field (part of its production being allocated to the fertiliser industry). This caused an increase in the subsidy budget to guarantee a fixed price for urea buyers, although the budget has stabilised in recent years.

Fertiliser subsidy for fiscal years 2016/17 and 2018/19 as per budget documents (INR billion)

	2016/17 actual	2017/18 budget est.	2017/18 revised	2018/19 budget est.
Urea subsidy	475	498	427	450
Payment for indigenous urea	380	370	320	350
Payment for urea subsidy	20	30	50	-
Payment for imported urea (net recovery)	75	98	57	100
Nutrient-based (NPK) subsidy	188	202	223	251
Payment for indigenous fertilisers	118	123	144	158
Payment for imported fertilisers	70	79	79	93
Total	663	700	650	701

Source: FAI (2018), *Annual Report 2017-2018*, https://www.faidelhi.org/general/FAI%20Annual%20Report%202017_18.pdf.

Developing domestic natural gas production would alleviate the subsidy burden – according to the Fertiliser Association of India (FAI), every million cubic metres of imported LNG substituted by domestic production could save INR 8.7 billion (approximately USD 130 million) of subsidy, and switching to full domestic supply could cut the subsidy by INR 230 billion (USD 3.3 billion) per year (The Hindu Business Line, 2018b). The FAI also points out the issue of delays in fixed-cost reimbursement to fertiliser producers, which further adds to the rising cost of supply from imported sources.

The Cabinet approved in March 2018 the continuation of the urea subsidy programme initiated in 2017 to fiscal year 2019/20. This decision implies a freeze in urea prices until 2020 (PIB, 2018).

Sources: FAI (2018), *Annual Report 2017-2048*, https://www.faidelhi.org/general/FAI%20Annual%20Report%202017_18.pdf, PPAC (2019b), *Monthly Reports, Natural Gas Production, Availability and Consumption*, Ministry of Petroleum and Natural Gas, Government of India, https://ppac.gov.in/content/22_2_Archives.aspx, The Hindu Business Line (2018b), "Replacing imported LNG with domestic gas can save INR 23,000 crore in fertiliser subsidy: FAI", www.thehindubusinessline.com/economy/replacing-imported-lng-with-domestic-gas-can-save-23000-cr-in-fertiliser-subsidy-fai/article25664574.ece (accessed 19 March 2019).

India is also trying to bridge the pricing gap by renegotiating its long-term LNG supply contracts. Taking advantage of its growing importance as an LNG buyer and the ample market supply, India obtained lower import prices in exchange for greater contracted volumes:

- In December 2015, Qatar's Rasgas and India's Petronet LNG renegotiated the terms of their 25-year supply contract of 7.5 Mtpa. Petronet LNG obtained a revision of its pricing formula in which the oil reference period was switched from a five-year average of Japanese Crude Cocktail (average price of Japan's basket of crude oil imports) to a three-month average of Brent prices, resulting in the LNG price responding more quickly to changes in oil prices. As oil prices were falling, LNG prices were adjusted downwards when the new formula was applied. Petronet was also allowed to waive a USD 1.8 billion penalty for taking lower-than-contracted volumes. The parties also signed an agreement for an additional 1 Mtpa for 12 years starting in 2016.
- In September 2017, Petronet LNG renegotiated with ExxonMobil its 1.5 Mtpa supply contract sourced from Australia's Gorgon LNG in a similar way. While the revised deal includes a lower oil indexation coefficient (from 14.5% to 13.9%) and the inclusion of shipping charges by the seller, it was complemented by the inclusion of an additional 1 Mtpa of contracted volume.
- In April 2018, GAIL announced that the price of its coming LNG supply from Gazprom (based on a 2012 20-year sales and purchase agreement) had been renegotiated.

Pakistan

Natural gas is Pakistan's main energy source, accounting for over 40% of total energy consumption, with domestic production being the primary source of supply. All activities relating to the development, exploration, distribution and transmission of natural gas in Pakistan are regulated by the Oil and Gas Regulatory Authority (OGRA). Natural gas transport and distribution networks are owned and operated by state-owned companies, Sui Northern Gas Pipelines Limited (SNGPL) and Sui Southern Gas Pipelines Limited (SSGPL), and OGRA has issued licences to other operators for the sale and transmission of natural gas. OGRA is also responsible for setting consumer and producer natural gas prices, which are sanctioned by the federal government.

End-user prices are divided by class of user and for some of them, such as residential consumers, by sub-classes according to their monthly consumption volumes.

The price revision of October 2018 led to an unprecedented increase in the natural gas price for some categories, including the largest consumers among residential users. The residential sector, which was previously split into three sub-classes of monthly volumes (up to 100 m³, up to 300 m³, and above), was further divided into seven sub-classes with more subdivisions for the

largest consumers. Whereas previous price revisions were more or less homogeneous (a 6% increase for all in January 2013, and a 4% increase for up to 300 m³ and 13% for over 300 m³ in September 2015), the 2018 revision led to a double-digit price increase for all sub-classes, and up to a 143% increase for users consuming more than 400 m³ per month (Table 4.2).

Table 4.2. Evolution of natural gas prices for residential sector consumers in Pakistan, 2013–18

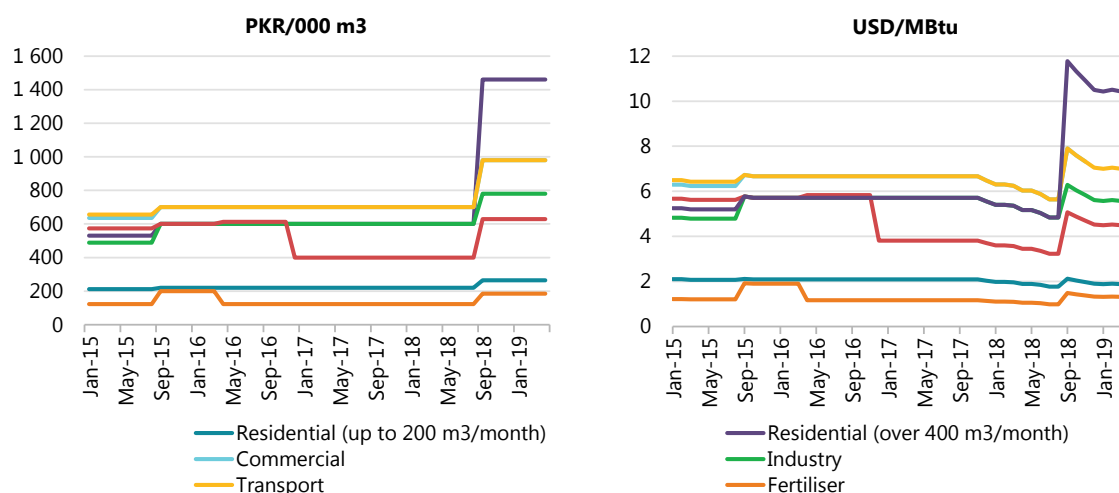
Prices in PKR per MBtu

Consumption	January 2013	September 2015	September 2018
up to 50 m ³ /month	106.14 (+6%)	110 (+4%)	121 (+10%)
up to 100 m ³ /month	106.14 (+6%)	110 (+4%)	127 (+15%)
up to 200 m ³ /month	212.28 (+6%)	220 (+4%)	264 (+20%)
up to 300 m ³ /month	212.28 (+6%)	220 (+4%)	275 (+25%)
up to 400 m ³ /month	530.69 (+6%)	600 (+13%)	780 (+30%)
up to 500 m ³ /month	530.69 (+6%)	600 (+13%)	1460 (+143%)
over 500 m ³ /month	530.69 (+6%)	600 (+13%)	1460 (+143%)

Source: OGRA (2019a), *Consumer Gas Prices*, www.ogra.org.pk/consumer-gas-prices.

Other classes of consumer were also hit by higher-than-usual price increases, with a 57% increase for most power generation users, 40% for compressed natural gas for transport and for most commercial users, and 30% for industry – excluding textiles which remained flat (Figure 4.10). The successive devaluations of the rupee and a falling exchange rate as the market anticipates a bailout from the International Monetary Fund (accepted in late May) tend to counterbalance most of the increase when converting the prices into US dollars – which then further increases the cost of imports in local currency (Figure 4.11).

Figure 4.10. Evolution of natural gas consumer prices in Pakistan, 2015–19



Source: OGRA (2019a), *Consumer Gas Prices*, www.ogra.org.pk/consumer-gas-prices.

Consumer prices increased substantially in Pakistan at the end of 2018, especially for wholesale and large retail customers.

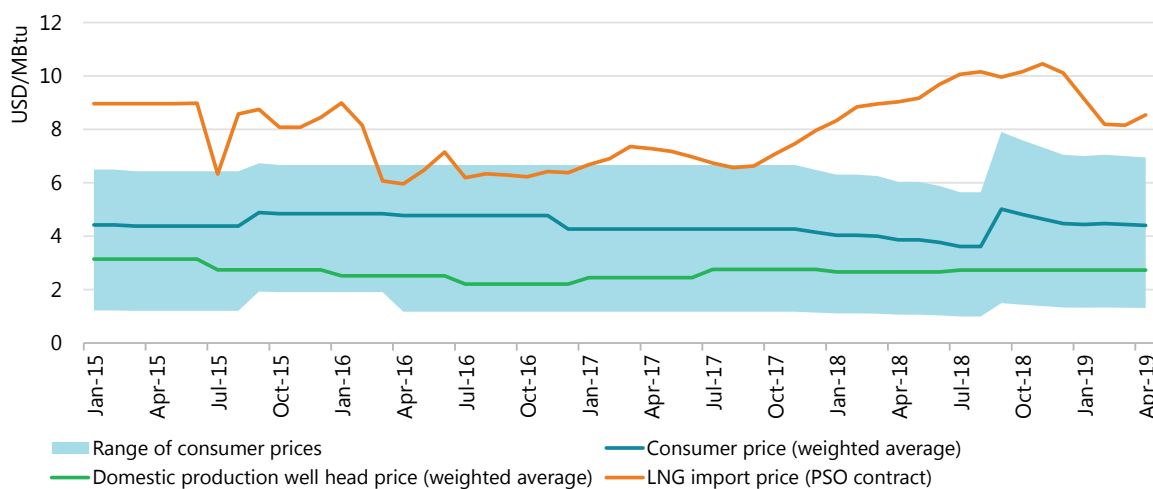
The government ordered an enquiry in early 2019 on suspicion of inflated gas bills being issued to some 3.5 million consumers following the application of the September 2018 price revision and overestimated gas pressure factors. The government ordered the return of excessive

amounts charged and announced it would reconsider the subdivision of domestic consumers introduced in September 2018 (Bhutta, 2019a).

Domestic production operates under a framework of concessions for onshore regions and production-sharing contracts for offshore fields. Well head prices are set and published at field level by OGRA (some denominated in US dollars and some in Pakistani rupees) for a usual effective period of six months.⁷ According to the July 2018 well head price notification bulletin, prices at field level range from USD 1.35 to 8.50/MBtu, resulting in a weighted average price of USD 2.73/MBtu (Figure 4.11).

LNG imports remain a marginal source of supply, but have increased from 1.5 bcm in 2015 when Pakistan began importing LNG, to almost 10 bcm in 2018. Pakistan sources its LNG imports from different providers, including long-term contracts and short-term procurement – mainly through tenders. The main source of LNG supply comes from a long-term contract signed between Pakistan State Oil (PSO) and Qatargas, using an oil-indexed pricing formula with a 13.37% slope and based on a three-month average of Brent crude oil prices (OGRA, 2019c). The increase in crude oil prices since 2017 has led to higher import prices, which have remained above the highest level of consumer prices (Figure 4.11). Qatar agreed in March 2019 to increase its LNG exports to Pakistan by 200 million cubic feet per day (or the equivalent of 2 bcm/y), in spite of an ongoing investigation by the National Accountability Board into potential irregularity and renegotiation (Bhutta, 2019b).

Figure 4.11. Natural gas supply costs and average consumer price in Pakistan, 2015–19



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

Domestic production prices have remained stable, while oil-indexed LNG import contracts have been impacted by oil price recovery and remain above the range of consumer prices.

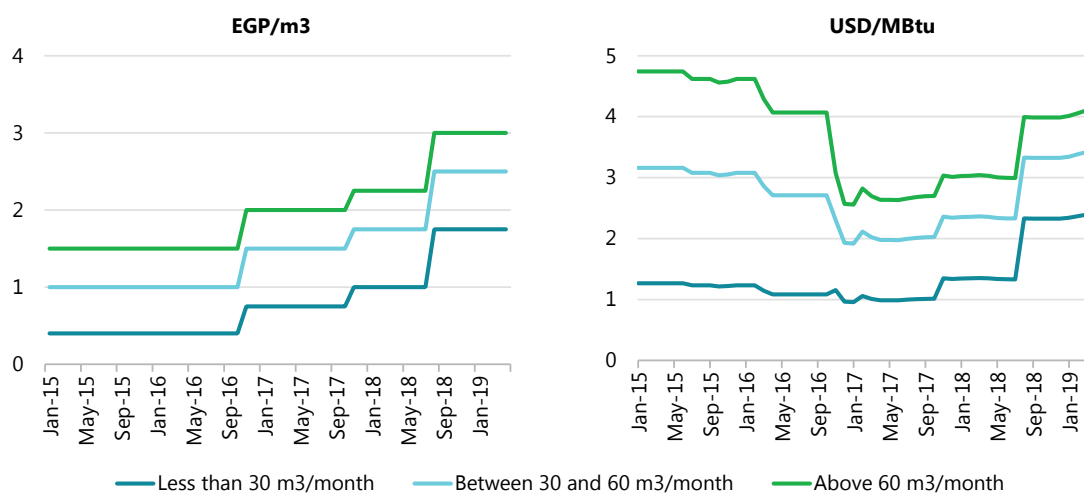
⁷ At the time of writing the latest available set of prices dates back to July 2018.

Egypt

Egypt became a net natural gas importer in 2015 after a decade of LNG exports, pushed by decreasing domestic production and growing consumption. In parallel with this shift in supply structure, the Egyptian government embarked on a process of liberalising its energy market, starting with the electricity sector with the enactment of the “New Electricity Law” (Law No. 87 of 2015). The law allows for private-sector participation in the generation and distribution of electricity, introduces the concept of competitive electricity markets and restructures the roles and competencies of incumbent utility and transmission companies to ensure fair competition. The electricity liberalisation process will be completed by 2022 (see Chapter 1).

Reform of the domestic natural gas market was introduced in August 2017 with the “Law for Gas Market Activities Regulation” (Law No. 196 of 2017), implemented in early 2018 by Prime Ministerial Decree No. 239 of 2018. The new framework encompasses the opening of the gas market to new shippers and suppliers, third-party access to infrastructure, the unbundling of vertically integrated companies, and the creation of the Gas Regulation Authority (GasReg) in charge of regulating and monitoring gas market activities – which does not include exploration and production (GasReg, 2017).

Figure 4.12. Evolution of natural gas consumer prices in Egypt, 2015–19



Sources: Central Bank of Egypt (2019), *Official Exchange Rates Historical*, www.cbe.org.eg/en/EconomicResearch/Statistics/Pages/OfficialRatesHistorical.aspx; Egypt Today (2017), “No increase in gas prices for factories: Minister”, www.egypttoday.com/Article/3/9297/No-increase-in-gas-prices-for-factories-Minister; Enterprise (2016), “Breaking news: Egypt to cut fuel subsidies, raise price of petrol at the pumps”, <https://enterprise.press/stories/2016/11/04/breaking-news-egypt-to-cut-fuel-subsidies-raise-price-of-petrol-at-the-pumps/>; Fick, M. (2014), “UPDATE 1-Egypt to lift natural gas prices for homes, businesses”, *Reuters*, www.reuters.com/article/egypt-energy-gas-idUSL6NoND1J520140421; Hua and Stanway (2018), “CORRECTED-UPDATE 1-Egypt hikes gas prices by up to 75 pct in IMF-backed austerity plan”, *Reuters*, www.reuters.com/article/egypt-economy-gas/update-1-egypt-hikes-gas-prices-by-up-to-75-pct-in-imf-backed-austerity-plan-idUSL8N1UH0DX.

Successive natural gas price hikes have been enacted since late 2016 as part of a wider economic reform programme and floating of the Egyptian pound.

The scope of the Gas Market Regulation law does not include natural gas pricing. On the production side, selling prices to the Egyptian Natural Gas Holding Company (EGAS), the Egyptian NOC, are determined by the provisions of production-sharing agreements. These were set at a flat rate of below USD 3/MBtu until the mid-2010s, and then substituted by individual prices negotiated on a project basis for recent offshore developments. On the

consumption side, natural gas prices are set by government decree. Prices for retail consumers have been revised three times since the end of 2016 (Figure 4.12), in conjunction with the reform programme linked to the USD 12 billion International Monetary Fund (IMF) three-year Extended Fund Facility (EFF) and the Central Bank of Egypt's decision to float the Egyptian pound against the US dollar in November 2016.

The latest price revision, enacted in September 2018, led to increases for retail consumers of up to 75%. Prices for industrial consumers increased by an average of 50% in November 2016 (Adel, 2016). Similar price revisions were conducted for petroleum products, electricity and other regulated products and services in the framework of the EFF reform programme. The IMF reported in February 2019, as part of its fourth EFF review, a decrease in the share of energy subsidies from 4.1% of gross domestic product in fiscal year (FY) 2016/17 to 2.1% for FY2018/19, and a projected 1.2% for FY 2019/20 (IMF, 2019). The Minister of Finance announced in late 2018 that Egypt would not seek further IMF funding at the end of the EFF. At the time of writing, there is no guideline on future natural gas price evolution or deregulation, in a context where Egypt regained self-sufficiency as a natural gas producer and is planning to progressively restart its LNG exports.

Russia

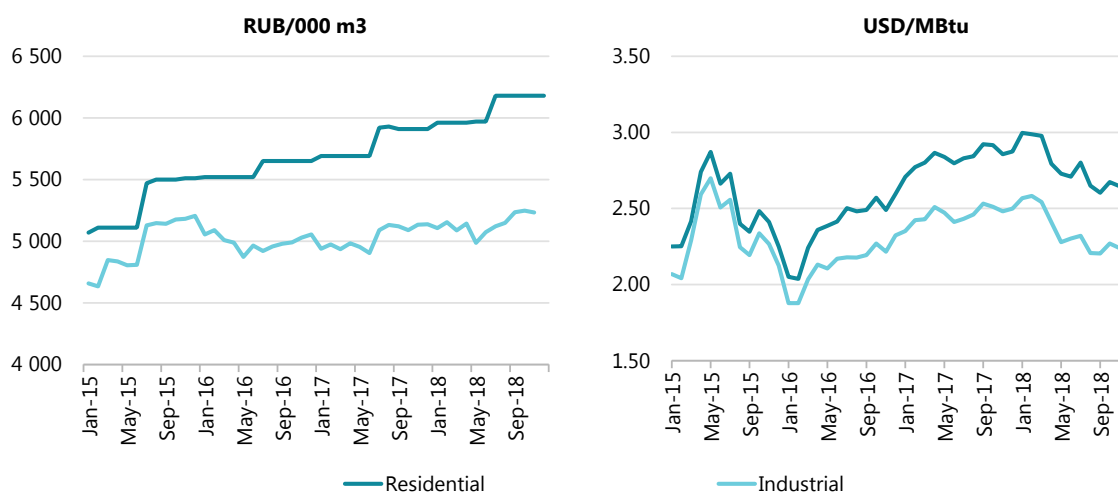
The objective of achieving a Russian domestic price transition to international benchmarks was first formulated in 2006 when the government announced its objective to converge with European netback prices.⁸ The successive price increases, coupled with the opportunity for alternative suppliers to enter the domestic market, led to a diminution of Gazprom's market share.

Gazprom retains its role of pipeline system operator and is required to provide non-discriminatory access to alternative suppliers – in 2017 it provided transmission services to 24 alternative suppliers for a volume of 138 bcm, out of a total of 354 bcm distributed domestically (representing a 40% market share for alternative suppliers excluding off-grid consumption) (Gazprom, 2019). Gazprom's main competitors on the domestic market are oil and gas producing companies such as Novatek, Rosneft and Lukoil. In respect of the cross-border natural gas trade, Gazprom retains its monopoly on pipeline exports, while the legal framework was amended in 2013 by Presidential Order to allow for alternative suppliers to export LNG (Reuters, 2013), which enabled Novatek to develop its Yamal LNG export facility.

The Federal Antimonopoly Service (FAS) reportedly drafted a government resolution in mid-2018 that supports a framework to ensure a transition to market-based prices for the wholesale natural gas market to be effective by mid-2019 (Analytical Center for the Government of the Russian Federation, 2018).

Retail prices for residential consumers have been re-evaluated several times over the recent past (Figure 4.13), growing by 22% between early 2015 and mid-2018 from RUB 5 070 (Russian rubles) to RUB 6 180 per thousand cubic metres. However, the ruble's depreciation since the beginning of 2018 has offset part of the increase when converting domestic prices into US dollars, thus widening the gap with international market prices.

⁸ That is, export prices to Europe minus transport costs and transit fees.

Figure 4.13. Evolution of natural gas prices in Russia, 2015–19

Source: Rosstat (2019), *Central Statistical Database*, www.gks.ru/dbscripts/cbsd/DBInet.cgi?pl=9460018.

The gas price for residential consumers has increased by over 20% since early 2015, while prices for industrial customers have remained stable.

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Annexes

Tables

Table A.1 World natural gas demand by region and key country (bcm)

Region	2000	2010	2018*	2020	2022	2024
Asia Pacific	310	586	837	906	982	1 063
China	25	106	284	334	392	450
India	28	64	61	69	78	89
Japan	83	102	128	121	116	108
North America	794	850	1 056	1 079	1 096	1 116
United States	661	683	855	873	884	895
Middle East	174	369	526	550	573	597
Iran	62	144	214	222	231	239
Saudi Arabia	38	73	91	95	98	102
Eurasia	565	650	666	667	664	662
Russia	391	466	493	488	483	479
Caspian	82	105	121	129	130	132
Europe	509	605	536	532	537	538
European Union	481	545	476	473	478	478
Central and South America	96	152	168	172	178	181
Argentina	37	46	53	55	56	57
Brazil	9	27	34	34	35	35
Africa	57	106	151	163	170	177
Algeria	20	27	45	45	47	50
Egypt	18	44	60	69	74	76
World	2 505	3 315	3 940	4 069	4 200	4 332

Note: 2018* 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: 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 A.2 World natural gas demand by sector and region (bcm)

Region	2000	2010	2018*	2020	2022	2024
Asia Pacific	310	586	837	906	982	1 063
Power generation	141	267	344	355	364	376
Industry	80	148	229	260	294	333
Residential and commercial	42	89	132	144	163	185
North America	794	850	1 056	1 079	1 096	1 116
Power generation	190	279	389	407	413	418
Industry	232	182	216	232	241	249
Residential and commercial	262	254	288	266	261	260
Middle East	174	369	526	550	573	597
Power generation	79	164	221	234	245	257
Industry	56	122	156	164	171	179
Residential and commercial	22	47	75	76	77	79
Eurasia	565	650	666	667	664	662
Power generation	308	340	329	329	327	326
Industry	80	109	115	118	118	118
Residential and commercial	109	106	118	117	116	115
Europe	509	605	536	532	537	538
Power generation	137	207	162	161	167	167
Industry	148	131	133	133	133	134
Residential and commercial	195	226	207	205	205	204
Central and South America	96	152	168	172	178	181
Power generation	26	44	58	57	59	59
Industry	34	57	52	53	55	57
Residential and commercial	11	15	19	20	20	21
Africa	57	106	151	163	170	177
Power generation	28	57	79	85	88	92
Industry	12	25	33	35	38	40
Residential and commercial	4	6	13	14	15	15
World	2 505	3 315	3 940	4 069	4 200	4 332

Note: 2018* 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 A.3 World natural gas production by region and key country (bcm)

Region	2000	2010	2018*	2020	2022	2024
Asia Pacific	290	490	625	653	683	724
Australia	33	53	132	144	149	152
China	27	96	160	184	211	242
Indonesia	70	86	73	73	73	74
North America	765	817	1 076	1 153	1 182	1 216
United States	545	604	859	950	981	1 016
Middle East	196	463	640	653	686	713
Iran	59	144	220	225	237	245
Qatar	24	121	171	171	172	175
Saudi Arabia	38	73	92	95	98	100
Eurasia	709	828	939	954	990	1 016
Russia	573	657	725	737	761	771
Caspian	118	150	192	196	207	223
Europe	319	315	250	232	218	202
The Netherlands	74	90	38	32	21	10
Norway	53	110	127	124	125	126
United Kingdom	115	58	41	40	36	33
Central and South America	99	160	179	176	182	190
Argentina	41	42	47	50	54	57
Brazil	7	15	25	25	26	26
Africa	124	210	231	248	259	271
Algeria	82	85	96	92	92	95
Egypt	18	57	58	74	77	77
World	2 503	3 284	3 940	4 069	4 200	4 332

Note: 2018* 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: Armenia, Azerbaijan, Georgia, Kazakhstan, Kyrgyzstan, Tajikistan, Turkmenistan and Uzbekistan.

Table A.4 World LNG liquefaction capacity by region (bcm)

Region	2000	2010	2018	2020	2022	2024
Asia Pacific	75	110	208	223	229	229
North America	-	-	31	88	105	122
Middle East	32	113	136	136	136	136
Eurasia	-	13	28	36	37	37
Europe	-	6	6	6	6	6
Central and South America	4	24	27	27	27	27
Africa	28	73	93	94	98	102
World	140	338	529	610	638	659

Note: This includes capacity currently offline due to technical or security issues

Table A.5 World LNG regasification capacity by region (bcm)

Region	2000	2010	2018	2020	2022	2024
Asia Pacific	350	460	672	752	793	793
North America	62	184	189	189	189	189
Middle East	-	-	31	39	39	39
Eurasia	-	-	-	4	4	4
Europe	79	178	241	249	252	252
Central and South America	4	18	46	59	59	59
Africa	-	-	13	11	3	3
World	495	840	1 192	1 308	1 339	1 339

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.²

Asia 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,³ the Philippines, Singapore, Sri Lanka, Thailand, Viet Nam and other Asian countries and territories.⁴

Caspian

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

Central and South 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.⁵

Eurasia

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

² 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.

³ Including Hong Kong.

⁴ 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.

⁵ 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, St. Vincent and the Grenadines, Suriname and Turks and Caicos Islands.

Europe

Albania, Austria, Belgium, Bosnia and Herzegovina, Bulgaria, Croatia, Cyprus,⁶ Czech Republic, Denmark, Estonia, Finland, the Former Yugoslav Republic of North Macedonia, France, Germany, Gibraltar, Greece, Hungary, Iceland, Ireland, Italy, Kosovo,⁷ 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,⁸ 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.

Middle East

Bahrain, the Islamic Republic of Iran, Iraq, Israel,⁹ Jordan, Kuwait, Lebanon, Oman, Qatar, Saudi Arabia, the Syrian Arab Republic, the United Arab Emirates and Yemen.

North Africa

Algeria, Egypt, Libya, Morocco and Tunisia.

North America

Canada, Mexico and the United States.

⁶ 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.

⁷ The designation is without prejudice to positions on status, and is in line with the United Nations Security Council Resolution 1244/99 and the Advisory Opinion of the International Court of Justice on Kosovo's declaration of Independence.

⁸ Note by Turkey: The information in this document with reference to "Cyprus" relates to the southern part of the Island. There is no single authority representing both Turkish and Greek Cypriot people on the Island. Turkey recognises the Turkish Republic of Northern Cyprus (TRNC). Until a lasting and equitable solution is found within the context of United Nations, Turkey shall preserve its position concerning the "Cyprus issue".

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⁹ 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.

List of acronyms, abbreviations and units of measure

Acronyms and abbreviations

ADGSM	Australian Domestic Gas Security Mechanism
APM	Administered Pricing Mechanism (India)
ARS	Argentinian peso
ASEAN	Association of Southeast Asian Nations
CAAGR	compound annual average growth rate
CCGT	combined-cycle gas turbine
CBM	coalbed methane
CDD	cooling degree days
CNOOC	China National Offshore Oil Corporation
CNG	compressed natural gas
CNPC	China National Petroleum Corporation
CNY	Chinese yuan renminbi
DUC	drilled but uncompleted well
EFF	Extended Fund Facility
EGAS	Egyptian Natural Gas Holding Company
EIA	Energy Information Administration
EOR	enhanced oil recovery
FAI	Fertiliser Association of India
FID	final investment decision
FLNG	floating liquefied natural gas
FSRU	floating storage and regasification unit
FY	fiscal year
FYP	Five-Year Plan
GDP	gross domestic product
HDD	heating degree days
HELP	Hydrocarbon Exploration Licensing Policy (India)
IMF	International Monetary Fund

IMO	International Maritime Organization
INR	Indian rupee
JCC	Japanese Crude Cocktail
L-cal	lower calorific value
LNG	liquefied natural gas
LNGC	liquefied natural gas carrier
LPG	liquefied petroleum gases
LTO	light tight oil
NDRC	National Development and Reform Commission (China)
NEA	National Energy Administration (China)
NNPC	Nigerian National Petroleum Corporation
NOC	national oil company (China)
NPD	Norwegian Petroleum Directorate
NPT	Nadym-Pur-Taz (Russia)
NRA	Nuclear Regulation Authority (Japan)
OGRA	Oil and Gas Regulatory Authority (Pakistan)
OIL	Oil India
ONGC	Oil and Natural Gas Corporation (India)
OPEC	Organization of the Petroleum Exporting Countries
PKR	Pakistani rupee
PNGRB	Petroleum and Natural Gas Regulatory Board (India)
PSC	production-sharing contract
PSO	Pakistan State Oil
PV	photovoltaic
RMG	ready-made garments
SHPGX	Shanghai Petroleum and Natural Gas Exchange
TANAP	Trans-Anatolian Natural Gas Pipeline
TAP	Trans-Adriatic Pipeline
TPA	third-party access

TSO	transmission system operator
TTF	Title Transfer Facility (the Netherlands)
UGS	underground gas storage
USD	United States dollar
WND	West Nile Delta
y-o-y	year-on-year

Units of measure

bcm	billion cubic metres
bcm/y	billion cubic metres per year
GW	gigawatt
GWe	gigawatts electrical
km	kilometre
mb/d	million barrels per day
mcm	million cubic metres
mcm/d	million cubic metres per day
MBtu	million British thermal units
MJ/m ³	megajoules per cubic metre
Mtpa	million tonnes per annum
m ³	cubic metre
MW	megawatt
MWe	megawatt electrical
MWh	megawatt hour
tcm	trillion cubic metres
tCO ₂ -eq	tonne of CO ₂ equivalent
TWh	terawatt hour

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Natural gas demand grew at a remarkable clip last year, increasing by 4.6%, its highest growth rate since the beginning of the decade. Future growth will be more measured, supported by economic expansion in emerging markets – especially in Asia – and sustained policy support in the People’s Republic of China to battle air pollution.

The supplies to meet that new growth will come from both new domestic production in these fast-growing economies but also increasingly from major exporting countries, led by the development of the abundant shale gas resources in the United States. International trade, supported by the strong growth in liquefied natural gas export capacity, will play a growing role in the development of natural gas markets as they move further towards globalisation. The recent convergence in market prices in major regions provides an indication of this increasing integration. However, establishing market-driven pricing mechanisms in fast-growing countries remains a challenge – albeit one that is being addressed by pricing reforms in several leading emerging economies around the world.